Operating Company	Generating Unit	Current Winter MW Rating	Date Placed In-Service or Added to Pool
OPCo	Amos 3 (2/3)	867	1973
OPCo	Gavin 1	1,320	1974
OPCo	Gavin 2	1,320	1975
I&M	Cook 1	1,084	1975
I&M	Cook 2	1,107	1978
APCo	Mountaineer	1,320	1980
APCo	Smith Mountain 3	106	1980
CSP	All Units[C]	2,061	1980
I&M	Rockport 1 (85%)	1,122	1984
KPCo	Rockport 1 (15%)	198	1984
I&M	Rockport 2 (85%)	1,105	1989
KPCo	Rockport 2 (15%)	195	1989
CSP	Zimmer	330	1991
CSP	Waterford	840	2005
APCo	Ceredo	516	2005
CSP	Darby	507	2007
CSP	Lawrenceburg	1,186	2007

[A] I&M's Breed Plant was designed as a 500 MW unit, and was subsequently re-rated at 325 MW. The Breed Plant was retired on March 31, 1994.

[B] OPCo has an application pending before the PUCO to retire Sporn 5.

[C] The 2,061 MW does not include CSP's Conesville Unit Nos. 1 and 2 (both 125 MW units), which were retired on December 31, 2005.

Figure 2 shows that at least one of the Pool members added generation in every year from 1951 to 1969, except for 1955, 1956 and 1962. As a result, in January 1970, the Pool members' capacity positions, on a MW basis, were as follows:

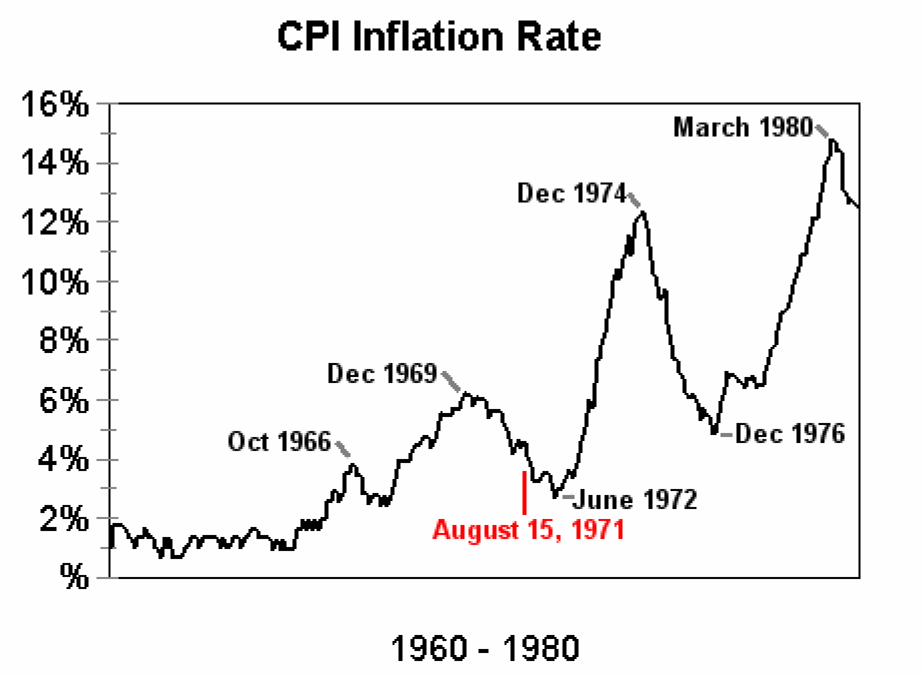
(As of January 1970)

Company	(Deficit)/Surplus	As % of Cap. Reservation
APCo	(231)	-7.7%
I&M	(541)	-22.0%
KPCo	669	162.9%
OPCo	103	2.4%

The relative deficit/surplus positions of the then Pool members were largely a result of KPCo's 1969 addition of Big Sandy Unit No. 2, the first in a series of generating units, each approximately 800 MW, that had been planned and were being built on the AEP-East System at the time.

On August 15, 1971, President Nixon imposed wage and price controls across the United States. As shown on Figure 3, inflation had been above historical levels since the mid-1960s, exceeding 6% briefly in 1970 and persisting above 4% in 1971.

Figure 3



The inflationary pressures experienced in the United States economy from the mid-1960s through the early 1980s had a significant impact on the cost of capacity additions for the AEP-East System.

From 1971 through 1980, the year CSP became a Pool member, the AEP-East System continued to add generation nearly every year to meet the projected needs of its customers.[1] By January 1973, when the 800 MW-series of units were all in service, but none of the 1300 MW units under construction had been completed, the Pool members' capacity positions, on a MW basis, were as follows:

(As of January 1973)

Company	**(Deficit)/Surplus**	**As % of Cap. Reservation**
APCo	433	11.0%
I&M	(1,490)	-44.3%
KPCo	568	111.1%
OPCo	489	9.2%

I&M's deficit position in January 1973 was largely a result of construction delays at the Cook Nuclear Plant, which was expected to be in-service by 1972 when the plant was announced in 1966.

During the 1970s, peak demands on the AEP-East System were beginning to show the effects of inflationary pressures and the 1973-1975 recession, which were pushing up electric rates and affecting the demand for electricity, and other differences among the AEP-East operating companies, such as the effects of geographical location, weather and electric heat saturation. For example, as shown on Figure 1, OPCo's actual peak demands from 1973 through 1976 (4205 MWs, 4336 MWs, 4244 MWs and 4287 MWs) were relatively flat, while APCo's actual peak demands continued to rise during the same period (3257 MWs, 3338 MWs, 3804 MWs and 4093 MWs). By 1977, however, three 1300 MW units, Amos Unit No. 3 (1973), Gavin Unit No. 1 (1974), Gavin

[1] As shown on Figure 2, during the 1971 to 1980 period, generation was added each year except for 1976, 1977 and 1979. When planning began for APCo's 1300 MW Mountaineer Plant in early 1974, it was expected to be placed in service in December 1977, but financing difficulties delayed its completion until 1980.

Unit No. 2 (1975), and the first nuclear generating unit on the AEP-East System, Cook Unit No. 1 (1975), had already been placed in service; Cook Unit No. 2 (1978) was substantially complete; and APCo's 1300 MW Mountaineer Plant had already been delayed to a 1980 in-service date. Because OPCo has not added any significant generation since Gavin Unit No. 2 went into service in 1975, any changes in OPCo's capacity situation since that time have been a function of generation additions made by other Pool members, and changes in the relative peak demands of the Pool members.

In the 1970s, APCo was exploring options for additional generating facilities to be located in the Commonwealth. In June 1974, the FPC issued APCo a license to construct an 1800 MW combination pumped storage and hydroelectric project involving two dams on the New River in Virginia ("Blue Ridge Project"). In 1976, legislation was enacted which incorporated a 26.5 mile segment of the New River into the Wild and Scenic Rivers System. The legislation prohibited any project, whether licensed or not, from invading, inundating or otherwise adversely affecting the incorporated river segment. This legislation effectively blocked the construction of the Blue Ridge Project.

On July 25, 1978, APCo announced it was investigating the possibility of building a nuclear generating plant in central Virginia. As envisioned, the nuclear plant was to consist of two reactors, each with a net generating capacity of between 1150 and 1288 MWs. On September 5, 1979, a little over five months after the March 28, 1979 accident at the Three Mile Island Nuclear Plant, APCo announced it was halting its study, citing a growing number of uncertainties involving nuclear power. Attachment 3 is a summary of events about this possible nuclear plant prepared from APCo's records.

By January of 1981, both Cook nuclear units were in service, four 1300 MW units -- Amos Unit No. 3, Gavin Unit No. 1, Gavin Unit No. 2 and APCo's Mountaineer Plant -- had begun operating, and CSP had become a Pool member (1980). Also, throughout the 1970s, as documented on Attachment 2, APCo, I&M and OPCo retired approximately 169 MWs, 157 MWs, 717 MWs of generation, respectively. This combination of generation additions and retirements, in conjunction with changes in relative peak demands that occurred throughout the 1970s and 1980, resulted in the following capacity positions, on a MW basis, for the Pool members, as of January 1, 1981:

(As of January 1981)

Company	(Deficit)/Surplus	As % of Cap. Reservation
APCo	(292)	-4.7%
CSP	(357)	-12.5%
I&M	(900)	-20.2%
KPCo	(226)	-17.6%
OPCo	1,775	26.3%

The Three Mile Island accident, and the back-to-back recessions of 1980 (January 1980 – July 1980) and 1981-1982 (July 1981 – November 1982), had a significant impact upon AEP-East System capacity additions post-1980, both in the case of plants still on the drawing board and those already under construction. On August 30, 1977, APCo applied to the FPC for a preliminary permit to study the feasibility of constructing a pumped-storage hydro-electric generating facility at one of two potential sites in western Virginia. The proposed storage project, which came to be known as Brumley Gap Project, was to have an installed capacity on the order of 3000 MWs, with an estimated average annual output of seven million megawatt hours. As shown on Attachment 4, which is a summary of events prepared at the time, between when the

Brumley Gap Project was announced in 1977 and 1982, a number of citizen and environmental groups actively opposed the issuance of a preliminary permit for the project. Although the FERC issued the preliminary permit on January 18, 1982, because of various court proceedings, APCo surrendered its preliminary permit for the Brumley Gap Project on November 1, 1982.

In 1984, I&M announced plans to delay the in-service date for Rockport Plant No. 2 from 1987 until 1989, while keeping Rockport Unit No. 1 on schedule for completion in December 1984. Construction at the Rockport Plant had commenced in 1977. The decision to delay the in-service date of Rockport Unit No. 2 was based upon the AEP-East System's slower than projected load growth and other factors including financing considerations.

As shown on Figure 1, the AEP-East System's peak demands from 1980 (when APCo's Mountaineer Plant, the last major generation addition on the AEP-East System prior to Rockport Unit No. 1, was placed in service) through 1983 were as follows: 1980, 14,474 MWs; 1981, 15,141 MWs; 1982, 15,047 MWs; and 1983, 14,236 MWs. Financing considerations also resulted in a unique ownership situation for the Rockport Plant.

Rockport Unit No. 1 is owned equally by I&M and AEP Generating Company ("AEGCo"), which was formed as a financing vehicle for the Rockport Plant. Rockport Unit No. 2 is owned by a non-affiliate lessor, with I&M and AEGCo each leasing 50% of the unit. AEGCo's respective shares (50% or 650 MWs) of both Rockport Unit Nos. 1 and 2 are purchased by I&M (70%) and KPCo (30%), through a long-term FERC-approved purchase power agreement. Because of the economic slowdown precipitated by the 1980 – 1982 recessions, 250 MWs of I&M's share of Rockport Unit No. 2 were sold to a non-affiliated utility under a 20-year unit power agreement that expired on December 31, 2009.

The same year that I&M announced the delayed in-service date for Rockport Unit No. 2 (*i.e.*, 1984), the three owners of the Zimmer Nuclear Plant, CSP, the Cincinnati Gas & Electric Company ("CG&E"), and Dayton Power and Light Company ("DP&L")[2], made an historic announcement -- the Zimmer Plant was to be converted to a single, 1300 MW coal-fired plant. At the time of the announcement, the Zimmer Plant was 97% complete as an 800 MW nuclear plant, having been under construction since 1972, well before CSP became an AEP-East operating company and joined the Pool in 1980. When the conversion of the Zimmer Plant was completed in 1991, CSP's 330 MW share of the plant was added to the Pool. The Zimmer Plant was the last major generation addition on the AEP-East System until 2005. The Pool members' capacity positions, on a MW basis, as of January 1991 were as follows:

(As of January 1991)

Company	**(Deficit)/Surplus**	**As % of Cap. Reservation**
APCo	(1,320)	-18.4%
CSP	(1,530)	-40.3%
I&M	635	14.4%
KPCo	53	3.8%
OPCo	2,161	33.4%

In addition to having an effect on capacity additions on the AEP-East System, the 1980 - 1982 recessions also had a profound impact on the peak demands of the AEP-East operating companies since then. Until the most recent recession (December 2007

[2] CSP, CG&E (now Duke Energy), and DP&L own 25.4%, 46.5% and 28.1% of the Zimmer Plant, respectively. Duke Energy and DP&L are not AEP affiliates.

– June 2009), the 1981-1982 recession was considered the worst recession since the Great Depression. Yet, the effect of that recession, along with all other factors that effect peak demands, has varied significantly from Pool member to Pool member.

Figure 4 sets out the peak demands of the Pool members in 1979, the year before the 1980 recession, and 2007, the beginning of the most recent recession. It also shows the percentage increase in peak demands from 1979 to 2007, calculated as follows:

(2007 peak demand – 1979 peak demand) ÷ 1979 peak demand

Figure 4
Pool Members
Percentage Increase in Peak Demands
1979 – 2007

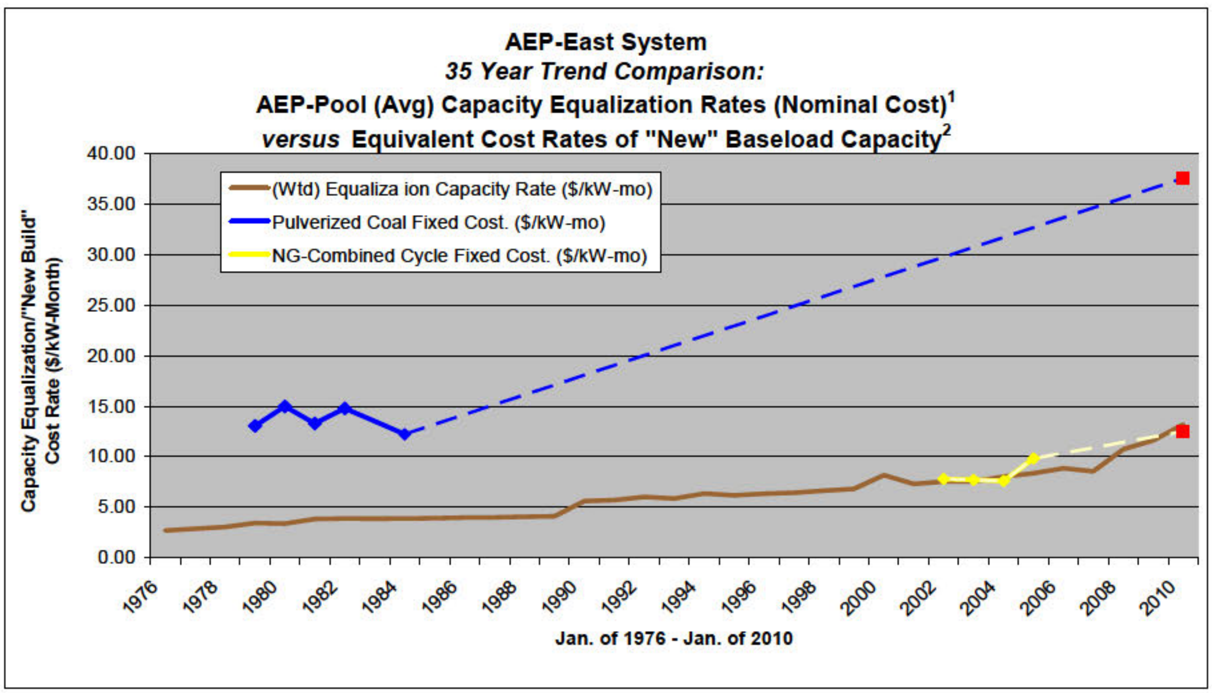
Company	1979 Peak Demand (MW)	2007 Peak Demand (MW)	Percentage Increase
APCo	4493	8003	78%
CSP	1852	4723	155%
I&M	2923	4528	55%
KPCo	876	1808	106%
OPCo	4950	5491	11%

From 1991 until 2005, the Pool members did not add any significant capacity on the AEP-East System. Consequently, the changes in the Pool members' relative capacity positions during that time-frame were primarily a function of differences in peak demands among the Pool members.

