IN THE SUPREME COURT OF OHIO
On Appeal From the Public Utilities Commission of Ohio

Industrial Energy Users – Ohio, et al. Appellants, v. The Public Utilities Commission of Ohio, Appellee.	)))))))))))	Case No. 06-1594 Appeal from the Public Utilities Commission of Ohio Case No. 05-376-EL-UNC

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CERTIFICATE OF SERVICE

I hereby certify that a true copy of the foregoing Supplement to Merit Brief was served upon the below-listed counsel by first class postage prepaid, U.S. Mail, this 13th day of November 2006.

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FILE

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Recover Costs Associated with the Construction and Ultimate Operation of an Integrated Gasification Combined Cycle Electric Generating Facility	)))))))	Case No. 05- 376 -EL-UNC

APPLICATION

INTRODUCTION

1. Columbus Southern Power Company (CSP) and Ohio Power Company (OP) (collectively, the Companies) are public utilities and electric light companies as those terms are defined in §§ 4905.02 and 4905.03(A)(4), Ohio Rev. Code, respectively.

2. The Companies also are electric distribution utilities (EDU) as that term is defined in § 4928.01(A)(6), Ohio Rev. Code.

3. The Companies are electric utility operating company subsidiaries of American Electric Power Company, Inc. (AEP).

4. Pursuant to §§ 4928.35(D) and 4928.14, Ohio Rev. Code, the Companies (as EDUs) are required to provide a firm supply of generation service to their customers: a) who have not switched to a Competitive Retail Electric Service (CRES) provider; b) who have switched to a CRES provider and then default back to their respective Company's generation service because the CRES provider has failed to deliver generation service; or c) who simply choose to return to their respective Company. This statutory requirement recently has been characterized by the Commission as a

Provider of Last Resort (POLR) obligation (In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of a Post-Market Development Period Rate Stabilization Plan), Case No. 04-169-EL-UNC (the RSP case) January 26, 2005 Opinion and Order, pp. 27, 29, 37, 38).

5. In its RSP Opinion and Order the Commission authorized the establishment of a POLR charge. (p. 27). Elsewhere in its Opinion and Order the Commission stated that the Companies "will be held forth as the POLR to consumers.... Consistent with Ohio law, the POLR designation places expectations upon EDUs; the companies must have sufficient capacity to meet unanticipated demand." (p. 37). The Commission urged the Companies "to move forward with a plan to construct an integrated gasification combined-cycle (IGCC) facility in Ohio." (*Id.*). In that connection, the Commission stated that it "is exploring regulatory mechanisms by which utilities, given their POLR responsibilities, might recover the costs of these new facilities." (p. 38).

6. As part of their fulfillment of their ongoing POLR responsibility, the Companies are prepared to embark on the path toward construction of a 600 MW IGCC facility at a site in Ohio. On a preliminary basis the Companies have asked the PJM RTO to analyze the impacts of locating a 600 MW facility in Meigs County, Ohio in the Great Bend area. The Companies will share in the costs of the IGCC facility based upon the retail loads of each Company during the expected operating life of the facility.

   IGCC technology represents an advanced form of coal-based generation that offers enhanced environmental performance. The integration of coal gasification technology, which removes pollutants before the gas is burned, with combined cycle technology results in fewer emissions of nitrogen oxide, sulfur dioxide, particulates and mercury, in addition to lower carbon dioxide emissions. The Companies believe that construction of an IGCC facility presents an economical and environmentally effective option for their long-term fulfillment of their POLR obligation. This is particularly true in light of natural gas fuel price projections and volatility, and increasingly restrictive environmental requirements for existing and future coal-fired generation which must be anticipated as a matter of prudent planning, including, for example, the potential of significant capital expenditures related to retrofitting traditionally built pulverized coal fired generating facilities. In addition, IGCC has many financial benefits, including its:

- Superior efficiency with lower priced Eastern bituminous coal,
- Superior environmental performance,
- Adaptability to carbon capture and disposal, to conform to anticipated future emission reduction laws and regulations, and
- Potential for by-product sales opportunities.

The Companies will submit in this docket a more detailed discussion outlining the technological and economic benefits associated with an IGCC facility.

The large investment for IGCC now will yield greater long-term adaptability to many environmental regulatory scenarios of the future. The following chart provides extensive data comparing the cost and operational specifications of IGCC to traditional pulverized coal (PC) processes, as well as natural gas combined cycle (NGCC) – a parallel process to IGCC, but with a costlier fuel source. The data were compiled by the Electric Power Research Institute, and are based on nationally accepted economic assumptions regarding fuel costs, heat rates and financial expenditures.

Technology	PC Subcritical	PC Supercritical	IGCC (E-Gas) W/ Spare	IGCC (E-Gas) No Spare	NGCC High CF	NGCC Low CF
Total Plant Cost, $/kW	1,230	1,290	1,350	1,250	440	440
Total Capital Requirement, $/kW	1,430	1,490	1,610	1,490	475	475
Fixed O&M, $/kW-yr	40.5	41.1	56.1	52.0	5.1	5.1
Variable O&M, $/MWh	1.7	1.6	0.9	0.9	2.1	2.1
Avg. Heat Rate, Btu/kWh (HHV)	9,310	8,690	8,630	8,630	7,200	7,200
Capacity Factor, %	80	80	80	80	80	40
Levelized Fuel Cost, $/Mbtu (2003$)	1.50	1.50	1.50	1.50	5.00	5.00
Capital, $/MWh (Levelized)	25.0	26.1	28.1	26.0	8.4	16.9
O&M, $/MWh (Levelized)	7.5	7.5	8.9	8.3	2.9	3.6
Fuel, $/MWh (Levelized)	14.0	13.0	12.9	12.9	36.0	36.0
Levelized Total COE, $/MWh	[illegible]	46.6	[illegible]	[illegible]	[illegible]	[illegible]

Source: Electric Power Research Institute

As shown, the incremental cost difference in the levelized cost of electricity between IGCC and other technologies is relatively small. However, the savings with IGCC in the event of retrofitting for future carbon capture regulations are significant, as will be supported in the Companies' more detailed discussion.

7. In order to proceed, however, the Companies must have an approved mechanism by which costs associated with constructing and operating such a project throughout the life of the facility can be recovered in rates authorized by the Commission. Therefore, consistent with the Commission statements noted above, the Companies submit this application in which they propose a three-phase regulatory mechanism for recovering their costs, including carrying costs, associated with meeting their POLR responsibilities. As described in greater detail below:

> In Phase I, the Companies would recover during 2006 the actual dollars they will have spent on the IGCC facility up to the time of the execution of an Engineering, Procurement and Construction (EPC) contract (approximately in June 2006);
>
> In Phase II, beginning in 2007 through the time the IGCC facility goes into commercial operation, the Companies would recover a carrying charge on their construction costs incurred from the execution of the EPC contract until the beginning of Phase III; and
>
> In Phase III, which would last through the commercial life of the IGCC facility, the Companies would collect a return on as well as a return of their investment in the facility, and would collect their operating expenses, including fuel and consumables, through rates authorized by the Commission.

PHASE I RECOVERY

7. The Companies propose to recover certain IGCC costs in 2006 as a temporary generation rate surcharge on the standard service rate schedules authorized in the RSP order. Those costs, which are projected to total approximately $18 million, are the actual costs incurred through February 28, 2005 (Actual Costs) as well as the costs projected to be incurred from March 2005 until the Companies enter into the EPC

contract which is currently estimated to occur in June 2006 (Projected Costs). To begin recovering these Actual and Projected Costs, the Companies propose that they be authorized to assess a generation rate surcharge on the standard service rate schedules authorized in the RSP order, effective with the first billing cycle in January 2006. The surcharge would remain in effect for 12 billing months. Any customer that receives its generation service from a CRES provider during any portion or all of this period will avoid the surcharge for such period of time.

9. The Actual Costs amount to $932,000. These costs, which have been deferred, generally relate to the following categories of activities:

Dollars are in $000s

Category	Actuals Thru February 28, 2005
Scoping Study	$ 145
Outside Services	$ 342
New Generation Labor	$ 80
Engineering Services Labor	$ 248
Other Internal Labor and Corporate Overhead	$ 82
Expenses	$ 35
Total Generation Costs	**$ 932**
Intercomnection	$ -
Total Interconnection Costs	**$ -**
TOTAL COSTS	**$ 932**

10. The Projected Costs are estimated to be $17 million. The costs generally relate to the following categories of activity.

Dollars are in $000s

Category	March 2005 Thru June 2006
Scoping Study/Front End Engineering and Design	$ 9,750
Outside Services	$ 1,100
New Generation Labor	$ 2,540
Engineering Services Labor	$ 1,240
Other Internal Labor and Corporate Overhead	$ 1,103
Expenses	$ 890
Total Generation Costs	$ 16,623
Interconnection	$ 400
Total Interconnection Costs	$ 400
TOTAL COSTS	$ 17,023

11. The proposed Phase I surcharge to the standard service rate schedules, as determined using a peak demand allocation and projected energy, would be as shown in the following chart.

Columbus Southern Power Company

Rate Schedule	Surcharge (¢/kWh)
R-R, R-R-1, RLM, RS-ES and RS-TOD	0.05801
GS-1	0.04987
GS-2	0.05083
GS-3	0.03935
GS-4, IRP-D	0.03337
SBS	0.04070
SL	0.01661
AL	0.01893

Ohio Power Company

Rate Schedule	Surcharge (¢/kWh)
RS, RS-ES, RS-TOD and RDMS	0.03933
GS-1	0.04441
GS-2 and GS-TOD	0.04543
GS-3	0.03262
GS-4, IRP-D	0.02664
EHG	0.04838
EHS	0.06258
SS	0.04965
OL	0.00961
SL	0.00958
SBS	0.03174

For residential customers using 1,000 Kwh per month, the monthly surcharge would amount to 58¢ and 39¢ for CSP and OP, respectively.

PHASE II RECOVERY

12. Beginning with the first billing cycle in 2007 and through the last billing cycle before the IGCC plant is in commercial operation (currently estimated to occur in mid-2010), the Companies propose that they be authorized to collect an annually levelized carrying charge on the cumulative construction costs (including the carrying costs deferred after the EPC contract is executed and through the end of 2006) through a generation rate surcharge on the standard service rate schedules authorized by the Commission. The carrying charge would be based on each Companies' respective weighted average cost of capital, using an 11.75% return on equity, applied to each company's Construction Work in Process for the IGCC facility at the end of each month. During this period the Companies would not capitalize any carrying charges recovered pursuant to the Phase I and Phase II recovery provisions.

The generation rate surcharge will be in addition to the standard service offer generation rates authorized in the RSP order during the first portion of this recovery phase, i.e. from the first billing cycle in 2007 until the last billing cycle of 2008. From the first billing cycle of 2009 until the next phase of recovery (Phase III) begins with commercial operation of the IGCC facility, the surcharge will be in addition to the standard service offer generation rates authorized by the Commission for that period of time. Any customer that receives its generation service from a CRES provider during any portion or all of these periods will avoid the surcharge for such period of time. The current projection of the total cost of construction of the IGCC facility, without carrying costs, is $1,033,000,000. The estimated carrying costs are $237,488,000. The surcharges, based on those estimated carrying costs, calculated in the same manner as the Phase I surcharges for each company for 2007, 2008, 2009 and 2010 are estimated to be:

Columbus Southern Power Company

Rate Schedule	Surcharge (¢/kWh)			
	2007	2008	2009	2010
R-R, R-R-1, RLM, RS-ES and RS-TOD	0.03553	0.16667	0.32329	0.38721
GS-1	0.03054	0.14326	0.27789	0.33282
GS-2 and GS-TOD	0.03113	0.14603	0.28325	0.33924
GS-3	0.02410	0.11306	0.21929	0.26265
GS-4, IRP-D	0.02043	0.09586	0.18593	0.22269
SBS	0.02492	0.11693	0.22680	0.27164
SL	0.01017	0.04773	0.09258	0.11088
AL	0.01159	0.05439	0.10551	0.12637

Ohio Power Company

Rate Schedule	Surcharge (¢/kWh) 2007	2008	2009	2010
RS, RS-ES, RS-TOD and RDMS	0.02420	0.11423	0.22298	0.26432
GS-1	0.02733	0.12898	0.25177	0.29846
GS-2	0.02795	0.13193	0.25753	0.30529
GS-3	0.02008	0.09475	0.18495	0.21924
GS-4, IRP-D	0.01640	0.07738	0.15104	0.17905
EHG	0.02977	0.14050	0.27425	0.32511
EHS	0.03851	0.18173	0.35475	0.42053
SS	0.03055	0.14418	0.28145	0.33364
OL	0.00591	0.02790	0.05447	0.06456
SL	0.00589	0.02781	0.05429	0.06436
SBS	0.01953	0.09219	0.17996	0.21333

The Companies also request specific accounting authority to defer on their books the carrying cost accrued during the period of time from the execution of the EPC contract and the commencement of carrying cost recovery in the second phase of cost recovery (first billing cycle of 2007) and to amortize those carrying costs over the twelve months in 2007.

PHASE III RECOVERY

13. Prior to the Companies placing the IGCC facility in commercial operation, the Companies will file with the Commission an IGCC Recovery Factor that would be based on a return on as well as a return of the investment in the facility, as well as operating expenses, including fuel and consumables. In other words, the IGCC facility would be treated as if it were a single asset regulated utility. After a hearing and showing that costs are reasonable, the Commission will approve the IGCC Recovery Factor. The IGCC Recovery Factor would be subject to future Commission-approved adjustment for changes in relevant factors, such as IGCC

investment level, customer load, appropriate rate of return, life expectancy of the facility and operating expenses. Moreover, the IGCC Recovery Factor will be adjusted annually to reflect changes in the costs of fuel and consumables since the IGCC Recovery Factor was most recently set, and any prior over-or under-recovery of actual costs of fuel, which include purchased power, and consumables. In this regard, the Companies request accounting authority to practice deferred accounting for over/under recoveries of the costs of fuel and consumables.

The Commission-approved IGCC Recovery Factor will be compared to the Commission-approved standard service offer for the applicable period and an IGCC Adjustment Factor will be calculated to reflect the revenue difference between the IGCC Recovery Factor and the Commission-approved standard service offer. The IGCC Adjustment Factor will be reflected as a charge or credit to the Companies' approved distribution rate schedules and will continue for the period that the particular standard service offer and IGCC Recovery Factor are in effect. The IGCC Adjustment Factor and resulting charge or credit will be revised throughout the life of the IGCC facility as the Commission approves a change to the Companies' standard service offer and as the IGCC Recovery Factor changes.

If the Commission has not issued a final order concerning an IGCC Recovery Factor filing within 90 days of the Companies' filing, the proposed IGCC Recovery Factor will become effective on an interim basis and will remain in effect until such time as the Commission's final order is implemented. The Commission's final order will provide for a reconciliation of the authorized IGCC Recovery Factor as compared to the interim IGCC Recovery Factor that had been in effect.

14. The Companies recognize that the actual revenues collected during the first and second phases of cost recovery are likely to result in either an over- or under-recovery of the actual revenues intended to be recovered. This is due to variations in actual customer loads and actual expenditure levels from projections used in establishing the surcharges in those two phases. Therefore, the Companies propose that monthly, throughout Phases I and II, the net of the over- and under- recovered revenues be subtracted from or added to the Construction Work in Process accounts for the IGCC facility which upon commercial operation will be used in determining the IGCC Recovery Factor during the third phase of recovery.

<u>OTHER RSP IMPACTS</u>

15. The portion of the Companies' request in this application for IGCC-related revenues during the three-year rate stabilization period (2006-2008) is not being submitted pursuant to the provision of the RSP order which permits the Companies to request additional generation rate increases above the fixed generation increases. (See Opinion and Order, January 26, 2005, Case No. 04-169-EL-UNC, pp. 21,22). Nonetheless, in light of the environmental compliance capabilities of the IGCC facility, some parties might believe that the revenues collected pursuant to this application during the rate stabilization period should be used to reduce the amounts of additional generation rate increases the Companies can request under the RSP. In recognition of that concern, the Companies propose that the IGCC-related revenues

collected through surcharges during the rate stabilization period will be tracked and those amounts will be considered as reducing the amounts of additional generation rate increases that each Company can request under the RSP.

Further, additional revenues collected pursuant to this application during 2006 and 2007 will not be considered as part of the generation rate levels which will be increased by 3% and 7%, for CSP and OP respectively, in 2007 and 2008 pursuant to the RSP order.

In light of the POLR obligation resting on EDUs in Ohio and the fact that the Companies do not have an affiliated CRES provider, the Companies do not believe that they are required to corporately separate. Since corporate separation might be required after the rate stabilization period, the Companies request, as part of this application, any waiver that would be needed to permit the Companies, as EDUs, to retain ownership of the IGCC facility.

CONCLUSION

16. The Companies' construction and operation of an IGCC facility in Ohio, with assured cost recovery, are consistent with the Governor's charge to the Commission and other state agencies "to enhance the business climate in Ohio as it competes on a regional, national and global basis for economic development projects." (RSP Opinion and Order, p. 37). It also is consistent with the Commission's observation that the state's policy is to provide customers a "future secure in the knowledge that electricity will be available at competitive prices." (*Id.*). This facility will help fulfill the Companies' POLR obligation, and thereby encourage business development in their

service areas. Moreover, the facility itself will create valuable jobs in an economically depressed area of Ohio. It is expected that construction employment will peak at about 1900 jobs. Ongoing operation of the IGCC facility should result in about 125 permanent jobs. The IGCC facility is expected to produce about $10 million per year in state and local tax revenue. All the while, Ohio's environment will be improved by having this new "environmentally friendly" generating facility which will be capable of using competitively priced Ohio high sulfur coal to meet the Companies' customers' default demand for electric energy.

17. Cost recovery throughout the life of the IGCC facility needs to be addressed at the outset for the Companies to pursue construction of the facility. Therefore, the Companies request that the Commission expeditiously approve this application so that they can proceed with bringing IGCC technology to their customers and to Ohio. In this regard, the Companies request that the Commission establish a procedural schedule to consider this application.

Respectfully submitted,

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BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Columbus Southern Power Company and Ohio Power Company for Authority to Recover Costs Associated with the Construction and Ultimate Operation of an Integrated Gasification Combined Cycle Electric Generating Facility.	:	Case No. 05-376-EL-UNC

POST HEARING BRIEF SUBMITTED ON BEHALF OF THE STAFF OF THE PUBLIC UTILITIES COMMISSION OF OHIO

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I. INTRODUCTION

The real challenge in this case is determining how long term provider of last resort (POLR) obligations should be provisioned. There are substantial risks and uncertainties surrounding the long run security and reliability of the electricity supply and its ability to fulfill the POLR needs. As a follow on to the rate stabilization plans adopted by the Commission for Ohio's electric distribution utilities (EDUs), this case continues the process of determining how these risks and uncertainties could or should be addressed –but with a longer term view. The problems associated with a developing market for electricity are complex and long term and it should not be surprising that this case offers no final answers but rather only presents possibilities that might, and the Staff believes should, be explored further.

Much time will be spent, and the Staff believes wasted, with a detailed critique of the company proposal, especially regarding the "least cost" debate and present economic justification for building an IGCC unit. There is no point in this debate until AEP comes back with a detailed cost presentation. AEP is presently negotiating a "wrap" agreement with GE/Bechtel that would provide for construction of, and performance guarantees associated with, the IGCC unit in exchange for AEP's agreement to pay a firm price. Tr. III at 268-269; Tr. II at 45. Given that AEP will also be assuming certain additional costs and directly undertaking certain construction tasks, the Company has recognized that it will need to subsequently bring a rate-case-style application before the Commission in a subsequent phase of litigation. Tr. II at 52. AEP witness Mr. Baker recognized, with respect to the timing of the cost proceeding, that it would occur later and separate from this current stage of the proceedings. Tr. II at 52-53. At issue in that subsequent phase will be the appropriate level of cost recovery as well as the method of recovery (rate design). *Id.* But those issues need not, and should not, be decided presently.

The company proposal is very useful, however, in that it lays out a conceptual way to address the uncertainties in provisioning the POLR services in the long run. But the company proposal is not a plan which could be implemented today. The current proposal has no schedules, budgets, or designs. Feasibility studies have not been done. Financing options have not been fully explored. Economic comparisons have not been adequately developed or evaluated. No purpose is served by belaboring these points. They are obvious. The value of AEP's proposal lies elsewhere.

The proposal represents the only suggestion that is available currently which offers a way to develop a plan to address the very real concerns about the long term reliability and security of the energy supply for the POLR obligation. The Staff would welcome other proposals but the simple fact is that there are presently none. One must work with the tools at hand. Whether the company proposal is a good tool or a poor one is a determination that can only be made after additional development work is done and physical and economic feasibility studies are finished.

