WKC-2 2nd half

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.*

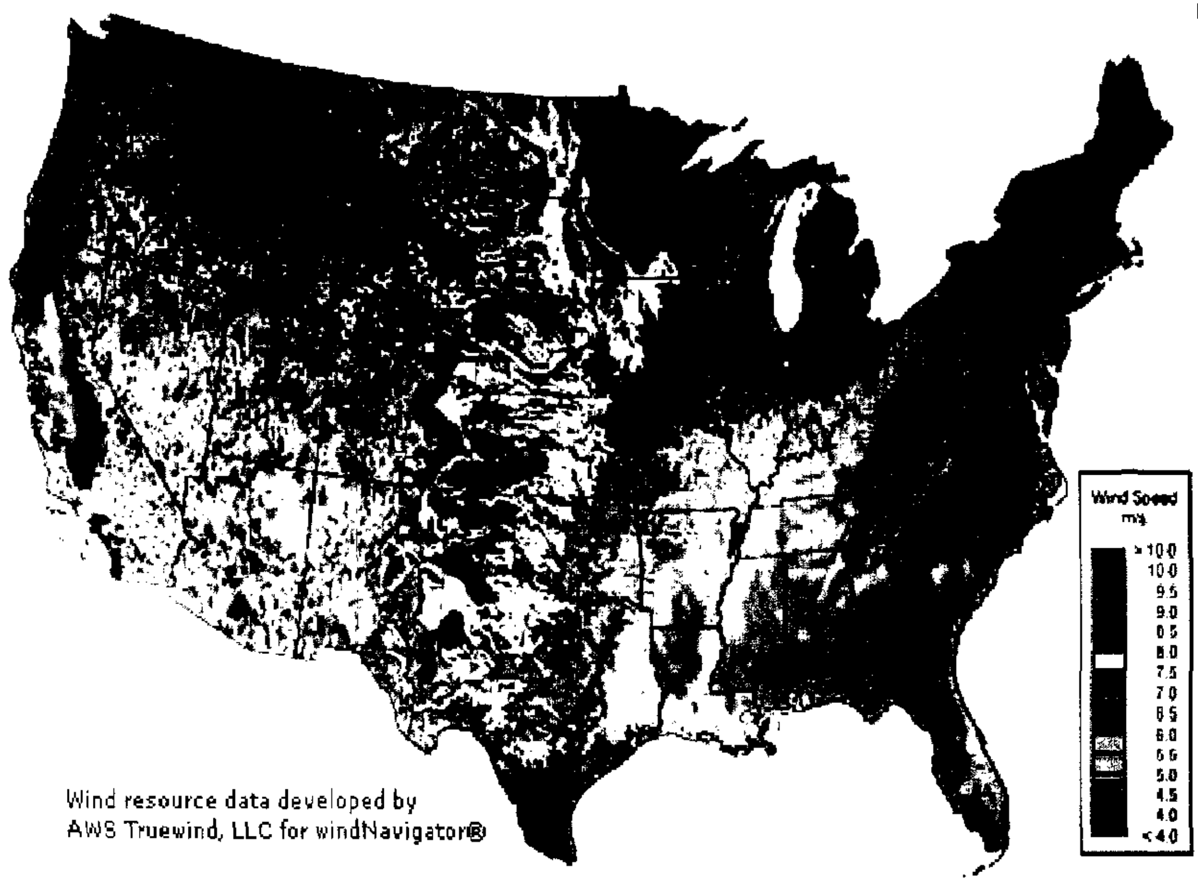
6.3.1 Wind

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

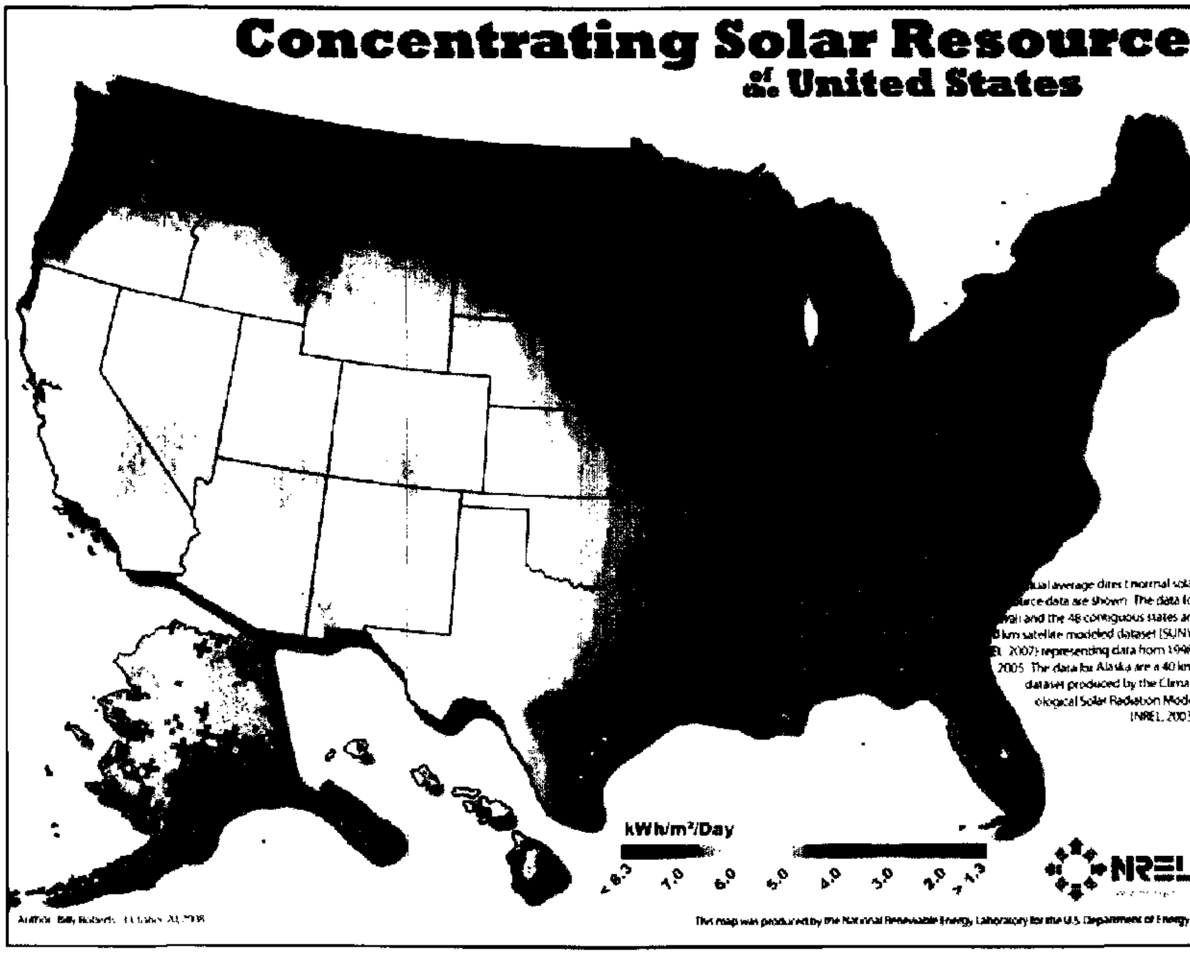


Source: U.S. Department of Energy

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

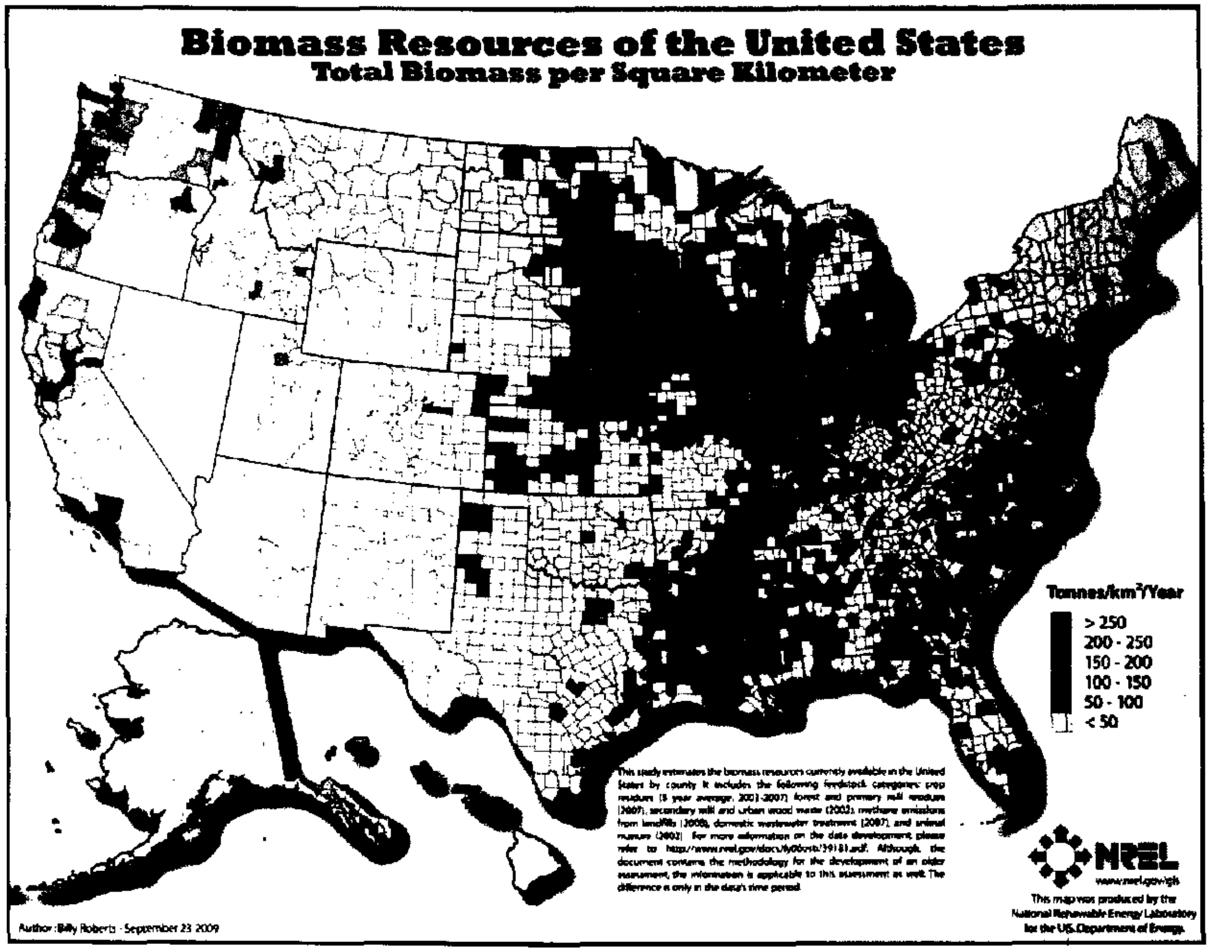
Switchgrass	**Wood Chips / Sawdust**
(per Purdue University Study) o 6 -to- 8 tons /yr. per acre yield o @ 6700 Btu/lb (non-dried, as harvested)	*(per AEP-Forestry)* o 70 -to-100 tons /yr. per acre yield* * "clear cutting" on a <u>*40-year cycle*</u> o @ 4800 Btu/lb (green, non-dried)
A 200-MW Dedicated Biomass Facility (70% C.F.) would require... **110k -to- 150k harvested acres** *(172 - 234 sq. mi,)*	*A 200-MW Dedicated Biomass Facility (70% C.F.) would require...* **510k -to- 730k timbered acres** *(795 - 1,140 sq. mi,)*
[illegible] *of switchgrass-fired biomass capacity* [illegible] *approx.* ***45 MM t/yr. of switchgrass*** *which* [illegible] *dedicated agri-land mass =* ***6.5 MM acres*** [illegible] *cropland and pasture/grassland* [illegible] *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.

