AMERICAN ELECTRIC POWER

2010 AEP-EAST INTEGRATED RESOURCE PLAN

2011-2020

Issued: 2010

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 and regulatory proposals to control carbon, hazardous air pollutants and coal combustion residuals

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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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 for a largely regulated utility such as AEP is to cost-effectively match its energy supply needs with projected customer demand. 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 are currently mandated or projected to be mandated.

Planning for future resource requirements during volatile periods can be challenging. The robustness and timing of economic recovery and its impact on load, commodity prices, varying levels of proposed or emerging environmental legislation or federal regulation regarding greenhouse gases/carbon dioxide (GHG/CO_2), hazardous air pollutants (HAPs), coal combustion residuals (CCR) as well as existing and proposed mandates for renewable energy and demand-side management (DSM) represent major "drivers" of uncertainty that must be addressed during this planning process.

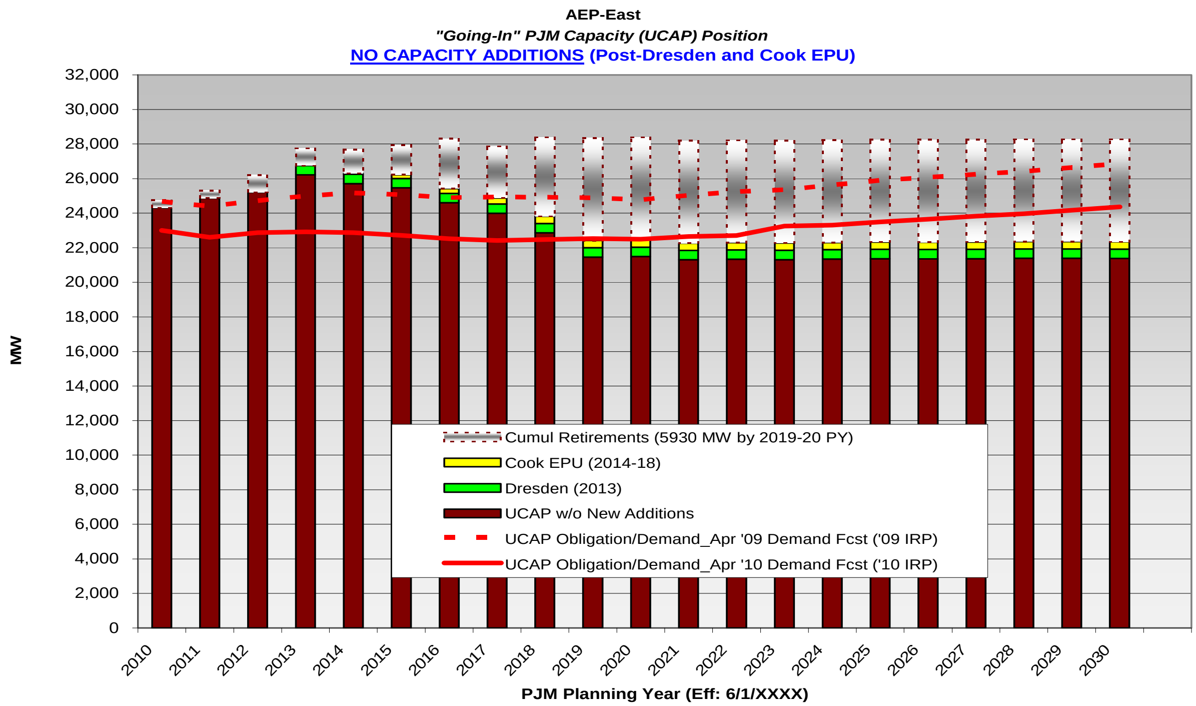
This Executive Summary provides high-level results of the Integrated Resource Plan (IRP or "Plan") process and analyses for the AEP-East zone of the AEP system covering the 10-year period 2011-2020 (Planning Period), with additional modeling and analyses conducted through 2030 (Study Period).[1]

The following **Summary Exhibit 1** offers the "going-in" capacity need of each of the AEP-East zone prior to uncommitted capacity additions. It amplifies that the region's overall capacity need does not occur until the end of the Planning Period (2018-2019). "Committed" new capacity embedded in this Plan includes completion of the 540 MW Dresden combined cycle facility in 2013, the assumed performance of the Donald C. Cook Nuclear Plant Extended Power Uprate (EPU) project, and assumed near-term execution of purchase power agreements for renewable energy (largely, wind) resources.

This going-in capacity profile also considered the potential retirement of close to *6,000 MW* of primarily older, less-efficient coal-fired units over the Planning Period due largely to external factors including known or anticipated environmental initiatives from the U.S. Environmental Protection Agency (EPA), as well as the December 2007 stipulated New Source Review (NSR) Consent Decree. In spite of this potential, this AEP-East IRP requires no new baseload capacity resources in the forecast period. Rather, the proposed EPU initiative at the Cook Nuclear Station during the 2014-2018 time period and peaking resources required in 2017 and 2018, in addition to wind purchases and DSM are assumed to be added to maintain anticipated minimum PJM capacity reserve margin requirements (approximately 15.5% of peak demand) as well as system reliability/restoration needs. It is anticipated that additional natural gas-fired peaking and intermediate capacity would be added shortly after the 2020 Planning Period to meet future load obligations.

[1] Whereas this document focuses on collective affiliate Operating Company planning requirements of the "AEP-West" zone companies operating within the Southwestern Power Pool (SPP) Regional Transmission Organization (RTO), or *"AEP-SPP"*, comparable planning has also been performed for the affiliate *East* zone AEP Operating Companies residing in the PJM RTO.

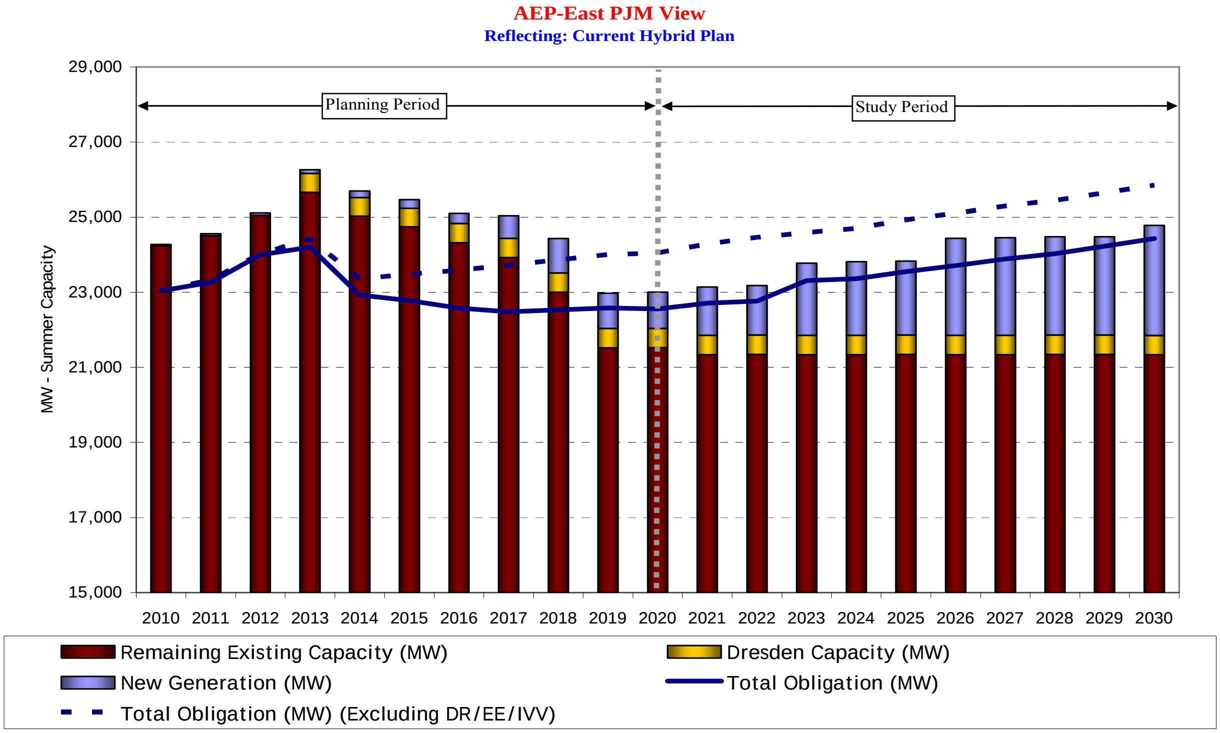
Summary Exhibit 1



Source: AEP Resource Planning

The following **Summary Exhibit 2** demonstrates AEP-East's capacity position relative to this PJM reserve requirement, now inclusive of capacity additions as proposed in this 2010 IRP. As this table indicates, the combination of traditional supply-side additions and demand-side measures that provide demand reductions/energy efficiency (DR/EE) allow AEP-East to meet this PJM reserve margin criterion.

Summary Exhibit 2



Source: AEP Resource Planning

Major Drivers

Load

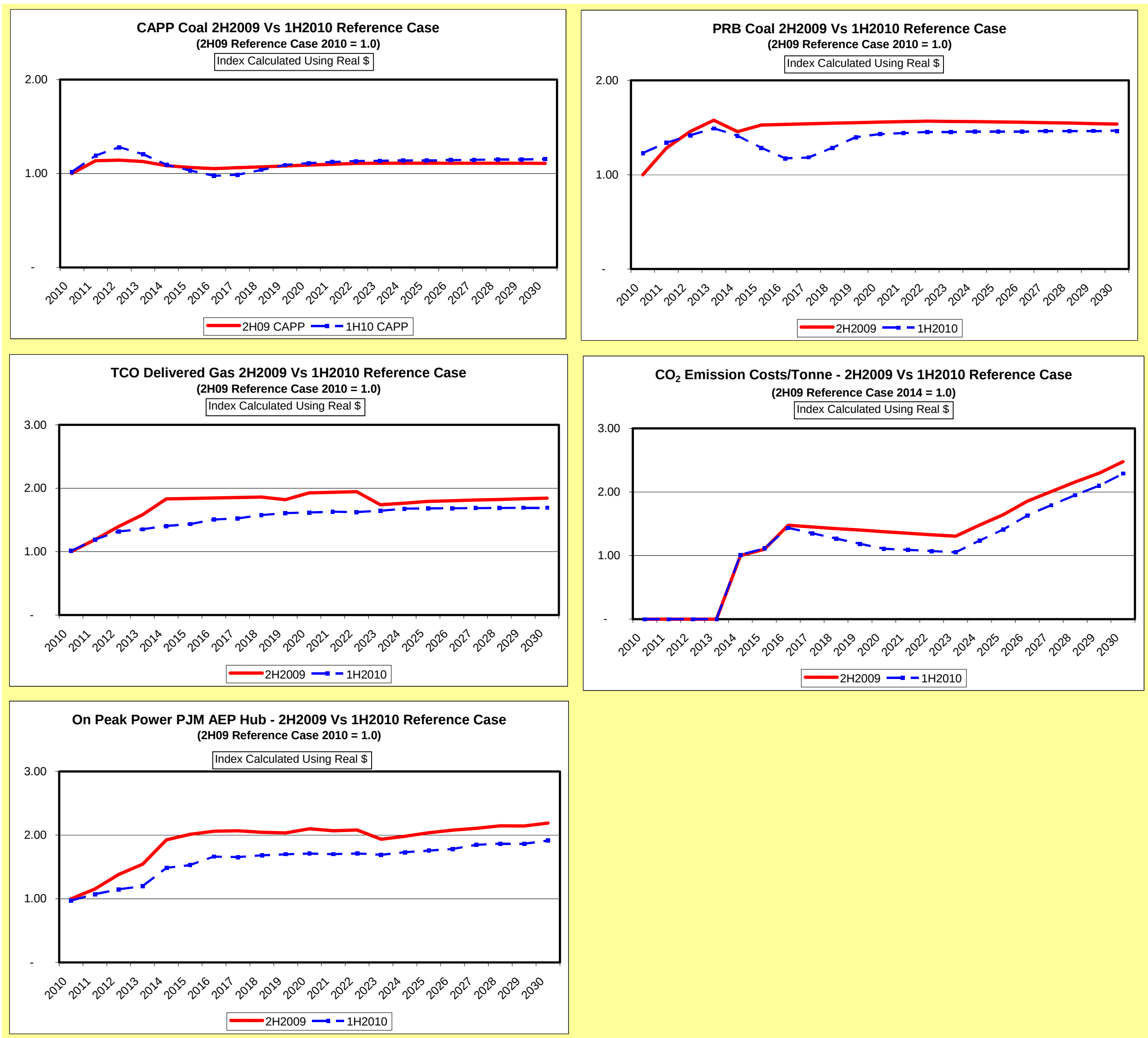
Anticipated load and peak demand is one of the chief underpinnings of the planning process. Over the 10-year Planning Period, the AEP-East region's internal demand profile has a 0.71% Compound Annual Growth Rate (CAGR). This equates to an approximate **150 MW per year increase** over the Planning Period if the load growth was uniform. This is considerably lower than the CAGR projected in the previous, 2009 IRP load forecast of 1.31 percent, or about 280 MW annually. This lower growth rate obviously delays the need for replacement capacity even with the prospect of accelerated AEP-East coal unit retirements.

Commodity Pricing

AEP updates its commodities forecast twice each year. The Fall of 2009 forecast (2H09 Forecast) was used as the basis for resource modeling in this IRP process. After comparing the 2H09 Forecast to the subsequent long term forecast prepared in the Spring of 2010 (1H10 Forecast), as shown in **Summary Exhibit 3**, it was apparent that the effects of the recently-revised pricing estimates were not significant in determining future resource additions and did not warrant a new resource evaluation. Note that with the economic recovery, prices for on-peak power, coal and natural gas will rise in real terms over the next 3 to 5 year period and then remain relatively stable.

Summary Exhibit 3

Commodity Price Comparison 2H09 to 1H10



Potential Carbon Legislation

There has been much activity and discussion in Congress regarding legislation to require reductions in GHG/CO_2 emissions. In this 2010 IRP it has been assumed that such legislated or regulated carbon restrictions will ultimately be established. The pricing assumptions and requirements for CO_2 used in this IRP were developed after the U.S. House passage of the Waxman-Markey Bill. Future IRPs will naturally reflect legislation (or regulation) that is enacted or developed after this report is issued. The driving planning assumptions around Climate Change in this 2010 IRP include substantive GHG/CO_2 reduction legislation effective *by 2014* with an economy-wide cap-and-trade regime effective in the same year. Although Waxman-Markey assumes a 2012 start-date, and more recent legislation introduced in the Senate ("Kerry-Lieberman" Discussion Draft) assumes a 2013 start-date, the assumption is that such comprehensive GHG/CO_2 legislation will not be approved by Congress this year and, as such, will not be effective until *at least* 2014.

Proposed EPA Rulemaking

The 2010 IRP considered potential future U.S. EPA rulemaking around HAPs. According to the AEP Environmental Services group, such federal rulemaking for HAPs could become effective by as early as the end of 2015 when a "command-and-control" policy could require all U.S. coal and lignite units to install Maximum Available Control Technologies (MACT) including (combined) Flue Gas Desulphurization (FGD), Selective Catalytic Reduction (SCR), as well as, potentially, Activated Carbon Injection (ACI) with fabric filter emissions control equipment for mercury and numerous other heavy metals, toxic compounds, and acid gases.

In addition, new rules on the handling and disposal of CCR are also being developed and could likewise be implemented as early as 2017, requiring significant additional capital investment in the coal fleet to convert "wet" flyash and bottom ash disposal equipment and systems—including attendant landfills and ponds—to "dry" systems, plus build waste-water treatment facilities to address plant groundwater run-off. Further, the federal EPA has also recently issued proposed rulemaking to replace the former Clean Air Interstate Rules (CAIR) for sulfur dioxide (SO_2), oxides of nitrogen (NO_X), and particulate matter (PM), which had previously been vacated by the federal courts. In lieu of a national cap-and-trade for those effluents, this "Transport Rule" would potentially establish *state-specific* emission budgets for SO_2 and both Annual and Seasonal (May-September) NO_X. In the AEP-East zone states (Indiana, Kentucky, Ohio, Virginia and West Virginia), such proposed Transport Rule emission reduction requirements are likewise contentious in that it would theoretically involve acceleration of already-planned environmental retrofits to as early as January, 2014; in-service dates that may be implausible to achieve.

In summary, the cumulative cost of complying with these collective emerging environmental rules could ultimately be hugely burdensome on the AEP-East Operating Companies and its customers. Therefore, such requirements, if formally established by EPA, could then also accelerate proposed retirement dates of any currently non-retrofitted coal unit in the AEP-East fleet as established within this 2010 IRP as discussed below.

Additional Potential Coal Unit Dispositions

An AEP-East unit disposition study was undertaken by an IRP Unit Disposition evaluation team involving numerous AEP functions. As in the past, the team's primary intent was to assess the relative composition and timing of potential unit retirements. As in previous reviews, the predominant focus in the East was again on the roughly 5,300 MW of older-vintage, less-efficient, non-environmental control-retrofitted (i.e., "Fully-Exposed") coal units in the AEP-East fleet.

As suggested above, in this 2010 IRP cycle review, the team considered financial implications of the potential (dispatch) cost impacts associated with CO_2 emissions, as well as cost to comply with assumed HAPs rulemaking. In addition, factors including PJM operational flexibility, emerging unit liabilities, and workforce/community impacts were considered when recommending the relative multi-tier profile of potential unit retirements.

It should be noted that the conclusions of this updated unit disposition 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 Consent Decree related to the NSR litigation.

AEP has assumed for planning purposes that all of the "Fully-Exposed" coal units in the AEP-East fleet would be retired over the course of the decade under the notion that the implementation of any U.S. EPA HAPs and/or CCR rulemaking would be potentially "extended and staggered" beyond end-of 2015 in recognition of the national exposure (i.e., roughly 1/3 of U.S. coal units that are likewise fully-exposed and not likely to be retrofitted to achieve such rules.) Moreover, given the relative 'retrofit vs. retire' economics, it is further assumed that OPCo's ***Muskingum River Unit 5****—a relative newer, more thermally-efficient 600-MW coal unit—would likewise be retired in the mid-to-late Planning Period... for a total of nearly 6,000 MW of coal unit retirements.*[2]

Carbon Capture and Storage Technology

While the 2010 IRP does not include any coal-fired baseload additions, it does recognize that the existing fossil fleet will likely be subject to CO_2 emission reduction requirements in the future be it through legislated or regulated means. Therefore, the Plan includes the continued development and phase-in of Carbon Capture and Storage (CCS) at the (APCo) Mountaineer Plant as a practical, technology-advancing strategy. AEP has received partial funding from the U.S. Department of Energy (DOE) on the proposed Phase 2 (235-MW slipstream) CCS initiative at Mountaineer. Projects such as this one will position us well should legislation provide for "Bonus Allowances". Both the Waxman-Markey Bill and the (Draft) Kerry-Lieberman comprehensive climate change legislation in the U.S. Senate offer such "Bonus Allowance" provisions.

Assuming such CCS Bonus Allowances *are* available, this 2010 AEP-East IRP has also assumed that both the APCo Mountaineer Station and a unit at the OPCo Gavin Station (combined 2,600 MW) would have CCS fully-installed toward the end of the Planning Period in 2019-2020.

[2] For 2010 Plan purposes, other than Muskingum River U5, all other comparable AEP-East "Partially-Exposed" coal units not currently fully-retrofitted to meet either NSR Consent Decree or anticipated HAPs rulemaking requirements (Big Sandy Unit 2, Rockport Units 1&2, Conesville Units 5&6) are assumed to be retrofitted and would *continue operation* throughout the Study Period.

Peak Demand Response and Energy Efficiency

Recognizing the prospects of higher marginal or "avoided" costs, AEP initiatives to improve grid efficiency and install advanced metering, as well as a national groundswell focused on usage efficiency, the AEP-East 2010 IRP reflects approximately 415 MW of incremental peak demand reduction (above the 473 MW of interruptible load currently in place) by the end of 2011, growing to 1,213 by the end of 2014.

These incremental reductions in peak demand result from a suite of sources including:

- "Passive" demand reductions via customer-focused energy efficiency ("24/7"-type) programs (560 MW);
- "Active" demand response ("peak shaving"-type) program opportunities (600 MW); and
- unique utility infrastructure efficiency initiatives such as Integrated Volt/Var Control (IVVC) (53 MW).

Further, this Plan fully reflects legislative and regulatory mandated levels of AEP-East Operating Company energy efficiency and demand response in Ohio, Indiana and Michigan.

Wind and Other Renewable Resources

Along with the prospects of comprehensive GHG/CO_2 legislation—or even as a "carve-out" as part of any potential Energy Bill that could be contemplated in Congress—the possible introduction of a Federal Renewable Portfolio Standard (RPS) has resulted in the planned AEP system-wide addition of 2,000 MW of renewable resources by approximately mid-decade, or end-of-2014. Note that this represents an approximate 3-year shift from prior (2009 IRP) planned commitments of 2,000 MW of System-wide renewable resources by the end of *2011*; however, as recent unfavorable regulatory decisions in both Virginia and Kentucky surrounding cost recovery of planned wind purchase transactions has resulted in this "extension" of that prior goal.

The largest portion of these additions (about 1,100 MW nameplate of, predominantly, wind resources) is assumed to be applicable to AEP-East. Placed in addition to current and planned AEP-SPP region affiliates—Public Service Company of Oklahoma (PSO) and Southwestern Electric Power Company (SWEPCO)—long-term wind development/purchases as well as economically-screened biomass co-firing opportunities, the overall AEP System is positioned to achieving a ***target of 10 percent of energy sales from renewable sources by the end of the IRP Planning Period (2020)***, again consistent with Ohio Substitute S.B. 221 and other state-mandated renewable requirements in Michigan, West Virginia, Oklahoma and Texas.

Emerging Technologies

AEP is committed to pursuing emerging technologies that fit into the capacity resource planning process including, among others, fuel cells, solar, energy storage as well as "smart-grid" enabling meters and distribution infrastructure. These largely *distributed* technologies, while currently expensive relative to traditional demand and supply options—and in consideration of AEP-East's current capacity and energy "length" in PJM—have the capability to evolve into far more common and accepted resource options as costs come down and performance/efficiencies continue to improve. For each of these options, both the technology and associated costs will continue to be very closely monitored for inclusion in future annual planning cycles.

As an example, the 2010 AEP-East IRP includes the addition of IVVC technology into the distribution system infrastructure which will reduce voltages and, hence customer usage behind the meter. This technology therefore helps cost-effectively mitigate the need for new capacity and reduces energy requirements resulting in reduced emissions.

Portfolio Risk Analysis

Given the uncertainties facing AEP in the future, a number of diverse resource portfolios were analyzed under a wide range of future commodity pricing scenarios. This allowed the resource planners to evaluate whether near-term decisions may adversely impact future costs to customers. The portfolios that were evaluated include accelerated near-term coal unit retirements (over-and-above Muskingum River U5), additional DR/EE and renewable resources, the addition of nuclear capacity, as well as various combinations of these end-states under various commodity pricing scenarios. This exercise provided intelligence in establishing the final recommended plan.

AEP-East Recommended Plan: 2011-2020

(Including AEP-East Company Responsibility)

- ✓ Complete the 540 MW Dresden Combined Cycle Facility by 2013 (AEG-APCo)
- ✓ Retire 5,930 MW of coal-fired generating units over the period: 2012-to-2019 (Various), including the 600 MW Muskingum River Unit 5 (OPCo)
- ✓ 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 peaking duty cycle (e.g., Combustion Turbine) capacity: 314 MW by 2017 (APCo), and an additional 314 MW by 2018 (KPCo/APCo) for both ultimate capacity *and* anticipated system reliability/restoration ("Black Start") requirements
- ✓ Purchase or construct an *additional* 1,600 MW (nameplate) of wind generation by 2020 (Various), over-and-above the 626 MW already in operation, to achieve both state-mandated renewable requirements (OH, MI, WVa) as well as contribute to a 10% (of retails sales) "target" by 2020
- ✓ Co-fire with biomass feedstock at existing units, or acquire the "equivalent" of approximately 150 MW of dedicated biomass generation by 2018 (CSP, OPCo, & APCo)
- ✓ Purchase or construct an additional 215 MW (nameplate) of solar generation for the AEP-Ohio Companies (CSP and OPCo) in order to achieve "solar-specific" renewable mandates set forth under Ohio S.B. 221, in addition to the 10 MW solar (Wyandot) PPA already in operation
- ✓ Continue the Carbon Capture and Storage (CCS) project at Mountaineer (APCo) and ultimately fully install CCS at Mountaineer and Gavin Unit 1 (OPCo) by 2020 [3]
- ✓ Implement Energy Efficiency programs totaling over 6,000 GWh (868 MW of attendant "passive" Demand Response) by 2020 across all AEP-East states/companies to meet either legislative or regulatory mandated (OH, MI, IN) requirements or, incrementally, known/anticipated initiatives in non-mandated states
- ✓ Implement "Active" Demand Response initiatives totaling 600 MW by 2015 (Various)
- ✓ Upgrade the distribution system with IVVC technology, reducing (peak) demand by 106 MW and customer energy usage totaling roughly 500 GWh by 2018 (Various)

[3] Any CCS implementation beyond the current Mountaineer "Phase 2" (235-MW slipstream) project would be subject to qualification and receipt of cost-offsetting "(CO_2) Bonus Allowances" emanating from potential comprehensive Climate Change legislation currently before the U.S. Congress.

The following **Summary Exhibit 4** offers a view of the 2010 AEP-East IRP:

Summary Exhibit 4

"Hybrid" Portfolio:

Reflective of April-10 Load Forecast (a)

AEP-East

Period	Pln Yr	(b) Capacity (Retire)	CCS Retrofit Unit	CCS Retrofit Capac	CCS Retrofit Derate	Efficiency: Dem (c) Response ("Active"DR)	Efficiency: Energy (a) Efficiency ("Passive"DR)	Efficiency: Infrastruc. (e.g. IVVC)	Renewable (Nameplate) (d): Wind	Renewable (Nameplate) (d): (e) Biom	Renewable (Nameplate) (d): Solar	Thermal Resources (summer rating)	Oper Co. Assigned		PJM-CLR Capacity Position (above PJM IRM min) (MW)
	2010	*(440)*					16		451		10			(f)	*1,240*
(10-Year) Planning Period	*2011*					100	90		101	*44*	10			(g)	*1,292*
	2012	*(560)*				100	93		100		11			(h)	*1,113*
	2013					150	102		100	25	10	(Dresden) CC-540	*APCo*		*2,038*
	2014	*(395)*				150	112	19	300	25	26	Cook2 (Ph1)-45	*I&M*		*2,720*
	2015	*(925)*	*MT*	*235*	*(58)*	100	89	31	400		27	Cook1&2 (Ph1&2)-168	*I&M*		*2,188*
	2016	*(1,175)*					67	17	250	*(44)*	26	Cook1 (Ph2)-68	*I&M*		*1,934*
	2017	*(675)*					59	16	150		26	Cook2 (Ph3)-68 NG Peaking-314	*I&M* *APCo*	(i)	*1,968*
	2018	*(400)*					48	17	50	*100*	26	Cook1 (Ph3)-68 NG Peaking-314	*I&M* *APCo/KPCo*	(j)	*1,856*
	2019	*(1,373)*	*MT*	*1,065*	*(137)*		88		100		26				*343*
	2020		*GV1*	*1,300*	*(195)*		104		150		27				*399*
Study Period	*2021*						72		100	*50*	29	NG Peaking-314	*APCo/KPCo*	(k)	*388*
	2022		*AM3*	*1,300*	*(195)*		51		100		45				*359*
	2023						35		200			NG Intermediate-611	*APCo*		*420*
	2024						21		150	*100*	45				*403*
	2025						16		150						*232*
	2026						5		150		20	NG Intermediate-611	*APCo*		*677*
	2027						1		150	*50*					*523*
	2028								100		25				*403*
	2029														*204*
	2030										31	NG Peaking-314	*APCo*		*304*
				3,900				*"Nameplate"*	*3,252*	*350*	*420*				
	Cumul.	*(5,943)*			*(585)*	600	1,069	100	423	50	160	3,435			

2010-2030
Net Addition
(692)

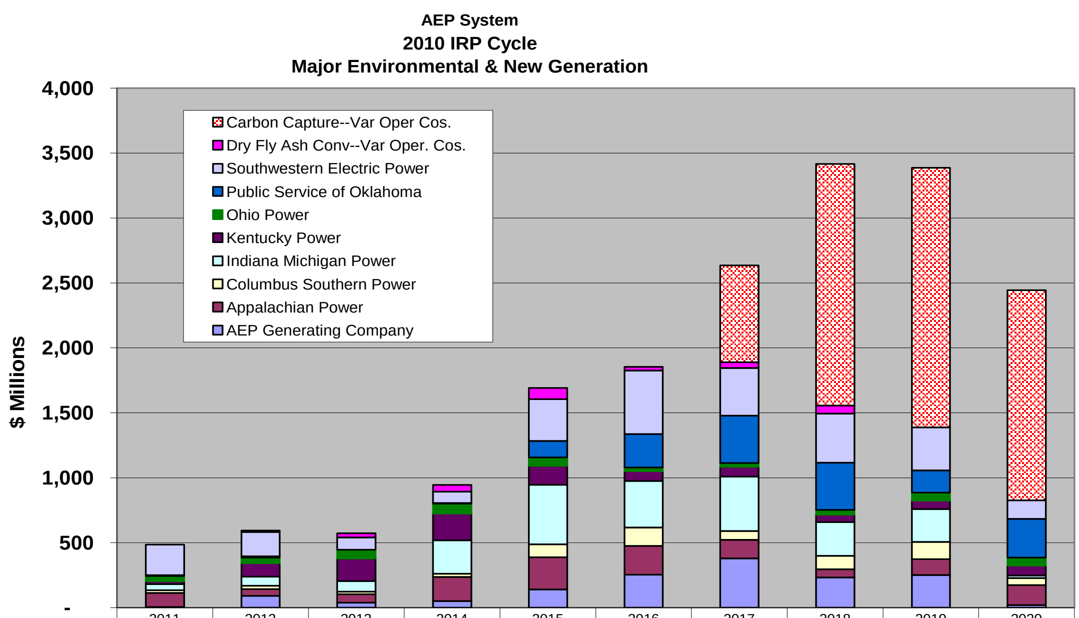
(a) *Underlying Peak Demand as well as "Passive" (Energy Efficiency) Demand Reduction levels are per AEP-Economic Forecasting "**April '10**" **Forecast** (Note: includes mandated EE requirements in OH, IN, MI)*
(b) Reflects PJM planning year that capacity is de-committed in PJM-FRR
(c) "Active" DR (i.e. demand response curtailment programs/tariffs) only
(d) 13% of wind nameplate and 38% of solar nameplate can be "counted" as PJM capacity (per *initial* PJM criteria)
… Assumes 'full-year' energy impact (i.e. *in-service* by 12/31 of Year -1)
(e) Only 25 MW '2013' and '2014' biomass represents incremental capacity via a dedicated biomass facility (assumed AEP-Ohio PPA)…
… balance represents 'equivalent' biomass-sourced energy via co-firing.... through, initially, *existing* AEP-Ohio units
(f) "2010" wind: Fowler Ridge I, II & II (350 MW: AP, I&M, CSP, OP); Grand Ridge I & III (100.5 MW: AP)… "2010" solar: Wyandotte (10MW: CSP, OPCo)
(g) "2011" wind: Beech Ridge (100.5 MW: AP) only… i.e., assumes Lee-Dekalb (100 MW: KP) eliminated as KPSC denied recovery and, as per contract, it may then be voided
(h) "2012" wind: Represents 'Unidentified' 100-MW wind designated to AEP-Ohio companies to be in-keeping w/ requirements of S.B. 221
(i) Assumes advanced four-years (from 2021) to provide Black-Start requirements @ TC area
(j) " " three-years (from 2024) to provide Black-Start requirements @ KM area
(k) " " three-years (from 2021) to provide Black-Start requirements @ SP area

Source: AEP Resource Planning

Plan Impact on Capital Requirements

This Plan includes new capacity resource additions, as described, as well as unit uprates and assumed 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 5** includes estimates for such projects over the entire AEP System.

Summary Exhibit 5



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Carbon Capture--Var Oper Cos.	-	-	-	-	-	-	746	1,861	2,000	1,618
Dry Fly Ash Conv--Var Oper. Cos.	-	12	34	52	86	28	43	62	-	-
Southwestern Electric Power	236	187	95	87	320	488	366	377	330	142
Public Service of Oklahoma	6	9	0	5	127	258	366	364	172	299
Ohio Power	40	43	66	77	65	28	30	36	62	63
Kentucky Power	23	104	174	207	145	75	76	56	65	76
Indiana Michigan Power	47	70	81	257	458	360	418	261	252	19
Columbus Southern Power	21	27	20	25	100	141	69	103	133	55
Appalachian Power	107	52	66	185	248	222	141	63	122	155
AEP Generating Company	5	90	37	50	140	253	380	232	252	18

Source: AEP Resource Planning

It is important to reiterate the capital spend level reflected on the **Summary Exhibit 5** is "incremental" in that it does not include "Base"/business-as-usual capital expenditure requirements of the generation facilities or transmission and distribution capital requirements. 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 is subject to change* as, particularly, AEP's system-wide and operating company-specific "Capital Allocation" processes continue to be refined. Also, while the spend level includes cost to install Carbon Capture equipment, these projects are included only under the assumption that any comprehensive GHG/CO_2 bill requiring significant reductions in CO_2 emissions will include a provision to receive credits or allowances that would largely offset the cost of such equipment.

Conclusions

The recommended AEP-East capacity resource plan reflected on **Summary Exhibit 4 provides the lowest reasonable cost solution through a combination of traditional supply, renewable and demand-side resources.** The most recent (April 2010) "tempered" load growth, combined with the completion of the Dresden natural gas-combined cycle facility, additional renewable resources, increased DR/EE initiatives, and the proposed capacity uprate of the Cook Nuclear facility allow AEP-East region to meet its reserve requirements until the 2018-2019 timeframe, at which point modeling indicates new peaking capacity will be required. Other than the aforementioned D.C. Cook uprate, no new baseload capacity is required over the 10-year Planning Period.

The Plan also positions the AEP-East Operating Companies to achieve legislative or regulatory mandated state renewable portfolio standards and energy efficiency requirements, and sets in place the framework to meet potential CO2 reduction targets and emerging U.S. EPA rulemaking around HAPs and CCR at the intended least reasonable cost to its customers.

The resource planning process is becoming increasingly complex given these uncertainties as well as spiraling technological advancements, changing economic and other energy supply fundamentals, uncertainty around demand and energy usage patterns as well as customer acceptance for embracing efficiency initiatives. All of these uncertainties necessitate flexibility in any on-going plan. Moreover, the ability to invest in capital-intensive infrastructure is increasingly challenged in light of current economic conditions, and the impact on the AEP-East Operating Companies' customer costs-of-service/rates will continue to be a primary planning consideration.

Other than those initiatives that fall within some necessary "actionable" period over the next 2-3 years, this long-term Plan is also 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, the movement towards increasing use of renewable generation and end-use efficiency, as well as legislative and regulated proposals to control greenhouse gases and numerous other hazardous pollutants… all of which will likely result in either the retirement or costly retrofitting of all existing AEP-East coal units.

Finally, bear 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 here reflects, to a large extent, assumptions that are clearly subject to change. In summary, it represents a very reasonable "snapshot" of future requirements at this particular point in time.

1.0 Introduction and Planning Issues

This report documents the processes and assumptions required to develop the recommended integrated resource plan (IRP or the "Plan") for the AEP-East System. The IRP process consists of the following steps:

- Describe the company, the resource planning process in general (**Section 1**).
- Describe the implications of current issues as they relate to resource planning (**Section 2**).
- Identify current supply resources, including projected changes to those resources (e.g. de-rates or retirements), and transmission system integration issues (**Section 3**).
- Provide projected growth in demand and energy which serves as the underpinning of the plan (**Section 4**).
- Combine these two projected states (resources versus demand) to identify the need to be filled (**Section 5**).
- Describe the analysis and assumptions that will be used to develop the plan such as future resource options (**Section 6**), evaluation of demand side measures (**Section 7**), and fundamental modeling parameters (**Section 8**).
- Perform resource modeling and use the results to develop portfolios, including the selection of the ultimate "Hybrid Plan" (**Section 9**).
- Utilize risk analysis techniques on selected portfolios (**Section 10**).
- Present the findings and recommendations, plan implementation and, finally, plan implications on AEP East operating companies (**Sections 11 and 12**).

1.1 IRP Process Overview

This report presents the results of the IRP analysis for the AEP East (PJM) zone of the AEP System, covering the ten year period 2011-2020 (Planning Period), with additional planning modeling and studies conducted through the year 2030 (extended Study Period). The information presented in this IRP includes descriptions of assumptions, study parameters, methodologies, and results including the integration of supply and demand side resources.

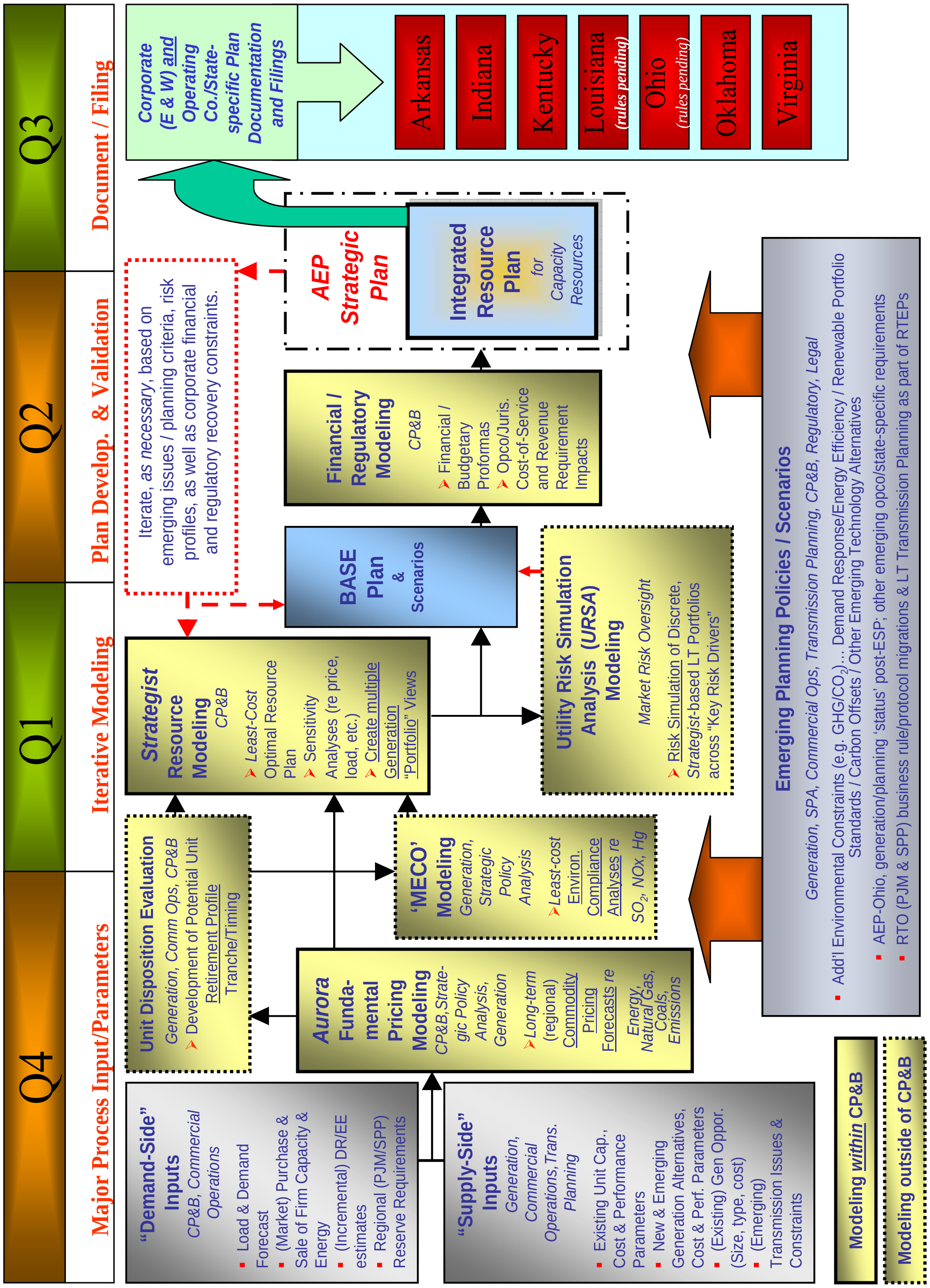
In addition to the need to set forth a long-term strategy for achieving regional reliability/reserve margin requirements, capacity resource planning is critical to AEP due to its impact on:

- **Capital Expenditure Requirements**
- **Rate Case Planning**
- **Integration with other Strategic Business Initiatives e.g.,** corporate sustainability goals, environmental compliance, transmission planning, etc

*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.*

The IRP process is displayed graphically in **Exhibit 1-1**.

Exhibit 1-1: IRP Process Overview

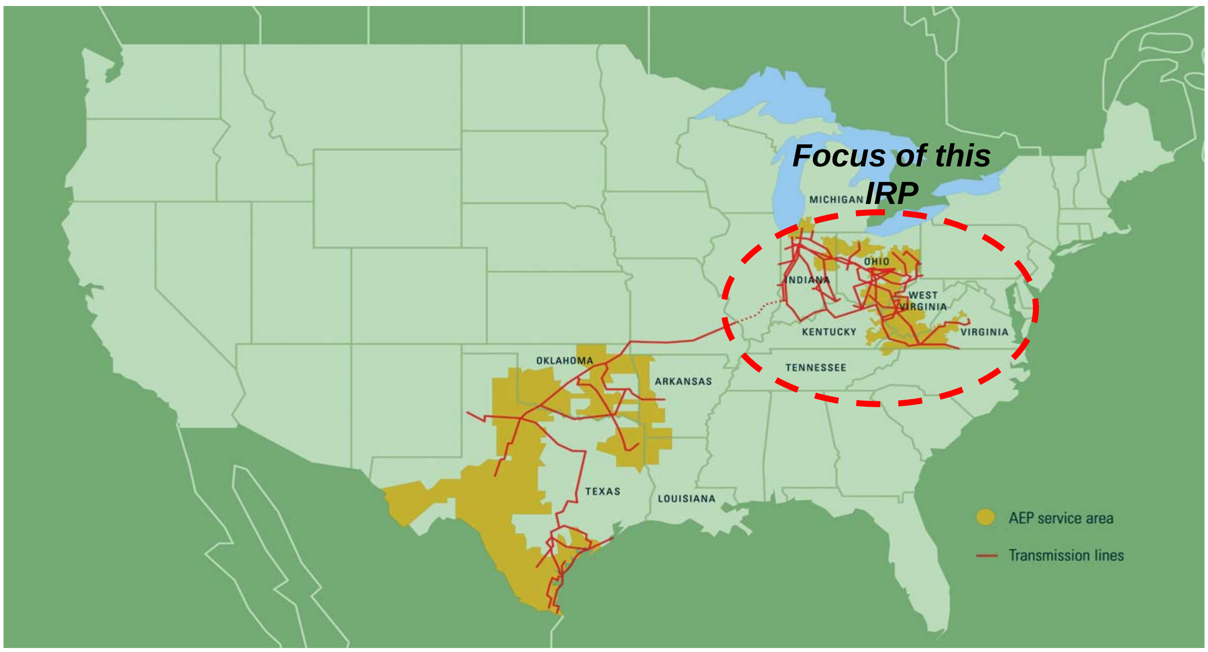


Source: AEP Resource Planning

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 1-2: AEP System, East and West Zones



Source: AEP Internal Communications

AEP owns and/or operates 80 generating stations in the United States, with a capacity of approximately 38,000 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 214,000 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).[4] CSP and OPCo operate as a single business unit called AEP-Ohio.

[4] 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.

Other than a discussion of the requirements of the FERC-approved AEP System Integration Agreement (SIA), this document will only address 2010 resource planning for the AEP-East zone. Planning for affiliates PSO and SWEPCO operating in SPP will be communicated in a separate IRP document.

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 2009, 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 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.