One clear advantage with building an IGCC unit is that it is clean coal technology. Staff witness Wissman presented uncontroverted testimony as to the benefits of clean coal technology:

> Coal is Ohio's, as well as the nation's, most abundant resource. It is well documented in FERC proceedings that, in order to continue to meet increasing demand for natural gas, imports of LNG will need to increase. And yet, the national energy policy has been to move toward less reliance on foreign supplies for our generation and transportation. In addition, natural gas price increases and volatility, as well as its limited domestic supplies and/or deliverability, have caused the nation to take a closer look at our energy resources.

Staff Ex. 1 (Wissman Test.) at 3. Staff witness Wissman also observed that "[t]he IGCC technology mitigates coal's disadvantage on the environmental front." *Id.* at 6. After documenting AEP's aging generation fleet and the upcoming need for base load capacity and discussing the increasingly stringent environmental requirements, Staff witness Wissman concluded that "there does appear to be a need to invest in new clean coal technology given the aforementioned circumstances. *Id.* As a related matter, Staff witness Lambeck also observed that IGCC technology is "very attractive for high sulfur bituminous coals" and concluded that "the value of IGCC may be its importance as a hedging strategy – a way to keep using the nation's most abundant energy resource while providing options to deal with long-term environmental demands." Staff Ex. 2 (Lambeck Test.) at 3-4.

Finally, witness Wissman indicated that "staff supports the deployment of new base load coal generation, and believes *it is reasonable to provide some inventive to do so*" in light of the EDU's POLR obligation. *Id.* at 7. In addition to the direct economic and environmental impact of building an IGCC unit in Ohio, there are also significant secondary or indirect benefits including the creation of new jobs, generation of new tax revenue and promotion of advanced technology. Staff will, therefore, argue in this brief that the company should be permitted to recover the relatively small costs, compared to the risks that Staff sees, of exploring further the IGCC proposal (*i.e.*, the phase I costs). The other issues of approving an actual proposal to build a plant and related cost recovery matters should be left for separate determination in the near future.

II. DISCUSSION OF POLR ISSUES

A. SCOPE OF AN OHIO EDU's POLR OBLIGATION

The POLR obligation falls on the EDU. The EDU is the entity that operates the distribution wires and these wires must remain charged for connected customers to receive service. The obligation is statutory (see Ohio Revised Code Section 4928.14) but, even if there were no statute, the EDU is the only entity that could fill the POLR obligation. Neither a CRES provider nor a regional transmission organization such as PJM can provide POLR service. As further explained below, RTOs have a role at the wholesale, not retail level, to facilitate market transactions and indirectly promote reliability; but RTOs do not have direct responsibility to the customers of a particular EDU when a real problem develops. Similarly, even though a CRES provider does have a retail relationship and direct responsibility to customers, the EDU still stands as the backup POLR provider and that standby duty is distinct from the CRES function of fulfilling day-to-day or minute-to-minute power requirements; CRES providers do not provide distribution service and the EDU's POLR function is a distribution-related service.

Only an EDU can fulfill the POLR function. It is simply a fact that customer load cannot be dropped as quickly as suppliers can fail. Customers whose alternative supply has failed will continue to receive service because they cannot, practically speaking, be terminated. Likewise, customers who shop and return to the EDU for service for whatever reason must be served with an adequate and reliable standard service offer (SSO). Indeed, whatever situation arises, the EDU is required to supply power because demand and supply must match or the distribution system will fail. There must be capacity available ancillary to the provision of the distribution service.

A CRES provider cannot perform this function because it does not provide distribution service and is not obligated to provide backup generation service or make a standard service offer. OCC witness Lechnar claimed that a CRES provider would incorporate capacity-related charge into its retail rates (based on its capacity credits required to be obtained by the CRES provider participating in the PJM market) and, thus, customers could pay twice if the EDU collected a capacity-related charge. Tr. IV at 242, 246. Mr. Lechnar further claimed that collection of *any* generation-related charge by an EDU would inhibit competition by CRES providers. OCC Ex. 1 (Lechnar Test.) at 17-20. These assertions fail to recognize the distinction between the distribution company's POLR obligation and a CRES provider's retail generation supply service. Even Mr. Lechnar admitted that "the POLR obligation is one where capacity is there to support any customers that may come back to the system." Tr. IV at 248.

The scope of the EDU's POLR obligation is to stand ready to serve all comers, including customers returning from a defaulting supplier. This "fallback" position of the EDU is not an enviable task and involves real costs, including a generation-related cost. Although not identical, POLR service can be analogized to "standby service" traditionally offered by Ohio EDUs. Standby service usually is available only to large industrial customers that have alternative energy supplies or resources but want a backup service where the customer's own source of generation is not available. For example, CSP offers standby service to customers that have their own power production facilities but want to have backup service for reliability purposes. *See* Columbus Southern Power Co. (PUCO No. 5) Schedule SBS (Standby Service), Original Sheet No. 27. Although CSP's standby service tariff can only be used for up to 30% forced outage rate (or 2,628 hours per year), *id.* at Sheet 27-4, an EDU's POLR service must be planned to serve 24 hours per day, 7 days per week and 365 days every year. In any case, additional charges apply for the provision of standby service that are beyond the cost of the customer's own source of power production. *Id.* at Sheets 27-2 through 27-8. Likewise, POLR charges are in addition to (but separate and distinct from) unbundled generation charges paid to the EDU or a CRES provider.

The point is that having backup power available is more expensive than relying solely on one source of generation and involves additional costs as well. The Ohio General Assembly has already made the choice to require EDUs to undertake the POLR obligation and provide backup service as part of the regulated distribution function. Given that POLR service must be provided, it makes sense to incorporate long-term planning and resource management designed to lower the cost of the mandatory POLR obligation associated with retail electric competition. POLR service is complimentary, not duplicative of, a CRES provider's capacity-related cost relating to the provision of retail generation service.

The EDU's POLR service is distinct from the competitive generation service offered by a CRES provider.[1] Contrary to OCC witness Lechnar's assertion, the EDU's fulfillment of the POLR function is complementary to CRES provider functions and actually *promotes* retail competition for generation service by providing a safety net or backstop service for shopping customers. As a related matter, although the capacity-related component of the EDU's obligation is only one aspect of POLR, it provides a vital function that facilitates choice for all customers and thereby benefits all customers (*i.e.*, both shoppers and non-shoppers alike). In reality, the POLR obligation is probably best fulfilled through a portfolio of options, not just one; building a generation plant could be part of a reasonable POLR plan but is not the sole method for fulfilling the EDU's statutory obligation. Ultimately, it could serve to promote competition

[1] As further discussed below, the EDU's POLR obligation also differs from the RTO's function in helping to facilitate an adequate supply of capacity and energy.

and maintain price stability, while simultaneously ensuring that adequate capacity exists for Ohio's electric consumers.

It is easy to miss the complexity of the POLR obligation. Since the minute-to-minute obligation is so visible, and dire if it is not met, it might appear that the minute-to-minute reliability is all there is. This would be a mistake. The minute-to-minute reliability does not arise spontaneously, it must be planned. A vital aspect of the POLR requirement is assuring that there will be a supply available not just in the next minute, but also next week, next month, and ten years from now. *POLR is forever.*

The ability of AEP (or any EDU) to meet the long range aspect of the POLR requirement is of great concern to the Staff. The longer-than-anticipated market development period and widespread inability of the wholesale electricity market to yield desirable prices for most customers suggest it is unwise to rely solely on the spot market to ensure "reasonably priced retail electric service." Ohio Rev. Code Ann. § 4928.02(A) (Anderson 2005). Of course, a market-based approach is still warranted (and required); but there are many different ways to formulate a market-based SSO designed to incorporate the EDU's POLR obligation.

For example, AEP's application to build an IGCC plant involves a recovery mechanism that would result in either a charge or a credit when the cost is compared to future market-based SSO offerings. AEP Ex. 2 (Baker Test.) at 9-13. Thus, AEP's proposal is properly considered as a market-based rate recovery plan. In substance, though, AEP's Ohio customers would get the benefit of the bargain to the greatest extent where the IGCC unit costs are mostly lower than the market-based SSO price over the long-term. Indeed, a detailed economic analysis of whether the IGCC costs beat the projected market prices over the long term would be appropriate standard by which to review the proposal in more detail during the subsequent phase of this proceeding;

concluding that the customers' overall costs are likely to beat the market constitutes a market-based offering. At this stage, however, the Commission needs to consider the more basic issues involving the scope of an EDU's POLR obligation and whether that obligation can be fulfilled through a capacity addition that serves as a distribution-related POLR generation service.

If decisions regarding new electric capacity in Ohio could be delayed for several years or decades, there would be more information available to reach those decisions and more certainty/less risk associated with the decisions. As discussed below, some pertinent factors may not be captured when using present market, financial, and regulatory conditions for long term decision-making regarding reliability and security of electric supply. But Staff believes that such capacity decisions are timely now and submits that the best information available should be used (while recognizing that not all questions can be definitively answered at this time).

It will be pointed out that this Commission no longer regulates generation and, therefore, cannot take any steps regarding plant construction. This objection has no merit. AEP's application does not, in Staff's view, represent an effort to re-regulate generation; the underlying issues of distribution reliability exist and have impact in the context of deregulation, whether or not they are proactively addressed through a proposal like the application. Distribution reliability continues to be the charge of the Commission in the electric deregulation era. *See* Ohio Rev. Code Ann. §§ 4928.02(A), 4928.05 and 4928.06 (Anderson 2005). Staff believes that the ability of the generation fleet to supply the ancillary services needed to support the distribution of electricity is under serious, though long-term, threat. Efforts must be made to address this concern.

This is entirely apart from electric generation service. Electricity is unregulated and can be sold at the prices determined in the market. Indeed, the kinds of services about which Staff is concerned are the very services needed to maintain the sound distribution system needed for competitive sales to occur. Arranging for a long-term supply of concrete to maintain a road is not regulating the traffic of concrete trucks down that road. This objection has no validity and should be rejected.

Unavoidably, the future of electric competition lacks certainty; this is true not only for retail customers, but also for the EDUs themselves. But given the long term POLR obligation faced by EDUs, the Commission should be looking for a win-win solution – as it found in the RSP plans – to promote both rate stability and service reliability in a market-based setting. The AEP proposal certainly has the *potential* to satisfy those key features, but has not yet been proven.

B. KEY CONSIDERATIONS FOR PROVISIONING POLR

There are three basic options for provisioning POLR both in the short and long term. An EDU could turn to the market, turn to other owners, or construct (or have constructed) a facility. Of course, a comprehensive POLR provision plan will probably involve, not just one of these options, but a portfolio of options and hedges –especially over the long term. The EDU should have discretion and latitude in fulfilling its POLR obligation, rather than the Commission making those decisions or dictating specific directives in advance.

For the most immediate POLR concerns, turning to the markets appears quite adequate. Under current conditions, there appears to be sufficient physical supply of capacity available to meet consumers' needs. That being the case, it is plausible that the EDU might rely on the availability of spot power to meet its POLR requirements today. The present existence of a significant reserve margin means that there will likely be plants available to produce electricity when it is needed today. The reserve margin does not indicate what the price of that power will be. It might be quite a high price if the purchase had to be made at a point of high demand or the reverse. And while the capacity of peaking units may be readily available, the cost is not always reasonable. Thus it appears that although the market can supply electricity, there is a financial risk presented by relying on the spot market.

If the EDU is to supply no-notice POLR power at a stabilized price, rather than simply flowing through whatever price the market presents at the time the purchase is made, the EDU would need to make other arrangements to deal with the financial risk of offering a stabilized price. Building a generation unit (or having someone build it for the EDU) could be one component within a portfolio of options available to the EDU that would operate as an economic hedge against higher costs that POLR customers would otherwise face, absent such a diverse portfolio of options. The cost and efficiencies associated with such arrangements form the basis of the various kinds of stabilization rates found in the RSP orders of this Commission.

The costs of rate stabilization include the costs to acquire access to sufficient power to supply customers, both current and returning, across the stabilization period. This is done through a combination of market purchases of a variety of futures products and also bi-lateral arrangements with other suppliers outside established markets. This hybrid approach appears sufficient for the intermediate run, that is to say the next three years (*e.g.*, during the RSP period).

This hybrid approach does little for more distant times. The world does not end in three years. The POLR need will still exist and EDUs will remain obligated to fulfill that need. It is when one examines those needs in the more distant future that the possibility of third option, construction, arises. Why not just rely on the markets even in the future? The nature of the situation makes such reliance impossible. The shrinking of base load reserve margins is one of the Staff's significant concerns. This means that there will not be capacity in the market in the future to supply demand. In light of the present market conditions and quasi-regulatory structure, the market presents a challenge and does not stand alone as an easy solution. Likewise, one could not simply turn to other suppliers to provide the capacity in this more distant future because they will not have the capacity to sell.

Construction of new capacity is the only way to provide security of supply in the long run. Whether this construction is done by the EDU itself, as suggested by AEP, or by another entity, makes no difference to the Staff. Staff is very concerned that there may not be enough capacity to meet customers' needs in five, ten, or twenty years unless steps are taken today. It may seem surprising to some that the Staff has such concerns given the relatively sound current reserve margins. But there are threats on the horizon which will destroy the current, secure situation.

Obsolescence, market structure/conditions and environmental regulation will conspire to destroy our current favorable reserves. There is no question that this will happen, it is merely a matter of when it happens. Thus, it is reasonable for an EDU to consider and incorporate these factors in long term planning for the provision of POLR service (conversely, it would be unreasonable to ignore those factors). Of course, these same threats need to be considered by the Commission in addressing capacity issues related to an EDU's provision of POLR service.

1) OBSOLESCENCE

There is substantial reason to be concerned about the obsolescence of the existing generation in Ohio. This obsolescence affects the two predominate kinds of plants in Ohio, pulverized coal and natural gas, differently. The fleet of pulverized coal plants in Ohio is simply old. The plants have an average age of 44 years and they are not being replaced. Staff Ex. 1 (Wissman Test.) at 6. No new pulverized coal plant has been built in 14 years.

The plain reality is that these plants will wear out and no longer be available. The day that these plants will be worn out and decommissioned may be hastened by the need to invest in them to meet current environmental requirements. AEP estimates that it will need to spend $3.7 billion over the next five years to meet the current Clean Air Interstate Rule and the Clean Air Mercury Rule. Such huge investment needs hasten the day when the plants will simply be shut down. The problem with shutting down these plants is that there is no replacement.

For years, the demands of new growth and coal plant retirements have been countered with the construction of gas-fired capacity. Essentially all new construction in Ohio for more than a decade has been gas-fired. Staff Ex. 1 (Wissman Test.) at 5-6. While this approach seemed the environmentally friendly at the time, it has lead to a large reliance on natural gas as a fuel source. Natural gas has been shown to be less than reliable. High prices and the volatility of natural gas have already idled some gas-fired capacity, rendering it economically obsolete. Serious questions exist about the long-term supply of natural gas. It may be that natural gas simply will not be available for electric generation purposes at some point in the future, rendering the plants technically obsolete.

In the long run, there is substantial reason to believe that the current capacity reserve will be reduced and, it appears that nothing is being done about this problem.

2) ENVIRONMENTAL RISK

While it is apparent that there are significant risks to Ohio's generation currently, there is an even more dire possibility. Even if our old coal plants can be patched together for decades more, and we can afford to retrofit mercury and sulfur controls on them, and even if there is natural gas to burn, and even if we can afford the natural gas to burn, the largest risk remains. Judging from the level of interest both in the United States and beyond, it appears that some sort of carbon sequestration will be required in the timeframe about which we are concerned. Europe already has a trading regime for carbon allowances, several U.S. states are considering carbon restriction measures, and many businesses are altering there operations to anticipate a carbon constrained environment. Staff Ex. 3 (Lambeck Test.) at 5. While it is uncertain when such limitations might be enforced, generating assets are very long lived (that is of course one of the problems here, our plants are very old) and it is a virtual certainty that restrictions will be imposed over the life of the assets.

All fossil generation, both pulverized coal and natural gas, are vulnerable to carbon emission limitations. Both produce large volumes of carbon dioxide. At this point there is no hedge for this risk. The vast majority of generation in the Midwest, and the country generally, is fossil-fueled. Staff Ex. 1 (Wissman Test.) at 4-5. Thus there is no practical way to buy a hedge from any other supplier. All other suppliers are in the same position. Their plants produce carbon dioxide as well. The only practical hedge against this large risk is to build a new facility which anticipates carbon sequestration.

An IGCC as suggested by AEP is one such facility which can relatively easily be altered to allow for the capture and disposition of carbon dioxide. This is not magic. The IGCC facility allows the removal of Carbon Dioxide before the synthetic gas is burned with air. The removal from the relatively small volume of fuel before it is burned is easier than removal from the smokestack after combustion.

It is largely agreed among the expert witnesses in this case that the key advantage offered by the IGCC technology is its potential to sequester carbon as part of the gasification process in order to virtually eliminate the substantial carbon dioxide emissions normally associated with a coal plant; the debate is whether it is cost-effective. Within the time frame for decision in this case, the Commission will not know for certain whether carbon sequestration regulations will be passed during the operational life of the plant (or what the content and timing of such requirements may be). But all of the expert witnesses in this case either opined that carbon sequestration regulations would likely be passed within the life of the plant or simply did not offer an opinion as to whether such regulations would be passed. Staff Ex. 3 (Lambeck Test.) at 4-5; Staff Ex. 1 (Wissman Test.) at 7-9; AEP Ex. 4 (Mudd Test.), BHB/MJM Ex. 1 (White Paper) at 19; AEP Ex. 3 (Braine Test.), BHB/MJM Ex. 1 (White Paper) at 19; IEU Ex. 24 (Solomon Test.) at 16-18 (indicating only that there are no current requirements for carbon sequestration). OEG Ex. 10 (Higgins Test.) at 20-21 (refers to "uncertainties concerning future environmental requirements" and says that there will be a "clear economic winner" depending on what happens but offers no opinion as to prospects of carbon capture regulations). No expert witness stated a belief that carbon sequestration regulations would not be passed during the life of the plant.

Hence, the real question on this point becomes whether it is reasonable or prudent to make a long-term decision to build a plant based on the assumption that carbon sequestration regulations will be adopted during the life of the plant. Ultimately, the presence or absence of this assumption can substantially impact the outcome of any economic determination regarding the construction of a new generation plant. For now, it is sufficient to conclude that these matters need not be presently determined but may need to be addressed in the future phase of this proceeding.

There are other technologies which anticipate removal of carbon dioxide in addition to IGCC as proposed by AEP. Staff Ex. 3 (Lambeck Test.) at 3-4. Staff has no preference between these approaches. The selection should be a matter of economic comparison. This technology choice should be explored by AEP as it develops a plan as a result of this case.

3) MARKET CONDITIONS/RTO SRUCTURE

It will be argued that the PJM RPM proposal addresses the future capacity concerns and, thus, customers will be paying for capacity twice, both through an IGCC surcharge and through the PJM rates. This objection misses the point. The RPM process, if approved, does have a mechanism which would provide for a four-year rolling capacity market. Although it may be unlikely that the RPM proposal will ever be adopted, the Commission is not likely to know that outcome within the time frame for deciding the initial phase of this proceeding.[2] Part of this debate is reflected in the fact that MISO has a completely different view of whether capacity market should be established by RTOs.

In the unlikely event that RPM is adopted and applies to AEP,[3] the most that could be argued is that the RPM prices reflect capacity needs through a four-year horizon. Staff's concerns are beyond that four-year horizon. As discussed above, a vital aspect of the POLR requirement is assuring that there will be a supply available not just in the next minute, but also next week, next month, and for decades to come.

Further, as discussed above in relation to CRES providers, the scope of the EDU's POLR obligation is to stand ready to serve all comers, including customers returning from a defaulting

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[2] One of many issues that will be debated before FERC in connection with the RPM proposal is whether resource adequacy requirements are within FERC's jurisdiction (and whether fulfillment of that task is within an RTO's purpose). The Energy Policy Act of 2005 preserves State authority to take action to ensure the safety, adequacy, and reliability of electric service. Energy Policy Act of 2005 (P.L. 109-58) Section 1211(i)(3).

[3] Even if adopted, the RPM proposal contains a provision whereby PJM members can opt out of the RPM; so even if RPM is approved by the FERC, it is possible that AEP would remain a PJM member but not participate in the capacity market.

supplier. This fallback position of the EDU involves real costs, including a generation-related cost. As discussed above, providing backup power is more expensive and incorporating long-term planning into the provision of POLR service would be designed to lower the cost of that mandatory obligation associated with retail electric competition (which benefits all customers).