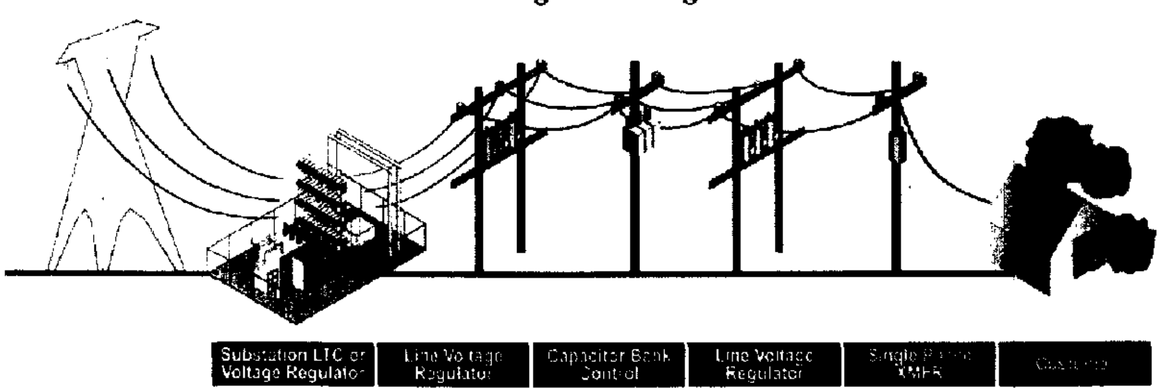
6.4.4 Distributed Generation

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

[illegible]					
	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.

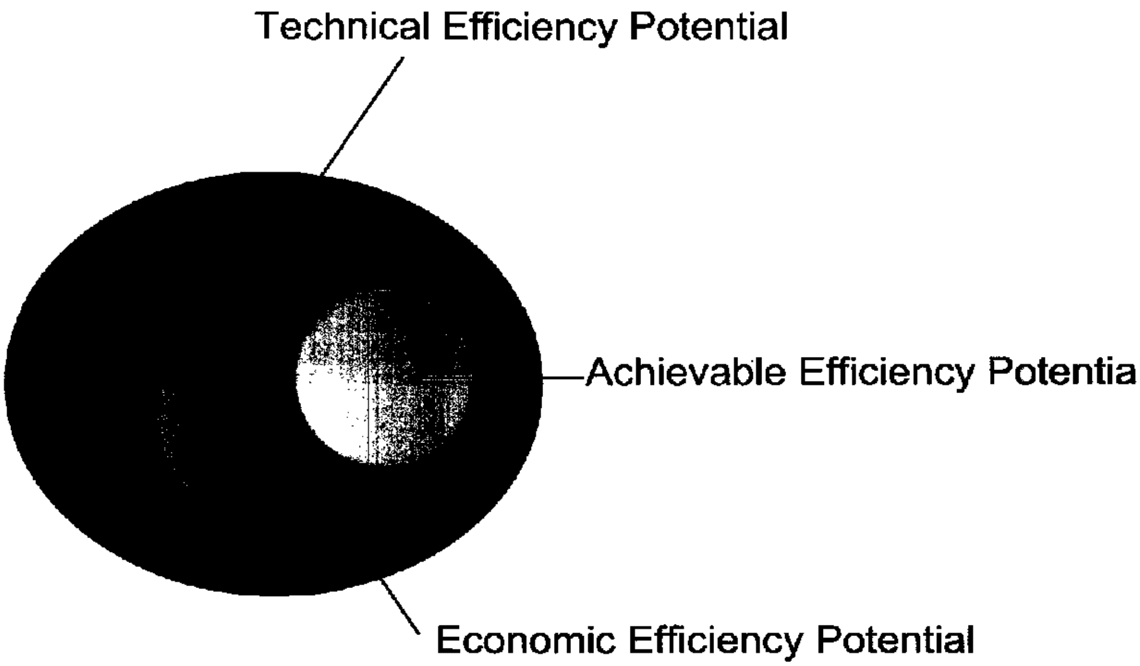
A larger and more comprehensive gridSMART demonstration project involves 110,000 customers in central Ohio. Paid for in part with a \$75M grant from the DOE, the \$150M project will include smart meters, distribution automation equipment to better manage the grid, community energy storage devices, smart 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

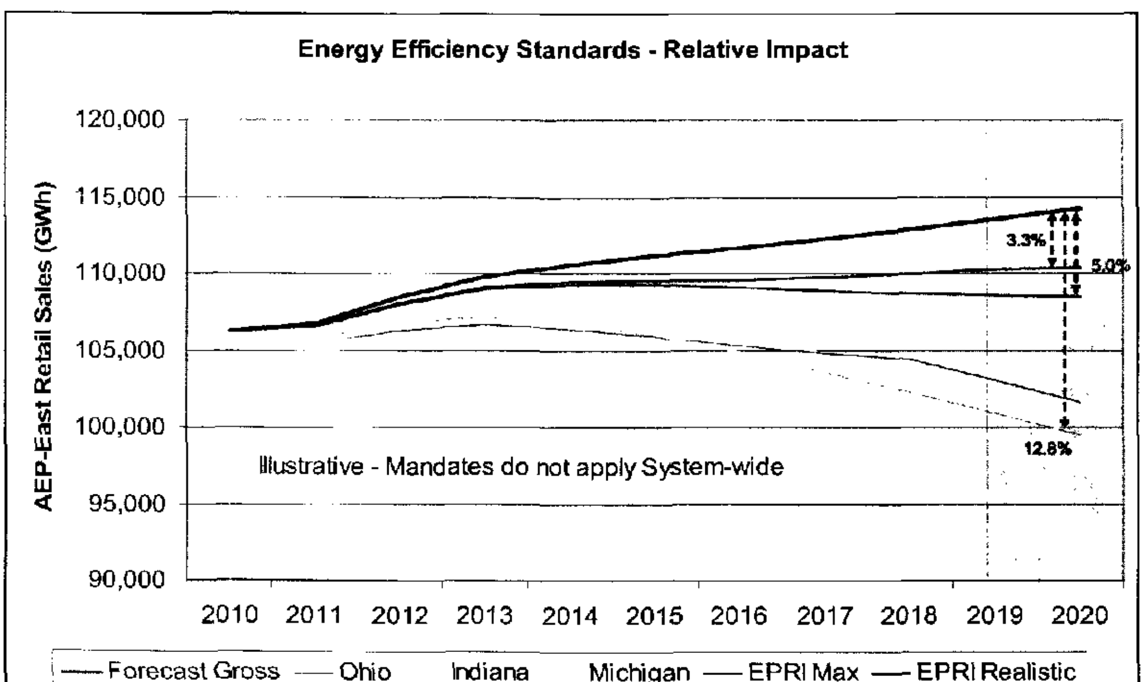
6 Non-discounted
7 Assumes no energy savings from demand interruptions
8 Blocks are non-homogeneous

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

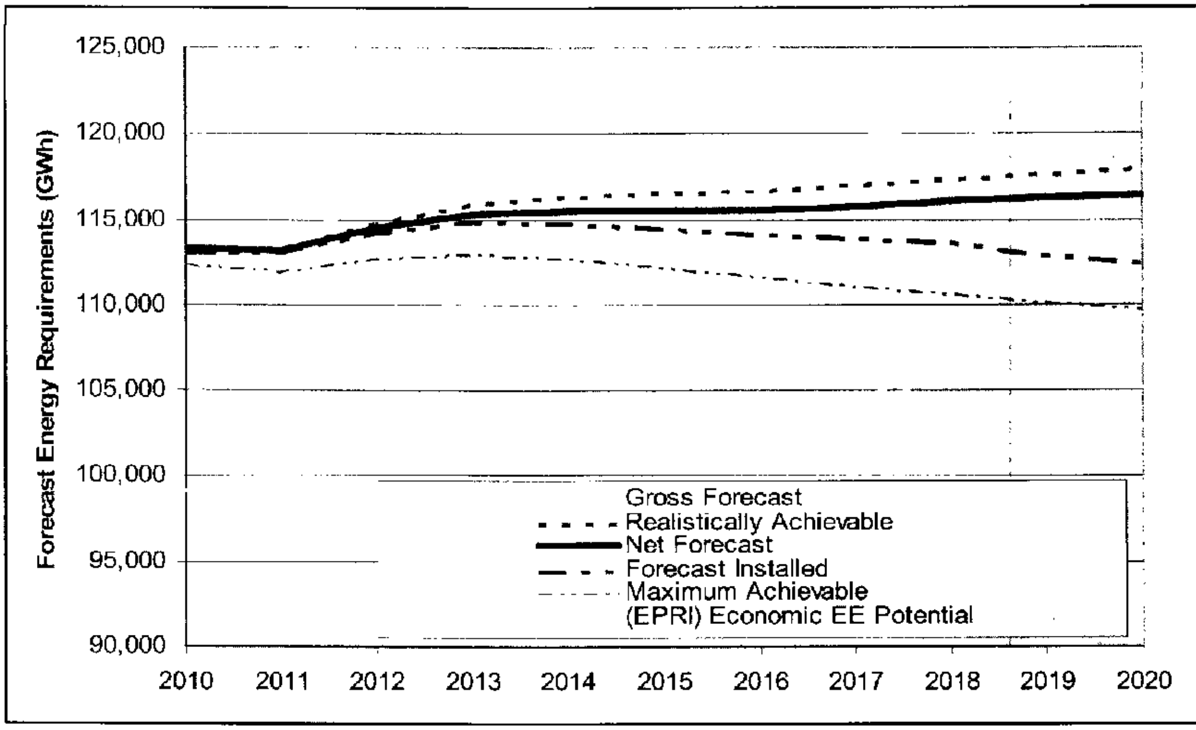
7.5.1 Energy Efficiency

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:

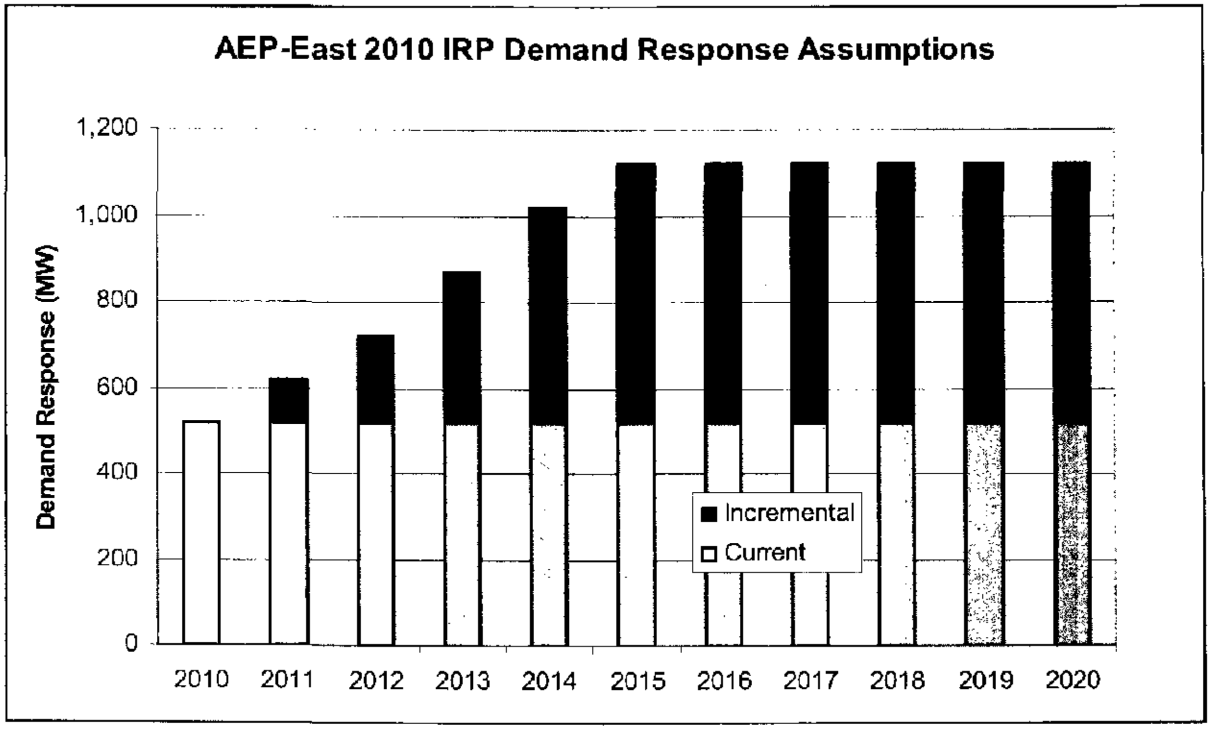
By 2020, as a result on energy efficiency programs, peak demand is reduced by 873 MW in the AEP-East zone; consumption is reduced by 5,602 GWh.