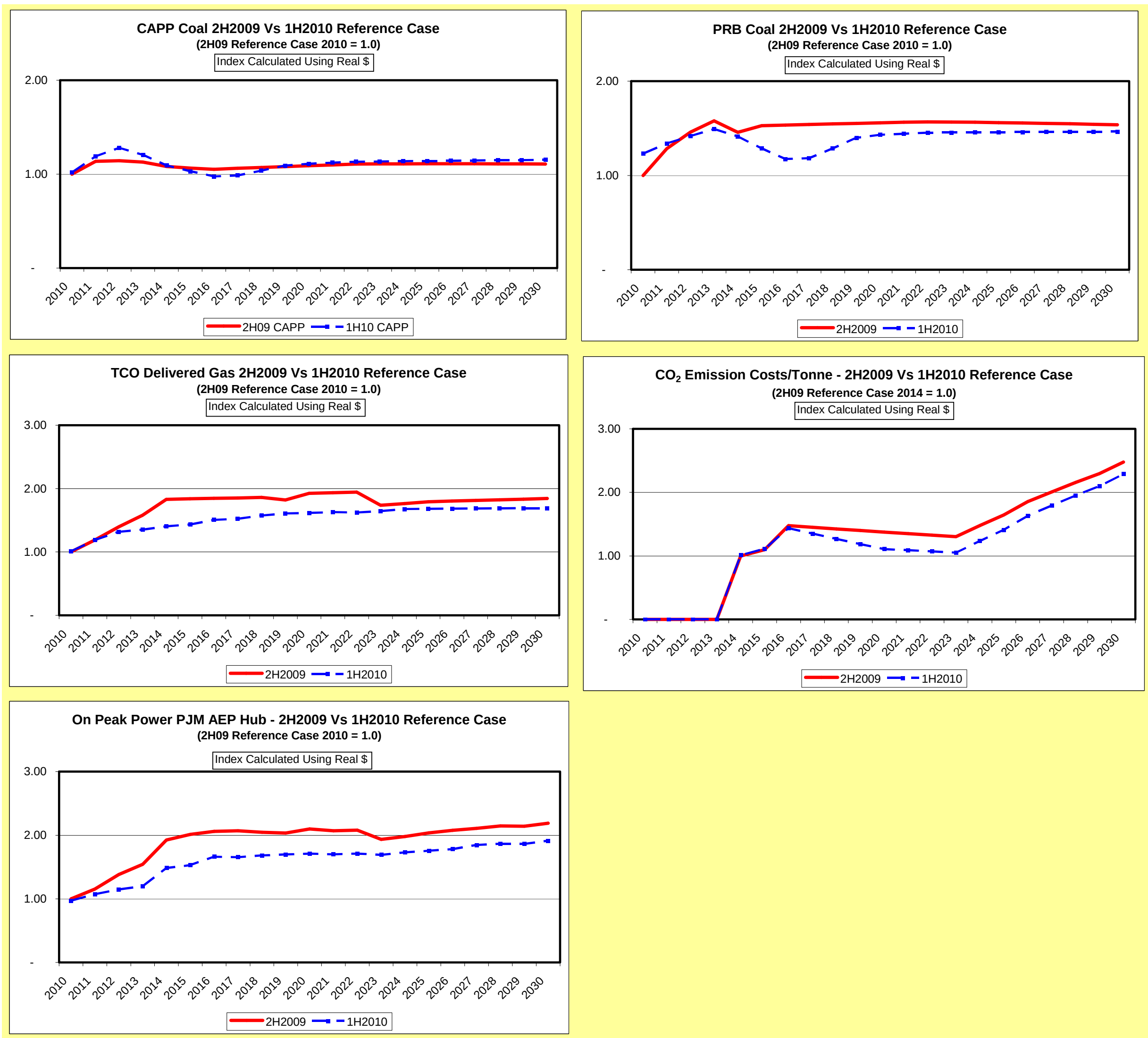
1.2.3 AEP System Interchange Agreement (East and West)

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.

1.3 Commodity Pricing

AEP updates its commodities forecast twice each year. The Fall of 2009 forecast (2H09 Forecast) was used as the basis for resource modeling in this IRP. After comparing the 2H09 Forecast to the subsequent long term forecast prepared in the Spring of 2010 (1H10 Forecast), as shown in Exhibit 1-3, it was apparent that the effects of the revised pricing estimates were not significant in determining future resource additions and did not warrant a new resource evaluation.

Exhibit 1-3 Comparison of 2H09 and 1H10 Commodity Forecasts



2.0 Industry Issues and Their Implications

2.1 Environmental Rulemakings and Legislation

This 2010 IRP considered existing and potential U. S. Environmental Protection Agency (EPA) rulemakings as well as proposed legislation controlling CO_2 emissions. Emission compliance requirements have a major influence on the consideration of supply-side resources for inclusion in the IRP because of their potential significant effects on both capital and operational costs. The cumulative cost of complying with these rules could ultimately have an impact on proposed retirement dates of any currently non-retrofitted coal and lignite units.

2.1.1 Mercury and Hazardous Air Pollutants Regulation

The Clean Air Mercury Rule (CAMR) was issued by the U.S. EPA in May 2005. The rule instituted a cap-and-trade program to limit emissions of mercury from coal-fired power plants across the United States. The CAMR required coal-fired power plants to begin monitoring mercury emissions on January 1st, 2009, with cap and trade emission reductions required beginning on January 1st, 2010. However, the CAMR was appealed by various entities, and in February 2008 the United States Court of Appeals for the District of Columbia Circuit issued a decision vacating the CAMR.

With the vacatur of CAMR and the completion of the appeals process, the U.S. EPA has announced its intent to develop a new regulatory program for mercury emissions and other Hazardous Air Pollutants, including, among others, arsenic, selenium, lead, cadmium and various acid gases (collectively "HAPs" or "HAPs rulemaking") under the Maximum Achievable Control Technology (MACT) provision of the Clean Air Act. A MACT rule for HAPs will establish regulations that are "command and control"; meaning that it will not be a cap-and-trade program and that unit specific controls or emission rates will need to be met. The EPA has set a deadline for a proposed MACT rule to be issued for public review and comment in March 2011 and a final rule to be issued in November 2011. This rule is expected to take effect as early as December 2015. However, the MACT standards for HAPs has not been established, and the requirements for each unit will not be tentatively known until a proposed rule is issued and will not be definitively known until a final rule is issued late next year.

Although not definitively known, AEP Engineering Project and Field Services (EP&FS) and AEP Environmental Services attempted to identify reasonable proxies for MACT at each AEP coal unit. For the most part, some combination of Flue Gas Desulphurization (FGD) and Selective Catalytic Reduction (SCR), or Activated Carbon Injection (ACI) with fabric filter fugitive dust collection systems would likely be required for compliance.

2.1.2 Coal Combustion Residuals (CCR) Regulation

CCRs are the materials that result from combusting coal, and can include bottom ash, fly ash, and byproduct created from FGD systems capturing SO_2 from flue gas. Currently CCRs are classified as non-hazardous waste. Disposal of these materials is currently regulated at the state level. However, the U.S. EPA is developing a new regulatory program that will move regulation to the Federal level to ensure greater consistency across the country on disposal practices. A draft CCR disposal rule was issued in mid-2010. A final rule is expected in roughly a year, or mid-2011. The EPA has indicated it may regulate disposal of these materials as a special class of non-hazardous waste, or potentially as a hazardous waste. Either approach will result in more restrictive disposal requirements than currently exist.

2.1.3 Transport Rule

On July 6, 2010 the U.S. EPA proposed a Transport Rule to replace the 2005 Clean Air Interstate Rule (CAIR) which was vacated in 2008 by the U.S. Court of Appeals for the District of Columbia. The Transport Rule will require 31 states and the District of Columbia to reduce power plant emissions of sulfur dioxide (SO_2) and oxides of nitrogen (NO_X). The emission reductions will be state specific with limited allowance trading opportunity, and will become effective at an intermediate level in 2012, then at a final, more restrictive level in 2014. The emission reductions will be relative to a 2005 base year level. Each state will be required to develop source (plant) specific targets.

Once the Transport Rule is finalized and source specific targets are communicated, an action plan can be established to comply with this requirement. AEP's expectation is that this rule may influence the timing of certain FGD retrofits, plant operations, and/or unit retirements. However, given that AEP must operate within a previously established New Source Review (NSR) Consent Decree "cap" for NO_X and SO_2, and also retrofits or retire certain units by specific dates, the incremental Transport Rule compliance measures are not expected to significantly change the resource plan established in this report.

2.1.4 New Source Review—Consent Decree.

In December, 2007 AEP entered into a settlement of outstanding litigation around NSR compliance. Under the terms of the settlement, AEP will complete its environmental retrofit program on its operated Eastern units, operate those units under a declining annual cap on total SO_2 and NO_X emissions and install additional control technologies at certain units. The most significant additional control projects involve installing FGD and SCR systems at nine AEP-East coal fired units (Amos 1-3, Big Sandy 2, Cardinal 1, Conesville 4, Muskingum River 5 and Rockport 1 and 2) over an 11 year period beginning in 2009.

2.1.5 Carbon and Greenhouse Gas (GHG) Legislation

The electric utility industry, as a major producer of CO_2, will be significantly affected by any GHG legislation. The push towards federal climate change legislation is continuing within Congress. The Waxman-Markey "American Climate and Energy Security Act of 2009" was approved by the House of Representatives in June 2009, but was not followed up with comparable legislation being approved by the U.S. Senate. In December 2009 the U. S. EPA issued a finding that GHG from industry, vehicles, and other sources represent a threat to human health and the environment. In June 2010 the Senate voted 53-47 to reject an attempt to block the U.S. EPA from imposing new limits on carbon emissions. This defeat is seen as providing momentum to climate legislation efforts. Climate change legislation currently in the U.S. Senate is being sponsored by Senators Kerry and Lieberman. In most respects this draft legislation comports with the cap-and-trade provisions of the Waxman-Markey Bill.

With climate legislation on the horizon, the Company has embarked on an initiative 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" has been constructed at the Mountaineer Plant in West Virginia and successfully began operation in the fall of 2009.

The carbon capture and storage equipment (CCS) operating on AEP's 1,300 MW Mountaineer Plant is a 20 MW (electric) product validation. It is designed to capture approximately 100,000 metric tons of CO_2 per year over a four to five year period; the CO_2 is being stored in deep geologic reservoirs. AEP now plans to scale up the Mountaineer Chilled Ammonia Process (CAP) to capture CO2 from a 235 MWe slip stream and has been awarded $336 million in funding from the U.S. Department of Energy. The expectation is for the commercial scale technology project to have a 90% capture rate of approximately 1.5 million tons of CO_2 per year and be online in 2015.

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

2.2 Additional Implications of Environmental Legislation – Unit Disposition Analysis

An AEP-East unit disposition study was undertaken by an IRP Unit Disposition evaluation team involving numerous AEP functional disciplines including: Fossil & Hydro Operations, Engineering, Project & Field Services (EP&FS), Environmental Services, Fuel Emissions Logistics (FEL), Commercial Operations, Transmission Planning, and Resource Planning. This fourth quarter 2009 effort was a follow-up to earlier studies that have been performed annually since 2005. As before, the team's primary intent was to assess the relative composition and timing of potential unit retirements. As in previous reviews, the initial focus was on the older-vintage, less-efficient, uncontrolled coal units in the AEP-East fleet. Factors including PJM operational flexibility, emerging unit liabilities, and workforce/community factors were considered when recommending the relative profile of potential unit retirements. In this 2010 IRP cycle review the team also considered the implications of the potential (dispatch) cost impacts associated with CO_2 emissions, as well as cost to comply with assumed emerging HAPs and CCR rulemaking on, particularly, the relatively newer and reasonably-thermally efficient uncontrolled super-critical coal units operating in the AEP-East fleet.

For instance, according to the AEP Environmental Services group, such federal rulemaking for HAPs could become effective by as early as the end of 2015 when a "command-and-control" policy could require all U.S. coal and lignite units to install mercury and heavy metals/toxins control technologies including (combined) FGD, SCR, as well as, potentially, ACI with fabric filter emissions control equipment. New rules on the handling and disposal of CCRs could likewise be implemented as early as 2017, requiring additional investment in the coal fleet to convert "wet" fly ash and bottom ash disposal equipment and systems — including attendant landfills and ponds — to "dry" systems. The cumulative cost of complying with these rules will most certainly require additional analysis and may have an impact on proposed retirement dates of any currently non-retrofitted coal unit.

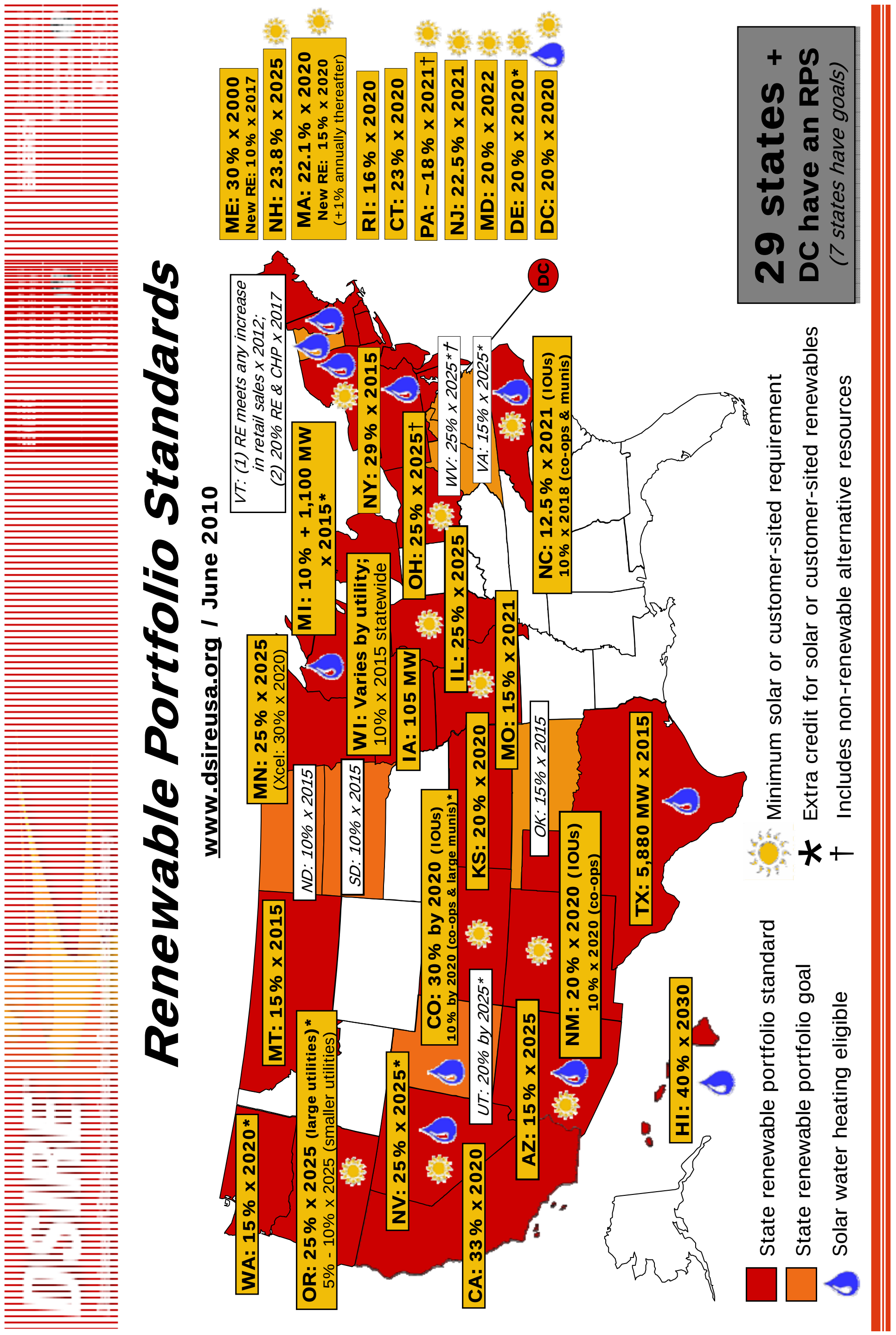
It should be noted that the conclusions of this updated unit disposition study are for the expressed purpose of performing this overall long-term IRP analysis and reflect on-going and evolving disposition assessments. ***From a capacity perspective, no formal decisions have been made with respect to specific timing of any such unit retirements,*** *except as identified in the NSR Consent Decree stipulations*. These disposition analyses and renderings are deemed necessary so that the *prospects* for any ultimate decisions can be integrated into a capacity replacement plan in a way that is ratable and practical.

2.3 Renewable Portfolio Standards

As identified in **Exhibit 2-1**, 29 states and the District of Columbia have set standards specifying that electric utilities generate a certain amount of electricity from renewable sources. Seven other states have established renewable energy goals. Most of these requirements take the form of "renewable portfolio standards," or RPS, which require a certain percentage of a utility energy 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 passed out of Committee a combined 15% RES/EES by 2021 and is also considering the House legislation. However, on July 27, 2010 Senate Majority Leader Harry Reid introduced a modest package of draft energy legislation which did not include a renewable standard. Therefore, there is only a slight possibility of passage of a federal RPS in 2010, with much improved likelihood in 2011.

Exhibit 2-1: Renewable Standards by State



2.3.1 Implication of Renewable Portfolio Standards on the AEP-East IRP

Renewable Portfolio Standards and goals have been enacted in well 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 and/or an RPS will impose the need for adding more renewables resulting in a significant increase in investments across the renewable resource industry.

Wind is currently one of the most viable large-scale renewable technologies and has been added to utility portfolios mainly via long-term power purchase agreements (PPA). Recently, many IOUs have begun to add wind projects to their generation portfolios. The best sites in terms of wind resource and transmission are rapidly being secured by developers. Further, while an extension of the Federal Production Tax Credit (PTC) and investment tax credits (ITC) for wind projects - to the end of 2012 - was enacted in February 2009, it may not be extended further as the implementation of federal carbon or renewable standards is expected to make unnecessary the development incentive provided by the PTC/ITC. Acquiring this renewable energy and/or the associated Renewable Energy Credit/Certificate (REC) sooner limits the risk of increased cost that comes with waiting for further legislative clarity nationally or in the AEP states, combined with the likely expiration of these federal incentives. AEP has experienced, however, that regulators in states without mandatory standards are reluctant to approve PPAs that result in increased costs to their ratepayers. By the end of 2010 AEP operating companies I&M, APCo, and AEP-Ohio (CSP & OPCo) will be receiving energy from at least 9 wind contracts and 1 solar project, with total nameplate ratings of 636 MW. **Exhibit 2-2** summarizes the AEP-East Zone's renewable plan, by operating company.

Exhibit 2-2: Renewable Energy Plan Through 2030

AEP System - East Zone

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

as well as Known or Emerging State Mandates

2010 IRP

Year	APCo Solar Nameplate (MW)	APCo Wind Nameplate (MW)	APCo Biomass Equivalent (MW)	APCo Energy as % of Sales	I&M Solar Nameplate (MW)	I&M Wind Nameplate (MW)	I&M Biomass Equivalent (MW)	I&M Energy as % of Sales	KPCo Solar Nameplate (MW)	KPCo Wind Nameplate (MW)	KPCo Biomass Equivalent (MW)	KPCo Energy as % of Sales	AEP-Ohio Solar Nameplate (MW)	AEP-Ohio Wind Nameplate (MW)	AEP-Ohio Biomass Equivalent (MW)	AEP-Ohio Energy as % of Sales	AEP-East Solar Nameplate (MW)	AEP-East Wind Nameplate (MW)	AEP-East Biomass Equivalent (MW)	AEP-East Energy as % of Sales
2009	0	75	0	0.8%	0	0	0	0.0%	0	0	0	0.0%	0	0	0	0.0%	0	75	0	0.2%
2010	0	276	0	2.7%	0	150	0	2.5%	0	0	0	0.0%	0	100	0	0.7%	0	526	0	1.6%
2011	0	376	0	3.6%	0	150	0	2.5%	0	0	0	0.0%	20	100	44	1.1%	20	626	44	2.1%
2012	0	376	0	3.6%	0	150	0	2.4%	0	0	0	0.0%	31	200	44	1.8%	31	726	44	2.3%
2013 (b)	0	**376**	0	3.5%	0	**200**	0	3.2%	0	**0**	0	0.0%	41	**250**	44	2.1%	41	**826**	44	2.6%
2014	0	376	0	3.5%	0	350	0	5.6%	0	100	0	4.2%	67	300	94	3.3%	67	1,126	94	3.8%
2015	0	376	0	3.5%	0	650	0	10.2%	0	100	0	4.2%	94	400	94	4.0%	94	1,526	94	5.0%
2016	0	376	0	3.5%	0	650	0	10.3%	0	100	0	4.2%	120	650	50	5.3%	120	1,776	50	5.6%
2017	0	376	0	3.5%	0	650	0	10.3%	0	100	0	4.2%	146	800	50	6.3%	146	1,926	50	6.0%
2018	0	376	0	3.4%	0	650	0	10.3%	0	100	0	4.2%	172	850	150	8.4%	172	1,976	150	6.9%
2019	0	376	0	3.4%	0	650	0	10.4%	0	100	0	4.1%	198	950	150	9.1%	198	2,076	150	7.2%
2020	0	376	0	3.4%	0	650	0	10.3%	0	100	0	4.1%	225	1,100	150	10.2%	225	2,226	150	7.6%
2021	0	376	0	3.3%	0	700	0	11.0%	0	150	0	6.1%	256	1,100	200	11.2%	256	2,326	200	8.3%
2022	0	409	0	3.6%	0	700	0	11.0%	0	150	0	6.0%	301	1,167	200	11.8%	301	2,426	200	8.6%
2023	0	409	0	3.6%	0	700	0	10.9%	0	150	0	6.0%	301	1,367	200	13.1%	301	2,626	200	9.1%
2024	0	409	0	3.5%	0	750	50	13.7%	0	150	50	11.1%	345	1,467	200	13.8%	345	2,776	300	10.2%
2025	0	409	0	3.5%	0	800	50	14.3%	0	150	50	11.1%	345	1,567	200	14.4%	345	2,926	300	10.5%
2026	0	409	0	3.5%	0	850	50	15.0%	0	150	50	11.0%	364	1,667	200	15.0%	364	3,076	300	10.9%
2027	0	409	0	3.4%	0	850	50	14.9%	0	200	63	14.1%	364	1,767	238	16.2%	364	3,226	350	11.6%
2028	0	409	0	3.4%	0	850	50	14.8%	0	200	63	14.0%	389	1,867	238	16.8%	389	3,326	350	11.8%
2029	0	409	0	3.4%	0	850	50	14.7%	0	200	63	13.9%	389	1,867	238	16.7%	389	3,326	350	11.7%
2030	0	409	0	3.3%	0	850	50	14.7%	0	200	63	13.8%	420	1,867	238	16.7%	420	3,326	350	11.7%

(a) Data excludes 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.

Source: AEP Resource Planning

2.3.2 Ohio Renewable Portfolio Standards

Ohio Substitute SB 221 Alternative Energy requires that 25% of the retail energy sold in Ohio 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 above the levels mandated in the energy efficiency and Renewable Energy provisions. Renewable Energy includes solar (photovoltaic or thermal), wind, incremental hydro, geothermal, solid-waste decomposition, biomass, biologically-derived methane, fuel cells, and storage resources.

At least one-half of the Alternative Energy mandate must be met with renewable resources by 2025. Advanced Energy must provide the balance of the 25 percent goal not attained with Renewable Energy. There is a further sub-requirement that solar constitute at least 0.5 percent of retail sales by that date, and that at least half the renewable resources be from sites located in the State of Ohio. Compliance may be satisfied with the purchase of Renewable Energy Certificates (REC). There are annual benchmark requirements, which began in 2009, for the Renewable and Solar requirement and sub-requirement, respectively. **Exhibit 2-3** shows the results of the current plan for AEP-Ohio in meeting the renewable energy requirements.

Exhibit 2-3: Ohio Renewable Energy Requirement and Plan

AEP-Ohio Renewables Requirement and Plan

Full Year	Solar Benchmark		Solar Plan	Total Benchmark		Total Plan
	Pct	GWh	GWh	Pct	GWh	GWh
2010	0.010%	4	0	0.50%	223	303
2011	0.030%	13	26	1.00%	440	498
2012	0.060%	26	37	1.50%	657	796
2013	0.090%	40	48	2.00%	896	951
2014	0.120%	54	76	2.50%	1,130	1,512
2015	0.150%	68	104	3.50%	1,592	1,827
2016	0.180%	82	132	4.50%	2,048	2,403
2017	0.220%	100	160	5.50%	2,498	2,862
2018	0.260%	118	188	6.50%	2,945	3,804
2019	0.300%	136	216	7.50%	3,393	4,119
2020	0.340%	154	245	8.50%	3,839	4,578
2021	0.380%	171	278	9.50%	4,274	4,996
2022	0.420%	188	326	10.50%	4,700	5,236
2023	0.460%	205	326	11.50%	5,126	5,810
2024	0.500%	223	374	12.50%	5,563	6,145
2025	0.500%	223	374	12.50%	5,567	6,432

Note: (2009/2010) Benchmarks (were/will be) met with both Purchased and Plan RECs

Source: AEP Resource Planning

2.3.3 Michigan Clean, Renewable, and Efficient Energy Act

Michigan's "Clean, Renewable, and Efficient Energy Act" (2008 PA 295) requires that 10 percent of retail sales be met from renewable resources by the year 2015. The initial requirement is for 2012 and the percentage ramps up over the next three years as shown in **Exhibit 2-4**. 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 2-4: AEP I&M-Michigan Renewable Requirement and Plan

I&M Michigan Renewables Requirement and Plan

Full Year	Renewable Benchmark		Total Renewable Energy Plan	Existing Hydro Credits	Total Plan
	Pct	GWh	GWh	GWh	GWh
2010	0.0%	0	0	0	0
2011	0.0%	0	0	0	0
2012	2.0%	59	70	17	88
2013	3.3%	99	93	17	110
2014	5.0%	148	161	17	178
2015	10.0%	296	293	17	310
2016	10.0%	295	293	17	310
2017	10.0%	295	293	17	310
2018	10.0%	295	293	17	310
2019	10.0%	296	293	17	310
2020	10.0%	298	293	17	310
2021	10.0%	299	315	17	332
2022	10.0%	300	315	17	332
2023	10.0%	302	315	17	332
2024	10.0%	303	397	17	414
2025	10.0%	305	419	17	436

Source: AEP Resource Planning

2.3.4 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, 12% by 2022, and 15% by 2025. 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 even though the Virginia State Corporation Commission denied the Company's request for recovery of Virginia share of costs associated with its three most recent wind purchased power agreements totaling 201 MW (90 MW net).

2.3.5 West Virginia Alternative and Renewable Energy Portfolio Standard

The West Virginia Alternative and Renewable Energy Portfolio Standard act was passed in the 2009 session of the West Virginia Legislature (SB297). Since its initial passage it has been amended three separate times, once apparently by a transcription error. The act requires that as of January 1, 2015 electric utilities (an electric distribution company or electric generation supplier who sells electricity to retail customers in West Virginia) must own "credits" equal to a certain percentage of the electric energy sold to customers in West Virginia in the previous year. For 2015 to 2019 the credits must equal 10 percent of the previous year's sales. For 2020 to 2024, the credits must equal 15 percent and after January 1, 2025 the credits must equal 25 percent. The requirements apparently sunset on June 30, 2026 as the result of a section added from one of the amendments.

Credits can be earned by either the utilization of an "alternative energy resource," a "renewable energy resource" or the employment of an "energy efficiency or demand-side energy initiative project" or a "Greenhouse gas emission reduction or offset project." The act carries specific definitions and sub-characterizations related to each of these categories.

2.4 Energy Efficiency Mandates

The Energy Independence and Security Act of 2007 ("EISA") 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. Additionally, mandated levels of demand reduction and/or energy efficiency attainment, subject to cost effectiveness criteria, are in place in Ohio, Indiana and Michigan in the AEP-East Zone. The Ohio standard, if cost-effective criteria are met, will result in installed energy efficiency measures equal to over 20 percent of all energy otherwise supplied by 2025. Indiana's standard achieves installed energy efficiency reductions of 13.90% by 2020 while Michigan's standard achieves 10.55%. Virginia has a voluntary 10% by 2020 target, while West Virginia allows energy efficiency to count towards its renewable standard. No mandate currently exists in Kentucky, however KPCo has offered DR/EE programs to customers since the mid-1990's.

2.4.1 Implication of Efficiency Mandates: Demand Response/Energy Efficiency (DR/EE)

The AEP System (East and West zones) 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. Concurrently, several states served by the AEP System have mandated levels of efficiency and demand reduction. Within the AEP-East zone, Ohio and Michigan have statutory benchmarks which took effect in 2009. As a result of the DSM generic case in Indiana, regulatory benchmarks have been put into effect beginning in 2010 for Indiana. In lieu of mandates or benchmarks, stakeholders expect realistic levels of cost-effective demand-side measures to be employed. 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.

2.4.2 Ohio Energy Efficiency Requirements

Energy Efficiency must produce prescribed reductions in energy usage that cumulatively add to 22.2 percent of annual retail energy sold by the year 2025. Additionally, peak demand must be reduced 7.75 percent by 2018. Annual Energy Efficiency and Demand Response benchmark goals have been in-place since 2009.

2.4.3 Transmission and Distribution Efficiencies

The IRP also takes into account other technology initiatives designed to improve the efficiency of the AEP energy delivery and distribution systems. These initiatives include the demonstration of technologies for more effective integrated volt/var controls (IVVC) and community energy storage on the distribution system (CES) that would reduce customer usage, as well as advanced transmission infrastructure technologies to reduce energy losses within the energy delivery system. The transmission and distribution technology programs are designed to avoid or defer the need for infrastructure and reduce emissions by avoiding energy usage and energy lost in the transmission and distribution of energy to ultimate AEP customers.

2.5 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 and operate the generation, a forecast of what had traditionally been stable fuel prices and growth in demand over time. Volatile fuel prices and uncertainty surrounding the economy and environmental legislation require that the process used to determine the traditional “supply and demand” elements of a resource plan is sufficiently flexible to incorporate more subjective criteria. The introduction of a cap-and-trade system around CO_2 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. Likewise, 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.

3.0 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 4.2**)
- Current DR/EE impacts (see **Section 4.3**)
- RTO-specific capacity reserve margin criteria (see **Section 5.1**)

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.

3.1 Existing AEP Generation Resources

Exhibit 3-1 offers a summary of all supply resources for the AEP-East zone (with detail appearing in **Appendix A**). The current (June 1, 2010) AEP-East summer supply of 27,810 MW is composed of the following resource components (the coal resources include AEP's share of OVEC):

Exhibit 3-1: AEP-East Capacity (Summer) as of June 2010

Supply Resource Type	Nameplate (Winter) Rating MW	Nameplate (Winter) Rating % of Total	Summer Rating MW	PJM UCAP MW
Coal	22,385	77%	22,152	22,136
Nuclear	2,115	7%	2,029	2,029
Hydro	745	3%	680	948
Gas/Diesel	3,186	11%	2,865	3,256
Wind	718	2%	80	48
Solar	10	0%	4	0
Total	**29,159**	**100%**	**27,810**	**28,417**

Source: AEP Resource Planning

3.2 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-EP&FS for selected 1,300 and 800 MW-series coal-steam turbine generating units. Additionally, AEP continues to work towards improving heat rates of its generating fleet. Such improvements, while not necessarily increasing capacity, do improve fuel efficiency.

3.2.1 D. C. Cook Nuclear Plant (Cook) Extended Power Uprating (EPU)

A change which is not included in **Appendix B** but which is reflected in the 2010 Plan is a strategic project that will increase the generating capability of Cook Units 1 and 2. Implemented in conjunction with a series of plant modifications tied to NRC relicensing requirements 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 Cook:

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 Nuclear Regulatory Commission plant license and need to be replaced to maintain margins and allow continued plant operation.
3. The Nuclear Steam Supply Systems 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 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* resource optimization 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 2010 IRP.

3.3 Capacity Impacts of Environmental Compliance Plan

As also detailed in **Appendix B**, the capability forecast of the existing generating fleet reflects several unit de-ratings associated with environmental retrofits (largely scrubbers or CCS) 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.

3.4 Existing Unit Disposition

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-East zone generating assets consisting of a total of 26 units with a summer rating of 5,343 MW.

- Big Sandy Unit 1 (273 MW) 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 (95 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 1-4 (985 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**.

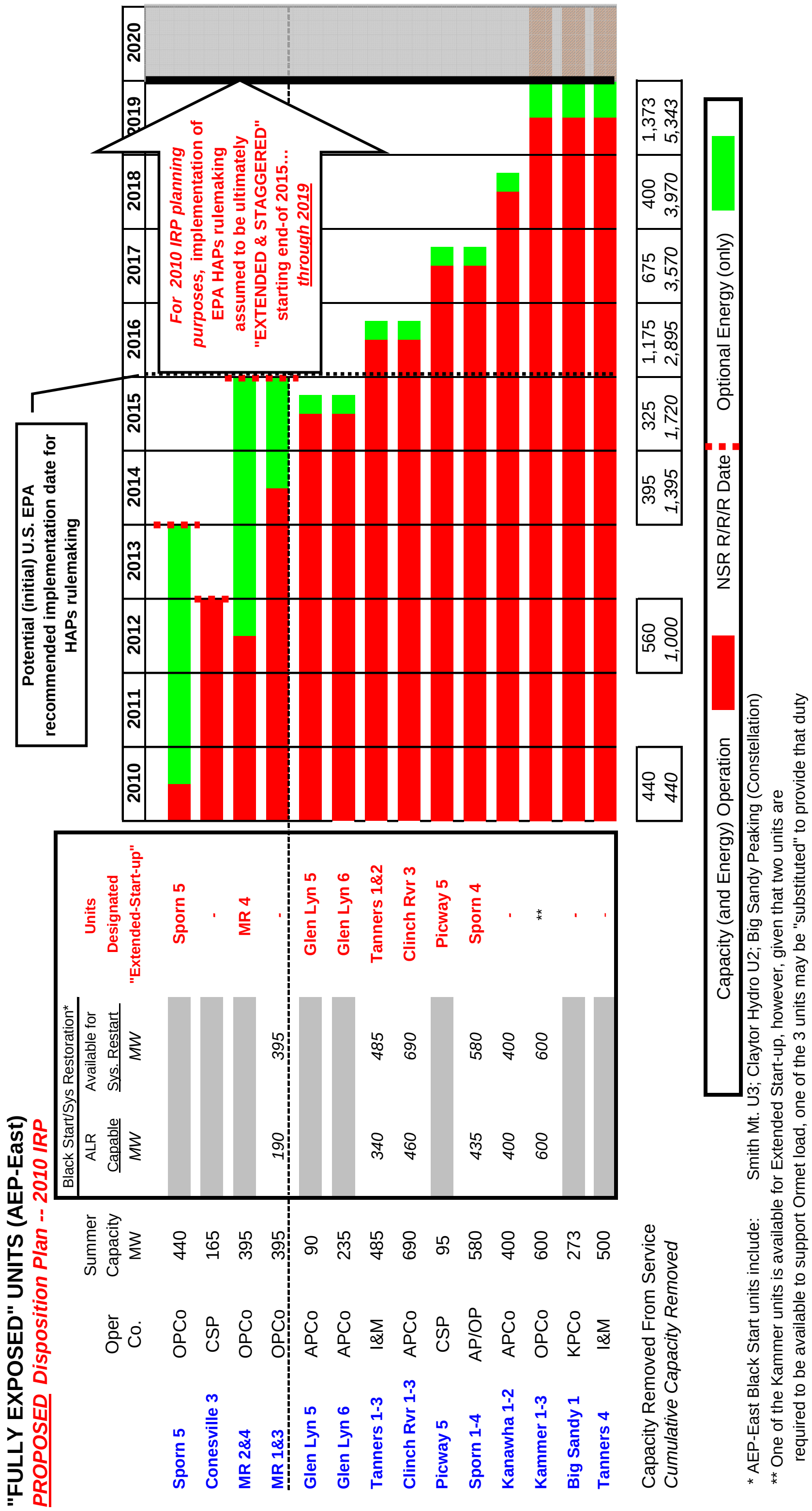
In order to develop a comprehensive assessment of potential unit disposition recommendations, a team encompassing multiple functional disciplines (engineering, operations, fuels, environmental, and commercial operations) also sought to confirm or challenge the preliminary economic findings by examining 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.

3.4.1 Findings and Recommendations—AEP-East Units

The Unit Disposition Working Group findings are summarized here and in **Exhibit 3-2**. Given the size (over 5,000 MW) of the group of AEP-East units "fully exposed" to future emission expenses for CO_2, possible new mercury/hazardous air pollutant and coal combustion residuals (CCR) rulemakings, it is practical to begin a stepped approach to their disposition–thus 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 initial unit retirements include only those R/R/R units designated in the NSR Consent Decree. Through 2014 this includes Sporn 5, 440 MW, retiring in **2010** (R/R/R date 2013); Conesville 3, 165 MW (R/R/R date 2012) and Muskingum River 2 & 4, 395 MW (R/R/R date 2015) retiring in **2012**; and Muskingum River 1 & 3, 395 MW (R/R/R date 2015), with a potential retirement date of **2014**.
- ✓ The remaining "fully exposed" units are projected to retire between 2015 and 2019, assuming a staggered implementation schedule for any HAPs/Mercury/CCR regulations that may be imposed on a unit specific basis.

Exhibit 3-2: AEP East Fully Exposed Unit Disposition/Retirement Profile



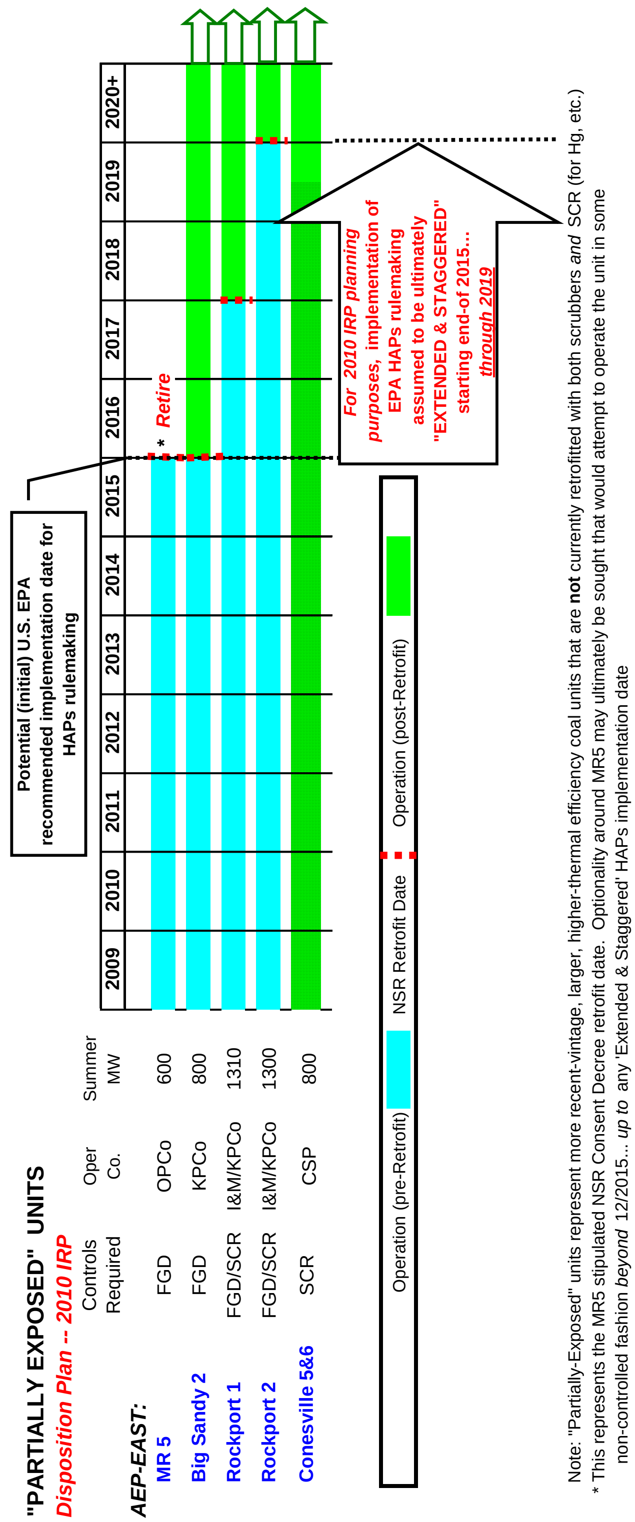
Source: AEP Resource Planning

In addition, certain larger, supercritical coal units which are considered "partially exposed" to these same potential regulations due to their lack of specific environmental control equipment were also evaluated for possible retirement. These units include:

- Big Sandy Unit 2 (800 MW, summer rating) KPCo - requires FGD by 2015
- Muskingum River Unit 5 (600 MW) OPCo – requires FGD by 2015
- Rockport Units 1and 2 (2610 MW) I&M/KPCo – requires FGD/SCR by 2017 (Unit 1)/2019 (Unit 2)
- Conesville Units 5 and 6 (CSP) (790 MW) – requires SCR by 2019

The Resource Planning group analyzed, under two pricing scenarios, various options for each unit including retrofitting, retiring, or converting to gas. With the exception of Muskingum River 5, the decision to retrofit with the required controls represents the lowest cost for AEP-East customers. (See **Exhibit 3-3)** As with all long range planning assumptions, the decision to retrofit or retire these partially exposed units will be revisited in subsequent IRPs. As rules surrounding HAPS, CCR, and the Transport Rule are finalized, more certainty with regard to the timing and magnitude of incremental capital investments to comply with these regulations will certainly factor into the retrofit/retire decision making process. Given FGD construction lead times and the NSR Consent Decree stipulations, a final decision on Muskingum River 5 and Big Sandy 2 will be required before the end of 2011.

Exhibit 3-3: Partially Exposed Unit Disposition Profile



Source: AEP Resource Planning

3.4.2 Extended Start-Up

As part of AEP's continuing effort to manage operating and maintenance expenses, AEP-East launched a plan to place 10 generating units - representing 1,925 megawatts (MW) of capacity - in "extended startup" status for nine months of the year. This action includes the 450-MW Unit 5 at the Sporn Plant. AEP had announced plans to mothball Sporn 5 in April of 2009, noting that the unit has no PJM capacity obligations in 2010. Because Sporn 5 has no PJM capacity obligation, it will be the only unit to operate in the four-day "extended startup" mode year-round.

The plan, which took effect June 1, 2010 allows the company to re-deploy and maximize the productivity of employees at several coal-fired units that are projected to run less frequently over the next few years.

The units that will be placed in extended startup status are:

- Picway Unit 5, 95 MW, CSP;
- Muskingum River Unit 4, 215 MW, OPCo;
- Clinch River Unit 3, 235 MW, APCo.;
- Tanners Creek Units 1 & 2, 290 MW, I&M.;
- Glen Lyn Units 5 & 6, 335 MW, APCo;
- Sporn Units 3, 4 & 5, 750 MW, APCO (Unit 3), OPCO (Units 4&5); and

In extended startup mode, the affected units will remain off line until needed to meet demand. When needed, plant staff will be able to start the affected units during a window of four days during the nine non-peak months of the year. In addition, Kammer Units 1-3 (OPCo) are now in a "substitute operation" mode, where only two units will be staffed and operating at any one time.

3.4.3 Implications of Retirements on Black Start Plan

The eventual retirement of Conesville 3, and in time other units such as the Muskingum River and Tanners Creek 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 for the provision of black-start service and NERC Standards regarding the maintenance of a system restoration plan have implications on the planning, timing, announcement, etc. of the unit retirements. The AEP Generation, Transmission, and Commercial Operations groups have studied this issue and developed a list of recommended system restoration options. As the highest priority option, AEP generation engineering and Conesville plant management are completing control modifications and a test program to provide automatic load rejection capability for Conesville 5 and 6.

3.4.4 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 Transmission Owner will coordinate with the Generation Owner for the their 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.

3.4.5 AEP's Required Actions and Options

If AEP retires Conesville 3 in 2012, PJM must be notified in 2010. PJM will require the Conesville 3 black-start capability to be replaced and the Conesville 5 and 6 control system modifications are expected to provide for automatic load rejection capability for those units. If the Conesville 5 and 6 tests are successfully completed this fall, it is expected that Conesville 5 and 6 will be automatic load reject capable and can replace and/or augment the service previously provided by Conesville 3. Accordingly, AEP Generation is coordinating with AEP Transmission Operations to update the System Emergency Operations Plan to take this capability into account after the control modifications are successfully tested by year-end 2010.

AEP and its customers will pay for the black-start service, either by providing the service or by purchasing it. AEP will continue to improve and enhance its System Emergency Restoration plans to ensure compliance with all applicable NERC Standard protocols.