The capacity charges that APCo pays to a surplus Pool member under the IA are calculated by multiplying the surplus member's surplus capacity by its capacity equalization rate ("capacity rate"). The capacity rate is made up of two components: the primary capacity investment rate and the fixed operating rate. Under the IA, the primary capacity investment rate reflects the surplus member's embedded cost of capacity times a FERC-approved carrying charge rate; the fixed operating rate reflects the surplus member's non-hydro plant operating expense and one-half of the non-hydro plant maintenance expense divided by its installed capacity.

Figure 5 shows the AEP-East System capacity rates from January 1976 through January 2010, as well as comparative fixed cost figures for building new pulverized coal or combined cycle units. This comparison illustrates that, until recently, capacity equalization rates paid by APCo have been below the annualized cost of new base load generation.

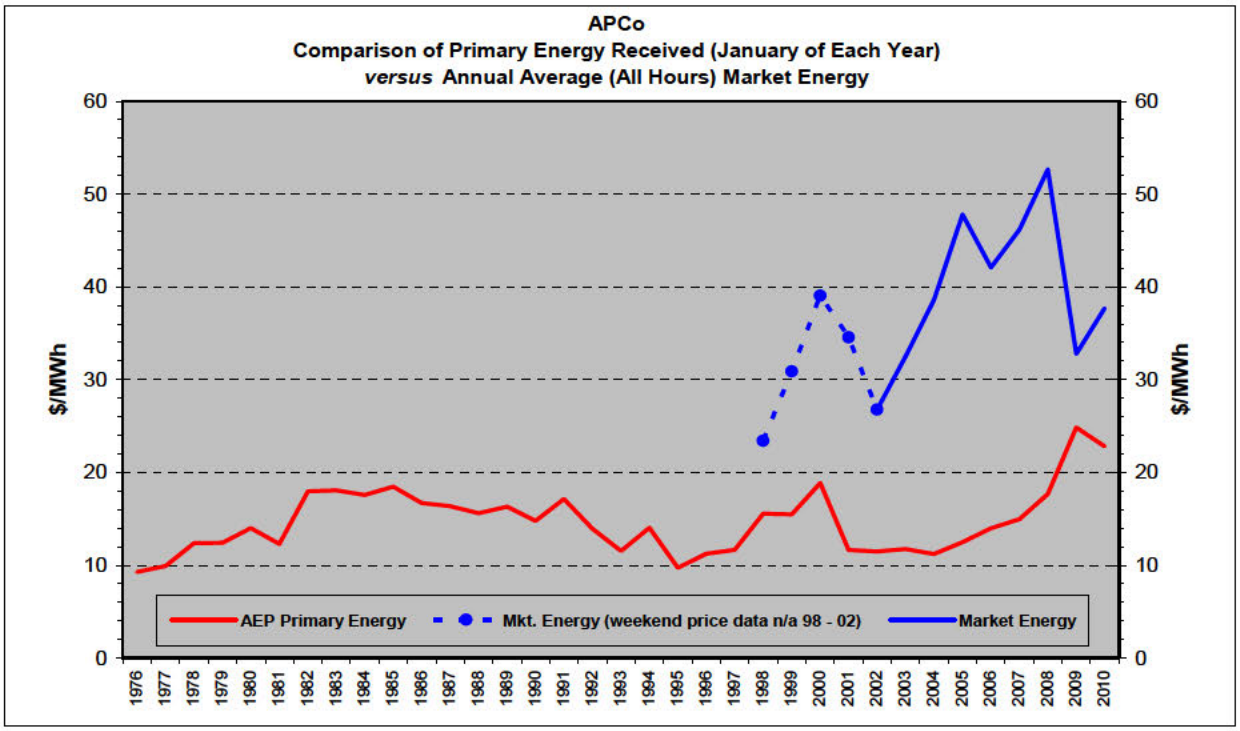
Figure 5



Data Sources: (1) AEP System East Equalization Rates paid by APCo: based on AEP Interchange Power Billing Statements, "Member Primary Capacity Surplus and Deficit", Months (January only) 1976 - 2010
(2) Plant Fixed Cost: based on RFC Region data from Ventyx Velocity Suite, "Generating Plant Statistics" (1991) dataset or FERC Form 1 (1979-2005 data points) and the U.S. Energy Information Administration (EIA) (2010 data points only)

Likewise, Figure 6 compares the historical cost of energy received by APCo through the IA to the indexed cost of energy from the available energy markets. As with the cost of capacity paid in the IA versus the contemporaneous cost of new-build base load capacity shown in Figure 5, the costs that APCo has paid for energy required to meet its customers' needs continues to compare favorably to market options. In particular, as represented in Figure 6, such "primary energy rates" have remained relatively stable when compared to recent energy market volatility.

Figure 6



Market Energy Price Hub: PJM West - 1998-2001; VACAR 2002-2004; AD Hub 2005-2010

For most of the time from 1976 until 1990, OPCo was the only surplus Pool member. During that period, the capacity rate paid by deficit Pool members remained relatively flat. This indicates that OPCo's embedded cost of capacity and plant O&M expenses remained relatively stable over this period, even though the FERC approved a higher Pool carrying charge rate in 1979.

Since 1990, the year after Rockport Unit No. 2 was placed in service, both OPCo and I&M have been surplus Pool members. I&M's higher embedded cost of capacity[3] explains the increase in the capacity rate in 1990.

Changes in the capacity rate from 1990 to 2010 were primarily attributable to increases in the embedded cost of OPCo's capacity caused by environmental regulations. While I&M's embedded cost of capacity did increase during this period due to on-going investments in the Cook Nuclear Plant, OPCo made significant investments in facilities to control the emissions of sulfur dioxide and nitrogen oxides. Figure 7 lists the flue-gas desulfurization facilities ("FGDs" or "scrubbers") and selective analytic reduction equipment ("SCRs") that OPCo has added to its generating plants.

Figure 7
Ohio Power Company
FGDs and SCRs

Plant	Equipment	Year
Gavin 1	FGD	1994
Gavin 2	FGD	1995
Gavin 1 and 2	SCRs	2001
Amos 3 (jointly owned with APCo)	SCR	2002
Cardinal 1	SCR	2003
Muskingum River 5	SCR	2005
Mitchell 1 and 2	FGDs	2007
Mitchell 1 and 2	SCRs	2007
Cardinal 1	FGD	2008
Amos 3 (jointly owned with APCo)	FGD	2009

The 1990s also saw the introduction of "open access transmission" and increased competition in wholesale generation markets. Many states examined retail

[3] I&M's Cook Nuclear Plant and Rockport Unit Nos. 1 and 2 were placed in-service either in or after 1975, the year OPCo added its last generating facility.

competition, and several, including three served by AEP-East operating companies – Ohio, Michigan and Virginia -- implemented retail competition.

In 2004, the AEP-East operating companies joined PJM Interconnection, L.L.C. ("PJM"), which is both a Regional Transmission Organization ("RTO") that has functional control over transmission assets in its footprint, and a generation power pool that dispatches over 167,000 MWs of capacity in the District of Columbia and all or parts of 13 states. By the fall of that year, approximately three years before the country's most recent recession started in December 2007, the Integrated Resource Plan ("IRP") for the AEP-East System was projecting that over 3000 MWs of new capacity would be required by 2010. Natural gas combustion turbines ("CTs") were identified as the most economic, incremental generation for the bulk of these additions. At that time, it was estimated that these new CTs, with expected 12,500 BTU/kWh heat rates, would cost approximately $475/kW in 2005 dollars.

When compared to the pulverized coal, nuclear and hydro-electric generating facilities that Pool members had brought on-line from 1951 to 1991, beginning in 2004, AEP planners had a vastly different and growing array of supply-side and demand-side options from which to choose to meet that demand. The list of supply side options included or would soon include the following: coal: pulverized coal ("PC"), advanced PC, and integrated gasification combined cycle ("IGCC") plants; natural gas: conventional combined cycle ("CC"), advanced CC, conventional CT and advanced CT plants; nuclear plants; and renewables, such as biomass, geothermal, landfill gas, conventional hydro, wind and solar thermal. As shown on the chart on page 10 of the main portion of this Report on Capacity Matters, the costs of these supply side options, in 2010 dollars, range from a low of $665/kW for natural gas advanced CT peaking capacity to $8,232/kW for landfill gas. AEP planners also have available an increased variety of demand-side management, energy efficiency and demand response programs ("DSM" or "EE/DR") intended to limit load growth.

In the late 1990s, through the early part of the last decade, many new, non-regulated, natural gas merchant plants had been built by Independent Power Producers ("IPPs") when natural gas prices were in the $2-$3/MMBTU range. These prices created "spark spreads," the difference between gas prices and electricity prices, which appeared to favor gas generation as a low-cost form of generation. Once gas prices began rising, many of these gas plants became "distressed' in the sense that they were rarely dispatched as economic resources.

Given the AEP-East System's projected capacity needs, in the fall of 2004, AEP launched an initiative to identify and evaluate existing "distressed" marketplace assets to determine if these assets could be acquired at a discount (when compared to newly-built generation) that exceeded the near-term carrying costs of these assets.

Several facilities, which were either already in operation or under construction, and which were directly connected to the AEP transmission system, as well as an asset relocation option, were identified for possible acquisition. In 2005, AEP pursued the acquisition of the Waterford and Ceredo Plants. CSP purchased Waterford in September 2005, and APCo purchased Ceredo in December 2005.

Waterford is a combined cycle ("CC") plant with a winter capacity and heat rate of approximately 840 MW and 7280 BTUs/kWh, respectively. It consists of three GE 7FA

CTs and one GE D11 steam turbine bottoming cycle. The plant is connected to the AEP 345 kV system in CSP's service territory, near OPCo's Muskingum River Plant.

Ceredo is a CT plant with a winter capacity and heat rate of approximately 516 MW and 12,000 BTUs/kWh, respectively. Ceredo is comprised of six GE 7EA CTs with evaporative coolers. The plant is connected to the APCo 138 kV system.

At the time the acquisition of the Waterford and Ceredo Plants was being negotiated, CSP was the most deficit Pool member based upon the projected difference between its Primary Capacity and its Primary Capacity Reservation, divided by its Primary Capacity Reservation, as those terms are defined in the Interconnection Agreement. Figure 8 shows the forecast used to assign the Waterford Plant to CSP.

Figure 8

Forecasted East Pool Capacity Settlement

Forecast Year: 2006

AEP Member	**Capacity Positions Prior to Waterford**				
	Member Load Ratios (MLRs)	Member Primary Capacity (MW)	Member Primary Cap Reservation (MW)	Surplus/ (Deficit) (MW)	Primary Capacity Deficit (%)
(1)	(2)	(3)	(4)=(2)xSum(3)	(5)=(3)-(4)	(6)=(5)/(4)
2006					
APCO	0.31435	5,899	7,284	(1,385)	-19%
CSP	0.18443	2,595	4,274	(1,679)	**-39%**
I&M	0.19330	5,100	4,479	621	---
KPCO	0.07339	1,450	1,701	(251)	-15%
OPCO	0.23454	8,129	5,435	2,694	---
TOTAL	1.00000	23,173	23,173	-	

Multiplying each Pool member's projected MLR times the projected total Primary Capacity for all five Pool members produces the projected Member Primary Capacity Reservation for each Pool member. The difference between each Pool member's Primary Capacity and its Member Primary Capacity Reservation represents each member's MW surplus or deficit position in the Pool. To determine the relative deficits of the short Pool members, each of these member's deficits is divided by its respective Member Primary Capacity Reservation.

The Ceredo Plant was assigned to APCo, even though it was in an approximate tie with CSP as the most capacity deficit Pool member following CSP's acquisition of the Waterford Plant. As shown in Figure 9, APCo and CSP each had a forecasted deficit of approximately 23%.

Figure 9

Forecasted East Pool Capacity Settlement
Forecast Year: 2006

AEP Member (1)	**Capacity Positions Prior to Ceredo** Member Load Ratios (MLRs) (2)	Member Primary Capacity (MW) (3)	Member Primary Cap Reservation (MW) (4)=(2)xSum(3)	Surplus/ (Deficit) (MW) (5)=(3)-(4)	Primary Capacity Deficit (%) (6)=(5)/(4)
2006					
APCO	0.31435	5,899	7,613	(1,714)	**-23%**
CSP	0.18443	3,447	4,467	(1,020)	**-23%**
I&M	0.19330	5,100	4,682	418	---
KPCO	0.07339	1,450	1,777	(327)	-18%
OPCO	0.23454	8,325	5,681	2,644	---
TOTAL	1.00000	24,221	24,221	(0)	

Limited consideration was given to splitting the ownership of the Ceredo Plant between APCo and CSP. However, splitting ownership of the Ceredo Plant, particularly between two companies with different regulatory and customer choice regimes, was considered potentially problematic. While there are existing AEP generating plants that are owned by more than one Pool member (*e.g.,* Amos Unit No. 3), there were concerns with making additional shared ownership assignments if, for example, the Interconnection Agreement were ever to be terminated.

As part of the assignment process, consideration was also given to the fact that the Ceredo Plant was physically located in West Virginia, a state served by APCo. While PJM does not require generation to be near the load it serves, all else being equal, generation nearer such load is preferred since it may mitigate concerns regarding congestion and losses and events such as major transmission line outages, or grid emergency isolation and/or blackout events. Fundamentally, these are all events that can create issues with generation reaching the load it is intended to serve, the farther away such generation is from such load.

In 2006, while AEP continued to pursue "distressed" gas generation, CSP/OPCo and APCo also initiated proceedings that would allow them to build IGCC plants in Ohio and West Virginia. The impetus behind those filings was the potential regulation of green house gases ("GHG"), including carbon dioxide. The IGCC plants were intended to meet long-term base load capacity needs identified in the AEP-East operating companies' IRP process, while the "distressed" natural gas CC and CT plants would provide intermediate and peaking power, respectively.

Also, in 2006, AEP pursued the acquisition of the Darby Plant, which is nearly identical to the Ceredo Plant, consisting of six GE 7EA CTs with a winter capacity of approximately 507 MW. CSP purchased Darby in April 2007.

CSP was assigned the Darby Plant because it was the most deficit Pool member following APCo's addition of Ceredo, and CSP's retirement of Conesville Unit Nos. 1 and 2 in December 2005. As seen in Figure 10, for 2007, CSP had a forecasted deficit of approximately 26%, compared to capacity deficits of 22% and 21%, respectively, for APCo and KPCo. The projected deficit positions of APCo, CSP and KPCo for the subsequent years 2008 through 2011 were also forecasted, and CSP was projected to remain the most deficit Pool member in those years due to its expected higher rate of load growth than either APCo or KPCo.