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

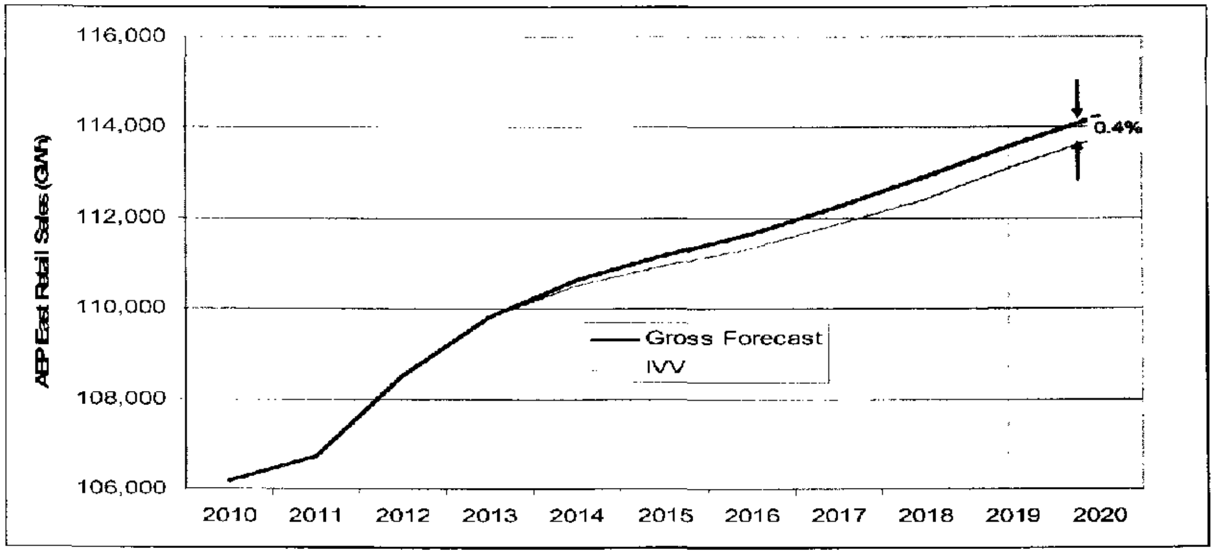


Source: AEP Resource Planning

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

[illegible]				
	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.

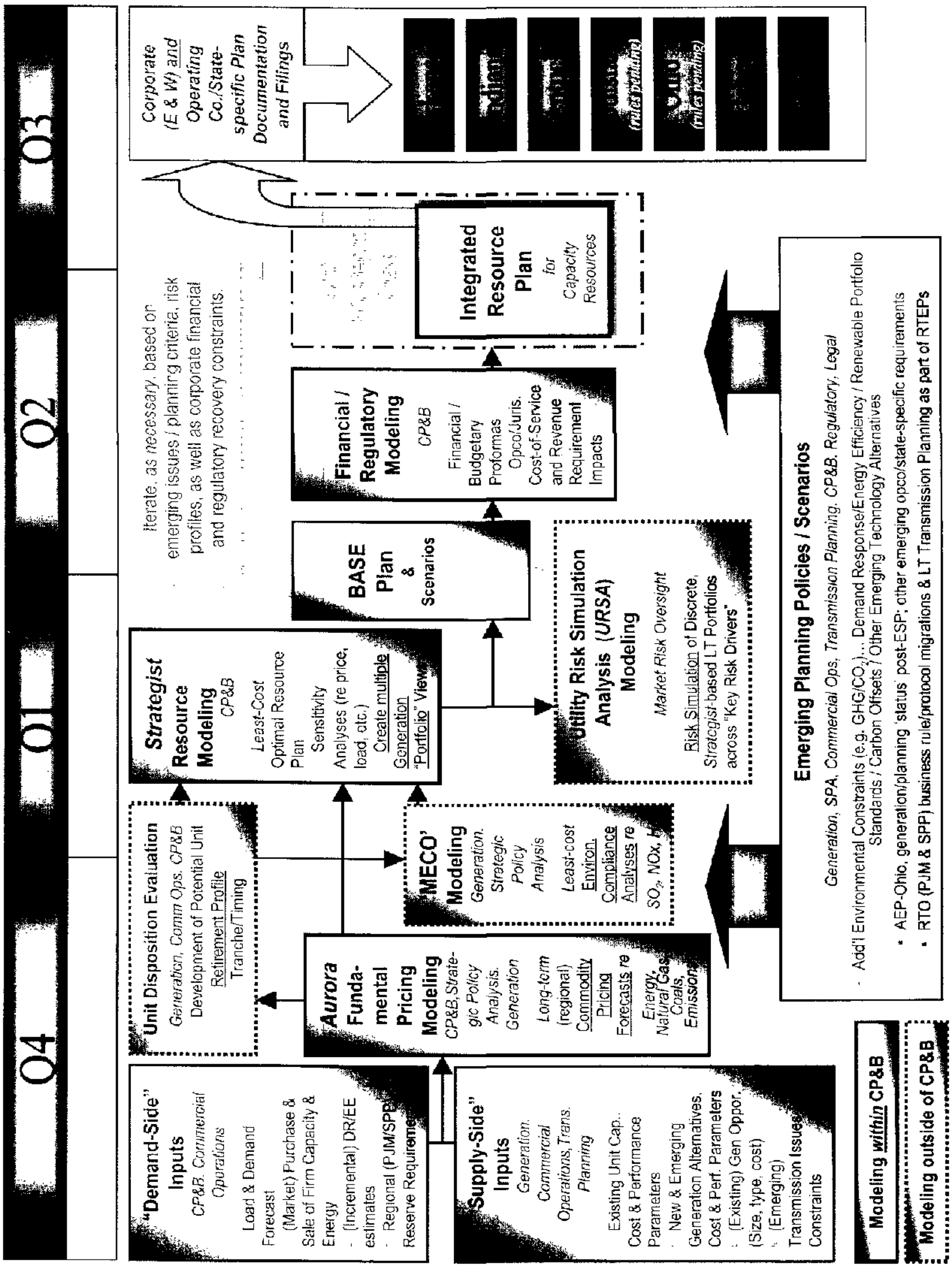
That does not mean, however, that the best or optimal plan is the one with the absolute least cost over the planning horizon evaluated. As discussed in this (and prior) section, other factors–some more difficult to quantify than others–were considered in the determination of the AEP-East Integrated Resource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

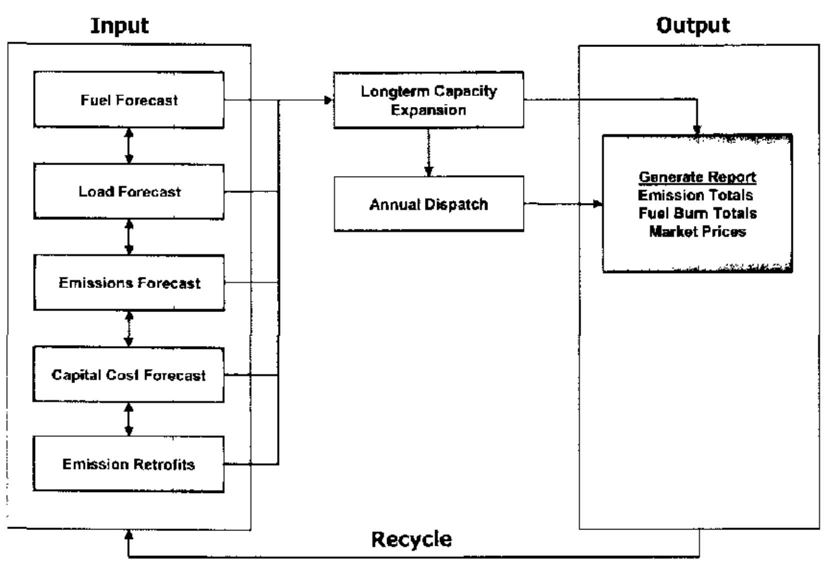
8.3 Key Fundamental Modeling Pricing Scenarios

This section includes excerpts from the "Long Term Forecast 2010-2030: Consumer Choice: A Time to Choose, 3H-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.

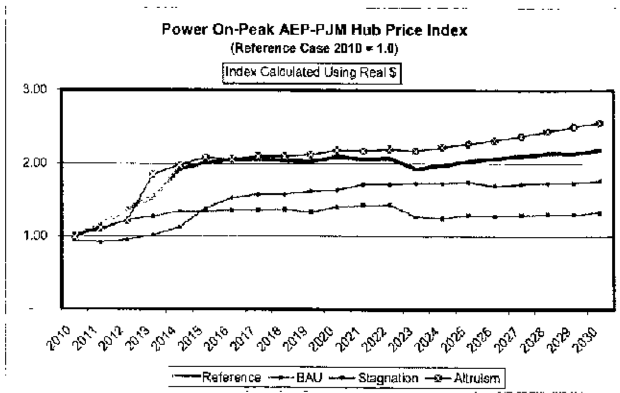
Business As Usual (BAU) – As the title of this case suggests, it assumes there is no change from 2009. This includes no change in environmental policies such as carbon. The economic outlook in this scenario is identical to the Reference economic profile other than there is no economic impact observed 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.

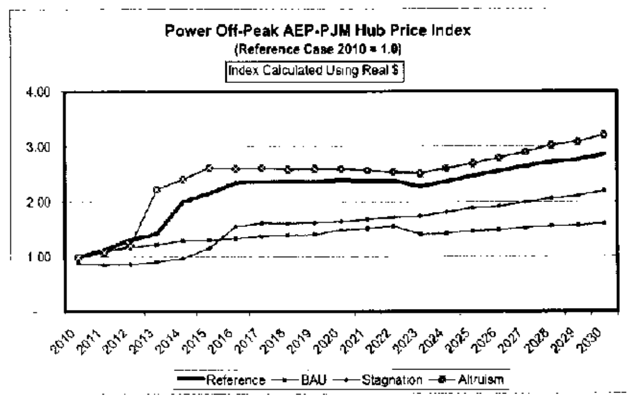
Stagnation – Concerns of rising government debt and no clear path for the transformation of the economy from less consumer driven results in a stagnated economy similar to Japan's experience. Much like Japan, the country continues to prop up insolvent banks. Optimistically, the U.S. will react faster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

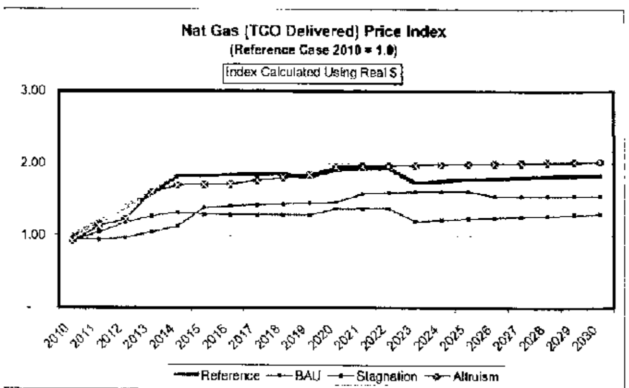
Altruism – This scenario is the hardest to imagine and construct. There is a united front across the majority of the world for the reduction of carbon. There is one carbon price accepted by all so no major wealth transfers occur. If this assumption did not occur, we could see mass economic shifting as 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.