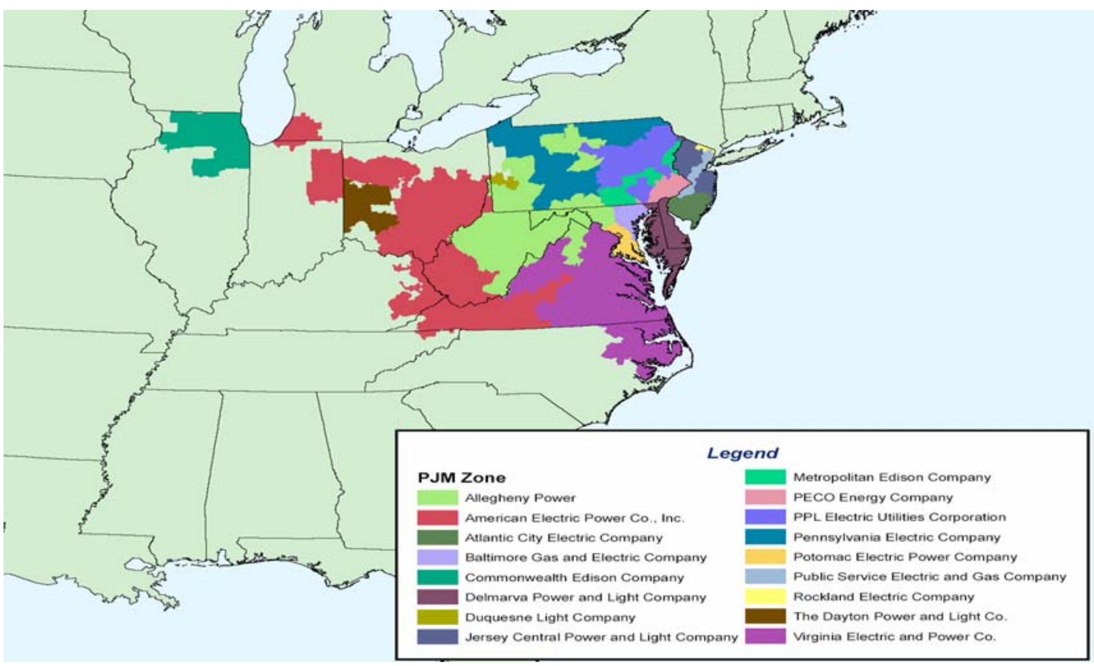
3.5 AEP Eastern Transmission Overview

3.5.1 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. 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 18 neighboring transmission systems at 130 interconnection points, of which 49 are at or above 345 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 has been participating in the PJM markets (see **Exhibit 3-4**).

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



Source: www.pjm.com

3.5.2 Current System Issues

As a result of the eastern Transmission System's geographical location and expanse 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, the applicable RFC standards and performance criteria, and AEP's planning 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.

3.5.3 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.

3.5.4 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 generation and over 6,000 MW of additional merchant generation connected to its eastern Transmission System. AEP, in conjunction with PJM, has interconnection agreements in the AEP service territory with several merchant plant developers for additional generation to be connected to the eastern Transmission System over the next several years. There are also significant amounts of wind 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 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, the impact of these retirements could be significant. The retirement of these units requires the addition of dynamic reactive compensation such as a Static VAR Compensator (SVC) device, which will be added within the Columbus metro area in 2012.

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 Potomac-Appalachian Transmission Highline (PATH) project, which consists of a 765-kilovolt transmission line extending some 276 miles from the Amos Substation in Putnam County, W.Va., to the proposed Kemptown Substation in Frederick County, Maryland, 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.

4.0 Demand Projections

4.1 Load and Demand Forecast Process Overview

One of the most critical underpinnings of the IRP process is the projection of anticipated resource "needs," which, in turn, centers on the long-term forecast of load and (peak) demand. The AEP-East internal long-term load and peak demand forecasts were based on the AEP Economic Forecasting group's load forecast completed in April 2010. AEP Economic Forecasting utilizes a collaborative process to develop load forecasts. Customer representatives and other operating company personnel routinely provide input on customers (large customers in particular) and local economic conditions. Taking this input into account, the AEP Economic Forecasting group analyzes data, develops and utilizes economic and load forecast data and models, and computes load forecasts. Economic Forecasting and operating company management team members review and discuss the analytical results. The groups work together to obtain the final forecast results. The forecast incorporates the effects of energy policy on both a state and federal level such as the 2009 American Reinvestment and Recovery Act (ARRA), Energy Independence and Security Act of 2007 (EISA) as well as load/price elasticity associated with policy impacts on the price of electricity.

The electric energy and demand forecast process involves three specific forecast model processes, as identified in **Exhibit 4-1**.

Exhibit 4-1: 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, under proprietary license by Itron Inc., 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, appliance saturations, 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), the Energy Independence and Security Act of 2007 (EISA), and the 2009 American Reinvestment and Recovery Act (ARRA),. 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 reflecting the manifestation of energy policy impacts.

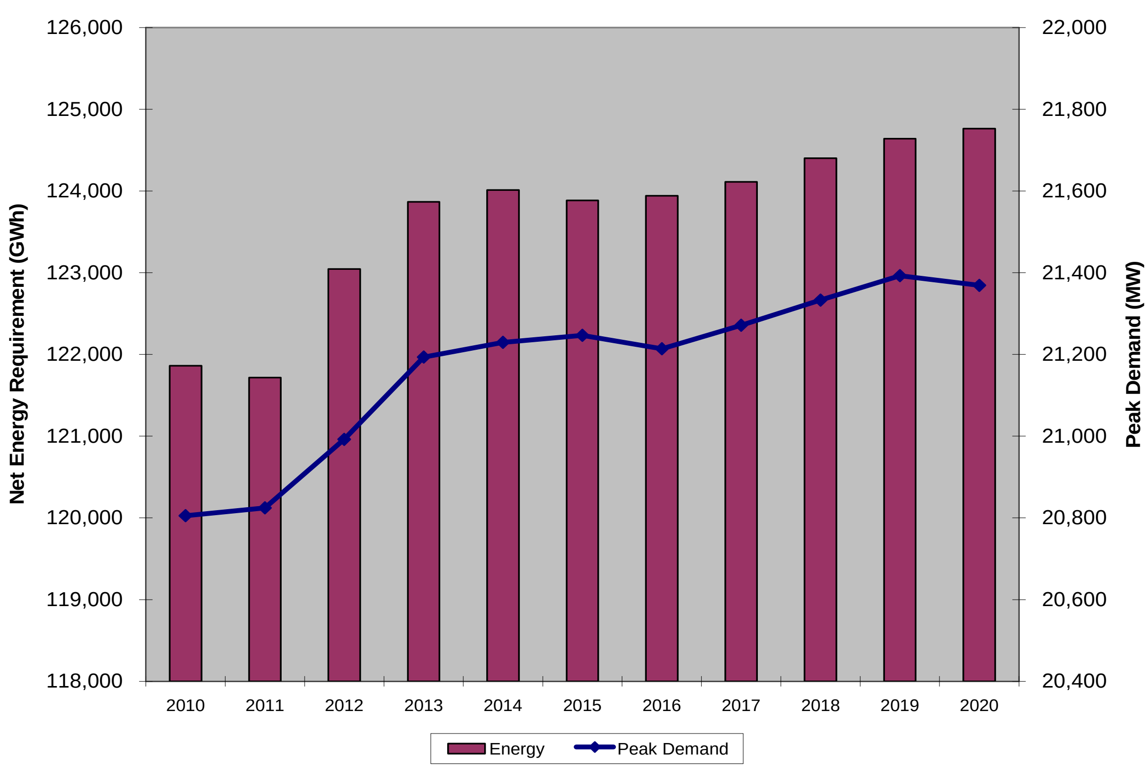
AEP uses processes that take advantage of the relative strengths of both the short and long term methods. The regression models typically used in the shorter-term modeling employ the latest available sales and weather information to represent the variation in sales on a monthly basis for short-term applications. 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 applies the strengths of both load-modeling approaches.

4.2 Peak Demand Forecasts

Exhibit 4-2 reflects the AEP Economic Forecasting Group's forecast of annual peak demand for the AEP-East zone, utilized in this IRP.

Specifically, **Exhibit 4-2** identifies the AEP-East region's internal demand profile as having 0.27% Compound Annual Growth Rate (CAGR) including the impacts of projected (embedded) Demand Response/DSM which will be discussed later in this document. This equates to a **56 MW per year increase** over the 10-year IRP period through 2020 if the load growth was steady. As the graph shows, the impact of the existing recession depresses peak demand in 2010 and 2011 with a gradual increase in 2012 and 2013 from the assumed economic recovery. In addition, the chart indicates a 0.24% rate of growth, reflective of forecasted DSM/energy efficiency impacts, for internal energy sales over the 10-year period.

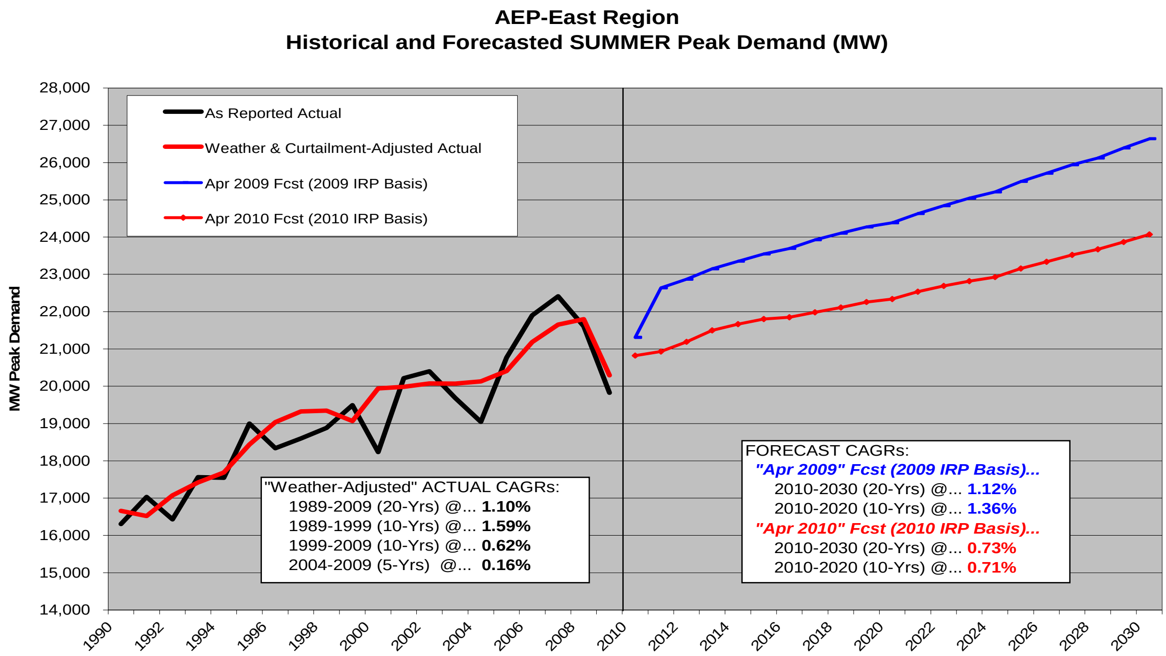
Exhibit 4-2: AEP-East Peak Demand and Energy Projection



Source: AEP Economic Forecasting

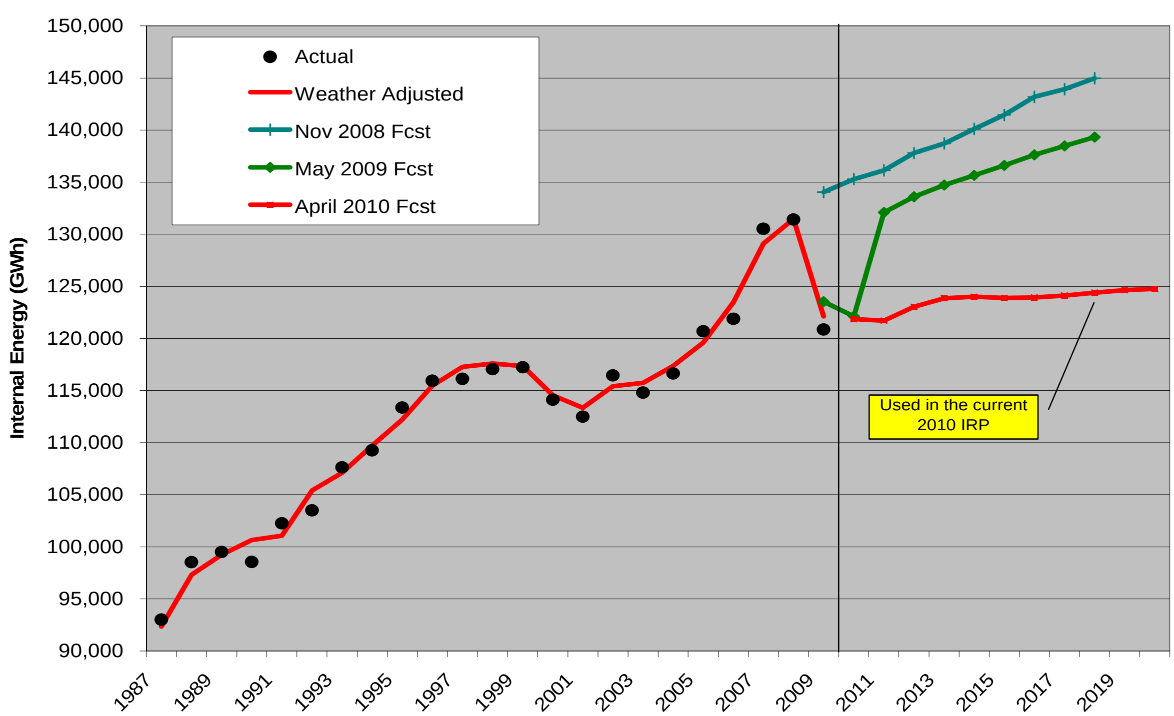
Exhibits 4-3 and **4-4** show the current demand and energy forecasts, respectively, compared to historical actual data and recent forecasts. Note that for both demand and energy, the current forecast is significantly lower as recessionary impacts on demand are being reflected. The impact of future DSM programs has been excluded from the two peak forecasts to make them comparable.

Exhibit 4-3: AEP-East Peak Actual and Forecast (Excludes DSM)



Source: AEP Economic Forecasting

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



Source: AEP Economic Forecasting

4.2.1 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 plan to serve those retail load obligations* 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 a major industrial load operating six aluminum potlines at its facilities– would *continue at the current existing level of approximately 60% of its full capacity* (approximately 4 potlines). Two other large industrial customers are assumed to remain idle in the forecast.
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) assumed to be renewed or extended over the planning period under *long-term contracts*. However, an observation from the underlying data to support **Exhibit 4-2** 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 DR/EE program offerings and targets mandated by state commissions. The DR/EE legislative and regulatory mandated goals in Indiana, Michigan and Ohio are very aggressive, yet assumed achievable in the load forecast. 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.
5) Finally this forecast incorporates the net effects of *Price Elasticity (*described below). In so doing the forecast attempts to predict the load reduction that occurs as a result of a shift in consumer behavior as a reaction to price fluctuations.

The impacts from energy policy such as EISA and ARRA are expected to be reflected 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. Efficiency standards for appliance equipment including residential boilers, clothes washers and dishwashers are also set to increase through 2014. Efforts to promote energy efficiency in commercial buildings as well as in industrial energy use are expected as well. **Section 7** of this document details the impacts from the DSM programs that are currently offered as well as program impacts estimated in future years

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, a price elasticity effect on demand has been embedded in the load forecast. The timing and impact of this scenario is truly speculative, and represents only one of many possible policy actions.

As mentioned above, one of the drivers of the load forecast deals with price elasticity. An example of a completely inelastic good is one that consumers cannot or will not change their consumption of in response to changes in the price of the product. In the short term, most consumers can make minimal changes to their electricity consumption behavior, so electricity is one example of a fairly inelastic good. The **exception** is energy intensive industrial sectors, where companies can shift production to other facilities, close facilities, switch fuels or change capital equipment. Changing large energy using equipment (A/C, furnace, etc) for most consumers is a long-term decision. To make a truly informed decision, any price differential between the competing fuels must be known to be sustainable for consumers to take the financial risk. The long-term nature of these decisions makes electricity (or natural gas) even less price elastic in the long-term. Since consumers have limited options for change, price changes are very significant and become even more so during stressful economic periods.

Over the last 4 to 6 years, the price of electricity has increased significantly. In real terms (adjusting for inflation), the price increases reverse a long-term trend of prices declining over previous decades. In response, the growth in electricity consumption has been dampened with the increased prices. In an industry with sales growth around 1% per year, even a product with a low price response (elasticity) will see an impact. For example, using 1% load growth with no price changes and an overall own-price elasticity of -0.15, a long-term doubling of price, 100% increase, will result in a 15% decrease in consumption. Over a 15 year period, 1% load growth would be reduced to no load growth. Therefore, the expected costs of achieving environmental, renewable and energy efficiency goals for the company will continue to increase the burden on the consumer and thus reduced load growth going forward.

5.0 Capacity Needs Assessment

Based on the assessment of AEP-East's current resources as described in **Section 3**, and its energy and peak demand projections as discussed in **Section 4**, a capacity needs assessment can be established that will determine the amount, timing and type of resources required for this 2010 IRP Cycle.

- The 2010 AEP-East load forecast as updated in April, 2010, accounts for:
  1) AEP-East region's internal demand profile as having 0.27% CAGR (or 0.71 when projected, embedded DSM is excluded). This equates to **56 MW per year increase** (or 152 MW when DSM is excluded) over the 10-year IRP period through 2020 if the load growth was steady.
  2) A major industrial customer will operate at 60% load;
  3) 1,119 MW of peak demand reduction due to interruptible loads and Advanced Time of Day pricing by 2020.
- The forecast of AEP-East capability additions/subtractions reflected through the ten years 2011 through 2020:
  1) the potential retirement of **2,300 MW** of coal fired capacity by 2015 and up to 6,000 MW by 2020;
  2) 199 MW of plant derates associated with environmental and biomass retrofits partially offset by plant efficiency and other improvements of 73 MW.

5.1 PJM Planning Constructs - Reliability Pricing Model (RPM)

Effective with its 2007/08 delivery year (June 1, 2007 through May 31, 2008), PJM instituted the RPM capacity-planning regime. 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-drawn demand curve. In steady-state mode, the auction will be held 38 months before the beginning of the plan year, with subsequent incremental auctions to trim up the capacity commitments as capacity commitments, unit reliability/contribution and demand forecasts change.

FERC has authorized, and PJM has provided for an alternative to the capacity auction, called the Fixed Resource Requirement (FRR), which may 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 and with more cost certainty. AEP has previously elected to "opt-out" of the RPM (auction) and has been utilizing the FRR (self-planning) construct. That opt-out of the PJM capacity auction currently is effective through the 2013/14 delivery year, for which the auction was held in

May, 2010. 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 commitment period.

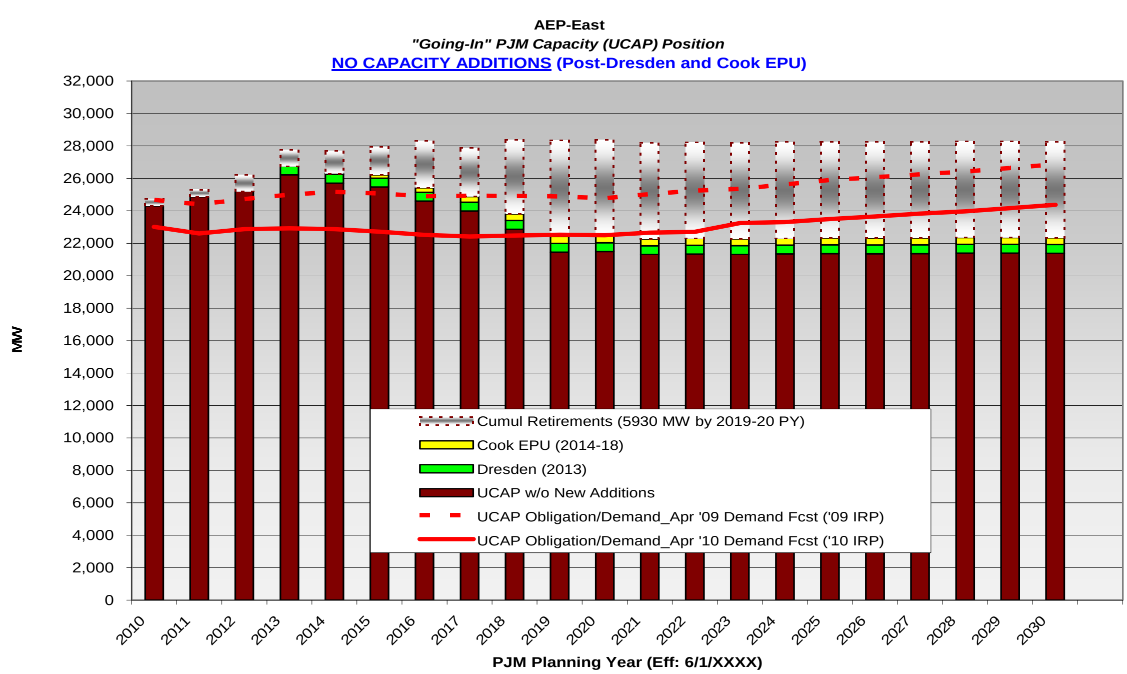
5.2 PJM Going In Forecast and Resources

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

The forecast 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.

Exhibit 5-1 offers the "going-in" capacity need of the AEP-East zone prior to uncommitted capacity additions. It amplifies that the region's overall capacity need does not occur until the end of the Planning Period (2018-2019). "Committed" new capacity includes completion of the 540 MW Dresden combined cycle facility in 2013, the assumed performance of the Donald C. Cook Nuclear Plant Extended Power Uprate (EPU) project, and assumed execution of purchase power agreements for renewable energy (largely, wind) resources.

Exhibit 5-1: Summary of Capacity vs. PJM Minimum Required Reserves



Source: AEP Resource Planning

The going-in capacity forecast considered the potential retirement of close to *6,000 MW* of largely older, less-efficient coal-fired units over the Planning Period due largely to external factors including known or anticipated environmental initiative from the U.S. Environmental Protection Agency (EPA), as well as the December 2007 stipulated New Source Review (NSR) Consent Decree. In spite of this potential, this AEP-East IRP requires no new baseload capacity resources in the forecast period. Rather, the proposed EPU initiative at the Cook Station during the 2014-2018 time period and peaking resources required in 2017 and 2018, in addition to wind purchases and DSM are proposed to be added to maintain anticipated minimum PJM nominal (capacity) reserve margin requirements (approximately 15.5% increasing to 16.2%) as well as system reliability/restoration needs. Additional natural gas-fired peaking and intermediate capacity would be added after 2020 to meet future load obligations.

5.3 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) black start.

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.

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.

5.4 RTO Requirements and Future Considerations

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 be 15.3%, as currently set for the 2013/14 planning year and remain unchanged for the remainder of the Planning Period. Finally, it was assumed that the underlying PJM EFORd for 2013/14 (6.30%) would remain unchanged for the remainder of the Planning Period.

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 was heavily impacted by the Cook outage, AEP's EFORd is projected to improve from 8.41% in 2009/10 to 5.02% in 2020/11.

This assumption tends to reduce the amount of new installed capacity needed to meet PJM requirements.

The inclusion of First Energy (FE) and Duke/Cinergy in the PJM footprint will impact the PJM IRM determination for the forecast period. The PJM study entitled 2009 PJM Reserve Requirement Study for the 11-Year Planning Horizon June 1st 2009 - May 31st 2020 dated November 4, 2009 by the PJM Staff included sensitivity study to evaluate the effect of the ATSI move to the PJM footprint. The study did not, however, evaluate the effect of Duke/Cinergy move to PJM Interconnection as this was announced after the completion of the study. The 2010 study should consider the Duke/Cinergy move from Midwest ISO to PJM Interconnection.

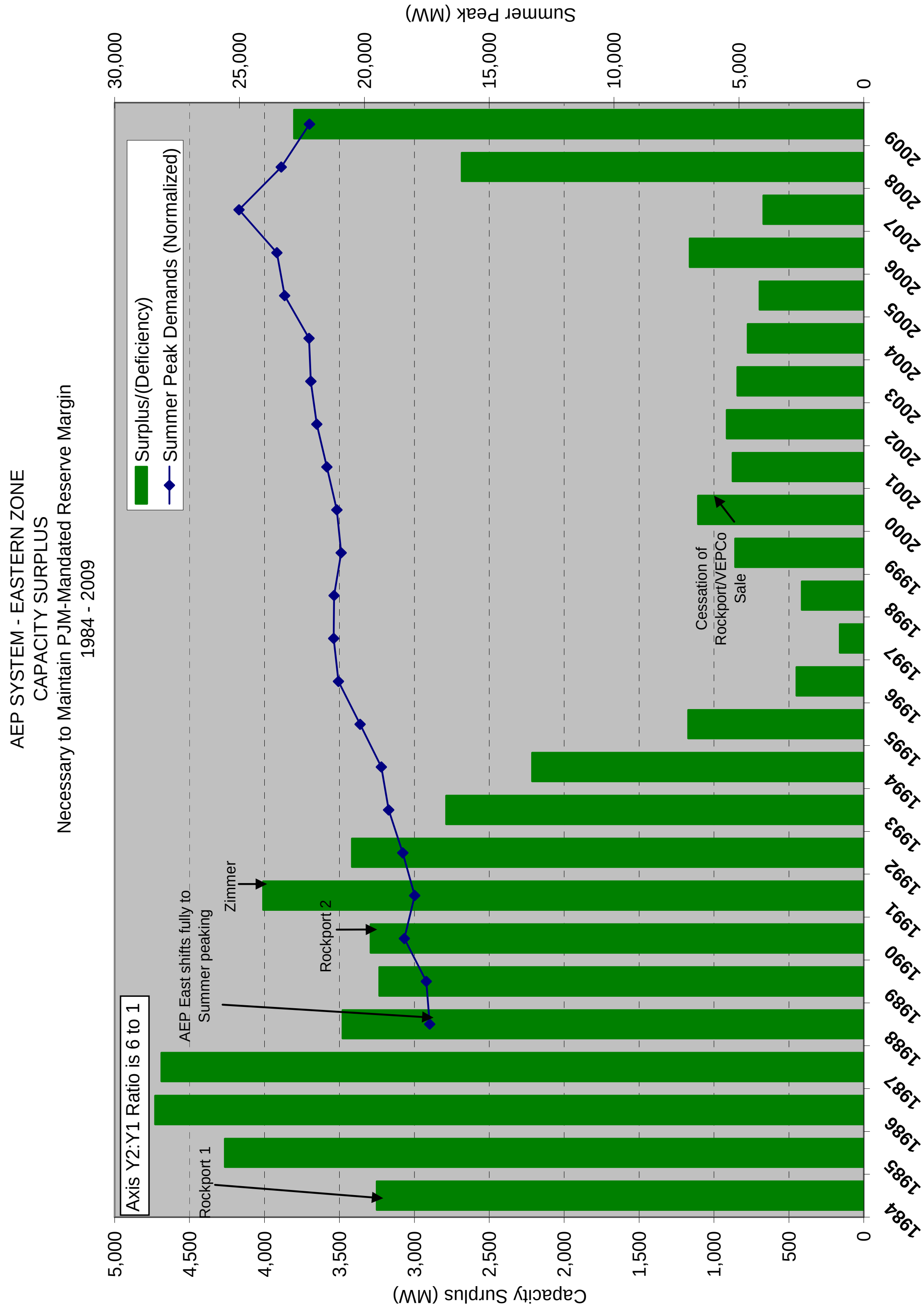
Second, the future valuation of AEP exposed generating assets take into consideration the costs profiles relative to the wholesale market position. The integrated dispatch of FE and Allegheny and the move of Duke/Cinergy generating assets to PJM will impact the PJM wholesale power markets and thus, in turn, the valuation of the AEP exposed generating assets

Beyond the FE and Duke/Cinergy matters, a FERC regulatory matter of note the November, 2009 FERC Declaratory Order issued in response to a petition from SunEdison related to solar energy installations and "retail" energy sales behind the utility meter. This order illustrates the direction of federal policy and how new entrants and new technologies are evolving with respect to retail electricity sales and the intersection of State jurisdictional net metering and FERC jurisdictional wholesale regulations.

5.5 Capacity Positions—Historical Perspective

To provide a perspective, an historical relative capacity position for the AEP-PJM zone is presented in **Exhibit 5-2**. AEP's East zone (as part of ECAR) experienced ample capacity reserves throughout the decade of the 1980s and most of the 1990s. In the early 2000s the trending clearly suggested that anticipated load growth would soon result in zonal capacity deficiencies, on a planning basis. The economic decline that occurred over the past two years has again allowed AEP's East zone to maintain an adequate capacity position however, given the volatility that has been experienced over the past decade, it would be prudent to maintain a flexible plan that can react to quick changes.

Exhibit 5-2: AEP Eastern Zone, Historical Capacity Position



Source: AEP Resource Planning

6.0 Resource Options

6.1 Resource Considerations

An 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, conformance with applicable NERC Standards and, ultimately, from the perspective of affordability. In addition, given the unique impact of generation on the environment, the planning effort must ultimately be in concert with anticipated long-term requirements as established by the environmental compliance planning process.

6.1.1 Market Purchases

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

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:

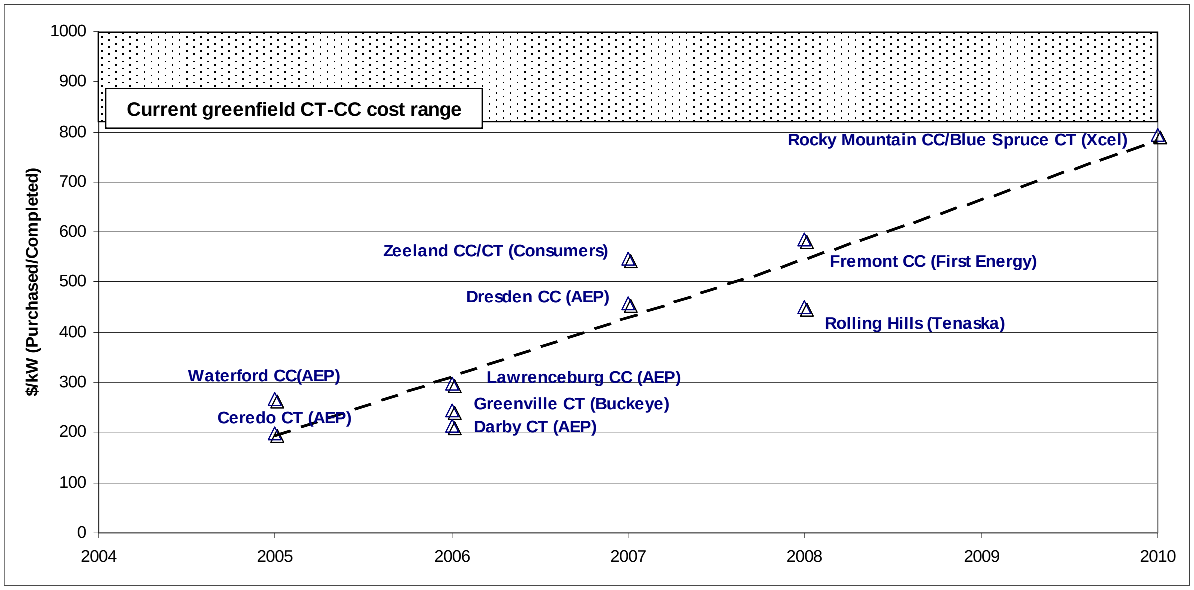
- this IRP assumes the need to ultimately build generating capability to meet the requirements of its customers for which it has assumed an obligation to serve (including Ohio);
- the regional market price of capacity ultimately will, as represented above, begin to approach the fixed cost of new-build generation; and
- the purchase of merchant generation assets relative to new-build generation represents a different risk profile with respect to siting, costs and schedule.

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 (which are limited), or to capacity resources residing outside of the PJM RTO. However, AEP has an option to participate in RPM so long as AEP remains an RPM participant for no less than 5 years.

6.1.2 Generation Acquisition Opportunities

Other market purchase opportunities are constantly being explored in continued recognition of the need for additional capacity. 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* resource optimization 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. However, as shown in **Exhibit 6-1**, the cost of these available assets are now beginning to approach that of a greenfield project.

Exhibit 6-1: Recent Merchant Generation Purchases



Source: AEP Resource Planning

6.2 Traditional Capacity-Build Options

6.2.1 Generation Technology Assessment and Overview

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

6.2.2 Baseload Alternatives

Coal-based baseload technologies include pulverized coal (PC) combustion designs, integrated gasification combined cycle (IGCC), and circulating fluidized bed combustion (CFB) facilities. Nuclear is a 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 the 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 due to the uncertainties surrounding costs, schedules, and regulatory recovery.

6.2.2.1 Pulverized Coal

PC plants are the workhorse of the U.S. electric power generation industry. 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 produce 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 ash byproduct is often used in concrete, paint, and plastic applications.

Steam cycle thermodynamics 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 or double reheat systems to 1,000°F, while supercritical steam cycles typically operate at up to 3,600 psig, with 1,000-1,050°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 units are now being designed to operate at or above 3,600 psig and >1,100°F steam temperatures, known as an *ultra supercritical* (USC) design. AEP's Turk plant which is currently under construction in Arkansas is a new USC design.

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 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.

This cost-performance tradeoff favors USC designs as fuel and carbon prices increase.

6.2.2.2 Integrated Gasification Combined Cycle

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 with carbon capture 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, the coal gasification process appears well-positioned for integration of ultimate carbon capture and storage technologies, which will be a critical measure in any future mitigation of greenhouse gas emissions associated with the generation of electricity. 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 thermal efficiencies comparable 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. It is believed that this will ultimately lead to improved net thermal efficiency than would be required by PC technology utilizing post-combustion carbon capture technology.

6.2.2.3 Circulating Fluidized Bed Combustion

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 bituminous and sub-bituminous coal plus a wide range of fuels that cannot be accommodated by PC designs. These fuels include, 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 advantage fuel flexibility. Coal is combusted in a hot bed of sorbent particles that are suspended in motion (fluidized) by combustion air blown in from below through a series of nozzles. CFB boilers operate at lower temperatures than pulverized coal-fired boilers. The energy conversion efficiency of CFB plants tends to be slightly lower than that of pulverized coal-fired counterparts of the same size and steam conditions because of higher excess air and auxiliary power requirements.

CFB boilers capitalize on the unique characteristics of fluidization to control the combustion process, minimize NO_X formation, and capture SO_2 in situ. Specifically, SO_2 is captured during the combustion process by limestone being fed into the bed of hot particles that are fluidized by the combustion air blown in from below. The limestone is converted into free lime, which reacts with the SO_2. 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. Commercial CFB units utilize a subcritical steam cycle, resulting in a lower thermal efficiency.

6.2.2.4 Carbon Capture

CO_2 capture is the separation of CO_2 from a flue gas stream or from the atmosphere and the recovery of a concentrated stream of CO_2 that is suitable for storage or conversion. Efforts are focused on systems for capturing CO_2 from coal-fired power plants, although the technologies developed will need to 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% volume. This is a challenging application for CO_2 capture because:

- The low pressure and low 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.
- CO_2 capture processes require large amounts of steam and electricity to separate the CO_2 from the flue gas stream thereby increasing unit heat rates, increasing auxiliary power requirements and reducing the electrical energy available for delivery to ultimate customers.
- Compressing captured CO_2 from atmospheric pressure to pipeline pressure (1,200 to 2,000 pounds per square inch) adds to the 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 2012 Department of Energy aspirational goal for advanced CO_2 capture and storage 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 even though the conditions for CO_2 capture are more favorable in an IGCC plant.

6.2.2.4.1 Carbon Capture Technology and Alternatives

Reducing CO_2 emissions from a fossil-fuel technology can be accomplished in three ways: increased generating efficiency thereby lowering the emission rate or CO_2 produced per unit of electric energy produced, 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 an amine-based absorption process.

As previously mentioned in this report, AEP is pursuing an alternative approach. AEP is currently conducting a validation of Alstom's chilled ammonia PC carbon capture technology on a 20

MW flue gas slipstream at its 1,300 MW Mountaineer Plant in West Virginia. It is anticipated that this technology, when fully developed, will achieve 90% CO_2 capture with a 15% parasitic loss and netting a lower cost than other retrofit technologies. Based on the results of the Mountaineer slip-stream test, a subsequent 235 MW commercial installation of this chilled ammonia technology is in the early stage of Phase I development for Mountaineer.

This 235 MW cost/performance profile will be modeled in subsequent IRPs.

6.2.2.5 Carbon Storage

Storage is the placement of CO_2 into a repository in such a way that it will remain stored 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 are 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.

6.2.2.6 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, capital costs and completion risk continue to temper its consideration. For these stated reasons, among others, AEP does not view new new nuclear capability as a viable candidate to meet the capacity resource needs of AEP-East within this near-term period (2010-2020). 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 zone's ultimate need for baseload capacity;
2) the cost and performance uncertainty surrounding the advancement and commercialization of IGCC technology;
3) the cost and performance uncertainty of carbon capture and storage technology; and

4) the continued push to address AEP's carbon footprint and the mitigating impact additional nuclear power clearly would have in that regard.

Growth in U.S. nuclear generation since 1977 has been primarily achieved through "uprating" – the practice of increasing capacity at an existing nuclear power plant. As of October 2009, the NRC had approved 129 uprates totaling 5,726 MWe of capacity. That amount is equivalent to adding another five-to-six conventional-sized nuclear reactors to the electricity supply portfolio. Extended power uprates (EPU) can provide up to 20% of additional capacity. The EPU and related projects for the Cook Plant (as described in **Section 3.2.1** of this report) – are therefore consistent with the recent trends in the nuclear industry.

6.2.3 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. Over the last several years, these units' staffs have made strides to improve ramp rates, regulation capability, and reduce downturn (minimum load capabilities). As the fleet continues to age and sub-critical units are retired, other generation dispatch alternatives and new generation will need to be considered to cost effectively meet this duty cycle's operating characteristics.

6.2.3.1 Natural Gas Combined Cycle (NGCC)

An NGCC plant combines a steam cycle and a combustion gas turbine cycle to produce power. Waste heat (~1,100°F) from one or more combustion turbines passes through a heat recovery steam generator (HRSG) producing 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 the 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, small footprint and shorter construction periods than coal-based plants. In the past 8 to 10 years NGCC plants were often 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 an inability to maintain optimum air-to-fuel pressure and turbine exhaust and steam temperatures. Methods to address these include:

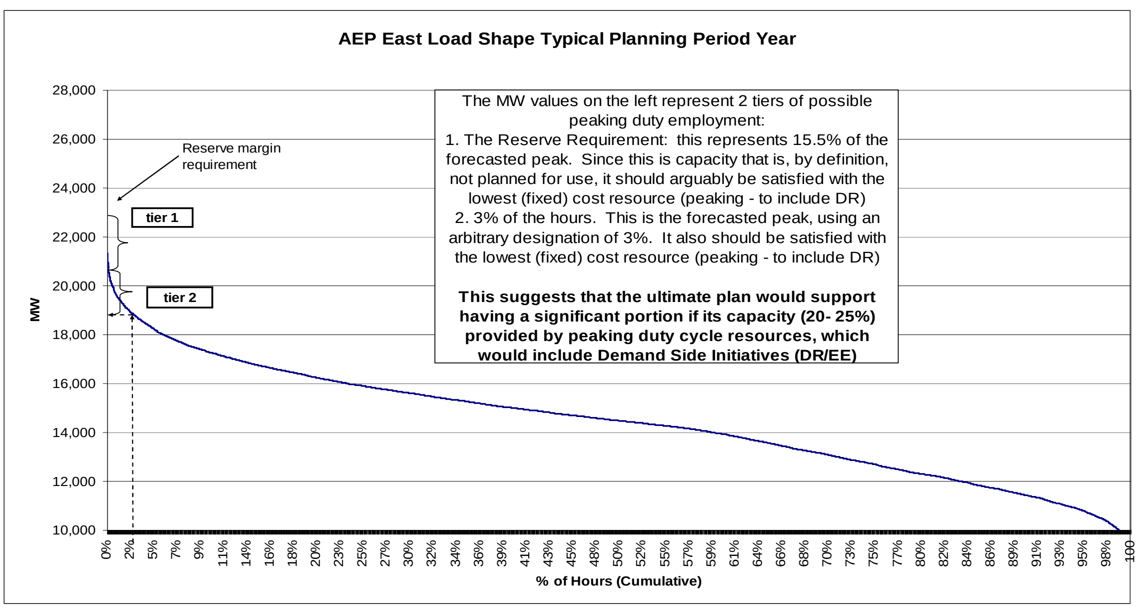
- Installation of advanced automated controls.
- Supplemental firing while at full load with a reduction in firing when load decreases. When supplemental firing reaches zero, fuel to the gas turbine is cutback. This approach would reduce efficiency at full load, but would likewise greatly reduce efficiency 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.

6.2.4 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. 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. As a result, fuel efficiency and other variable costs are of less concern. This capacity should be obtained at the lowest practical installed cost, despite the fact that such capacity often has very high energy costs. For this reason, acquisition of existing gas generation 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 6-2**. 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.

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.

Exhibit 6-2: AEP East Typical Load Duration Curve



Source: AEP Resource Planning

6.2.4.1 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 provides rotating shaft power to drive 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, i.e., not recovered as in a combined cycle design. While not as efficient (at 30-35% LHV), they are, however, inexpensive to purchase, compact, and simple to operate. Further, simple cycle frame CTs can be started up and placed in service far more rapidly (30 minutes) than a combined cycle unit requiring four or more hours from start to full load resulting from the CC unit thermal steam cycle.

6.2.4.2 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 frame machine requires 20 minutes to ramp up to full load while the smaller LM6000 aeroderivative only needs 10 minutes from start to full load. However, the cost per kW of an aeroderivative is on the order of 20% higher than a frame machine.

The AD performance operating characteristics of 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 frame machines 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 variable renewables such as solar and wind. This operating characteristic is expected to become more valuable over time as: a) the penetration of variable renewables increase, b) baseload generation processes become more complex limiting their ability to load follow and; c) intermediate coal-fueled generating units are retired from commercial service.

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 less than 100 MW range are more efficient and have lower heat rates in simple cycle operation than industrial units of equivalent 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.[5]

[5] Turbomachinery International, Jan/Feb. 2009; Gas Turbine World; EPRI TAG

6.2.5 Energy Storage

Energy storage refers to technologies that allow for storage of energy during off-peak periods of 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 can also be applied at other times to temporarily mitigate transmission congestion if it is economically to do so in conjunction with generating resources that are curtailed by inadequate transmission infrastructure. Energy storage consists of batteries (Sodium Sulfur "NaS," Lithium Ion, and others), super capacitors, flywheels, compressed air energy storage (CAES) 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 prospective storage-related utility planning with several variations of compressed air energy storage in research and development.

6.2.5.1 Sodium Sulfur Batteries (NaS):

Storage technologies are receiving 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. Battery installations can be located near load points, thus avoiding transmission and distribution line losses associated with traditional generation. The downside currently is the significant manufactured cost per kW, transportation limitations due to their weight, and total installed costs in the range of $2,000 per kW.

In light of battery-storage's potential for: 1) 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.

6.2.5.2 Community Energy Storage (CES)

Community energy storage (CES) is being tested as a distributed storage option. 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 distribution game-changing technology, which should also provide voltage sag mitigation as well as emergency transformer load relief.

6.3 Renewable Alternatives

Renewable generation alternatives use 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 such as solar, geothermal, new hydro, and tidal are either under development or exist. However not all are economic options for AEP within the service territory based on their current state of development, or for financial, meteorological, or geographical reasons. Within the AEP service territory, without significant leaps in technology, biomass co-firing in coal power plants and wind power plants are the primary options for economically (or realistically) generating electricity on a significant scale from renewable sources.

As highlighted in the **Section 2** Introduction, although effective in 29 states (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. The prospect of a Federal RPS and additional state standards is sufficiently tenable to warrant an evaluation of renewable generation in conjunction with this IRP process. Further, renewable energy sources deliver attractive CO_2 benefits in a potentially carbon-constrained policy environment, should that environment be realized.

AEP's New Technology Development group continues to evaluate a wide range of renewable technologies, with the latest updates (December 2009) included in **Appendix I**. 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 \$/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 and also was compared to AEP-East's avoided cost to calculate an imputed REC value. A project is considered reasonable if the projected market value of equivalent RECs is greater than this imputed REC value for a particular technology.