Figure 10

Forecasted East Pool Capacity Settlement

Forecast Year: 2007

AEP Member (1)	**Capacity Positions Prior to Darby** Member Load Ratios (MLRs) (2)	Member Primary Capacity (MW) (3)	Member Primary Cap Reservation (MW) (4)=(2)xSum(3)	Surplus/ (Deficit) (MW) (5)=(3)-(4)	Primary Capacity Deficit (%) (6)=(5)/(4)
2007					
APCO	0.32563	6,249	8,044	(1,795)	-22%
CSP	0.18578	3,404	4,586	(1,182)	**-26%**
I&M	0.19314	5,115	4,770	345	---
KPCO	0.07390	1,450	1,825	(375)	-21%
OPCO	0.22155	8,480	5,472	3,008	---
TOTAL	1.00000	24,698	24,698	-	

As AEP was continuing to work on the Darby acquisition, the Lawrenceburg Plant was identified as an additional acquisition opportunity. Lawrenceburg is a two-unit natural gas CC plant located in Indiana. Each unit is a two-on-one configuration with two GE 7FA CTs and a GED11 steam turbine. Each unit has a winter capacity of approximately 593 MW, for a total plant winter capacity of approximately 1186 MW.

Due to the size of Lawrenceburg, consideration was given once again to shared ownership of the plant. Consideration was also given to an assignment of some portion of Lawrenceburg to I&M because the plant is physically located in Indiana.

Given these considerations, before assigning Lawrenceburg, AEP forecasted the relative capacity positions of the Pool members, not just in the near-term, but in the intermediate term as well. The capacity forecast used to make the assignment of Lawrenceburg to CSP is shown in Figure 11.

Figure 11

Forecasted East Pool Capacity Settlement
Forecast Years: 2007-2011

AEP Member (1)	Member Load Ratios (MLRs) (2)	Member Primary Capacity (MW) (3)	Member Primary Cap Reservation (MW) (4)=(2)xSum(3)	Surplus/ (Deficit) (MW) (5)=(3)-(4)	Primary Capacity Deficit (%) (6)=(5)/(4)
	Capacity Positions Prior to Lawrenceburg				
2007					
APCO	0.31084	6,254	7,785	(1,531)	-20%
CSP	0.19195	3,761	4,808	(1,047)	**-22%**
I&M	0.19954	5,118	4,998	120	---
KPCO	0.06874	1,450	1,722	(272)	-16%
OPCO	0.22892	8,463	5,734	2,729	---
TOTAL	1.00000	25,046	25,046	(0)	
2008					
APCO	0.31259	6,214	7,829	(1,615)	**-21%**
CSP	0.19177	3,875	4,803	(928)	-19%
I&M	0.19757	5,148	4,948	200	---
KPCO	0.06895	1,450	1,727	(277)	-16%
OPCO	0.23032	8,389	5,769	2,620	---
TOTAL	1.00119	25,076	25,076	0	
2009					
APCO	0.30852	6,226	7,727	(1,501)	-19%
CSP	0.19033	3,627	4,767	(1,140)	**-24%**
I&M	0.19789	5,178	4,956	222	---
KPCO	0.06799	1,460	1,703	(243)	-14%
OPCO	0.22863	8,389	5,726	2,663	---
TOTAL	0.99336	24,880	24,880	0	
2010					
APCO	0.30305	6,226	7,590	(1,364)	-18%
CSP	0.18831	3,462	4,716	(1,254)	**-27%**
I&M	0.19578	5,437	4,904	533	---
KPCO	0.06693	1,460	1,676	(216)	-13%
OPCO	0.22518	7,942	5,640	2,302	---
TOTAL	0.97925	24,527	24,526	0	
2011					
APCO	0.30364	6,226	7,605	(1,379)	-18%
CSP	0.18998	3,462	4,758	(1,296)	**-27%**
I&M	0.19713	5,542	4,937	605	---
KPCO	0.06692	1,460	1,676	(216)	-13%
OPCO	0.22577	7,942	5,655	2,287	---
TOTAL	0.98345	24,632	24,631	0	
5-YR AVG.					
APCO	0.30773	6,229	7,707	(1,478)	-19%
CSP	0.19047	3,637	4,770	(1,133)	**-24%**
I&M	0.19758	5,285	4,949	336	---
KPCO	0.06791	1,456	1,701	(245)	-14%
OPCO	0.22776	8,225	5,705	2,520	---
TOTAL	0.99145	24,832	24,832	0	

In order to avoid legal complications associated with the plant being owned by an AEP operating company that does not provide retail service in Indiana and is not recognized as an Indiana utility, AEGCo purchased Lawrenceburg in May 2007. AEGCo is already recognized as an Indiana utility due to its previously mentioned partial ownership of the Rockport plant. The FERC approved a 10-year unit power agreement for the sale of Lawrenceburg's output from AEGCo to CSP shortly thereafter.

Following the assignment of Lawrenceburg to CSP, AEP continued to pursue additional "distressed" generation opportunities with the expectation that the next assignment would likely go to APCo given its projected capacity deficit. In September 2007, AEGCo purchased the partially completed, nominal 580 MW Dresden National Gas CC plant located in Dresden, Ohio. Dresden consists of one unit that is a two-on-one configuration of two GE7FA CTs and one GED11 steam turbine. At the time of purchase, Dresden was approximately 45% complete. Shortly after Dresden's purchase, work began to complete construction of the plant. Although AEP pursued other "distressed" generation into 2008, the Dresden Plant was the last such plant that AEP was able to acquire.

During this time frame, AEP planners were facing new challenges on several fronts. To begin with, the AEP-East System was facing a number of unit retirements, in part because of a Consent Decree entered into by AEP, the Federal Government and other stakeholders in December 2007. Although legislation limiting carbon dioxide emissions had stalled, the EPA also initiated a series of actions that could dramatically affect the cost and viability of coal generation in the future. These actions are depicted on Attachment 5. These evolving regulations may require unit-specific, rather than system-wide solutions.

In this same time frame, the 2007-2009 recession reduced AEP-East System loads and the need for capacity. This in turn led to construction being halted on the Dresden Plant. The economic downturn also played a part in putting an end to the acquisition of “distressed” natural gas generation because the few remaining assets that had not yet been purchased were no longer economical. Along with adverse decisions by regulators and courts, the recession derailed plans for IGCCs in Ohio and West Virginia. All of these circumstances are factors that contributed to the current capacity surplus and deficit positions among the Pool members and APCo’s capacity equalization payments.

The relative surplus and deficit positions of the Pool members today, the capacity rate paid by deficit members, and the level of APCo’s capacity equalization payments, are the cumulative result of the decisions and circumstances described in this Appendix A. In many instances, the decisions described herein were based upon projections or assumptions. In some cases, these projections or assumptions did not materialize. In other cases, the results of these decisions were impacted by circumstances beyond AEP’s control. Given such things as the divergent cost of future supply-side and demand-side options, and uncertainties in environmental regulations, it will only get more difficult, over time, for Pool members to respond to such matters within the current structure of the Pool Agreement.

Ex PLC 9

Attachment 1

Interconnection Agreement

COMPOSITE COPY

INTERCONNECTION AGREEMENT

BETWEEN

APPALACHIAN POWER COMPANY

KENTUCKY POWER COMPANY

OHIO POWER COMPANY

COLUMBUS AND SOUTHERN OHIO ELECTRIC COMPANY *

INDIANA & MICHIGAN ELECTRIC COMPANY

AND WITH

AMERICAN ELECTRIC POWER SERVICE CORPORATION,

AS AGENT

Dated: July 6, 1951, as modified and supplemented by:

Modification No. 1, August 1, 1951
Modification No. 2, September 20, 1962
Modification No. 3, April 1, 1975
Supplement No. 1 to
Modification No. 3, August 1, 1979
Supplement No. 2 to
Modification No. 3, August 27, 1979
Modification No. 4, November 1, 1980 *
Compliance Filing (FERC ordered), Opinion 266,
Docket Nos. ER84-579-006 and EL86-10-001

* Pursuant to Modification No. 4 the terms "Member" and "Members", whenever said terms appear in the 1951 Agreement, shall, on and after the time when Modification No. 4 shall become effective, include Columbus Company.

CONTENTS

0.1 THIS AGREEMENT, made and entered into as of the 6th day of July, 1951 by and between APPALACHIAN POWER COMPANY (Appalachian Company), a Virginia corporation, KENTUCKY POWER COMPANY (Kentucky Company), a Kentucky corporation, OHIO POWER COMPANY (Ohio Company), an Ohio corporation, COLUMBUS AND SOUTHERN OHIO ELECTRIC COMPANY (Columbus Company), an Ohio corporation, INDIANA & MICHIGAN ELECTRIC COMPANY (Indiana Company), an Indiana corporation, said companies (herein sometimes called 'Members' when referred to collectively and 'Member' when referred to individually), being affiliated companies of an integrated public utility electric system, and AMERICAN ELECTRIC POWER SERVICE CORPORATION (Agent), a New York corporation, being a service company engaged solely in the business of furnishing essential services to the aforesaid companies and to other affiliated electric utility companies.

The term "affiliate" shall include American Electric Power Company, Inc., Appalachian Power Company, Columbus and Southern Ohio Electric Company, Indiana & Michigan Electric Company, Kentucky Power Company, Ohio Power Company, Kingsport Power Company, Michigan Power Company, Wheeling Electric Company, and any subsidiaries, direct or indirect, of the foregoing.

W I T N E S S E T H,

T H A T:

0.2 WHEREAS, the Members own and operate electric facilities in the states herein indicated: (i) Appalachian Company in Tennessee, Virginia, and West Virginia, (ii) Kentucky Company in Kentucky, (iii) Ohio Company in Ohio and West Virginia, and (iv) Indiana Company in Indiana and Michigan, and (v) Columbus Company in Ohio, and

0.3 WHEREAS, the Members' electric facilities are now and have been for many years interconnected through their respective transmission facilities at a number of points (hereby designated and hereinafter called "Interconnection Points"), such facilities and the transmission facilities of other affiliated electric utility companies forming an integrated transmission network; and

0.4 WHEREAS, the transmission facilities of each Member are interconnected at a number of points with the transmission facilities of various non-affiliated electric utility companies, and those of Appalachian Company are interconnected with those of Tennessee Valley Authority, (said companies and Tennessee Valley Authority hereinafter sometimes called "Foreign Companies" when referred to collectively and "Foreign Company" when referred to individually; and

0.5 WHEREAS, the Members through cooperation with each other have been successful for some years in achieving substantial economies in the conduct of their business by coordinating the expansion and operation of their power supply facilities; and

0.6 WHEREAS, the Members believe that a fuller realization of the benefits and advantages through coordinated operation of their electric supply facilities will be better assured and more efficiently and economically achieved by having such operation directed and supervised by a centrally located organization skilled in the technique of system operation on a large scale and thoroughly familiar with the power supply facilities of the Members, and that their participation in the coordinated expansion and operation of their facilities will be simplified and facilitated by having such procedures conducted by a single clearing agent; and

0.7 WHEREAS, the Members believe that the Agent designated herein for such purpose is qualified to perform such services for them.

0.8 NOW, THEREFORE, in consideration of the premises and of the mutual covenants and agreements hereinafter contained, the parties hereto agree as follows:

ARTICLE I

PROVISIONS FOR, AND CONTINUITY OF INTERCONNECTED OPERATION

1.1 Throughout the duration of this agreement the systems of the Members shall be operated in continuous synchronism through each of the various lines interconnecting their respective systems; provided, however, if synchronous operation of the systems through a particular line or lines becomes interrupted because of reasons beyond the control of any Member or because of scheduled maintenance that has been agreed to by the Members, the Members shall cooperate so as to remove the cause of such interruption as soon as practicable and restore the affected line or lines to normal operating condition.

1.2 Each Member shall keep the portions of the lines interconnecting their respective systems, together with all associated facilities and appurtenances, that are located on their respective sides of the Interconnection Points in a sutiable condition of repair at all times in order that said lines will operate in a reliable and satisfactory manner and that reduction in their capacity will be avoided.

ARTICLE 2

OPERATING COMMITTEE

2.1 The parties herein shall appoint representatives to act as the "Operating Committee" in cooperation with each other and the Agent in the coordination and operation and/or use of the electric power sources of or available to the Members and of their transmission and distribution and substation facilities to the end that the advantages to be derived thereunder may be realized to the fullest practicable extent.

2.2 Each Member shall designate in writing delivered to the other Members and Agent, the person who is to act as its representative on said committee and the person or persons who may serve as alternate whenever such representative is unable to act. Agent shall designate in writing delivered to the Members the person who is to act as its representative on said committee. Such person shall act as chairman of the Operating Committee and shall be known as the "Pool Manager". All such representatives or alternates so designated shall be fully authorized to cooperate with the other representatives or alternates in all matters described in this agreement as responsibilities of the Operating Committee.

ARTICLE 3

AGENT'S RESPONSIBILITIES

3.1 For the purpose of carrying out the coordinated operation of the generating and transmission facilities of Members and the most efficient use of the energy produced by them and of other energy available to them, the Members hereby delegate to Agent and Agent hereby accepts the responsibility of supervising and directing such operation and use, and in furtherance thereof Agent agrees as follows; viz:

3.11 To coordinate the operation of the electric power sources of or available to the Members, which include their own generating stations and electric power available to them through interconnection with affiliated companies other than Members and Foreign Companies.

3.12 To arrange for and conduct such meetings of the Operating Committee as may be required to insure the effective and efficient carrying out of all matters of procedure essential to the complete performance of the provisions of this agreement.

3.13 To prepare and collect such log sheets and other records as may be needed to afford a clear history of the electric power and energy supplied under this agreement. Preparation and collection of such log sheets and other record shall be coordinated with similar responsibilities of the Members as provided for under Article 9.

3.14 To render to each Member as promptly as possible after the end of each calendar month a statement setting forth the electric power and energy transactions carried out during such month pursuant to the provisions of this agreement in such detail and with such segregations as may be needed for operating records or for settlements hereunder.

3.15 To make arrangements with Foreign Companies on behalf of the Members for the purchase, sale, or interchange of power and energy between such companies and the Members, such arrangements to be made in addition to similar arrangements to be made under agreements between an individual Member and a Foreign Company and to be made whenever in the judgment of the Members the effecting of matters of operation and contract related thereto can be simplified and their performance facilitated.

3.16 To carry out cash settlements for electric power and energy supplied under this agreement. Settlements by the Members shall be made for each calendar month through an account (hereby designated and hereinafter called "SYSTEM ACCOUNT") to be administered by Agent. Payments to or from such account shall be made to or by Agent as clearing agent of the account. The total of the payments made by Members to the SYSTEM ACCOUNT for a particular month shall be equal to the payments made to the Members from the SYSTEM ACCOUNT for such month.

ARTICLE 4

MEMBERS' OBLIGATIONS AND RIGHTS

4.1 For the purpose of obtaining the most efficient coordinated expansion and operation of their electric power supply facilities the Members hereby agree to operate and utilize their electric power sources under the direction of the Pool Manager in such manner that each Member shall receive at all times sufficient electric power and energy from such sources to meet its specific load obligations.

Each member shall, to the extent practicable, install or have available to it under contract such capacity as is necessary to supply all of the requirements of its own customers.

4.2 The Members agree that their electric power sources, which shall include all the generating stations owned by the Members and all electric power available to them through interconnection with affiliated companies other than Members and Foreign Companies, shall be used as needed to carry the combined load obligations of the Member under the direction of the Pool Manager. Each Member in return shall receive at all times sufficient electric power and energy from such sources to meet the specific load obligations of such Member.