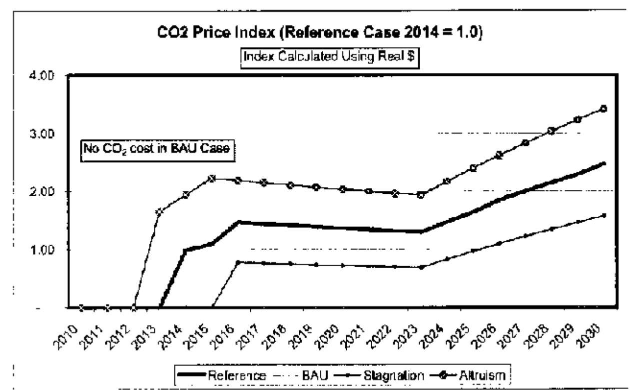
The relationship among commodity prices under the different economic scenarios is shown in **Exhibit 8-3**. Forecasts of particular importance include coal prices, natural gas, CO_2, and on-peak and off-peak power prices. Because commodity price forecasts are considered business sensitive information,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

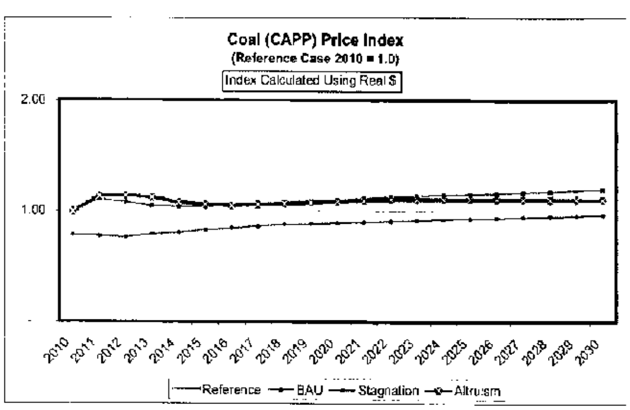
Exhibit 8-3 Commodity Price Forecast by Scenario

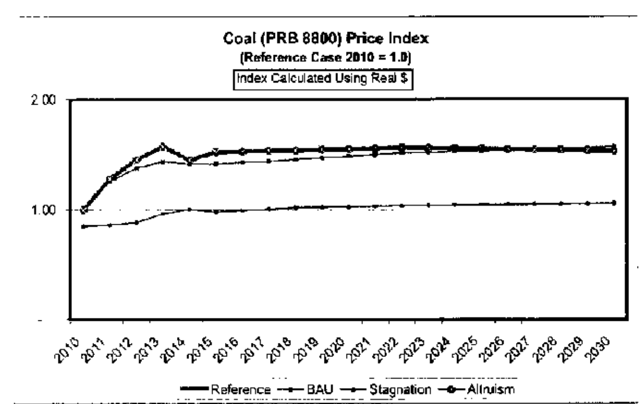












9.0 Resource Portfolio Modeling

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, 15 percent (versus 10 percent) by 2020 and 22.5 percent (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

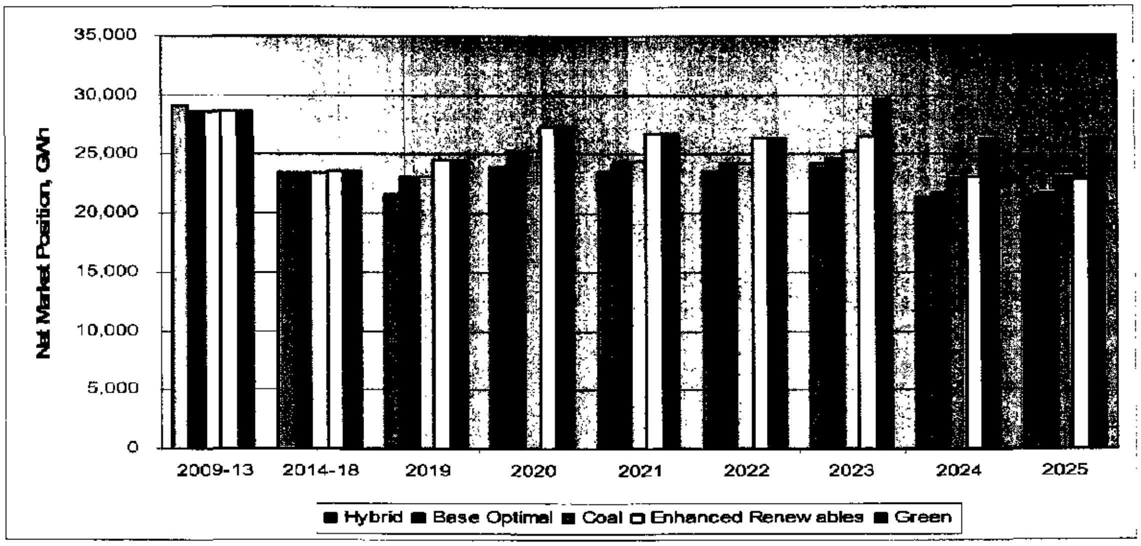
AEP East 2010-2035 CPW ($000)	NO Carbon Legislation / Regulation World	(Ultimate) Carbon Legislation		
Pricing Scenario	"BAU"-(Alt) LOW Proxy- (No CCS)	"Stagnation" - LOW Proxy- (with CCS*)	"Reference" -BASE Proxy- (with CCS*)	"Altruism" -HIGH Proxy- (with CCS*)
'BAU' (No CO2) (LOW Price w/o CO2)Scenario 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	$123,097,462	$134,123,709	$145,379,495
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	$136,638,930	$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	[illegible]
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

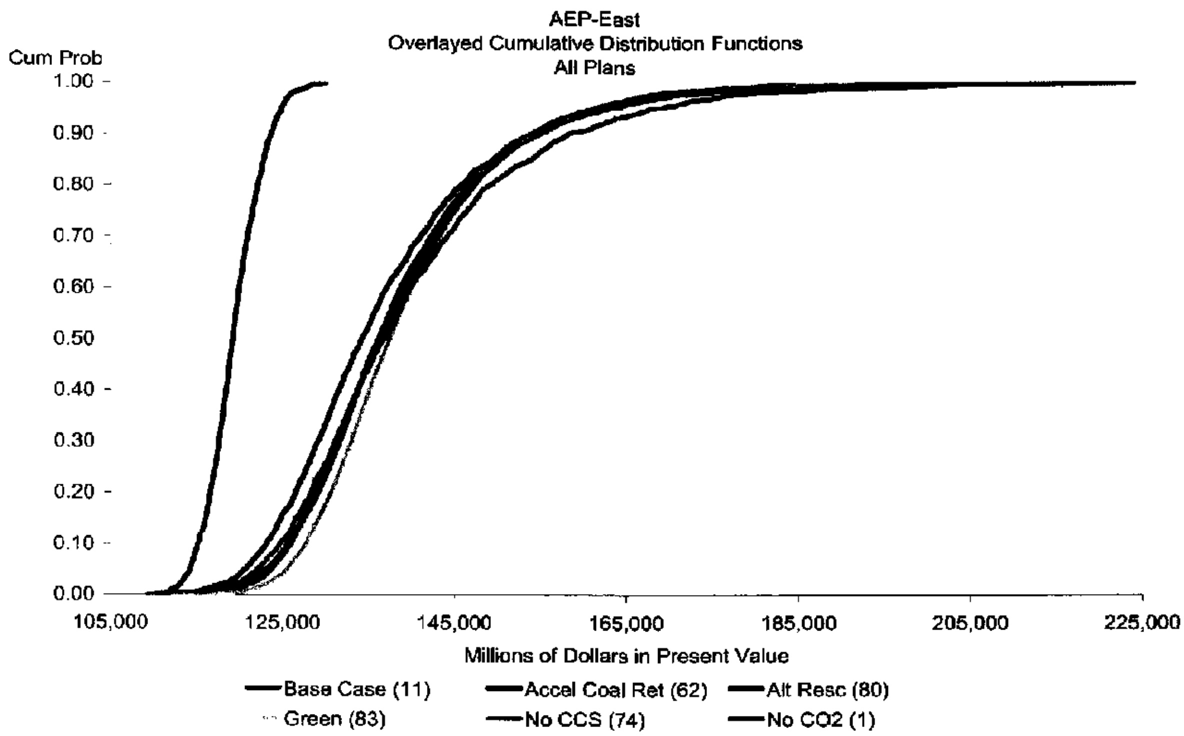
Exhibit 10-3 shows reasonably consistent results across all plans modeled. These comparative results also suggest that, given the fuel/generation diversity of the capacity resource options introduced into the analysis, the relative economic exposure would appear to be small irrespective of the plan selected.

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.

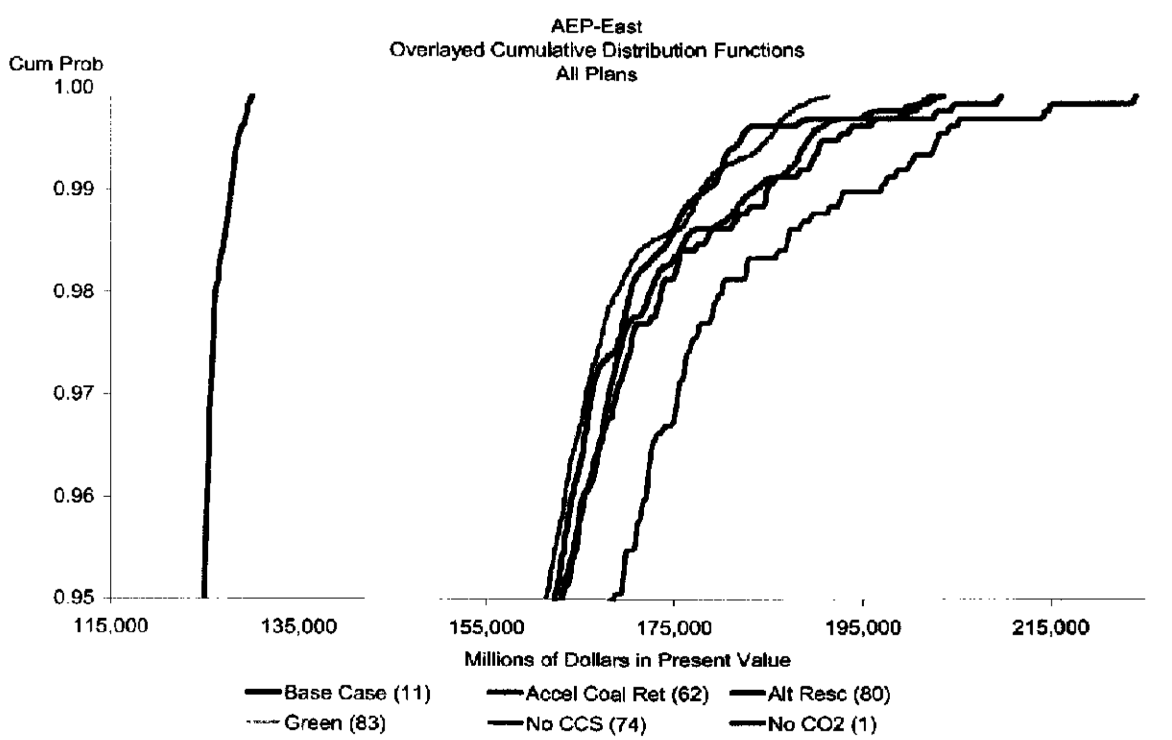
The estimated distributions of revenue required under the seven plans are rather similar. **Exhibits 10-4** and **10-5** show the superimposed graphs of all six distribution functions. **Exhibit 10-4** shows entire distributions; **Exhibit 10-5** shows only the region at or above the 95th percentile.