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 or without the federal production tax credit & investment tax credit
- solar generation
  - ✓ with or without the federal investment tax credit
- 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.*

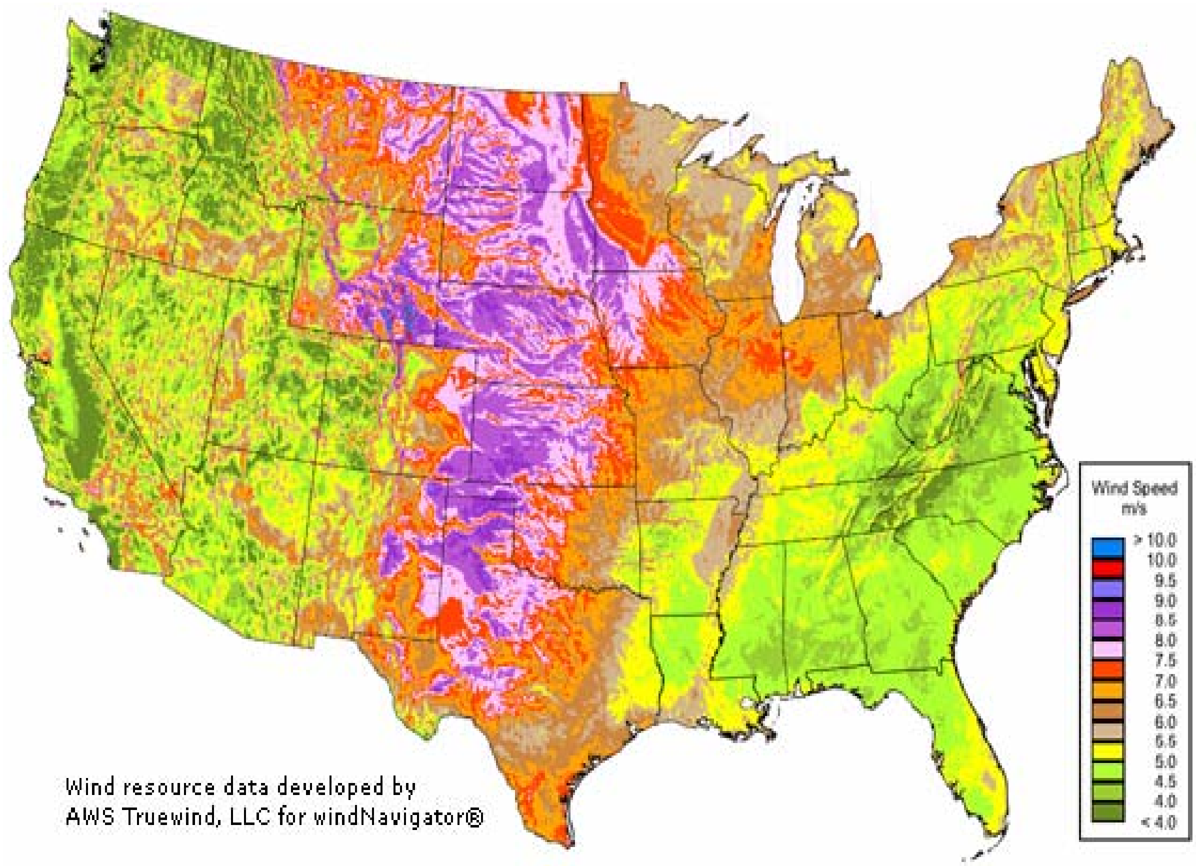
6.3.1 Wind

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 with over 25,000 MW of wind online as of January 2010. 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 turbine 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 becoming competitive within the AEP-East zone due largely, however, to subsidies, such as the federal production tax credit as well as consideration given to REC values, anticipated rising fuel costs or future carbon costs.

A drawback of wind is that it represents a variable source of power in most non-coastal locales, with capacity factors ranging from 30 to 45 percent; thus its life-cycle cost ($/MWh), excluding subsidies, is typically higher than the marginal (avoided) cost of energy, in spite of wind's zero dollar 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 6-3** shows the wind resource locations in the U.S. and their relative potential.

Exhibit 6-3: United States Wind Power Locations

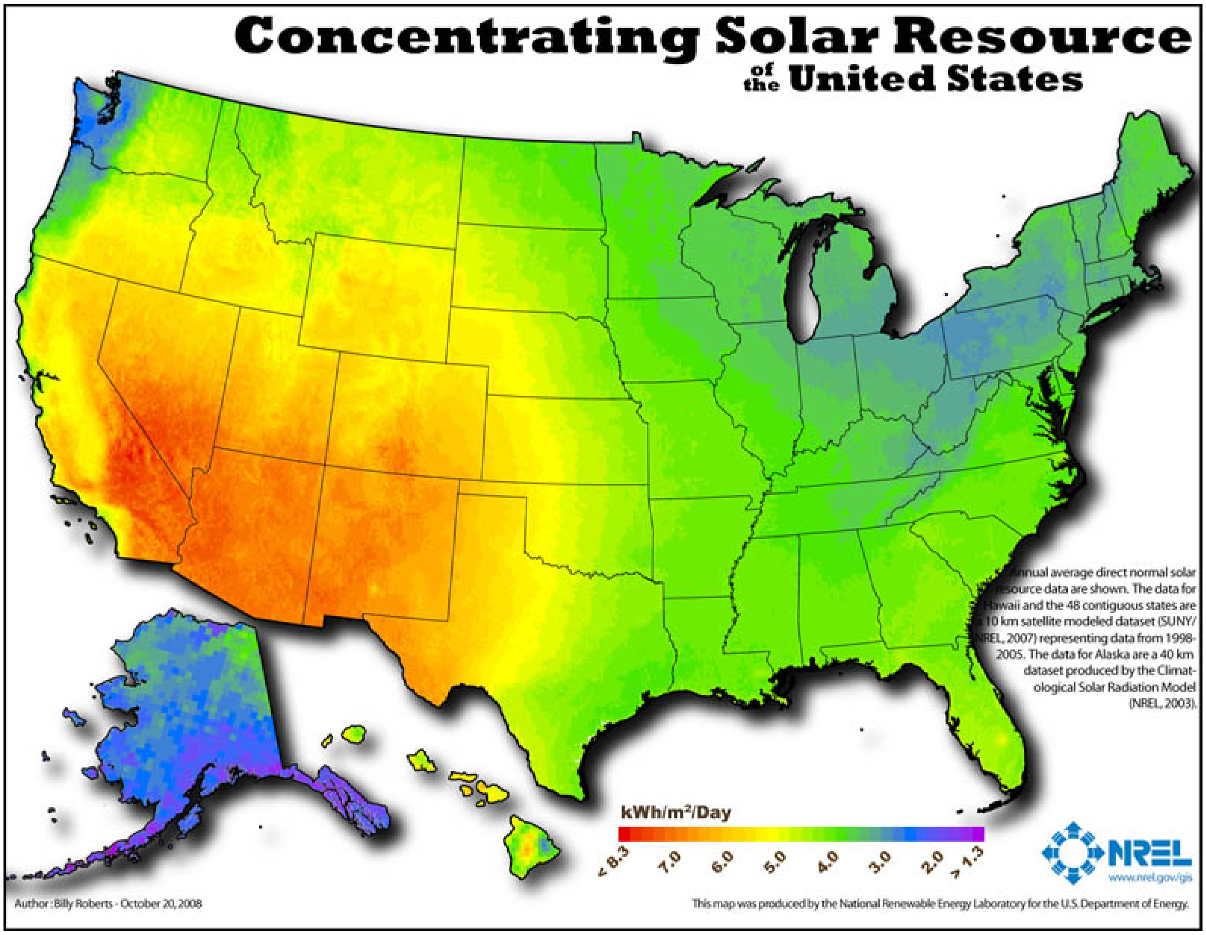


Source: U.S. Department of Energy

6.3.2 Solar

Solar power takes a couple of viable forms to produce electricity: concentrating and photovoltaics. Concentrating solar – which heats a working fluid to temperatures sufficient to power a turbine - produces electricity on a large scale (100 MW) and is similar to traditional centralized supply assets in that way. Photovoltaics produce electricity on a smaller scale (2 kW to 20 MW per installation) and are distributed throughout the grid. In the AEP-East zone, solar has applications as both large scale and distributed generation. The appeal of solar is broad and recent legislation in Ohio has made its pursuit mandatory subject to rate impacts, beginning in 2009. Solar photovoltaics are represented in this IRP as though this full solar requirement is to be met 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 6-4** shows the potential solar resource locations in the U.S.

Exhibit 6-4: United States Solar Power Locations



Source: NREL

6.3.3 Biomass

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

It is generally accepted that sustainably produced biomass represents a carbon neutral fuel. Carbon from the atmosphere is converted into biological matter by photosynthesis. Upon combustion, the carbon returns to the atmosphere as carbon dioxide (CO_2) where it can be recaptured by new biomass growth replacing the biomass used as fuel. 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 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 used to remove NO_X from the exhaust gas. Although these relatively minor obstacles can be mitigated through various means, the major obstacles to the utilization of biomass as a feedstock include volatile costs of transportation and substitute uses for the fuel. Biomass has many competing demands, such as the pulp and paper markets, agriculture industries, and 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 dedicated land necessary to generate sufficient quantities of biomass as identified in **Exhibit 6-5**.

Exhibit 6-5: Land Area Required to Support Biomass Facility

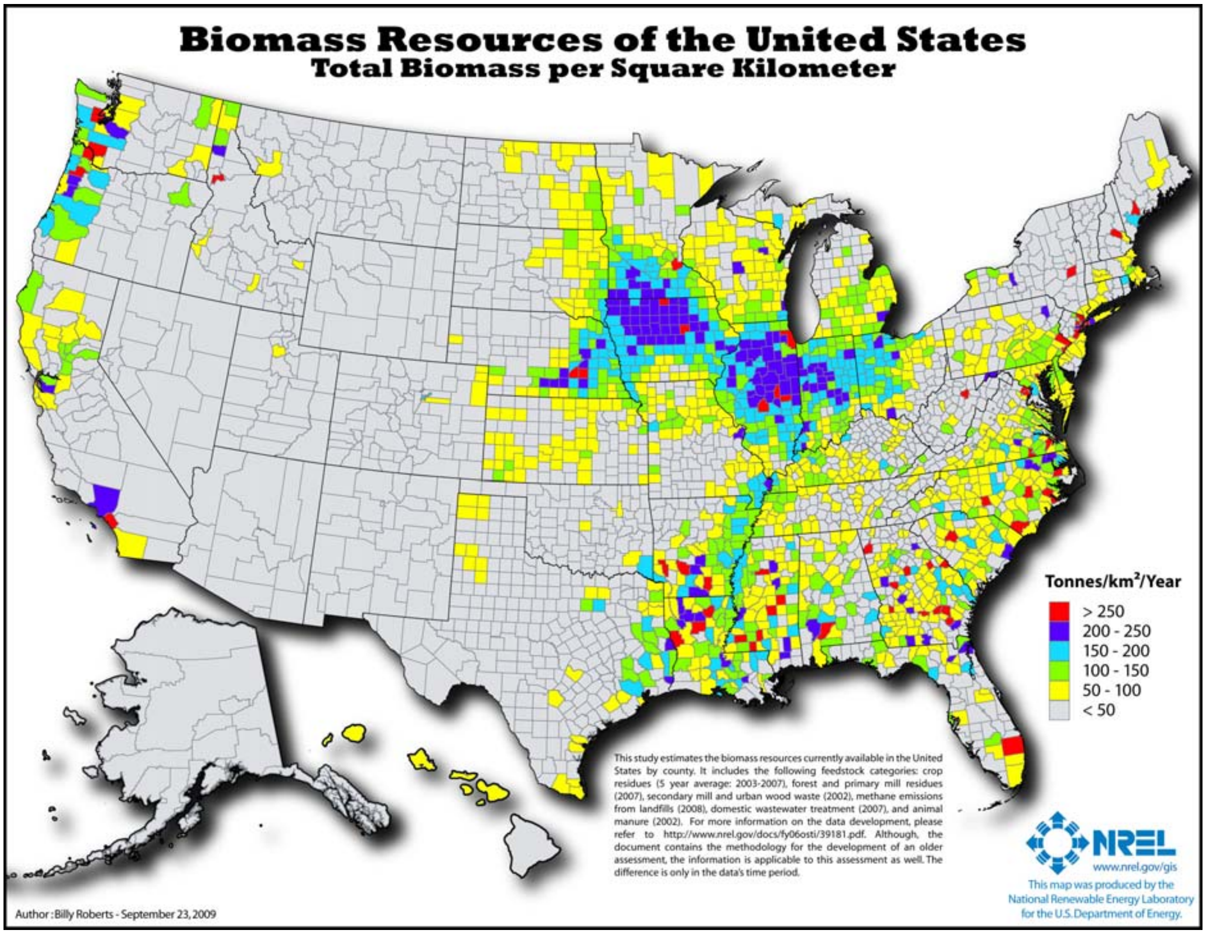
Switchgrass	Wood Chips / Sawdust
(per Purdue University Study) o 6 -to- 8 tons /yr. per acre yield o @ 6700 Btu/lb (non-dried, as harvested) *A 200-MW Dedicated Biomass Facility (70% C.F.) would require…* **110k -to- 150k harvested acres** *(172 - 234 sq. mi,)*	*(per AEP-Forestry)* o 70 -to-100 tons /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 inhibits the near-term viability of the technology on a large scale. **Exhibit 6-6** 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 6-6: Biomass Resources in the United States



Source: NREL

6.3.4 Renewable Energy Certificates (RECs)

An additional option for complying with renewable standards involves the purchase of renewable energy certificates, or "RECs". RECs are generated contaminant with carbon-neutral energy, but are sold separately providing the energy produced is sold into the relevant grid. This arrangement allows for efficient transfer of costs from over-producers to under-producers of required carbon-neutral energy. In nascent markets, where over-production does not exist, RECs will be scarce or non-existent, driving values high. High REC values, in turn, will foster additional capital investment, until REC values reach equilibrium.

In AEP-East zone states with renewable requirements (Ohio and Michigan), REC markets exist or are developing for renewable (in-state and deliverable) and solar (in-state and deliverable) but are not yet reliable sources for compliance.

6.3.5 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 E**). Based on current AEP renewable resources, and considering an additional 1,000 MW of renewable resources committed to by the year-end 2014, together with the prospective renewable projects listed in **Exhibit 6-7**, included in the 2010 IRP (AEP-East and SPP), this internal commitment is projected to be satisfied. Note that the 2014 target represents an approximate 3-year shift in prior (2009 IRP) planned commitments of 2,000 MW of System-wide renewable resources by the end of *2014*; however, as recent unfavorable regulatory decisions in both Virginia and Kentucky surrounding cost recovery of planned wind purchase transactions has resulted in this "extension" of that prior goal.

Exhibit 6-7: Renewable Sources Included in AEP-East and AEP-SPP 2010

AEP-System
Existing and Projected Renewables for 2010 IRP

Unit, Plant, or Contract	Unit Type: Solar	Unit Type: Wind	Unit Type: Biomass	Size (MW)	First Full Energy Year	Renewable as % of Sales	Notes
Wind (SW Mesa)		X		31	Existing	0.1%	Existing (RECs only)
Wind (Weatherford)		X		147	Existing	0.5%	Existing
Wind (Blue Canyon II)		X		151	Existing	0.9%	Existing (RECs only until 2013)
Wind (Sleeping Bear)		X		95	Existing	1.2%	Existing
Wind (Camp Grove)		X		75	Existing	1.4%	Existing
Wind (Fowler Ridge I & III)		X		200	2010	1.8%	Executed PPA
Wind (Grand Ridge II & III)		X		101	2010	2.0%	Executed PPA
Wind (Fowler Ridge II)		X		150	2010	2.4%	Executed PPA (Add'l take)
Wind (Majestic)		X		80	2010	2.6%	Executed PPA (RECs only until 2012)
Wind (Blue Canyon V)		X		99	2010	2.9%	Executed PPA (RECs only until 2013)(Add'l take)
Wind (Beech Ridge)		X		101	2011	3.1%	Executed PPA(PSC-Apprvd)
Wind (Elk City)		X		99	2011	3.3%	Executed PPA (RECs only until 2013)(Add'l take)
Solar (Wyandot)	X			10	2011	3.4%	Executed PPA
Solar (Ohio)	X			10	2011	3.4%	w/ ITC
Biomass (Ohio units)			X	44	2011	3.5%	Ohio Units 10% Co-Fire
Wind (East)		X		100	2012	3.6%	w/ PTC
Wind (Minco)		X		100	2012	3.9%	Minco (PSO)
Solar (Ohio)	X			10	2012	3.9%	w/ ITC
Wind (East)		X		100	2013	4.1%	w/ PTC
Solar (Ohio)	X			10	2013	4.1%	w/ ITC
Biomass (East)			X	50	2014	4.4%	RECs PPA or Unit Co-Fire (No New Capacity)
Wind (East)		X		300	2014	5.0%	No PTC
Solar (Ohio)	X			26	2014	5.0%	w/ ITC
Wind (East)		X		400	2015	5.9%	No PTC
Wind (West)		X		200	2015	6.4%	No PTC
Solar (Ohio)	X			26	2015	6.4%	w/ ITC
Solar (Distributed)	X			25	2015	6.5%	(E&W) No ITC
Biomass (Ohio units)			X	(44)	2016	6.3%	Retirement of Ohio Units 10% Co-Fire
Wind (West)		X		200	2016	6.9%	No PTC
Wind (East)		X		250	2016	7.4%	No PTC
Solar (Ohio)	X			26	2016	7.4%	No ITC
Wind (West)		X		200	2017	7.9%	No PTC
Wind (East)		X		150	2017	8.2%	No PTC
Solar (Ohio)	X			26	2017	8.3%	No ITC
Solar (Ohio)	X			26	2018	8.3%	No ITC
Wind (East)		X		50	2018	8.4%	No PTC
Biomass (East)			X	100	2018	8.9%	RECs PPA or Unit Co-Fire (No New Capacity)
Wind (East)		X		100	2019	9.1%	No PTC
Solar (Ohio)	X			26	2019	9.1%	No ITC
Wind (West)		X		300	2020	9.9%	No PTC
Wind (East)		X		150	2020	10.2%	No PTC
Solar (Ohio)	X			26	2020	**10.2%**	No ITC

Source: AEP Resource Planning

6.4 Demand-Side Alternatives

6.4.1 Background

Demand Side Management 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 response (DR) programs, while round-the-clock measures are energy efficiency (EE) programs. The distinction between peak demand reduction and energy efficiency is important, as the solutions for accomplishing each objective are typically different, but not necessarily mutually exclusive.

6.4.2 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) zone, this maximum (System peak) 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 between the utility and a large consumer of power, typically an industrial customer. In return for reduced rates, an industrial customer allows the utility to "interrupt" or reduce power consumption during peak periods, freeing up that capacity for use by 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 energy manager to deactivate or cycle discrete appliances, typically air conditioners, hot water heaters, lighting banks, 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.
- *Time-differentiated 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 as two rates (peak and off-peak) and to as often as 15-minute increments known as "real-time pricing". Accomplishing real-time pricing requires digital (smart) 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. 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.

6.4.3 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 a building/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 include efficient lighting, weatherization, efficient pumps and motors, efficient HVAC infrastructure, and efficient appliances, most commonly. Often, multiple measures are bundled into a single program that might be offered to either residential or commercial/industrial customers.

EE measures will, in all cases, reduce the amount of energy consumed but may have limited effectiveness at the time of peak demand. Energy Efficiency is viewed as a readily deployable, relatively low cost, and clean energy resource that provides many benefits. According to a March 2007 DOE study such benefits include:

- Economics: Reduced energy intensity provides competitive advantage and frees economic resources for investment in non-energy goods and services
- Environment: Saving energy reduces air pollution, the degradation of natural resources, risks to public health and global climate change.
- Infrastructure: Lower demand lessens constraints and congestion on the electric transmission and distribution systems
- Security: Energy Efficiency can lessen our vulnerability to events that cut off energy supplies

However, market barriers to Energy Efficiency exist for the customer/participant.

Market Barriers to Energy Efficiency	
High First Costs	Energy-efficient equipment and services are often considered "high-end" products and can be more costly than standard products, even if they save consumers money in the long run.
High Information or Search Costs	It can take valuable time to research and locate energy efficient products or services.
Consumer Education	Consumers may not be aware of energy efficiency options or may not consider lifetime energy savings when comparing products.
Performance Uncertainties	Evaluating the claims and verifying the value of benefits to be paid in the future can be difficult.
Transaction Costs	Additional effort may be needed to contract for energy efficiency services or products.
Access to Financing	Lending industry has difficulty in factoring in future economic savings as available capital when evaluating credit-worthiness.
Split Incentives	The person investing in the energy efficiency measure may be different from those benefiting from the investment (e.g. rental property)
Product/Service Unavailability	Energy-efficient products may not be available or stocked at the same levels as standard products.
Externalities	The environmental and other societal costs of operating less efficient products are not accounted for in product pricing or in future savings

Source: Eto, Goldman, and Nadel (1998): Eto, Prahl, and Schlegel (1996); and Golove and Eto (1996)

To overcome many of the participant barriers noted above, a portfolio of programs may often include several of the following elements:

- Consumer education
- Technical training
- Energy audits
- Rebates and discounts for efficient appliances, equipment and buildings
- Industrial process improvements

The level of incentives (rebates or discounts) offered to participants is a major determinant in the pace of market transformation and measure adoption.

Additionally, the speed with which programs can be rolled out also varies with the jurisdictional differences in stakeholder and regulatory review processes. The lead time can easily exceed a year for getting programs implemented or modified. This IRP begins adding demand-side resources in 2011 that are incremental to approved or mandated programs.

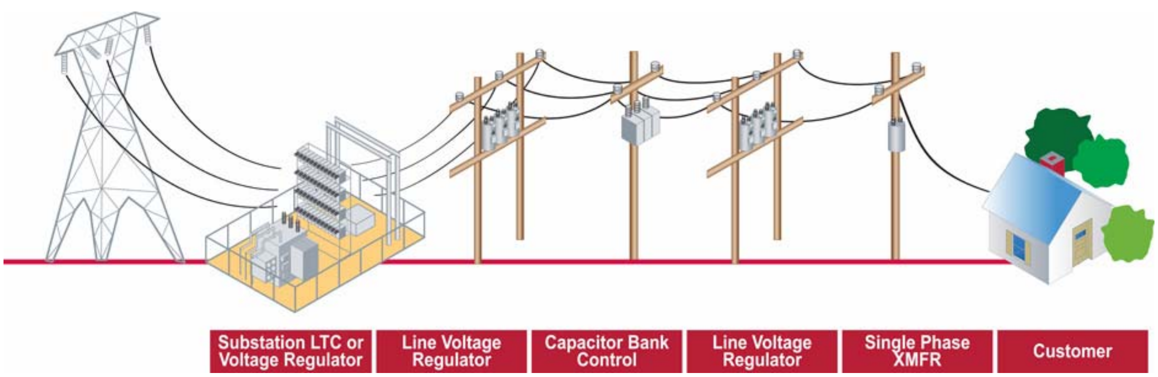
6.4.4 Distributed Generation

Distributed generation refers to (typically) small scale customer-sited generation downstream of the customer meter. Common examples are combined heat and power (CHP), residential solar applications, and even wind. Currently, these sources represent a negligible component of demand-side resources as even with available Federal tax credits, they are typically not economically justifiable.

6.4.5 Integrated Voltage/VaR Control

IVVC provides all of the benefits of power factor correction, voltage optimization, and condition-based maintenance in a single, optimized package. In addition, IVVC enables conservation voltage reduction (CVR) on a utility's system. CVR is a process by which the utility systematically reduces voltages in its distribution network, resulting in a proportional reduction of load on the network. A 1% reduction in voltage typically results in a 0.5% to 0.7% reduction in load.

Exhibit 6-8: Integrated Voltage/VaR Control



6.4.6 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.

7.0 Evaluating DR/EE Impacts for the 2010 IRP

7.1 Demand Response/Energy Efficiency Mandates and Goals

The Energy Independence and Security Act of 2007 (“EISA”) 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. Additionally, legislative and/or regulatory mandated levels of demand reduction and/or energy efficiency attainment, subject to cost effectiveness criteria, are in place in Ohio, Indiana and Michigan in the AEP-East Zone. The Ohio standard, if cost-effective criteria are met, will result in installed efficiency measures equal to over 20 percent of all energy otherwise supplied by 2025. Indiana’s standard achieves installed efficiency reductions of 13.90% in 2020 while Michigan’s standard achieves 10.55%. Virginia has a voluntary 10% by 2020 target. While no mandate currently exists in Kentucky, KPCo has offered DR/EE programs to customers since the mid-1990’s.

As identified in this document and in the Company’s 2010 Corporate Accountability Report, 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.

7.2 Current DR/EE Programs

As of June 1, 2010, active energy efficiency programs exist in Kentucky, Ohio, Michigan, with additional programs filed in Indiana and West Virginia. Demand response programs, consisting of interruptible tariffs, time differentiated rates, and load control, are currently being offered. The demand and energy impacts of the installed programs (as of March 31, 2010) are shown in **Exhibit 7-1**. **Appendix G** lists annual energy efficiency programs and demand reduction forecasts by operating company, by year.

Exhibit 7-1: AEP-East Embedded DR/EE Programs

Installed Demand Reductions (MW)					Energy Reductions (GWh)
	Energy Efficiency	Interuptible	ATOD	Total	Energy Efficiency
Ohio	38	140	0	178	305
APCo	0	14	107	121	0
I&M	2	258	0	260	8
Kentucky	3	0	0	3	4
AEP-East	43	412	107	562	317

Source: AEP Resource Planning

7.2.1 gridSMART Smart Meter Pilots

Smart meter pilots are underway in Indiana and Ohio. As of June 1st, 2010, nearly 200,000 customers have been equipped with the new meters. The meters allow for time-differentiated pricing which should result in more efficient customer use of electricity and peak usage reductions.

AEP's first gridSMART pilot program began in 2009 in South Bend, Indiana. The year-long South Bend pilot involved approximately 10,000 meters and was to end after the 2009 cooling season, but it has been extended to include the 2010 cooling season because of some early technical problems.

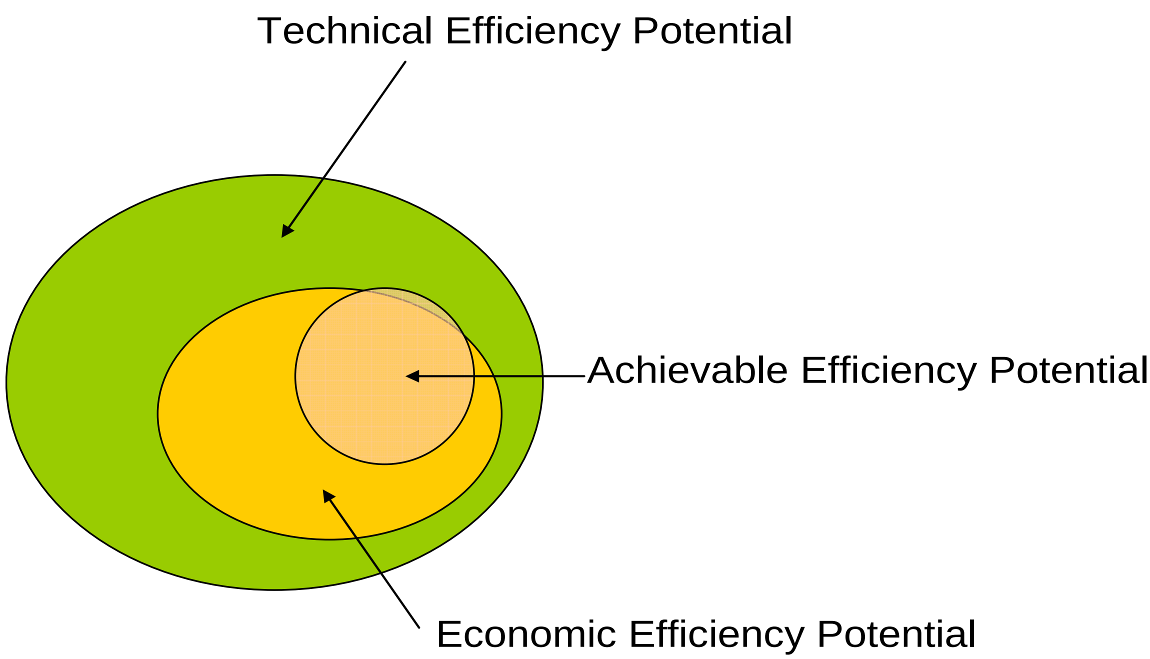
A larger and more comprehensive gridSMART demonstration project involves 110,000 customers in central Ohio. Paid for in part with a $75M grant from the DOE, the $150M project will include smart meters, distribution automation equipment to better manage the grid, community energy storage devices, smart appliances and home energy management systems, a new cyber security center, PHEV (Plug-in/hybrid electric vehicle) demonstrations, and installation of utility-activated control technologies that will reduce demand and energy consumption without requiring customers to take action. This last technology is known as such as Integrated Voltage VaR Control (IVVC), a form of voltage control that allows the grid to operate more efficiently. In IVCC, sensors and intelligent controllers monitor load flow characteristics and direct controls on capacitor and voltage regulating equipment to optimize power factor (Var flow) and voltage levels. Power factor optimization improves energy efficiency by reducing losses on the system. Voltage optimization can allow a reduction of system voltage that still maintains minimum levels needed by customers, enabling consumers to use less energy without any changes in behavior or appliance efficiencies. Early results indicate a range of 0.5% to 1% of energy demand reduction for a 1% voltage reduction is possible.

The results of these pilots will greatly inform the impacts assigned to larger roll-outs of these meters and related projects such as IVVC, should they ultimately be approved. It is still unknown how much deployment of these meters will change customer consumption patterns relative to traditional meters. As these behaviors become discernible and quantifiable, their effects will be incorporated into future load forecasts and IRPs.

7.3 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. For states that do not have mandates in place, DR/EE savings were developed using an achievable potential target (**Exhibit 7-2**).

Exhibit 7-2: 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 due to the existence of market barriers. How much effort and money is deployed towards removing or lowering the barriers is a decision made by state governing bodies.

States with legislative or regulatory requirements universally require that these requirements be met economically and provide for "off ramps" if or when pursing the goals no longer meets that criterion. "Economic potential" is estimated to be in the 20-25% range of total consumption. The "achievable" range is a fraction of the economical range. This achievable amount must be further split between what can or should be accomplished with utility-sponsored programs and what should fall under codes and standards. Both amounts are represented in this IRP as reductions to what would otherwise be the load forecast.

7.4 Utility-sponsored DSM modeling/forecasting

Two sources were used as the basis for the analysis in this IRP. The first source is an AEP Measures Database that was specifically developed for AEP and its jurisdictions as part of its DSMore software package. DSMore, an industry-standard software tool, analyzes DR/EE programs and produces test results in line with DR/EE industry standards. The AEP Measures Database was used to determine which measures would be modeled in the current IRP. The second is a national energy efficiency study published by the Electric Power Research Institute (EPRI) in January of 2009. This study defines realistically achievable EE target levels. It estimates a cumulative achievable target of 3.3% EE savings by 2020 relative to a baseline forecast which includes the effects of the increased standards required in EPAct 2007.

7.4.1 DSM Proxy Resources

The DSMore Measures Library was used to find viable measures by Residential and Commercial class for the IRP. Measures were organized into groups and then evaluated based on their Total Resource Cost Test (TRC) scores. The TRC measures the net costs of a EE program as a resource option based on the total costs of the program, including both the participant's and the utility's costs. Aggregate blocks were considered viable and chosen for optimization modeling only if their TRC scores were above 1.00 except for Residential Low and Moderate Income Weatherization. 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. As such, the following measure blocks were chosen.

Exhibit 7-3: DSM Proxy Resources Costs

Measure	Levelized Resource Cost $/kWh[6]	Levelized Program Cost $/kWh[1]	TRC Score
C& I Lighting	.059	.033	1.05
C&I Pumps & Motors	.040	.023	1.53
Residential Lighting	.033	.019	1.86
Residential Water Heating	.034	.019	2.39
Residential Low Income	.070	.070	0.86
C&I Demand Response[7]	N/A	N/A	1.8
IVVC[8]	.034-.047	.034-.047	2.1-2.5

Source: AEP Resource Planning

These blocks served as proxy resources for the actual programs that will, over time, be implemented. The blocks have individual characteristics or load shapes. It is desirable that, in

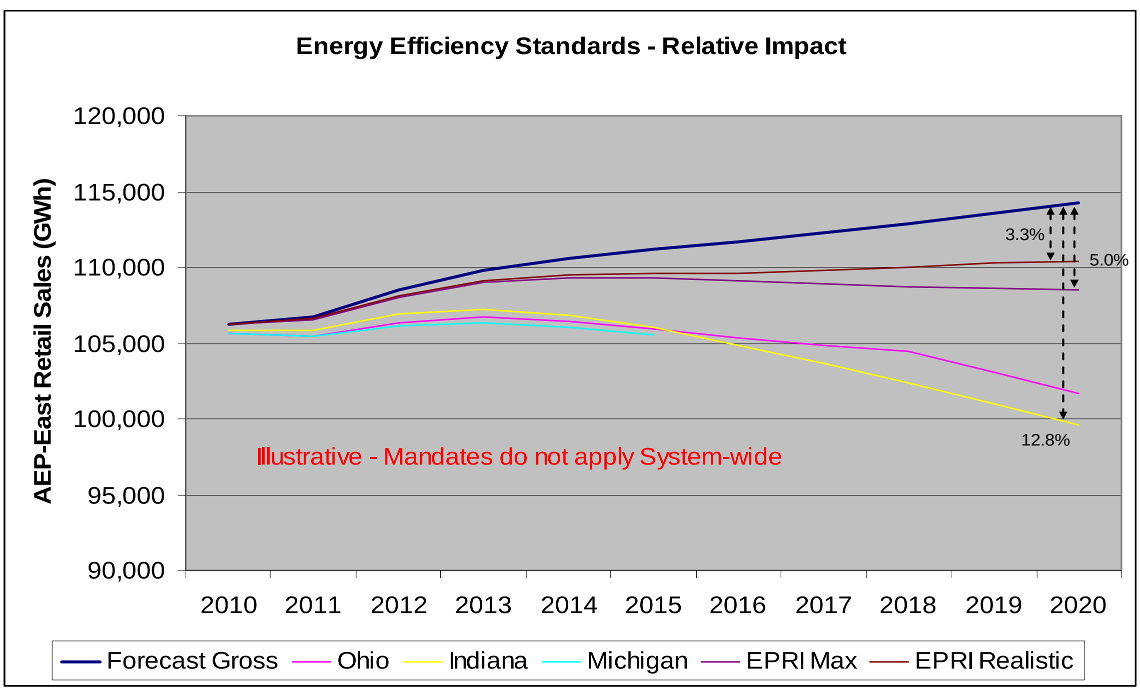
6 Non-discounted
7 Assumes no energy savings from demand interruptions
8 Blocks are non-homogeneous

aggregate, the blocks will have similar characteristics to what eventually gets implemented so that the remainder of the supply-side optimization is accomplished with reasonably accurate demand-side interrelationships.

7.4.2 DSM Levels

Energy usage and energy savings amounts for states that did not have pre-existing mandates were made based on EPRI's January 2009 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 [utility-sponsored] 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. It is noteworthy that the mandates in Ohio and Indiana exceed what EPRI has determined is realistic or even possible by 2020. While conflicting, this outcome is possible if the jurisdictions involved are willing to exceed the funding levels envisioned as maximums by EPRI; it is on this basis that mandates were assumed to be met through 2020.

Exhibit 7-4: Energy Efficiency Impacts



Source: AEP Resource Planning

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. These blocks provide a reasonable proxy for demand-side resources within the context of an optimization model.

7.5 Validating Incremental DR/EE resources

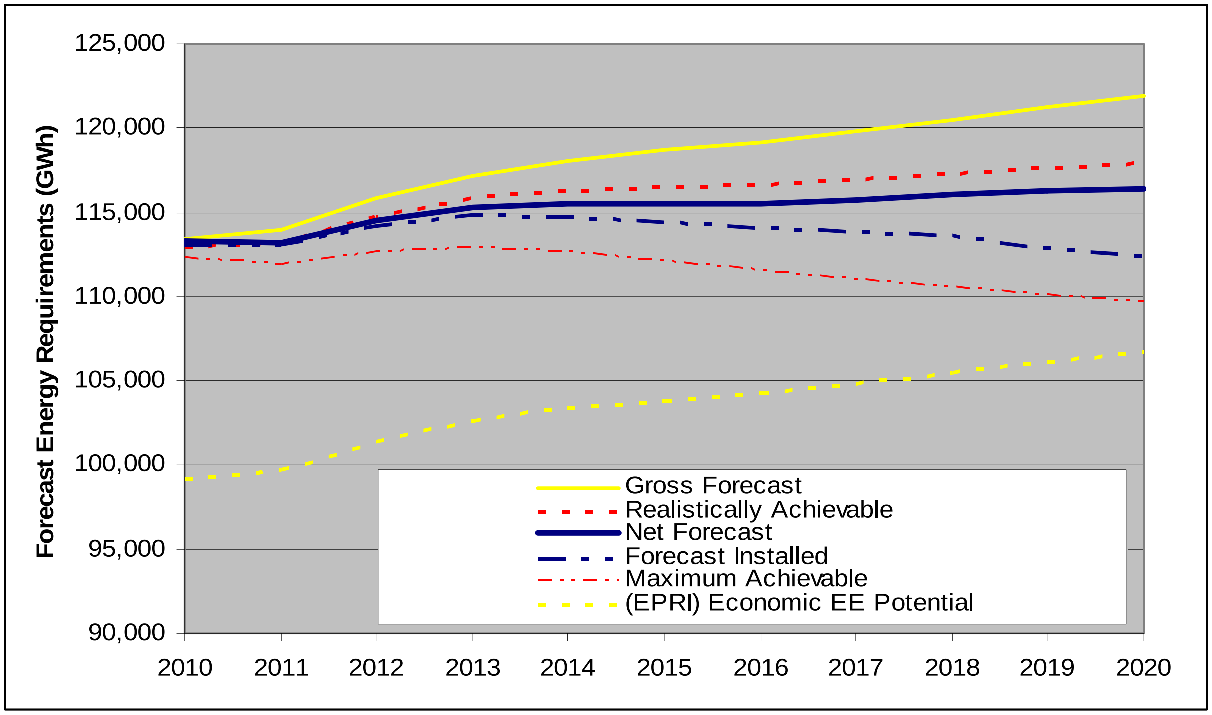
7.5.1 Energy Efficiency

Energy Efficiency resource blocks were made available within the *Strategist* model with annual constraints by program and in total. These constraints keep the resource modeling process from selecting DR/EE resources faster than is practical in non-mandated states. The result of the constraints is a roll out of programs that is consistent with the EPRI realistically achievable level of demand side resources.

Since the blocks were prescreened for cost-effectiveness, this process merely validates the incremental resources within the supply optimization. As a practical matter, actual 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.

Exhibits 7-5 through **7-7** show the net forecast with relevant benchmarks. The forecasted DSM levels exceed the EPRI realistically achievable level due to aggressive requirements in Ohio, Michigan and Indiana.

Exhibit 7-5: AEP -East Energy Efficiency Program Assumptions



Source: AEP Resource Planning

Results:

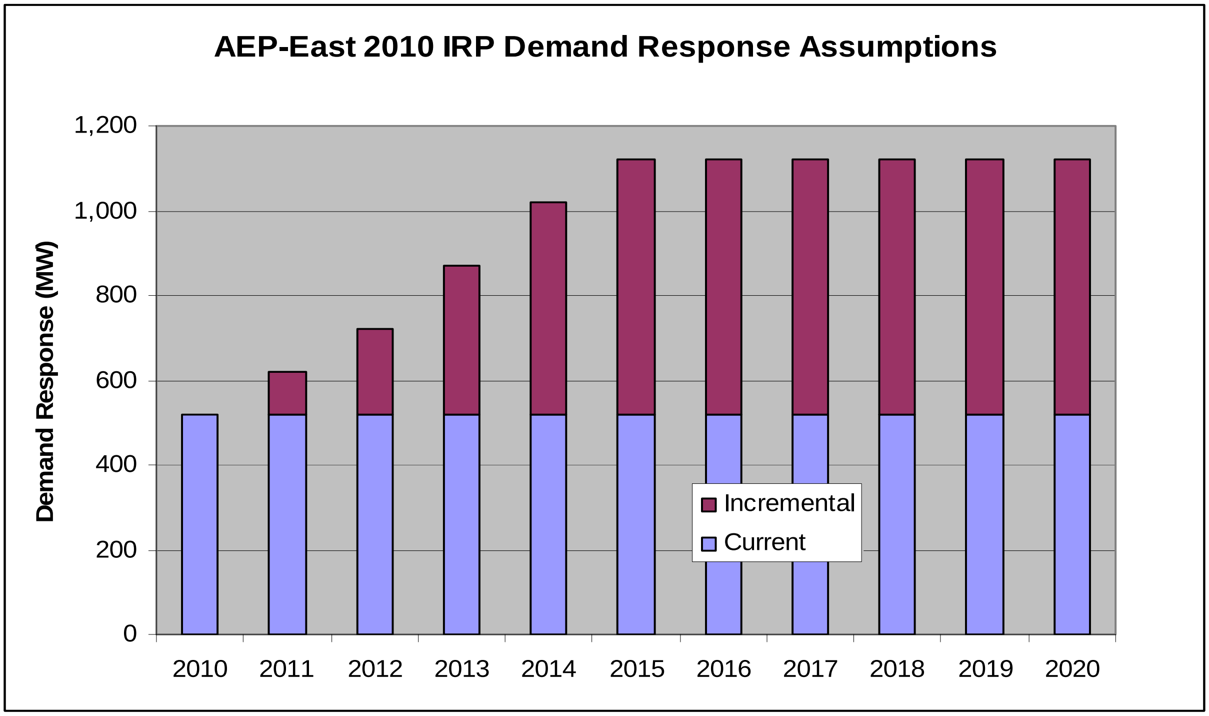
By 2020, as a result on energy efficiency programs, peak demand is reduced by 873 MW in the AEP-East zone; consumption is reduced by 5,602 GWh.

7.5.2 Demand Response

The demand response resource blocks were made available within the *Strategist* model with annual constraints by program and in total. These resources are incremental to the tariff-based demand response that is currently in place. The results are consistent with levels for demand response in the EPRI study.

Currently, given the extensively long capacity position in AEP-East, the addition of incremental DR, while having value relative to PJM, may have limited value to the AEP-East System given the current cap limitation in the supplementary auction of 1,300 MW. AEP's inability to realize the full PJM value might hinder cost recovery in some or all jurisdictions. However, incremental DR may include the added flexibility to effect peak reductions at the Operating Companies, providing desirable concomitant value within the AEP-East System Pool. Additionally, demand response capabilities are being aggressively cultivated by FERC, RTOs, and some states. Given that background, and uncertainty surrounding potential EPA HAP rules, it is reasonable to continue pursuit of a robust demand response capability which would include (AEP customer) assets that are currently committed to PJM through independent third-party curtailment service providers (CSPs).

Exhibit 7-6: AEP -East Demand Response Assumptions

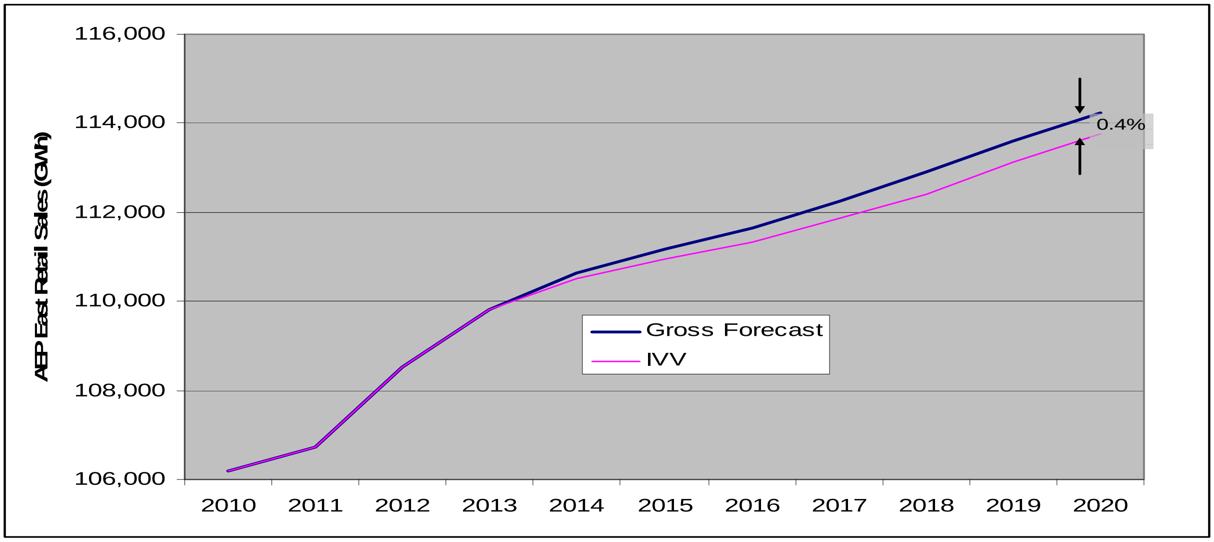


Source: AEP Resource Planning

7.5.3 IVVC

IVVC blocks varied in cost effectiveness. *Strategist* was able to pick the most promising project blocks first and add subsequent blocks when it was economical to do so. In the AEP-East System, blocks became economic beginning in 2014. Five of the available seven blocks were ultimately selected.

Exhibit 7-7: AEP -East IVV Response Assumptions



Source: AEP Resource Planning

7.6 Discussion and Conclusion

The assumption of aggressive peak demand reduction and energy efficiency achievement reflect not only legislative and regulatory mandated levels of DR/EE in Indiana, Ohio, Michigan, Oklahoma and Texas but AEP's sytem-wide commitment to demand-side resources in other jurisdictions.