The distinctions between RTOs and EDUs are significant. As an RTO, PJM is not a player in the retail electricity market, does not have a retail relationship with consumers and is not responsible or accountable to consumers. Rather, PJM operates in the wholesale electricity market and attempts to *facilitate* wholesale transactions (but is not really even directly responsible to ensure that those transactions even occur). Likewise, PJM is a regional *transmission* organization, and does not provide *distribution* services like an EDU; the POLR capacity service at issue in this case is a distribution service.

The fact that RPM refers to reliability does not change any of those things or make PJM's service something that it is not. For all these reasons, POLR service is not duplicative of PJM/RPM capacity charges. Consequently, no double payment is possible, because the capacity charges associated with PJM's RPM proposal relate to a different service and different capacity cost than those associated with the generation-related component of an EDU's retail POLR service.

Another feature of AEP's proposal that should be remembered in this context is that the benefits of the IGCC facility would be retained by the distribution customer (credits for below market costs are made to the distribution rate) – regardless of whether the customer shops or not. The calculated IGCC Recovery Factor is a non-bypassable sur-charge or sur-credit that would flow through to all customers, shoppers and non-shoppers alike; hence, there is no impact on shopping.[4] Independent of any capacity-related charges relating to PJM's wholesale capacity market (whether paid directly by CRES providers or paid indirectly by retail customers), the EDU's retail POLR charges are separate and distinct and are not properly viewed as duplicative.

III. STAFF RECOMMENDATION

An examination of the state of the electric market then shows consumers in Ohio in a position of great, but not immediate, vulnerability. This vulnerability is not today and not tomorrow and not even within four years. It should not cause panic but it should engender sober, thoughtful planning. The facts are clear. Our coal fleet is aged and needs large new investments to run at all. Our natural gas fleet is economically hobbled currently and may not have fuel to burn at some point. Both kinds of plants are threatened by the possibility of carbon restrictions. Existing markets and possible bi-lateral transactions can do nothing for these risks. The only alternative is to evaluate the possibility of construction of new facilities which anticipate carbon controls. Therefore, the Staff recommends that the Commission allow AEP to recover the costs of the first phase of its proposal (the pre-construction costs). In this way the company will have the funds to investigate, analyze, evaluate, and develop a realistic plan to address the very real concerns presented in this case.

For the sake of clarity we will also point out what we are not addressing or recommending at this time. Staff does not presently recommend the approval of Phases II and III. Only time and investigation will tell if a realistic and cost-effective plan can be developed.

4 During cross examination of Staff witness Wissman, the IGCC Recovery Factor rate design was discussed in passing and there was an incomplete or ambiguous discussion of how the rider is to be calculated. Tr. V at 209-212. AEP witness Baker did testify in some detail as to the company's proposed method for calculating the IGCC Recovery Factor as a function of unit's cost differential (compared to the SSO $/kWh) and the plant's actual generation output, then weighted or spread over the company's total load. AEP Ex. 2 (Baker Test.) at 11. But the rate design of the Phase III IGCC Recovery Factor is not really an issue to be decided in this phase of the proceeding and debating this point now is akin to a family arguing over what color a room should be painted in a house that they have not yet purchased.

Only time and investigation will tell if IGCC or some other technology is the better hedge against carbon rules. Only time and investigation will tell if AEP or some other entity should build a plant. Staff believes that its recommendation provides for the time and the investigation to develop answers to these questions. We do not have those answers now.

For example, the Energy Policy Act of 2005 also provides significant incentives for deployment of clean coal technologies, including IGCC. There are more than $6 billion in funding authorizations relating to clean coal programs and incentives and nearly $3 billion in related tax incentives. Tr. V at 112-113; Energy Policy Act of 2005 (P.L. 109-58) Title IV, Subtitles A, B and C; Title XIII, Subtitle A; Title IX, Subtitles F and G; Title XVII. These provisions could positively impact the economic analysis associated with AEP's proposal (to be examined in phase two) and provide additional support for concluding that the proposal should be more closely examined.

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CERTIFICATE OF SERVICE

I hereby certify that a true copy of the foregoing **Post-Hearing Brief** submitted on behalf of the Staff of the Public Utilities Commission of Ohio, was served by electronic mail and regular U.S. mail, postage prepaid, or hand-delivered, upon the following parties of record, this 20th day of September, 2005.

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281 pg

FILE

BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

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In the Matter of the Application of Columbus Southern Power Company for Authority to Recover Costs Associated with the Construction and Ultimate Operation of an Integrated Gasification Electric Generating Facility.	:	Case No. 05-376-EL-UNC

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PROCEEDINGS

before Hearing Examiners Steven D. Lesser and Greta See, at the Public Utilities Commission of Ohio, commencing at 10:00 a.m., on Monday, August 8, 2005, in Hearing Room 11-C, 180 East Broad Street, Columbus, Ohio.

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VOLUME I

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Regarding the PJM GIFSA notation of several fees that were paid to PJM, do the companies intend to recover these fees?

A. We would be looking for recovery of those fees, yes.

Q. And those fees would be recovered in Phase I costs under the company's proposal; is that accurate?

A. I believe that's true.

Q. I'm going to skip around. I went out of order. Let's step back to the macro level for minute.

In your testimony you state that the companies will not go forward with the IGCC facility in Ohio if recovery of the costs is not assured. Is that accurate?

A. Can you point me to a specific --

Q. Page 3, line 9.

A. Yes, that's what I have in the testimony.

Q. And by the word "assured," you mean the companies expect a guarantee for full cost recovery of all construction and operation costs of the IGCC plant from customers; correct?

A. We are asking for the approval of this Commission for the recovery of reasonable costs associated with building this plant.

Q. And it's my understanding, and we started this discussion with Mr. Kurtz, if Ohio does not guarantee full cost recovery, you will review the order and see if there are modifications, but -- is that correct, modifications that you can accept?

A. We would review any order by the Commission and evaluate how it fits into the plan that we filed.

Q. And if the Commission denies approval of your application completely or the companies decide not to accept that modification that we just spoke of, the companies would consider building the plant in other locations; correct?

A. As I tried to state when I was responding to Mr. Kurtz, the company is looking to find a state commission or commissions who are interested in pursuing the development of this technology, so we would look to see if there were other commissions who were interested in offering us the kind of cost recovery that we've asked for here.

Q. And along that line, AEP has already considered building this proposed facility or another 600 megawatt facility in Kentucky and West Virginia; right?

A. We have looked at sites, three sites, being Ohio, West Virginia and Kentucky, as possible locations for an IGCC facility.

Q. And when you say "looked at," you have conducted studies regarding those sites; correct?

A. Yes. And we've asked PJM to conduct studies.

Q. It's your understanding that both Kentucky and West Virginia are regulated states, I believe you said to Mr. Kurtz.

A. I don't remember that, but I would be willing to say that the generation is regulated in the states of West Virginia and Kentucky.

Q. And has AEP filed an application before either of these commissions for approval of cost recovery for constructing the IGCC plant?

A. No, we have not.

Q. And thus AEP has not received any order approving or has not received any verbal approval of costs of recovery regarding such a plant from these states.

A. We have not.

Q. And it's also my understanding, Mr. Baker, that you have not had discussions with other state commissions or staff or other public utilities commissions regarding construction of the plant and receiving full recovery of those costs.

THE WITNESS: Can I have the question read back?

(Question read.)

A. I don't agree with that question.

MS. BOJKO: Strike the question. I will rephrase. I think there are two questions here.

Q. It is my understanding from our discussion previously in deposition that you have had preliminary discussions with other states about such issues. Is that what you're referencing?

A. Yes.

Q. I apologize. The question as written is that the companies or any affiliate have not had discussions with commissioners or staff of any public utilities commission or other agencies regarding the construction of the IGCC plant and receiving full recovery of its costs prior to the plant being constructed and in operation. Is that accurate?

A. It is absolutely accurate. We have not in the state of Ohio asked for full recovery of the power plant before it is operational. We've asked for a plan for recovery.

Q. You have asked for approval of Phase I and Phase II costs prior to the construction and completion of the IGCC plant, have you not?

A. That's not the full cost of the power plant.

Q. Phase III is what you're referencing, which would then be after the plant is in operation, and then a surcharge will be charged to customers recovering the remaining costs.

FILE

BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

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In the Matter the
Application of Columbus
Southern Power Company and:
Ohio Power Company for :
Authority to Recover Costs:
Associated with the : Case No. 05-376-EL-UNC
Construction and Ultimate :
Operation of an Integrated:
Gasification Combined :
Cycle Electric Generating :
Facility. :

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PROCEEDINGS

before Hearing Examiners Steven D. Lesser and Greta See, at the Public Utilities Commission of Ohio, commencing at 10:00 a.m., on Tuesday, August 9, 2005, in Hearing Room 11-C, 180 East Broad Street, Columbus, Ohio.

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VOLUME II

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ORIGINAL

believe you have relative to this facility?

MR. CONWAY: "This facility" being the IGCC facility?

MS. McALISTER: Being the IGCC facility.

A. Practically, we've said this unit, we want it in rate base, we want it as part of Columbus & Southern and Ohio for the life of its facility. I don't think we've taken a position on whether we've waived anything or not, but practically that's what the company's planning to do.

Q. So there's no guarantee.

A. There is nothing in this filing that addresses that issue.

Q. Okay. You talked a little bit yesterday about when the companies expect to come in for a determination on the reasonableness of the costs and the difference between reasonableness and prudence; do you recall that?

A. I do remember that discussion.

Q. What standard does AEP expect the PUCO to apply in order to determine whether the Phase III costs are reasonable?

A. I believe that they would look at whether AEP performed the way they should in entering into

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BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

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In the Matter the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Recover Costs Associated with the Construction and Ultimate Operation of an Integrated Gasification Combined Cycle Electric Generating Facility.	Case No. 05-376-EL-UNC

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PROCEEDINGS

before Hearing Examiners Steven D. Lesser and Greta See, at the Public Utilities Commission of Ohio, commencing at 9:00 a.m., on Friday, August 12, 2005, in Hearing Room 11-C, 180 East Broad Street, Columbus, Ohio.

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VOLUME V

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A. The Power Siting Board itself did not or does not have the capability of creating or recommending incentives, if you will.

Q. What incentives did the Commission make available or suggest might be available to Lima Energy IGCC to help that project move forward?

A. I don't believe there's been any application by Lima directly to this commission for anything of that nature.

Q. Okay. Let's assume that the application in this case is granted as requested by AEP, would it be your position that Lima Energy should have the same opportunity as AEP's IGCC facility to obtain assured cost recovery?

THE WITNESS: Could I have the question reread, please?

(Question read.)

A. Even given the assumption that you laid out in the beginning of that question, that the Commission would grant this application as it was filed, I'm not sure that precisely the same treatment could or would be afforded to Lima. What the staff is suggesting is that in the Commission deliberations they need to make sure that they don't give AEP some advantage by providing this opportunity without looking at some potential opportunities for others that wish to invest.

Q. Okay. Fair enough.

But I gave you an assumption, I asked you to assume that the application was granted. What would be necessary, in your judgment, to allow Lima Energy IGCC the same or comparable opportunity relative to ensure cost recovery? What would the customers need to be prepared to pay to help out Lima Energy?

THE WITNESS: Could I have the first question reread? I think there were two there.

Q. The same question stated differently. Let me withdraw the questions and I'll try it again.

Based upon your notion -- the notion that you've advanced here today that the Commission needs to be mindful that whatever it does relative to this application may trigger an obligation to treat others in a comparable fashion -- is that a fair statement?

A. Yes.

Q. Okay. If the application in this case is granted, what would be the comparable treatment for the Lima Energy IGCC facility?

A. I'm not sure I know. I believe that what the staff -- well, I know what the staff is suggesting, but the staff believes that the Commission needs to, as you said, be mindful that they can't foreclose opportunities for others. Precisely what that would take and what form that would take, I don't know.

There could be perhaps, you know, a purchased power agreement available to Lima from an EDU that would -- I mean, a comparable situation would be that Lima would provide some POLR opportunities in the state through an EDU, for instance through a purchased power agreement. Precisely what that would look like, I don't know. The staff didn't really evaluate all potential opportunities that should be put on the table.

Q. And I appreciate the difficulties associated with trying to get specific, but based upon the concepts that we're talking about here, if the Commission were to grant this application and provide comparable opportunities to independent power producers or merchant plant owners, it would mean that there's another wave of costs that might be unloaded on customers as a result of the obligation to comparably treat merchant plant generators or owners of independent power production facilities, right?

A. Again, not necessarily. I think that --

Q. But perhaps.

A. Again, in this instance it appears that, you know, a POLR obligation may carry some additional costs with it, so how that revenue comes about and flows to whom, it is I believe all questionable at this point. I would not qualify it necessarily as another layer of costs.

Q. Okay. But something needs to be done for the merchants and the IPPs, we don't quite know what it might be, it may involve additional costs; is that a fair statement? Not necessarily, it may.

A. I don't know that something in general needs to be done. I'm just suggesting that if something is done for AEP to afford this technology to go forward, that there -- the Commission needs to be mindful that there are potentially other applicants out there that would like to go forward and they haven't yet, for various reasons.

Q. This is one that's already been certified.

Q. And have you made recommendations to PJM that additional baseload generating capacity be added within the PJM region?

A. Not specifically. As I indicated, we have responded to the RPM that PJM is pursuing. We've had informal discussions with PJM employees, we've attended and participated in all their meetings regarding this.

We have not explicitly told PJM what we want in Ohio, but again, we have clearly responded and they're aware of our views relative to the flaws with the RPM.

Q. Did you review, for purposes of preparing your testimony or otherwise, the work papers of Mr. Braine that support the economic analysis in the White Paper that was attached to both his testimony and Mr. Mudd's testimony?

A. I had reviewed, obviously, the White Paper in evaluating this case, but I believe I've indicated that the staff has stayed away from the economics and numbers because we believe that it is premature. I have very little confidence in what numbers are in this application because everything is subject to change.

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FILE

EXHIBIT NO.________

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Recover Costs Associated with the Construction and Ultimate Operation of an Integrated Gasification Combined Cycle Electric Generating Facility	)))))))	Case No. 05-376-EL-UNC

DIRECT TESTIMONY OF
WILLIAM M. JASPER
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

Filed: May 5, 2005

With the merger of Central and South West Corporation and AEP in 2000 I was named Director of Major Projects. In that role I was responsible for the execution of major generation projects in AEP's western fleet. In 2004 I was named to the position of Director Field Services, responsible for major capital projects in AEP's existing fleet. Also in 2004 I accepted my current role as Director New Generation Projects.

Purpose of Testimony

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to review the process by which AEP intends to contract for and construct an IGCC facility. I will then discuss the process for the determination of the cost of that facility. Finally, I will explain the bases of the "actual" spend and "projected" spend amounts used to develop the Phase I surcharge amounts in the application.

Scoping Process

Q. Please describe the process that will initially be utilized to determine the scope and the cost of a new IGCC plant.

A. AEPSC entered into an agreement with General Electric ("GE") and Bechtel in the early part of 2005 to conduct a scoping study for an AEP-specific IGCC plant. This work by GE and Bechtel has been conducted in parallel with their efforts to develop the scope and cost of a standard GE/Bechtel "reference" plant.

Q, What does the term "reference" plant mean?

A. The term "reference" plant describes a standard plant design that an entity may establish to be used as the starting point for the design of a specific plant. This standard design sets the definition of most of the major equipment of the plant. With an "off the shelf" estimate of this reference plant available, it becomes more straightforward to develop a scope and cost estimate for this reference plant and determine the incremental cost of AEP-specific options contemplated as additions or deletions from the scope and estimate of this reference plant.

Q. What is the expected output of this scoping study?

A. This study provides for a number of technical deliverables. These deliverables ultimately provide for a basic definition of the configuration of the proposed IGCC plant. To facilitate the development of this basic scope definition, there have been a number of studies to consider the internal processes of the plant to allow us to determine those processes that offer the best fit to our needs in terms of balancing capital costs and the benefits derived from exercising a certain design-related option. Additionally, the scoping study provides for the development of a "high level" project schedule and an indicative cost estimate.

Q. Does the scoping study being conducted by GE and Bechtel cover the entire scope of the proposed plant?

A. No. We will develop the scope for certain parts of the plant. The portions of scope we will develop include those site-related items or plant systems with which we are most familiar. This includes fuel and material unloading and handling, switchyard and transmission interconnection, river frontage improvements and development.

Q. When will this happen?

A. One of the deliverables of the scoping study by GE/Bechtel is an indicative estimate of the costs for its reference plant. This then has to be adjusted to the AEP-specific scope and the indicative estimate for that scope finalized. The GE/Bechtel alliance has notified AEP that they began an eight-week process in early April to finalize their estimate. The cost estimates for the components of AEP's scope are also currently under development. When the AEP estimates have been gathered, they will be reviewed for conformance with the expected scope, verified to be on a consistent basis and prepared for combination with the GE/Bechtel estimate. This task by AEP is expected to be complete by the time that the finalization of the GE/Bechtel estimates is accomplished.

Q. Why has AEP selected GE/Bechtel to initiate work on this project?

A. It is of critical importance that AEP mitigate its risk in a project of this nature. To accomplish this, AEP plans to enter into a lump sum turnkey EPC contract with an entity to provide for coverage of substantially all of the scope within one commercial package. In this package one supplier will be responsible for the design, supply, construction, startup, testing and warranties of all major equipment and supporting systems. This will allow substantially all of the facility to be covered by one set of guarantees. These guarantees will have much higher limits than would be the case if equipment and systems were supplied on an individual vendor basis.

The alliance of GE and Bechtel has been the only party capable of supplying a utility grade IGCC facility to step forward with a commercial package be employed for acid gas removal and a variety of potential performance enhancements.

With the optimization of scope options finalized, the scope of the plant going into the next phase of the project will be considered finalized. This second phase of the project is termed Front End Engineering and Design, or FEED.

Front End Engineering and Design Process (FEED)

Q. What happens during FEED?

A. During FEED, GE/Bechtel performs more detailed engineering and design of the AEP-specific plant. This includes defining and selecting specific equipment to be utilized in the plant. This allows GE/Bechtel to obtain vendor pricing on this equipment and to develop the quantities of bulk commodities such as piping, cable and conduit, concrete and steel for the ultimate installation. All of this leads to the development of a definitive cost estimate and a definitive schedule for the AEP-specific IGCC plant.

Q. When will FEED take place?

A. FEED will begin after the reconciliation and finalization of the indicative cost estimates is complete. Prior to that time, the AEP-specific scope will be established. Upon completion of these activities, the scope, price and commercial terms for the FEED will be agreed to by AEP and GE/Bechtel and an agreement for the FEED process executed. This agreement is expected to be executed in July 2005. The FEED process is expected to have a duration of 12 months, completing at the end of June 2006.

Q. What is the work product that is developed in FEED?

A. The primary products of the FEED process are a definitive scope of work, specifications to enable the procurement of major equipment and a definitive cost for the completion of the project.

Q. What is planned for the project subsequent to FEED?

A. After FEED, AEP will negotiate a lump sum, turnkey EPC contract. This EPC contract will provide for the completion of the project including engineering, procurement, construction, training of operators, commissioning and startup, testing, schedule and performance guarantees and warranties. This will be performed for a fixed price according to a defined schedule.

Q. Why is a lump sum, turnkey contract desired in this instance?

A. It is AEP's contracting philosophy that the parties to a contract who can most reasonably manage the risk - in this case, the EPC contractor - be the party to take that risk under the contract. The burden of cost overruns will be on the EPC contractor.

Estimates of Total Project Cost

Q. What was used as the basis for the facility costs used in the Companies' application filed on March 18, 2005?

A. Those IGCC facilities that have been constructed in the recent past were the first generation of IGCC facilities. With the purchase by General Electric of the Texaco gasification business, and GE's existing expertise in the power generation business, General Electric is taking the IGCC technology to a fully commercialized product. As such, it is anticipated that the costs of implementing this technology will be substantially reduced from the costs from the earlier development facilities. Some estimates by EPRI and by General Electric have placed the cost of this commercialized technology as low as $1250/kw. This can be compared with the actual costs of the earlier facilities of up to $2500/kw. For the purposes of this filing, AEP has conservatively selected $1600/kw as the basis of the projected cost of the proposed facility exclusive of transmission interconnection and landfill costs. This results in an estimated total direct cost of the facility of:

Plant EPC (600MW at $1600/kw)	$ 960,000,000
Transmission Interconnection	$ 9,000,000
Landfill	$ 34,000,000
Total	$1,003,000,000

As the Companies' witness, Mr. Nelson, testifies, when construction-related overheads are added to these direct costs, the estimated total cost is $1,033,000,000.

Q. How will the cost of the proposed AEP IGCC facility be refined?

A. As detailed above, the indicative cost estimate will be refined through the eight-week process that started in early April. Once the proposed scope is settled, the twelve-month FEED process will result in a firm price for the EPC AEP-specific contract scope.