4.3 The Members recognize that in carrying out the interconnected operation of their respective transmission systems as herein provided, electric energy being received by a portion of a particular Member's transmission system from another portion of such system or from the system of another interconnected company, or electric energy being delivered by a portion of a particular Member's transmission system to another portion of such system or to the system of another interconnected company, may flow over the transmission system of another Member. In respect of such flow of electric energy (hereinafter called "Energy Transfer") the Members agree that such Energy Transfer over their respective transmission facilities shall be permitted whenever it occurs, and, except as may be specifically agreed to otherwise by the Members, no Member shall make a charge at any time to another Member to permit such Energy Transfer. Electric power and energy associated with such Energy Transfer, including electrical losses associated therewith, shall be accounted for each clockhour. Proper consideration shall be given to such electrical losses in accordance with the manner determined and agreed upon by the Operating Committee, and such consideration shall be fully in accord with the provisions of LINE LOSS FACTOR as defined under subdivision 5.15 of Article 5.

ARTICLE 5

DEFINITIONS OF LOAD, CAPACITY, AND ENERGY CLASSES
AND RELATED FACTORS ASSOCIATED WITH SETTLEMENTS
FOR POWER SUPPLIED FROM MEMBER'S ELECTRIC POWER SOURCES

5.1 Load, capacity, and energy shall be designated and allocated to various classes for the purposes of effecting settlements under this agreement. Load, capacity, and energy classes and related factors associated with the settlement for electric power and energy supplied from electric power sources of the Members are defined as follows; viz:

Load

5.2 MEMBER LOAD OBLIGATION - A Member's internal load plus any firm power sales to Foreign Companies and to affiliated companies other than Members. Principally characterized by the Member assuming the load obligation as its own firm power commitment and by the Member retaining advantages accruing from meeting the load.

5.3 SYSTEM LOAD OBLIGATION - Load obligation shared proportionately by the Members where one Member or Agent will act as Agent of the Members in meeting the commitment; principally characterized by the load not being considered as a part of any MEMBER LOAD OBLIGATION.

(Examples of SYSTEM LOAD OBLIGATIONS are electric power and energy deliveries made to Foreign Companies under emergency and storage power arrangements with such companies.)

5.4 MEMBER DEMAND - MEMBER LOAD OBLIGATION determined on a clock-hour integrated kilowatt basis.

5.5 MEMBER MAXIMUM DEMAND - The MEMBER MAXIMUM DEMAND in effect for a calendar month for a particular Member shall be equal to the maximum MEMBER DEMAND experienced by said Member during the twelve consecutive calendar months next preceding such calendar month.

5.6 MEMBER LOAD RATIO - The ratio of a particular Member's MEMBER MAXIMUM DEMAND in effect for a calendar month to the sum of the five MEMBER MAXIMUM DEMANDS in effect for such month.

Capacity

5.7 MEMBER PRIMARY CAPACITY - The aggregate capacity of the electric power sources of a particular Member, in Kilowatts, that is normally expected to be available to carry load. Such capacity shall include (i) the capacity installed at the generating stations owned by the Member and (ii) the capacity available to that Member through inter-connection arrangements with affiliated companies or Foreign Companies, if so designated by the Operating Committee with the approval of the Members.

5.7.1 All determinations by the Operating Committee pursuant to (ii) of Section 5.7 with respect to purchases of capacity from non-affiliated companies shall take into account, but shall not be limited to, the following circumstances and considerations: (1) the term during which such capacity will be available, a commitment from a reliable source of power and energy for at least five years being normally regarded as appropriate for inclusion as a capacity source of a particular Member, with purchases of a short or intermediate duration being normally regarded as System purchases under Article 7; (2) whether the availability of the purchased capacity will be comparable to the availability of the installed primary capacity of the Members, although the Operating Committee may make adjustments in the quantity of purchased capacity to be included as Member Primary Capacity to give effect to any disparity in the availability of such purchased capacity; (3) the need on the part of a Member with a Member Primary Capacity deficit of an extended nature to rectify or alleviate such deficit and the interest of all Members in maintaining an equalization among the Members of capacity resources over a period of time.

5.7.2 In the event that arrangements are made hereunder for any Member to make capacity available to an affiliated company or to a Foreign Company through the sale by such Member, for its own account, of unit capacity or other non-firm capacity, the amount of the capacity so sold shall be excluded from the Primary Capacity of such Member.

5.8 SYSTEM PRIMARY CAPACITY - The sum of the MEMBER PRIMARY CAPACITY of all the Members.

5.9 MEMBER PRIMARY CAPACITY RESERVATION - SYSTEM PRIMARY CAPACITY multiplied by the MEMBER LOAD RATIO of a particular Member.

5.10 MEMBER PRIMARY CAPACITY SURPLUS - Difference between the MEMBER PRIMARY CAPACITY and MEMBER PRIMARY CAPACITY RESERVATION of a particular Member, when such MEMBER PRIMARY CAPACITY exceeds such MEMBER PRIMARY CAPACITY RESERVATION.

5.11 MEMBER PRIMARY CAPACITY DEFICIT - Difference between the MEMBER PRIMARY CAPACITY and MEMBER PRIMARY CAPACITY RESERVATION of a particular Member, when such MEMBER PRIMARY CAPACITY is less than such MEMBER PRIMARY CAPACITY RESERVATION.

Energy

5.12 POOL - Electric energy delivered by one Member, from its MEMBER PRIMARY CAPACITY, to another Member shall be considered to be energy delivered to the POOL by the former Member and received from the POOL by the latter Member.

Electric energy delivered by a Foreign Company to a Member, other than energy associated with a Member's MEMBER PRIMARY CAPACITY, shall be considered to be energy delivered to the POOL. Electric energy delivered by a Member to a Foreign Company to meet a SYSTEM LOAD OBLIGATION shall be considered to be energy delivered by the POOL to the Foreign Company.

5.13 PRIMARY ENERGY - Electric energy delivered to the POOL from the MEMBER PRIMARY CAPACITY of a particular Member to meet another Member's deficiency in capacity. The deficiency may be caused by one or both of two reasons, the total MEMBER PRIMARY CAPACITY of a particular Member may not be great enough to meet its MEMBER LOAD OBLIGATION or a Member may have a portion of its MEMBER PRIMARY CAPACITY out of service for maintenance and the remainder may not be great enough to meet its MEMBER LOAD OBLIGATION.

5.14 ECONOMY ENERGY - Electric energy delivered to the POOL from the MEMBER RRIMARY CAPACITY of a particular Member to displace energy that otherwise would be supplied by less efficient MEMBER PRIMARY CAPACITY of another Member to meet its MEMBER LOAD OBLIGATION.

5.15 LINE LOSS FACTOR - The transmission electrical loss factor to be applied for settlement purposes to a particular metered quantity of energy delivered to the POOL by a Member. The Operating Committee shall determine and agree upon the LINE LOSS FACTOR required, such determinations to be governed by the understanding that the Member receiving such energy shall bear the entire loss caused in transmitting such energy over the facilities of the delivering Member and over the facilities of any other party whose system may be used for such delivery.

ARTICLE 6

SETTLEMENTS FOR POWER AND ENERGY SUPPLIED FROM MEMBER'S ELECTRIC POWER SOURCES

6.1 As promptly as practicable following the end of each month (all references to month mean calendar month), for electric power and energy supplied under this agreement during such month from SYSTEM PRIMARY CAPACITY, the Members shall carry out cash settlements through the SYSTEM ACCOUNT in accordance with the following; viz:

Primary Capacity Equalization Charge

6.2 For each kilowatt of MEMBER PRIMARY CAPACITY SURPLUS each Member having such surplus during any month shall receive payment from the SYSTEM ACCOUNT at a rate per kilowatt per month equal to the MEMBER PRIMARY CAPACITY INVESTMENT RATE plus the MEMBER PRIMARY CAPACITY FIXED OPERATING RATE, as hereinbelow defined, applicable to the particular surplus.

6.21 The MEMBER PRIMARY CAPACITY INVESTMENT RATE chargeable against the SYSTEM ACCOUNT for any calendar month by a particular Member shall be equal to the product of (A) the MEMBER WEIGHTED AVERAGE INVESTMENT COST, determined pursuant to subdivision 6.211 below, and (B) the MONTHLY CARRYING CHARGE FACTOR, determined pursuant to subdivision 6.212 below.

6.211 The MEMBER WEIGHTED AVERAGE INVESTMENT COST shall be equal to the ratio of (i) the total installed cost of production plant of the generation stations, other than hydro, classified as part of a particular Member's MEMBER PRIMARY CAPACITY to (ii) the total kilowatt capability of such generating stations. The total installed cost of production plant used in the determination of the MEMBER WEIGHTED AVERAGE INVESTMENT COST, as described above, shall be the total cost of such plant for the aforesaid generating stations included, as of the end of the next preceding year, in Accounts 310 to 316, inclusive, Accounts 320 to 325, inclusive and Accounts 340 to 346, inclusive, of the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission for Public Utilities and Licensees, as in effect on January 1, 1975.

6.212 The MONTHLY CARRYING CHARGE FACTOR shall be 0.0137, or such larger amount as shall be established by order of the Federal Energy Regulatory Commission issued upon rehearing or reconsideration of its Opinion No. 50, issued July 27, 1979 in Docket No. E-9408.

6.22 The MEMBER PRIMARY CAPACITY FIXED OPERATING RATE chargeable against the SYSTEM ACCOUNT for any calendar month by a particular Member shall be equal to the weighted average fixed operating cost as hereinbelow defined, incurred by said Member during such month. Such weighted average fixed operating cost for purposes hereof shall be equal to the ratio of the fixed operating expense, i.e., the total production expenses minus the fuel and one-half of the maintenance expenses, incurred by a particular Member during a month at the generating stations other than hydro, classified as a part of its MEMBER PRIMARY CAPACITY to the total kilowatt capability of such generating stations.

6.3 For each kilowatt of MEMBER PRIMARY CAPACITY DEFICIT, any Member having such deficit during any month shall make payment into the SYSTEM ACCOUNT at a rate per kilowatt per month equal to the total payments from the SYSTEM ACCOUNT during any such month, determined pursuant to subdivision 6.2 above, divided by the total kilowatts of MEMBER PRIMARY CAPACITY DEFICITS for such month.

Primary Energy Charge

6.4 For PRIMARY ENERGY delivered to the POOL during any month by any Member, the Member so delivering such energy shall receive payment from the SYSTEM ACCOUNT at a rate per kilowatt-hour equal to said Member's MEMBER PRIMARY ENERGY RATE, as hereinbelow defined, for such month. The MEMBER PRIMARY ENERGY RATE chargeable against the SYSTEM ACCOUNT for any month by said Member shall be equal to the Member's weighted average variable production cost, as hereinbelow defined, for such month. Such weighted average variable production cost for purposes hereof shall be equal to the ratio of the sum of the fuel and one-half of the maintenance expenses incurred by said Member during a month at the generating stations other than hydro, classified as part of such Member's MEMBER PRIMARY CAPACITY to the total kilowatt-hours of net generation at said generating stations during such month.

6.5 For PRIMARY ENERGY received from the POOL during any month by any Member, said Member shall make payment into the SYSTEM ACCOUNT for energy so received at a rate per kilowatt-hour equal to the MEMBER PRIMARY ENERGY RATE payable from the SYSTEM ACCOUNT to the other Members for such month for such PRIMARY ENERGY. THe rate applicable to such PRIMARY ENERGY shall be determined from clock-hour records to be kept by Agent as provided under Article 3. Such records shall indicate the receiving Member and supplying Member for each kilowatt-hour classified as PRIMARY ENERGY.

Economy Energy Charge

6.6 For ECONOMY ENERGY delivered to the POOL during any month the Member delivering such energy shall receive payment from and the Member receiving such energy shall make payment to the SYSTEM ACCOUNT at the ECONOMY ENERGY RATE, as herein-below defined, applicable to the energy so delivered and received. The ECONOMY ENERGY RATE applicable to a particular kilowatt-hour of ECONOMY ENERGY shall be equal to the out-of-pocket cost of delivering said kilowatt-hour to the POOL plus one-half the difference between such cost and the out-of-pocket cost of generation avoided by the Member receiving such energy. Said kilowatt-hour shall be considered to be supplied from the highest cost source carrying load to meet MEMBER LOAD OBLIGATIONS of the supplying Member, excluding sources operated for minimum operating requirements, and its out-of-pocket cost shall include fuel expense and an appropriate portion of maintenance expense of generating facilities. The cost of generation avoided by the Member receiving said kilowatt-hour of ECONOMY ENERGY shall be considered to be the out-of-pocket cost that would be experienced if said kilowatt-hour were not delivered and its equivalent generated upon the most efficient operable unloaded generation of the receiving Member. Such out-of-pocket cost shall include cost of fuel and an appropriate portion of maintenance expense of generating facilities. The appropriate portion of maintenance expense allocable to the out-of-pocket cost of the supplying Member and to the avoided cost of the receiving Member shall be determined and agreed upon by the Operating Committee.

<u>System Primary Energy Rate</u>

6.7 Settlements for various classes of electric power and energy delivered under transactions with Foreign Companies shall include the use of a rate referred to as SYSTEM PRIMARY ENERGY RATE. For purposes of this agreement, the SYSTEM PRIMARY ENERGY RATE chargeable for any month shall be equal to the weighted average variable operating cost, as hereinbelow defined, incurred during such month at the generating stations, other than hydro, classified as part of the SYSTEM PRIMARY CAPACITY. Such weighted average variable operating cost for purposes hereof shall be equal to the ratio of the variable production expenses, i.e., the fuel and one-half of the maintenance expenses, incurred during a month at the generating stations, other than hydro, classified as part of the SYSTEM PRIMARY CAPACITY to the total kilowatt-hours of net generation generated at said generating stations during such month.

ARTICLE 7

TRANSACTIONS WITH FOREIGN COMPANIES

7.1 As promptly as practicable following the end of each month, cash settlements by the Members through the SYSTEM ACCOUNT for power transactions carried out in their behalf with Foreign Companies during such month shall be effected in accordance with the principles and procedures provided therefor under this Article 7. Any sale of power included in a Member's MEMBER LOAD OBLIGATION and any purchase of power included in a Member's MEMBER PRIMARY CAPACITY shall be excluded from such transactions. All other types of transactions carried out by any Member or on behalf of the Members with any Foreign Company shall be considered a transaction made on behalf of the collective interest of the Members. Costs and benefits associated with such transactions shall be shared proportionately as hereinbelow provided.

Settlement For Power And Energy
Purchases From Foreign Companies

Power and Energy Purchases
other than Economy Energy

7.2 Definitions of billing factors required for settlements by the Members through the SYSTEM ACCOUNT for electric power and energy, other than ECONOMY ENERGY PURCHASE from any Foreign Company shall be as follows; viz:

7.21 SYSTEM PURCHASE FROM FOREIGN COMPANY - All energy purchased from a Foreign Company either by a particular Member or by the Members collectively through arrangements made on their behalf by Agent, except ECONOMY ENERGY or such energy as may be purchased to meet a SYSTEM LOAD OBLIGATION (settlement for energy so purchased that is supplied to another Foreign Company is provided for under subdivisions 7.5 and 7.7 below.)

7.22 MEMBER RESERVATION OF SYSTEM PURCHASE FROM FOREIGN COMPANY - For a month, the SYSTEM PURCHASE FROM FOREIGN COMPANY multiplied by the MEMBER LOAD RATIO of a particular Member.

7.23 MEMBER ENTITLEMENT OF SYSTEM PURCHASE FROM FOREIGN COMPANY - For a month, when the quantity of the MEMBER RESERVATION OF SYSTEM PURCHASE FROM FOREIGN COMPANY for a particular Member exceeds such quantity of energy delivered to said Member by the Foreign Company, the difference between such quantities is the MEMBER ENTITLEMENT OF SYSTEM PURCHASE FROM FOREIGN COMPANY of said Member for such month.