The amount of DR/EE included in this Plan is 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. Indiana enacted a high mandate this year which requires cumulative energy savings of 13.9% by 2020.
- Increased awareness and acceptance of the purported link between global climate change and the consumption of fossil fuels will drive increased adoption of conservation measures, independent of economic benefit.
- 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.
- In states without existing legislative or regulatory mandates, the level of DR/EE is consistent with EPRI's "realistically achievable" levels. Where these levels are exceeded in states with mandates, it is reasonable to expect compliance with those mandates, albeit at potentially high costs.

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 by jurisdiction to reflect the environment. Executing this plan will enable AEP to fulfill its system-wide commitment of 1,000 MW of demand reduction capability and 2,250 GWh of energy efficiency by 2012.

The following **Exhibit 7-8** summarizes the AEP-East EE assumptions for the 2010 IRP. The data is split by "Net" and "Installed". "Installed" indicates the annualized impacts of DSM measures at the time of installation while "Net" reflects the expected impact. It is less than the installed impact due to assumptions about the timing of the installation (partial year savings), measure fade (measures failing and not being replaced) and "snap back" (the use of saved energy for other purposes).

Installation of these measures is predicated on securing adequate cost recovery. For this planning cycle, it is assumed that such recovery would be forthcoming. For the 10 year planning horizon, this level of DSM still closely matches the EPRI Realistically Achievable.

Exhibit 7-8: Incremental Demand-Side Resources Assumption Summary

Energy Efficiency

	Installed		Net	
	GWh	MW	GWh	MW
2010	233	38	91	16
2011	900	149	683	107
2012	1,592	266	1,266	200
2013	2,385	404	1,897	304
2014	3,294	563	2,560	416
2015	4,249	708	3,215	505
2016	5,091	844	3,676	573
2017	5,971	988	4,069	631
2018	6,887	1,136	4,408	680
2019	8,383	1,392	4,967	768
2020	9,487	1,593	5,602	873

IVVC

	Installed		Net	
	GWh	MW	GWh	MW
2010	0	0	0	0
2011	0	0	0	0
2012	0	0	0	0
2013	0	0	0	0
2014	136	20	136	20
2015	253	53	253	53
2016	338	70	338	70
2017	423	88	423	88
2018	509	105	509	105
2019	509	106	509	106
2020	509	105	509	105

Demand Response

	Installed		Net	
	GWh	MW	GWh	MW
2010	0	0	0	0
2011	0	100	0	100
2012	0	200	0	200
2013	0	350	0	350
2014	0	500	0	500
2015	0	600	0	600
2016	0	600	0	600
2017	0	600	0	600
2018	0	600	0	600
2019	0	600	0	600
2020	0	600	0	600

Total Incremental DSM

	Installed		Net	
	GWh	MW	GWh	MW
2010	233	38	91	16
2011	900	249	683	207
2012	1,592	466	1,266	400
2013	2,385	754	1,897	654
2014	3,429	1,084	2,696	936
2015	4,502	1,361	3,468	1,158
2016	5,429	1,514	4,015	1,244
2017	6,394	1,676	4,493	1,319
2018	7,395	1,842	4,917	1,385
2019	8,891	2,098	5,475	1,474
2020	9,996	2,298	6,111	1,578

Source: AEP Resource Planning

8.0 Fundamental Modeling Scenarios

8.1 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 8-1.** 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 2010 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.

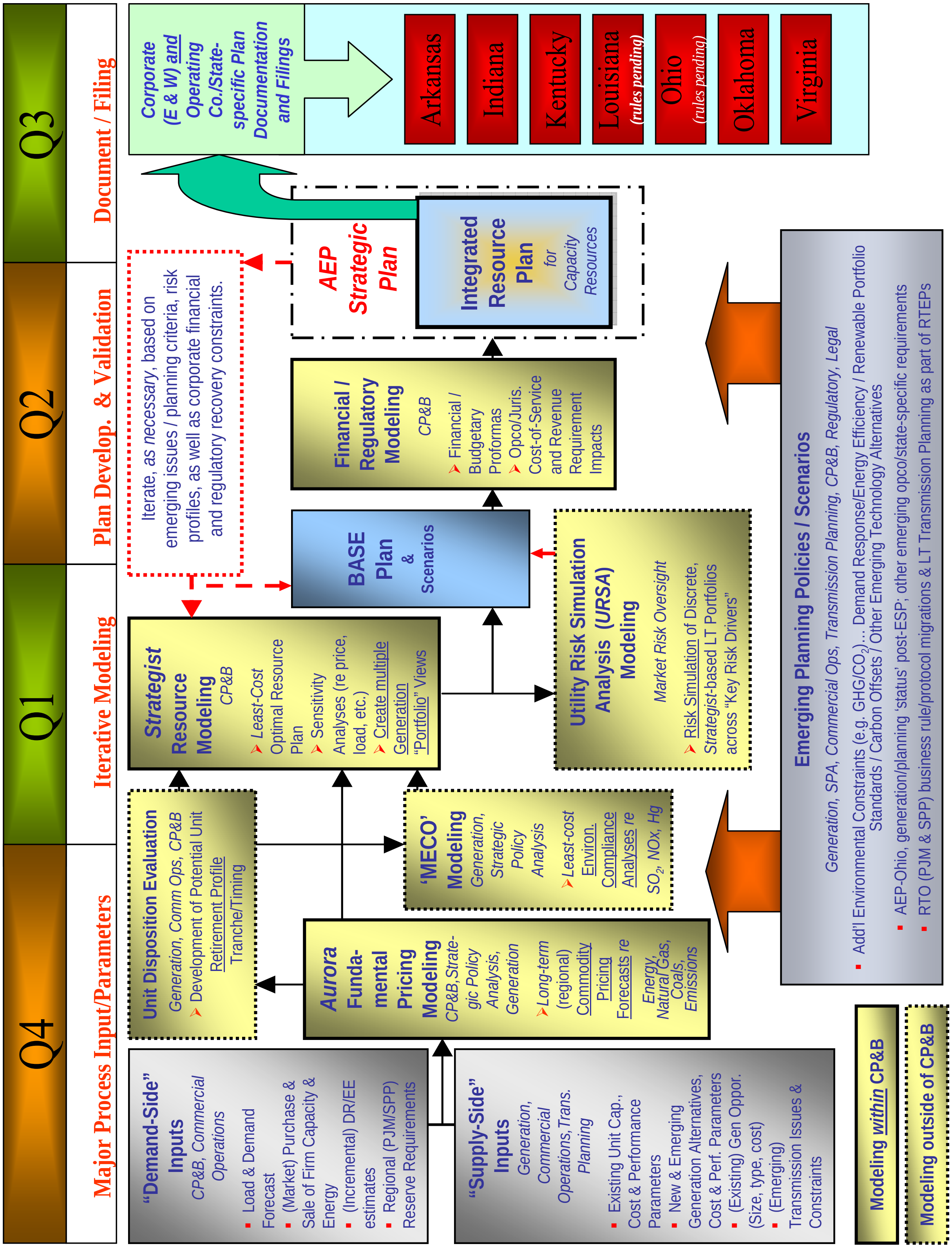
That does not mean, however, that the best or optimal plan is the one with the absolute least cost over the planning horizon evaluated. As discussed in this (and prior) section, other factors–some more difficult to quantify than others–were considered in the determination of the AEP-East Integrated Resource Plan (IRP). To challenge the robustness of the Plan, sensitivity analyses were performed to address these factors.

8.2 Methodology

The IRP process aims to address the long-term "gap" between resource needs and current resources (**Section 5**). 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* [9] 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.

[9] A proprietary long-term resource optimization tool of Ventyx - an ABB company - utilized extensively in the utility industry for over two decades.

Exhibit 8-1: IRP Modeling and Planning Process Flow Chart



Source: AEP Resource Planning

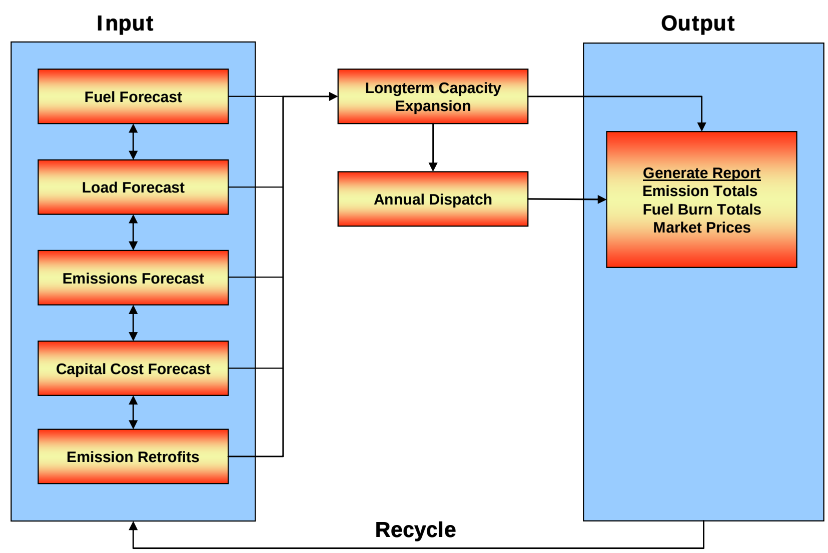
8.3 Key Fundamental Modeling Pricing Scenarios

This section includes excerpts from the "Long Term Forecast 2010-2030: Consumer Choice: A Time to Choose, 2H-2009" *prepared by AEPSC's Strategic & Economic Analysis (SEA) organization and issued February 2010.*

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 8-2 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 8-2: Long-term Forecast Process Flow



Source: AEP SEA

In this report, four distinct scenarios were developed: the "Reference Case", "Business As Usual (BAU) Case", "Stagnation", and "Altruism Case". The scenarios are described below:

Reference – The point of the label "Reference" is not because it is the most likely outcome. It is labeled Reference because it represents what we have typically done in the company – use Moody's Economy.com as the economic outlook. As compared to previous reference cases, the start of carbon policies have been moved up to 2014 versus 2015, indicating an increased likelihood of a policy. The carbon treatment policy follows a "Waxman-Markey" like policy, except starting in 2014 versus 2012.

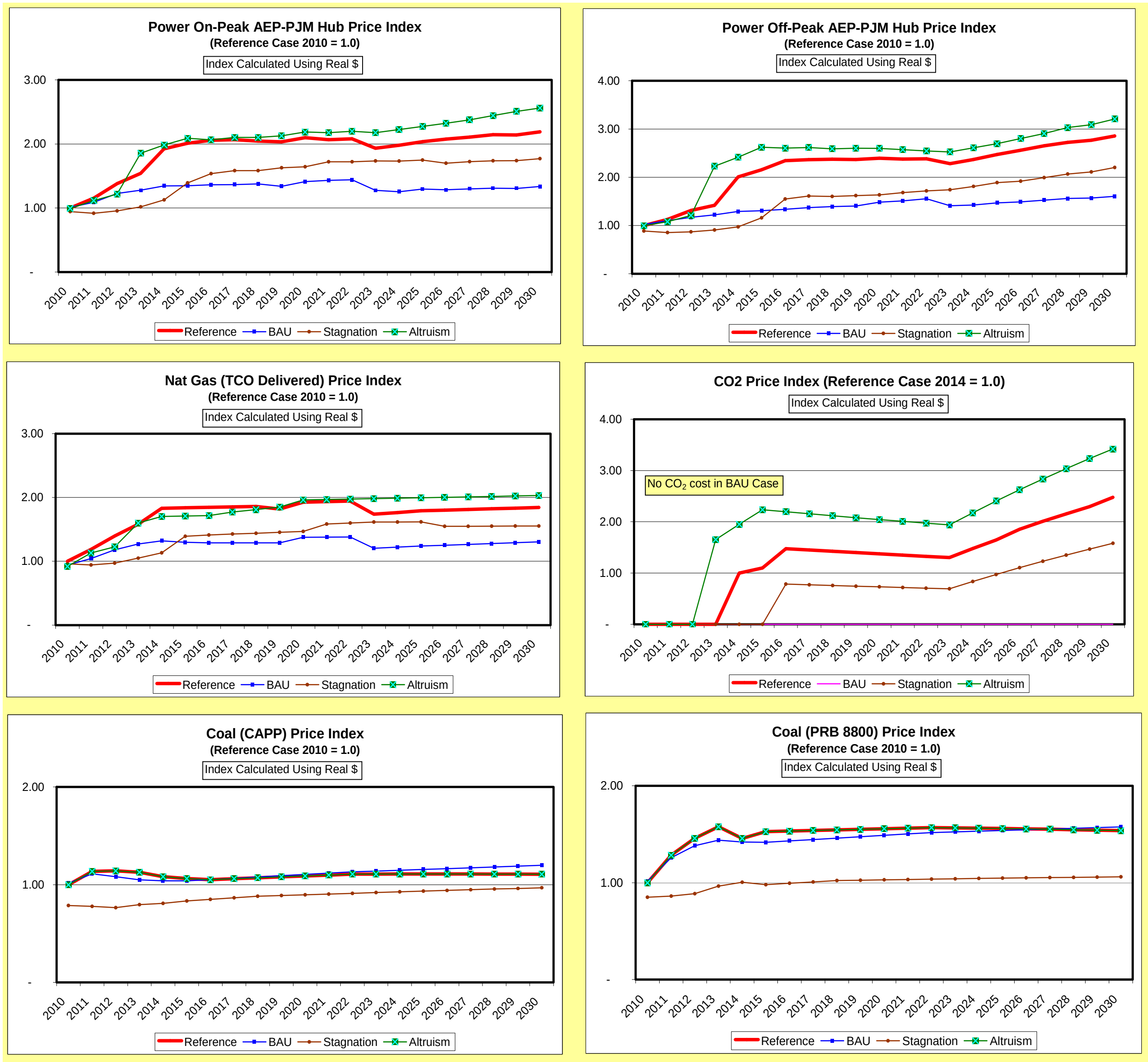
Business As Usual (BAU) – As the title of this case suggests, it assumes there is no change from 2009. This includes no change in environmental policies such as carbon. The economic outlook in this scenario is identical to the Reference economic profile other than there is no economic impact observed in 2014 due to carbon policies. This scenario is probably the least likely given that nothing changes, but it certainly is the easiest to conceive because everything is known.

Stagnation – Concerns of rising government debt and no clear path for the transformation of the economy from less consumer driven results in a stagnated economy similar to Japan's experience. Much like Japan, the country continues to prop up insolvent banks. Optimistically, the U.S. will react faster and remember lessons learned so that stagnation lasts only five years versus Japan's decade plus.

Altruism – This scenario is the hardest to imagine and construct. There is a united front across the majority of the world for the reduction of carbon. There is one carbon price accepted by all so no major wealth transfers occur. If this assumption did not occur, we could see mass economic shifting as corporations could move to regions that had no carbon policies. Societies across the world take on the problem and develop a moral backing in order to absorb the increased cost and the sacrifices needed to achieve the targets. In the U.S., this cost will come in the form of continued production tax credits, increased CO_2 costs and increased fossil fuel costs due to increased environmental constraints for drilling and mining.

The relationship among commodity prices under the different economic scenarios is shown in **Exhibit 8-3**. Forecasts of particular importance include coal prices, natural gas, CO_2, and on-peak and off-peak power prices. Because commodity price forecasts are considered business sensitive information, the comparisons are made using an index, with the Reference Case 2010 price set as 1.0.

Exhibit 8-3 Commodity Price Forecast by Scenario



9.0 Resource Portfolio Modeling

9.1 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.[10] The solution is bounded by user-defined set of resource technologies, commodity pricing, and prescribed sets of constraints.

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;
- Program costs of DR/EE alternatives

[10] *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 order to create a full regulatory cost of service, additional cost were developed to capture the revenue requirement impact from the embedded fixed cost of AEP's existing generation, transmission and distribution systems (i.e. G/T/D costs). These additional G/T/D revenue requirements were added to the incremental revenue requirements developed by *Strategist* to create a full regulatory cost of service.

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.

9.1.1 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 15.3% effective 2013/2014 and through the 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 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.

9.2 Resource Options/Characteristics and Screening

9.2.1 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).

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 eight, 82 MW GE-7EA Combustion Turbine units (summer rating of 78.5 MW x 8 = 628 MW), available beginning in 2019. Note: No more than one block could be selected per year.
- *Intermediate capacity* was modeled as single natural gas Combined Cycle (2 x 1 GE-7FB with duct firing platform) units, each rated 650 MW (613 MW summer) available beginning in 2019.
- *Baseload capacity* burning eastern bituminous coals was modeled. The potential for future legislation limiting CO_2 emissions was considered in selecting the solid fuel baseload capacity alternatives. Two solid fuel alternatives were made available to the model:
  - ✓ 526 MW Ultra Supercritical PC unit (summer rating of 520 MW) where the unit is installed with chilled ammonia carbon capture and storage (CCS) technology that would capture 90% of the unit's CO_2 emissions. This option could be added beginning in 2020.
  - ✓ 776 MW Integrated Gasification Combined Cycle (IGCC) "H" Class unit equipped with CCS technology that would reduce 90% of the unit's carbon emissions. This alternative could be added by *Strategist* beginning in 2020 and;

In addition, beginning in the year 2022:

  - ✓ *Strategist* could select an 800 MW share of a 1,606 MW nuclear, Mitsubishi Heavy Industries (MHI) Advanced Pressurized Water Reactor (771 MW summer)

In order to maintain a balance between peaking, intermediate and baseload capacity resources, only eight Combustion Turbine (CT) units could be added in any year. If the addition of eight 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.

9.2.2 Demand-side Alternative Screening

As described in **Section 7**, eighteen "blocks" of EE programs were available each year to be evaluated in *Strategist* over the 2011-2015 period. There were also a total of twelve 50 MW blocks of DR that could be added (2-3 per year) over the 2011-2015 period. In addition, there were a total of 7 blocks of Integrated Voltage/Var (IVV) control that could be added over the 2012-2018 period. The economics of the DR/EE/IVV blocks were screened in order to minimize the problem size of the full *Strategist* optimization. The DR/EE/IVV blocks were evaluated under all of the economic scenarios described in **Section 8**. The results of this screening analysis showed that 560 MW of EE and 600 MW of DR were selected under all of the economic scenarios. In all economic scenarios, 30 MW to 110 MW of IVV was selected depending on the economic scenario.

9.3 *Strategist* Optimization

9.3.1 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 eight, 82 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.

9.3.2 Strategic Portfolios

Strategic decisions that were considered when constructing the underlying AEP-East resource portfolios include:

- **Renewable Resources:**
  - ✓ On an AEP system-wide basis, to achieve 6% 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 reflects additional state mandates, 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.

9.4 Optimum Build Portfolios for Four Economic Scenarios

9.4.1 Optimal Portfolio Results by Scenario

Given the four fundamental pricing scenarios developed by AEP-FA from **Section 8.3**, as well as the modeling constraints and certain planning commitments, *Strategist* modeling was used to develop the incremental portfolios identified in **Exhibit 9-1**:

Exhibit 9-1: Model Optimized Portfolios under Various Power Pricing Scenarios

	Business As Usual Case Optimization	Stagnation Case Optimization	Reference Case Optimization	Altruism Case Optimization
2010				
2011				
2012				
2013				
2014				
2015				
2016				
2017				
2018				
2019	8 - 82 MW CTs, 1 - 650 MW CC	8 - 82 MW CTs, 1 - 650 MW CC	8 - 82 MW CTs, 1 - 650 MW CC	8 - 82 MW CTs, 1 - 650 MW CC
2020				
2021	8 - 82 MW CTs	8 - 82 MW CTs	8 - 82 MW CTs	8 - 82 MW CTs
2022				
2023				
2024		8 - 82 MW CTs	8 - 82 MW CTs	8 - 82 MW CTs
2025				
2026	8 - 82 MW CTs	8 - 82 MW CTs	8 - 82 MW CTs	8 - 82 MW CTs
2027				
2028				
2029	8 - 82 MW CTs	8 - 82 MW CTs	8 - 82 MW CTs	8 - 82 MW CTs
2030				
Total East System Cost				
2010-2035 CPW ($M)	119,139,548	123,097,624	134,133,179	145,370,495
2010 - 2030 Levelized ($/MWh)	82.85	88.35	95.48	103.68
Number of Units Added				
CT	32	40	40	40
CC	1	1	1	1
PC	0	0	0	0
IGCC	0	0	0	0
Nuclear	0	0	0	0
Total Capacity (MW)	3,274	3,930	3,930	3,930
Total Optimized DR/EE/IVV (MW Reduced)	1,185	1,265	1,265	1,265

Source: AEP Resource Planning

Notes:

1) *Because Renewable assets and a base level of incremental DR/EE/IVV 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 2020 as represented by the horizontal line. For modeling purposes Strategist constructs portfolios through 2030.*

9.4.2 Observations: 2019 Combined-cycle Addition

As shown in **Exhibit 9-1**, all pricing scenarios added a CC unit in 2019. The CC addition is made because of the constraint imposed on the model that allows only a single block of 8 CTs to be added in any one year. Had the model been allowed to add as many CT blocks as economic, an additional block of 8 CTs would have been added in 2019 instead of the CC under all pricing scenarios.

9.4.3 Additional Portfolio Evaluation

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

- Retirement Transformation Plan – Accelerate All "Fully" Exposed Unit Retirements to 1/2016 and Retire All "Partially" Exposed Units between 1/2016 and 1/2020
- No CCS Retrofits on Existing Units
- Alternative Resource Plan - Enhanced Renewables and DR/EE/IVV + Best "Contrary" Nuclear Plan
- Green Plan - Alternative Resources Plan + Retirement Transformation Plan

Exhibit 9-2 provides a summary of these portfolios under Reference Case conditions.

Exhibit 9-2: Portfolio Summary

	Retirement Transformation Plan	No CCS Retrofits on Existing Units	Alternative Resource Plan	Green Plan
2009				
2010				
2011				
2012				
2013				
2014				
2015				
2016	8 - 165 MW CTs, 1 - 650 MW CC			8 - 82 MW CTs
2017	8 - 165 MW CTs, 2 - 650 MW CC			
2018			8 - 165 MW CTs, 1 - 650 MW CC	8 - 165 MW CTs, 2 - 650 MW CC
2019	8 - 165 MW CTs, 2 - 650 MW CC	8 - 165 MW CTs, 1 - 650 MW CC	8 - 82 MW CTs	8 - 165 MW CTs, 2 - 650 MW CC
2020				
2021	8 - 82 MW CTs		1-800 MW Nuke	1-800 MW Nuke
2022				
2023				
2024		8 - 82 MW CTs		
2025	8 - 82 MW CTs			
2026		8 - 82 MW CTs	8 - 82 MW CTs	
2027				8 - 82 MW CTs
2028	8 - 82 MW CTs			
2029		8 - 82 MW CTs	8 - 82 MW CTs	
2030				8 - 82 MW CTs
Total East System Cost Under Reference Price Scenario				
2010-2035 CPW ($M)	136,035,511	136,638,030	136,115,947	137,196,444
2010 - 2030 Levelized ($/MWh)	9.72	9.73	9.72	9.83
Number of Units Added				
CT	48	32	32	40
CC	5	1	1	4
Nuclear	0	0	1	1
Total Capacity (MW)	7,186	3,274	4,074	6,680
Total Optimized DSM (MW Reduced)	1,265	1,265	1,703	1,703

Source: AEP Resource Planning

9.4.3.1 "Retirement Transformation" Plan

The objective behind examining this portfolio was to determine the increased cost of a portfolio that accelerated the retirement of all "Fully Exposed" units and the retirement all of the "Partially Exposed" units that were scheduled to receive emission retrofits. In all other cases, several of the Full

Exposed units had retirement dates that occurred after 2016. In the Retirement Transformation Plan, those retirements that were profiled to occur from 2016 through 2019 as part of the Unit Disposition analysis described in Section 3 were accelerated to January 2016. In addition, the Partially Exposed units were assumed to be retired on the date they were originally profiled as part of the same disposition process to receive emission retrofits.

9.4.3.2 "No CCS Retrofits" Plan

In all other pricing scenarios but Business As Usual, approximately 3,700 MW of existing AEP-East solid-fuel units were assumed to be retrofitted with CCS technology. When CCS retrofits were installed, CO_2 "Bonus Allowances" were awarded to AEP to offset the cost of installing the CCS retrofits.[11] In this portfolio, the objective was to determine the increased cost of CO_2 emission exposure by not performing the CCS retrofits and obtaining the Bonus Allowances. Instead, AEP's entire solid-fuel generating fleet would be subject to the assumed CO_2 emissions cost under each pricing scenario.

9.4.3.3 "Alternative Resource" Plan

The Alternative Resource Plan was created by combining:

- Increasing the levels of renewable energy resources and DR/EE/IVV added to the system by a relative magnitude of fifty percent, and;
- The "Best" Contrary Nuclear Plan, which was the best "sub-optimal" plan established by *Strategist* that included a nuclear baseload resource..

The renewable energy targets set for this scenario require that 6% of system-wide energy sales be met with renewable energy resources by 2013, <u>15 percent</u> (versus 10 percent) by 2020 and <u>22.5 percent</u> (versus 15 percent) by 2030. The timing of the nuclear unit addition in the Contrary Nuclear Plan was established during the initial optimization analysis as the "optimal" point in time in the early 2020s to add Nuclear baseload capacity.

9.4.3.4 "Green" Plan

The Green Plan was created by combining the Retirement Transformation Plan and the Alternative Resource Plan. The purpose of creating the Green Plan was to test the economics of a portfolio with very low emissions profiles by introducing the accelerated retirement of solid fuel units, increased levels of renewable energy and DR/EE/IVV and the addition of a low emitting nuclear unit.

A summary of the Optimal Portfolio and Additional Portfolio plan's costs over the full (2010-2035) extended planning horizon, and under the various pricing scenarios is shown in **Exhibit 9-3**.

[11] "Bonus Allowances" designed to incentivize commercial development of CCS technology have been incorporated as part of the House-approved Waxman-Markey Bill as well as comparable Senate legislation currently under discussion.

Exhibit 9-3: Optimized Plan Results (2010-2035) Under Various Pricing Scenarios

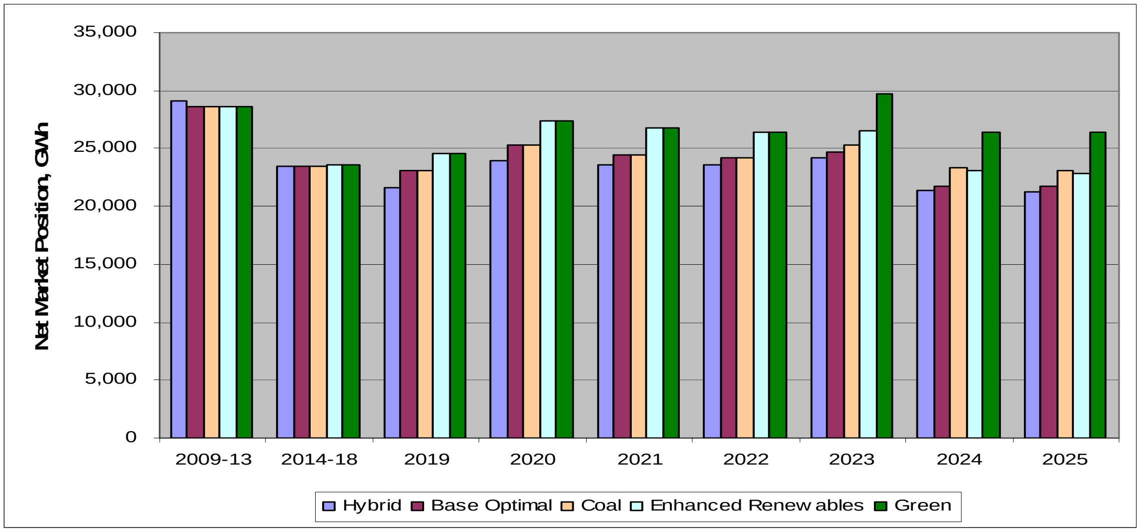
AEP East 2010-2035 CPW ($000)	NO Carbon Legislation / Regulation World	(Ultimate) Carbon Legislation		
Pricing Scenario	"BAU"-(Alt) LOW Proxy- (No CCS)	"Stagnation" - LOW Proxy- (with CCS*)	"Reference" -BASE Proxy- (with CCS*)	"Altruism" -HIGH Proxy- (with CCS*)
'BAU' (No CO2) (LOW Price w/o CO2)Scenario Optimal Plan	$119,139,548	$123,608,730	$136,014,837	$148,670,225
'Stagnation' (LOW Price w/ CO2) Scenario Optimal Plan	$126,137,376	$123,097,624	$134,133,179	$145,385,453
'REFERENCE' (BASE Price) Scenario Optimal Plan	$126,137,376	$123,097,624	$134,133,179	$145,385,453
'Altruism' (HIGH Price) Scenario Optimal Plan	$126,133,852	$123,097,452	$134,123,709	$145,370,495
Retirement Transformation Plan...Reflect RETIREMENT of all 'Partially Exposed' Units; 2016-2020		$124,624,453	$136,035,511	$146,132,185
No CCS Retrofits (in lieu of assumed {subsidized} ~5,500 MW by 2020 in 'BASE')		$124,256,115	$136,638,030	$149,257,679
"Alternative Resources Plan"... Best 'HIGH' Renewable / "Efficiency"' + Best 'Contrary' Nuc		126,602,394	136,115,947	146,666,529
"Green Plan"... 'Alternative Resources' Plan (above) + Retire All 'Partially-Exposed' Units by 1/2016 + Retire All 'Partially-Exposed' Units by 1/2020		$127,568,854	137,196,444	$146,776,618

Source: AEP Resource Planning

9.4.4 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 as older coal units retire. This leaves a smaller number of units available to serve a baseload function. 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 is reduced when AEP maintains a minimum net market (energy) position of approximately 10% of its annual energy requirements, or 12,000 GWH. **Exhibit 9-4** shows that each of the portfolios evaluated meet this criteria.

Exhibit 9-4: Annual Energy Position of Evaluated Portfolios



Source: AEP Resource Planning

9.4.5 Portfolio Views Selected for Additional Risk Analysis

The following summarizes the six 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 10**.

- Reference Pricing Case Optimal Plan (Base Plan)
- Business As Usual Pricing Case Optimal Plan (No CO_2 Plan)
- Retirement Transformation Plan
- No CCS on Existing Units Plan
- Alternate Resources Plan
- "Green 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.

10.0 Risk Analysis

The six portfolios identified in **Section 9** that were selected using *Strategist* and the Hybrid plan were subjected to rigorous "stress testing" to ensure that none would have outcomes that would be deleterious under a probabilistic array of input variables.

10.1 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,
- uranium prices,
- power prices,
- emissions allowance prices,
- full requirements loads.
- steam and combustion units forced out.

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 10-1 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 necessarily the same between different plans.)

Exhibit 10-1: Key Risk Factors – Weighted Means for 2010

	Simulated Outcomes – Hybrid Plan			
	All Outcomes	RRaR-Exceeding Outcomes		
Variable	Mean	Mean	Difference	% Diff
AEP Internal Onpeak Load	16,033	16,024	(8.78)	-0.05%
AEP Onpeak Power Spot	75.47	82.47	7.00	9.28%
CO2 Allowance Spot	25.04	58.24	33.20	132.59%
NYM Coal Spot	61.60	65.49	3.89	6.31%
Henry Hub Gas Spot	7.94	9.07	1.13	14.23%
Uranium Spot	0.81	0.82	0.01	1.23%
Steam Units Forced Out	1,668	1,670	1.74	0.10%
Combustion Units Forced Out	509.46	510.06	0.60	0.12%

Source: AEP Market Risk Oversight

The price of CO_2 allowance, spot gas, and on-peak power prices 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 132.59%, 14.23%, and 9.28%, which is significantly greater than the relative difference of other risk factors.

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.

10.2 Installed Capital Cost Risk Assessment

In order to further scrutinize the six 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 10-2** 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 10-2: 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%	-7.5%	Base	13.33%	27%	40%
Gas-fuel Units	-10%	-5%	Base	6.67%	13.33%	20%
Nuclear Units	-15%	-7.5%	Base	16.67%	33%	50%

Source: AEP Resource Planning

10.3 Results Including Installed Capital Cost Risk

Exhibit 10-3 summarizes the Installed Capital Cost Risk-adjusted results for all six AEP-East plans.

Exhibit 10-3: Risk -Adjusted CPW 2010-2035 Revenue Requirement ($ Millions)

PLAN	50th Percentile	95th Percentile	Revenue Requirement at Risk
No CO2	119,190	124,965	5,775
Base Case	134,174	163,009	28,835
Accel Coal Ret	136,092	162,162	26,070
No CCS	136,701	168,324	31,623
Alt Resc	136,370	162,955	26,585
Green	137,424	161,280	23,856

Source: AEP Resource Planning

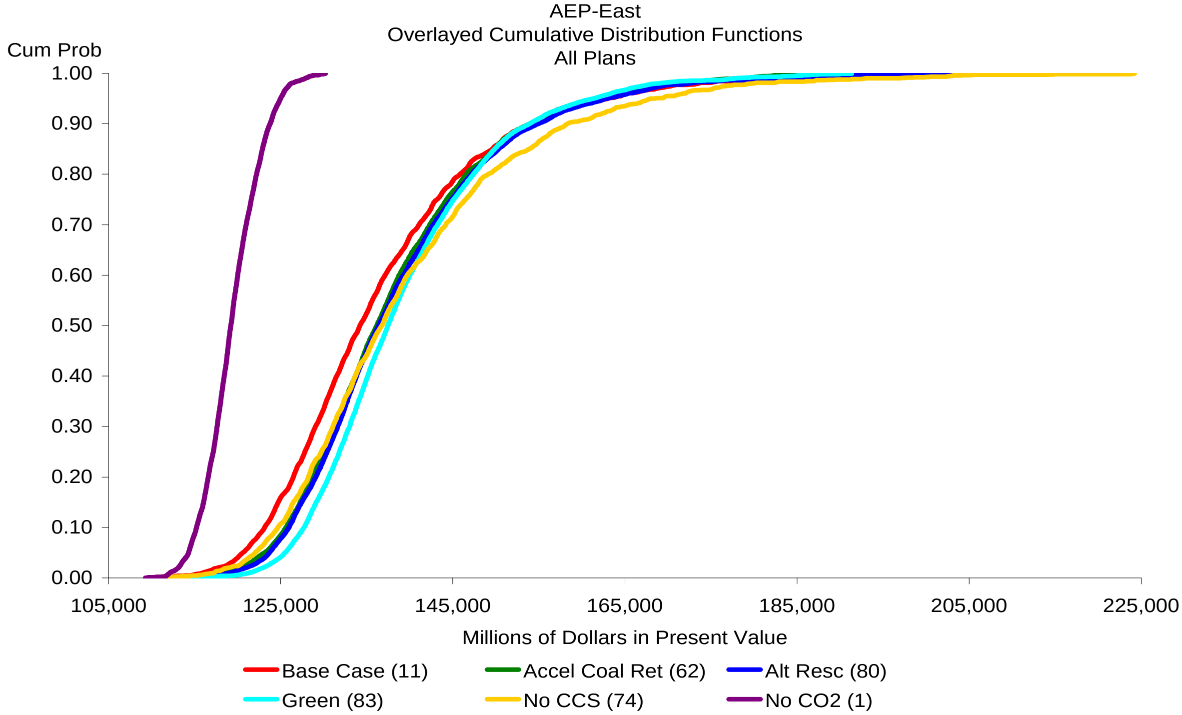
Exhibit 10-3 shows reasonably consistent results across all plans modeled. These comparative results also suggest that, given the fuel/generation diversity of the capacity resource options introduced into the analysis, the relative economic exposure would appear to be small irrespective of the plan selected.

The three lowest-cost plans at the 50^{th} percentile are the No CO_2, Base Case, and Accelerated Coal Retirements. However, the lowest cost plans at the Revenue Requirement at Risk are the No CO_2, Green, and Accelerated Coal Retirements. While the lowest cost plan at the 95^{th} percentile is the No CO_2 plan, keep in mind that the No CO_2 plan is not directly comparable to the other plans in that CO_2 costs are excluded. The plan was included to point out the expected cost of CO_2 legislation on ratepayers. As the exhibit shows, this impact ranges from approximately $15 billion to $40 billion on a net present value basis.

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.

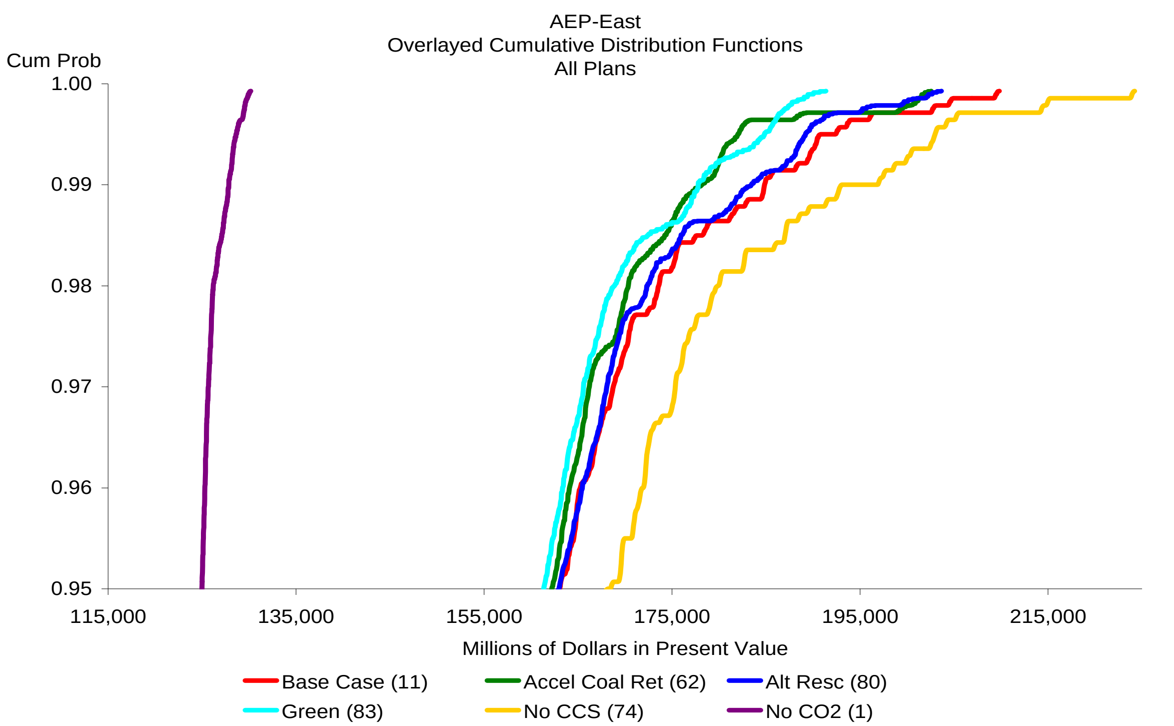
The estimated distributions of revenue required under the seven plans are rather similar. **Exhibits 10-4** and **10-5** show the superimposed graphs of all six distribution functions. **Exhibit 10-4** shows entire distributions; **Exhibit 10-5** shows only the region at or above the 95th percentile.

Exhibit 10-4: Distribution Function for All Portfolios



Source: AEP Resource Planning

Exhibit 10-5: Distribution Function for All Portfolios at > 95% Probability



Source: AEP Resource Planning

10.4 Conclusion from Risk Modeling

The Base Plan had the lowest cost at the 50% probability level but had the second highest cost at the 95% probability level (the Green Plan had the lowest). While the Green Plan has a lower RRaR at 95% probability, it is significantly more expensive at the 50% probability level. The risk mitigation benefits of the Green Plan are tied to potential extremes in CO_2 pricing, as indicated from the discrete modeling results from *Strategist* where the Green Plan is the preferred plan under the Altruism pricing, but not under other pricing scenarios.

The results indicate that AEP-East should continue to aggressively pursue addition of renewables and DR/EE where regulatory support is provided, and to remain open to the possibility of the addition of nuclear capacity. Recent experience has shown that state regulatory bodies are under pressure from ratepayers to keep rates low, especially during the current economic climate, and as a result they may be reluctant to support efforts to increase energy diversity that are not required by a state or federal mandate if those initiatives cause near-term rates to increase. This may limit the levels of renewables and DR/EE that could potentially be employed in the resource mix. The levels used in the Hybrid Plan, while somewhat aggressive, are believed to be realistically achievable.

The Hybrid Plan, developed using a more recent, lower load forecast, does not show the need for baseload capacity even after all proposed coal unit retirements occur, which would suggest that, at this point in time consideration of a nuclear addition is not warranted. The URSA results show that the planned additions of CCS equipment on existing facilities, which is a component of the Hybrid Plan, produces a lower cost plan than excluding CCS. The addition of a full scale CCS equipment retrofit will be dependent first on the successful outcome of the Mountaineer pilot project and then on the federal incentives which are expected to be necessary to keep such retrofits at a reasonable cost to customers.

11.0 Findings and Recommendations

11.1 Development of the "Hybrid" Plan

Using the intelligence gained from the *Strategist* runs for various pricing and sensitivity scenarios, an AEP-East "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, 2010. The revised forecast reflected a downturn in economic conditions over AEP's East service area and in turn, a reduction in AEP East'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% - 8% and a 5% - 10% 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 2010 IRP analysis, 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 No CCS Retrofit view, CCS retrofits were introduced into the AEP-East plan so as to accelerate this further migration to a reduced CO_2 position.
- Due to the retirement of certain units that provide black start capability, the addition of quick-start CT capacity was accelerated to replace this function in certain operating areas.

Based on the array of discrete results from varying pricing scenarios and strategic portfolios, and the risk analysis described in **Section 10**, 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 11-1**.

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 2010 revised load forecast. In addition, the CCS retrofits assumed in the majority of the optimization runs were included in the Hybrid Plan. The reduction in peaking requirements with the April load forecast allowed the number of peaking resources to be reduced from 28 in the Reference Case to 16 in the Hybrid Plan, however an intermediate resource was added in place of eight 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*.

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 compares favorably to other portfolios when subjected to robust statistical analysis, providing low reasonable life-cycle cost on average, and relatively low risk to its customers. Other benefits include:

- Keeping coal as a viable fuel in a carbon-constrained world through the use of CCS technology. 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, securing 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.

Exhibits 11-1 through **11-3** offer a summary of the Hybrid plan and the resulting AEP-East generating fleet from capacity and energy mix standpoint. From an environmental stewardship perspective, note that **Exhibit 11-2** shows the respective AEP-East fleet continues to migrate to a lower carbon emitting portfolio. The most significant take-away, as shown in **Exhibit 11-3,** would be that, in 2020 and 2030, the plan relies more heavily on renewable resources and nuclear and less on baseload coal to meet its needs.