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

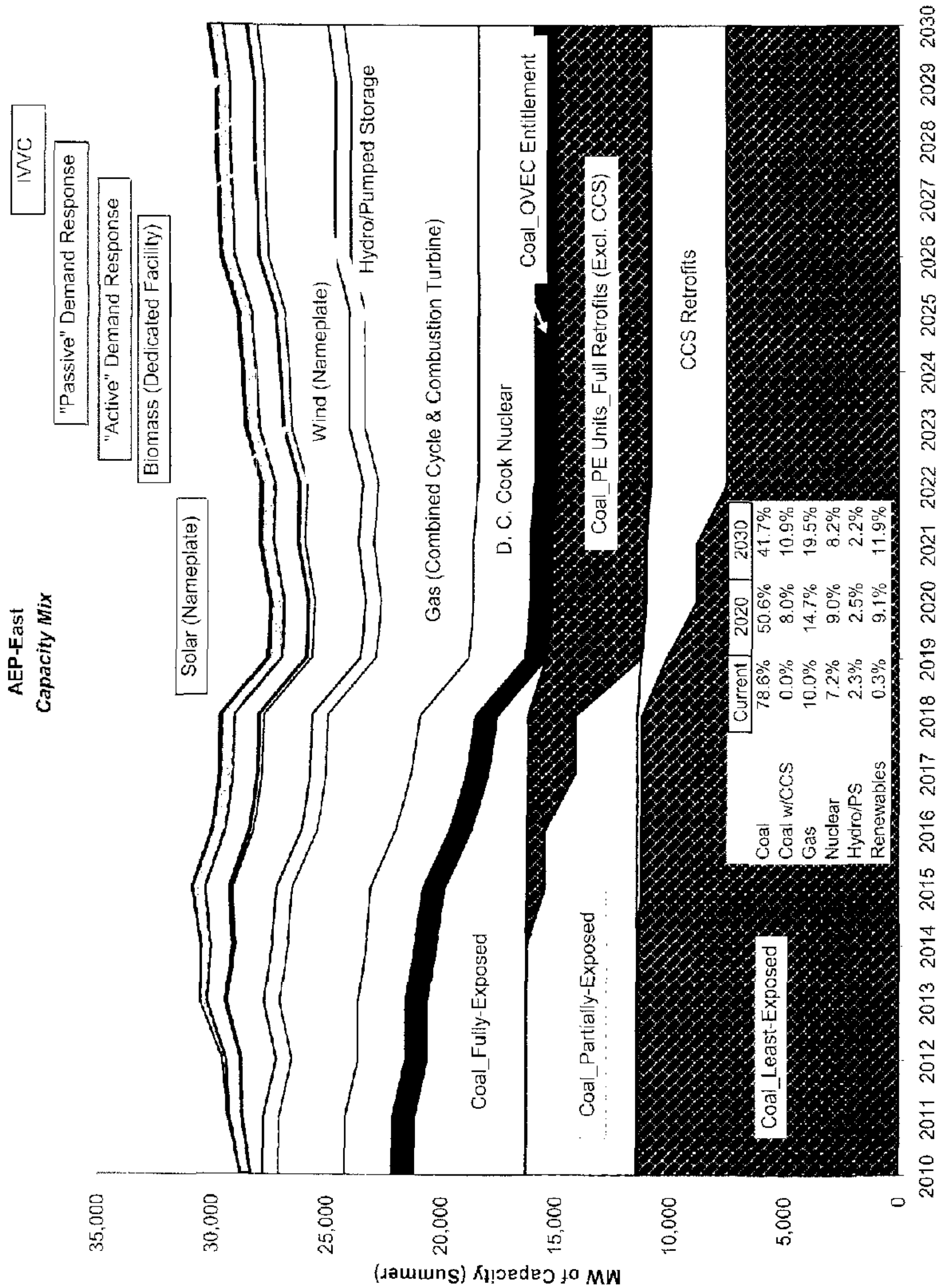
Period	Pln Yr	(b) Capacity (Retire)	CCS Retrofit Unit	CCS Retrofit Capac	CCS Retrofit Derate	Efficiency: Dem (c) Response ("Active"DR)	Efficiency: Energy (a) Efficiency ("Passive"DR)	Efficiency: Infrastruc. (e.g. IVVC)	Renewable (Nameplate) (d): Wind	Renewable (Nameplate) (d): (e) Biom	Renewable (Nameplate) (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		28				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

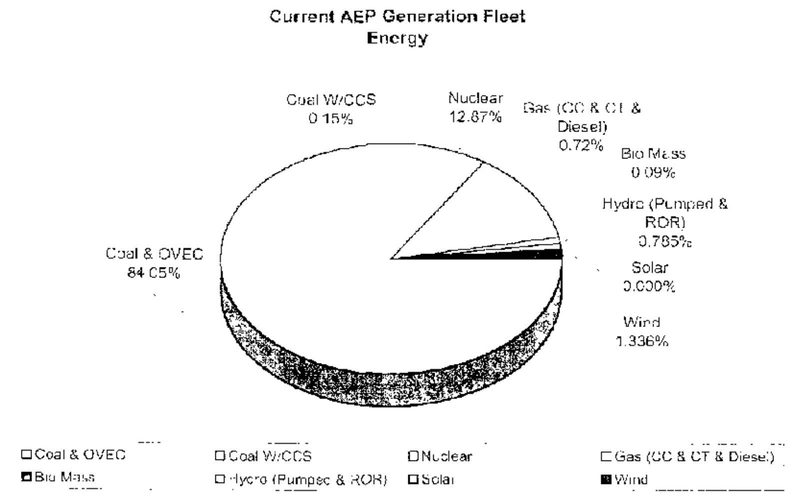
Source: AEP Resource Planning

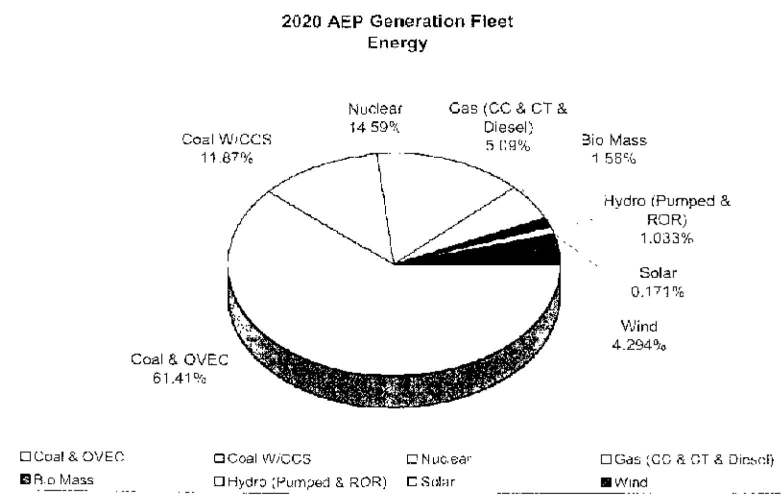
Exhibit 11-2: AEP-East Generation Capacity

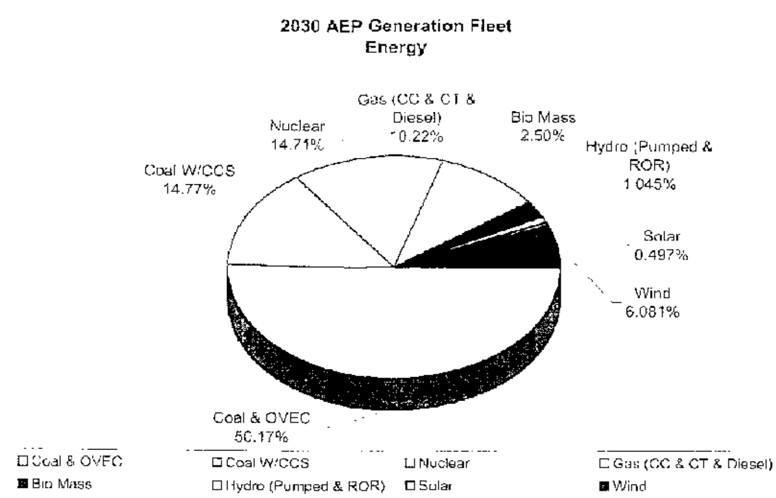


Source: AEP Resource Planning

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

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			1,073	118	2,451	103	0	*1,585*
2010 Plan			1,468	225	2,152	150	100	*1,585*
Difference			395	107		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

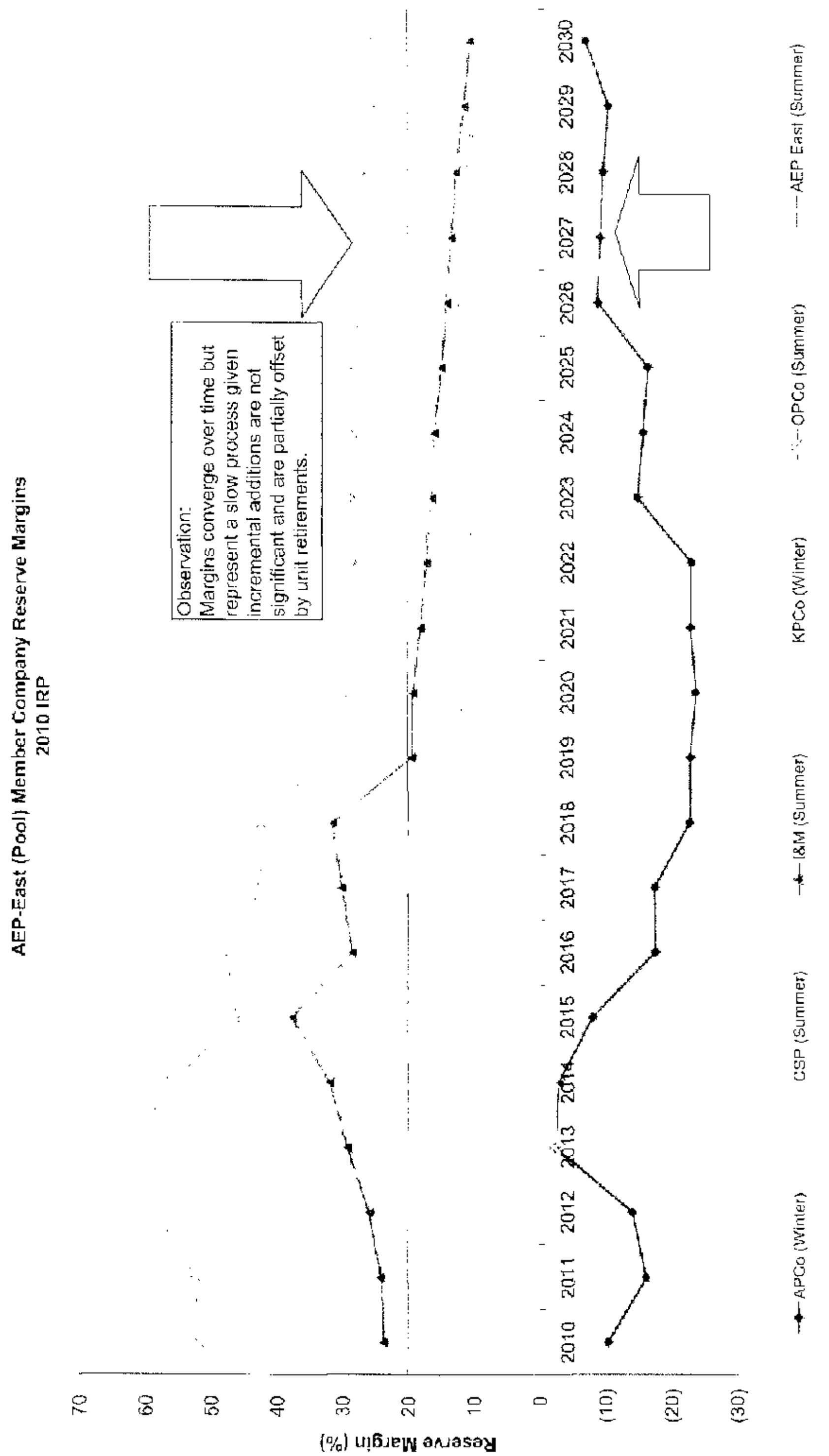
As described throughout this report, the recommended resource plan for AEP's Eastern (PJM) zone was formulated on a region-wide view, recognizing that AEP plans and operates its eastern fleet on an integrated basis, as outlined in the AEP Interconnection ("Pool") Agreement. As specified in the Pool Agreement, 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.