Estimates of Phase I Costs

Q. What costs are included in the actual pre-construction Phase I activity estimate?

A. The costs included in the Phase 1 estimate are generally those expenditures that will be incurred up to the point of entering into the lump sum turnkey EPC contract. Specifically, these include:

1. The GE/Bechtel scoping study;
2. The GE/Bechtel FEED;
3. Outside services and internal costs for the definition of scope and estimation of costs for items outside the anticipated EPC scope. This includes materials handling, switchyard and transmission interconnection, site development and river frontage improvements;
4. AEP internal costs for environmental permitting; and
5. AEP internal costs for overall project management.

Q. What is the total Phase I cost estimate?

A. The Phase I actual costs through February 28, 2005 and projected costs (March 1, 2005 through June 30, 2006) are shown in WMJ Exhibit 1. They are approximately $18 million.

Q. What is the basis for these costs?

A. The GE/Bechtel scoping study is being conducted pursuant to a fixed price agreement. The fixed price for these services is $528,000. GE/Bechtel has stated that the total cost of FEED will be up to $20 million. Recognizing that a substantial portion of the work conducted during FEED is for the development of the GE/Bechtel product and therefore properly assignable to GE/Bechtel, and based upon communications with GE/Bechtel, AEP has estimated the portion of FEED to be billable to AEP to be just less than one half of the total. As shown on WMJ Exhibit 2, the scoping study/FEED is estimated to total $9,895,000. This includes the $145,000 in actual expenditures through February 2005 and

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EXHIBIT NO. ______

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus) Southern Power Company and Ohio Power) Company for Authority to Recover Costs) Associated with the Construction and Ultimate) Operation of an Integrated Gasification) Combined Cycle Electric Generating Facility)	Case No. 05-376-EL-UNC

SUPPLEMENTAL TESTIMONY
OF
BRUCE H. BRAINE
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

Filed: August 3, 2005

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
SUPPLEMENTAL TESTIMONY OF
BRAINE H. BRAINE
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY
CASE NO. 05-376-EL-UNC

Q. Please state your name.

A. My name is Bruce H. Braine.

Q. Have you filed Direct Testimony in this proceeding?

A. Yes, I have.

Q. Have you reviewed Mr. J Bertram Solomon's Direct Testimony?

A. Yes I have.

Q. In his testimony, on page 13, Mr. Solomon notes that he corrected a transposition error in your spreadsheet which increased the estimated total cost of the IGCC and pulverized coal by $0.213/MWh and by $0.05/MWh for a combined cycle. Do you agree with this correction?

A. Yes , I do. The spreadsheet error that Mr. Solomon cites does result in the changes he notes in his testimony. I would add, however, that this change is very small. It increases in Table 2 the levelized costs of IGCC coal from 56.2 to 56.4 dollars per MWh and PC from 52.2 to 52.4 dollars per MWh, or by only about 0.4 percent. (and the gas CC plant by only 0.1 dollars per MWh) . Importantly, the relative NPV cost comparison shown in Figure 1 is unchanged. The cost of IGCC is still $9 million less than the coal PC plant or as noted in the White Paper on page 20, the IGCC coal plant costs are still "similar" to the PC coal plant costs.

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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company For Authority to Recover Costs Associated with the Construction and Ultimate Operation of an Integrated Gasification Combined Cycle Electric Generating Facility	)	Case No. 05-376-EL-UNC

DIRECT PREPARED TESTIMONY OF
JOHN BAARDSON ON BEHALF OF
BAARD GENERATION, LLC

July 15, 2005

DIRECT TESTIMONY OF JOHN BAARDSON

1Q: Please state your name, title and business address:

1A: My name is John A. Baardson and I am the president of Baard Generation LLC. My business address is 9013 NE Highway 99, Suite S, Vancouver, WA 98665.

2Q: What is your educational background and work experience.

2A: I received a degree in chemical engineering from Brigham Young University in 1979, and a masters of business administration degree from Central Michigan University in 1984. For the past two decades I have lead project teams building clean fuel power plants and ethanol/biomass facilities.

3Q: Please describe Baard Generation LLC, and explain its interest in the matter at bar.

3A: Baard Generation LLC (formerly known as Nordic Power) was formed in 1989 to build clean fuel power plants. Since its inception, Baard has developed 1,200 MW of such generation. Currently, Baard is exploring two possible sites for an integrated gasification combined cycle electric generation ("IGCC") facility in Ohio. At both Ohio sites Baard is also exploring carbon dioxide sequestration. Ohio contains attractive sites for IGCC, for it has access to high btu coal, a strong transmission system, and depleted oil and gas wells which may be appropriate for conversion to CO2 sequestration wells.

The concern Baard has with the application is the fact that retail customers who would take power from a Baard IGCC plant, would potentially have to pay the Phase III IGCC rider to the American Electric Power ("AEP") operating company - even though such customers would not be taking power from the AEP IGCC unit. This creates an extra barrier for independent IGCC power producers like Baard to sell power to retail customers of AEP. The extra cost to retail customers of independent IGCC power serves as a deterrent to building or selling IGCC power in the AEP service area. It also is unfair to customers of independent IGCC power producers who, via their power prices, are paying the full development cost of the generation units they actually take power from; and thus should not have to make an added payment to funding AEP's IGCC plant.

4Q: Can an independent power producer like Baard build a clean coal generation plant without guarantees from captive utility customers?

4A: Yes, so long as the independent IGCC power producer can sign a long term sales agreement, or receive significant government funding. A generator, independent or utility, cannot commit hundreds of millions of dollars on a generation facility using new IGCC technology without a firm purchase obligation to buy the power at a price which supports the project. For independent IGCC power producers, obligations to purchase are a matter of arranging contracts for future deliveries with very large retail end users or marketers. The key to making such sales is the price of the generation. Hence the concern that the AEP Phase III rider could effectively add to the price of independent IGCC power generation.

Because IGCC and carbon sequestration are new technologies, they have start up costs that exceed conventional coal generation plants. On the other hand, because IGCC and carbon sequestration are new technologies they hold the promise of lower pollution control costs in the future. Further, there are small funding grants from governmental agencies available today, and potentially significant government funds in the future that directly or indirectly could bring down the cost per MW of clean coal generation. On the federal level, both the House and Senate versions of the pending Energy Act have set aside hundreds of millions of dollars for both research, generation and loan guarantees for clean coal use. This includes specific references to IGCC projects. In fact, Section 406 of HB 66 (the House version of the Energy Act) offers loan guarantees to IGCC units, but only if the projects do not have rate payer guarantees. A copy of the clean coal section of HB 66 was attached as an addendum to the Baard intervention and comments. Bottom line is that Baard is actively investigating both conventional and government sponsored methods of financing an Ohio independent IGCC plant.

5Q: Will Baard definitely build an IGCC plant in Ohio?

5A: Baard will build an IGCC plant in Ohio if it is economical to do so. By that I mean that if Baard through good management, prudent selection of technology, and use of available government development monies can build and operate an IGCC plant with carbon sequestration at generation prices sufficiently low to attract commitments to buy power, Baard will build the plant. Further, Baard is just one player in a sizable independent power industry, many of whom have already built conventional units in Ohio and are likely to do so again.

6Q: What are your recommendation to the Commission as to the application at bar?

6A: AEP is one of the leading firms in terms of sophistication and financial strength in the electric generation industry. If AEP believes that the proposed IGCC project is too financially risky to build without a price guarantee from the captive customers, then it is also too risky an investment for the captive customer. The Commission should at a minimum refrain from rushing into a rate payer commitment at this time when significant changes in funding are becoming available for IGCC and carbon sequestration plants that could lower the price.

Second, if the Commission elects to grant AEP a customer guarantee, the guarantee should be limited to just the customers who take power from the AEP IGCC plant. To make customers of independent IGCC plants who are already paying the development costs of the facilities they take power from pay for the AEP IGCC plant is unfair to the customer. Further, it damages the market for additional construction or sales of power from new independent IGCC plants. Considering that the IGCC will not be operational until 2010, and that the guarantee will last potentially for several decades thereafter, the Phase III surcharge could be a significant barrier to market development of independent IGCC plants in the AEP service area for a long time. Thus, the rider to support the IGCC plant should be made bypassable for those buying power from an independent IGCC power plant, if approved at all.

12Q: Does this conclude your testimony?

12A: Yes, other than to thank the Commission for this opportunity to present the views of Baard Generation LLC.

FILE

BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Columbus Southern Power Company and Ohio Power Company for Authority to Recover Costs Associated with the Construction and Ultimate Operation of an Integrated Gasification Combined Cycle Electric Generating Facility.	:	Case No. 05-376-EL-UNC

PREPARED TESTIMONY
of
KIM WISSMAN

Deputy Director, Utilities Department
Public Utilities Commission of Ohio

Staff Exhibit ___________

Please state your name, title and business address.

1\. A. My name is Kim Wissman and I am the Deputy Director of the Utilities Department, Public Utilities Commission of Ohio. My business address is 180 East Broad Street, Columbus, Ohio 43215.

2\. Q. What is your educational background and experience relevant to this proceeding?

A. I received a Bachelor of Science Degree in Economic from Kenyon College. I have been employed by this Commission since 1979. My concentration throughout my career at the agency has been in electricity. I have performed analysis, oversight and policy development regarding rate case preparation, cost-of-service studies, contract and tariff approval, cogeneration matters, management performance and financial audits on company fuel and purchased-power procurement practices and cost recovery. Currently, I also serve as Executive Director of the Ohio Power Siting Board, responsible for siting major utility facilities in the state of Ohio including gas and electric transmission lines and generating stations, and provide policy guidance in independent transmission system operators, regional cooperative efforts, and federal energy matters. I currently have responsibility for oversight of the Facilities, Siting and Environmental Analysis Division and the Policy and Market Analysis Division of the Utilities Department.

3\. Q. What is the purpose of staff testimony?

A. The Staff believes that there is a need for investment in baseload capacity and that the choice of baseload capacity should be made with an awareness of the strong risks posed by increasingly stringent environmental regulation and concerns, including those of carbon sequestration. We also recognize that Ohio electric distribution utilities have unique responsibilities for satisfying requirements as providers of last resort. We view AEP's proposal as an innovative simultaneous approach to both the capacity investment issue and the POLR issue. At the same time, we recognize that other solutions may be possible.

Staff will address a limited number of issues. After review of the Applicant's filing and testimony, as well as intervener testimonies, staff believes the particular issues raised by those parties have been adequately addressed. Staff is not addressing the overall economic issues associated with AEP's proposed IGCC plant or whether the Commission should grant or deny the application. Instead, there are a limited number of areas that staff does not believe are currently represented sufficiently in the existing record. Staff is therefore, through its testimony, providing a more complete and robust record for the Commission to consider in its deliberations.

4. Q. The company is proposing the construction of an IGCC generation facility in this case. Does the staff have a preference regarding generation technology?

A. No. Staff does not advocate a specific technology, per se. We do, however, strongly support a diversified energy portfolio that is economically sound on a forward-looking basis. We currently have a good mix of generation resources in Ohio, and do support a continuance of that in the future. Of course, there are many important factors that can affect the technology choice for a particular

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EXHIBIT NO. ________

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Recover Costs Associated with the Construction and Ultimate Operation of an Integrated Gasification Combined Cycle Electric Generating Facility	)))))))	Case No. 05-376-EL-UNC

SUPPLEMENTAL TESTIMONY OF
WILLIAM M. JASPER
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

Filed: August 3, 2005

BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO
SUPPLEMENTAL TESTIMONY OF
WILLIAM M. JASPER
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY
CASE NO. 05-376-EL-UNC

Q. Please state your name.

A. My name is William M. Jasper.

Q. Have you filed Direct Testimony in this proceeding?

A. Yes.

Q. In your Direct Testimony, you discuss the GE/Bechtel scoping study. Has this study been completed?

A. While a great deal of work has been accomplished on this scoping study, there are remaining elements that require additional work prior to being deemed completed.

Q. What remains to be completed as a part of this study?

A. A FEED scoping document is being developed as the definitive documentation of the scope of the AEP specific plant. This will be the basis used for starting the FEED process. It is a comprehensive product of the scoping study. Certain details are being worked out between the GE/Bechtel and AEP project teams to make this a mutually agreed, accurate representation of this FEED starting point. Similarly, GE/Bechtel is working out details in their indicative cost in order to satisfactorily demonstrate consistency with the target price of $1600/kw for the direct EPC costs.

Q. When will this be done?

are traditionally considered to be Owner's costs. These Owner's costs include materials handling beyond what is required for reclaim from a storage pile and conveyance to the plant's silos. The Owner's costs also include river frontage improvements for providing for the mooring and unloading of barges and initial site preparation to provide the EPC contractor a flat and level site on which to build.

2. AEP costs for project management, AEP engineering and construction management (PM, E &C).

Q. What is AEP's current estimate of the Phase I activities in this application?

A. The Phase I actual costs through June 30, 2005 and projected costs (July 1, 2005 through June 30, 2006) are shown in WMJ Exhibit 4. They are approximately $23.7 million.

Q. Does this conclude you supplemental testimony?

A. Yes, it does.

SUMMARY OF
THE COMMISSION'S OPINION AND ORDER OF SEPTEMBER 28, 2000
IN THE COLUMBUS SOUTHERN POWER COMPANY AND OHIO POWER COMPANY
ELECTRIC TRANSITION PLAN CASES
CASE NOS. 99-1729-EL-ETP AND 99-1730-EL-ETP

On June 22, 1999, the Ohio General Assembly passed legislation requiring the restructuring of the electric utility industry and providing for retail competition with regard to the generation component of electric service (Amended Substitute Senate Bill No. 3 of the 123rd General Assembly). Governor Bob Taft signed this legislation (SB 3) on July 6, 1999, and most provisions of SB 3 became effective on October 5, 1999. Section 4928.31, Revised Code, requires each electric utility to file with the Commission a transition plan for the company's provision of retail electric service in the state of Ohio.

On December 30, 1999, Columbus Southern Power Company and Ohio Power Company (hereinafter jointly referred to as "AEP") filed transition plans, as well as requests for receipt of transition revenues. On May 8, 2000, a stipulation and recommendation on AEP's transition plans, was filed on behalf of the following 23 parties:

AEP,
Appalachian People's Action Coalition,
Association for Hospitals and Health Systems, also d/b/a the Ohio Hospital Association,
Buckeye Power, Inc.,
Columbia Energy Services Corporation,
Columbia Energy Power Marketing Corporation,
Enron Energy Services, Inc.,
Industrial Energy Users-Ohio,
The Kroger Company,
Mid-Atlantic Power Supply Association,
National Energy Marketers Association,
NewEnergy Midwest, LLC,
Ohio Consumers' Counsel,
Ohio Council of Retail Merchants,
Ohio Department of Development,
Ohio Manufacturers' Association,
Ohio Partners for Affordable Energy,
Ohio Rural Electric Cooperatives, Inc.,
Peco Energy Company, d/b/a Exelon Energy,
Public Utilities Commission staff,
Strategic Energy L.L.P.,
WPS Energy Services, Inc., and
WSOS Community Action Commission, Inc.

Dynegy, Inc. and Ohio Environmental Council have stated that they do not oppose the May 8, 2000 stipulation. The evidentiary hearings were held on May 9, 31, and June 7, 8, and 12, 2000. Local public hearings were held on June 5, 2000, in East Liverpool, Ohio and on June 22,2000, in Columbus, Ohio. On June 19, 2000, AEP and Ameritech New Media, Inc. filed a stipulation to resolve their differences.

In the opinion and order, the Commission is approving the agreements submitted by the various parties listed above with certain modifications regarding the load shaping service, the operational support plan, and the employee assistance plan. The Commission defers a ruling upon the independent transmission plan, as allowed by Section 4928.34(A)(13), Revised Code. The Commission found that the terms of the agreements, considered in their totality, advance the public interest and provides substantial benefits to all customer classes. The stipulations provide for extended rate freezes, flexibility for larger contract customers not otherwise available, and defined transition periods for AEP. The stipulations, among other things:

(1) Provide a five-percent reduction of AEP's generation component for residential rate schedules;
(2) Create shopping credits that facilitate the development of the retail marketplace;
(3) Commit AEP to absorb certain costs associated with transitioning to a competitive marketplace;
(4) Commit AEP to provide certain types of assistance to transmission users for a period of time;
(5) Commit AEP to provide funds (up to $10 million) for reimbursement of certain transmission costs of suppliers and customers;
(6) Commit AEP to develop and propose resolutions of reciprocity and interface/seams issues;
(7) Provide a credit to suppliers for consolidated billing; and
(8) Provide relief from certain charges for certain customers that switch suppliers between 2006 and 2007.

The Commission also determined that AEP's transition plan filings, as amended by the settlement agreements and subject to the conclusions in the decision, are in compliance with the statutory requirements contained in SB 3. By approving the stipulations as set forth in this decision, the Commission also authorizes certain accounting treatments for AEP to create the necessary regulatory assets, defer costs, and recover those costs through a regulatory transition charge.

This summary was prepared to provide a brief statement of the Commission's action in these cases. It is not part of the Commission's decision and does not supersede the full text of the Commission's opinion and order.

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BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Applications of Columbus Southern Power Company and Ohio Power Company for Approval of Their Electric Transition Plans and for Receipt of Transition Revenues.	)))))	Case Nos. 99-1729-EL-ETP 99-1730-EL-ETP

OPINION AND ORDER

The Commission, coming now to consider the stipulations, testimony, and other evidence presented in these proceedings, hereby issues its Opinion and Order.

APPEARANCES:

Marvin I. Resnick, Edward J. Brady, and Kevin F. Duffy, American Electric Power Service Corporation, One Riverside Plaza, Columbus, Ohio 43215, and Porter, Wright, Morris & Arthur, LLP, by Daniel R. Conway and Mary Kay Fenlon, 41 South High Street, Columbus, Ohio 43215-6194, on behalf of Columbus Southern Power Company and Ohio Power Company.

Betty D. Montgomery, Attorney General of the State of Ohio, by Duane W. Luckey, Section Chief, and Thomas W. McNamee and Stephen A. Reilly, Assistant Attorneys General, Public Utilities Section, 180 East Broad Street, 9th Floor, Columbus, Ohio 43215-3793, on behalf of the staff of the Public Utilities Commission of Ohio.

Betty D. Montgomery, Attorney General of the State of Ohio, by Jodi M. Elsass-Locker, Assistant Attorney General, 77 South High Street, 29th Floor, Columbus, Ohio 43215, and Maureen R. Grady, 369 South Roosevelt Avenue, Columbus, Ohio 43209, on behalf of the Ohio Department of Development.

Robert S. Tongren, Ohio Consumers' Counsel, and Colleen L. Mooney, Terry L. Etter, Ann M. Hotz, and Dirken D. Winkler, Assistant Consumers' Counsel, 10 West Broad Street, Suite 1800, Columbus, Ohio 43215-3485, on behalf of the residential customers of Columbus Southern Power Company and Ohio Power Company.

McNees, Wallace & Nurick, by Samuel C. Randazzo, Gretchen J. Hummel, and Kimberly J. Wile, Fifth Third Center, 21 East State Street, Suite 1700, Columbus, Ohio 43215-4228, on behalf of Industrial Energy Users-Ohio.

Boehm, Kurtz & Lowry, by Michael L. Kurtz, 2110 CBLD Center, 36 East Seventh Street, Cincinnati, Ohio 45202, on behalf of The Kroger Company.

Chester, Willcox & Saxbe LLP, by John W. Bentine and Jeffrey L. Small, 17 South High Street, Suite 900, Columbus, Ohio 43215, and William T. Zigli and Ivan L. Henderson, 601 Lakeside Avenue, Room 106, Cleveland, Ohio 44114, and Climaco, Lefkowitz, Peca, Wilcox & Garfoli Co. LPA, by Anthony J. Garfoli, Joe Hegedus, and Scott Simpkins, on behalf of the city of Cleveland.

Chester, Willcox & Saxbe LLP, by John W. Bentine and Jeffrey L. Small, 17 South High Street, Suite 900, Columbus, Ohio 43215, on behalf of the Ohio Council of Retail Merchants and American Municipal Power-Ohio, Inc.

Craig G. Goodman, 3333 K Street, NW, Suite 425, Washington D.C. 20007, on behalf of The National Energy Marketers Association.

Calfee, Halter & Griswold LLP, by Kevin M. Sullivan, Richard J. Mattera, and Peter A. Rosato, 1400 McDonald Investment Center, 800 Superior Avenue, Cleveland, Ohio 44114, on behalf of Ameritech New Media, Inc.

William M. Ondrey Gruber, 2714 Leighton Road, Shaker Heights, Ohio 44120, and Vicki L. Deisner, 1207 Grandview Avenue, Room 201, Columbus, Ohio 43212-3449, on behalf of Ohio Environmental Council.