Exhibit 11-1: Hybrid Plan

"Hybrid" Portfolio:

Reflective of April-10 Load Forecast [(a)]

AEP-East

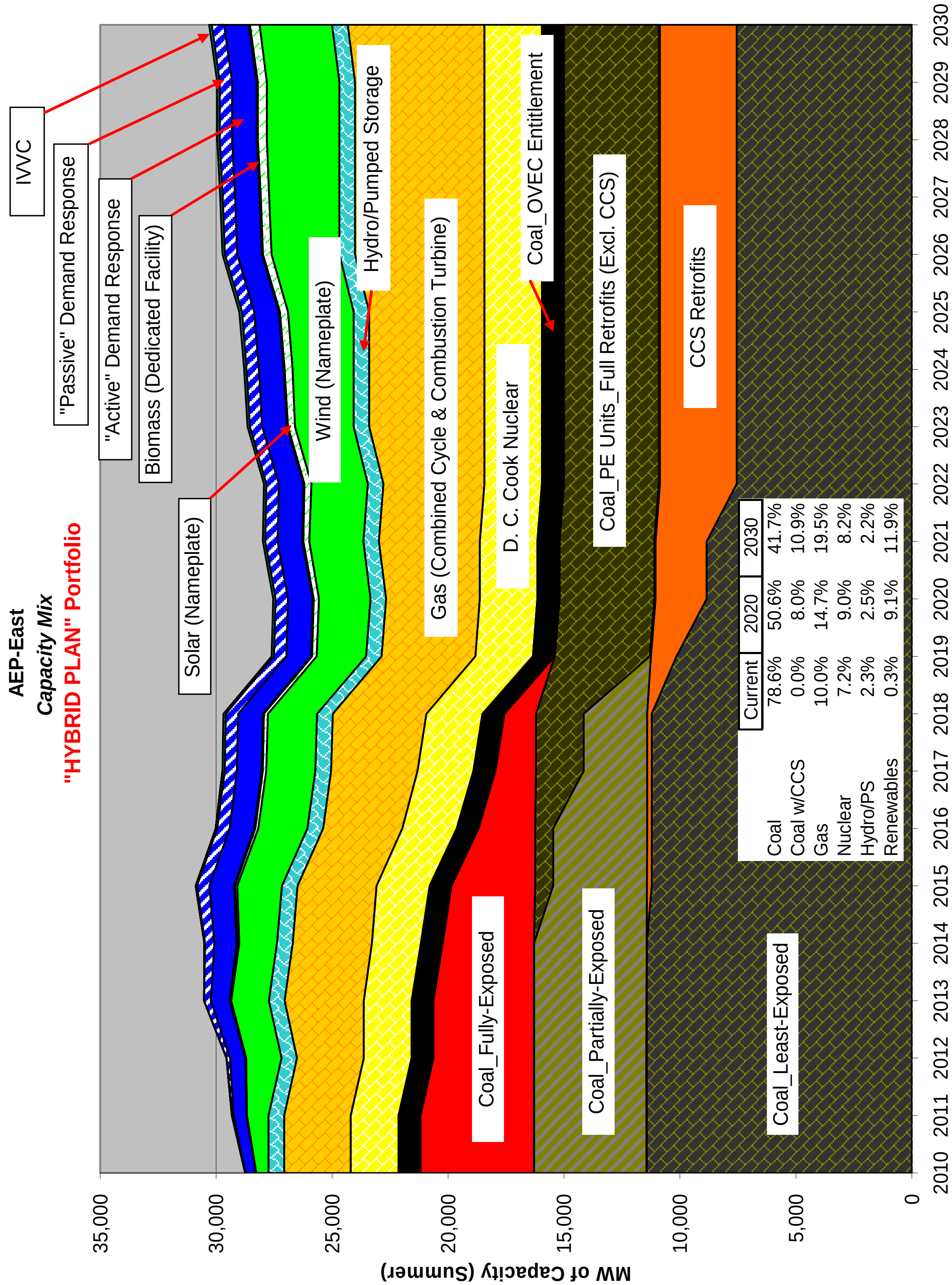
Period	Pln Yr	(b) Capacity (Retire)	CCS Retrofit Unit	CCS Retrofit Capac	CCS Retrofit Derate	Efficiency: Dem (c) Response ("Active"DR)	Efficiency: Energy (a) Efficiency ("Passive"DR)	Efficiency: Infrastruc. (e.g. IVVC)	Renewable (Nameplate) (d): Wind	Renewable (Nameplate) (d): (e) Biom	Renewable (Nameplate) (d): Solar	Thermal Resources (summer rating)	Oper Co. Assigned		PJM-CLR Capacity Position (above PJM IRM min) (MW)
	2010	(440)					16		451		10		⇩	(f)	1,240
(10-Year) Planning Period	2011					100	90		101	44	10			(g)	1,292
	2012	(560)				100	93		100		11			(h)	1,113
	2013					150	102		100	25	10	(Dresden) CC-540	APCo		2,038
	2014	(395)				150	112	19	300	25	26	Cook2 (Ph1)-45	I&M		2,720
	2015	(925)	MT	235	(58)	100	89	31	400		27	Cook1&2 (Ph1&2)-168	I&M		2,188
	2016	(1,175)					67	17	250	(44)	26	Cook1 (Ph2)-68	I&M		1,934
	2017	(675)					59	16	150		26	Cook2 (Ph3)-68 NG Peaking-314	I&M APCo	(i)	1,968
	2018	(400)					48	17	50	100	26	Cook1 (Ph3)-68 NG Peaking-314	I&M APCo/KPCo	(j)	1,856
	2019	(1,373)	MT	1,065	(137)		88		100		26				343
	2020		GV1	1,300	(195)		104		150		27				399
Study Period	2021						72		100	50	29	NG Peaking-314	APCo/KPCo	(k)	388
	2022		AM3	1,300	(195)		51		100		45				359
	2023						35		200			NG Intermediate-611	APCo		420
	2024						21		150	100	45				403
	2025						16		150						232
	2026						5		150		20	NG Intermediate-611	APCo		677
	2027						1		150	50					523
	2028								100		25				403
	2029														204
	2030										31	NG Peaking-314	APCo		304
				3,900				"Nameplate"	3,252	350	420				
	Cumul.	(5,943)			(585)	600	1,069	100	423	50	160	3,435			

2010-2030 Net Addition
(692)

(a) *Underlying Peak Demand as well as "Passive" (Energy Efficiency) Demand Reduction levels are per AEP-Economic Forecasting "**April '10**" **Forecast** (Note: includes mandated EE requirements in OH, IN, MI)*
(b) Reflects PJM planning year that capacity is de-committed in PJM-FRR
(c) "Active" DR (i.e. demand response curtailment programs/tariffs) only
(d) 13% of wind nameplate and 38% of solar nameplate can be "counted" as PJM capacity (per *initial* PJM criteria)
… Assumes 'full-year' energy impact (i.e. *in-service* by 12/31 of Year -1)
(e) Only 25 MW '2013' and '2014' biomass represents incremental capacity via a dedicated biomass facility (assumed AEP-Ohio PPA)…
… balance represents 'equivalent' biomass-sourced energy via co-firing.... through, initially, *existing* AEP-Ohio units
(f) "2010" wind: Fowler Ridge I, II & II (350 MW: AP, I&M, CSP, OP); Grand Ridge I & III (100.5 MW: AP)… "2010" solar: Wyandotte (10MW: CSP, OPCo)
(g) "2011" wind: Beech Ridge (100.5 MW: AP) only… i.e., assumes Lee-Dekalb (100 MW: KP) eliminated as KPSC denied recovery and, as per contract, it may then be voided
(h) "2012" wind: Represents 'Unidentified' 100-MW wind designated to AEP-Ohio companies to be in-keeping w/ requirements of S.B. 221
(i) Assumes advanced four-years (from 2021) to provide Black-Start requirements @ TC area
(j) " " three-years (from 2024) to provide Black-Start requirements @ KM area
(k) " " three-years (from 2021) to provide Black-Start requirements @ SP area

Source: AEP Resource Planning

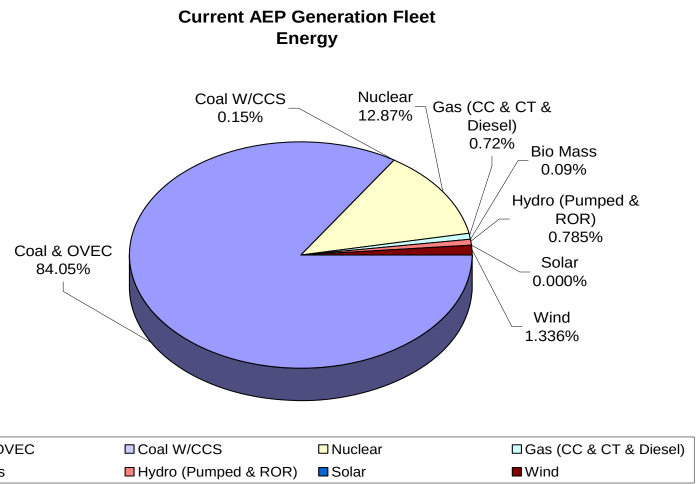
Exhibit 11-2: AEP-East Generation Capacity

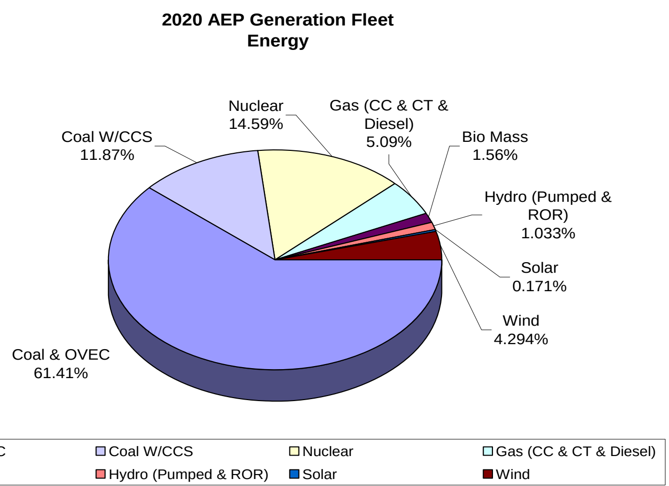


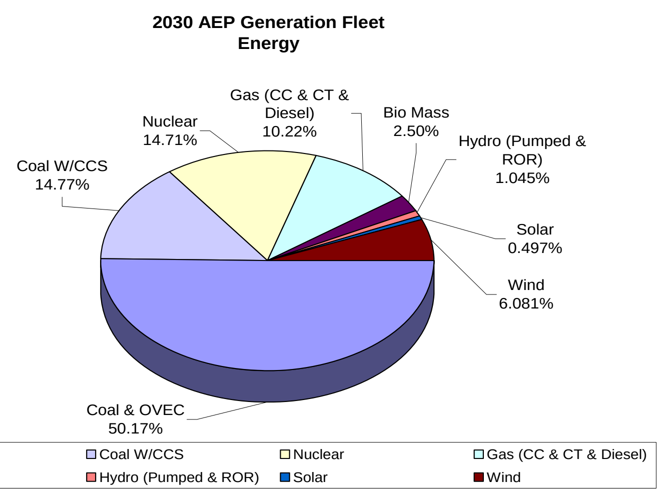
	Current	2020	2030
Coal	78.6%	50.6%	41.7%
Coal w/CCS	0.0%	8.0%	10.9%
Gas	10.0%	14.7%	19.5%
Nuclear	7.2%	9.0%	8.2%
Hydro/PS	2.3%	2.5%	2.2%
Renewables	0.3%	9.1%	11.9%

Source: AEP Resource Planning

Exhibit 11-3: Change in Energy Mix with Hybrid Plan Current vs. 2020 and 2030







Source: AEP Resource Planning

11.2 Comparison to 2009 IRP:

The 2009 IRP for AEP-East recommended a slightly different build profile than the current 2010 IRP. The most notable difference between the two plans is that the fleet capacity reductions associated with retiring older coal fired units now concludes in 2019 versus 2023 in the 2009 Plan. Also, Muskingum River 5 is expected to retire in 2015 rather than be retrofitted with an FGD system. This increases the fossil capacity to be removed from service during the next decade. Total new thermal capacity remains unchanged, although the 2009 Plan included a 628 MW peaking facility in 2018 which has been replaced in the 2010 Plan with two 314 MW peaking facilities, one in 2017 and one in 2018. These facilities are required primarily for system restoration, not peaking capacity. Renewable generation sources are generally consistent with the 2009 Plan, however new DSM has increased. This 2010 Plan also introduces Volt/Var Control technology to reduce consumption. A summary of the plan differences is presented in **Exhibit 11-4**.

Exhibit 11-4: Comparison of 2010 IRP to 2009 IRP

2010 Vs 2009 IRP for AEP-East (10 Year Plan Period)

All Units in MW	*Planned Resource Reductions*		*Planned Resource Additions*					
			DSM	RENEWABLE				THERMAL
	Unit Retirements (summer-rating)	Environmental Retrofits	*New* Demand Reduction *(Cumul. Contribution)*	Solar (Nameplate)	Wind (Nameplate)	Biomass (Derate / New Facility	IVVC	Peaking/ Intermediate/ Baseload
2009 Plan	*(3,470)*	*(113)*	1,073	118	2,451	103	0	***1,585***
2010 Plan	*(5,943)*	*(390)*	1,468	225	2,152	150	100	***1,585***
Difference	*(2,473)*	*(277)*	**395**	**107**	**(299)**	**47**	**100**	***0***

Source: AEP Resource Planning

12.0 AEP-East Plan Implementation & Conclusions

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.

12.1 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.

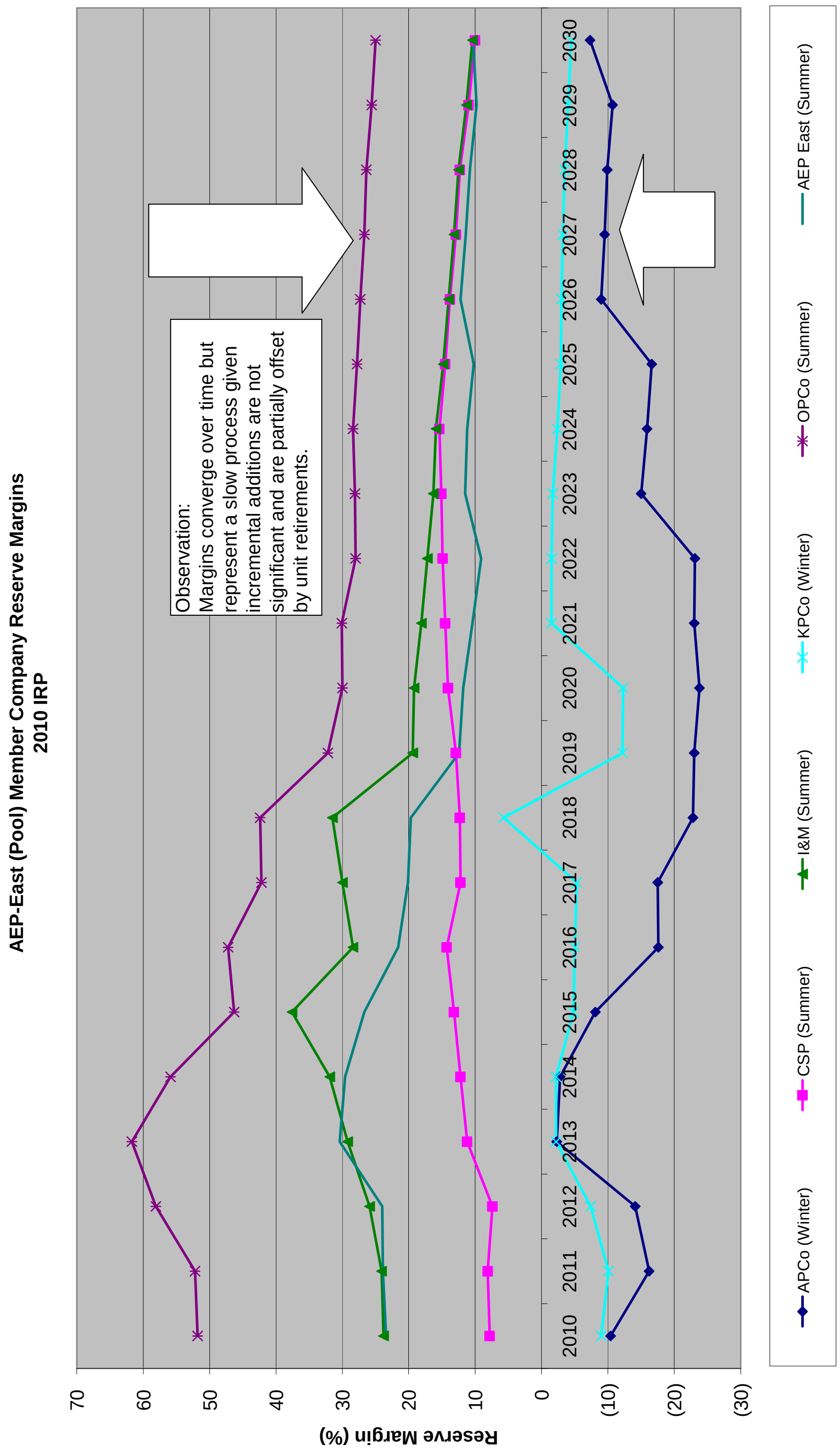
Exhibit 12-1 identifies the resulting Member Company Reserve Margins over the next 20 years. As reflected in the chart, the result of this ownership regiment serves to:

- 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.

Also, **Appendix J** 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.

Resource Planning

Exhibit 12-1: Projected AEP-East Reserve Margin, By Company and System for IRP Period



Source: AEP Resource Planning

12.2 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 12-2 summarizes the projected incremental System Pool/Capacity Settlement impacts to the AEP-East zone Member Companies assumed in this recommended 2010 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, $449 million by the end of 2020

Exhibit 12-2: Incremental Capacity Settlement Impacts of the IRP

Capacity Settlement Benefits/(Costs) ($in Millions) - IRP Change											
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
APCo	-	65	6	92	78	72	(6)	7	(11)	74	73
CSP	-	(14)	(30)	(29)	(32)	10	58	62	104	177	208
I&M	-	(21)	(25)	(33)	(17)	51	21	44	69	21	22
KPCo	-	3	5	4	9	22	34	37	77	39	42
OPCo	-	(33)	45	(34)	(38)	(155)	(107)	(151)	(239)	(310)	(345)
Total	-	0	0	0	0	0	0	0	0	0	0

Source: AEP Financial Forecasting

12.3 New Capacity Lead Times

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 shown in **Exhibit 12-3**:

Exhibit 12-3: New Capacity Lead Times

	Approximate Lead Time (years)	
Technology	Permitting, license, design	Construction
Simple Cycle	1	1.5
Combined Cycle	1.5 to 2	2
Solid Fuels	2 to 4	4
Nuclear	4	5
Solar PV (e.g., 10 MW Juwi solar)	0.5 to 1	1
Wind Farm	1 to 2	1
Biomass Co-fire	0.5 to 1	0.5

Source: AEP Resource Planning

12.4 AEP-East Implementation Status

1) **Wind Contracts** (by 12/31/2010): Contracts have been signed for wind purchases for a total of 726 MW (nameplate) on behalf of APCo (376 MW), CSP (50 MW), I&M (150 MW), KPCo (100 MW), and OPCo (50 MW). Regulatory approvals have been received for some of these contracts in four of the five states (Virginia, West Virginia, Indiana, and Michigan), however two states, Virginia and Kentucky, denied inclusion of wind PPA costs. Virginia denied three contracts totaling 201 MW (Grand Ridge II, Grand Ridge III, and Beech Ridge), while Kentucky denied the 100 MW FPL Energy wind contract (Lee- Dekalb). No approval was sought or received in Ohio.

2) **DSM Jurisdictional Activity:**

Indiana:
▪ Included in the Phase II Order of Cause 42693 are rules dictating the process for the development and implementation of energy efficiency programs. I&M has several "core-plus" and "core" programs that have Commission approval are expected to be implemented in 2010. During 2010, "core" programs will be transitioned to the State-wide third-party administrator.
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.
Kentucky:
▪ Reestablished industrial collaborative process to begin offering programs to serve this customer class.
Ohio:
▪ Three-year program plans filed in 2009 (Case No. 09-1090-EL-POR) for compliance with S.B. 221.
West Virginia:
▪ APCo filed for a three-year program for energy efficiency in June, 2010 and is awaiting a ruling from the Commission.

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) **NG Combustion Turbines (**2017 and 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 opportunities and acquire additional distressed assets, 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 2017, AEP continues to monitor the regional market for potential asset purchase opportunities.

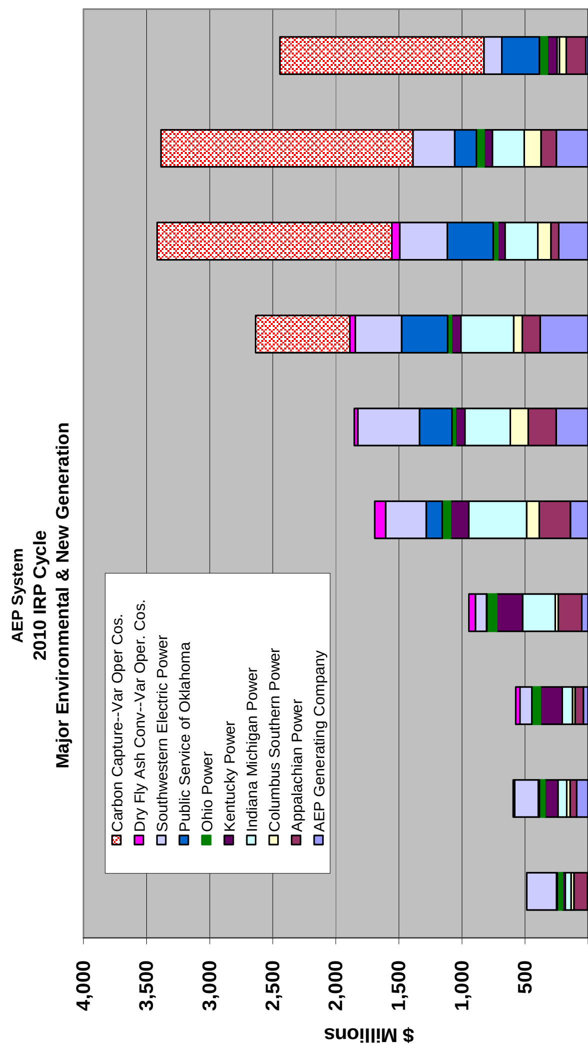
5) **Solar** (2010-2012): AEP-Ohio has a PPA for 10 MW of solar capacity which began commercial operation in June, 2010. This will meet the solar benchmarks included in SB 221 through 2011. Solar benchmarks for 2010, 2011 and 2012 are 5 GWh, 15 GWh, and 29 GWh respectively, as shown in Exhibit 2-3.

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

12.5 Plan Impacts on Capital Spending

This Plan includes new capacity resource additions, as described, as well as unit uprates and assumed 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, **Exhibit 12-4** includes estimates for such projects over the entire AEP System.

Exhibit 12-4: Incremental Capital Spending Impacts of the IRP



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Carbon Capture--Var Oper Cos.	-	-	-	-	-	-	746	1,861	2,000	1,618
Dry Fly Ash Conv--Var Oper. Cos.	-	12	34	52	86	28	43	62	-	-
Southwestern Electric Power	236	187	95	87	320	488	366	377	330	142
Public Service of Oklahoma	6	9	0	5	127	258	366	364	172	299
Ohio Power	40	43	66	77	65	28	30	36	62	63
Kentucky Power	23	104	174	207	145	75	76	56	65	76
Indiana Michigan Power	47	70	81	257	458	360	418	261	252	19
Columbus Southern Power	21	27	20	25	100	141	69	103	133	55
Appalachian Power	107	52	66	185	248	222	141	63	122	155
AEP Generating Company	5	90	37	50	140	253	380	232	252	18

Source: AEP Resource Planning

It is important to reiterate the capital spend level reflected on the **Exhibit 12-4** is "incremental" in that it does not include "Base"/business-as-usual capital expenditure requirements of the generating facilities sector or transmission and distribution capital requirements. 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 is subject to change* as, particularly, new AEP's system-wide and operating company-specific "Capital Allocation" processes continue to evolve. Also, while the spend level includes cost to install Carbon Capture equipment, these projects are included only under the assumption that any comprehensive GHG/CO_2 bill requiring significant reductions in CO_2 emissions will include a provision to receive credits or allowances that would largely offset the cost of such equipment.

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

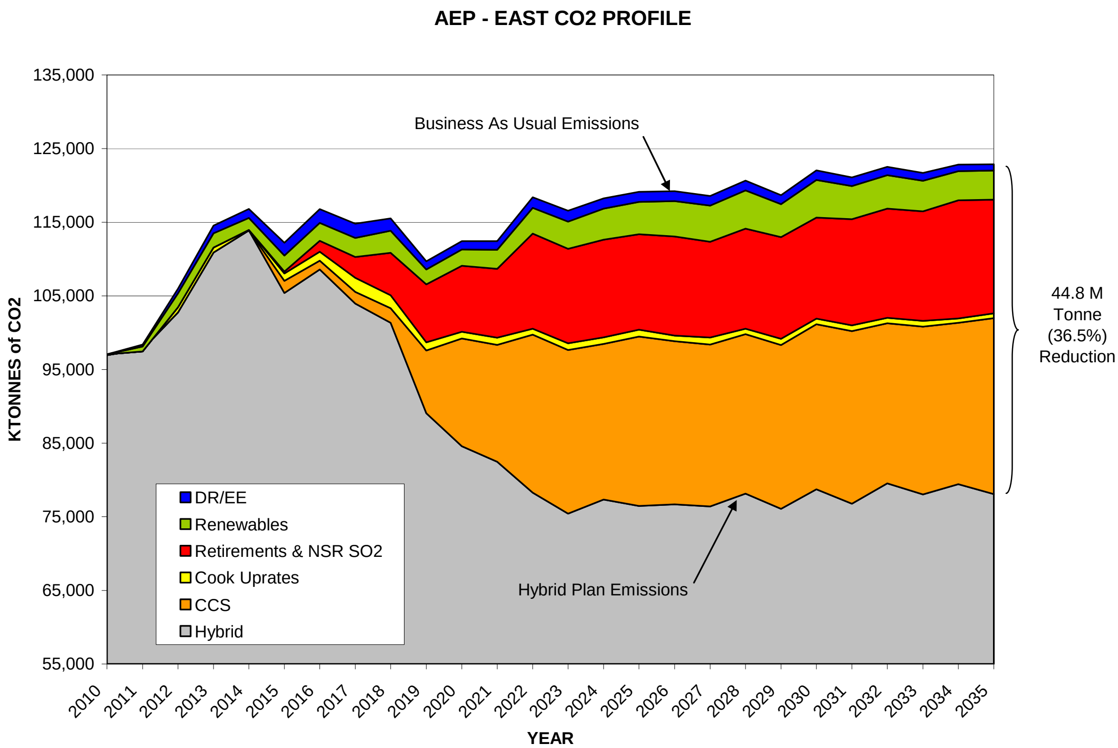
The Hybrid Plan includes resource additions that will result in lowering AEP's carbon emissions over the next 20 years. By retiring older, less efficient coal fired units, increasing nuclear capacity at the Cook plant, adding wind and solar resources, adding carbon capture and storage to larger coal 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 Storage

The following **Exhibit 12-5** reflects those comparable components within this 2010 IRP as set forth as a multi-colored "prism" that are anticipated to contribute to the overall AEP-East system's initiatives to reduce its carbon footprint:

Exhibit 12-5: AEP-East System CO_2 Emission Reductions, by "Prism" Component



Source: AEP Resource Planning

12.7 Conclusions

The recommended AEP-East capacity resource plan **provides the lowest reasonable cost solution through a combination of traditional supply, renewable and demand-side resources**. The most recent (April 2010) "tempered" load growth, combined with the completion of the Dresden natural gas-combined cycle facility, additional renewable resources, increased DR/EE initiatives, and the proposed capacity uprate of the Cook Nuclear facility allow AEP-East region to meet its reserve requirements until the 2018-2019 timeframe, at which point modeling indicates new peaking capacity will be required. Other than the aforementioned D.C. Cook uprate, no new baseload capacity is required over the 10-year Planning Period.

The Plan also positions the AEP-East Operating Companies to achieve legislative or regulatory mandated state renewable portfolio standards and energy efficiency requirements, and sets in place the framework to meet potential CO_2 reduction targets and emerging U.S. EPA rulemaking around HAPs and CCR at the intended least reasonable cost to its customers.

The resource planning process is becoming increasingly complex given these uncertainties as well as spiraling technological advancements, changing economic and other energy supply fundamentals, uncertainty around demand and energy usage patterns as well as customer acceptance for embracing efficiency initiatives. All of these uncertainties necessitate flexibility in any on-going plan. Moreover, the ability to invest in capital-intensive infrastructure is increasingly challenged in light of current economic conditions, and the impact on the AEP-East Operating Companies' customer costs-of-service/rates will continue to be a primary planning consideration.

Other than those initiatives that fall within some necessary "actionable" period over the next 2-3 years, this long-term Plan is also 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, the movement towards increasing use of renewable generation and end-use efficiency, as well as legislative and regulated proposals to control greenhouse gases and numerous other hazardous pollutants… all of which will likely result in either the retirement or costly retrofitting of all existing AEP-East coal units.

Finally, bear 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 here reflects, to a large extent, assumptions that are clearly subject to change. In summary, it represents a very reasonable "snapshot" of future requirements at this particular point in time.

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, 2010

Plant Name	Unit No.	In-Service Date		AEP Own/ Contract	Winter Capability (MW)	Summer Capability (MW)	Fuel Type	SCR Installation Year	FGD Installation Year	Super Critical	Age
					APCo						
Amos	1	1971		O	790	800	Coal	2005	2011	Y	39
Amos	2	1972		O	790	790	Coal	2004	2010	Y	38
Amos	3	1973		O	433	428	Coal	2004	2009	Y	37
Clinch River	1	1958		O	235	230	Coal	--	--	N	52
Clinch River	2	1958		O	235	230	Coal	--	--	N	52
Clinch River	3	1961		O	235	230	Coal	--	--	N	49
Glen Lyn	5	1944		O	95	90	Coal	--	--	N	66
Glen Lyn	6	1957		O	240	235	Coal	--	--	N	53
Kanawha River	1	1953		O	200	200	Coal	--	--	N	57
Kanawha River	2	1953		O	200	200	Coal	--	--	N	57
Mountaineer	1	1980		O	1,314	1,299	Coal	2004	2007	Y	30
Sporn	1	1950		O	150	145	Coal	--	--	N	60
Sporn	3	1951		O	150	145	Coal	--	--	N	59
APCo Coal					5,067	5,022					42
Ceredo	1-6	2001	(a)	O	516	450	Gas (CT)	--	--	N	9
APCo Gas					516	450					9
APCo Hydro		Various		O	92	50	Hydro	--	--		
Summersville	1-2	2001		C	28	14	Hydro	--	--		9
APCo Hydro			(b)		119	64					9
Smith Mountain	1	1965		O	66	66	PSH	--	--	--	45
Smith Mountain	2	1965		O	174	174	PSH	--	--	--	45
Smith Mountain	3	1980		O	105	105	PSH	--	--	--	30
Smith Mountain	4	1966		O	174	174	PSH	--	--	--	44
Smith Mountain	5	1966		O	66	66	PSH	--	--	--	44
APCo Pumped Storage					585	585					42
APCo Wind		Various	(c)	C	58	45	Wind	--	--	--	
Total APCo					**6,346**	**6,166**					
					Cardinal-Buckeye						
Cardinal	2	1967		C	595	585	Coal	2004	2008	Y	43
Cardinal	3	1977		C	630	630	Coal	2004	2012	Y	33
Buckeye Coal					1,225	1,215					38
Robert Mone	1-3	2001	(d)	C	134	44	Gas (CT)	--	--	--	9
Buckeye Gas					134	44					9
Total Buckeye					**1,359**	**1,259**					
					CSP						
Beckjord	6	1969		O	52	52	Coal	--	--	N	41
Conesville	3	1962		O	165	165	Coal	--	--	N	48
Conesville	4	1973		O	337	337	Coal	2009	2009	Y	37
Conesville	5	1976		O	400	400	Coal	2015	1976	N	34
Conesville	6	1978		O	400	400	Coal	2015	1978	N	32
Picway	5	1955		O	100	95	Coal	--	--	N	55
Stuart	1	1971		O	151	151	Coal	2004	2008	Y	39
Stuart	2	1970		O	151	151	Coal	2004	2008	Y	40
Stuart	3	1972		O	151	151	Coal	2004	2008	Y	38
Stuart	4	1974		O	151	151	Coal	2004	2008	Y	36
Zimmer	1	1991		O	330	330	Coal	2004	1991	Y	19
CSP Coal					2,388	2,383					35
Waterford	1-6	2002	(a)	O	840	810	Gas (CC)	2002	--	N	8
Darby	1-6	2002	(e)	O	507	438	Gas (CT)	2002	--	N	8
Lawrenceburg	1-6	2004	(e)	O	1,186	1,120	Gas (CC)	--	--	N	6
Stuart Diesel	1-4	1969		O	3	3	Oil (Diesel)	--	--	N	41
CSP Gas/Oil					2,536	2,371					7
CSP Wind		Various	(c)	C	7	7	Wind	--	--	--	
CSP Solar		Various	(f)	C	1	2	Solar	--	--	--	
Total CSP					**4,931**	**4,762**					

(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
(f) The capacity of the Solar Energy Projects are listed at the preliminary PJM credit, 6.67%(winter) and 38%(summer) of the nameplate capacity

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, 2010

Plant Name	Unit No.	In-Service Date		AEP Own/ Contract	Winter Capability (MW)	Summer Capability (MW)	Fuel Type	SCR Installation Year	FGD Installation Year	Super Critical	Age
					I&M						
Rockport	1	1984		O	1,122	1,118	Coal	2017	2017	Y	26
Rockport	2	1989		C	1,105	1,105	Coal	2019	2019	Y	21
Tanners Creek	1	1951		O	145	145	Coal	--	--	N	59
Tanners Creek	2	1952		O	145	145	Coal	--	--	N	58
Tanners Creek	3	1954		O	205	195	Coal	--	--	N	56
Tanners Creek	4	1964		O	500	500	Coal	--	--	Y	46
I&M Coal					3,222	3,208					32
I&M Hydro			(b)		15	11	Hydro	--	--	--	
Cook Nuclear	1	1975		O	994	972	Nuclear	--	--	--	35
Cook Nuclear	2	1978		O	1,121	1,057	Nuclear	--	--	--	32
I&M Nuclear					2,115	2,029					33
I&M Wind		Various	(c)	C	22	22	Wind	--	--	--	
Total I&M					**5,374**	**5,270**					
					KPCo						
Big Sandy	1	1963		O	278	273	Coal	--	--	N	47
Big Sandy	2	1969		O	800	800	Coal	2004	2015	Y	41
Rockport	1	1984		O	198	197	Coal	2017	2017	Y	26
Rockport	2	1989		C	195	195	Coal	2019	2019	Y	21
KPCo Coal					1,471	1,465					37
Total KPCo					**1,471**	**1,465**					37
					OPCo						
Amos	3	1973		O	867	857	Coal	2004	2009	Y	37
Cardinal	1	1967		O	595	585	Coal	2004	2008	Y	43
Gavin	1	1974		O	1,320	1,315	Coal	2004	1994	Y	36
Gavin	2	1975		O	1,320	1,315	Coal	2004	1994	Y	35
Kammer	1	1958		O	210	200	Coal	--	--	N	52
Kammer	2	1958		O	210	200	Coal	--	--	N	52
Kammer	3	1959		O	210	200	Coal	--	--	N	51
Mitchell	1	1971		O	770	770	Coal	2007	2007	Y	39
Mitchell	2	1971		O	790	790	Coal	2007	2007	Y	39
Muskingum River	1	1953		O	205	190	Coal	--	--	N	57
Muskingum River	2	1954		O	205	190	Coal	--	--	N	56
Muskingum River	3	1957		O	215	205	Coal	--	--	N	53
Muskingum River	4	1958		O	215	205	Coal	--	--	N	52
Muskingum River	5	1968		O	600	600	Coal	2005	2015	Y	42
Sporn	2	1950		O	150	145	Coal	--	--	N	60
Sporn	4	1952		O	150	145	Coal	--	--	N	58
Sporn	5	1960		O	0	0	Coal	--	--	Y	50
OPCo Coal					8,032	7,912					41
OPCo Hydro		1983	(b)	O	26	20	Hydro	--	--	--	27
OPCo Wind		Various	(c)	C	7	7	Wind	--	--	--	
OPCo Solar		Various	(e)	C	1	2	Solar	--	--	--	
Total OPCo					**8,064**	**7,941**					

(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
(f) The capacity of the Solar Energy Projects are listed at the preliminary PJM credit, 6.67%(winter) and 38%(summer) of the nameplate capacity

	Winter (MW)	Summer (MW)
TOTAL AEP-East (excl. OVEC)	**27,546**	**26,863**
OVEC Purchase Entitlement	980	947
TOTAL AEP-East	**28,526**	**27,810**

Totals by type			
	Coal	22,385	22,152
	Nuclear	2,115	2,029
	Hydro	745	680
	Gas/Diesel	3,186	2,865
	Wind	93.30	80.30
	Solar	1.36	3.84
	Total	**28,526**	**27,810**

Appendix B, Figure 1 Assumed FGD Scrubber Efficiency and Timing

	Current Scrubber Efficiency - %	New - FGD Installs		FGD - Upgraded	
Units	2010	Month / Year	Scrubber Efficiency - %	Month / Year	Scrubber Efficiency - %
Amos 1	-	Feb-11	95.0	Apr-11	96.0
Amos 2	-	Mar-10	96.0		
Amos 3	97.0	-	-	-	-
Big Sandy 2	-	Jun-15	98.0	-	-
Cardinal 1	95.5	-	-	-	-
Cardinal 2	95.5	-	-	-	-
Cardinal 3	-	Jan-12	95.0	Jan-13	96.5
Conesville 4	94.5	-	-	Jan-11	97.0
Conesville 5	96.0	-	-	-	-
Conesville 6	96.0	-	-	-	-
Gavin 1	94.5	-	-	-	-
Gavin 2	95.0	-	-	-	-
Mitchell 1	97.7	-	-	-	-
Mitchell 2	98.0	-	-	-	-
Mountaineer 1	98.5	-	-	Jan-18	98.0
Rockport 1	-	Jun-17	95.0	-	-
Rockport 2	-	Jun-19	95.0	-	-
Stuart 1-4	97.0	-	-	-	-
Zimmer 1	93.0	-	-	-	-

Notes:
Assumed scrubber efficiencies per T. A. March (4/23/10), Amos 1 per WSR (4/23/10)
Delayed FGD in-service per MSC10-3 maintenance schedule, thus delayed scrubber upgrade 1 month.

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

	Capacity Rating NDC (MW)	HP/1st RH Turbine ADSP Improvement (18 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 (Comm. Oper.)	In-Service Date	FGD Derate (MW)	Net (MW) after FGD	In-Service Date
Amos 1	800			812	Feb-11							(22)	790	Feb-11
Big Sandy 1	260	278	Jan-10											
Big Sandy 2	800											(40)	760	Jun-15
Cardinal 1	595													
Cardinal 2	595													
Cardinal 3	630											(10)	620	Jan-12
Gavin 1	1320					0	Jun-09			1125	Jan-20			
Gavin 2	1320					0	Jun-11							
Mountaineer 1	1314									1256	Nov-15			
Mountaineer 1	1256									1125	Jan-19			
Rockport 1	1320							1355	Jun-17			(35)	1320	Jun-17
Rockport 2	1300							1335	Jun-19			(35)	1300	Jun-19

Sources:
1) Increase in capacity shown at Big Sandy 1 (18-MW), Cardinal 1+2 capacity increase from 580-MW to 595-MW with a summer derate in May-Oct per N. Akins (2/15/10).
2) The 20-MW capacity increase at both Gavin 1+2 have been removed in June of 2009 & 2011, however there is a heat rate improvement per D. L. Untch/D. M. Collins (5/27/09). To be consistent with the AEP-East Capacity update per N. Akins (2/15/10), the forecast will show a 5-MW derate in July & August.
3) Revised main stop valve (MSV) ratings of 35-MW per M. A. Gray (8/30/06).
4) Mountaineeer 1 includes a a seasonal derate in the periods Jun-Sep per R. E. Dool (2/04/10).
5) Carbon Capture project which began in October 2009 will reflect a 6-MW capacity reduction. The 2010 Strategic Plan CLR (2/09/10) assumes the commercial operation of carbon capture at Mountaineer; capacity reduction of an additional (58-MW) 11/2015 and (131-MW) 1/2019 for a total of 195-MW.
6) Forecast shows a capacity reduction for CCS of 195-MW at Gavin 1 effective 1/2020 per the 2010 Strategic Plan.
7) No change in unit capacity after the MSV/FGD are installed at Rockport 1+2 per D. L. Untch/D. M. Collins (1/14/10).
8) The FGD at Amos 1 has been delayed from 1/1/2011 to 2/1/2011, and the FGD at Muskingum 5 has been cancelled

Appendix C, 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 SO_2 (g) (Lb/mmBtu)	Emission Rates NO_X (Lb/mmBtu)	Emission Rates CO_2 (Lb/mmBtu)	Capacity Factor (%)	Overall Availability (%)
Base Load							
Pulv. Coal (Ultra-Supercritical) (h)	618	24	0.07	0.070	205.3	85	89.6
CFB (h)	585	26	0.07	0.070	210.3	80	90.7
IGCC ("F"Class)(h)	630	24	0.01	0.057	205.3	85	87.5
IGCC ("H"Class)(h)	862	17	0.01	0.057	205.3	85	87.5
Nuclear (US ABWR)	1,606	64	0.00	0.000	0.0	90	94.0
Base Load (90% CO2 Capture New Unit)							
Pulv. Coal (Ultra-Supercritical) (h)	526	29	0.0708	0.070	20.5	85	89.6
CFB (w/ CCS, Amine, NOAK)(h)	497	30	0.0665	0.070	20.5	80	89.6
IGCC ("F"Class, w/ CCS, NOAK)(h)	535	28	0.0090	0.057	20.5	85	87.5
IGCC ("F"Class w/ 20% Biomass, w/ CCS)(h)	482	31	0.0090	0.057	11.4	85	87.5
IGCC ("H"Class, w/ CCS)(h)	776	19	0.0090	0.057	20.5	85	87.5
Intermediate							
Combined Cycle (1X1 GE7FA)	255	60	0.0007	0.008	116.0	25	89.1
Combined Cycle (2X1 GE7FA, w/ Duct Firing)	621	60	0.0007	0.008	116.0	60	89.1
Combined Cycle (1X1 GE7FH)	385	60	0.0007	0.008	116.0	25	89.1
Combined Cycle (1X1 SW501G)	387	60	0.0007	0.008	116.0	25	89.1
Combined Cycle (2X1 GE7FB, w/ Duct Firing)	652	60	0.0007	0.008	116.0	60	89.1
Combined Cycle (2X1 M701G)	962	60	0.0007	0.008	116.0	60	89.1
Intermediate (90% CO2 Capture New Unit)							
Combined Cycle (2X1 GE7FB, w/ Amine Scrubbing)	554	71	0.0007	0.008	11.6	60	89.1
Combined Cycle (2X1 M701G, w/ Chilled Ammonia)	818	71	0.0007	0.008	11.6	60	89.1
Peaking							
Combustion Turbine (2X1GE7EA)	164	57	0.0007	0.009	116.0	3	90.1
Combustion Turbine (2X1GE7EA,w/ Inlet Chillers)	164	59	0.0007	0.009	116.0	3	90.1
Combustion Turbine (2X1GE7FA)	332	57	0.0007	0.009	116.0	3	90.1
Combustion Turbine (2X1GE7FA, w/ Inlet Chillers)	332	59	0.0007	0.009	116.0	3	90.1
Aero-Derivative (1X GE LM6000PF)	46	60	0.0007	0.056	116.0	3	89.1
Aero-Derivative (1X GE LM6000PC)	60	60	0.0007	0.056	116.0	90	89.1
Aero-Derivative (1X GE LMS100PB, w/ Inlet Chillers)	98	59	0.0007	0.009	116.0	30	90.1
Aero-Derivative (2X GE LMS100PB, w/ Inlet Chillers)	196	59	0.0007	0.009	116.0	3	90.1
CAES Facility	300	60	0.0007	0.008	116.0	47	95.0

Notes: (a) Installed cost, capability and heat rate numbers have been rounded.
(b) All costs in 2010 dollars. Assume 2.0% escalation rate for 2010 and beyond.
(c) $/kW costs are based on Standard ISO capability.
(d) Total Plant & Interconnection Cost w/AFUDC (AEP-East rate of 4.90%,site rating $/kW).
(e) Transmission Cost ($/kW,w/AFUDC).
(f) Levelized Fuel Cost (40-Yr. Period 2011-2050)
(g) Based on 4.5 lb. Coal.
(h) Pittsburgh #8 Coal.

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

AEP SYSTEM - EASTERN ZONE
Projected Summer Peak Demands, Generating Capabilities, and Margins (UCAP)
Based on (April 2010) Load Forecast
2010 IRP (Hybrid Prime)

		Obligation to PJM										Resources								AEP Position (MW)	
Planning Year		Internal Demand (a)	DSM (b)	Projected DSM 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)	(1)	21,641	473	0.957	1.080	22,873	1,400	24,273	28,807	1,131				27,676	8.41%	25,348	1,075	1,075
2010 /11	(k)	20,395	(16)	(1)	20,394	445	0.955	1.083	21,631	1,405	23,036	28,417	1,207	10 MW Solar & 250 MW Wind	36	0	27,246	10.90%	24,276	1,208	1,240
2011 /12	(k)	20,674	(206)	(59)	20,615	445	0.955	1.083	21,871	1,396	23,267	28,412	1,492	10 MW Solar & 100 MW Wind	17	0	26,973	8.95%	24,559	1,244	1,292
2012 /13	(k)	21,375	(399)	(16)	21,360	445	0.950	1.080	22,605	1,396	24,001	27,883	873	10 MW Solar & 100 MW Wind	17	0	27,080	7.26%	25,114	1,048	1,113
2013 /14	(k)	21,741	(651)	(206)	21,536	445	0.957	1.080	22,806	1,396	24,202	27,875	(4)	540 MW D CC2 & 10 MW Solar & 100 MW Wind	557	0	28,506	7.95%	26,240	1,461	2,038
2014 /15		20,755	(932)	(399)	20,356	445	0.957	1.080	21,532	1,396	22,928	27,256	(4)	26 MW Solar & 300 MW Wind	49	0	27,936	8.19%	25,648	2,099	2,720
2015 /16		20,869	(1,153)	(651)	20,218	445	0.957	1.080	21,382	1,396	22,778	26,401	(4)	26 MW Solar & 400 MW Wind	62	0	27,143	8.02%	24,966	1,509	2,188
2016 /17		20,967	(1,237)	(932)	20,035	445	0.957	1.080	21,184	1,396	22,580	25,294	(4)	26 MW Solar & 250 MW Wind	42	0	26,079	6.00%	24,514	1,200	1,934
2017 /18		21,093	(1,312)	(1,153)	19,940	445	0.957	1.080	21,082	1,396	22,478	24,697	(4)	314 MW CT* & 26 MW Solar & 150 MW Wind	343	0	25,825	5.34%	24,446	904	1,968
2018 /19		21,224	(1,377)	(1,237)	19,987	445	0.957	1.080	21,133	1,396	22,529	24,234	(4)	314 MW CT* & 26 MW Solar & 50 MW Wind	330	0	25,693	5.09%	24,385	475	1,856
2019 /20		21,351	(1,465)	(1,312)	20,039	445	0.957	1.080	21,189	1,396	22,585	22,658	(4)	26 MW Solar & 100 MW Wind	23	0	24,140	5.02%	22,928	(1,061)	343
2020 /21		21,391	(1,569)	(1,377)	20,013	445	0.957	1.080	21,161	1,396	22,557	22,658	(4)	26 MW Solar & 150 MW Wind	29	0	24,169	5.02%	22,956	(1,033)	399

Notes: (a) Based on (April 2010) Load Forecast (with implied PJM diversity factor)
Includes Monongahela Power & NCEMC

(b) Existing plus approved DR, EE, and IVV

(c) The impact of new DSM is delayed two years to represent either
(1) its impact on actual load feeding through the PJM load forecast process or
(2) verification prior to being offered into the PJM RPM auction.