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)	(36)	(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.

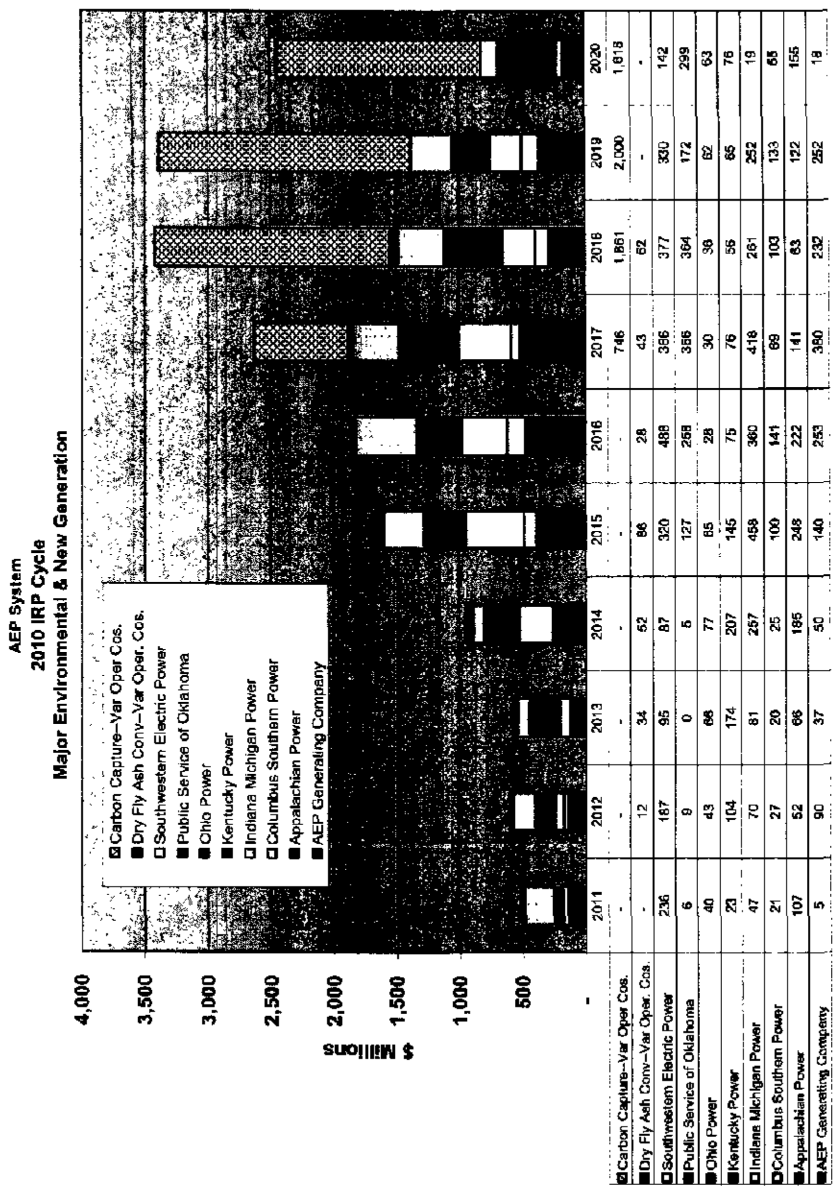
5) **Solar** (2010-2012): AEP-Ohio has a PPA for 10 MW of solar capacity which began commercial operation in June, 2010. This will meet the solar benchmarks included in SB 221 through 2011. Solar benchmarks for 2010, 2011 and 2012 are 5 GWh, 15 GWh, and 29 GWh respectively, as shown in Exhibit 2-3.

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



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 <u>only</u> 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*)

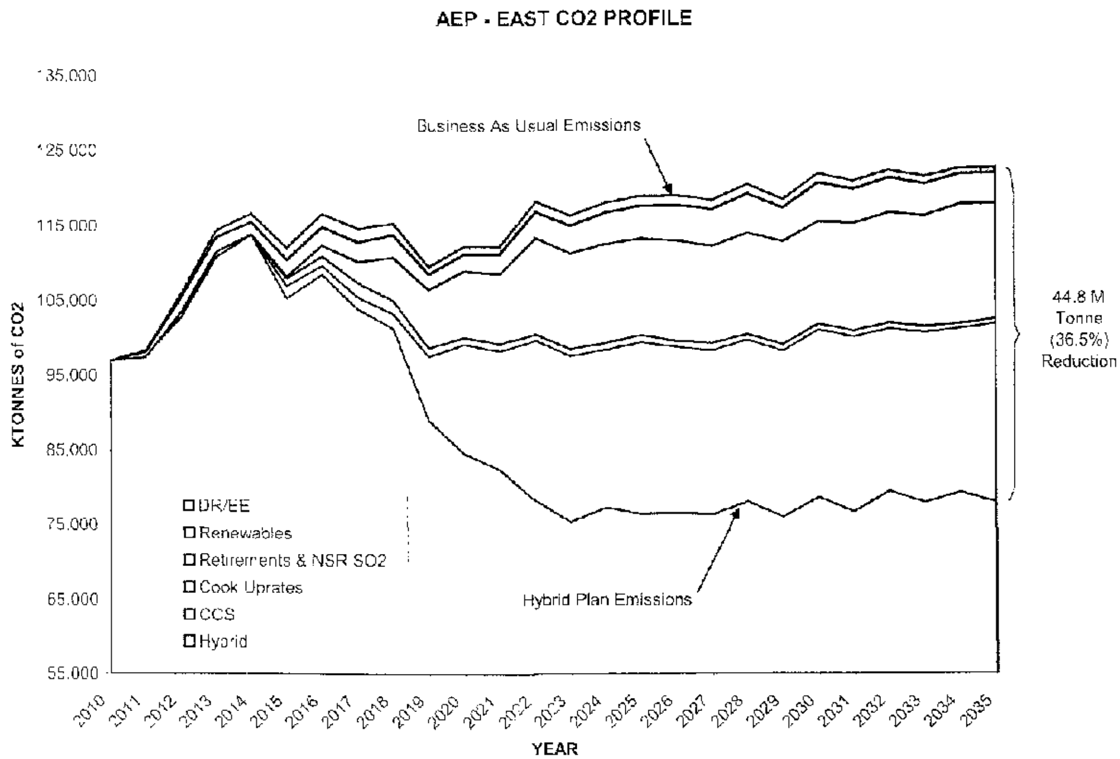
The Hybrid Plan includes resource additions that will result in lowering AEP's carbon emissions over the next 20 years. By retiring older, less efficient coal fired units, increasing nuclear capacity at the Cook plant, adding wind and solar resources, adding carbon capture and storage to larger coal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

Units	Current Scrubber Efficiency - %	New - FGD Installs		FGD - Upgraded	
	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.

AMERICAN ELECTRIC POWER

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

AEP Eastern Fleet

Anticipated Capacity Changes Incorporated into Long-Range Planning

Unit / Amount / Timing

	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)	NO_x (Lb/mmBtu)	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	96.0

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.

AMERICAN ELECTRIC POWER

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'l (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	1,262
2012 /13 (k)	21,375	(399)	(16)	21,360	445	0.950	1.080	22,605	1,398	24,001	27,663	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	1,398	24,202	27,675	(4)	540 MW D CC2 & 10 MW Solar & 100 MW Wind	567	0	28,606	7.95%	26,240	1,461	2,038
2014 /15	20,755	(932)	(399)	20,358	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%	24,968	1,509	2,168
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	446	0.957	1.080	21,082	1,396	22,478	24,697	(4)	314 MW CT* & 26 MW Solar & 150 MW Wind	343	0	26,826	6.34%	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	476	1,866
2019 /20	21,361	(1,465)	(1,312)	20,039	445	0.957	1.080	21,189	1,396	22,585	22,656	(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	22,656	(4)	26 MW Solar & 150 MW Wind	29	0	24,169	5.02%	22,958	(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 60 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 Solar Nameplate (MW)	APCo Wind Nameplate (MW)	APCo Biomass Equivalent (MW)	APCo Energy as % of Sales	CSP Solar Nameplate (MW)	CSP Wind Nameplate (MW)	CSP Biomass Equivalent (MW)	CSP Energy as % of Sales
2009	0	75	0	0.8%	0	0	0	0.0%
2010	0	276	0	2.7%	0	60	0	0.8%
2011	0	376	0	3.6%	6	90	2	0.9%
2012	0	376	0	3.6%	13	100	2	1.7%
2013 (b)	0	376	0	3.5%	17	125	2	2.1%
2014	0	376	0	3.5%	28	160	27	3.6%
2015	0	376	0	3.5%	38	190	27	4.2%
2016	0	376	0	3.5%	49	273	25	5.5%
2017	0	376	0	3.5%	58	323	25	6.4%
2018	0	376	0	3.4%	71	323	75	8.5%
2019	0	376	0	3.4%	83	373	75	9.4%
2020	0	376	0	3.4%	95	448	75	10.7%
2021	0	376	0	3.3%	113	448	75	10.8%
2022	0	409	0	3.8%	125	615	75	12.0%
2023	0	409	0	3.6%	125	615	75	13.5%
2024	0	409	0	3.5%	147	665	75	14.4%
2025	0	409	0	3.5%	147	715	75	15.1%
2026	0	409	0	3.5%	156	765	75	15.8%
2027	0	409	0	3.4%	156	815	94	17.3%
2028	0	409	0	3.4%	169	865	94	18.0%
2029	0	409	0	3.4%	169	865	94	17.9%
2030	0	409	0	3.3%	185	865	94	17.8%

Year	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
2009	0	0	0	0.0%	0	0	0	0.0%
2010	0	150	0	2.5%	0	0	0	0.0%
2011	0	150	0	2.5%	0	0	0	0.0%
2012	0	150	0	2.4%	0	0	0	0.0%
2013 (b)	0	200	0	3.2%	0	0	0	0.0%
2014	0	350	0	5.6%	0	100	0	4.2%
2015	0	650	0	10.2%	0	100	0	4.2%
2016	0	650	0	10.3%	0	100	0	4.2%
2017	0	650	0	10.3%	0	100	0	4.2%
2018	0	650	0	10.3%	0	100	0	4.2%
2019	0	650	0	10.4%	0	100	0	4.1%
2020	0	650	0	10.3%	0	100	0	4.1%
2021	0	700	0	11.0%	0	150	0	6.1%
2022	0	700	0	11.0%	0	150	0	6.0%
2023	0	700	0	10.9%	0	150	0	6.0%
2024	0	750	50	13.7%	0	150	50	11.1%
2025	0	800	50	14.3%	0	150	50	11.1%
2026	0	850	50	15.0%	0	150	50	11.0%
2027	0	850	50	14.9%	0	200	63	14.1%
2028	0	850	50	14.8%	0	200	63	14.0%
2029	0	850	50	14.7%	0	200	63	13.9%
2030	0	850	50	14.7%	0	200	63	13.8%

Year	OPCo Solar Nameplate (MW)	OPCo Wind Nameplate (MW)	OPCo Biomass Equivalent (MW)	OPCo 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	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	5.8%
2017	87	477	25	6.3%	148	800	50	6.3%	148	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	862	125	13.8%	345	1,567	200	14.4%	345	2,926	300	10.5%
2026	208	902	125	14.4%	384	1,667	200	15.0%	364	3,076	300	10.9%
2027	208	952	144	15.4%	384	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 RPB/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 Solar Nameplate (MW)	PSO Wind Nameplate (MW)	PSO Biomass Equivalent (MW)	PSO Energy as % of Sales	SWEPCO Solar Nameplate (MW)	SWEPCO Wind Nameplate (MW)	SWEPCO Biomass Equivalent (MW)	SWEPCO Energy as % of Sales	AEP-SPP Solar Nameplate (MW)	AEP-SPP Wind Nameplate (MW)	AEP-SPP Biomass Equivalent (MW)	AEP-SPP 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	7.6%
2012	0	691	0	16.8%	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	23.6%	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	23.8%	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%

(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.