7.24 MEMBER OBLIGATION OF SYSTEM PURCHASE FROM FOREIGN COMPANY - For a month, when the quantity of the MEMBER RESERVATION OF SYSTEM PURCHASE FROM FOREIGN COMPANY for a particular Member is less than such quantity of energy delivered to said Member by the Foreign Company, the difference between such quantities is the MEMBER OBLIGATION OF SYSTEM PURCHASE FROM FOREIGN COMPANY of said Member for such month.

7.25 MEMBER DEFICIT OF SYSTEM PURCHASE FROM FOREIGN COMPANY - For a month, when the quantity of the MEMBER OBLIGATION OF SYSTEM PURCHASE FROM FOREIGN COMPANY for a particular Member exceeds the quantity of kilowatt-hours of SYSTEM PURCHASE from FOREIGN COMPANY delivered to the POOL by the Member, the difference between such quantities is the MEMBER DEFICIT OF SYSTEM PURCHASE FROM FOREIGN COMPANY of said Member for such month.

7.26 MEMBER SURPLUS OF SYSTEM PURCHASE FROM FOREIGN COMPANY - For a month, when the quantity of the MEMBER ENTITLEMENT OF SYSTEM PURCHASE FROM FOREIGN COMPANY for a particular Member exceeds the quantity of kilowatt-hours of SYSTEM PURCHASE FROM FOREIGN COMPANY received from the POOL by said Member, the difference between such quantities is the MEMBER SURPLUS OF SYSTEM PURCHASE FROM FOREIGN COMPANY of said Member for such month.

7.3 To effect a proportionate sharing of the cost of any SYSTEM PURCHASE FROM FOREIGN COMPANY, purchases so made from each Foreign Company shall be treated separately as follows:

7.31 At the end of each month, from data supplied by the Members, Agent shall determine the cost of SYSTEM PURCHASE FROM FOREIGN COMPANY.

7.32 The total cost so determined multiplied by the [MEMBER] LOAD RATIO of a particular Member shall be the gross amount chargeable to said Member.

7.33 If a particular Member has established a MEMBER DEFICIT OF SYSTEM PURCHASE FROM FOREIGN COMPANY, the adjusted gross amount chargeable to the Member shall equal the sum of the gross amount determined under subdivision 7.32 above plus the amount chargeable to the Member for the MEMBER DEFICIT OF SYSTEM PURCHASE FROM FOREIGN COMPANY. The rate applicable to such deficit shall be the SYSTEM PRIMARY ENERGY RATE determined for the particular month.

7.34 If a particular Member has established a MEMBER SURPLUS OF SYSTEM PURCHASE FROM FOREIGN COMPANY, the adjusted gross amount chargeable to the Member shall equal the difference between the gross amount determined under subdivision 7.32 above and the amount to be credited to the Member for the MEMBER SURPLUS OF SYSTEM PURCHASE FROM FOREIGN COMPANY. The rate applicable to such surplus shall be the SYSTEM PRIMARY ENERGY RATE determined for the particular month.

7.35 If the adjusted gross amount chargeable to a particular Member for any month as determined under either subdivisions 7.33 or 7.34 is greater than the payment make by said Member to the Foreign Company for the SYSTEM

PURCHASE FROM FOREIGN COMPANY, said Member shall make payment into the SYSTEM ACCOUNT of the difference between such amount and payment. Conversely, if the amount so determined for a particular Member is less than the Member's aforesaid payment to the Foreign Company, such Member shall receive payment from the SYSTEM ACCOUNT of the difference between such amount and such payment to the Foreign Company.

Economy Energy Purchases

7.4 Settlement by the Members through the SYSTEM ACCOUNT for ECONOMY ENERGY PURCHASE from a Foreign Company shall be governed by the principle that the saving in production expense realized by the System (the term "System" as used in this agreement refers to the electric facilities of the Members viewed as a unit) shall be shared by the Members in proportion to their respective MEMBER LOAD RATIOS.

(The following illustrates the application of the principle and procedure for effecting such settlements:

It is assumed that Appalachian Company has purchased a block of ECONOMY ENERGY PURCHASE at a rate of 1.00 mill per kilowatt-hour which has displaced generation at Twin Branch Station of Indiana Company; the production expense saving to Indiana Company being 2.00 mills per kilowatt-hour.

Charges payable to and credits payable from the SYSTEM ACCOUNT for such energy shall be at the following rates: (1) pay Appalachian Company at a rate per kilowatt-hour equal to the sum of 1.00 mill plus the product of 2.00 mills times Appalachian Company's MEMBER LOAD RATIO, (2) pay Ohio Company at a rate per kilowatt-hour equal to the product of 2.00 mills times Ohio Company's MEMBER LOAD RATIO, and (3) charge Indiana Company at a rate per kilowatt-hour equal to the sum of 1.00 mill plus the product of 2.00 mills times the sum of Appalachian Company's and Ohio Company's MEMBER LOAD RATIOS.)

For the purpose of this agreement, the cost of generation avoided by the System in receiving a kilowatt-hour of ECONOMY ENERGY PURCHASE shall be considered to be the out-of-pocket cost, i.e., fuel expense and an appropriate portion of maintenance expense of generating facilities that would be experienced if said kilowatt-hour were not delivered and its equivalent generated upon the most efficient operable unloaded generation of the System. The appropriate portion of maintenance expense allocable to the out-of-pocket cost of such generating facilities shall be determined and agreed upon by the Operating Committee.

Settlement for Power Sales to Foreign Companies

7.5 Settlement by the Members through the SYSTEM ACCOUNT for electric power and energy sales to Foreign Companies shall be governed by the principle that the difference between the amount charged a Foreign Company for the power and energy supplied under such a sale and the production expenses, i.e., out-of-pocket costs incurred by the System in making such supply, shall be shared by the Members in proportion to the respective MEMBER LOAD RATIOS. Electric Power and energy for such sales shall be considered to be supplied from the higher cost of the following two sources: (1) from the highest cost source carrying load on the System, excluding sources operated for minimum operating requirements, or (2) the highest cost source supplying power to the System under arrangements with Foreign Companies.

(The following illustrates the application of the principles and procedures for effecting such settlements:

It is assumed that Indiana Company has sold a block of energy at a rate of 4.00 mills per kilowatt-hour which has been supplied by carrying a block of load that would not otherwise be carried at Philo Station of Ohio Company, the out-of-pocket cost incurred by Ohio Company being 3.00 mills per kilowatt-hour.

Charges payable to and credits payable from the SYSTEM ACCOUNT for such energy would be at the following rates: (1) charge

Indiana Company at a rate per kilowatt-hour equal to the sum of 3.00 mills plus the product of 1.00 mill times the sum of Appalachian Company's and Ohio Company's MEMBER LOAD RATIOS, (2) pay Ohio company at a rate per kilowatt-hour equal to the sum of 3.00 mills and the product of 1.00 mill times Ohio Company's MEMBER LOAD RATIO, and (3) pay Appalachian Company at a rate per kilowatt-hour equal to the product of 1.00 mill times Appalachian Company's MEMBER LOAD RATIO.)

Settlement For Power and Energy Received Under
Interchange Arrangements With Foreign Companies

Power and Energy Received other
than Interchange Economy Energy

7.6 Definitions of billing factors required for settlements by the Members through the SYSTEM ACCOUNT for electric power and energy received, other than INTERCHANGE ECONOMY ENERGY, from any Foreign Company under interchange arrangements which require no cash settlements shall be as follows; viz:

7.61 SYSTEM INTERCHANGE FROM FOREIGN COMPANY - All energy received from Foreign Company by either a particular Member or by the Members collectively through arrangements made on their behalf by Agent, which requires no cash settlement, except INTERCHANGE ECONOMY ENERGY.

7.62 MEMBER RESERVATION OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY - For a month, the SYSTEM INTERCHANGE FROM FOREIGN COMPANY multiplied by the MEMBER LOAD RATIO of a particular Member.

7.63 MEMBER ENTITLEMENT OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY - For a month, when the quantity of the MEMBER RESERVATION OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY for a particular Member exceeds the quantity of such energy delivered to the Member by the Foreign Company, the difference between such quantities is the MEMBER ENTITLEMENT OF SYSTEM

INTERCHANGE FROM FOREIGN COMPANY of such Member for such month.

7.64 MEMBER OBLIGATION OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY - For a month, when the quantity of the MEMBER RESERVATION OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY for a particular Member is less than the quantity of such energy delivered to the Member by the Foreign Company, the difference between such quantities is the MEMBER OBLIGATION OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY of said Member for such month.

7.65 MEMBER DEFICIT OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY - For a month, when the quantity of the MEMBER OBLIGATION OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY for a particular Member exceeds the quantity of kilowatt-hours of SYSTEM INTERCHANGE FROM FOREIGN COMPANY delivered to the POOL by said Member, the difference between such quantities is the MEMBER DEFICIT OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY of said Member for such month.

7.66 MEMBER SURPLUS OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY - For a month, when the quantity of the MEMBER ENTITLEMENT OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY for a particular Member exceeds the quantity of kilowatt-hours of SYSTEM INTERCHANGE FROM FOREIGN COMPANY received from the POOL by said Member, the difference between such quantities is the MEMBER SURPLUS OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY of said Member for such month.

7.7 To effect a proportionate sharing of the benefits of SYSTEM INTERCHANGE FROM FOREIGN COMPANY, electric energy so received from each Foreign Company shall be treated separately as follows:

7.71 If a particular Member has established a MEMBER DEFICIT OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY, said Member shall make payment into the SYSTEM ACCOUNT for the kilowatt-hours of such deficit at the SYSTEM PRIMARY ENERGY RATE determined for the particular month.

7.72 If a particular Member has established a MEMBER SURPLUS OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY, said Member shall receive payment from the SYSTEM ACCOUNT for the kilowatt-hours of such surplus at the SYSTEM PRIMARY ENERGY RATE determined for the particular month.

Interchange Economy Energy

7.8 The priciples described under subdivision 7.4 above for the settlement of ECONOMY ENERGY PURCHASE shall also govern the settlements by the Members through the SYSTEM ACCOUNT for INTERCHANGE ECONOMY ENERGY received from a Foreign Company. It shall be assumed for the purpose of such settlement that payment to the Foreign Company for INTERCHANGE ECONOMY ENERGY was made at a rate of zero mills per kilowatt-hour.

Settlements For Power Delivered Under Interchange Arrangements With Interconnected Foreign Companies

7.9 Settlement hereunder for electric power and energy (hereinafter called "SYSTEM INTERCHANGE TO FOREIGN COMPANY") delivered to any Foreign Company under interchange arrangements with either a particular Member or with the Members collectively through arrangements made on their behalf by Agent, which require no cash settlements, will be governed by the principle that the production expenses, i.e., out-of-pocket costs incurred by the System in making such deliveries, shall be shared by the

Members in proportion to their respective MEMBER LOAD RATIOS.

(The following illustrates the application of the principle and procedure for effecting such settlements:

It is assumed that Appalachian Company has delivered a block of SYSTEM INTERCHANGE TO FOREIGN COMPANY which has been supplied by carrying a block of load that would not otherwise be carried at Windsor Station of Ohio Company; the out-of-pocket cost incurred by Ohio Company being 3.50 mills per kilowatt-hour.

Charges payable to and credits payable from the SYSTEM ACCOUNT for such energy shall be at the following rates: (1) charge Appalachian Company and Indiana Company at rates per kilowatt-hour equal to the product of 3.50 mills per kilowatt-hour and their respective MEMBER LOAD RATIOS, and (2) pay Ohio Company at a rate equal to the sum of the rates charged Appalachian Company and Indiana.)

As described under subdivision 7.5 above, electric power and energy for sales to Foreign Companies shall be considered to be supplied from the higher cost of the following two sources: (1) from the highest cost source carrying load on the System, excluding sources operated for minimum operating requirements, or (2) the highest cost source supplying electric power and energy to the System under arrangements with Foreign Companies. Similarly, following the determination and designation of such source for the aforesaid sales, electric power and energy for SYSTEM INTERCHANGE TO FOREIGN COMPANY deliveries shall be considered to be supplied from the higher cost of the balance of said two sources.

ARTICLE 8

DELIVERY POINTS, METERING POINTS AND METERING

Delivery Points

8.1 All electric energy delivered under this agreement shall be of the character commonly known as three-phase sixty-cycle energy, and shall be delivered at the various Interconnection

Points where the transmission systems of the Members are interconnected at the nominal unregulated voltage designated for such points, and at such other points and voltages as may be determined and agreed upon by the Members.

Metering Points

8.2 Electric power and energy supplied and delivered by one Member to another Member shall be measured by suitable metering equipment to be provided, owned, and maintained by the Members at such metering points as are determined and agreed upon by them.

Metering

8.3 Suitable metering equipment at metering points as provided under subdivision 8.2 above shall include electric meters which shall give for each direction of flow the following quantities (1) an automatic record for each clock-hour of kilowatt-hours and (2) a continuous integrating record of the kilowatt-hours.

8.4 Measurements of electric energy for the purpose of effecting settlements under this agreement shall be made by standard types of electric meters, installed and maintained by the owner at the metering points as provided under subdivision 8.2 above. The timing devices of all meters having such devices shall be maintained in time synchronism as closely as practicable. The meters shall be sealed and the seals shall be broken only upon occasions when the meters are to be tested or adjusted. For the purpose of checking the records of the metering equipment installed by any Member as hereinabove provided, the other Members shall have the right to install check metering equipment at the aforesaid metering points. Metering equipment so installed by one Member on the premises of another Member shall be owned and maintained by the Member installing such equipment. Upon termination of this agreement the Member owning such metering equipment shall remove it from the premises of the other Member. Authorized representatives of any Member shall have access at all reasonable hours to the premises where the meters are located and to the records made by the meters.

8.5 The aforesaid metering equipment shall be tested by the owner at suitable intervals and its accuracy of registration maintained in accordance with good practice. On request of any Member, special tests shall be made at the expense of the Member requesting such special test.

8.6 If on any test of metering equipment, an inaccuracy shall be disclosed exceeding two percent, the account between the Members for service theretofore delivered shall be adjusted to correct for the inaccuracy disclosed over the shorter of the following two periods: (1) for the thirty-day period immediately preceding the day of the test or (2) for the period that such inaccuracy may be determined to have existed. Should the metering equipment as hereinabove provided for fail to register at any time, the electric power and energy delivered shall be determined from the check meters, if installed, or otherwise shall be determined from the best available data.

ARTICLE 9

RECORDS AND STATEMENTS

9.1 In addition to meter records to be kept by the Members as provided under Article 8, the Members shall keep in duplicate such log sheets and other records as may be needed to afford a clear history of the various deliveries of electric power and energy made pursuant to the provisions of this agreement. The originals of log sheets and other records shall be retained by the Member keeping the records and the duplicates shall be delivered as determined and agreed upon by the Operating Committee.

ARTICLE 10

TAXES

10.1 If at any time during the duration of this agreement, there should be levied and/or assessed against any Member any tax by any taxing authority in respect of the electric power and energy generated, purchased, sold, imported, transmitted, interchanged, or exchanged by said Member in addition to or different from the forms of such taxes now being levied or assessed against said Member, or there should be any increase or decrease in the rate of such existing or future taxes, and such taxes or changes in such taxes should result in increasing or decreasing the cost to said Member in carrying out the provisions of this agreement, then in such event adjustments shall be made in the rates and charges for electric power and energy furnished hereunder to make allowance for such taxes and changes in such taxes in an equitable manner.