(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:
AEP share of OVEC capacity
Assumes hydro units, including Summersville, are derated to August average output in 2014/15
WIND FARM (nameplate):
275 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: Amos 2: 12 MW (turbine); Big Sandy 1: 0 MW (turbine); Gavin 1: 0 MW (turbine)
2010/11: Amos 1: 12 MW (turbine)
2011/12: Cook 2: 14 MW (Uprate); Gavin 2: 0 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)

(g) continued
CCS DERATES:
2009/10: Mountaineer 1: 6 MW
2015/16: Mountaineer 1: 58 MW
2018/19: Mountaineer 1: 131 MW
2019/20: Gavin 1: 195 MW
2021/22: Amos 3: 195 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: Amos 2: 22 MW; Conesville 4: 2 MW
2010/11: Amos 1: 22 MW; Kyger Creek 4-5: 3 MW each
2011/12: Cardinal 3: 10 MW; Kyger Creek 1-3: 3 MW each
2012/13: Clifty Creek 4,6: 2 MW each
2013/14: Clifty Creek 1-3,5: 2 MW each
2015/16: Big Sandy 2: 40 MW
2017/18: Rockport 1: 35 MW
2019/20: Rockport 2: 35 MW
SCR DERATES:
2009/10: Conesville 4: 0 MW
2019/20: Conesville 5-6: 4 MW each
2020/21: Rockport 1: 0 MW
2022/23: 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; Muskingum River 5
2016/17: Tanners Ck. 1-3; Clinch R. 1-3
2017/18: Picway 5; Sporn 1-4
2018/19: Kanawha River 1&2
2019/20: Kammer 1-3; Big Sandy 1; 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 2010/11-2011/12 and 30 MW in 2012/13
Ceredo/Darby/Glen Lyn Sale to AMPO,ATSI, and IMEA
2010/11-2012/13 (45 MW, 374 MW, 157 MW)
RPM Auction Sales 2007/08 - 2012/13 (777 MW, 1406 MW, 1389 MW
, 1463 MW, 1404 MW, 690 MW ICAP)
3.6 MW capacity credit from SEPA's Philpot Dam via Blue Ridge contract

(i) New wind and solar capacity value is assumed to be 13% and 38% 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

(*) Combustion Turbines (CT) added to maintain Black Start capability

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

AEP System - East Zone

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

as well as Known or Emerging State Mandates

2010 IRP

Year	APCo				CSP				I&M				KPCo			
	Solar Nameplate (MW)	Wind Nameplate (MW)	Biomass Equivalent (MW)	Energy as % of Sales	Solar Nameplate (MW)	Wind Nameplate (MW)	Biomass Equivalent (MW)	Energy as % of Sales	Solar Nameplate (MW)	Wind Nameplate (MW)	Biomass Equivalent (MW)	Energy as % of Sales	Solar Nameplate (MW)	Wind Nameplate (MW)	Biomass Equivalent (MW)	Energy as % 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	2.7%	0	50	0	0.8%	0	150	0	2.5%	0	0	0	0.0%
2011	0	376	0	3.6%	8	50	2	0.9%	0	150	0	2.5%	0	0	0	0.0%
2012	0	376	0	3.6%	13	100	2	1.7%	0	150	0	2.4%	0	0	0	0.0%
2013 (b)	0	**376**	0	3.5%	17	**125**	2	2.1%	0	**200**	0	3.2%	0	**0**	0	0.0%
2014	0	376	0	3.5%	28	150	27	3.5%	0	350	0	5.6%	0	100	0	4.2%
2015	0	376	0	3.5%	38	190	27	4.2%	0	650	0	10.2%	0	100	0	4.2%
2016	0	376	0	3.5%	49	273	25	5.5%	0	650	0	10.3%	0	100	0	4.2%
2017	0	376	0	3.5%	59	323	25	6.4%	0	650	0	10.3%	0	100	0	4.2%
2018	0	376	0	3.4%	71	323	75	8.5%	0	650	0	10.3%	0	100	0	4.2%
2019	0	376	0	3.4%	83	373	75	9.4%	0	650	0	10.4%	0	100	0	4.1%
2020	0	376	0	3.4%	95	448	75	10.7%	0	650	0	10.3%	0	100	0	4.1%
2021	0	376	0	3.3%	113	448	75	10.8%	0	700	0	11.0%	0	150	0	6.1%
2022	0	409	0	3.6%	125	515	75	12.0%	0	700	0	11.0%	0	150	0	6.0%
2023	0	409	0	3.6%	125	615	75	13.5%	0	700	0	10.9%	0	150	0	6.0%
2024	0	409	0	3.5%	147	665	75	14.4%	0	750	50	13.7%	0	150	50	11.1%
2025	0	409	0	3.5%	147	715	75	15.1%	0	800	50	14.3%	0	150	50	11.1%
2026	0	409	0	3.5%	156	765	75	15.9%	0	850	50	15.0%	0	150	50	11.0%
2027	0	409	0	3.4%	156	815	94	17.3%	0	850	50	14.9%	0	200	63	14.1%
2028	0	409	0	3.4%	169	865	94	18.0%	0	850	50	14.8%	0	200	63	14.0%
2029	0	409	0	3.4%	169	865	94	17.9%	0	850	50	14.7%	0	200	63	13.9%
2030	0	409	0	3.3%	185	865	94	17.8%	0	850	50	14.7%	0	200	63	13.8%

Year	OPCo				AEP-Ohio				AEP-East			
	Solar Nameplate (MW)	Wind Nameplate (MW)	Biomass Equivalent (MW)	Energy as % of Sales	Solar Nameplate (MW)	Wind Nameplate (MW)	Biomass Equivalent (MW)	Energy as % of Sales	Solar Nameplate (MW)	Wind Nameplate (MW)	Biomass Equivalent (MW)	Energy as % of Sales
2009	0	0	0	0.0%	0	0	0	0.0%	0	75	0	0.2%
2010	0	50	0	0.6%	0	100	0	0.7%	0	526	0	1.6%
2011	12	50	42	1.3%	20	100	44	1.1%	20	626	44	2.1%
2012	17	100	42	1.8%	31	200	44	1.8%	31	726	44	2.3%
2013 (b)	24	**125**	42	2.1%	41	**250**	44	2.1%	41	**826**	44	2.6%
2014	39	150	67	3.2%	67	300	94	3.3%	67	1,126	94	3.8%
2015	55	210	67	3.9%	94	400	94	4.0%	94	1,526	94	5.0%
2016	71	377	25	5.1%	120	650	50	5.3%	120	1,776	50	5.6%
2017	87	477	25	6.3%	146	800	50	6.3%	146	1,926	50	6.0%
2018	101	527	75	8.4%	172	850	150	8.4%	172	1,976	150	6.9%
2019	115	577	75	9.0%	198	950	150	9.1%	198	2,076	150	7.2%
2020	130	652	75	9.9%	225	1,100	150	10.2%	225	2,226	150	7.6%
2021	142	652	125	11.5%	256	1,100	200	11.2%	256	2,326	200	8.3%
2022	176	652	125	11.6%	301	1,167	200	11.8%	301	2,426	200	8.6%
2023	176	752	125	12.7%	301	1,367	200	13.1%	301	2,626	200	9.1%
2024	198	802	125	13.3%	345	1,467	200	13.8%	345	2,776	300	10.2%
2025	198	852	125	13.8%	345	1,567	200	14.4%	345	2,926	300	10.5%
2026	208	902	125	14.4%	364	1,667	200	15.0%	364	3,076	300	10.9%
2027	208	952	144	15.4%	364	1,767	238	16.2%	364	3,226	350	11.6%
2028	220	1,002	144	15.9%	389	1,867	238	16.8%	389	3,326	350	11.8%
2029	220	1,002	144	15.8%	389	1,867	238	16.7%	389	3,326	350	11.7%
2030	236	1,002	144	15.8%	420	1,867	238	16.7%	420	3,326	350	11.7%

(a) Data excludes 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.

AEP System - SPP Zone

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

as well as Known or Emerging State-Specific Mandates

2010 IRP

Year	PSO				SWEPCO				AEP-SPP			
	Solar Nameplate (MW)	Wind Nameplate (MW)	Biomass Equivalent (MW)	Energy as % of Sales	Solar Nameplate (MW)	Wind Nameplate (MW)	Biomass Equivalent (MW)	Energy as % of Sales	Solar Nameplate (MW)	Wind Nameplate (MW)	Biomass Equivalent (MW)	Energy as % of Sales
2009	0	393	0	9.4%	0	31	0	0.6%	0	424	0	4.9%
2010	0	492	0	11.8%	0	111	0	2.4%	0	602	0	7.0%
2011	0	591	0	14.0%	0	111	0	2.3%	0	701	0	7.8%
2012	0	691	0	15.8%	0	111	0	2.2%	0	801	0	8.7%
2013 (b)	0	**691**	0	15.7%	0	**111**	0	2.2%	0	801	0	8.6%
2014	0	691	0	15.5%	0	111	0	2.2%	0	801	0	8.6%
2015	0	691	0	15.5%	25	311	0	6.5%	25	1,001	0	10.8%
2016	0	691	0	15.4%	25	511	0	10.5%	25	1,201	0	12.8%
2017	0	791	0	17.6%	25	611	0	12.4%	25	1,401	0	14.9%
2018	0	791	0	17.5%	25	611	0	12.3%	25	1,401	0	14.8%
2019	0	791	0	17.4%	25	611	0	12.2%	25	1,401	0	14.6%
2020	0	941	0	20.5%	25	761	0	15.0%	25	1,701	0	17.6%
2021	0	941	0	20.4%	25	861	0	16.8%	25	1,801	0	18.5%
2022	0	941	0	20.2%	25	961	0	18.5%	25	1,901	0	19.3%
2023	0	1,041	0	22.2%	25	961	0	18.3%	25	2,001	0	20.2%
2024	0	1,041	0	22.0%	25	1,061	0	20.0%	25	2,101	0	21.0%
2025	0	1,041	0	21.8%	25	1,161	0	21.7%	25	2,201	0	21.7%
2026	9	1,141	0	23.8%	34	1,161	0	21.5%	44	2,301	0	22.6%
2027	9	1,141	0	23.6%	34	1,261	0	23.1%	44	2,401	0	23.4%
2028	22	1,141	0	23.5%	47	1,261	0	23.0%	69	2,401	0	23.3%
2029	22	1,341	0	27.3%	47	1,261	0	22.8%	69	2,601	0	24.9%
2030	38	1,341	0	27.3%	63	1,361	0	24.4%	100	2,701	0	25.8%

Year	AEP-System			
	Solar Nameplate (MW)	Wind Nameplate (MW)	Biomass Equivalent (MW)	Energy as % of Sales
2009	0	499	0	1.4%
2010	0	1,128	0	2.9%
2011	20	1,327	44	3.5%
2012	31	1,527	44	3.9%
2013	41	**1,627**	44	4.1%
2014	67	1,927	94	5.0%
2015	119	2,527	94	6.5%
2016	145	2,977	50	7.4%
2017	171	3,327	50	8.3%
2018	197	3,377	150	8.9%
2019	223	3,477	150	9.1%
2020	250	3,927	150	$\boxed{\textbf{10.2\%}}$
2021	281	4,127	200	10.9%
2022	326	4,327	200	11.4%
2023	326	4,627	200	12.0%
2024	370	4,877	300	13.0%
2025	370	5,127	300	13.5%
2026	408	5,377	300	14.0%
2027	408	5,627	350	14.7%
2028	458	5,727	350	14.9%
2029	458	5,927	350	15.2%
2030	520	6,027	350	$\boxed{\textbf{15.4\%}}$

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

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

Appendix F, Figure 1, Internal Demand by Company

APPALACHIAN POWER COMPANY
MONTHLY PEAK INTERNAL DEMAND - (MW) W/O EMBEDDED DSM
JANUARY 2010 - DECEMBER 2039

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Summer	Winter
2010	6,887	7,008	6,102	5,236	4,677	5,554	5,567	6,005	5,284	5,154	5,750	6,461	6,005	7,008
2011	7,087	7,220	6,212	5,290	4,733	5,670	5,587	6,041	5,374	5,187	5,828	6,587	6,041	7,220
2012	7,465	7,584	6,726	5,625	5,131	6,070	6,021	6,486	5,737	5,542	6,170	6,954	6,486	7,584
2013	7,542	7,662	6,851	5,718	5,197	6,163	6,112	6,589	5,827	5,616	6,272	7,074	6,589	7,662
2014	7,603	7,726	6,978	5,789	5,235	6,240	6,183	6,671	5,897	5,656	6,367	7,191	6,671	7,726
2015	7,658	7,785	7,097	5,851	5,259	6,301	6,238	6,737	5,949	5,687	6,447	7,304	6,737	7,785
2016	7,673	7,803	6,912	5,860	5,283	6,329	6,267	6,768	5,978	5,695	6,461	7,312	6,768	7,803
2017	7,710	7,829	7,126	5,906	5,377	6,390	6,322	6,822	6,025	5,791	6,524	7,382	6,822	7,829
2018	7,762	7,879	7,174	5,949	5,417	6,443	6,378	6,882	6,080	5,827	6,554	7,427	6,882	7,879
2019	7,813	7,931	7,224	5,993	5,463	6,501	6,438	6,947	6,141	5,866	6,593	7,470	6,947	7,931
2020	7,842	7,955	7,247	6,011	5,488	6,541	6,480	6,992	6,183	5,889	6,620	7,493	6,992	7,955
2021	7,926	8,041	7,127	6,077	5,554	6,618	6,559	7,077	6,260	5,949	6,690	7,564	7,077	8,041
2022	7,982	8,097	7,181	6,121	5,605	6,677	6,619	7,143	6,320	5,989	6,738	7,614	7,143	8,097
2023	8,008	8,109	7,383	6,185	5,696	6,737	6,673	7,197	6,367	6,085	6,774	7,673	7,197	8,109
2024	8,044	8,147	7,418	6,200	5,725	6,785	6,722	7,250	6,415	6,108	6,800	7,699	7,250	8,147
2025	8,130	8,234	7,500	6,269	5,789	6,866	6,804	7,339	6,496	6,169	6,875	7,776	7,339	8,234
2026	8,185	8,296	7,555	6,308	5,835	6,926	6,866	7,406	6,556	6,207	6,925	7,822	7,406	8,296
2027	8,247	8,359	7,420	6,352	5,889	6,992	6,932	7,479	6,622	6,250	6,975	7,874	7,479	8,359
2028	8,286	8,402	7,456	6,363	5,931	7,042	6,984	7,534	6,675	6,271	7,025	7,904	7,534	8,402
2029	8,333	8,441	7,677	6,467	6,028	7,119	7,055	7,606	6,735	6,388	7,046	7,987	7,606	8,441
2030	8,398	8,510	7,740	6,511	6,080	7,187	7,123	7,681	6,802	6,430	7,106	8,045	7,681	8,510
2031	8,466	8,579	7,807	6,557	6,133	7,255	7,192	7,756	6,872	6,478	7,163	8,103	7,756	8,579
2032	8,508	8,627	7,649	6,566	6,173	7,309	7,248	7,818	6,927	6,504	7,221	8,135	7,818	8,627
2033	8,604	8,726	7,741	6,635	6,247	7,399	7,338	7,915	7,015	6,567	7,310	8,222	7,915	8,726
2034	8,641	8,751	7,951	6,746	6,346	7,472	7,403	7,983	7,070	6,679	7,397	8,291	7,983	8,751
2035	8,720	8,834	8,024	6,798	6,407	7,550	7,483	8,068	7,149	6,728	7,374	8,358	8,068	8,834
2036	8,745	8,864	8,056	6,798	6,441	7,605	7,537	8,130	7,204	6,753	7,422	8,381	8,130	8,864
2037	8,873	8,995	8,174	6,883	6,524	7,708	7,642	8,243	7,305	6,831	7,534	8,492	8,243	8,995
2038	8,955	9,079	8,051	6,935	6,593	7,793	7,726	8,334	7,390	6,886	7,614	8,566	8,334	9,079
2039	9,036	9,169	8,132	6,985	6,661	7,875	7,810	8,425	7,471	6,943	7,690	8,639	8,425	9,169

Notes: Load Forecast per J. M. Harris (04/26/10). Demands do not reflect a reduction for PJM marginal losses OR reflect mandated commission approved and incremental DSM programs for APCo, CSP, I&M, KPCo & OPCo. WPCo load moved from OPCo to APCo 1/2012.

COLUMBUS SOUTHERN POWER COMPANY
MONTHLY PEAK INTERNAL DEMAND - (MW) W/O EMBEDDED DSM
JANUARY 2010 - DECEMBER 2039

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Summer	Winter
2010	3,422	3,390	3,101	2,766	3,517	3,724	4,139	4,273	3,719	2,958	3,069	3,331	4,273	3,422
2011	3,395	3,363	3,097	2,763	3,527	3,736	4,152	4,291	3,743	2,972	3,078	3,337	4,291	3,395
2012	3,426	3,392	3,212	2,774	3,577	3,783	4,196	4,333	3,783	2,992	3,210	3,356	4,333	3,426
2013	3,474	3,444	3,268	2,827	3,636	3,842	4,260	4,400	3,844	3,036	3,060	3,402	4,400	3,474
2014	3,497	3,477	3,294	2,853	3,671	3,874	4,295	4,438	3,873	3,056	3,076	3,424	4,438	3,497
2015	3,500	3,488	3,305	2,867	3,693	3,893	4,315	4,463	3,901	3,071	3,087	3,442	4,463	3,500
2016	3,499	3,494	3,214	2,877	3,707	3,896	4,326	4,471	3,914	3,074	3,209	3,442	4,471	3,499
2017	3,511	3,503	3,309	2,875	3,738	3,926	4,357	4,499	3,946	3,088	3,335	3,464	4,499	3,511
2018	3,518	3,521	3,324	2,890	3,762	3,949	4,378	4,521	3,971	3,097	3,345	3,472	4,521	3,521
2019	3,531	3,544	3,343	2,908	3,785	3,971	4,397	4,544	3,993	3,108	3,148	3,484	4,544	3,544
2020	3,533	3,546	3,347	2,919	3,803	3,977	4,406	4,554	4,002	3,112	3,143	3,486	4,554	3,546
2021	3,574	3,599	3,283	2,951	3,838	4,007	4,438	4,578	4,023	3,121	3,270	3,492	4,578	3,599
2022	3,589	3,616	3,303	2,968	3,857	4,027	4,465	4,603	4,044	3,132	3,279	3,509	4,603	3,616
2023	3,600	3,610	3,392	2,960	3,875	4,050	4,491	4,626	4,067	3,144	3,400	3,530	4,626	3,610
2024	3,610	3,613	3,406	2,968	3,896	4,072	4,510	4,636	4,085	3,152	3,199	3,539	4,636	3,613
2025	3,640	3,656	3,434	2,994	3,933	4,104	4,551	4,682	4,118	3,176	3,221	3,568	4,682	3,656
2026	3,664	3,683	3,454	3,015	3,966	4,133	4,588	4,719	4,147	3,196	3,235	3,591	4,719	3,683
2027	3,689	3,708	3,372	3,036	3,998	4,164	4,629	4,759	4,180	3,218	3,359	3,615	4,759	3,708
2028	3,706	3,718	3,394	3,054	4,021	4,192	4,663	4,792	4,211	3,233	3,374	3,639	4,792	3,718
2029	3,736	3,741	3,506	3,052	4,058	4,235	4,710	4,841	4,250	3,263	3,515	3,676	4,841	3,741
2030	3,763	3,769	3,533	3,075	4,094	4,272	4,750	4,887	4,284	3,285	3,340	3,703	4,887	3,769
2031	3,795	3,804	3,566	3,104	4,139	4,311	4,800	4,940	4,325	3,257	3,357	3,735	4,940	3,804
2032	3,821	3,824	3,475	3,129	4,178	4,345	4,845	4,984	4,360	3,285	3,473	3,759	4,984	3,824
2033	3,867	3,880	3,521	3,170	4,229	4,398	4,910	5,048	4,414	3,323	3,508	3,808	5,048	3,880
2034	3,899	3,891	3,639	3,208	4,266	4,446	4,964	5,102	4,460	3,364	3,656	3,850	5,102	3,899
2035	3,938	3,934	3,676	3,242	4,316	4,497	5,020	5,163	4,512	3,398	3,689	3,890	5,163	3,938
2036	3,961	3,945	3,834	3,268	4,362	4,537	5,067	5,216	4,548	3,425	3,516	3,913	5,216	3,961
2037	4,022	4,023	3,755	3,315	4,431	4,599	5,144	5,296	4,613	3,473	3,559	3,972	5,296	4,023
2038	4,069	4,068	3,678	3,354	4,486	4,656	5,212	5,365	4,670	3,514	3,679	4,017	5,365	4,069
2039	4,114	4,120	3,724	3,397	4,541	4,713	5,283	5,434	4,729	3,555	3,715	4,066	5,434	4,120

Notes: Load Forecast per J. M. Harris (04/26/10). Demands do not reflect a reduction for PJM marginal losses OR reflect mandated commission approved and incremental DSM programs for APCo, CSP, I&M, KPCo & OPCo.

Appendix F, Figure 2, Internal Demand by Company

INDIANA MICHIGAN POWER COMPANY
MONTHLY PEAK INTERNAL DEMAND - (MW) W/O EMBEDDED DSM
JANUARY 2010 - DECEMBER 2039

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Summer	Winter
2010	3,817	3,694	3,421	3,237	3,222	4,046	4,436	4,417	3,831	3,233	3,257	3,548	4,436	3,817
2011	3,827	3,705	3,432	3,253	3,235	4,065	4,459	4,439	3,851	3,248	3,263	3,556	4,459	3,827
2012	3,908	3,784	3,560	3,310	3,332	4,164	4,558	4,538	3,943	3,310	3,372	3,623	4,558	3,908
2013	3,975	3,850	3,622	3,375	3,392	4,234	4,634	4,614	4,012	3,366	3,414	3,675	4,634	3,975
2014	3,989	3,865	3,638	3,396	3,409	4,247	4,642	4,625	4,027	3,400	3,420	3,707	4,642	3,989
2015	4,000	3,876	3,650	3,412	3,422	4,260	4,656	4,640	4,042	3,421	3,425	3,725	4,656	4,000
2016	3,998	3,877	3,597	3,422	3,424	4,262	4,656	4,642	4,047	3,438	3,427	3,733	4,656	3,998
2017	4,021	3,898	3,669	3,422	3,458	4,292	4,684	4,672	4,076	3,422	3,479	3,685	4,684	4,021
2018	4,040	3,919	3,690	3,447	3,487	4,314	4,707	4,696	4,099	3,447	3,491	3,794	4,707	4,040
2019	4,062	3,941	3,710	3,471	3,509	4,338	4,731	4,720	4,124	3,473	3,505	3,711	4,731	4,062
2020	4,071	3,951	3,721	3,475	3,518	4,352	4,746	4,736	4,139	3,489	3,502	3,719	4,746	4,071
2021	4,107	3,986	3,701	3,511	3,547	4,392	4,790	4,780	4,178	3,523	3,533	3,752	4,790	4,107
2022	4,130	4,009	3,722	3,537	3,568	4,420	4,823	4,812	4,206	3,548	3,554	3,773	4,823	4,130
2023	4,147	4,024	3,788	3,542	3,595	4,450	4,855	4,843	4,232	3,558	3,599	3,782	4,855	4,147
2024	4,157	4,033	3,799	3,552	3,610	4,467	4,876	4,864	4,250	3,574	3,596	3,806	4,876	4,157
2025	4,194	4,071	3,833	3,581	3,642	4,510	4,924	4,911	4,291	3,609	3,622	3,840	4,924	4,194
2026	4,219	4,094	3,857	3,609	3,663	4,541	4,960	4,946	4,321	3,634	3,638	3,863	4,960	4,219
2027	4,242	4,118	3,823	3,634	3,683	4,571	4,994	4,980	4,350	3,657	3,658	3,884	4,994	4,242
2028	4,259	4,133	3,838	3,661	3,695	4,593	5,020	5,008	4,373	3,678	3,673	3,885	5,020	4,259
2029	4,288	4,160	3,918	3,663	3,741	4,636	5,067	5,051	4,410	3,699	3,723	3,934	5,067	4,288
2030	4,315	4,188	3,943	3,685	3,765	4,670	5,106	5,090	4,443	3,727	3,740	3,959	5,106	4,315
2031	4,344	4,215	3,971	3,715	3,789	4,705	5,146	5,130	4,478	3,755	3,759	3,985	5,146	4,344
2032	4,358	4,230	3,928	3,741	3,801	4,728	5,173	5,158	4,501	3,775	3,764	3,999	5,173	4,358
2033	4,404	4,274	3,951	3,785	3,838	4,780	5,230	5,214	4,550	3,817	3,804	4,041	5,230	4,404
2034	4,431	4,298	4,049	3,787	3,876	4,822	5,277	5,259	4,587	3,836	3,861	4,058	5,277	4,431
2035	4,465	4,332	4,080	3,813	3,913	4,863	5,323	5,306	4,627	3,869	3,884	4,104	5,323	4,465
2036	4,476	4,344	4,102	3,839	3,926	4,887	5,352	5,335	4,652	3,891	3,884	4,117	5,352	4,476
2037	4,526	4,392	4,138	3,885	3,962	4,940	5,411	5,393	4,701	3,932	3,917	4,161	5,411	4,526
2038	4,556	4,422	4,084	3,917	3,989	4,978	5,455	5,437	4,739	3,962	3,943	4,189	5,455	4,556
2039	4,584	4,450	4,119	3,946	4,011	5,013	5,496	5,478	4,773	3,991	3,967	4,215	5,496	4,584

Notes: Load Forecast per J. M. Harris (04/26/10). Demands do not reflect a reduction for PJM marginal losses OR reflect mandated commission approved and incremental DSM programs for APCo, CSP, I&M, KPCo & OPCo.

KENTUCKY POWER COMPANY
MONTHLY PEAK INTERNAL DEMAND - (MW) W/O EMBEDDED DSM
JANUARY 2010 - DECEMBER 2039

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Summer	Winter
2010	1,403	1,483	1,270	1,103	977	1,086	1,168	1,260	1,032	1,009	1,185	1,374	1,260	1,483
2011	1,467	1,545	1,289	1,111	982	1,106	1,164	1,257	1,047	1,011	1,196	1,395	1,257	1,545
2012	1,471	1,543	1,341	1,120	997	1,122	1,169	1,262	1,056	1,021	1,212	1,416	1,262	1,543
2013	1,481	1,548	1,372	1,138	1,018	1,144	1,173	1,267	1,076	1,031	1,231	1,448	1,267	1,548
2014	1,492	1,549	1,411	1,157	1,023	1,160	1,175	1,272	1,084	1,036	1,258	1,492	1,272	1,549
2015	1,507	1,554	1,458	1,181	1,018	1,168	1,177	1,276	1,089	1,040	1,283	1,542	1,276	1,554
2016	1,506	1,555	1,402	1,184	1,011	1,168	1,177	1,277	1,090	1,040	1,281	1,541	1,277	1,555
2017	1,510	1,559	1,462	1,180	1,021	1,174	1,180	1,277	1,097	1,053	1,340	1,551	1,277	1,559
2018	1,517	1,566	1,469	1,187	1,026	1,179	1,186	1,283	1,103	1,056	1,306	1,557	1,283	1,566
2019	1,517	1,568	1,474	1,194	1,043	1,184	1,193	1,290	1,110	1,061	1,305	1,558	1,290	1,568
2020	1,512	1,565	1,473	1,196	1,039	1,185	1,196	1,294	1,107	1,062	1,299	1,555	1,294	1,565
2021	1,520	1,575	1,422	1,207	1,043	1,195	1,206	1,305	1,117	1,071	1,304	1,562	1,305	1,575
2022	1,524	1,580	1,430	1,215	1,046	1,203	1,214	1,315	1,126	1,077	1,308	1,567	1,315	1,580
2023	1,522	1,580	1,488	1,213	1,062	1,210	1,218	1,316	1,134	1,091	1,378	1,573	1,316	1,580
2024	1,522	1,582	1,491	1,216	1,075	1,215	1,225	1,323	1,141	1,093	1,325	1,574	1,323	1,582
2025	1,533	1,593	1,503	1,229	1,081	1,226	1,237	1,336	1,146	1,102	1,334	1,584	1,336	1,593
2026	1,538	1,601	1,510	1,237	1,085	1,235	1,246	1,348	1,155	1,109	1,338	1,590	1,348	1,601
2027	1,545	1,609	1,458	1,245	1,090	1,244	1,256	1,359	1,165	1,115	1,342	1,596	1,359	1,609
2028	1,546	1,613	1,463	1,250	1,089	1,250	1,264	1,367	1,173	1,119	1,342	1,599	1,367	1,613
2029	1,550	1,617	1,527	1,256	1,113	1,261	1,271	1,372	1,184	1,137	1,363	1,611	1,372	1,617
2030	1,557	1,626	1,536	1,264	1,126	1,270	1,281	1,383	1,194	1,142	1,368	1,618	1,383	1,626
2031	1,564	1,634	1,545	1,272	1,131	1,279	1,291	1,395	1,196	1,149	1,373	1,625	1,395	1,634
2032	1,567	1,639	1,487	1,276	1,129	1,286	1,299	1,403	1,204	1,153	1,375	1,627	1,403	1,639
2033	1,579	1,651	1,500	1,287	1,136	1,297	1,312	1,417	1,216	1,162	1,385	1,639	1,417	1,651
2034	1,579	1,653	1,564	1,294	1,157	1,307	1,317	1,420	1,227	1,179	1,473	1,648	1,420	1,653
2035	1,587	1,663	1,574	1,303	1,166	1,316	1,328	1,433	1,238	1,185	1,410	1,656	1,433	1,663
2036	1,583	1,660	1,631	1,301	1,171	1,321	1,334	1,439	1,236	1,186	1,403	1,653	1,439	1,660
2037	1,602	1,682	1,593	1,318	1,180	1,336	1,350	1,457	1,251	1,199	1,420	1,671	1,457	1,682
2038	1,610	1,692	1,538	1,327	1,186	1,347	1,362	1,471	1,263	1,207	1,428	1,681	1,471	1,692
2039	1,619	1,703	1,550	1,338	1,192	1,357	1,374	1,484	1,277	1,215	1,436	1,690	1,484	1,703

Notes: Load Forecast per J. M. Harris (04/26/10). Demands do not reflect a reduction for PJM marginal losses OR reflect mandated commission approved and incremental DSM programs for APCo, CSP, I&M, KPCo & OPCo.

Appendix F, Figure 3, Internal Demand by Company

OHIO POWER COMPANY
MONTHLY PEAK INTERNAL DEMAND - (MW) W/O EMBEDDED DSM
JANUARY 2010 - DECEMBER 2039

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC		
2010	4,786	4,550	4,375	3,950	4,116	4,709	5,124	5,022	4,656	3,815	4,241	4,332	5,124	4,786
2011	4,825	4,603	4,425	3,996	4,148	4,745	5,161	5,059	4,696	3,841	4,280	4,381	5,161	4,825
2012	4,487	4,268	4,186	3,728	3,901	4,466	4,846	4,744	4,410	3,614	4,076	4,116	4,846	4,487
2013	4,552	4,332	4,254	3,795	3,958	4,528	4,907	4,805	4,470	3,677	3,882	4,174	4,907	4,552
2014	4,588	4,370	4,291	3,835	3,992	4,564	4,942	4,841	4,506	3,709	3,911	4,204	4,942	4,588
2015	4,609	4,395	4,319	3,868	4,019	4,595	4,972	4,871	4,540	3,737	3,938	4,235	4,972	4,609
2016	4,618	4,407	4,289	3,888	4,034	4,609	4,983	4,882	4,553	3,743	4,186	4,237	4,983	4,618
2017	4,641	4,426	4,349	3,891	4,062	4,640	5,011	4,908	4,580	3,785	4,282	4,265	5,011	4,641
2018	4,655	4,443	4,366	3,911	4,080	4,659	5,029	4,926	4,599	3,797	4,270	4,278	5,029	4,655
2019	4,675	4,466	4,389	3,935	4,102	4,685	5,052	4,952	4,624	3,812	4,016	4,295	5,052	4,675
2020	4,676	4,468	4,393	3,949	4,110	4,691	5,057	4,957	4,631	3,814	4,013	4,295	5,057	4,676
2021	4,715	4,511	4,387	3,986	4,141	4,724	5,091	4,989	4,661	3,835	4,287	4,316	5,091	4,715
2022	4,736	4,533	4,410	4,011	4,161	4,747	5,116	5,014	4,684	3,849	4,302	4,335	5,116	4,736
2023	4,750	4,541	4,460	4,004	4,180	4,772	5,140	5,036	4,706	3,883	4,389	4,354	5,140	4,750
2024	4,753	4,541	4,465	4,011	4,187	4,781	5,150	5,048	4,715	3,882	4,083	4,355	5,150	4,753
2025	4,784	4,576	4,496	4,042	4,216	4,814	5,188	5,086	4,747	3,905	4,106	4,384	5,188	4,784
2026	4,806	4,598	4,517	4,064	4,238	4,838	5,217	5,113	4,773	3,918	4,118	4,403	5,217	4,806
2027	4,829	4,621	4,494	4,088	4,260	4,865	5,249	5,143	4,800	3,934	4,394	4,422	5,249	4,829
2028	4,843	4,631	4,509	4,107	4,276	4,884	5,272	5,165	4,821	3,939	4,402	4,436	5,272	4,843
2029	4,871	4,656	4,572	4,111	4,305	4,921	5,310	5,200	4,853	3,984	4,477	4,468	5,310	4,871
2030	4,893	4,678	4,595	4,132	4,327	4,948	5,338	5,231	4,879	3,999	4,206	4,488	5,338	4,893
2031	4,919	4,703	4,621	4,157	4,353	4,977	5,372	5,263	4,908	4,017	4,222	4,510	5,372	4,919
2032	4,928	4,709	4,585	4,170	4,366	4,993	5,393	5,283	4,925	4,020	4,491	4,518	5,393	4,928
2033	4,968	4,753	4,624	4,210	4,402	5,035	5,440	5,328	4,966	4,048	4,523	4,556	5,440	4,968
2034	4,992	4,770	4,682	4,210	4,427	5,068	5,474	5,360	4,996	4,088	4,620	4,582	5,474	4,992
2035	5,020	4,796	4,711	4,236	4,453	5,101	5,510	5,395	5,027	4,106	4,615	4,608	5,510	5,020
2036	5,027	4,801	4,813	4,251	4,472	5,121	5,535	5,420	5,047	4,115	4,321	4,614	5,535	5,027
2037	5,082	4,858	4,773	4,299	4,516	5,171	5,591	5,475	5,097	4,152	4,360	4,663	5,591	5,082
2038	5,122	4,896	4,763	4,336	4,553	5,215	5,642	5,523	5,141	4,188	4,669	4,698	5,642	5,122
2039	5,155	4,931	4,797	4,369	4,585	5,254	5,677	5,564	5,180	4,212	4,697	4,730	5,677	5,155

Notes: Load Forecast per J. M. Harris (04/26/10). Demands do not reflect a reduction for PJM marginal losses OR reflect mandated commission approved and incremental DSM programs for APCo, CSP, I&M, KPCo & OPCo.

AEP SYSTEM - (EAST)
MONTHLY PEAK INTERNAL DEMAND - (MW) W/O EMBEDDED DSM
JANUARY 2010 - DECEMBER 2039

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Summer	Winter
2010	20,159	20,044	17,552	16,199	16,053	18,561	20,383	20,821	18,415	15,664	17,143	18,724	20,821	20,159
2011	20,437	20,367	17,725	16,322	16,167	18,732	20,473	20,930	18,599	15,758	17,258	18,939	20,930	20,437
2012	20,581	20,495	18,870	16,468	16,466	19,014	20,736	21,191	18,843	16,050	17,695	19,168	21,191	20,581
2013	20,845	20,764	19,206	16,753	16,706	19,302	21,025	21,495	19,136	16,286	17,506	19,485	21,495	20,845
2014	20,990	20,916	19,446	16,927	16,821	19,455	21,176	21,663	19,295	16,391	17,685	19,711	21,663	20,990
2015	21,095	21,026	19,655	17,069	16,892	19,564	21,291	21,800	19,421	16,481	17,839	19,930	21,800	21,095
2016	21,118	21,064	18,644	17,117	16,946	19,612	21,341	21,852	19,482	16,497	18,073	19,936	21,852	21,118
2017	21,193	21,134	19,727	17,164	17,164	19,770	21,477	21,984	19,607	16,728	18,683	20,096	21,984	21,193
2018	21,294	21,245	19,835	17,275	17,261	19,886	21,597	22,111	19,735	16,806	18,533	20,189	22,111	21,294
2019	21,403	21,370	19,952	17,391	17,368	20,015	21,729	22,258	19,874	16,894	18,211	20,273	22,258	21,403
2020	21,440	21,403	19,996	17,447	17,418	20,078	21,799	22,338	19,949	16,933	18,239	20,304	22,338	21,440
2021	21,651	21,631	19,168	17,627	17,584	20,259	21,996	22,533	20,126	17,056	18,630	20,434	22,533	21,651
2022	21,769	21,753	19,292	17,739	17,699	20,390	22,151	22,690	20,266	17,140	18,727	20,541	22,690	21,769
2023	21,806	21,771	20,310	17,785	17,891	20,538	22,285	22,819	20,377	17,345	19,323	20,670	22,819	21,806
2024	21,867	21,826	20,378	17,832	17,948	20,637	22,391	22,926	20,478	17,376	18,623	20,707	22,926	21,867
2025	22,062	22,037	20,566	18,006	18,108	20,828	22,613	23,159	20,676	17,514	18,781	20,880	23,159	22,062
2026	22,193	22,181	20,691	18,118	18,229	20,977	22,786	23,337	20,836	17,603	18,882	20,988	23,337	22,193
2027	22,334	22,321	19,807	18,237	18,362	21,131	22,967	23,523	21,000	17,697	19,314	21,103	23,523	22,334
2028	22,423	22,406	19,892	18,304	18,460	21,251	23,113	23,669	21,135	17,764	19,397	21,181	23,669	22,423
2029	22,532	22,509	20,982	18,443	18,693	21,463	23,317	23,868	21,300	18,013	19,816	21,377	23,868	22,532
2030	22,680	22,666	21,129	18,558	18,825	21,630	23,504	24,068	21,470	18,106	19,340	21,506	24,068	22,680
2031	22,844	22,832	21,290	18,690	18,971	21,803	23,705	24,282	21,653	18,194	19,458	21,644	24,282	22,844
2032	22,938	22,926	20,342	18,750	19,075	21,929	23,863	24,442	21,792	18,260	19,937	21,715	24,442	22,938
2033	23,177	23,180	20,564	18,950	19,279	22,169	24,136	24,718	22,038	18,425	20,137	21,933	24,718	23,180
2034	23,267	23,242	21,650	19,096	19,515	22,378	24,335	24,913	22,203	18,662	20,795	22,106	24,913	23,267
2035	23,456	23,439	21,836	19,243	19,680	22,580	24,564	25,156	22,417	18,797	20,705	22,269	25,156	23,456
2036	23,515	23,492	22,106	19,286	19,779	22,716	24,725	25,330	22,558	18,862	20,095	22,322	25,330	23,515
2037	23,834	23,831	22,198	19,526	20,012	22,989	25,036	25,653	22,840	19,066	20,348	22,594	25,653	23,834
2038	24,040	24,037	21,327	19,686	20,206	23,210	25,293	25,918	23,073	19,233	20,960	22,776	25,918	24,040
2039	24,237	24,253	21,520	19,841	20,390	23,425	25,544	26,172	23,298	19,381	21,132	22,956	26,172	24,253

Notes: Load Forecast per J. M. Harris (04/26/10). Demands do not reflect a reduction for PJM marginal losses OR reflect mandated commission approved and incremental DSM programs for APCo, CSP, I&M, KPCo & OPCo.

Appendix F, Figure 4, Internal Energy by Company

APPALACHIAN POWER COMPANY
MONTHLY ENERGY REQUIREMENT - (GWH) W/O EMBEDDED DSM
JANUARY 2010 - DECEMBER 2020

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
2010	3,825	3,239	3,097	2,671	2,629	2,847	3,064	3,100	2,722	2,748	2,974	3,529	36,444
2011	3,851	3,249	3,095	2,652	2,624	2,860	3,078	3,127	2,721	2,735	2,967	3,548	36,508
2012	4,110	3,593	3,326	2,864	2,857	3,088	3,337	3,386	2,937	2,972	3,181	3,767	39,418
2013	4,172	3,527	3,368	2,912	2,898	3,130	3,396	3,431	2,989	3,014	3,217	3,827	39,881
2014	4,218	3,564	3,404	2,933	2,911	3,169	3,434	3,461	3,025	3,031	3,235	3,873	40,259
2015	4,248	3,591	3,433	2,944	2,915	3,202	3,461	3,490	3,045	3,033	3,255	3,906	40,523
2016	4,249	3,717	3,434	2,945	2,935	3,217	3,461	3,522	3,059	3,040	3,284	3,912	40,776
2017	4,300	3,631	3,469	2,970	2,975	3,248	3,496	3,559	3,083	3,081	3,312	3,938	41,062
2018	4,331	3,657	3,490	3,002	3,004	3,269	3,535	3,589	3,104	3,116	3,334	3,965	41,396
2019	4,364	3,685	3,512	3,039	3,033	3,293	3,576	3,613	3,140	3,148	3,354	4,002	41,760
2020	4,382	3,817	3,540	3,058	3,037	3,330	3,599	3,630	3,171	3,162	3,370	4,028	42,126

Notes: Load Forecast per J. M. Harris (04/26/10). Energy does not reflect a reduction for PJM marginal losses OR reflect mandated commission approved and incremental DSM programs for APCo, CSP, I&M, KPCo & OPCo. WPCo load moved from OPCo to APCo 1/2012.

COLUMBUS SOUTHERN POWER COMPANY
MONTHLY ENERGY REQUIREMENT - (GWH) W/O EMBEDDED DSM
JANUARY 2010 - DECEMBER 2020

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
2010	2,027	1,788	1,839	1,618	1,685	1,880	2,081	2,056	1,736	1,692	1,743	1,985	22,130
2011	2,019	1,779	1,838	1,611	1,691	1,883	2,080	2,070	1,744	1,702	1,745	1,986	22,147
2012	2,049	1,863	1,868	1,633	1,719	1,898	2,110	2,092	1,751	1,732	1,747	1,991	22,453
2013	2,081	1,830	1,898	1,666	1,746	1,922	2,149	2,116	1,784	1,760	1,763	2,026	22,739
2014	2,094	1,844	1,918	1,679	1,752	1,941	2,165	2,125	1,802	1,772	1,764	2,046	22,902
2015	2,091	1,847	1,932	1,684	1,752	1,953	2,173	2,134	1,811	1,775	1,775	2,060	22,988
2016	2,086	1,909	1,906	1,681	1,759	1,955	2,162	2,150	1,812	1,773	1,815	2,059	23,068
2017	2,107	1,861	1,924	1,689	1,776	1,967	2,177	2,161	1,818	1,790	1,819	2,064	23,153
2018	2,113	1,869	1,930	1,701	1,784	1,968	2,190	2,168	1,820	1,802	1,819	2,071	23,235
2019	2,120	1,877	1,939	1,715	1,790	1,970	2,205	2,169	1,832	1,809	1,817	2,084	23,329
2020	2,121	1,933	1,956	1,719	1,782	1,983	2,208	2,167	1,840	1,807	1,810	2,091	23,417

Notes: Load Forecast per J. M. Harris (04/26/10). Energy does not reflect a reduction for PJM marginal losses OR reflect mandated commission approved and incremental DSM programs for APCo, CSP, I&M, KPCo & OPCo OR estimated Ohio Choice customer load migration.