David C. Rinebolt, 337 South Main Street, 4th Floor, Suite 5, Findlay, Ohio 45840, on behalf of Ohio Partners for Affordable Energy.

Ohio State Legal Services Association, by Michael R. Smalz, 861 North High Street, Columbus, Ohio 43215, on behalf of the Appalachian People's Action Coalition.

Ellis Jacobs, 333 West First Street, Suite 500, Dayton, Ohio 45402, on behalf of the WSOS Community Action Commission, Inc.

Bricker & Eckler LLP, by Sally W. Bloomfield, Elizabeth H. Watts, and Amy Straker Bartemes, 100 South Third Street, Columbus, Ohio 43215-4291, on behalf of Mid-Atlantic Power Supply Association, Columbia Energy Services Corporation, Columbia Energy Power Marketing Corporation, and Ohio Manufacturers' Association.

Bricker & Eckler LLP, by Sally W. Bloomfield, Elizabeth H. Watts, and Amy Straker Bartemes, 100 South Third Street, Columbus, Ohio 43215-4291, and David Dulick, 2600 Monroe Boulevard, Norristown, Pennsylvania 19403, on behalf of Peco Energy d/b/a Exelon Energy.

Bricker & Eckler LLP, by Sally W. Bloomfield, Elizabeth H. Watts, and Amy Straker Bartemes, 100 South Third Street, Columbus, Ohio 43215-4291, and Wanda M. Schiller, Two Gateway Center, Pittsburgh, Pennsylvania 15222, on behalf of Strategic Energy L.L.C.

Sutherland Asbill & Brennan LLP, by Paul F. Forshay, Keith McCrea, James M. Bushee, David A. Codevilla, and Daniel J. Oginsky, 1275 Pennsylvania, Avenue, NW, Washington D.C. 20004-2415; and Amy Gold, P.O. Box 4402, Houston, Texas 77210, on behalf of Shell Energy Services Co., LLC.

Vorys, Sater, Seymour & Pease, by M. Howard Petricoff, 52 East Gay Street, P.O. Box 1008, Columbus, Ohio 43216-1008, on behalf of NewEnergy Midwest, LLC and WPS Energy Services, Inc.

Vorys, Sater, Seymour & Pease, by M. Howard Petricoff, 52 East Gay Street, P.O. Box 1008, Columbus, Ohio 43216-1008, and Janine L. Migden, Enron Corp., 400 Metro Place North, Dublin, Ohio 43017-3375, on behalf of Enron Energy Services Inc.

Vorys, Sater, Seymour & Pease, by M. Howard Petricoff and Joseph C. Blasko, 52 East Gay Street, P.O. Box 1008, Columbus, Ohio 43216-1008, and David L. Cruthirds, 1000 Louisiana Street, Suite 5800, Houston, Texas 77002-5050, on behalf of Dynegy, Inc.

Vorys, Sater, Seymour & Pease, by Philip F. Downey and Stephen M. Howard, 52 East Gay Street, P.O. Box 1008, Columbus, Ohio 43216-1008, on behalf of the Ohio Cable Telecommunications Association.

Thompson Hine & Flory, LLP, by Robert P. Mone and Scott A. Campbell, 10 West Broad Street, Suite 700, Columbus, Ohio 43215, on behalf of Ohio Rural Electric Cooperatives, Inc. and Buckeye Power, Inc.

Logothetis, Pence & Doll, by John R. Doll, 111 West First Street, Suite 1100, Dayton, Ohio 45402-1156, and Speigel & McDairmid, by Cynthia S. Bogorad, Scott H. Strauss, David B. Lieb, 1350 New York Avenue NW, Suite 1100, Washington D.C. 20005-4798, on behalf of United Workers Union of America, AFL-CIO, and the Utility Workers Union of America, Local Union Nos. 111, 116, 296, 468, 478, 492, and 544.

Richard L. Sites, 155 East Broad Street, 15th Floor, Columbus, Ohio 43215, on behalf of the Association for Hospitals and Health Systems, also d/b/a Ohio Hospital Association.

Taft, Stettinius & Hollister LLP, by James J. Mayer, 1800 Firstar Tower, 425 Walnut Street, Cincinnati, Ohio 45202-3957, and Thomas J. Russell, Unicom Corporation, 125 Clark Street, Room 1535, Chicago, Illinois 60603, on behalf of Unicom Energy, Inc. and Unicom Energy Services, Inc.

Thomas M. Myers, 56000 Dilles Bottom, Shadyside, Ohio 43947, on behalf of International United Mine Workers of America (UMWA), AFL-CIO, and UMWA District Six, Local Union Nos. 1604, 1857, 1886, and 6362.

OPINION:

I. HISTORY OF THESE PROCEEDINGS

On June 22, 1999, the Ohio General Assembly passed legislation requiring the restructuring of the electric utility industry and providing for retail competition with regard to the generation component of electric service (Amended Substitute Senate Bill No. 3 of the 123rd General Assembly). Governor Bob Taft signed this legislation (hereinafter SB 3) on July 6, 1999, and most provisions of SB 3 became effective on October 5, 1999. Section 4928.31, Revised Code, requires each electric utility to file with the Commission a transition plan for the company's provision of retail electric service in the state of Ohio. The plan must include a rate unbundling plan, a corporate separation plan, a plan to address operational support systems and any other technical implication issues related to competitive retail electric service, an employee assistance plan, and a consumer education plan.

On November 30, 1999, as subsequently modified and/or clarified on January 4, 20, and 27, and February 17, 2000, the Commission adopted rules for the filing and processing of electric transition plans and adopted a consumer education framework. *In the Matter of the Commission's Promulgation of Rules for Electric Transition Plans and of a Consumer Education Plan, Pursuant to Chapter 4928, Revised Code*, Case No. 99-1141-EL-ORD.

On December 30, 1999, the Columbus Southern Power Company and Ohio Power Company[1] each filed transition applications with the Commission. Each company requested approval of its electric transition plan and for authorization to recover transition revenues. Thereafter, on January 14 and February 28, 2000, AEP filed amendments to the transition plan applications.

A technical conference was conducted on January 10, 2000, at which AEP explained its filing and answered questions from participants. Preliminary objections to the applications were submitted on February 10, 11, 14, and 15, 2000. Pursuant to Section 4928.32(B), Revised Code, the Staff Report of Exceptions and Recommendations was filed on March 28, 2000. A procedural/settlement conference was conducted on March 3, 2000, and, on March 10, 2000, the attorney examiner issued an entry summarizing the rulings made during the conference and scheduling an additional prehearing conference. AEP filed additional supplemental testimony on April 18, 2000, in accordance with the attorney examiner's directive.

Intervention was granted in this proceeding to the following parties:

Appalachian People's Action Coalition (APAC);
American Municipal Power-Ohio, Inc. (AMP-Ohio);
Ameritech New Media, Inc. (ANM);
Association for Hospitals and Health Systems, also d/b/a the Ohio Hospital Association (OHA);
Buckeye Power, Inc.;
City of Cleveland (Cleveland);
Columbia Energy Services Corporation;
Columbia Energy Power Marketing Corporation (Columbia Energy companies[2]);
Dynegy, Inc. (Dynegy);
Enron Energy Services, Inc. (Enron);
Industrial Energy Users-Ohio (IEU-Ohio);
The Kroger Company (Kroger);
Mid-Atlantic Power Supply Association (MAPSA);
National Energy Marketers Association (NEMA);

1 The two utilities will be referred to individually as "CSP" and "OP" or collectively as "the companies" or "AEP", since the utilities are operating companies within the American Electric Power family.

2 Columbia Energy Services Corporation and Columbia Energy Power Marketing Corporation jointly filed a motion to intervene in these proceedings and shall be jointly referred to as "Columbia Energy companies".

NewEnergy Midwest, LLC (NewEnergy);
Ohio Consumers' Counsel (OCC);
Ohio Council of Retail Merchants (OCRM);
Ohio Department of Development (ODOD);
Ohio Environmental Council (OEC);
Ohio Manufacturers' Association (OMA);
Ohio Partners for Affordable Energy (OPAE);
Ohio Rural Electric Cooperatives, Inc. (OREC[3]);
Peco Energy Company, d/b/a Exelon Energy (Exelon);
PP&L EnergyPlus Co., LLC (EnergyPlus);[4]
Shell Energy Services Company, L.L.C. (Shell);
Strategic Energy L.L.P. (Strategic);
Unicom Energy, Inc.;
Unicom Energy Services, Inc. (Unicom[5]);
United Mine Workers of America, AFL-CIO;
UMWA District Six, Local Union Nos. 1604, 1857, 1886, and 6362 (UMWA[6]);
Utility Workers Union of America, AFL-CIO;
Utility Workers Union of America, Local Union Nos. 111, 116, 296, 468, 478, 492, and 544 (UWUA[7]);
WPS Energy Services, Inc. (WPS); and
WSOS Community Action Commission, Inc. (WSOS).

The joint motion to intervene by Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company was denied on March 23, 2000. The Ohio Cable Telecommunications Association (OCTA) filed to intervene in these proceedings. However, OCTA filed two days later a notice of conditional withdrawal of its intervention request.

The second prehearing conference was conducted as scheduled on April 28, 2000. On May 8, 2000, a stipulation and recommendation (Jt. Ex. 1) was filed. That stipulation was signed by AEP, the Commission staff, APAC, Columbia Energy companies, Enron, NewEnergy, WPS, Exelon, IEU-Ohio, Kroger, MAPSA, NEMA, OCC, OCRM, OHA, OPAE, OREC, Strategic, WSOS, ODOD, and OMA. The stipulation purports to resolve all issues in these proceedings, except for one issue related to AEP's proposed gross receipts/excise tax rider. Dynegy and OEC later stated that they do not oppose the stipulation. On May 8, 2000, Shell filed testimony opposing the transition plans in several respects. The hearing

3 Buckeye Power, Inc. and Ohio Rural Electric Cooperatives, Inc. jointly filed a motion to intervene in these proceedings and shall be jointly referred to as "OREC".

4 EnergyPlus was granted intervention in these proceedings, but filed a notice of withdrawal on March 13, 2000.

5 Unicom Energy, Inc. and Unicom Energy Services, Inc. jointly filed a motion to intervene in these proceedings and shall be jointly referred to as "Unicom".

6 United Mine Workers of America, AFL-CIO and UMWA District Six, Local Union Nos. 1604, 1857, 1886, and 6362 jointly filed a motion to intervene in these proceedings and shall be jointly referred to as "UMWA".

7 Utility Workers Union of America, AFL-CIO, and Utility Workers Union of America, Local Union Nos. 111, 116, 296, 468, 478, 492, and 544, jointly filed a motion to intervene in these proceedings and shall be jointly referred to as "UWUA".

began on May 9, 2000, at which time it became clear that there was opposition to the proposed stipulation. At the request of the parties, the hearing was continued and, pursuant to oral rulings made by the attorney examiners, parties interested in the gross receipts/excise tax issue were given an opportunity to present evidence for the Commission's consideration. Additionally, parties were given the opportunity to present evidence in support of and in opposition to the stipulation. The hearing then continued on May 31, June 7, 8, and 12, 2000. Only AEP, OCC, Shell, the staff, and UWUA participated in the later stages of the hearing.

On June 19, 2000, AEP and ANM file an agreement to remove from AEP's transition plan proceedings the substantive issues related to AEP's originally proposed pole attachment tariff provisions. Those two parties agreed that the pole attachment issues should instead be addressed in two cases already pending before the Commission. *In the Matter of Applications of Columbus Southern Power Company and Ohio Power Company for Approval of Pole Attachment Tariffs and Related Matters,* Case Nos. 97-1568-EL-ATA and 97-1569-EL-ATA.

Local public hearings were conducted on June 5 and 22, 2000, in East Liverpool and Columbus, Ohio, respectively. On July 10, 25, and 26, 2000, AEP, OCC, Shell, the staff, IEU-OH, and UWUA filed briefs.

II. SUMMARY OF THE STIPULATIONS

The stipulation submitted on May 8, 2000 provides, among other things, that the companies' transition plans (as then-supplemented and revised) should be approved, except as specifically modified in that stipulation. Additionally, the stipulation states that:

(1) Neither company will impose any lost revenue charges (generation transition charges) on any switching customer (Sec. IV).

(2) All distribution electric rates in effect on December 31, 2005, will be frozen through December 31, 2007 for OP and through December 31, 2008 for CSP. Such frozen rates can, however, be adjusted to reflect the cost of complying with changes in environmental (distribution-related), tax and regulatory laws or regulations, relief from storm damage expenses, in the event of an emergency, or to reflect changes in the transmission/distribution facilities allocation (Sec. V).

(3) CSP will absorb the first $20 million of consumer education, customer choice implementation, and transition plan filing costs and will be permitted to defer the remainder of those actual costs (estimated to be $40.6 million), plus a carrying charge and recover those costs by a rider as a cost of service in future distribution rates. OP will absorb the first $20 million of consumer education, customer choice implementation, and transition plan filing costs and will be permitted to defer the remainder of those actual costs (estimated to be $45.5 million),

plus a carrying charge and recover those costs by a rider as a cost of service in future distribution rates. Determination of costs to be recovered (including the carrying charge) will be subject to Commission review (Sec. VI).

(4) During the market development period (MDP), CSP will provide a shopping incentive of 2.5 mills/kilowatt-hour to the first 25 percent of the residential class load that switches to a competitor. Any unused portion of that shopping incentive will be credited to CSP's regulatory transition cost recovery. There will be no further shopping incentive for CSP and no shopping incentive at all for OP (Sec. VII).

(5) AEP will transfer, by December 15, 2001, all operational control of transmission facilities to an operating regional transmission organization (RTO) that is approved by the Federal Energy Regulatory Commission (FERC). In the meantime, the companies will provide up to $10 million for certain costs imposed upon any supplier or customer associated with transmission charges imposed by the Pennsylvania-New Jersey-Maryland (PJM) Independent System Operator and/or Midwest Independent System Operator (MISO) for generation originating in those areas (Sec. VIII).[8]

(6) The companies shall refile: (a) the unbundled residential tariffs so as to reflect a five percent reduction in the generation component, including the regulatory transition charge (RTC) component, and shall not seek to reduce that five percent during the MDP; and (b) the tariffs and UNB-8 schedules so as to achieve a revenue-neutral rate design and equalized bills within the commercial class (Sec. IX and X).

(7) For issues being handled by the operational support plan (OSP) working group, the signatory parties accept any resolutions agreed upon by the working group. Further, the companies agree to abide by the determinations of the Commission as they relate to OSP issues (Sec. XI).

(8) With respect to customer switching, the operating companies agree that, during the MDP, customers that can take generation service from the companies during any part of May 16 through September 15 must either remain a customer through April 15 of the following year or choose a market-based tariff which will not be lower than the generation cost

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8 The stipulation specifically noted that, if any governmental agency invalidates or imposes conditions upon this aspect of the stipulation, the provision is deemed withdrawn and the parties agree to negotiate in good faith to restore the value of the provision.

embedded in the standard offer. Nonaggregated residential customers will be permitted to shop three times during the MDP and to return two times to the default tariff before being required to choose from one of the above two options (Sec. XII).

(9) The companies shall provide distribution services to each retail customer or supplier of electric energy in the same quality and price and subject to the same terms and conditions as provided by the companies to similarly situated retail customers, itself or any affiliate. Before participating in an approved RTO, the companies and/or their affiliates shall provide transmission services under their pro forma transmission tariff and in compliance with federal conduct requirements (Sec. XIII).

(10) AEP will provide a $1.00 credit to suppliers for each consolidated bill issued by that provider during the first year of the MDP. The signatory parties agree to further negotiate a similar future credit. AEP shall reasonably attempt to implement supplier consolidated billing as soon as practicable (Sec. XIV).

(11) Commercial and industrial customers need only provide 90 days notice to the companies of their intent to purchase electricity from another supplier, including providing such notice 90 days prior to January 1, 2001 (Sec. XV).

(12) The companies' revenues from RTCs during the transition period and from existing frozen and unbundled rates recovered during the MDP are sufficient to recover regulatory assets as of the beginning of the MDP and for obligations required by the stipulation. The signatory parties agree that the Commission should direct the companies to amortize such regulatory assets during the MDP and thereafter, until fully amortized. Recorded regulatory assets as of the beginning of the MDP should be amortized on a per-kilowatt basis during the MDP and recovered through existing frozen and unbundled rates. Additionally, the signatory parties suggest that the Commission specifically address concerns of potential violations of the Internal Revenue Code's normalization rules regarding amortization of liabilities related to investment tax credits and excess deferred income taxes (Sec. XVII and Attach. I).

(13) Between January 1, 2006 and December 31, 2007, the first 20 percent of OP residential customer load that switches from OP's standard offer as of December 31, 2005, to another provider will not be charged the RTC. Customers that remain

on the standard offer under Section 4928.14(A) or (B), Revised Code, do not count as load that switches to a new provider (Sec. XVIII).[9]

(14) AEP and the signatory marketers will further negotiate an AEP load shaping service. All such marketing intervenors shall be notified of dates, times, and locations for such meetings (Sec. XIX).

(15) The operating companies will establish Universal Service Fund (USF) riders and Energy Efficiency Revolving Loan Fund (EERLF) riders at the rates determined by ODOD and approved by the Commission (Sec. XX).

(16) The marketer intervenors' acceptance of the companies' corporate separation plan does not constitute acceptance of the companies' interpretation of Rule 4901:1-20-16(G)(4), Ohio Administrative Code (O.A.C.), relating to code of conduct (Sec. XXI).

(17) The parties agree that the stipulation is conditioned upon acceptance in its entirety and without alteration. If the Commission rejects all or part of the agreement, or materially modifies its terms, any adversely affected party may file an application for rehearing or terminate and withdraw from the stipulation (Sec. XXII).

As noted above, a second stipulation was filed in these dockets. On June 19, 2000, AEP and ANM filed a stipulation (hereinafter referred to as the ANM agreement, so as to distinguish it from the other stipulation) to remove from AEP's transition plan proceedings the substantive issues related to AEP's originally proposed pole attachment tariff provisions. Among other things, ANM does not object to AEP's proposed withdrawal of the originally proposed pole attachment tariffs, while AEP agrees to not object to ANM's involvement (including discovery activities) in AEP's pending pole attachment tariff proceedings in Case Nos. 97-1568-EL-ATA and 97-1569-EL-ATA, *supra.* AEP further agrees to not include the originally proposed pole attachment tariff provisions in any filing in the transition plan proceedings.

III. OPPOSITION TO THE TRANSITION PLANS AND STIPULATIONS AND REVIEW OF SECTION 4928.34, REVISED CODE

Although a large number of parties were granted intervention in this proceeding, only Shell and the UWUA continued to offer any opposition to AEP's transition plans, as modified by the settlement agreements entered into by the majority of parties. The UWUA addressed only one issue related to AEP's employee assistance plan. Shell, on the other hand, takes issue with several particular aspects of the transition plan stipulation on

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9 The stipulation specifically noted that, if this provision is rejected by the Commission or determined unlawful by a court, the remainder of the stipulation will remain in effect.

legal and conceptual grounds. Moreover, in Shell's view, it does not believe that the stipulation as a whole will establish the incentives for competitive suppliers to either enter AEP's service territory or remain there over time, all the while providing a financial windfall to AEP (Shell Initial Br. at 3-4, 61-66, 68; Shell Reply Br. at 1-2, 7, 17). AEP, OCC, IEU-Ohio, and the staff argue that the stipulation balances the diverse interests of nearly all parties to these proceedings and provides a number of varied benefits that are in the public interest, some of which are beyond what the Commission has authority to order (AEP Ex. 18, at 5-10; AEP Initial Br. at 10; OCC Initial Br. at 12-13; OCC Reply Br. at 11; IEU Br. at 3-4; Staff Initial Br. at 5, 6-8; Staff Reply Br. at 3-4).

As noted earlier, Section 4928.31(A), Revised Code, provides that the company's transition plan must include a rate unbundling plan that specifies the unbundled components for electric generation, transmission, and distribution service components to be charged by the company on the start date of competitive retail electric service. The transition plan must also contain a corporate separation plan, a plan to address operational support systems, an employee assistance plan, and a consumer education plan (*Id.*). AEP's transition plans include those, as well as other proposals.

Section 4928.34(A), Revised Code, requires the Commission to make determinations with respect to 15 separate "prerequisites" prior to approving a company's transition plan. Each of the opposing intervenors' comments and the 15 prerequisites is discussed below.