ARTICLE 11

BILLINGS AND PAYMENTS

11.1 All bills for amounts owed hereunder shall be due and payable on the twentieth day of the month next following the monthly or other period to which such bills are applicable, or on the fifteenth day following receipt of bill, whichever date be later. Interest on unpaid amounts shall accrue at the rate of six percent per annum from the date due until the date upon which payment is made. Unless otherwise agreed upon a calendar month shall be the standard monthly period for the purpose of settlements under this agreement.

ARTICLE 12

MODIFICATION

12.1 Any Member, by written notice given to the other Members and Agent not less than ninety days prior to the beginning of any calendar year of the duration of this agreement, may call for a reconsideration of the terms and conditions herein provided. If such reconsideration is called for, there shall be taken into account any changed conditions, any results from the application of said terms and conditions, and any other factors that might cause said terms and conditions to result in an inequitable division of the benefits of interconnected operation or in an inadequate realization of such benefits. Any modification in terms and conditions agreed to by the Members following such reconsideration shall become effective the first day of January of the calendar year next following the aforesaid ninety-day notice period.

ARTICLE 13

DURATION OF AGREEMENT

13.1 This agreement shall become effective August 1, 1951, and shall continue in effect for an initial period expiring December 31, 1971, and thereafter for successive periods of one year each until terminated as provided under subdivision 13.2 below.

13.2 Any Member upon at least three years' prior written notice to the other Members and Agent may terminate this agreement at the expiration of said initial period or at the expiration of any successive period of one year.

ARTICLE 14

TERMINATION OF EXISTING AGREEMENTS

14.1 Upon their joint execution of this agreement Appalachian Company and Ohio Company agree that the interconnection agreements between them dated November 28, 1930, and September 1, 1936, respectively, and all supplements and amendments thereto, shall terminate as of July 31, 1951, and that all further obligations between them in respect thereof shall cease and terminate as of such date, except in respect of any payments or liabilities incurred in respect thereof prior to such termination date.

14.2 Upon their joint execution of this agreement Indiana Company and Ohio Company agree that the interconnection agreements between them, dated October 15, 1930, and September 1, 1936, respectively, and all supplements and amendments thereto, shall terminate as of July 31, 1951, and that all further obligations between them in respect thereof shall cease and terminate as of such date, except in respect of any payments or liabilities incurred in respect thereof prior to such termination date.

ARTICLE 15

REGULATORY AUTHORITIES

15.1 This agreement is made subject to the jurisdiction of any governmental authority or authorities having lawful jurisdiction in the premises.

ARTICLE 16

ASSIGNMENT

16.1 This agreement shall inure to the benefit of and be binding upon the successors and assigns of the respective parties.

16.2 IN WITNESS WHEREOF, the parties hereto have caused this agreement to be executed in their respective corporate names and on their behalf by their proper officers thereunto duly authorized as of the day and year first above written.

(The numerous pages of the various signatories to the original Agreement and subsequent modifications thereto, are omitted herein.)

Attachment 2

Retired Generating Capacity
October 2000

American Electric Power
1 Riverside Plaza
Columbus, OH 43215 2373
614 223 1000

Ex PLC 9

AEP AMERICAN® ELECTRIC POWER

Date October 3, 2000

Subject Data on Retired Generating Capacity

From E. A. Davis

To

A. Azad	-	20th Floor	K. D. Mack	-	29th Floor
S. W. Burge	-	17th Floor	J. F. Norris	-	18th Floor
M. A Gray	-	22nd Floor	N. M. Lycakis	-	4th Floor
S. I. Haynes	-	14th Floor	P. A. May	-	14th Floor
J. E. Hollback	-	29th Floor	R. M. Murphy	-	23rd Floor
J. A. Howard	-	17th Floor	R. L. Reed	-	14th Floor
J. R. Jones	-	17th Floor	R. G. Ronk	-	Roanoke
M. H. Knapp	-	4th Floor	W. L. Sigmon	-	17th Floor
G. E. Laurey	-	26th Floor	B. L. Thomas	-	Roanoke
V. A. Lepore	-	22nd Floor	W. F. Vineyard	-	17th Floor
M.C. McCullough		17th Floor			

Attached is a revision of data on Retired Generating Capacity through August 2000.

If you have any further information regarding retired plants, dates or remarks, please advise me so that they may be included in the next revision.

Attachment

Mew: EAD:

AMERICAN ELECTRIC POWER SYSTEM
DATA ON RETIRED GENERATING CAPACITY

OPERATING COMPANY	PLANT	UNIT NUMBER	DATE CONST.	DATE ACQU.	DATE COMMERCIAL OPERATION	NAMEPLATE RATING KW	POWER FACTOR	NAMEPLATE RATING KVA	REMARKS
IM	Muncie (S)	2	1926			1,000	1.0	1,000	Retired June 12, 1946
APCO	West Liberty (I)	1	1930	1939		60	0.8	75	Retired July 24, 1946
		2	1937	1939		165	1.0	165	
IM	South Bend (S)	1	1911	1922		4,000	0.8	5,000	Retired Nov. 30, 1946
		3	1910	1922		2,500	1.0	2,500	
OPCO	Lima (S)	2	1928			1,250	0.8	1,562	Retired May. 30, 1947
IM	Marion (S)	2	1920			6,250	0.8	7,800	Retired Nov. 30, 1947
OPCO	Canton (S)	2	1910			4,000	0.8	5,000	Retired Nov. 30, 1947
		1	1925			1,500	0.8	1,875	
APCO	Abingdon (I)	1 & 2	1926	1945		500	0.8	625	Retired Dec. 31, 1947
APCO	Cabin Creek (S)	1	1914	1925		6,600	0.8	8,250	Retired July 31, 1948
IM	Hartford (H)	1 & 2	1921	1932		120	0.8	150	Retired May 31, 1948
			1922	1932		120	0.8	150	
IM	Winchester (I)	1,2,3		1948		240	0.8	300	Retired Dec. 31, 1948
APCO	Cranberry (I)	1	1938	1947		150	-	-	Retired July 31, 1949
		2	1938	1947		200	0.8	250	
		3	1938	1947		150	0.8	187	
		4	1942	1947		200	0.8	250	
APCO	Cranberry (H)	1	1927	1947		50	-	-	Retired March 31, 1951
		2	1927	1947		50	1.0	50	
APCO	Radford Arsenal (S)	1	1941	1949		6,000	0.8	7,500	Leased by AEP Co. from U.S.
		2	1941	1949		6,000	0.8	7,500	Gov't. Nov. 1, 1949 Net Capability
		3	1941	1949		6,000	0.8	7,500	10,000 KW, non-condensing units
		4	1941	1949		6,000	0.8	7,500	3&4 in dead storage. Returned
									to Gov't. July 1, 1951.

(S) = Steam (H) = Hydro (I) = Internal Combustion (G/T) = Gas Turbine

Ex PLC 9

AMERICAN ELECTRIC POWER SYSTEM
DATA ON RETIRED GENERATING CAPACITY

OPERATING COMPANY	PLANT	UNIT NUMBER	DATE CONST.	DATE ACQU.	DATE COMMERCIAL OPERATION	NAMEPLATE RATING KW	POWER FACTOR	NAMEPLATE RATING KVA	REMARKS
IM	Winchester (I)	4	1920	1948		380	0.8	475	Retired July 31, 1951
		5	1934	1948		500	0.8	625	
OPCO	Spencerville (I)	2	1941	1951		100	0.8	125	Retired Nov. 30, 1095
		3	1941	1951		100	0.8	125	
		1	1941	1951		200	0.8	250	Retired Dec. 31, 1951
		4	1947	1951		475	0.8	594	
OPCO	Cranberry Creek (S)	1	1949	1951		500	0.8	625	Retired May 31, 1952
OPCO	Sycamore St. (S)	1	1913	1951		150	1.0	150	Retired May 31, 1952
		2	1925	1951		200	0.8	250	
		3	1938	1951		300	0.8	375	
OPCO	Coshocton (H)	1	1912	1922		1,000	1.0	1,000	Retired Dec. 29, 1952
OPCO	Philo (S)	1	1925	-		40,000	0.95	42,105	Retired June 1, 1954
APCO	Stuart (I)	1	1932	1939		150	1.0	150	Retired June 15, 1954
OPCO	Ballville (S)	1	1915	1935		5,000	0.8	6,250	Retired July 1, 1954. The Ballville hydro and steam plants for sometime prior to 1935 were owned jointly by OPCO and Ohio State Power Co.
		2	1915	1935		5,000	0.8	6,250	
		3	1915	1935		5,000	0.8	6,250	
OPCO	Portsmouth (S)	1	1924	1925		5,000	0.8	6,250	Retired July 1, 1954
		2	1915	1925		1,500	0.8	1,875	
		3	1915	1925		3,000	0.8	3,750	
OPCO	Newark (S)	1	1918			3,000	0.8	3,750	Retired July 1, 1954
		2	1913			2,500	0.8	3,125	
		3	1916			3,000	0.8	3,750	

(S) = Steam (H) = Hydro (I) = Internal Combustion (G/T) = Gas Turbine

Ex PLC 9

AMERICAN ELECTRIC POWER SYSTEM
DATA ON RETIRED GENERATING CAPACITY

OPERATING COMPANY	PLANT		UNIT NUMBER	DATE CONST.	DATE ACQU.	DATE COMMERCIAL OPERATION	NAMEPLATE RATING KW	POWER FACTOR	NAMEPLATE RATING KVA	REMARKS
APCO	Kingsport	(S)	3	1912	1925		2,000	0.8	2,500	Retired Jan. 1, 1955
			4	1917	1925		4,000	0.8	5,000	
			5	1917	1925		4,000	0.8	5,000	
OPCO	Wheeling	(S)	1	1912			2,000	0.8	2,500	Retired Jan. 1, 1955
			2	1912			2,000	0.8	2,500	
			3	1914			5,000	0.8	6,250	
IM	S. Bend (Colfax)	(S)	4	1916	1922		7,500	0.7	10,715	Retired Jan. 1, 1955
APCO	Glen Lyn	(S)	1	1919			15,000	0.8	18,750	Retired Jan. 1, 1955
APCO	Roanoke	(S)	3	1927			6,750	0.8	8,450	Retired Jan. 1, 1955
			4	1918	1924		3,000	0.8	3,750	
OPCO	Lima	(S)	3	1928			1,000	0.8	1,250	Retired June 1, 1955
OPCO	Findley	(S)	1	1916	1951		1,000	0.8	1,250	Retired June 30, 1955
			2	1920	1951		3,000	0.8	3,750	
			3	1925	1951		5,000	0.8	6,250	
OPCO	St. Marys	(S)	1	1923	1951		4,000	0.8	5,000	Retired June 30, 1955
IM	Muncie	(S)	1	1916			10,000	0.8	12,500	Retired Jan. 1, 1956
APCO	Damascus	(H)	1	1924	1945		168	0.8	210	Retired Jan. 1, 1956
IM	Marion	(S)	1	1923			10,000	0.8	12,500	Retired Jan. 1, 1956
APCO	Hazard	(S)	1	1917	1922		1,500	0.8	1,875	Retired Jan. 1, 1958
			2	1926			5,000	0.8	6,250	
			3	1918	1922		3,000	0.8	3,750	
			4	1922	1922		10,000	0.8	12,500	

(S) = Steam (H) = Hydro (I) = Internal Combustion (G/T) = Gas Turbine

AMERICAN ELECTRIC POWER SYSTEM
DATA ON RETIRED GENERATING CAPACITY

OPERATING COMPANY	PLANT	UNIT NUMBER	DATE CONST.	DATE ACQU.	DATE COMMERCIAL OPERATION	NAMEPLATE RATING KW	POWER FACTOR	NAMEPLATE RATING KVA	REMARKS
APCO	Ravenswood (I)	1	1939	1956		125	0.8	156	Retired Dec. 2, 1958
		2	1951	1956		287	0.8	359	
		3	1947	1956		200	0.8	250	
APCO	Cabin Creek (S)	2	1914	1925		8,240	0.8	10,300	Retired Jan. 1, 1959
OPCO	Ballville (H)	1	1912	1935		1,000	1.0	1,000	Retired July 1, 1959
		2	1912	1935		1,000	1.0	1,000	
		3	1912	1935		1,000	1.0	1,000	
APCO	Stuart (H)	1	1923	1939		184	0.8	230	Retired March 1, 1960
APCO	Kenova (S)	1	1923	1924		15,000	0.8	18,750	Retired Jan. 1, 1961 - except for generators pending study on use as a synchronous condenser. Study showed no economic justificaton- generators retired July 1, 1961.
		2	1927			25,000	0.8	31,250	
IM	Spy Run (S)	1	1923	1947		12,500	0.8	15,625	Retired Jan. 1, 1961
		2	1922	1947		6,000	0.8	7,500	
		3	1914	1947		6,250	0.8	7,812	
		4	1914	1947		6,250	0.8	7,812	
IM	Decatur (S)	1	1920	1960		1,000	0.8	1,250	Retired Feb. 1, 1961(Unit #3 was destroyed in an explosion some years ago and was not replaced)
		2	1937	1960		2,000	0.8	2,500	
		4	1941	1960		5,000	0.8	6,250	
APCO	Rocky Mount (H)		1928	1926		150	0.8	187	Rebuilt in 1928. Retired May 31, 1961
IM	South Bend (H)	1	1904	1948		500	0.85	589	Facilities instaled by IM to parallel 25 cycle equipment with 60 cycle system were retired Oct. 31, 1962. Plant owned by Ind. Franklin Realty, Inc. Leased to IM. Dam and associatd real estate accepted by the city of South Bend on Oct. 13, 1964.
		2	1904	1948		500	0.85	589	
		3	1904	1948		500	0.85	589	

(S) = Steam (H) = Hydro (I) = Internal Combustion (G/T) = Gas Turbine

AMERICAN ELECTRIC POWER SYSTEM
DATA ON RETIRED GENERATING CAPACITY

OPERATING COMPANY	PLANT	UNIT NUMBER	DATE CONST.	DATE ACQU.	DATE COMMERCIAL OPERATION	NAMEPLATE RATING KW	POWER FACTOR	NAMEPLATE RATING KVA	REMARKS
APCO	Logan (S)	1	1915	1922		4,800	0.96	5,000	Retired Jan. 1, 1964
		2	1915	1922		4,800	0.96	5,000	
		3	1921	1922		28,000	0.96	18,750	
		4	1923			18,000	0.96	18,750	
		5	1937		11/1/37	4,800	0.96	5,000	
		A	1937		11/1/37	40,000	0.80	50,000	
APCO	Holston (H)	1	1936	1945		250	0.80	312	Original Unit #1 was placed in service in
		2	1927	1945		300	0.80	375	1921. Retired Jan. 1, 1964
OPCO	Minerva (S)	1	1930	1960		500	0.80	625	Retired March 19, 1965
		2	1936	1960		1,500	0.80	1,875	
		3	1950	1960		1,800	0.80	2,250	
IM	Kendallville (S)	1	1928	1957		1,000	0.80	1,250	Retired June 30, 1965
		2	1952	1957		6,000	0.80	7,500	
		3	1938	1957		1,500	0.80	1,875	
		4	1947	1957		3,000	0.80	3,750	
OPCO	Paulding (D)	1	1940	1964		400	0.80	500	City of Paulding Municipal Plant and
		2	1940	1964		580	0.80	725	distribution system acquired June 24,
		3	1945	1964		580	0.80	725	1964. Plant in cold reserve Aug. 8, 1964.
		4	1953	1964		1,000	0.80	1,250	Retired Sept. 1, 1966.
OPCO	Willard (S)	1	1931	1965		1,000	0.80	1,250	City of Willard Municipal Plant and
		2	1940	1965		1,500	0.80	1,875	distribution system acquired Nov. 17,
		3	1952	1965		2,500	0.80	3,125	1965. Plant in cold reserve Dec. 3, 1965.
									Retired Sept. 1, 1966
IM	Portland (S)	1	1948	1963		5,000	0.80	6,250	City of Portland Municipal Plant and
		2	1936	1963		3,000	0.80	3,750	distribution system acquired Jan. 1, 1963.
		3	1925	1963		2,000	0.80	2,500	Plant in cold reserve Apr. 16, 1963.
									Retired Aug. 31, 1966.