Year	AEP-System Solar Nameplate (MW)	AEP-System Wind Nameplate (MW)	AEP-System Biomass Equivalent (MW)	AEP-System 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	10.2%
2021	281	4,127	200	10.0%
2022	326	4,327	200	11.4%
2023	326	4,627	200	12.0%
2024	370	4,677	300	13.0%
2025	370	5,127	300	13.6%
2026	408	5,377	300	14.0%
2027	408	5,627	350	14.7%
2028	458	5,727	350	14.9%
2029	468	5,927	350	15.2%
2030	520	6,027	350	15.4%

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	6,481	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	3,609	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	3,630	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	3,860	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	4,085	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	4,184	4,558	4,538	3,943	3,310	3,372	3,623	4,558	3,908
2013	3,975	3,850	3,822	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	3,784	3,999	5,173	4,358
2033	4,404	4,274	3,951	3,785	3,838	4,760	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	5,336	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	1,164	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	1,306	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	1,318	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	1,166	1,403	1,653	1,439	1,660
2037	1,602	1,682	1,593	1,318	1,180	1,338	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	4,826
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	3,936	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	4,336	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	4,086	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	19,188	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	19,998	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	20,986	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	20,664	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	3,546	36,506
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	3,831	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	1,762	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	2,336	26,569
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	2,185	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	2,118	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	2,289	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	10,607	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	11,612	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

[redacted]

	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

[redacted]

	[redacted]			
	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

	[redacted]			
	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

	[redacted]			
	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

	[redacted]			
	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	1,036	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		Net	
	GWh	MW	GWh	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		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	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		Net	
	GWh	MW	GWh	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		Net	
	GWh	MW	GWh	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		Net	
	GWh	MW	GWh	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		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	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		Net	
	GWh	MW	GWh	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		Net	
	GWh	MW	GWh	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		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	2,898	938
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

AMERICAN ELECTRIC POWER

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

AMERICAN ELECTRIC POWER

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**
10-Year IRP Period	2010	2010/11				296	2.01					2.01				119	
	2011	2011/12				150	2.00									75	1.00
	2012	2012/13				150	2.00									80	0.50
	2013	2013/14			1	380	6.00			1						152	0.50
	2014	2014/15				380	8.80									152	0.80
	2015	2015/16				380	5.00									152	1.67
	2016	2016/17				380	3.00									152	1.00
	2017	2017/18		4		380	1.00		4							171	
	2018	2018/19		4		380	2.00		2							171	1.00
	2019	2019/20				380	3.00									171	1.50
	2020	2020/21				450	2.00									270	
Extended Planning Period	2021	2021/22		4		650	2.00		2			0.67				163	1.33
	2022	2022/23					4.00										2.00
	2023	2023/24	1			650	3.00	1								325	1.00
	2024	2024/25					3.00										1.00
	2025	2025/26				272	3.00									136	1.00
	2026	2026/27	1				3.00	1									1.00
	2027	2027/28				363	2.00									181	1.00
	2028	2028/29															
	2029	2029/30				453										227	
	2030	2030/31		4					4								

Period	Summer*	Winter	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														178	
	2011	2011/12														75	1.00
	2012	2012/13					1.00									90	0.30
	2013	2013/14					3.00					2.00				228	0.50
	2014	2014/15					6.00									228	1.20
	2015	2015/16														228	3.33
	2016	2016/17														228	2.00
	2017	2017/18														209	1.00
	2018	2018/19							2							209	1.00
	2019	2019/20														209	1.50
	2020	2020/21					1.00					1.00				180	
Extended Planning Period	2021	2021/22							2							488	
	2022	2022/23															2.00
	2023	2023/24					1.00									325	1.00
	2024	2024/25					1.00										1.00
	2025	2025/26					1.00									136	1.00
	2026	2026/27										1.00					1.00
	2027	2027/28														181	1.00
	2028	2028/29															
	2029	2029/30														227	
	2030	2030/31															

Capacity (MW/Unit)	CC	CT	D CC2	Solar	Wind**
Summer	611	79	540	0.069	50
Winter	[illegible]	80	625	0.069	30

* 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 <u>and</u> 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.

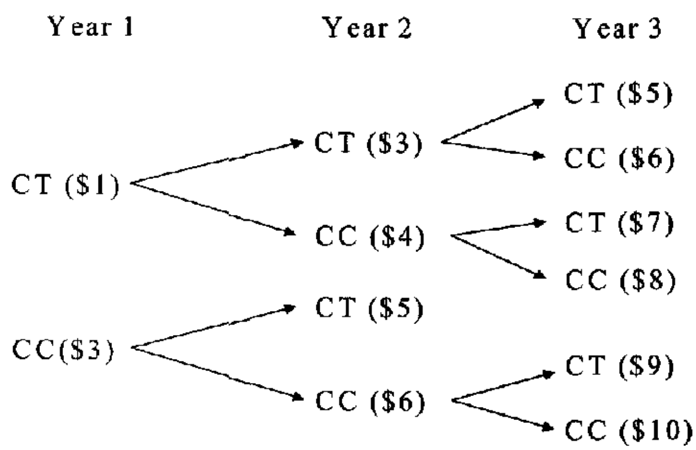
In summary, *Strategist* models the approach AEP uses to determine jurisdictional generation revenue requirements at an integrated, system level. For the purpose of comparing plans, these costs are expressed on a Cumulative Present Worth (CPW) basis for each plan, using standard calculation methods and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

SUPPLEMENTAL Appendix 3

4901:5-5-06 Resource Plans Requirements — **IRP Section Reference**

(B) In the long-term forecast report filed pursuant to rule 4901:5-3-01 of the Administrative Code, the following must be filed in the forecast year prior to any filing for an allowance under sections 4928.143(B)(2)(b) and (c) of the Revised Code:

(1) Existing generating system description. (a) The reporting person shall provide a brief summary narrative of the existing electric generating system. **If a hearing is to be held** on the forecast in the current year, the reporting person shall submit to the commission with its long-term forecast report, the anticipated operating, maintenance, and fuel expense of each unit for each year of the forecast period. The commission may make exceptions to this paragraph for good cause.	Section 1.2, Section 3, Appendix A
(b) A summary of the pooling, mutual assistance, and all agreements for purchasing from and selling power and energy to other utilities or nonutility generators, including costs and amounts, shall be provided.	Section 1.2.2, Appendix D

(2) Need for additional electricity resource options. The reporting person shall describe the procedure followed in determining the need for additional electricity resource options. All major factors shall be discussed, including but not limited to:	Section 1, Section 5
(a) System load profile.	Section 4, Appendix F
(b) Maintenance requirements of existing and planned units.	Section 3
(c) Number of units, unit size, and availability of existing and planned units.	Section 9
(d) Forecast uncertainty.	Section 8.3
(e) Electricity resource option uncertainty with respect to cost, availability, commercial in-service dates, and performance.	Section 10, Appendix M
(f) Lead times for construction or implementation of planned electricity resource options.	Section 12.3
(g) Power interchange with other electric systems, including consideration of the ability to buy and sell power.	Sections 5.1 & 5.2
(h) Price-responsive demand and price elasticity due to the implementation of time-differentiated pricing options and assessments of the value of lost load.	Section 6.4.2, Section 7.6
(i) Regulatory climate.	Section 2
(j) Reliability criteria, including a discussion and analysis of the reporting person's reliability criteria and factors influencing their selection, including, but not limited to: (i) Reliability measures used and factors including the selection. (ii) Engineering analysis performed. (iii) Economic analysis performed. (iv) Any judgments applied.	Section 5

(3) Resource plan.

(a) This paragraph shall include the electric utility's projected mix of resource options to meet the base case projection of peak demand and total energy requirements.	Section 11

(b) A discussion of the electric utility's projected system reliability shall be presented. It shall include:

(i) A discussion of the future adequacy of the electric utility's projected system in both the short- and long-term.	Section 12
(ii) A discussion of the future adequacy of fuel supplies in both the short- and long-term. Additionally, the reporting person shall provide, for the forecast period, a description of its overall fuel procurement policies and procedures. A description of the system's fuel requirements, the system's geographic source of fuel supply, and the percentage of fuel supply under contract shall be included.	Supplemental Appendix 5

SUPPLEMENTAL Appendix 3

4901:5-5-06 Resource Plans Requirements	IRP Section Reference
(c) The electric utility shall demonstrate the cost-effectiveness of the plan through a comparison over the ten-year forecast horizon of the revenue requirement and rate impacts of the selected plan and alternative plans evaluated. The selection of the plan shall demonstrate adequate consideration of the risks, reliability, and uncertainties associated with the person's selected plan and alternative plans, and of other factors the electric utility deems appropriate.	Sections 9 & 10
(d) The methodology for arriving at the plan must be fully explained and described. The description must be sufficiently explicit, detailed and complete to allow the commission and other knowledgeable parties to understand how the assessment was conducted. This description shall also include: (i) A general discussion of the decision-making process, criteria, and standards employed by the electric utility as it relates to the development of the resource plan. (ii) A discussion of how the plan is consistent with the overall planning objectives of paragraph (A) of rule 4901:5-5-03 of the Administrative Code. (iii) A discussion of key assumptions and judgments used in development of the resource plan.	Sections 1, 2, & 11; Apendices K, L, & M
(e) The reporting person shall provide information sufficient for the commission to determine the reasonableness of the resource plan, including:	
(i) The adequacy, reliability, and cost-effectiveness of the plan.	Section 9
(ii) Whether the methodology used to develop the plan evaluates demand-side management programs and nonelectric utility generation on both sides of the meter in a manner consistent with electric utility's generation and other electricity resource options. At a minimum, the total resource cost test as defined in rule 4901:1-39-01 of the Administrative Code, should be used to determine the cost-effectiveness of demand-side management programs.	Section 7
(iii) Whether the plan gives adequate consideration to the following factors: (a) Potential rate and customer bill impacts of the plan. (b) Environmental impacts of the plan and their associated costs. (c) Other significant economic impacts and their associated costs. (d) Impacts of the plan on the financial status of the company. (e) Other strategic considerations including flexibility, diversity, the size and lead time of commitments, and lost opportunities for investment. (f) Equity among customer classes. (g) The impacts of the plan over time. (h) Such other matters the commission considers appropriate.	Section 12

SUPPLEMENTAL Appendix 4

Forecasted (Summer) PEAK DEMAND Comparison by Recent "Forecast Vintage"

Columbus Southern Power Company

	Summer Peak (MW)				Summer PEAK Variances		
		Comparable Forecast Vintages					
	Sep-09	Sep-09 (Rev) *	Apr-10	Oct-10	Apr-10 v. Sep-09(Rev)	Oct-10 v. Sep-09(Rev)	Oct-10 v. Apr-10
BASED ON =>	*2010 LTFR*	*2010 LTFR (REV Form FE-D3)*	*2010 IRP*	*Latest Forecast*			
2010	4,308	4,308	4,266	4,474	-1.0%	3.9%	4.9%
2011	4,382	4,382	4,264	4,290	-2.7%	-2.1%	0.6%
2012	4,442	4,407	4,278	4,260	-2.9%	-3.3%	-0.4%
2013	4,507	4,431	4,314	4,289	-2.6%	-3.2%	-0.6%
2014	4,560	4,440	4,313	4,294	-2.9%	-3.3%	-0.4%
2015	4,611	4,446	4,301	4,284	-3.3%	-3.6%	-0.4%
2016	4,654	4,442	4,278	4,262	-3.7%	-4.0%	-0.4%
2017	4,717	4,458	4,279	4,268	-4.0%	-4.3%	-0.3%
2018	4,761	4,456	4,279	4,274	-4.0%	-4.1%	-0.1%
2019	4,800	4,399	4,267	4,270	-3.0%	-2.9%	0.1%
2020	4,829	4,332	4,229	4,241	-2.4%	-2.1%	0.3%