A. <u>Unbundling Plan and Transition Costs</u>

Beginning on the start date of competitive electric service, AEP proposes two tariff offerings: the standard tariff for customers who do not choose an alternative electric supplier and the open access distribution tariff for customers who do choose an alternative electric supplier. AEP's transition plan proposed that the open access distribution tariff be similar to the standard tariff, except that a stranded, generation transition charge (GTC) applies and no property tax credit applies (AEP Ex. 2, Part A). The individual components were derived based upon cost-of-service studies from CSP's and OP's last rate cases and were then functionalized (AEP Ex. 24A at 13-14). Adjustments were made to reflect the overall revenue level resulting from the prior rate cases and to match individual customer class revenues (*Id.*). For CSP, special adjustments were made so that the adjusted distribution component equaled the sum of the unbundled distribution and transmission components, less the revenue generated by the Open Access Transmission Tariff (OATT) (AEP Ex. 8A at 4). AEP sought recovery of stranded generation costs during the MDP and regulatory assets over the full 10-year period allowed by Section 4928.40, Revised Code (AEP Ex. 16, at 9-10; AEP Ex. 9A at 13). The companies also identified several transition costs that they requested be established as new regulatory assets (AEP Ex. 2, Part F, Sec. (B)(1)(a); AEP Ex. 16, at 6; AEP Ex. 9A at 8-12; AEP Ex. 9C at 6). AEP included the five-percent reduction required by Section 4928.40(C), Revised Code, in the proposed residential service rates (AEP Ex. 24A at 19).

AEP proposed to recover the following under the transition plan as filed:

Company	Regulatory Assets	Other Transition Costs	Total
CSP	$289,515,000	$73,684,000	$363,199,000
OP	$520,526,000	$90,260,000	$610,786,000

(AEP Ex. 2, Part F).

AEP contends that the stipulation provides additional benefits to the proposed unbundling plan and transition charges in several ways (AEP Initial Br. at 21-22, 59, 65-67). First, all distribution rates will be mostly frozen, effective December 15, 2005 through 2007 for OP and through 2008 for CSP (Jt. Ex. 1, at 3-4). Second, the frozen distribution rates can be adjusted to reflect changes in the functionalization of the transmission/distribution facilities under FERC's seven-factor test (*Id.* at 4). Third, the companies' tariffs and UNB-8 schedules will be revised consistent with Attachment 2 to the stipulation, in order to achieve revenue neutral rate designs and to equalize bill impacts for commercial customers (*Id.* at 7). Fourth, the companies will refile unbundled residential rate schedules that apply a five-percent reduction of the generation component, including the RTC component (*Id.* at 6). Fifth, the stipulation shortens the period during which the companies can recover stranded generation-related regulatory assets (from 10 years to seven years for OP and eight years for CSP) and limits the RTC levels for several years (*Id.* at 4 and Attach. 1). Next, the stipulation also specifies the levels of the RTCs for seven- and eight-year periods (*Id.* at Attach. 1). Under the stipulation, the companies can recover the following amounts as transition costs:

Company	In RTC During MDP	In Distribution Rates in Later Years
CSP	$191,156,000	$40,526,000
OP	$425,230,000	$45,533,000

(*Id.*; Tr. III, 50, 141).

Additionally, AEP states that the companies have each foregone assessing its proposed GTCs on switching customers and $20 million in customer education, customer choice implementation and transition plan filing costs (Jt. Ex. 1, at 3 and 4). The remainder of customer education, customer choice implementation and transition plan filing costs (approximately $40.5 and $45.5 million) will be deferred. CSP has agreed to provide an additional shopping incentive of 2.5 mills/kilowatt-hour for the first 25 percent of CSP's residential load that switches during the MDP, with the unused portion at December 31, 2005, being credited to the RTC (*Id.* at 5). Lastly, OP agreed that, for 2006 and 2007, the first 20 percent of OP residential customers that switch will not be charged the RTC (*Id.* at 10).

1. MDP Shopping Incentives

AEP's transition plans proposed shopping incentives that were the lower of the estimated market cost of electric energy or the unbundled generation rate (AEP Ex. 9A at 28; AEP Ex. 2 at Part H; Tr. IV, 105). AEP did not propose to increase the incentives in the MDP (AEP Ex. 9A at 28-29). The stipulation includes an explicit additional shopping incentive of 2.5 mills/kWh for the first 25 percent of CSP's residential load that switches during the MDP, with the unused portion at December 31, 2005, being credited to the RTC (Jt. Ex. 1, at 5).

In AEP's view, the transition plan stipulation would increase the proposed shopping incentive amounts by virtue of the companies agreeing to forego the amount of the GTCs and by the additional 2.5 mills/kilowatt-hour for the CSP residential class (AEP Initial Br. at 43).[10] AEP acknowledges that the stipulation states that "there will be no shopping incentive for [OP]", but contends that the language means there will be no explicit monetary incentive for OP customers during the MDP beyond that set forth in the plan (AEP Reply Br. at 22). Additionally, AEP argues that several other provisions in the stipulation constitute monetary and structural incentives to encourage shopping for CSP and OP customers (Tr. III, 148, 153, 157-160, 165, 167; AEP Reply Br. at 20-22).

Shell has criticized the shopping incentive provisions of the stipulation for several reasons. In Shell's opinion, the key to engendering good alternatives to the standard offer during the MDP is an adequate shopping credit structure that reflects the costs of serving retail markets and that adjusts to reflect significant changes in underlying wholesale costs (Shell Initial Br. at 2).[11] First, Shell argues that the shopping credit scheme does not meet the requirements of SB 3 since the stipulation does not provide any shopping incentive for CSP commercial customers or for any OP customers during the entire MDP (*Id.* at 13; Shell Ex. 7, at 4, 8). In this respect, Shell states that neither the stipulation nor the transition plan provides a complete shopping incentive that will meet the statutory minimum switch rate or the Commission's requirements (Shell Initial Br. at 13-14; Shell Reply Br. at 9-12). Next, Shell states that the stipulation's terms discriminate against OP residential ratepayers since the CSP counterparts will have a shopping credit (Shell Ex. 7, at 4; Shell Initial Br. at 13-18).

Also, Shell argues that the CSP shopping incentive is too small to produce the 20 percent load switching during the MDP (Shell Ex. 7, at 9-10; Shell Initial Br. at 12, 14, 18-19). Shell further states that there has been no evidence to support the CSP shopping credit level. Additionally, Shell states that, since there is no designated shopping credit for OP, the credit is simply the unbundled generation component in OP's tariff (Shell Ex. 6, at 49; Shell Ex. 7, at 8; Shell Initial Br. at 19). Shell provides an illustration as to why a marketer cannot effectively compete in AEP's territory under these circumstances (Shell Initial Br. at 19-23). Shell further states that the proposed fixed shopping incentives can become less economic over time, as other costs increase (Shell Initial Br. at 19-25, 32; Shell Ex. 7, at 7-10). Moreover, Shell points out that the declining block rate aspect of the shopping credits makes it increasingly difficult for competitors and will frustrate achievement of SB 3's 20 percent load switching (Shell Ex. 7, at 10; Shell Initial Br. at 23). Shell recommends that the Commission either: (1) direct the parties to return to the bargaining table to devise an

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10 AEP states that this level of shopping incentive could not have been achieved without CSP's consent because the total amount exceeds the unbundled generation component for CSP's residential customers, which is the highest level the Commission could require. See, Section 4928.04(A), Revised Code.

11 Shell's witness Dr. Wilson distinguished between a shopping credit and a shopping incentive. He explained that a "shopping credit" is the "total amount by which the switching customer's bill would be reduced because the customer is taking service from an independent provider", while the "shopping incentive" is a "component of the shopping credit and is specifically designed to encourage 20 percent of the market to shift" during the MDP (Tr. V, 74).

agreement that makes blocks of generation capacity (at predetermined prices) available for competitive suppliers (modeled after Duquesne Light Company and FirstEnergy Corporation arrangements); or (2) increase the shopping credits to the levels recommended by its expert witness (Shell Ex. 6, at 56-60; Shell Ex. 7, at 10-11; Shell Initial Br. at 26-28). Shell contends that those changes are necessary, not to make it more economical for Shell to serve customers, but to induce the 20 percent customer switching mandated by SB 3 (Shell Reply Br. at 17). Finally, Shell states that the Commission should establish a tracking mechanism to adjust the shopping credits in response to wholesale price increases or annually review the adequacy of the shopping credits in each service territory (Shell Ex. 7, at 10-11; Shell Initial Br. at 35; Shell Reply Br. at 15).

With regard to Shell's discrimination argument, AEP states that SB 3 does not require all transition plans to be the same and, thus, the fact that the 2.5 mills only applies to CSP residential customers cannot be found improper (AEP Reply Br. at 27). AEP contends that nearly every other marketer in these proceedings supports the shopping incentives of the stipulation and that is telling of their significance (*Id.* at 22). AEP criticizes Shell's expert's suggested shopping incentives as not being based upon the companies' actual unbundled generation components and as violating Section 4928.40(A), Revised Code, because they exceed the unbundled generation component (AEP Initial Br. at 44-46; AEP Reply Br. at 24). Moreover, AEP states that the Commission has no authority to order the companies to make blocks of generation available to suppliers (AEP Reply Br. at 18, 24). Therefore, the Commission should support the voluntary resolution that satisfied nearly every interested party (*Id.*).

The staff contends that SB 3's 20 percent switching rate is not a mandate (Staff Reply Br. at 5-6). Rather, it is one basis upon which the Commission can end the MDP early (*Id.*). Also, the staff states that, since the companies' transition charges are so low, the large shopping incentives that Shell seeks are not possible because the effect of Shell's request would deny the companies the opportunity to collect any transition costs from customers who shop (*Id.* at 8-9).

Shell argues first that the stipulation is discriminatory and violates SB 3 because it includes a shopping incentive during the MDP for CSP residential ratepayers, but not for OP residential ratepayers. Then, Shell also argues that there will be insufficient shopping incentives for both companies, which will be the generation shopping credit.[12] Thus, Shell has acknowledged that there would be an OP shopping incentive during the MDP under the stipulation and transition plan. At first blush, the stipulation would leave the impression that there will be no shopping incentive at all during the MDP for OP customers. However, AEP's plan included a shopping incentive for OP customers during the MDP and the stipulation did not modify that incentive. The fact that the proposed shopping incentives during the MDP vary between CSP and OP customers does not, in and of itself, lead us to conclude that the proposal before us should be rejected. In fact, we have already approved different shopping incentives between Ohio's utilities and the fact that both companies are within the AEP family does not convince us that the shopping incentives must be the same in order to be reasonable.

[12] We do not believe that Shell has presented consistent arguments on this point.

The main thrust of Shell's argument against the proposed MDP shopping incentives is that they will be too small to engender competition. We do not agree with Shell's contention that the MDP shopping incentives are unlikely to affect the market in AEP's territory. We believe that the stipulation's 2.5 mills/kWh (for the first 25 percent of CSP residential customers, which is approximately 125,000 customers) will further help ensure that CSP's residential customers have an incentive to shop. The remaining customers will have an adequate incentive to shop inasmuch as the shopping incentives will equal either the estimated market cost of electric energy or 100 percent of the unbundled generation rate. As Shell's Dr. Wilson acknowledged, there is not going to be one number that gives every supplier the ability to make it in a competitive market (Tr. V, 80). We believe, however, the MDP shopping incentives proposed will effectively foster early competition by providing significant motivation to CSP and OP customers to switch retail generation suppliers.

2. Post-MDP Incentive for OP Residential Customers

Section XVIII of the stipulation states that, for 2006 and 2007, the first 20 percent of OP residential customers that switch will not be charged the RTC (Jt. Ex. 1, at 10-11). It is estimated that, in the first year (2006), approximately $5 million of RTC revenues will not be collected (Tr. III, 117). AEP will not amortize these RTC costs for future collection; it will expense the cost (*Id.* at 117-118). Shell contends that this provision of the stipulation violates SB 3 because the transition charge is "nonbypassable" and is not permitted to be discounted, per Sections 4928.37(A)(1)(b) and (3), Revised Code (Shell Initial Br. at 28-29).

In response, AEP argues that the RTC cannot be "bypassable" during the MDP only and, since the MDP will not extend beyond December 31, 2005, this provision does not violate Section 4928.37(A)(1)(b), Revised Code (AEP Reply Br. at 28-29). As for the discount aspect of the provision, AEP states that, although the provision may "have the 'effect' of discounting the RTC, [it] is no different than providing an explicit monetary shopping incentive which offsets, i.e. discounts, the transition charge" (*Id.* at 29). Also, AEP believes that the statutory provision's goal is to prevent unjust discrimination among similarly situated customers and that will not occur under the stipulation because all residential customers will be eligible, but the discount ends when 20 percent switch (*Id.* at 29-30). AEP and the staff question the consistency of Shell's arguments thus far, stating that Shell should be welcoming this provision because its intent is to provide additional encouragement to OP residential customers to switch away from the standard offer after the MDP (*Id.* at 30; Staff Reply Br. at 11).

AEP correctly points out that the "nonbypassable" restriction in Section 4928.37(A)(1)(b), Revised Code, is limited to the MDP. Thus, we do not find that the reduced RTC for OP customers in 2006 and 2007 would violate that aspect of SB 3. Additionally, Sections 4928.37(A)(1) and (3), Revised Code, specifically state that the transition charges that an electric utility can receive between the start of electric competition and the expiration of the MDP shall not be discounted by any party. The stipulation before us would not allow the discounting of the RTC to take place during the MDP. For that reason, we also conclude that Section XVIII is not contrary to SB 3. Moreover, we believe that the effect of this provision will provide OP residential customers another sizeable incentive, after the MDP, to consider switching their generation supplier. For that reason, we find it to be consistent with the pro-competitive goals of SB 3.

3. Commission's Future Ability to Respond to the Market

Shell contends that the stipulation (Sections VI and VII) unreasonably restricts the Commission's authority to modify the shopping incentive and the collection of RTCs or to carry out its market monitoring functions (Shell Ex. 7, at 7-8; Shell Initial Br. at 30, 33-34). Shell points to Sections 4928.06, 4928.40(B)(1), and 4928.39, Revised Code, for support. Shell states that the Commission's ability to respond to unanticipated market changes is very important (particularly where a fixed shopping incentive regime applies during the MDP) and the signatory parties cannot agree to rewrite that authority (Shell Initial Br. at 31-32, 33). Shell believes market participants need the assurance that the Commission can and will take immediate action to safeguard the continuing viability of retail competition (*Id.* at 32-33). As in Shell's earlier recommendation, Shell suggests a tracking mechanism to adjust the shopping credits or annual consideration of whether the credits are adequate or require modification.

AEP and the staff do not agree that Sections VI and VII of the stipulation violate SB 3. AEP states that the Commission may, but is not required to, make adjustments to transition charges (AEP Reply Br. at 32). In AEP's view, the Commission may exercise that discretion and should concur with the signatory parties' conclusion that no such further reviews are necessary (*Id.*). Further, AEP states that there is virtually nothing to which the Commission's discretionary authority could be applied for three reasons: (1) the companies have waived their claims for GTCs for the MDP; (2) RTCs can only be adjusted prospectively and only after December 31, 2004; and (3) CSP's additional shopping incentive more than eliminates those customers' RTCs for the MDP (*Id.* at. 32-33). Staff states that there are a number of statutory obligations imposed upon the Commission that are unaffected by the stipulation and the Commission will assuredly fulfill its obligations under SB 3 (Staff Reply Br. at 12).

The Commission does not believe that Sections VI and VII of the stipulation conflict with Chapter 4928, Revised Code. Section 4928.40(B)(1), Revised Code, permits the Commission to conduct periodic reviews no more often than annually and, as it determines necessary, adjust the transition charges of the electric utility. It does not require such reviews or adjustments. We believe that the stipulation establishes reasonable transition charges, shopping credits, and incentives for customers to shop. We do not believe that Section VI or VII negate the Commission's broad authority to safeguard retail competition during the MDP. Various sections of SB 3 give the Commission continued oversight to monitor the progress of competitive retail electric services, to take action where necessary, and to promote the policies of the state of Ohio set forth in Section 4928.02, Revised Code. The Commission is charged with analyzing the efficacy of the market as it progresses over time and any evidence of the abuse of market power will be a signal for a change in the process.

4. Generation Transition Charges and Stranded Generation Benefits

As noted earlier, Section IV of the stipulation states that AEP will not impose lost revenue charges or GTCs on any switching customer (Jt. Ex. 1, at 3). AEP's original transition plan proposal included a proposed GTC of $291.43 million, representing above-market, stranded generation costs (AEP Ex. 9A at 12 and 9C at 5-6; Shell Ex. 6, at 39; Tr. III, 16). This calculation was based upon the difference between the generation components of the historic rates and the companies' projected market price of generation (Shell Ex. 6, at 38, 40-41; Tr.-III, 19-21, 22). Shell states that AEP's GTC approach allows it the opportunity for a windfall because there should be no GTC so long as AEP's generating plants are valued at a market value equal or greater than their net book value (Shell Ex. 6, at 41, 46-47; Tr. V, 114-115). For Shell, the correct generating plant valuations imply that there will be no GTC or stranded costs, only stranded benefits and, therefore, Section IV of the stipulation does not support a finding that the stipulation is reasonable (*Id.* at 43-44; Shell Reply Br. at 24-25).

Shell argues that the stipulation and the proposed corporate separation plan will result in the transfer of generation assets to an unregulated affiliate at too low a value and harm ratepayers by denying them any share of the "market premiums" associated with the generation assets (Shell Ex. 6, at 43-44, 46, 83; Shell Initial Br. at 36; Shell Reply Br. at 28-29). Shell presented evidence that the more appropriate estimate of AEP's generating assets is a market value of nearly $7 billion, as opposed to the book value of approximately $2.2 billion (Shell Ex. 6, at 33-34; Tr. V, 114). Thus, in Shell's view, AEP's agreement in the stipulation to forego the GTC is meaningless because AEP had no such transition costs in the first place (Shell Initial Br. at 43). In particular, Shell's witness Dr. Wilson argues that AEP utilized overly optimistic, low market prices for power, citing to AEP's recent higher-priced purchases in the wholesale market and third-party forecasts of prices in the area (Shell Ex. 6, at 15-18). Dr. Wilson noted that changing only the estimated market price of energy, as he suggested, raised the estimated value of the generation assets by more than $2 billion and resulted in an estimate of $1.5 billion of stranded benefits (*Id.* at 21). Next, Dr. Wilson noted that AEP improperly discounted by a full 12 months (rather than by six months) and deducted office building and other nongeneration plant construction costs from generation revenues (*Id.* at 22-23). Dr. Wilson then suggested that AEP should have assumed a 10.5 percent equity cost and a capital structure of 40 percent equity and 60 percent debt (*Id.* at 24-27). With all five of those inputs modified as suggested by Dr. Wilson, the value of AEP's generating plants would raise to nearly $5 billion and exceed book value by more than $2.5 billion (*Id.* at 27, 29, and JWW-5). Dr. Wilson noted that some other adjustments could be made, but he did not attempt them (*Id.* at 24, 31, 36-37).

In addition, Shell contends that AEP will recover over $616 million in RTCs and all off-system generation sales (Shell Initial Br. at 43-44). Moreover, Shell takes issue with the fact that, under the stipulation, AEP ratepayers continue to pay for the transferred generation assets through unbundled, frozen generation rates, but not receive any benefit from the sales that the unregulated generation affiliate might make to third parties (Shell Initial Br. at 43; Shell Reply Br. at 20-21). Taken together, the book value transfer of generation assets would not serve the public interest. Shell suggests that the Commission provide AEP ratepayers a share by: (1) offsetting RTC recovery, and (2) funding more generous shopping credits for residential ratepayers with generation-related market premiums and third-party sales revenues (Shell Ex. 6, at 46; Shell Ex. 7, at 12; Tr. V, 40-41; Shell Initial Br. at 44-45; Shell Reply Br. at 29).

AEP disagrees with Shell's argument on this issue. AEP points out that its corporate separation plan does not call for the transfer of its generation assets to an unregulated affiliate. Rather, the corporate separation plan involves the creation of new transmission and distribution subsidiaries; CSP and OP will continue to own and operate the generation assets. AEP disagrees with Shell's expert's estimate of AEP's generating assets and lists a number of reasons why the analysis is flawed (AEP Reply Br. at 35-37, 42-43). Specifically, AEP argues that the most accurate value of its generating assets is not necessarily measured by selling price (*Id.* at 35). AEP contends that Dr. Wilson's proposed substitute market price of electricity is too high and constitutes an improperly averaged price at times only when the companies were purchasing power, times of high demand and higher prices (*Id.* at 36-37). Next, AEP takes issue with Shell's reliance upon the valuation report and methodology of Research Data International (RDI) because it was a preliminary, working document for the FirstEnergy transition proceedings[13], which contained incorrect or non-comparable data (*Id.* at 42-42).