(S) = Steam (H) = Hydro (I) = Internal Combustion (G/T) = Gas Turbine

Ex PLC 9

AMERICAN ELECTRIC POWER SYSTEM
DATA ON RETIRED GENERATING CAPACITY

OPERATING COMPANY	PLANT	UNIT NUMBER	DATE CONST.	DATE ACQU.	DATE COMMERCIAL OPERATION	NAMEPLATE RATING KW	POWER FACTOR	NAMEPLATE RATING KVA	REMARKS
MPCO	Constantine (I)	1	1964	1967		800	0.80	1,000	A majority interest in MG&E was acquired
		2	1964	1967		350	0.80	438	by AEP as of Sept. 1, 1967. Plant retired
		3	1950	1967		635	0.80	794	Jan. 1, 1968.
		4	1956	1967		700	0.80	875	
		5	1964	1967		800	0.80	1,000	
APCO	Cabin Creek (S)	3	1919	1929		25,000	0.90	27,777	Units 3-7 wre deactivated Sept. 30, 1969
		4	1921	1925		22,000	0.80	27,500	and retired Jan. 1, 1974.
		5	1925	1925		20,000	0.80	25,000	
		6	1927			31,500	0.90	35,000	
		7	1931			5,000	0.80	6,250	
APCO	Glen Lyn (S)	2	1920			20,000	0.80	25,000	Unit #2 deactivated May 1, 1958 and
		3	1924			20,000	0.80	25,000	retired Jan. 1, 1974. Units 3 & 4 deactivated
		4	1927			25,000	0.80	31,250	July 1, 1971 and retired Jan. 1, 1974.
IM	Twin Branch (S)	1	1925			40,000	0.95	42,105	Units 1 & 2 were deactivated Feb. 4, 1971
		2	1925			40,000	0.95	42,105	and retired Jan. 1, 1974. Unit 3 was retired
		3LP			11/1/40	54,000	0.90	60,000	April 1, 1974.
		3HP			5/1/41	22,500	0.80	28,125	
OPCO	Philo (S)	2	1924			40,000	0.95	42,105	Unit 2 was deactivated May 12, 1958 and
		3-1	1929			53,000	0.85	62,353	retired Jan. 1, 1974. Unit 3 was deactivated
		Aux	1929			3,000	0.70	4,286	Nov. 6 1971 and retired Jan. 1, 1974.
		3-2	1929			53,000	0.85	62,353	
		3-3	1929			53,000	0.85	62,353	
		Aux	1929			3,000	0.70	4,286	
OPCO	Caldwell (I)	2		1969		235	0.80	294	Acquired from the Village of Caldwell June
		3		1969		392	0.80	490	5, 1969. The Plant was deactivated June 1,
		4		1969		360	0.80	450	1973 and retired May. 1, 1974.
		5		1969		360	0.80	450	
		6		1969		900	0.80	1,125	
		7		1969		500	0.80	625	

(S) = Steam (H) = Hydro (I) = Internal Combustion (G/T) = Gas Turbine

Ex PLC 9

AMERICAN ELECTRIC POWER SYSTEM
DATA ON RETIRED GENERATING CAPACITY

OPERATING COMPANY	PLANT	UNIT NUMBER	DATE CONST.	DATE ACQU.	DATE COMMERCIAL OPERATION	NAMEPLATE RATING KW	POWER FACTOR	NAMEPLATE RATING KVA.	REMARKS
OPCO	Martins Ferry (S)	1	1931	1970		2,500	0.80	3,125	Acquired from the City of Martins Ferry June 12, 1970. The Plant was deactivated March 1, 1973 and retired Dec. 1, 1974.
		3	1925	1970		1,000	0.80	1,250	
		4	1943	1970		3,000	0.80	3,750	
IM	Indiana Mobile (G/T) Gas Turbines	1			10/1/68	15,300	0.90	17,000	These Units were leased to Michigan Power Pool from Nov. 1968 to Feb. 1969. They were retired from the AEP System Dec. 1, 1974 and sold to Pacific Gas & Electric.
		2			11/8/68	15,300	0.90	17,000	
		3			12/17/69	15,300	0.90	17,000	
OPCO	Windsor (S)	1	1918			30,000	0.90	33,333	Windsor Plant was jointly owned by Ohio Power & West Penn Power. Ohio Power Units 1,3,5 & 7 were deactivated Oct. 1, 1973 and retired Jan. 1, 1975. West Penn Power owned units 2,4,6, & 8.
		3	1919			30,000	1.00	30,000	
		5	1919			30,000	0.90	33,333	
		7	1939			60,000	0.90	66,667	
IM	Lawton Park (S)	1	1932	1975		-	-	-	Acquired From Ft. Wayne City Light on Feb. 28, 1975. Retired March 1, 1975.
		2	1932	1975		-	-	-	
		3	1932	1975		-	-	-	
		4	1932	1975		-	-	-	
OPCO	Martins Ferry (I)	1	1965	1970		650	0.80	812.5	Acquired form the City of Martins Ferry June 12, 1970. Retired March 31, 1976.
		2	1965	1970		650	0.80	812.5	
		3	1965	1970		650	0.80	812.5	
IM	Decatur (I)	1	1953	1960		4,250	0.80	5,313	Acquired from the city of Decatur, Ind. on July 1, 1960. The plant was deactivated Nov. 8, 1960 Reactivated Jan. 16, 1967 and retired on Sept. 30, 1976.
MPCO	Portage (H)	1	1923	1967		168	0.80	210	Acquired with the purchase of MPCO Sept. 1,1967. The plant last generated in 1971 and was inoperable when it was retired Aug. 9, 1977.
OPCO	Philo (S)	4LP			10/31/41	39,400	0.90	43,778	Philo Units 4,5, & 6 were deactivated, June 1, 1975 and retired January 1, 1979.
		4HP			3/1/42	45,600	0.90	50,667	
		5LP			6/1/42	39,400	0.90	43,778	
		5HP			8/1/42	45,600	0.90	50,667	
		6			8/1/57	125,000	0.80	156,250	

(S) = Steam (H) = Hydro (I) = Internal Combustion (G/T) = Gas Turbine

Ex PLC 9

AMERICAN ELECTRIC POWER SYSTEM
DATA ON RETIRED GENERATING CAPACITY

OPERATING COMPANY	PLANT	UNIT NUMBER	DATE CONST.	DATE ACQU.	DATE COMMERCIAL OPERATION	NAMEPLATE RATING KW	POWER FACTOR	NAMEPLATE RATING KVA	REMARKS
OPCO	Tidd (S)	1			9/28/45	111,111	0.87	127,714	Tidd Unit 1 was deactivated Aug. 31, 1976 and retired Jan. 1, 1979. Unit 2 was deactivated Sept. 16, 1976 and retired Jan. 1, 1979.
		2			11/1/48	115,200	0.90	128,000	
OPCO	Woodcock (S)	1	1938	1951		5,000	0.80	6,250	Woodcock Plant was acquired through the purchase of Central Ohio Light & Power Co. on Jan. 15, 1951. All 5 units were deactivated on Feb. 28, 1975, and retired Jan. 1, 1979.
		2	1938	1951		5,000	0.80	6,250	
		3	1941	1951		7,500	0.80	9,375	
		4	1947	1951		10,000	0.80	12,500	
		5	1950	1951		10,000	0.80	12,500	
CSP	Picway (S)	3		1980	4/2/43	30,000	0.80	37,500	CSP was acquired by AEP May 9, 1980. Picway units 3 & 4 were retired June 17, 1980.
		4		1980	3/1/49	30,000	0.80	37,500	
IM	Twin Branch (S)	4LP			1/1/44	39,400	0.90	43,778	Twin Branch Units 4 & 5 were deactivated Nov. 30, 1979 and retired January 1, 1981.
		4HP			4/1/44	45,600	0.90	50,667	
		5LP			8/22/49	109,800	0.80	137,250	
		5HP			8/22/49	42,700	0.80	53,375	
APCO	Cabin Creek (S)	8LP			9/1/42	39,400	0.90	43,778	Cabin Creek Units 8 & 9 were deactivated Oct. 7, 1977 and retired Aug. 18, 1981.
		8HP			2/1/43	45,600	0.90	50,667	
		9LP			5/1/43	39,400	0.80	43,778	
		9HP			8/1/43	45,600	0.90	50,667	
CSP	Addison (I)		1967		5/9/80	13,750	0.80	17,187	Removed from service Aug. 1, 1982. Units 1, 2, & 3 sold to Hawaiian Electric Co. on Aug. 19, 1983. Units 4 & 5 were sold to Belyea Co. Inc.
CSP	Conesville (I)		1967		5/9/80	13,750	0.80	17,187	Removed from service Aug. 1, 1982 for load carrying purpose. 3 units kept for black start capability.
CSP	Pedro (I)		1967		5/9/80	13,750	0.80	17,187	Removed from service Aug. 1, 1982. Unit # 2 sold to Alaska Electric Light & Power Co. Units 3, 4, & 5 sold to Indiana Michigan Power Co.

(S) = Steam (H) = Hydro (I) = Internal Combustion (G/T) = Gas Turbine

Ex PLC 9

AMERICAN ELECTRIC POWER SYSTEM
DATA ON RETIRED GENERATING CAPACITY

OPERATING COMPANY	PLANT	UNIT NUMBER	DATE CONST.	DATE ACQU.	DATE COMMERCIAL OPERATION	NAMEPLATE RATING KW	POWER FACTOR	NAMEPLATE RATING KVA	REMARKS
CSP	Picway (G/T)	6	1966		5/9/80	18,594	0.85	21,875	Removed from service Aug. 1, 1982. Unit sold to Alaska Electric Light & Power Co.
CSP	Poston (I)		1967		5/9/80	13,750	0.80	17,187	Removed from service Aug. 1, 1982. Units sold to Alaska Electric Light & Power Co.
CSP	Stuart (I)		1969		5/9/80	-	0.80	-	Removed from service Aug. 1, 1982 for load carrying purpose. Unit kept for black start capability.
CSP	Walnut (G/T)	7	1968	1980	11/20/68	32,640	0.85	38,400	CSP was acquired by AEP May 9, 1980.
		8	1968	1980	2/3/69	32,640	0.85	38,400	Walnut Units 7 & 8 were retired Aug. 1, 1982.
		9-3	1970	1980	4/26/71	41,850	0.90	46,500	Walniut Units 9-3 and 9-4 were sold Dec. 30,
		9-4	1970	1980	4/26/71	41,850	0.90	46,500	1984. Walnut Unit 9-1 was sold on Sept. 30,
		9-1	1970	1980	4/26/71	41,850	0.90	46,500	1985
CSP	Poston (S)	1		1980	10/22/49	44,000	0.83	53,012	CSP was acquired by AEP May 9, 1980.
		2		1980	8/17/50	44,000	0.83	53,012	Poston Units 1,2,3,&4 were retired
		3		1980	4/23/52	69,000	0.85	81,176	October 31, 1987.
		4		1980	1/25/54	75,000	0.85	88,235	
CSP	Walnut (G/T)	9-2	1970	1980	4/26/71	41,850	0.90	46,500	Walnut Unit 9-2 was sold on May 25, 1988.
IM	Breed (S)	1LP	1960		7/31/60	247,775	0.85	291,500	Breed Plant retired on March 31, 1944, but
		1HP	1960		7/31/60	247,775	0.85	291,500	for safety reasons was not operated beyond January 27, 1944.
IM	Fourth St. (G/T)	1	1970	1975		15,000	0.85	17,647	Leased from city of Ft. Wayne Mar. 1, 1975. Sold to Wabash Power Equipment Co. on Aug. 17, 2000.

(S) = Steam (H) = Hydro (I) = Internal Combustion (G/T) = Gas Turbine

Ex PLC 9

Attachment 3

Appalachian Power Company
Summary of Events
Possible Nuclear Generating Plant in Central Virginia

Appalachian Power Company
Summary of Events
Possible Nuclear Generating Plant in Central Virginia

- On July 25, 1978, APCo and American Electric Power announced the beginning of a program, expected to take about four years, in order to investigate the possibility of building a nuclear generating plant in central Virginia.
- In this new release, Mr John Vaughn, executive vice president and operating head of APCo, stated that, "This generation project, is not in conflict with, or an alternative to, Appalachian Power's current study of a pumped-storage hydroelectric project in southwest Virginia Each type of capacity is intended to meet a particular need of the AEP System as a whole, in supplying the electric power requirements of its customers at the lowest possible cost."
- American Electric Power worked in conjunction with Bechtel Corporation to perform the necessary studies
- Studies began on a potential site located in Nelson County where the Tye River enters the James.
- A final list of eight sites was chosen for the next step of the screening process.
- The nuclear option that was being considered was envisioned to consist of two nuclear reactors, each with a net generating capacity of between 1,150,000 and 1,288,000 kilowatts.
- Several member of the Virginia General Assembly had been contacted, and there was a favorable response. In addition, members of the Virginia Delegation in the United States Congress, who represented our operating area and the areas affected by the studies, were contacted, and there was an atmosphere of support for nuclear generation
- The first phase of the program was to select a standard design from four available types of nuclear plants and to determine a preferred site.
- Phase I was to take about a year to complete.
- Preliminary physical explorations on the Tye River site as well as a complex screening of some 10,000 square miles of central Virginia were begun. This included areas within the watershed of the James, Roanoke, and Dan Rivers The screening involved aerial reconnaissance, in-depth map studies, preliminary geological studies, and an evaluation of the engineering, environmental, and sociological impacts of such a plant on the region.
- On March 28, 1979 the Three Mile Island accident occurred at the nuclear plant
- On September 5, 1979, APCo announced that it was halting its study into the possibilities of building a nuclear power plant in central Virginia The Company determined that there were a growing number of uncertainties at that time involving nuclear power. The reasons cited were:
    - the siting and licensing of such plants by the Nuclear Regulatory Commission;
    - the possibility of restrictive legislation by Congress;
    - the lack of a decision by Congress in choosing a procedure for nuclear-waste disposal; and
    - recent development in the nuclear industry, particularly the incident at Three Mile Island and all of the new design and operating requirements for nuclear units that are bound to arise from that incident

Ex PLC 9

Attachment 4

Appalachian Power Company
Brumley Gap Project
Summary of Events

Appalachian Power Company
Brumley Gap Project
Summary of Events

Date	*Summary of Events*
August 30, 1977	Appalachian Power Company (APCo) filed an Application at the Federal Energy Regulatory Commission (FERC) for Preliminary Permits to allow the utility to determine the feasibility of constructing a pumped storage hydroelectric generating facility at one of two potential sites in Western Virginia. The two sites were Powell Mountain, near Fort Blackmore, Virginia, about six miles south of Norton, with the upper reservoir in Wise County and the lower in Scott County, Virginia; and Brumley Gap in Washington County, about eight miles northwest of Abingdon.
October 24, 1977	The Dungannon, Virginia based group, "Save Our National Forest," notified FERC of its opposition to APCo's application for preliminary permits.
January 31, 1978	The 450 members of the Citizens for Better Reclamation, Inc. notified FERC of their opposition to the projects and urged denial of preliminary permits for the sites.
May 13, 1978	A coalition of 12 citizens groups, the Coalition of Appalachian Energy Consumers, were formed to oppose proposals for a possible hydroelectric generating facility at Brumley Gap or Powell Mountain. Groups represented in the Coalitions were: Save our National Forests, Brumley Gap Concerned Citizens, Save New River, Save Our Mountains, Stop the Powerline, United Citizens Against Fuel Adjustment, Citizen Action Research of Energy, Sierra Club-Old Dominion Chapter and Izaak Walton League of America-West Virginia Division.
June 14, 1978	APCo received a petition from the Brumley Gap Concerned Citizens detailing their refusal to permit entry by the Company's agents for any examinations or surveys. The petition included 119 signatures.
July 14, 1978	Members of the Brumley Gap Concerned Citizens burned letters received from APCo requesting permission to enter property in order to conduct preliminary studies in connection with the company's feasibility studies for a pumped storage hydroelectric project at Brumley Gap.
July 17, 1978	FERC received petitions (1) to intervene, (2) for a public hearing and (3) for denial of application or imposition of conditions from the CAEC and the Sierra Club In addition, the Army Corps of Engineers, TVA and the U.S. Forest Service filed input notices without taking official stances.
July 26, 1978	The Washington County Board of Supervisors passed a resolution temporarily withdrawing its support for the proposed studies; and asking for a 60-day moratorium on studies scheduled to begin in the area on August 14, 1978.