Ohio Power Company

	Summer Peak (MW)				Summer PEAK Variances		
		Comparable Forecast Vintages					
	Sep-09	Sep-09 (Rev) *	Apr-10	Oct-10	Apr-10 v. Sep-09(Rev)	Oct-10 v. Sep-09(Rev)	Oct-10 v. Apr-10
BASED ON =>	*2010 LTFR*	*2010 LTFR (REV Form FE-D3)*	*2010 IRP*	*Latest Forecast*			
2010	5,324	5,324	5,116	5,167	-3.9%	-3.0%	1.0%
2011	5,370	5,370	5,131	5,236	-4.5%	-2.5%	2.1%
2012	5,044	5,005	4,784	4,877	-4.4%	-2.5%	2.0%
2013	5,099	5,016	4,811	4,895	-4.1%	-2.4%	1.7%
2014	5,134	5,002	4,808	4,894	-3.9%	-2.1%	1.8%
2015	5,165	4,985	4,802	4,891	-3.7%	-1.9%	1.8%
2016	5,186	4,956	4,786	4,879	-3.4%	-1.6%	1.9%
2017	5,222	4,942	4,790	4,886	-3.1%	-1.1%	2.0%
2018	5,247	4,917	4,790	4,888	-2.6%	-0.6%	2.0%
2019	5,270	4,838	4,777	4,878	-1.2%	0.8%	2.1%
2020	5,279	4,745	4,731	4,834	-0.3%	1.9%	2.2%

AEP East

	Summer Peak (MW)				Summer PEAK Variances		
		Comparable Forecast Vintages					
	Sep-09	Sep-09 (Rev) *	Apr-10	Oct-10	Apr-10 v. Sep-09(Rev)	Oct-10 v. Sep-09(Rev)	Oct-10 v. Apr-10
BASED ON =>	*2010 LTFR*	*2010 LTFR (REV Form FE-D3)*	*2010 IRP*	*Latest Forecast*			
2010	21,453	21,453	20,805	21,144	-3.0%	-1.4%	1.6%
2011	21,813	21,813	20,825	21,200	-4.5%	-2.8%	1.8%
2012	22,041	21,967	20,992	21,322	-4.4%	-2.9%	1.6%
2013	22,321	22,162	21,193	21,500	-4.4%	-3.0%	1.4%
2014	22,524	22,272	21,230	21,547	-4.7%	-3.3%	1.5%
2015	22,721	22,376	21,247	21,571	-5.0%	-3.6%	1.5%
2016	22,869	22,427	21,214	21,542	-5.4%	-3.9%	1.5%
2017	23,096	22,557	21,272	21,615	-5.7%	-4.2%	1.6%
2018	23,273	22,638	21,334	21,685	-5.8%	-4.2%	1.6%
2019	23,444	22,611	21,389	21,752	-5.4%	-3.8%	1.7%
2020	23,561	22,530	21,369	21,736	-5.2%	-3.5%	1.7%

* In a 6/1/10 Company response to a Staff inquiry (e-mail from Steve Nourse to Dan Johnson, et al) in Case Nos. 10-501-EL-FOR and 10-502-EL-FOR, the CSP and OPCo 2010 LTFR Form 'FE-D3' was revised to reflect an "expanded" view of DSM activity *beyond* the initial (3-year) program period (2009-2011) originally projected --and filed-- in order to capture the impacts of long-term DSM benchmark requirements under S.B. 221. Such (expanded) DSM basis was subsequently reflected in the 'Apr-10' and 'Oct-10' peak demand forecasts shown above.

Other Notes:

- o For comparative purposes, forecasted Peak Demand profiles are reflective of DSM initiatives, but are not reflective of Ohio Customer Choice projections
- o For current planning purposes only, Ohio Power Company Sales for Resale customer Wheeling Power Company is assumed to merge with affiliate Appalachian Power Company (i.e. no impact on 'AEP East' results) effective 1-1-2012

SUPPLEMENTAL Appendix 4

Forecasted ENERGY REQUIREMENT Comparison by Recent "Forecast Vintage"

Columbus Southern Power Company

	Energy Requirement (GWh)				ENERGY Variances		
		Comparable Forecast Vintages					
	Sep-09	**Sep-09 (Rev) ***	**Apr-10**	**Oct-10**	**Apr-10 v. Sep-09(Rev)**	**Oct-10 v. Sep-09(Rev)**	**Oct-10 v. Apr-10**
BASED ON =>	*2010 LTFR*	*2010 LTFR (REV Form FE-D1)*	*2010 IRP*	*Latest Forecast*			
2010	22,272	22,272	22,094	22,910	-0.8%	2.9%	3.7%
2011	22,738	22,738	22,002	22,506	-3.2%	-1.0%	2.3%
2012	23,034	22,870	22,154	22,650	-3.1%	-1.0%	2.2%
2013	23,283	22,933	22,274	22,769	-2.9%	-0.7%	2.2%
2014	23,519	22,961	22,233	22,728	-3.2%	-1.0%	2.2%
2015	23,760	22,994	22,120	22,617	-3.8%	-1.6%	2.2%
2016	24,006	23,029	22,033	22,531	-4.3%	-2.2%	2.3%
2017	24,210	23,022	21,981	22,482	-4.5%	-2.3%	2.3%
2018	24,399	22,999	21,948	22,451	-4.6%	-2.4%	2.3%
2019	24,571	22,745	21,853	22,358	-3.9%	-1.7%	2.3%
2020	24,744	22,493	21,681	22,187	-3.6%	-1.4%	2.3%

Ohio Power Company

	Energy Requirement (GWh)				ENERGY Variances		
		Comparable Forecast Vintages					
	Sep-09	**Sep-09 (Rev) ***	**Apr-10**	**Oct-10**	**Apr-10 v. Sep-09(Rev)**	**Oct-10 v. Sep-09(Rev)**	**Oct-10 v. Apr-10**
BASED ON =>	*2010 LTFR*	*2010 LTFR (REV Form FE-D1)*	*2010 IRP*	*Latest Forecast*			
2010	30,809	30,809	30,462	30,754	-1.1%	-0.2%	1.0%
2011	31,245	31,245	30,603	31,331	-2.1%	0.3%	2.4%
2012	29,336	29,127	28,388	29,068	-2.5%	-0.2%	2.4%
2013	29,547	29,103	28,494	29,163	-2.1%	0.2%	2.3%
2014	29,697	28,992	28,489	29,159	-1.7%	0.6%	2.4%
2015	29,834	28,868	28,448	29,122	-1.5%	0.9%	2.4%
2016	29,979	28,751	28,412	29,090	-1.2%	1.2%	2.4%
2017	30,088	28,599	28,369	29,051	-0.8%	1.6%	2.4%
2018	30,182	28,431	28,354	29,039	-0.3%	2.1%	2.4%
2019	30,258	27,966	28,257	28,945	1.0%	3.5%	2.4%
2020	30,335	27,543	28,053	28,744	1.9%	4.4%	2.5%

AEP East

	Energy Requirement (GWh)				ENERGY Variances		
		Comparable Forecast Vintages					
	Sep-09	**Sep-09 (Rev) ***	**Apr-10**	**Oct-10**	**Apr-10 v. Sep-09(Rev)**	**Oct-10 v. Sep-09(Rev)**	**Oct-10 v. Apr-10**
BASED ON =>	*2010 LTFR*	*2010 LTFR (REV Form FE-D1)*	*2010 IRP*	*Latest Forecast*			
2010	124,680	124,680	121,863	123,523	-2.3%	-0.9%	1.4%
2011	127,247	127,247	121,716	124,572	-4.3%	-2.1%	2.3%
2012	128,748	128,374	123,044	125,877	-4.2%	-1.9%	2.3%
2013	129,874	129,080	123,868	126,690	-4.0%	-1.9%	2.3%
2014	130,808	129,545	124,012	126,836	-4.3%	-2.1%	2.3%
2015	131,758	130,026	123,885	126,713	-4.7%	-2.5%	2.3%
2016	132,766	130,561	123,941	126,775	-5.1%	-2.9%	2.3%
2017	133,638	130,961	124,111	126,951	-5.2%	-3.1%	2.3%
2018	134,467	131,316	124,400	127,245	-5.3%	-3.1%	2.3%
2019	135,257	131,140	124,641	127,490	-5.0%	-2.8%	2.3%
2020	136,062	131,019	124,764	127,618	-4.8%	-2.6%	2.3%

* In a 6/1/10 Company response to a Staff inquiry (e-mail from Steve Nourse to Dan Johnson, et al) in Case Nos. 10-501-EL-FOR and 10-502-EL-FOR, the CSP and OPCo 2010 LTFR Form 'FE-D1' was revised to reflect an "expanded" view of DSM activity *beyond* the initial (3-year) program period (2009-2011) originally projected --and filed-- in order to capture the impacts of long-term benchmark DSM requirements under S.B. 221. Such (expanded) DSM basis was subsequently reflected in the 'Apr-10' and 'Oct-10' energy requirement forecasts shown above.

Other Notes:
- o For comparative purposes, forecasted Energy profiles are reflective of DSM initiatives, but are not reflective of Ohio Customer Choice projections
- o For current planning purposes only, Ohio Power Company Sales for Resale customer Wheeling Power Company is assumed to merge with affiliate Appalachian Power Company (i.e. no impact on 'AEP East' results) effective 1-1-2012

SUPPLEMENTAL Appendix 5
Fuel Adequacy and Fuel Procurement Policy

The generating units of Ohio Power and Columbus Southern Power, known collectively as AEP Ohio, and the other AEP System-East Zone operating companies, which are predominantly coal-fired, are expected to have adequate fuel supplies to meet normal burn requirements in both the short-term and the long-term. AEPSC, acting as agent for AEP Ohio, is responsible for the procurement and delivery of fuel to AEP Ohio's generating stations, as well as setting coal inventory target level ranges and monitoring those levels. AEPSC's primary objective is to assure secure, flexible and competitively priced fuel supplies and transportation to meet generation requirements, recognizing the dynamic nature of fuel markets, environmental standards and regulatory requirements. Deliveries are arranged so that sufficient fuel is available at all times.

AEP-East obtains much of its total coal requirements under long-term arrangements, thus assuring the plants of a relatively stable and consistent supply of coal. The table below outlines the percentage of coal supply under contract for AEP Ohio for the years 2011 through 2020.

2011	81.72%
2012	53.70%
2013	46.51%
2014	43.25%
2015	42.50%
2016	44.40%
2017	44.45%
2018	18.97%
2019	7.52%
2020	0.00%

The remaining coal requirements are normally satisfied by making short-term purchases. Occasionally, purchases may also be made to test-burn any promising and potential new long-term sources of coal in order to determine their acceptability as a fuel source in a given power plant's generating units.

AEP-East's fuel requirements vary from plant to plant, depending upon such factors as environmental restrictions and boiler design, as well as the demand for electricity. In 2009, coal consumption at AEP-East operated plants aggregated to more than 48 million tons. Of this amount, AEP Ohio plants accounted for nearly 25 million tons. Historically, the coal supplies for the Ohio plants have primarily been provided by operations in Ohio, West Virginia, Kentucky, and Wyoming.

AEPSC, acting as agent for AEP Ohio, is also responsible for the procurement and delivery of gas to two AEP Ohio gas plants. These generating units do not have long term supply contracts as they provide peaking and intermediate load services. The two plants have had significantly low capacity factors with total consumption in 2009 of approximately 4.75 billion cubic feet. In addition, there are adequate fuel supplies available in the market, mitigating the need for long term supply contracts. The plants are served by various pipelines, including Texas Eastern, Columbia Gas and Dominion.