Moreover, AEP states that Section 4928.35(A), Revised Code, does not entitle ratepayers to share in market premiums, even if there were any (AEP Reply Br. at 43-44). AEP further argues that Shell's suggestion that any market premiums fund larger shopping credits for switching customers is a violation of Section 4928.35(A), Revised Code, because that provision prohibits adjusting the utility's frozen unbundled rates during the MDP (AEP Reply Br. at 44). Likewise, AEP argues that Shell's suggestion to reduce the RTC violates Section 4928.39, Revised Code, because regulatory assets are a separate and distinct component of transition costs that can be adjusted only on a prospective basis (*Id.* at 44-47).

Staff contends that Shell's GTC argument is inconsistent in saying that the unbundled generation charges are above market (based on old rate case data) and below market (based upon low market values) (Staff Reply Br. at 13-14). For this reason, staff says that Shell's position should be rejected (*Id.*).

As noted earlier, if the stipulation is approved, AEP no longer seeks to recover a GTC. Therefore, the remainder of Shell's concern here is the netting of AEP's alleged stranded benefits/market premiums against transition costs. The Commission is not convinced that Dr. Wilson's analysis for determining the market value of the generating assets is fully correct. For instance, we believe Dr. Wilson's use of market price of electricity was overstated because it relied upon purchase data at times when electric prices were high and did not account for such abnormality. It also appears to improperly average the prices. We think AEP's criticisms, on these points, are valid. Changes to this one input in the valuation methodology, as Dr. Wilson noted, has a significant impact on the stranded benefits/market premiums. We also are unwilling to accept Dr. Wilson's reliance upon the RDI generation asset valuation methodology as grounds for rejecting AEP's valuation methodology. No RDI representative testified in this proceeding and the document was apparently a work in progress. Moreover, only parts of the working document are part of the record in these proceedings. Dr. Wilson's apparent use of the same methodology (with some substituted figures) does not convince us that we must

13 *In the Matter of the Application of FirstEnergy Corp. on Behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Approval of Their Transition Plans and for Authorization to Collect Transition Revenues,* Case Nos. 99-1212-EL-ETP, 99-1213-EL-ATA, and 99-1214-EL-AAM (July 19, 2000).

accept the methodology or the figures therein. In fact, AEP has raised doubt in our minds as to the accuracy of some comparison figures contained in the working document and replied upon by Dr. Wilson. For these reasons, we do not agree with Dr. Wilson's analysis or his conclusion that any stranded benefits exceed the amount of the GTC that AEP has agreed to forego as part of the stipulation.

Furthermore, we believe that the stipulation provides a reasonable and equitable resolution on this issue. AEP has agreed to forego a claim of $291.43 million. The parties to the agreement have agreed, based on all of the terms and conditions of the agreement that there is no further netting or adjustments to the transtion cost recovery during the MDP. Based upon the above findings, the Commission concludes that there are no stranded generation benefits that should either offset the RTCs or further fund the shopping incentives proposed by the stipulation.

5. Frozen Generation Rates

This next argument also relates to Section IV of the stipulation wherein neither company will impose any lost revenue charges (GTC) on any switching customer (Jt. Ex. 1, at 3). Shell argues that, for non-switching customers, the frozen, unbundled generation rates only allow AEP another opportunity to collect excessive revenues since those rates will be uneconomic in a competitive market (Shell Initial Br. at 45; Shell Reply Br. at 24).[14] Shell further believes that the stipulation itself concedes an over-recovery of generation revenues because the signatory parties agree that RTC revenues and frozen rate revenues are sufficient to recover regulatory assets (Shell Initial Br. at 47). Next, Shell contends that these frozen generation rates represent a "*de facto* second RTC charge" because, under the stipulation, the companies will amortize and recover the value of the regulatory assets in excess of the stipulated regulatory asset rates (*Id.* at 48). Shell alleges that this is unlawful since some customers will pay it, but not others, and it will discourage customer switching (*Id.*).

AEP states that SB 3's framework allows customers who do not switch to pay (as part of the unbundled generation component) generation costs that may be uneconomic (AEP Reply Br. at 48). In AEP's view, the legislature specifically chose to freeze rates at pre-SB 3 levels and did not allow, for instance, for adjustments in current costs or sales levels when unbundling generation rates (*Id.* at 49-50). Furthermore, AEP alleges that customers will pay the same frozen, unbundled generation rates, regardless of whether the companies amortize the regulatory assets over the MDP or expense them immediately (*Id.* at 51). Thus, AEP believes Shell's issue is with the requirements of SB 3 and the legislature has already disagreed with Shell's position (*Id.* at 52). Thus, there is no statutory basis to contend that the stipulation is improper (*Id.*). AEP further points out that it calculated the unbundled generation rates in accordance with Section 4928.34, Revised Code, and Shell has not taken issue with them (*Id.* at 49).

We cannot agree with Shell's arguments on this point. We find that the unbundling plan agreed to by the stipulating parties to the transition plan stipulation is reasonable and consistent with Section 4928.34, Revised Code. The evidence of record shows that the

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14 Specifically, Shell contends that the frozen, unbundled generation rates are uneconomic because they are not reflective of current or competitive costs and demand (Shell Initial Br. at 46-47).

unbundling plan proposed by AEP follows the intent of Section 4928.34, Revised Code. In unbundling the rates for each customer class, AEP had to follow the requirements of SB 3, which not only dictated the manner in which the generation component would be determined, but also necessitated the use of the AEP's earlier cost-of-service studies. We find that AEP has followed the statutory scheme in unbundling its rates. Further, one of the purposes of this proceeding is to establish unbundled rates based on the already adopted cost-of-service studies, not to alter those studies or to determine whether more appropriate rates should be used when unbundling services. To do so would clearly be inconsistent with the mandate of Section 4928.34(A)(6), Revised Code, which requires the unbundling of the rates in effect on the day before the effective date of SB 3. Therefore, we find the generation components to be reasonable.

6. Distribution Rate Freeze

Section V of the stipulation states that, except in the event of certain limited changes, all distribution rates in effect on December 31, 2005, will be frozen for three years for CSP and two years for OP (Jt. Ex. 1, at 3). Shell presents two very different arguments against this provision. First, Shell views this provision as an anti-competitive albatross because, after the MDP, those frozen rates will recover generation-related retail costs and subsidize the post-MDP, "market-based" standard offer. Essentially, Shell contends that the existence of the frozen distribution rates invites the creation of a below-market rate for the standard offer and provides AEP an unfair competitive advantage over other suppliers (Shell Initial Br. at 50). Second, Shell states that the frozen distribution rates allow AEP additional opportunity for cost over-recovery since the rates are based upon costs and sales levels from old base rate cases, rather than the lower costs of a competitive market (*Id.* at 50-51). Shell also states that the rate freeze would again tie the Commission's hands in achieving the pro-competitive policies of SB 3 (*Id.* at 51).

AEP first states in response that Shell's criticism here is inconsistent with Shell's acceptance of a similar rate freeze provision in the FirstEnergy transition cases (AEP Reply Br. at 53). AEP acknowledges that the frozen distribution rates are unlikely to represent the items and levels of expense that the companies are incurring today or will be incurring at the end of 2005 (*Id.* at 54). However, AEP states that it is speculative to conclude that the companies will be over-recovering their distribution expenses in 2006, 2007 or 2008 (*Id.*). AEP notes that it and signatory consumer representatives have weighed the risks of the agreed-upon rate freeze and determined that it is a reasonable agreement as part of the overall stipulation, and the Commission should reject Shell's claims (*Id.*).

We do not agree with Shell on this point either. We believe that the distribution rate freeze will provide some certainty to customers in AEP's service territory at a time when they are evaluating the competitive generation market. That is to say, OP customers may be assured that competitive, generation-related costs are not being shifted to non-competitive, distribution charges after the MDP. Furthermore, to accept Shell's argument on this point, we must assume that the 2005 distribution rates will include generation-related costs and will not be reflective of distribution costs in 2006 through 2008. We are not willing to accept those assumptions.

7. USF Rider and EERLF Rider

On July 13, 2000, as amended on July 17, 2000, ODOD submitted a motion for approval of the USF and EERLF riders for AEP. ODOD states that the USF and EERLF riders were required to be effective on July 1, 2000 and January 1, 2001, respectively. However, due to delays in the transfer of this program, ODOD requested that the Commission make the USF rider effective September 1, 2000. On August 4, 2000, IEU-Ohio filed a motion to disapprove those proposed riders. ODOD, OCC, OPAE, APAC, and OEC filed a memorandum in support of those riders. AEP recommended that the Commission adopt ODOD's calculations in its reply brief (AEP Reply Br. at 64). By entry issued August 17, 2000, we agreed with the rates reflected in ODOD's motion. Accordingly, the USF rider rates proposed by ODOD ($0.0006240 for CSP and $0.0002998 for OP) became effective September 1, 2000. The approved rates for the EERLF rider will be $0.00010758 for both operating companies, effective January 1, 2001. A request for rehearing of our August 17, 2000 USF/EERLF ruling was then filed by IEU-Ohio, OMA, and OCRM. In a separate ruling issued this same day, we have granted rehearing in order for the ODOD and the Commission staff to provide additional data on various components of the USF riders. AEP's effective USF riders shall remain in effect pending the Commission's further review of this matter.

8. Load Shaping Service

Section XIX of the stipulation states that AEP and the signatory marketers will further negotiate an AEP load shaping service.[15] All such marketing intervenors shall be notified of dates, times, and locations for such meetings (Jt. Ex. 1, at 11).

Shell argues that the stipulation's terms relating to load shaping service are discriminatory much in the same way as the consolidated billing terms, which is fully addressed later (Shell Ex. 7, at 15; Shell Initial Br. at 58, footnote 160). Shell worries that, because negotiations will only take place with signatory marketers, the resulting load shaping services could confer benefits to only signatory parties (Tr. V, 119-120). Moreover, Shell argues that, since the generation affiliate(s) providing the load shaping service will be outside of the Commission's jurisdiction, there will be no means for curbing discriminatory actions. Shell recommends that the Commission condition any approval of the proposed corporate separation plan on the resulting unregulated generation affiliate(s)' providing services like load shaping to all market participants in a nondiscriminatory manner (Shell Initial Br. at 58-59, footnote 160).

We believe that Shell raises some valid points about the load shaping terms in the stipulation. Obviously, by agreeing to negotiate with stipulating marketers, AEP is not agreeing to negotiate with all marketers in its service territory. It is possible that any resulting load shaping service could then only confer benefits upon the negotiating marketers. However, we do not think that the entire stipulation or this part must be rejected because of this possibility. We believe that, as a condition of our approval of the stipulation and the transition plans, any resulting load shaping service must be provided in a nondiscriminatory manner. Furthermore, we direct AEP to open the negotiations to all

15 Load shaping service allows a marketer to better tailor its power purchases to meet customer demands (Tr. III, 121-122).

interested parties, not just signatory marketers, so that it is possible to develop a load shaping service that is based upon all interested persons' input. Not only do we think it is the smarter approach to take, we also think it can lead to a better end result.

9. Remaining Concerns with the Unbundling Plan and Transition Costs

Section 4928.34(A)(1), Revised Code, requires the Commission to determine whether the unbundled components for the electric transmission component of retail electric service equal the FERC tariff rates in effect on the date of approval of the transition plan. The unbundled transmission component must include a sliding scale of charges to ensure that refunds determined or approved by the FERC are flowed through to retail electric customers. After review of the filings and testimony submitted by AEP, we find that the companies' transition plans satisfy the requirements of Section 4928.34(A)(1), Revised Code.

Section 4928.34(A)(2), Revised Code, requires that the unbundled components for retail electric distribution service in the rate unbundling plan equal the difference between the costs attributable to the company's transmission and distribution rates based on the company's most recent rate proceeding, and the tariff rates for electric transmission service determined by the FERC under division (A)(1) of that code section. We find that the companies' filings satisfy this prerequisite. AEP's adjusted unbundled distribution component is the sum of the transmission and distribution components of rates in effect on October 5, 1999, less the revenue generated by the applicable OATT (AEP Ex. 24A at 15). AEP stated that, in identifying the costs in the operating companies' last rate cases, costs were assigned to functions where possible (*Id.* at 13-14). We believe that the companies' allocations are reasonable and the companies' filings, as amended by the stipulation (and subject to review in the companies' compliance filings), satisfy prerequisite (A)(2) of Section 4928.34, Revised Code.

Section 4928.34(A)(3), Revised Code, requires that all other unbundled components required by the Commission in the rate unbundling plan must equal the costs attributable to the particular service, as reflected in the company's schedule of rates and charges. In accordance with this provision, AEP's existing rates will be unbundled to separate out certain components that will be included in several riders in the operating companies' tariffs. We note that the stipulation provides for USF and EERLF riders for the companies (Jt. Ex. 1, at 11), which we fully discussed above. Based on the evidence presented in this proceeding, we find that the companies' filings, as amended by the stipulation (and subject to review of the companies' compliance filings), satisfy prerequisite (A)(3).

Section 4928.34(A)(4), Revised Code, requires that the unbundled components for retail electric generation service in the rate unbundling plan equal the residual amount remaining after the determination of the transmission, distribution, and other unbundled components, and after any tax related adjustments as necessary to reflect the effects of the amendment of Section 5727.111, Revised Code. Upon review of AEP's transition filings, as amended by the stipulation, we find that the companies have satisfied this prerequisite. In Rule 4901:1-20-03, Appendix A, Part (C)(1), O.A.C., the Commission proposed a formula for determining the residual generation component that includes transition charges. However, the Commission left open the possibility that companies could propose alternative formulations. *Rules for Electric Transition Plans, supra*, Opinion and Order at 16.

AEP proposed such an alternative in its transition filing, but has agreed in the stipulation not to impose the GTC on any switching customer (AEP Exs. 2, at 15A and 15B; Jt. Ex. 1, at 3). In addition, Section 4928.40(C), Revised Code, requires a five-percent reduction in the unbundled generation component for residential customers. Under the stipulation, the five-percent reduction is to be applied to the generation component, including the RTC component (Jt. Ex. 1, at 6). In addition, as described above, the settlement requires AEP to forego its right to seek reduction of the discount for residential customers during the MDP (*Id.*).

Section 4928.34(A)(5), Revised Code, requires that all unbundled components in the rate unbundling plan must be adjusted to reflect any rate base reductions on file with the Commission and as scheduled to be in effect by December 31, 2005, under rate settlements in effect on the effective date of this section. However, all earnings obligations, restrictions, or caps approved prior to the effective date of the statute are void. We find that the companies' filings, as amended by the stipulation, satisfy prerequisite (A)(5).

Section 4928.34(A)(6), Revised Code, requires that the total of all unbundled components is capped and, during the MDP, will equal the total of rates in effect on the day before the effective date of SB 3. The cap will be adjusted for changes in taxes, the universal service rider, and the temporary rider under Section 4928.61, Revised Code. Under AEP's filings, the total of the companies' unbundled rates is capped, with limited exceptions, during the MDP. Further, under the stipulation, distribution rates are frozen for additional years beyond the MDP, through the end of 2007 for OP and through 2008 for CSP (Jt. Ex. 1, at 3). In addition, under the companies' filings, the total of all unbundled components of existing rates and contracts equals the rates and charges of the bundled components, except for adjustments to reflect taxation changes under SB 3 and for the USF fund and EERLF riders (AEP Ex. 9A at 14-15). AEP's transition filings, as amended by the stipulation and taking into consideration our conclusion for the gross receipts/excise tax issue (discussed below), satisfy prerequisite (A)(6).

Section 4928.34(A)(7), Revised Code, requires the rate unbundling plan to comply with any rules adopted by the Commission under Section 4928.06(A), Revised Code.[16] The rules adopted by the Commission regarding unbundling of rates are set forth in Rule 4901:1-20-03, O.A.C., Appendix A. We find that the transition filings, through the various schedules and testimony submitted in this proceeding, satisfy Section 4928.34(A)(7), Revised Code.

Section 4928.34(A)(12), Revised Code, requires that the transition revenues authorized under Sections 4928.31 to 4928.40, Revised Code, be the allowable transition costs of the company pursuant to Section 4928.39, Revised Code, and that the transition charges for customer classes and rate schedules are the charges under Section 4928.40, Revised Code. Based upon the discussion above and our consideration of the record, we find that AEP's filings, subject to the modifications contained in the stipulation, satisfy the prerequisite set forth in Section 4928.34(A)(12), Revised Code.

16 Section 4928.06, Revised Code, directs the Commission to enact rules to effectuate commencement of competitive retail electric service. The Commission has enacted rules in compliance with this statute through various generic rule proceedings.

Section 4928.34(A)(15), Revised Code, requires that all unbundled components be adjusted to reflect the elimination of the gross receipt tax imposed by Section 5727.30, Revised Code. The signatory parties agree that the revenues from the agreed-upon RTCs and from existing frozen and unbundled rates recovered during the MDP are sufficient to recover regulatory assets as of the beginning of the MDP and to provide for the stipulation's obligations (Jt. Ex. 1, at 10). We believe that this agreement is envisioned by and consistent with the requirements of Section 4928.34(A)(15), Revised Code, as well as Section 4928.34(A)(6), Revised Code.[17]

Section 4928.39, Revised Code, requires the Commission to determine the total allowable amount of the company's transition costs to be received by the company as transition revenues. Such transition costs must meet the following criteria:

(1) The costs were prudently incurred.

(2) The costs are legitimate, net, verifiable, and directly assignable or allocable to retail electric generation service provided to electric consumers in this state.

(3) The costs are unrecoverable in a competitive market.

(4) The utility would otherwise be entitled an opportunity to recover the costs.

We believe that, under the proposed transition plans as modified by the proposed stipulation, the amount of transition costs has been determined and that it meets the requirements for recovery through transition charges.

B. <u>Corporate Separation Plan</u>

Under AEP's corporate separation plan, the companies have proposed to move the regulated transmission and distribution functions into newly created affiliates (AEP Ex. 2, Part B). As a result, AEP acknowledges that the new entities will own and operate all transmission and distribution assets and be public utilities, as defined in Sections 4905.02 and 4905.03, Revised Code (AEP Ex. 9A at 19; AEP Initial Br. at 47). AEP plans to seek the necessary federal authorization for the transfer of assets in 2000 (AEP Ex. 9A at 21). The corporate separation plan will take into consideration the overlapping financial arrangements that currently exist and refinance substantially all of the obligations over a period of time (AEP Ex. 20, at 3-7). In particular, the plan involves: (1) assigning specific debt that can be identified to individual assets and leaving the remaining debt and preferred stock obligations with the generation company; (2) retire debt and preferred stock obligations; and (3) replace debt and preferred stock obligations in a manner that does not create or will eliminate future financial overlaps (*Id.* at 5-6). Nearly all service offerings will remain the same; AEP identified one service (storage water heater rental

[17] Section 4928.34(A)(6), Revised Code, provides that the effect on customer rates from the tax overlap between the existing gross receipt tax and the new franchise tax "shall be addressed by the Commission through accounting procedures, refunds, or an annual surcharge or credit to customers, or through other appropriate means, to avoid placing the financial responsibility for the difference upon the electric utility or its shareholders."

program) that will be phased out as inappropriate in a competitive market for generation services (AEP Ex. 9A at 20). AEP's corporate separation plan and supporting testimony address safeguards, separate accounting, financial arrangements, complaint procedures, education and training, and a cost allocation manual (AEP Ex. 2, Part B; AEP Exs. 9A at 22-23, 9B at 3, 13, 20).

AEP contends that the stipulation enhances the corporate separation plan in three respects (AEP Initial Br. at 50). First, the cost allocation manual (CAM) will definitively follow the uniform system of accounts, as well as the generally accepted accounting principles (Jt. Ex. 1, at 11). Second, effective with the start of competition, the distribution affiliate will not provide competitive non-electric products or services to retail customers on a commercial basis, except under pre-existing contractual obligations or when incidental to the provision of customer services and not on a commercial basis (*Id.* at 11-12). Third, the stipulation requires that employees of the affiliates not have access to any information about the transmission or distribution systems that is not contemporaneously available in the same form and manner to nonaffiliated competitors of retail electric services (*Id.*).

Shell raises two concerns with the corporate separation plan of AEP (Shell Ex. 6, at 83-84, 86-87; Shell Initial Br. at 66-67). First, Shell states that the corporate separation plan allows excessive sharing of accounting services and management with affiliates (*Id.*). Second, Shell contends that "declared emergencies" under the corporate separation plan will allow AEP to violate the affiliate code of conduct (*Id.*).