August 7, 1978	APCo received a letter notification from S Strother Smith, attorney for Brumley Gap Concerned Citizens and property owners, denying permission to enter their properties to conduct preliminary studies.
Date	***Summary of Events***
August 10, 1978	APCo filed a request in Washington County Circuit Court for a court order to restrain property owners from interfering with APCo's right to enter property to conduct its feasibility studies.
August 21, 1978	Brumley Gap Concerned Citizens' attorney, S. Strother Smith III filed a petition in U.S. Western District Court challenging the constitutionality of VA's eminent domain laws and requested that Appalachian's suit in Washington County Circuit court to prevent interference with entry to private properties to conduct studies be removed to the Federal Court.
August 24, 1978	The City of Charleston, West Virginia submitted its intervention notice to the FERC.
November 7, 1978	FERC granted intervenor status to all parties who requested intervention in the consideration of a preliminary permit for either the Brumley Gap or Powell Mountain site studies.
December 20, 1978	Responses were filed for the first interrogatories of the Brumley Gap defendants. The Washington County Board of Supervisors voted 4-3 to request FERC to hold an evidentiary hearing on APCo's preliminary permit application.
January 15, 1979	The CAEC informed the FERC that other organizations had become members of the Coalition; and therefore should be added to the list of intervenors in APCo's application for preliminary permits. The new organizations included: Watauga Chapter of the Audubon Society, Roanoke Chapter of the VA Citizens Consumer Council, Concerned Citizens for Justice Inc , VPI and SU Chapter of Students for Safe Energy-Wolf Hills, Virginia Archaeological Chapter and Social Ministry of Senior West Virginians.
February 5, 1979	The Sierra Club and the CAEC filed a petition with FERC urging that the Commission defer consideration of a preliminary permit for both Brumley Gap and Powell Mountain pending receipt of additional data.
March 5, 1979	The FERC announced proposed rulemaking which included a requirement that work plan descriptions be filed with the agency in preliminary permit proceedings.
March 22, 1079	The staff of the FERC requested APCo to provide additional detailed information on work plans and environmental effects of site studies proposed by the Company in conjunction with the feasibility study of the Brumley Gap area.
May 11, 1979	The CAEC and the Sierra Club petitioned the FERC to order a comprehensive study of the power development planning of American Electric Power Company, parent of Appalachian Power Company.

Date	*Summary of Events*
July 18, 1979	The Sierra Club and the CAEC wrote directly to Charles B Curtis, Chairman of the FERC, urging his intervention in APCo's request for a preliminary permit for Brumley Gap. The Sierra Club and the CAEC requested the chairman to use his authority to obtain the performance of a comparative economic analysis of alternatives to the Brumley Gap project prior to the issuance of any permit.
August 21, 1979	United Mine Workers District 29 submitted a letter to the FERC endorsing several of the petitions filed in our preliminary permit proceeding by the Sierra Club and the CAEC.
September 12, 1979	FERC staff members, representatives of the Service Corporation, representatives of APCo, and members of the CAEC participated in field investigations of proposed activity sites in the Brumley Gap area.
November 2, 1979	The Sierra Club and the CAEC wrote Charles B. Curtis, Chairman of the FERC, again requesting his intervention into APCo's preliminary permit application for Brumley Gap. The letter referred to the recent action by the West Virginia Public Utilities Commission requiring APCo to submit economic data to the intervenors and requested the Chairman to require the production and analysis of this data prior to further consideration of the preliminary permit application.
November 20, 1979	The Advisory Council on Historic Preservation inquired by letter to FERC as to the Commission's compliance with historic preservation requirements in its consideration of the Brumley Gap permit application.
December 19, 1979	The Sierra Club submitted a letter to FERC arguing that the requirements of the National Historic Preservation Act were not being implemented by FERC in its consideration of the Brumley Gap permit.
December 27, 1979	The Sierra Club and Coalition of Appalachian Energy Consumers submitted to FERC a petition to compel the Commission to immediately exercise its statutory responsibilities under the Endangered Species Act. The petition argued that a "biological assessment" was required prior to the issuance of a permit.
December 28, 1979	The Sierra Club wrote to Director of the Office of Endangered Species, U S Fish and Wildlife Service, Department of Interior, asking that office to exercise its responsibilities to prevent FERC from engaging in action which will jeopardize endangered species at Brumley Gap, Virginia.

Date	***Summary of Events***
December 31, 1979	The Sierra Club and the CAEC submitted to FERC a "Petition to Require the FERC to Prepare an Environmental Impact Statement in Advance of the Issuance of Any Preliminary Permit" The argument was that the issuance of a permit is a major federal action which will significantly affect the human environment. The Sierra Club and the CAEC filed with FERC a "Petition to Defer Consideration of a Preliminary Permit Until the Commission Fulfills its Statutory Duties to Conduct Further Archaeological Studies." The petition argued the need for a Phase II Archaeological study of the entire area.
January 31, 1980	The FERC Staff issued a "Notice of Finding of No Significant Impact" insofar as studies under a preliminary permit were concerned; and indicated that the Environmental Assessment and FNSI were available upon request.
February 12, 1980	The Sierra Club and the CAEC wrote the FERC requesting the Commission to comply with its statutory duty. This included: (1) holding or sponsoring a public hearing or meeting to consider the Staff finding of no significant impact and the record on which it is based and (2) making available for, and inviting, public review and comment on the FNSI and its supportive data for 30 days prior to a final determination of the need for an environmental impact statement.
February 22, 1980	The Sierra Club and the CAEC filed with FERC a petition to defer issuance of a preliminary permit pending receipt of conservation and demand forecasting analyses of need for a facility at Brumley Gap. The Sierra Club and the CAEC had contracted Energy Systems Research Group, Inc. of Boston, Massachusetts, to perform the cited analyses.
June 20, 1980	The Sierra Club and the CAEC appealed by letter to the FERC to defer action on the preliminary permit for Brumley Gap. The groups urged the Commission to await the preliminary results, due July 15, of the econometric model analysis being performed by Energy Research Group, Inc. on the need for the project.
June 25, 1980	The FERC took up the preliminary permit application for Brumley Gap at its regularly scheduled meeting. The Commission staff urged issuance of a permit specifically conditioned to deal with sensitive environmental areas, but was overruled by the Commission in a 4-0 vote The Commission elected to consider the preliminary results of the econometric model analysis of the Energy Systems Research Group, Inc prior to acting on the application. The matter was rescheduled for the first Commission meeting in August.

Date	*Summary of Events*
July 23, 1980	The Sierra Club and the CAEC submitted to the FERC a Supplemental Petition to Deny or Defer Issuance of a Preliminary Permit The petition appended a preliminary economic and need analysis of the potential project by Energy System Research Group of Boston, Massachusetts, which alleged that the Brumley Gap Project would not be needed by AEP this century.
December 5, 1980	The CAEC and the Sierra Club filed with the FERC a final petition to deny or defer issuance of a preliminary permit for Brumley Gap. In support of their petition, the two groups submitted the final report prepared by Energy Systems Research Group, Inc. titled Economic and Need Analysis of the Pumped Storage Facility at Brumley Gap.
May 12, 1981	The Sierra Club/Coalition of American Electric Consumers filed a petition with FERC to reject the Brumley Gap preliminary permit application or to order a public hearing and prepare an environmental impact statement.
November 30, 1981	Judge Bell of the Washington County Circuit Court dismissed APCo's suit against the Brumley Gap landowners which had been filed on August 10, 1978 The motion for dismissal had been filed by the Company, and there was no objection from the Defendants.
January 12, 1982	The Washington County Board of Supervisors voted 6-1 in favor of a resolution reaffirming the previous Board's stance in opposition to the issuance of a preliminary permit for Brumley Gap.
January 13, 1982	The FERC voted 4-0 to issue a permit for Brumley Gap for a period of three years beginning on January 1, 1982.
July 29, 1982	The CAEC petitioned the U S. Courts of Appeals for the District of Columbia to review and set aside the Order of the FERC which issued a preliminary permit for Brumley Gap.
August 6, 1982	APCo filed with the U S Court of Appeals a motion for leave to intervene in the July 29, 1982 petition for review by the CAEC.
August 6, 1982	Concurrently with the motion for leave to intervene, APCo asked for expeditious consideration of its additional motion for a stay of the effective date of the preliminary permit being challenged
August 13, 1982	The FERC submitted a brief to the U.S. Court of Appeals in opposition to APCo's request for a stay of the effective date of the preliminary permit being challenged.
October 30, 1982	APCo announced it would file a request with the FERC on November 1, 1982 to withdraw its preliminary permit to conduct feasibility studies for a pumped storage hydroelectric project in southwestern Virginia.
November 1, 1982	APCo filed at FERC a request to surrender its preliminary permit for Brumley Gap.

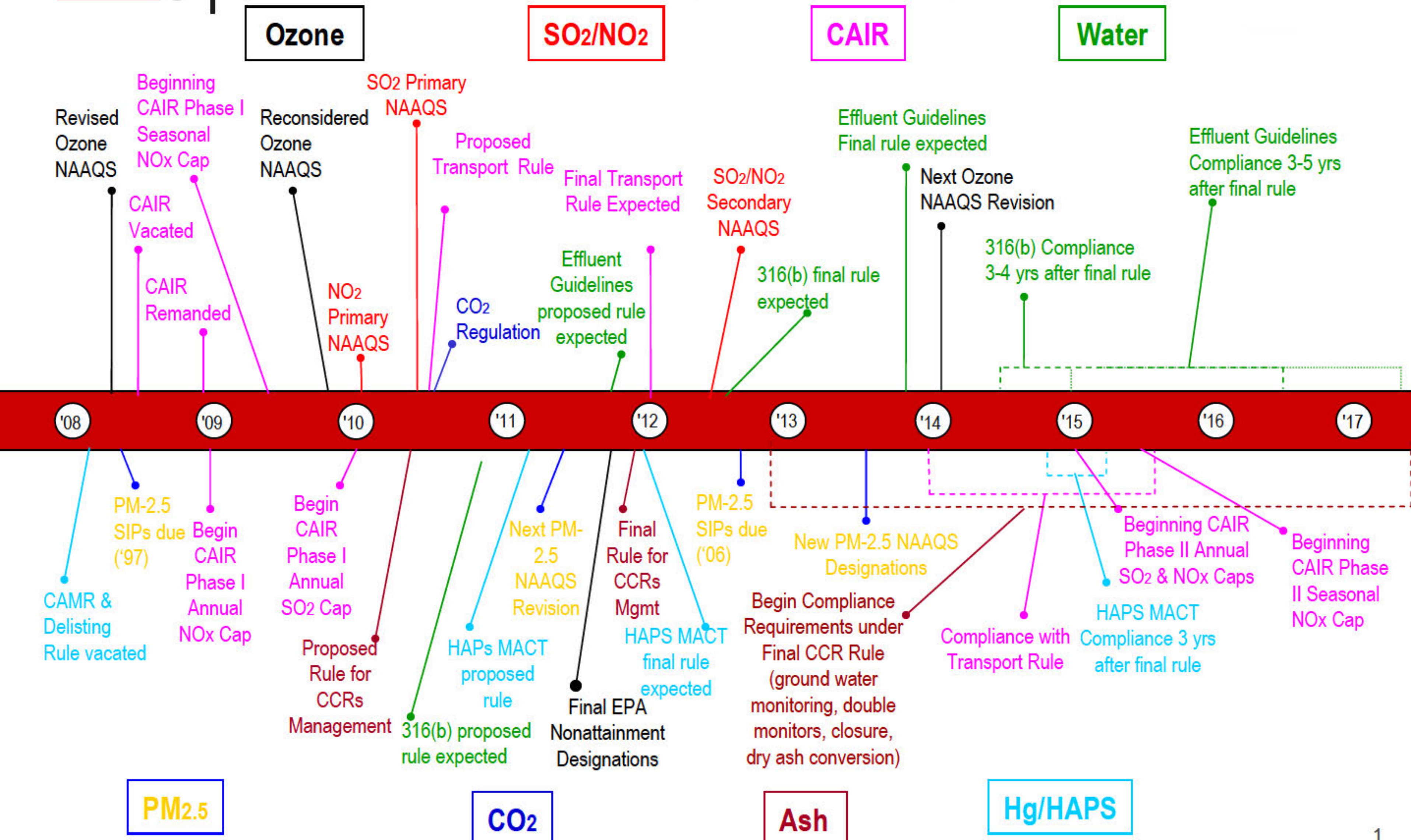
Ex PLC 9

Attachment 5

Impact of EPA Actions on future viability of coal generation

Ex PLC 9

EPA actions will dramatically impact the future viability of coal generation



– updated from Wegman (EPA 2003)

OHIO POWER COMPANY'S RESPONSES TO
INDUSTRIAL ENERGY USERS-OHIO DISCOVERY REQUESTS
PUCO CASE NO. 14-1693-EL-RDR
FIRST SET

REQUEST FOR PRODUCTION OF DOCUMENTS

RPD-1-003 Provide an interactive Excel spreadsheet containing the detailed calculations, including all individual cost items supporting the projected "Agreement costs" shown on Exhibit KDP-2 for the period 2015 through 2024.

RESPONSE

The IEU_RPD-1-003 **COMPETITIVELY-SENSITIVE Confidential** Attachments 1 and 2 for Excel spreadsheets containing the requested information for the period June 1, 2015 to December 31, 2024.

Attachment 1 contains the supporting information for the High Load, Weather Normalized Load and Low Load scenarios presented in Exhibit KPD-2. The Average of the High and Low Forecast was a simple average of the summarized results of the High and Low scenarios in Exhibit KDP-2, and therefore supporting data was not averaged at the detailed level for each of the individual PPA cost components.

Attachment 2 represents a forecast of electric plant in service, accumulated depreciation and depreciation expense. These forecasted values are common to all three scenarios.

Confidential attachments will be provided to parties who have executed a Protected Agreement.

Prepared by: Kelly D. Pearce

Redacted