INDIANA MICHIGAN POWER COMPANY
MONTHLY ENERGY REQUIREMENT - (GWH) W/O EMBEDDED DSM
JANUARY 2010 - DECEMBER 2020

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
2010	2,244	2,038	2,094	1,897	1,918	2,116	2,314	2,327	2,030	1,973	1,976	2,229	25,157
2011	2,260	2,044	2,104	1,894	1,935	2,125	2,313	2,348	2,038	1,982	1,982	2,226	25,251
2012	2,322	2,166	2,148	1,943	1,999	2,167	2,381	2,407	2,070	2,056	2,023	2,259	25,941
2013	2,363	2,128	2,177	1,988	2,033	2,194	2,432	2,436	2,117	2,092	2,045	2,305	26,308
2014	2,375	2,140	2,192	2,002	2,036	2,216	2,443	2,437	2,141	2,106	2,046	2,326	26,458
2015	2,373	2,147	2,212	2,010	2,033	2,235	2,450	2,446	2,151	2,104	2,062	2,335	26,559
2016	2,364	2,223	2,215	2,001	2,048	2,239	2,430	2,473	2,154	2,096	2,086	2,333	26,663
2017	2,404	2,166	2,236	2,009	2,078	2,256	2,449	2,493	2,162	2,128	2,101	2,333	26,815
2018	2,419	2,179	2,240	2,033	2,094	2,259	2,475	2,507	2,165	2,155	2,111	2,345	26,982
2019	2,435	2,192	2,245	2,058	2,107	2,262	2,501	2,509	2,191	2,170	2,113	2,369	27,153
2020	2,440	2,264	2,266	2,066	2,090	2,292	2,509	2,506	2,211	2,165	2,116	2,386	27,311

Notes: Load Forecast per J. M. Harris (04/26/10). Energy does not reflect a reduction for PJM marginal losses OR reflect mandated commission approved and incremental DSM programs for APCo, CSP, I&M, KPCo & OPCo.

Appendix F, Figure 5, Internal Energy by Company

KENTUCKY POWER COMPANY
MONTHLY ENERGY REQUIREMENT - (GWH) W/O EMBEDDED DSM
JANUARY 2010 - DECEMBER 2020

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
2010	795	690	670	582	572	599	623	657	569	570	636	753	7,715
2011	797	690	668	578	570	601	625	660	568	566	633	752	7,708
2012	800	713	667	577	570	602	628	663	568	566	632	754	7,740
2013	809	698	672	578	570	606	635	669	572	566	634	762	7,771
2014	819	705	678	577	567	609	637	670	572	563	635	771	7,802
2015	828	711	683	574	563	609	638	672	571	558	636	779	7,823
2016	827	733	681	574	565	611	638	675	573	559	640	778	7,854
2017	833	715	686	578	570	615	643	680	577	564	643	782	7,886
2018	837	718	688	582	574	618	647	683	580	568	645	785	7,926
2019	840	721	692	587	578	622	653	687	585	573	648	788	7,974
2020	840	743	695	589	580	626	655	689	588	574	649	790	8,019

Notes: Load Forecast per J. M. Harris (04/26/10). Energy does not reflect a reduction for PJM marginal losses OR reflect mandated commission approved and incremental DSM programs for APCo, CSP, I&M, KPCo & OPCo.

OHIO POWER COMPANY
MONTHLY ENERGY REQUIREMENT - (GWH) W/O EMBEDDED DSM
JANUARY 2010 - DECEMBER 2020

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
2010	2,798	2,513	2,631	2,327	2,341	2,513	2,722	2,747	2,411	2,364	2,450	2,691	30,508
2011	2,837	2,538	2,664	2,335	2,375	2,533	2,727	2,784	2,428	2,388	2,471	2,704	30,785
2012	2,650	2,441	2,470	2,175	2,229	2,351	2,567	2,601	2,241	2,256	2,281	2,496	28,758
2013	2,687	2,387	2,496	2,222	2,259	2,371	2,616	2,620	2,286	2,290	2,293	2,539	29,066
2014	2,702	2,404	2,522	2,242	2,263	2,405	2,636	2,624	2,321	2,306	2,292	2,568	29,286
2015	2,698	2,415	2,554	2,256	2,262	2,435	2,649	2,642	2,338	2,308	2,316	2,585	29,457
2016	2,687	2,504	2,545	2,245	2,285	2,442	2,624	2,680	2,341	2,299	2,363	2,577	29,592
2017	2,728	2,433	2,564	2,247	2,315	2,455	2,641	2,696	2,338	2,330	2,369	2,566	29,682
2018	2,738	2,440	2,560	2,269	2,325	2,447	2,665	2,702	2,333	2,353	2,367	2,574	29,772
2019	2,749	2,450	2,561	2,294	2,331	2,446	2,693	2,697	2,357	2,363	2,356	2,597	29,895
2020	2,745	2,522	2,589	2,297	2,302	2,478	2,693	2,685	2,377	2,347	2,348	2,612	29,996

Notes: Load Forecast per J. M. Harris (04/26/10). Energy does not reflect a reduction for PJM marginal losses OR reflect mandated commission approved and incremental DSM programs for APCo, CSP, I&M, KPCo & OPCo OR estimated Ohio Choice customer load migration.
WPCo load moved from OPCo to APCo 1/2012.

AEP SYSTEM - (EAST)
MONTHLY ENERGY REQUIREMENT - (GWH) W/O EMBEDDED DSM
JANUARY 2010 - DECEMBER 2020

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
2010	11,689	10,268	10,331	9,096	9,144	9,956	10,803	10,887	9,468	9,347	9,779	11,187	121,954
2011	11,763	10,300	10,369	9,069	9,196	10,003	10,823	10,990	9,499	9,372	9,799	11,217	122,399
2012	11,931	10,776	10,479	9,191	9,373	10,106	11,024	11,149	9,568	9,582	9,864	11,267	124,310
2013	12,112	10,570	10,611	9,366	9,505	10,222	11,228	11,272	9,747	9,723	9,951	11,459	125,765
2014	12,208	10,657	10,713	9,433	9,528	10,340	11,315	11,317	9,862	9,778	9,971	11,585	126,706
2015	12,237	10,711	10,814	9,469	9,525	10,436	11,371	11,384	9,917	9,778	10,044	11,664	127,349
2016	12,214	11,086	10,782	9,446	9,592	10,465	11,314	11,499	9,938	9,767	10,188	11,659	127,949
2017	12,372	10,807	10,878	9,492	9,716	10,541	11,406	11,589	9,976	9,893	10,244	11,682	128,595
2018	12,438	10,862	10,908	9,587	9,780	10,561	11,512	11,648	10,002	9,993	10,276	11,739	129,305
2019	12,507	10,925	10,949	9,693	9,840	10,592	11,627	11,676	10,105	10,063	10,288	11,839	130,104
2020	12,526	11,280	11,046	9,728	9,792	10,708	11,663	11,678	10,188	10,054	10,292	11,907	130,863

Notes: Load Forecast per J. M. Harris (04/26/10). Energy does not reflect a reduction for PJM marginal losses OR reflect mandated commission approved and incremental DSM programs for APCo, CSP, I&M, KPCo & OPCo OR estimated Ohio Choice customer load migration.
WPCo load moved from OPCo to APCo 1/2012.

Appendix G, Figure 1, DSM by Company

APCo (Includes Wheeling and Kingsport)

Energy Efficiency				
	Installed		Net	
	GWh	MW	GWh	MW
2010	0	0	0	0
2011	193	27	193	27
2012	293	40	293	40
2013	395	55	395	55
2014	498	76	498	76
2015	603	80	603	80
2016	604	80	604	80
2017	605	79	605	79
2018	606	79	606	79
2019	606	79	606	79
2020	606	78	606	78

IVVC				
	Installed		Net	
	GWh	MW	GWh	MW
2010	0	0	0	0
2011	0	0	0	0
2012	0	0	0	0
2013	0	0	0	0
2014	67	6	67	6
2015	116	25	116	25
2016	142	30	142	30
2017	167	36	167	36
2018	193	41	193	41
2019	193	41	193	41
2020	193	41	193	41

Demand Response				
	Installed		Net	
	GWh	MW	GWh	MW
2010	0	0	0	0
2011	0	31	0	31
2012	0	61	0	61
2013	0	107	0	107
2014	0	153	0	153
2015	0	184	0	184
2016	0	184	0	184
2017	0	184	0	184
2018	0	184	0	184
2019	0	184	0	184
2020	0	184	0	184

Total Incremental DSM				
	Installed		Net	
	GWh	MW	GWh	MW
2010	0	0	0	0
2011	193	57	193	57
2012	293	101	293	101
2013	395	162	395	162
2014	565	236	565	236
2015	719	289	719	289
2016	746	294	746	294
2017	772	298	772	298
2018	799	303	799	303
2019	799	304	799	304
2020	799	303	799	303

Ohio Power

Energy Efficiency				
	Installed		Net	
	GWh	MW	GWh	MW
2010	92	16	46	8
2011	270	47	181	30
2012	500	88	370	61
2013	765	134	572	95
2014	1,070	188	782	129
2015	1,382	243	980	162
2016	1,682	295	1,139	188
2017	1,985	348	1,259	208
2018	2,289	402	1,351	223
2019	2,901	509	1,572	260
2020	3,480	609	1,876	309

IVVC				
	Installed		Net	
	GWh	MW	GWh	MW
2010	0	0	0	0
2011	0	0	0	0
2012	0	0	0	0
2013	0	0	0	0
2014	15	3	15	3
2015	28	5	28	5
2016	39	7	39	7
2017	50	9	50	9
2018	60	11	60	11
2019	60	11	60	11
2020	60	11	60	11

Demand Response				
	Installed		Net	
	GWh	MW	GWh	MW
2010	0	0	0	0
2011	0	24	0	24
2012	0	48	0	48
2013	0	83	0	83
2014	0	119	0	119
2015	0	143	0	143
2016	0	143	0	143
2017	0	143	0	143
2018	0	143	0	143
2019	0	143	0	143
2020	0	143	0	143

Total Incremental DSM				
	Installed		Net	
	GWh	MW	GWh	MW
2010	92	16	46	8
2011	270	71	181	54
2012	500	135	370	109
2013	765	218	572	178
2014	1,085	310	797	251
2015	1,410	391	1,008	310
2016	1,721	445	1,178	338
2017	2,034	500	1,309	360
2018	2,349	556	1,412	378
2019	2,961	663	1,632	414
2020	3,540	763	1,936	464

Columbus Southern Power

Energy Efficiency				
	Installed		Net	
	GWh	MW	GWh	MW
2010	73	14	37	7
2011	217	42	145	27
2012	405	79	299	55
2013	622	122	465	86
2014	873	171	638	118
2015	1,130	221	802	148
2016	1,379	269	935	172
2017	1,632	319	1,037	192
2018	1,887	370	1,117	206
2019	2,403	471	1,305	241
2020	2,892	566	1,567	289

IVVC				
	Installed		Net	
	GWh	MW	GWh	MW
2010	0	0	0	0
2011	0	0	0	0
2012	0	0	0	0
2013	0	0	0	0
2014	31	6	31	6
2015	66	14	66	14
2016	100	21	100	21
2017	135	28	135	28
2018	170	35	170	35
2019	170	35	170	35
2020	170	35	170	35

Demand Response				
	Installed		Net	
	GWh	MW	GWh	MW
2010	0	0	0	0
2011	0	21	0	21
2012	0	43	0	43
2013	0	75	0	75
2014	0	107	0	107
2015	0	128	0	128
2016	0	128	0	128
2017	0	128	0	128
2018	0	128	0	128
2019	0	128	0	128
2020	0	128	0	128

Total Incremental DSM				
	Installed		Net	
	GWh	MW	GWh	MW
2010	73	14	37	7
2011	217	64	145	48
2012	405	122	299	98
2013	622	196	465	161
2014	904	284	669	231
2015	1,196	363	868	290
2016	1,480	418	1,035	321
2017	1,767	475	1,172	347
2018	2,057	533	1,287	370
2019	2,572	634	1,475	405
2020	3,062	729	1,736	452

Appendix G, Figure 2, DSM by Company

Kentucky Power

Energy Efficiency	Installed GWh	Installed MW	Net GWh	Net MW
2010	2	0	1	0
2011	47	7	43	6
2012	73	10	66	10
2013	99	14	90	13
2014	126	17	114	17
2015	154	20	138	20
2016	157	20	139	20
2017	159	20	139	20
2018	161	20	139	20
2019	163	20	140	20
2020	165	20	140	20

IVVC	Installed GWh	Installed MW	Net GWh	Net MW
2010	0	0	0	0
2011	0	0	0	0
2012	0	0	0	0
2013	0	0	0	0
2014	18	4	18	4
2015	30	6	30	6
2016	34	7	34	7
2017	39	8	39	8
2018	44	9	44	9
2019	44	9	44	9
2020	44	9	44	9

Demand Response	Installed GWh	Installed MW	Net GWh	Net MW
2010	0	0	0	0
2011	0	6	0	6
2012	0	12	0	12
2013	0	22	0	22
2014	0	31	0	31
2015	0	37	0	37
2016	0	37	0	37
2017	0	37	0	37
2018	0	37	0	37
2019	0	37	0	37
2020	0	37	0	37

Total Incremental DSM	Installed GWh	Installed MW	Net GWh	Net MW
2010	2	0	1	0
2011	47	13	43	13
2012	73	22	66	22
2013	99	35	90	35
2014	144	52	132	52
2015	184	64	168	64
2016	191	65	173	65
2017	198	66	178	66
2018	205	67	183	67
2019	207	67	183	67
2020	209	67	183	67

Indiana Michigan

Energy Efficiency	Installed GWh	Installed MW	Net GWh	Net MW
2010	66	8	8	2
2011	173	26	120	17
2012	321	49	238	34
2013	505	79	375	55
2014	725	111	528	75
2015	980	143	692	94
2016	1,269	180	860	113
2017	1,590	221	1,029	133
2018	1,943	266	1,194	151
2019	2,310	313	1,344	168
2020	2,344	319	1,414	176

IVVC	Installed GWh	Installed MW	Net GWh	Net MW
2010	0	0	0	0
2011	0	0	0	0
2012	0	0	0	0
2013	0	0	0	0
2014	5	1	5	1
2015	13	3	13	3
2016	23	4	23	4
2017	32	6	32	6
2018	42	8	42	8
2019	42	8	42	8
2020	42	8	42	8

Demand Response	Installed GWh	Installed MW	Net GWh	Net MW
2010	0	0	0	0
2011	0	18	0	18
2012	0	36	0	36
2013	0	63	0	63
2014	0	90	0	90
2015	0	109	0	109
2016	0	109	0	109
2017	0	109	0	109
2018	0	109	0	109
2019	0	109	0	109
2020	0	109	0	109

Total Incremental DSM	Installed GWh	Installed MW	Net GWh	Net MW
2010	66	8	8	2
2011	173	44	120	35
2012	321	86	238	70
2013	505	143	375	118
2014	730	202	533	167
2015	993	255	705	205
2016	1,292	293	883	226
2017	1,623	336	1,061	247
2018	1,985	383	1,236	268
2019	2,352	430	1,386	285
2020	2,386	435	1,456	293

AEP East

Energy Efficiency	Installed GWh	Installed MW	Net GWh	Net MW
2010	233	38	91	16
2011	900	149	683	107
2012	1,592	266	1,266	200
2013	2,385	404	1,897	304
2014	3,294	563	2,560	416
2015	4,249	708	3,215	505
2016	5,091	844	3,676	573
2017	5,971	988	4,069	631
2018	6,887	1,136	4,408	680
2019	8,383	1,392	4,967	768
2020	9,487	1,593	5,602	873

IVVC	Installed GWh	Installed MW	Net GWh	Net MW
2010	0	0	0	0
2011	0	0	0	0
2012	0	0	0	0
2013	0	0	0	0
2014	136	20	136	20
2015	253	53	253	53
2016	338	70	338	70
2017	423	88	423	88
2018	509	105	509	105
2019	509	106	509	106
2020	509	105	509	105

Demand Response	Installed GWh	Installed MW	Net GWh	Net MW
2010	0	0	0	0
2011	0	100	0	100
2012	0	200	0	200
2013	0	350	0	350
2014	0	500	0	500
2015	0	600	0	600
2016	0	600	0	600
2017	0	600	0	600
2018	0	600	0	600
2019	0	600	0	600
2020	0	600	0	600

Total Incremental DSM	Installed GWh	Installed MW	Net GWh	Net MW
2010	233	38	91	16
2011	900	249	683	207
2012	1,592	466	1,266	400
2013	2,385	754	1,897	654
2014	3,429	1,084	2,696	936
2015	4,502	1,361	3,468	1,158
2016	5,429	1,514	4,015	1,244
2017	6,394	1,676	4,493	1,319
2018	7,395	1,842	4,917	1,385
2019	8,891	2,098	5,475	1,474
2020	9,996	2,298	6,111	1,578

Appendix H, Ohio Choice by Company

Columbus Southern Power

Ohio Customer Choice		
	GWh	SUMMER Peak MW
2010	0	0
2011	139	28
2012	326	55
2013	454	76
2014	582	98
2015	780	132
2016	1,037	172
2017	1,293	214
2018	1,550	255
2019	1,806	298
2020	2,062	341

Ohio Power

Ohio Customer Choice		
	GWh	SUMMER Peak MW
2010	0	
2011	25	4
2012	71	12
2013	118	19
2014	164	26
2015	260	42
2016	374	61
2017	467	75
2018	559	90
2019	652	104
2020	745	119

AEP-East

Ohio Customer Choice		
	GWh	SUMMER Peak MW
2010	0	0
2011	164	32
2012	397	67
2013	572	95
2014	746	124
2015	1,041	176
2016	1,411	232
2017	1,760	291
2018	2,109	347
2019	2,458	405
2020	2,807	460

Appendix I, Renewable Energy Technology Screening

Levelized Cost of Renewables versus Avoided Production Cost

Type	Energy Source	$/MWh
Landfill Gas3.20925Combustion Turbine	Gas	-52.68
Incremental Hydro	Hydro	-37.95
New 24 MW Hydro	Hydro	-10.56
Anaerobic Digester0.173270566491537Int. Comb. Engine	Gas	-4.74
Anaerobic DigesterDairy CowInt. Comb. Engine	Anaerobic Digester	-4.74
100 MW Wind Farm 1 SPP PTC	SPP PTC	44.29
100 MW Wind Farm 2, PJM PTC	PJM PTC	45.93
Geothermal	Geothermal	69.70
100 MW Wind Farm SPP, no PTC	SPP no PTC	71.38
100 MW Wind Farm PJM, no PTC	PJM no PTC	73.13
New 2 MW Hydro	Hydro	102.56
McKinsey 2020 Solar - West (nth of a kind)	Solar	152.51
McKinsey 2020 Solar - East (nth of a kind)	Solar	203.34
Solar Installation 10 MW fixed Tilt thin film a-Si	Solar	226.85
SoCalEd 1 MW rooftop	Solar	233.36
SoCalEd 2 MW rooftop	Solar	317.88

Appendix J, Capacity Additions by Company

Period	Summer*	Winter	AEP CC	AEP CT*	AEP D CC2	AEP Solar	AEP Wind**	APCo CC	APCo CT*	APCo D CC2	APCo Solar	APCo Wind**	CSP CC	CSP CT*	CSP D CC2	CSP Solar	CSP Wind**	I&M CC	I&M CT*	I&M D CC2	I&M Solar	I&M Wind**	KPCo CC	KPCo CT*	KPCo D CC2	KPCo Solar	KPCo Wind**	OPCo CC	OPCo CT*	OPCo D CC2	OPCo Solar	OPCo Wind**
10-Year IRP Period	2010	2010/11				296	2.01					2.01				119															178	
	2011	2011/12				150	2.00									75	1.00														75	1.00
	2012	2012/13				150	2.00									60	0.50					1.00									90	0.50
	2013	2013/14			1	380	6.00			1						152	0.50					3.00					2.00				228	0.50
	2014	2014/15				380	8.00									152	0.80					6.00									228	1.20
	2015	2015/16				380	5.00									152	1.67														228	3.33
	2016	2016/17				380	3.00									152	1.00														228	2.00
	2017	2017/18		4		380	1.00		4							171															209	1.00
	2018	2018/19		4		380	2.00		2							171	1.00							2							209	1.00
	2019	2019/20				380	3.00									171	1.50														209	1.50
	2020	2020/21				450	2.00									270						1.00					1.00				180	
Extended Planning Period	2021	2021/22		4		650	2.00		2			0.67				163	1.33							2							488	
	2022	2022/23					4.00										2.00															2.00
	2023	2023/24	1			650	3.00	1								325	1.00					1.00									325	1.00
	2024	2024/25					3.00										1.00					1.00										1.00
	2025	2025/26				272	3.00									136	1.00					1.00									136	1.00
	2026	2026/27	1				3.00	1									1.00										1.00					1.00
	2027	2027/28				363	2.00									181	1.00														181	1.00
	2028	2028/29																														
	2029	2029/30				453										227															227	
	2030	2030/31		4					4																							

Capacity (MW/Unit)	CC	CT	D CC2	Solar	Wind**
Summer	611	79	540	0.069	50
Winter	669	86	625	0.069	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

Appendix K, Load Forecast Modeling

Process Summary

AEP utilizes a collaborative process to develop load forecasts. Customer representatives and other operating company personnel routinely provide input on customers (larger customers in particular) and economic conditions. Taking this input into account, the AEP Economic Forecasting group analyzes data, develops and utilizes economic and load forecast data and models, and computes load forecasts. Economic Forecasting and operating company management team members review and discuss the analytical results. The groups work together to obtain the final forecast results. Forecast updates are considered at least two times a year (or more often if deemed necessary).

Exhibit A-8

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

The electric energy and demand forecast modeling process is the accumulation of three specific forecast model processes as reflected in ***Exhibit A-8.*** The first process models the consumption of electricity at the aggregated customer premise level. These aggregated levels are the FERC revenue classifications of residential, commercial, industrial, other, 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 FERC revenue classes of residential, commercial, industrial, other and municipal and cooperatives are analyzed and forecasted separately. This categorization of customers’ premise meter readings allows for customers with like electrical consumption characteristics and behaviors to be modeled together. Similarly, utilizing separate short and long-term sales forecast models capitalizes on the strengths of each methodology.

Energy Sales Modeling

The short-term forecasts are developed utilizing autoregressive integrated moving average (ARIMA) models that incorporate weather and binary variables. Heating and cooling degree-days are the weather variables included in the model development. The short-term forecast period extends for up to 18 months on a monthly basis. These models are utilized to forecast all FERC classes and a number of large individual customers.

The long-term forecasts are developed utilizing a combination of econometric and Statistically Adjusted End-Use (SAE) models. The SAE models were developed by Itron Inc. Energy Forecasting unit. The process starts with an economic forecast provided by Moody's Economy.com for the United States as a whole, each state, and regions within each state. These forecasts include forecasts of employment, population, and other demographic and financial variables. The long-term forecast incorporates the economic forecast and other inputs to produce a forecast of kWh sales. Other inputs include regional and national economic and demographic conditions, energy prices, weather data, and customer-specific information.

AEP uses processes that take advantage of the relative strengths of each method. The regression models with time series error terms use the latest available sales and weather information to represent the variation in sales on a monthly basis for short-term applications. While these models provide advantages in the short run, without specific ties to economic factors, they are limited in capturing the structural trends in the electricity consumption that are important for the longer term planning. The long-term process, with its explicit ties to economic and demographic factors, tends to be structured for longer-term decisions.

Residential Sales

For the residential sector, the number of residential customers and usage per customer are modeled separately, and combined to forecast residential energy sales. Residential customers were modeled as a function of mortgage rates, service area employment, and lagged residential customers. Average residential usage is modeled using the SAE model. SAE models are econometric models with features of end-use models included to specifically account for energy efficiency impacts, such as those included in the Energy Policy Act of 2005. 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. The statistical part of the SAE model is the regression 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 the estimation. The forecast of residential energy sales is the product of residential customers and residential usage.

Commercial Sales

The commercial energy sales model is also an SAE model. In the commercial class, total energy sales are modeled. The primary economic drivers are service area commercial output (GDP), commercial electricity price, state commercial natural gas price and heating and cooling degree-days.

Industrial Sales

The industrial energy sales are forecast in total for the class. Where applicable, the mine power sectors sales are separated before modeling. For the total or total less mine power, energy sales are a function of selected Federal Reserve Board industrial production indexes, regional employment; and electricity and natural gas prices. Where relevant, the mine power energy sales are modeled as a function of state coal production, regional mining employment and mine power electricity price. Customer-specific information such as expansions, contractions and additions and informed judgment are all utilized in producing the forecasts.

Other Sales

Other ultimate sales are generally comprised of public street and highway lighting, municipal pumping, and other sales to public authorities sectors. The public street and highway lighting energy sales are modeled as a function of service area employment. The other sales to public authorities are related to service area employment and heating and cooling degree-days. The other sales forecast is the sum of these forecasts.

Municipal and Cooperatives

The municipal and cooperatives included in internal load are sales to cooperatives, municipals, private systems and state agencies. These are forecast by individual customer and generally are a function of service area employment and heating and cooling degree days.

Blending Short and Long-Term Sales

Forecast values for 2010 are taken from the short-term process. Forecast values for 2011 are obtained by blending the results from the short-term and long-term models. The blending process combines the results of the short-term and long-term models by assigning weights to each result and systematically changing the weights so that by the end of 2011 the entire forecast is from the long-term models. This blending allows for a smooth transition between the two separate processes, minimizing the impact of any differences in the results.

Energy Losses

Energy is lost in the transmission and distribution of the product. This loss of energy from the source of production to consumption at the premise is measured as the average ratio of all FERC revenue class energy sales measured at the premise meter to the net internal energy requirements metered at the source. In modeling, company loss study results are incorporated to apply losses to each revenue class.

Net Internal Energy Requirements

Net internal energy requirement is the sum of the FERC revenue class sales resulting from the blending process and energy losses.

Demand Forecast Model

The demand forecast model is a series of algorithms for allocating the monthly blended FERC revenue class sales to hourly demand. The inputs into forecasting hourly demand are blended FERC revenue class sales, energy loss multipliers, weather, 24-hour load profiles and calendar information.

The weather profiles are developed from representative weather stations in the service area. Twelve monthly profiles of average daily temperature that best represent the cooling and heating degree-days of the specific geography are taken from the last 30 years of historical values. The consistency of these profiles ensures the appropriate diversity of the company loads.

The 24-hour load profiles are developed from historical hourly company or jurisdictional load and end-use or revenue class hourly load profiles. The load profiles were developed from segregating, indexing and averaging hourly profiles by season, day types (weekend, midweek and Monday/Friday) and average daily temperature ranges. The end-use and class profiles were obtained from Iron, Inc. Energy Forecasting load shape library and modeled to represent each company or jurisdiction service area.

In forecasting, the weather profiles and calendars dictate which profile to apply and the sales plus losses results dictate the volume of energy under the profile. In the end, the profiles are benchmarked to the aggregate energy and seasonal peaks through the adjustments to the hourly load duration curves of the annual 8760 hourly values. These 8760 hourly values per year are the forecast load of the individual companies of AEP that can be aggregated by hour to represent load across the spectrum from end-use or revenue classes to total AEP-PJM, AEP-SPP or total AEP system. Net internal energy requirements are the sum of these hourly values to a total company energy need basis. Company peak demand is the maximum of the hourly values from a stated period (month, season or year).

Appendix L, Capacity Resource Modeling (Strategist) and Levelized Busbar Costs

The overriding objective of the modeling effort was to recommend an optimum system expansion plan, not only from a least-cost perspective but also from the perspectives of risk profile, achievability, and affordability. The analytical model served as the foundation from which all of the perspectives were examined and recommendations made. The process will be continually refined as experience is gained to take into account emerging issues identified by supporting work groups and management.

The Strategist Model

The *Strategist* resource-planning model, developed by *Ventyx*, allows a user to determine the least-cost resource mix for its system (in this case, AEP's East and West zones) from a user-defined set of resource technologies, under prescribed sets of constraints and assumptions. *Strategist* defines the "least-cost resource mix" as the combination of resource additions that ***produces the lowest overall system pre-tax cost (revenue requirement) inclusive of:***

- New resource capital carrying cost and fixed O&M
- Environmental retrofits
  - New-build capacity
  - Capacity (market) purchase costs
  - Total system-wide fuel costs (new-build and existing capacity)
  - Cost of system-wide (replacement) emission allowances (SO_2, NO_x, CO_2)
  - Net (market) "system transaction" cost or revenue (i.e. third-party energy purchases and/or sales).

Strategist allows all aspects of an integrated resource planning study to be considered with the depth and accuracy required for informed decision-making. Hourly chronological load patterns are recognized, detailed production costing logic is utilized, and the system employs a dynamic programming algorithm to develop the "optimal" and large suites of "sub-optimal" portfolios of capacity addition alternatives over a user-defined study period.

Strategist uses several modules (LFA, GAF, PROVIEW) that work in unison to simulate the operation of the generating system, including new resource additions that may be needed to meet future demand growth. These modules calculate the costs of serving a utility system's capacity and energy needs over the defined study period. The Load Forecast Adjustment module (LFA) is used to represent the utility's hourly demand and energy forecast. The Generation and Fuel module (GAF) works with the LFA to simulate the operation of a utility's generating units and any interaction with external markets. The PROVIEW module pulls information from the LFA and GAF modules as well as other generation alternative data to determine the least-cost resource plan for the utility system under prescribed sets of constraints and assumptions.

Strategist develops an initial "macro" (zone-specific) least-cost resource mix for a system by incorporating a wide variety of expansion planning assumptions including:

- Characteristics (e.g. capital cost, construction period, operating life) of resource addition alternatives that are available to meet future capacity needs

- Operating parameters (e.g. capacity ratings, heat rates, forced outage rates, etc) of existing and new units
- Fuel prices
- Prices of external market energy, capacity, and emission allowances
- Reliability constraints (e.g. minimum reserve margin targets, loss of load hours, unserved energy)
- Emission limits and environmental compliance options

All of these assumptions, and others, are considered in order to develop an integrated plan that best suits the utility system being analyzed.

To reiterate, *Strategist* does not develop a full "cost of service" (COS) profile. It considers only costs that change from plan to plan, not costs that are fixed, such as embedded costs of existing generating capacity or distribution costs. Transmission costs are included only to the extent that they are associated with new generating capacity. Specifically, *Strategist* includes and ultimately recognizes in its "incremental revenue requirement" output profile:

- Fixed costs of capacity additions, i.e. carrying charges on capacity and associated transmission based on a weighted average cost of capital (WACC) and fixed O&M
- Fixed costs of any capacity purchases
- Variable costs of the entire fleet of existing and any added units. This includes fuel, purchased energy, the market replacement cost of emission allowances (SO_2 and NO_X, and CO_2 in appropriate cases), and variable O&M costs. In addition, revenue from external energy transactions (Off-System Sales) is netted against these costs

Due to the netting of Off-System Sales revenues against variable costs, depending on the market spreads for energy, *Strategist* outcomes can represent relative "longer" or "shorter" market energy positions that can have significant bearing on the resulting net system cost and determination of a least-cost plan.

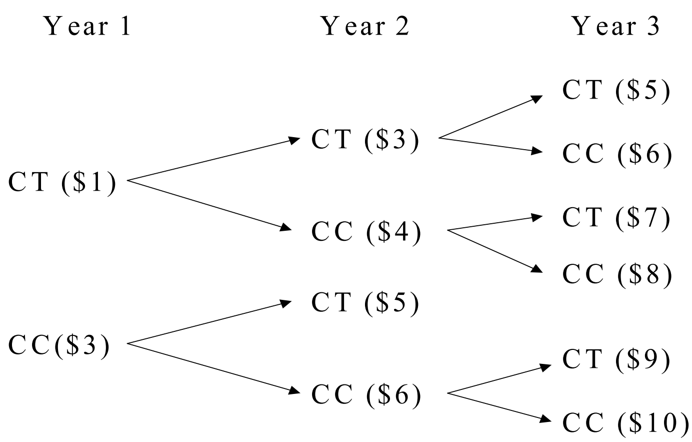
In summary, *Strategist* models the approach AEP uses to determine jurisdictional generation revenue requirements at an integrated, system level. For the purpose of comparing plans, these costs are expressed on a Cumulative Present Worth (CPW) basis for each plan, using standard calculation methods and a 9.0% WACC.

Overview of Need for Modeling Constraints

In the PROVIEW module of *Strategist*, the least-cost expansion plan is empirically formulated from *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 its least-cost objective function through user-defined constraints (in this case, a "minimum" on-going capacity reserve margin) 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 as well as the number of feasible states increases approximately exponentially with the number of resource alternatives being considered.

Exhibit A-9 offers a very simplistic example of this algorithm. The model has the choice of two capacity types (CT and CC) and must achieve its reserve requirement constraint through some economic combination of the capacity types over a three- year period. **Six** unique plans result after the elimination of one of the more expensive paths.

Exhibit A-9 Strategist chronological "dynamic programming" algorithm



* Note: Path "CC (Yr.1)" - CT (Yr.2)" eliminated from further consideration in Yr.3 because its cumulative cost ($5) is greater than a similar path - "CT (Yr. 1) - CC (Yr. 2)" costing $4

As can be seen in this example, the potential for creating hundreds of thousands of alternative combinations and feasible states 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 the model is attempting to solve. Several of these variables focus on limiting the number of a particular resource alternative that can be considered by the model during the Planning Period. In addition, other variables limit the years that a particular alternative is available for selection by the model.

Appendix M, Utility Risk Simulation Analysis (URSA) Modeling

The risk analysis of the five alternative IRP plans was done with the "Utility Risk Simulation Analysis" model (URSA), which was developed by AEP's Risk Management group. URSA was designed not only to estimate the risk in IRP plans but also to quantify one-year-ahead Earnings at Risk and for a variety of other risk-analytic purposes.

URSA is a Monte Carlo simulation model that represents the daily operation of AEP's assets under a large number of possible alternative futures. As noted above, for the IRP risk analysis, 1,399 alternative futures, each with its own, unique set of daily realizations of risk factors, were treated.

URSA is similar to a physical planning model such as Power Cost Inc.'s Gentrader, but it implements some computational economies to permit consideration of so many alternative futures. Notably, URSA treats only the peak and off peak periods of each day, not each hour. On the other hand, URSA does not reckon with "typical weeks" as many other structural models do, but rather treats explicitly each day of each alternative future. The aim of this approach is to produce a realistic depiction of unit commitment and dispatch.

1. Risk Factor Simulation

The risk analysis begins with a simulation of the daily values of the risk factors for each day of the period 2009-2020, for 1,399 alternative possible futures.

The price and load risk factors vary from day to day within each possible future in accordance with the outcomes of an analysis of the historical variations in these factors, including serial- and cross-correlation, and their relationship to the weather. The raw results obtained from the risk factor model are scaled to ensure that in each simulated year and month, the monthly means of the simulated risk factors agree with the economic forecast of these prices and loads, upon which the IRP is based.

The unit-specific outages also vary from day to day, but independently of the price and load risk factors. Unit outages are determined by a simple, binomial model that depends on the assumed rate of availability for the given unit and an assumed number of days out in case of forced outage. Simulated over many cases, the binomial model produces, for the given unit, an average rate of availability equal to the assumed rate.

2. Utility Operations in View of Given Risk Factors

On each day such day, the risk factors take on given values; AEP and its counterparties then act optimally to exercise any optionality that they may have; physical and financial results of these actions are then calculated and recorded; and the simulation proceeds to the next day.

The optionality in AEP's asset portfolio includes:

- to commit or not to commit any given thermal generating unit to the grid,
- to exercise or not to exercise any power purchase or sale options that it may own,
- how much power to produce from each committed thermal unit,
- how much water to run down, or pump up, at the Smith Mountain Hydro Pumped Storage facility,
- whether and in which direction to transmit power along the AEP West tie.

Under PJM commercial relations, much of this optionality is, in fact, exercised by PJM on AEP's behalf, based on structured commercial bids submitted to PJM by AEP. But it is assumed that the result of the bidding process and PJM's consequent decision-making is the same as if AEP were making these decisions optimally on its own behalf.

3. Representation of the Utility

a. Businesses

The URSA model divides AEP into three businesses:

- retail power supply,
- wholesale power supply and
- fuel supply,

each with its own set of activities and financial results. This division is a schematic one and does not correspond precisely to actual business divisions of AEP. Since, as explained below, fuel and allowance contracts are not treated in the IRP, the fuel supply business's role in the IRP simulations is merely to buy fuel and allowances at market and transfer them to the units. This always results in zero net revenues for the fuel supply business.

The total required revenues of the three businesses are the required revenues of AEP as a whole. Typically the activities of the wholesale business diminish, or make a negative contribution to, required revenue. Those of the retail business, which is responsible of the costs of supplying the native load, typically make a positive contribution to net revenue. The contribution of the fuel supply business is zero, since any fuel or allowances purchased at spot are immediately transferred at the same price.

The model does not treat AEP's transmission or distribution activities, or the corresponding revenues and expenditures. These are assumed to be the same for each IRP case considered.

In any case, the IRP risk analysis, in contrast to some other risk analyses to which this same model is applied, has little to do with these schematic divisions of AEP. Therefore, while the model produces business-specific results, IRP risk results are reported for AEP in total and not by business.

b. Assets

As reckoned with in this study, AEP's East assets consist of:

- thermal (steam and combustion) generating units,
- Smith Mountain pumped storage facility, and
- power purchase and sales contracts.

For analytical convenience, the model treats AEP's hydro generation, other than hydro pumped storage, as a power purchase contract with quantities supplied on a fixed schedule. For the purposes of the study, the returns to AEP's fuel purchase contracts, which typically expire within the next few years, are not treated. Instead, fuel expenditures are reckoned as if all fuel were purchased at spot. Also, returns to AEP's endowment of emissions allowances are not treated; here as with fuel, AEP's expenditures are reckoned at the simulated spot price.

c. Power Supply Obligations

The two power supply businesses are responsible for different sets of power sales contracts. For the East, the sales contracts of the retail power supply business are:

- AEP East load served on a tariff basis
- Buckeye Power
- the 250 MW tie to AEP West, which is modeled as a call option owned by the West

Those of the East wholesale power supply business are:

- certain municipals served on a full requirements basis and connected to the AEP grid,

Total power delivery obligations under all power sales contracts constitute the total load of the utility.

d. Power Supply Resources

To satisfy these obligations, the two power supply businesses jointly operate a given set of power generating units and manage a given set of power purchase contracts. The generating units are:

- the AEP East fleet of steam and combustion generating units and
- the Smith Mountain pumped storage facility.

The power purchase contracts are:

- the AEP East hydro units (which are modeled as a power purchase contract),
- both East, some capacity purchases during early future years,
- a set of power purchase contracts with OVEC, and
- some small sources of supply such as Summersville.

The capacity purchases contribute to the satisfaction of the operating reserve requirement for AEP East in total. But any energy that would flow from these suppliers is treated as a spot power purchase, not a contractual one.

The retail power supply business, as modeled, has the first call on all power supply resources, and takes the most economical opportunities. In each period, it specifies the energy that it takes from each generating unit and power purchase contract so as to satisfy exactly its total obligations under its power sales contracts while minimizing the cost of doing so. The retail business does not normally engage in spot power sales, but it will purchase spot power whenever doing so would reduce cost.

The wholesale power supply business, as modeled, has the second call on all power supply resources, taking energy from generating units and from power supply contracts only to the extent that anything is left by the retail business. It does this so as to maximize total net revenues from sales (which effectively minimizes AEP's required revenue). It engages freely in spot power sales.

e. Spot Power Supply

The difference between the total power generated or taken under purchase contracts on the one hand, and the total deliveries required under power sales contracts on the other, defines the utility's net spot market sales. URSA does not treat explicitly any short-term power deals not resulting in physical delivery. Effectively, trading activities apart from purchases or sales of physical power at spot are assumed to yield a zero net return.

Because the wholesale power supply business has the second and last call on the resources able to deliver power, it determines the total power produced. By this means it effectively also determines net spot power sales of the total utility. For example, if the retail business decides upon a net spot **purchase** of 100 MWh, and the final dispatch implies a net spot **sale** of 200 MWh, then the wholesale business sells 300 MWh at spot: the 100 MWh purchased by the retail business plus an additional 200 MWh to other purchasers.

4. Reckoning of Costs

a. Transfer Pricing

URSA's design lays some emphasis upon the appropriate prices for valuing transfers between different business units. This permits economically correct estimation of the revenue requirement contributed by each asset, and of the associated risk. But since any scheme of transfer prices nets out in total, the particular scheme employed has no effect on the estimation of costs for AEP East.

The value at which power is transferred from a generating unit to a power supply business employing it is correctly reckoned at the spot price. The gain or loss that may arise if this same power is sold at a contracted price does not belong to the generating unit, but to the given power supply contract**,** here viewed as an asset of the given power supply business. This applies even if the "contract" in question is the obligation to serve the retail load. This implies that any generating unit considered separately, which typically does not run unless it is in the money, makes a negative contribution toward (diminishes) required revenue. On the other hand, the power sales "deal" that represents the obligation to serve makes a substantial positive contribution to required revenue.

Based on these and analogous considerations, the following transfer prices apply:

- thermal generating units
  - buy fuel at the spot price,
  - buy emissions allowances at the spot price, and
  - sell power at the spot price;
- Smith Mountain
  - buys power at the spot price and
  - sells power at the spot price;
- power purchase contracts
  - buy power at the contract price and
  - sell power at the spot price;
- power sales contracts
  - buy power at the spot price and
  - sell power at the contract price

A consequence of these conventions is that all required revenue is due to assets, and in particular, the gains from spot power sales are due to the sources of the power sold, which are the generating units and power purchase contracts employed to produce the sold power.

It is worth repeating that for the utility in total, these transfer pricing considerations wash away.

b. Operating Companies

Because the AEP East system is fully integrated, and because the interest of the risk analysis is with total East required revenue, the analysis pays no attention to operating companies, but only simulates power supply activities and financial returns for AEP East in total.

c. Calculation of Required Revenue

Required revenue is the sum of all costs minus all revenues. Revenues from serving native load are assumed to be zero; that from transmitting on the AEP West tie is assume to be the difference in East-West power prices times the quantity transmitted; and those from supplying other power sales deals are assumed to be exactly the same as the cost of the power supplied. Since no fuel or allowance deals are reckoned with, there is no revenue from these sources. If a megawatt-hour is produced at some unit and supplied to the native load, the unit is credited with the market value of the power, but the load is correspondingly debited, and what is left in total is only the cost of producing the power. If the power is supplied to some other power sales deal then the profit, since the contract revenue is assumed to equal the cost of the power delivered, is the difference between the spot power price and the cost of producing the power supplied. The gain is the same if the power is supplied directly to the spot market. Hence, in aggregate, required revenue is the cost of satisfying the obligation to serve (including the West tie), minus the profits of selling, at spot, all other power produced.

d. Treatment of Contract Revenue -- Differences from Strategist Model

It was just said that URSA assumes that the fees obtained from the customer for external transactions are always precisely the same as the cost of providing the power. The reason is to wash these sales of possible gain or loss, and thus to purge from the risk analysis any risk due to external transactions. The risk analysis thus considers only risk arising from the obligation to serve the native load.

This assumption with regard to contract revenues differs from assumptions used in the *Strategist* analysis, which is used to develop the IRP plans. There, particular contractual prices are assumed for the various deals and are used to determine total contract revenues. The assumptions used in the risk analysis result in greater contract revenues on power sales, with the result that in total, URSA analysis calculates a smaller net present value required revenue for the period 2006-2030 than *Strategist* does. This is merely for purposes of the risk analysis and is not intended to supercede the *Strategist* estimate.

On the contrary, the *Strategist* assumption with regard to contract revenues is better for estimating total, net present value required revenue; while the URSA assumption is better for analyzing risks that arise particularly from the obligation to serve the native load.

5. Technical Comparison of URSA with Strategist

In late 2005 and early 2006, AEP's Risk Management and Corporate Planning groups collaborated in a technical comparison of detailed results from URSA and from *Strategist* under equivalent input assumptions. The inquiry particularly focused on costs and rates of operation (capacity factors) at AEP East and West generating units; and on total system power exports and imports, and associated revenues.

The conclusion was that for the same inputs, the two models substantially agreed in the rates of operation of AEP's various units, and in the associated costs. The main difference was that marginal, mid-stack units tend to be operated somewhat less by URSA than by *Strategist*. The reason for this is that URSA, with its daily unit commitment paradigm, cherry-picks short sequences *of favorable days when these units will be committed. This optionality is not available within* Strategist's "typical week" framework, and *Strategist* therefore tends to commit such units during the entire week, and to keep them running at minimum during unfavorable periods. This difference does not, however, impede the use of URSA to analyze the risk around cases developed using *Strategist*. In any case, since there is very little mid-stack capacity in AEP's East fleet, this difference is material mainly to the analysis of the West fleet.

URSA and *Strategist* produced very similar estimates of power imports and exports for AEP East; for AEP West, URSA produced marginally smaller estimates of exports and larger estimates of imports, due to the marginally lower rate at which it operated the West's relatively substantial holding of mid-stack units.