Shell presented no evidence on either of these points. We are not convinced that Shell's concerns about the language of the corporate separation plan warrant its rejection. As for the sharing of accounting services and management, we have previously explained that the corporate separation rules were not intended to prohibit all sharing of employees between affiliated entities. *Rules for Electric Transition Plans, supra,* Second Entry on Rehearing at 21. Moreover, we stated that certain centralized support functions may be permissible (*Id.*). Specifically, our corporate separation rules are "intended to require independent work/functions when the failure to maintain independent operations may have the effect of harming customers or unfairly disadvantaging unaffiliated suppliers of competitive retail electric service or non-electric products or services" (*Id.*). Without any evidence presented, we are not convinced that the AEP's plan could have the harmful effect we wish to avoid. Moreover, many interested parties have agreed to the contrary. Additionally, we are not convinced that AEP's corporate separation plan must contain a particular definition of "declared emergency". The corporate separation plan complies with Rule 4901:1-20-16(G)(4)(j), O.A.C., on this point and is acceptable.

Unlike the corporate separation plans proposed by the FirstEnergy Corporation operating companies and Cincinnati Gas & Electric Company,[18] AEP has presented a corporate separation plan that provides for structural separation by January 1, 2001 (expect for limited financial arrangements). Therefore, this Commission need not evaluate an interim plan under Section 4928.17(C), Revised Code. Section 4928.17(A)(2), Revised

[18] *In the Matter of the Application of Cincinnati Gas & Electric Company for Approval of Its Electric Transition Plan, Approval of Tariff Changes and New Tariffs, Authority to Modify Current Accounting Procedures, and Approval to Transfer its Generating Assets to an Exempt Wholesale Generator,* Case Nos. 99-1658-EL-ETP, et al. (August 31, 2000).

Code, requires that all plans satisfy the public interest in preventing unfair competitive advantage and abuse of market power. The plan must also be sufficient to ensure that no undue preference or advantage is extended to or received by the competitive retail affiliate from the utility affiliate. Section 4928(A)(3), Revised Code. We find that AEP has constructed its plan in a manner that achieves, to the extent reasonably practical, the structural separation contemplated by Section 4928.17(A)(1), Revised Code, and the corresponding Commission rules. However, the Commission reserves the right to invoke its authority to preserve fair competition, for both interim and permanent arrangements.

Section 4928.34(A)(8), Revised Code, states that the corporate separation plan required under Section 4928.31(A), Revised Code, must comply with Section 4928.17, Revised Code, and any rules adopted by the Commission pursuant to Section 4928.06(A), Revised Code. We find that the proposed corporate separation plan satisfies this prerequisite, for the reasons stated in the discussion above. We reserve the right to closely monitor the implementation of the plan to avoid competitive inequality, unfair competitive advantage or abuse of market power. We believe that through the periodic Commission review (i.e., through audits of the company's books and records, including the CAM) and the complaint process, this Commission may ensure that the corporate separation plan is implemented in accordance with the policy enunciated in SB 3.

C. OSP

Section 4928.34(A)(9), Revised Code, provides that the company's transition plan must comply with Commission requirements and rules regarding operational support systems and technical implementation issues pertaining to competitive retail electric service. The Commission's rules regarding operational support and technical implementation are set out in Appendix B of Rule 4901:1-20-03, O.A.C. Additionally, on November 30, 1999, the Commission issued an entry in Case No. 99-1141-EL-ORD, directing Ohio's investor-owned electric utilities and interested stakeholders to participate in a taskforce for the development of uniform business practices and electronic data interchange (EDI) standards. Pursuant to this directive, the Commission staff created the OSP taskforce (hereinafter referred to as OSPO). On May 15, 2000, numerous OSPO participants filed a pro forma certified supplier tariff (pro forma tariff) and a stipulation (hereinafter referred to as the OSPO stipulation) in each utility's transition plan case. The pro forma tariff contains a number of service regulations on which the parties were able to agree. These relate to: supplier registration and credit requirements, end-use customer enrollment process, supplier request for end-use customer information, end-use customer inquiries and requests for information, service request process, metering services and obligations, load profiling and scheduling, transmission scheduling agents, confidentiality of information, voluntary withdrawal by a competitive retail electric service provider, liability, and alternative dispute resolution. In the OSPO stipulation, the parties specifically requested the Commission to resolve issues in four general areas: (1) energy imbalance service, (2) minimum stay requirements for residential and small commercial customers returning to standard offer service, (3) consolidated billing and purchase of receivables, and (4) adoption of EDI standards. On May 18, 2000, the Commission issued an entry initiating a generic docket to establish procedures for parties desiring to file comments and reply comments regarding the OSPO stipulation and pro forma tariff. *In the Matter of the Establishment of Electronic Data Exchange Standards and Uniform Business Practices for the*

Electric Utility Industry, Case No. 00-813-EL-EDI (hereinafter 00-813). On July 20, 2000, the Commission issued a finding and order approving the OSPO stipulation and resolving the four issues left unresolved.

AEP's operational support and technical implementation plan is described in the testimony of Jeffrey Laine (AEP Ex. 14A and 14B). The OSP specifically addresses each requirement set forth in the Commission's rules (AEP Ex. 2, Part C). Specifically, as required by Rule 4901:1-20-03, Appendix B, Part (A), O.A.C., AEP's operational support plan addresses how the company intends to utilize its existing systems and what changes will be made to implement customer choice. Further, as required by Rule 4901:1-20-03, Appendix B, Part (B), O.A.C., the plan includes an electronic "clearinghouse" system that will provide functionality such as service provider registration, enrollment and switching, estimation and reconciliation, settlement, and bill data delivery (AEP Ex. 14B at 2).

Under the transition plan stipulation in this case, AEP agrees to incorporate into its transition plan, the OSPO stipulation and pro forma tariff with the exception of certain terms that the stipulating parties have agreed will apply to AEP. According to the companies, the settlement modifies the companies' plans by providing minimum stay requirements and consolidated billing credits (AEP Initial Br. at 55). AEP contends that these modifications bring additional benefits to customers and suppliers and, thus, encourage the development of the competitive retail market (*Id.*). Shell takes issue with four OSP-related items in the transition plans and stipulation: (1) supplier consolidated billing credit, (2) residential customer switching period (3) switching fee, and (4) additional certification requirements proposed by AEP.

1. Supplier Consolidated Billing Credit

AEP did not propose a supplier consolidated billing credit in the transition plans. Section XIV of the stipulation states that AEP will provide a $1.00 credit to suppliers for each consolidated bill issued by that provider during the first year of the MDP (Jt. Ex. 1, at 9; Tr. III, 101). The signatory parties agree to conduct further negotiations related to a similar future credit (*Id.*). Finally, that provision states that AEP shall reasonably attempt to implement supplier consolidated billing as soon as practicable (*Id.*).[19]

Shell believes that the stipulation's terms for a consolidated billing credit are inadequate to spur effective competition (Shell Ex. 7, at 16-17; Shell Initial Br. at 52). Shell, unlike most other marketers in these proceedings, provides consolidated billing for customers in Georgia and intends to do so in Ohio. First, Shell characterizes the stipulated credit amount as "anemic" and as requiring Shell's customers to pay twice for the billing service (once to Shell and a second time to AEP for costs not captured by the billing credit) (Tr. III, 115-116; Shell Initial Br. at 53; Shell Reply Br. at 27). Shell further states that the $1.00 is an arbitrary figure, while Shell's evidence supports a conclusion that CSP and OP residential accounting, collections and services average $3.70 and $4.00 per customer per month, respectively (Shell Ex. 7, at 20; Shell Initial Br. at 54-55). For that reason, Shell contends that the billing costs are virtually certain to be much higher than $1.00 (Shell Ex. 7, at 21). Shell also presented evidence of other utilities' billing costs, which were all quite a

[19] AEP has established its target date for implementing the supplier consolidated billing credit as January 1, 2001, the start of competition in Ohio (Jt. Ex. 1, at 7; Tr. III, 102, 156).

bit higher than $1.00 (*Id.* at 23, JWW-1S, JWWW-2S). For these reasons, Shell contends that the Commission should reject Section XIV and take one of two actions. Those are: either adopt a higher figure, no lower than $2.00 per bill, pending completion of a separate proceeding to determine actual costs, or require AEP to establish a separate affiliate to perform billing functions (*Id.* at 23-24; Shell Initial Br. 57).

Second, Shell also criticizes the stipulated process for modifying the credit because only signatory parties may participate in those future negotiations. Shell notes that even AEP acknowledged that, if none of the signatory parties seek such negotiations, they will not take place (Tr. III, 106; Shell Initial Br. at 58). Shell believes that none of the signatory marketers have an interest in performing consolidated billing and, therefore, there is a great risk that no future consolidated bill credit negotiations will take place. Shell also states that the stipulation's terms would have anti-competitive consequences, by excluding certain market participants from negotiations and by only allowing AEP to petition the Commission if negotiations fail (Shell Initial Br. at 59). Lastly, Shell points out that the stipulation also fails to provide a "fail-safe" credit in the event that the future negotiations are not completed in the 12-month period (Shell Ex. 7, at 24). In Shell's view, not only does AEP not have an incentive to agree to a higher billing credit, but the stipulation provides AEP with further incentive to let the 12 months expire so that the stipulated credit expires (Shell Initial Br. at 59).

AEP states that the Commission should view the stipulated consolidated billing credit as an extra bonus since AEP is not statutorily required to offer such a credit and since no other Ohio utility will be offering one as early as AEP (AEP Initial Br. at 54; AEP Reply Br. at 55). AEP also points out that the Commission did not require utilities to offer consolidated billing credits in consideration of the topic as part of the OSP issues (AEP Reply Br. at 55). Next, AEP contends that there is evidence to support the reasonableness of the stipulated credit amount. For instance, AEP's witness stated that the only avoided costs of providing billing services would be postage and the envelope, costs which are much less than $1.00 (Tr. III, 111-112, 149; AEP Reply Br. at 57). AEP also points out that Shell's witness acknowledged that other utilities have credits in the $1.00 range (Tr. V, 94). Next, AEP contends that there is no basis in Ohio law for the Commission to adopt Shell's recommendation for a separate billing affiliate. AEP next noted that it has agreed to keep Shell involved and informed of the consolidated bill discussions (Tr. III, 106-108)[20], so that concern has already been addressed by the companies (AEP Reply Br. at 58-59).

Staff contends that Shell's argument is premature because the stipulation is providing a credit only as a temporary measure during the first year (Staff Initial Br. at 9). Since "fine-tuning" can and will be addressed in the future and there are many more pressing items to address during the first phase of the transition, Shell's concern should be not adopted according to the staff (*Id.*). Additionally, the staff states that the consolidated billing credit is a unique advantage of this stipulation since no other stipulation provide such a credit (*Id.*).

We established in 00-813 a target date for consolidated bill-ready billing of no later than June 1, 2002, and a target date for supplier consolidated billing of no later than July 1,

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20 AEP agreed to also allow participation by customer groups, such as the OCC, the staff, industrials (Tr. III, 106-107).

2002. The stipulation before us, however, includes a target date for supplier consolidated billing that coincides with the start of competition. In this respect, AEP is planning to be the first utility to implement the necessary systematic changes for supplier consolidated billing. We find the stipulated target date by AEP to be reasonable.[21] Nevertheless, the crux of Shell's argument is not the start date, but the amount of the consolidated billing credit. Shell presented evidence from which it contends that the $1.00 credit is unreasonable. AEP presented evidence from which it contends that the $1.00 credit is reasonable. On balance, we conclude that, as part of an overall settlement of nearly all issues in these proceedings, the stipulated credit amount is acceptable. If this issue were fully litigated, we might very well reach a conclusion that differs from $1.00, but we cannot say that this provision (as part of a settlement reached with a broad range of interested parties and with a target of having the credit immediately available with the onset of competition) must be rejected. Additionally, AEP explained that, in the event that the system changes for supplier-consolidated billing are not in place at the start of competition on January 1, 2001, it would continue the consolidated billing credit on a day-for-day basis so that it was offered for a one-year period (Tr. III, 156-157). Lastly, inasmuch as AEP has agreed to include Shell in the future negotiations (as well as customer groups), we believe that eliminates Shell's concern that those future negotiations might not take place (Shell itself can ensure that the negotiations take place). For these reasons, we do not accept either one of Shell's suggested approaches for this issue.

2. Residential Customer Switching/Minimum Stay Requirement

The transition plan filing provided that all customers returning to the company from an alternative supplier be required to stay on the standard service offer for 12 months or the MDP, whichever is longer (AEP Ex. 2, Part A, UNB-1, Sheet Nos. 3-18D for OP and 3-14D for CSP; AEP Ex. 24A at 5-6). AEP has agreed to mitigate this requirement in the settlement (Jt. Ex 1, at 7-8). In Section XII of the stipulation, the operating companies agree that, during the MDP, customers who can take generation service from AEP between May 16 and September 15 must either remain a customer through April 15 of the following year or choose a market-based tariff which will not be lower than the generation cost embedded in the standard offer (*Id.* at 7). Under the stipulation, non-aggregated residential customers will be permitted to shop three times during the MDP and to return two times to the default tariff before being required to choose from one of the above two options (*Id.* at 8).

Shell contends that AEP's proposed minimum stay requirement violates SB 3 because SB 3 contemplates no limitation on a residential customer's freedom of movement between service options even if those movements involve a return to standard offer service (Shell Ex. 6, at 64; Shell Initial Br. at 60). Shell also claims that AEP's minimum stay provision could remove large numbers of such consumers from the competitive market place for substantial periods of time and reduce competition (Shell Initial Br. at 60).

AEP points out that Section 4928.31(A)(5), Revised Code, specifically allows transition plans to create reasonable minimum stay requirements (AEP Reply Br. at 60). Furthermore, AEP states that it is unrealistic for there to be no restrictions placed on

21 We note that, pursuant to Rule 4901:1-10-29(H)(1), O.A.C., the companies are still required to make rate-ready, electric disttribution utility-consolidated billing available to suppliers on January 1, 2001.

residential switching (*Id.*). Also, AEP states that the Commission has already rejected Shell's position in 00-813, there is no reason to alter that decision, and the Commission should adopt Section XII of the stipulation (*Id.* at 60-61).

With respect to the issue of AEP's minimum stay requirements and Shell's criticisms thereof, we defer to our rulings in 00-813. In that first order (page 13), we approved the use of minimum stay requirements conditioned upon the development of a market-based "come and go" rate alternative service and only in the event the customer voluntarily chooses to return to the standard offer service. We prohibited the imposition of a mandatory stay when a customer defaults to the utility's standard offer service due to the default of the supplier of electricity. We also established a uniform penalty free return to standard offer service policy and a uniform period throughout Ohio in which companies can impose a summer/stay period of May 16th through September 15th. On August 31, 2000, we granted rehearing with regard to the minimum stay ruling and adopted the "first year exemption" proposal (as opposed to the two free returns proposal) as the uniform rule in Ohio for residential and small commercial customers. This uniform rule differs from what AEP agreed upon in its stipulation, but AEP also agrees in that same stipulation to abide by our OSP determinations. Having addressed and considered Shell's arguments in 00-813, we conclude that no further conclusions need be expressed at this time. Accordingly, the Commission will modify the stipulation's treatment of minimum stay requirements so that AEP's minimum stay requirements are in full compliance with our orders in 00-813 and we reserve approval of any tariff provision relating thereto.[22] We also note that, as stated in our entry on rehearing in 00-813, our approval of the minimum stay requirements is conditioned upon the development of a uniform alternative, which will provide returning customers with a method of avoiding the minimum stay or which may eliminate the need for such requirement.

3. <u>Switching Fee and Alternative Metering Credit</u>

As part of its OSP, AEP originally proposed a $5.00 switching fee each time a customer-authorized change in provider occurs, except under certain limited circumstances (AEP Ex. 2, Part A, UNB-1, Sheet Nos. 3-3D and 3-18D for OP and Sheet Nos. 3-3D and 3-14D for CSP). AEP later modified its switching fee proposal, increasing it to $10.00 (AEP Ex. 24B at 4-5). AEP states that it proposed the increased fee because of certain Commission rules[23] and the items being discussed in the OSPO (AEP Ex. 24B at 4-

22 We note that the stipulation's minimum stay proposal was suggested to the Commission, <u>unless</u> the OSPO agreed upon other, less restrictive minimum stay requirements. As noted above, the OSPO did not agree upon minimum stay requirements and requested a Commission ruling. That has occurred and, thus, Section XII's prefatory clause has not been triggered. We make this statement so that all interested parties fully understand that we expect that the conclusions we reached in 00-813 on the minimum stay issue will be followed. We also make this statement in light of Mr. Forrester's testimony, which would leave one to believe that the stipulation's minimum stay provision would be triggered (and not the Commission's 00-813 minimum stay conclusions) if the Commission's conclusion in 00-813 was more restrictive than the stipulation (Tr. IV, 134-135). We do not accept the approach/interpretation set forth by Mr. Forrester and explicitly modify the stipulation on this issue and we reserve approval of any tariff provision relating thereto so that AEP's minimum stay requirements comply with our decisions in 00-813.

23 AEP specifically referred to the Commission's rules in *In the Matter of the Commission's Promulgation of Rules for Minimum Competitive Retail Electric Service Standards Pursuant to Chapter 4928, Revised Code* and *In the Matter of the Commission's Promulgation of Amendments to Rules for Electric Service and*

5). Shell argues that the switching fee proposed is excessive (Shell Ex. 6, at 66; Shell Initial Br. at 66-67).[24] AEP states that the Commission should deny Shell's objection, when it is weighed against the reasonableness of the stipulation as a package (AEP Reply Br. at 61-62).

Also as part of its OSP, AEP proposed an $0.11 monthly alternative metering credit for CSP residential customers and a $0.12 monthly alternative metering credit for OP residential customers (AEP Ex. 2, Part A, UNB-1, Sheet No. 10-1D). Shell states that the proposed alternative metering credits are too low and effectively amount to barriers for suppliers to undertake alternative metering (Shell Ex. 6, at 78; Shell Initial Br. at 66-67). Shell wants the credits to reflect the utilities' full cost, not only avoided cost (Shell Ex. 6, at 78). AEP states that the Commission should likewise deny Shell's objection, when it is weighed against the reasonableness of the stipulation as a package (AEP Reply Br. at 61-62).

Similar to our finding for the consolidated billing credit amount, we conclude that the switching fee and alternative metering credit amounts are acceptable. Although we might conclude, based upon a fully litigated record, that other amounts are more appropriate, we have no evidence in the record to do so. Shell presented no such evidence as to what it contends are appropriate dollar amounts. Accordingly, we conclude that the modified switching fee and the alternative metering credit amounts proposed by AEP are acceptable, in the context of the overall settlement package presented to us.

4. Supplier Registration Requirements

As part of the OSP, AEP proposed a two-step certification/registration process. AEP stated that, along with the Commission's certification process, it "proposes a registration process for its service territory" (AEP Ex. 2, Part A, UNB-1, Sheet No. 3-15D – 3-16D for CSP and Sheet No. 3-19D – 3-20D for OP). The registration process would require: (1) proof of certification, (2) $100 annual fee; (3) financial instrument to ensure against defaults and a description of the plan to meet requirements of firm service customers; (4) contact information; (5) dispute resolution process for supplier customer complaints; and (6) statement of adherence with tariffs and any agreements between AEP and the supplier (*Id.*). Shell contends that approval of the OSP will allow AEP to improperly impose additional certification requirements upon suppliers, beyond the Commission's certification requirements (Shell Ex. 6, at 68-72; Shell Initial Br. at 66-67).

As noted earlier, on July 19, 2000, we approved of the OSPO's proposed pro forma tariff. That tariff contained (in Section V) the following language associated with supplier registration process, beyond the Commission's certification requirements:

> The Company shall approve or disapprove the supplier's registration within 30 calendar days of receipt of complete registration information from the supplier. The 30 day time period may be extended for up to 30 days for

Safety Standards Pursuant to Chapter 4928, Revised Code, Case Nos. 99-1611-EL-ORD and 99-1613-EL-ORD, respectively.

24 Shell referred to the $5.00 switching fee proposal. We presume that Shell considers the current, higher fee proposal to be excessive as well and, therefore, shall address the argument.

good cause shown, or until such other time as is mutually agreed to by the supplier and the Company.

The approval process shall include, but is not limited to: successful completion of the credit requirements and receipt of the required collateral if any by the Company, executed EDI Trading Partner Agreement and Certified Supplier Service Agreement, payment and receipt of any supplier registration fee and completion of EDI testing for applicable transaction sets necessary to commence service.

The Company will notify the supplier of incomplete registration information within ten (10) calendar days of receipt. The notice to the supplier shall include a description of the missing or incomplete information.

Thus, we have agreed, not only that the electric utilities can have registration processes, but the registration processes can include some of the very items that were proposed by AEP in its transition plan. However, we believe that the stipulation before us resolves Shell's concerns over AEP's proposed registration requirements. In Section XI, the companies agree to accept resolution of issues by the OSP working group and to incorporate such in their transition plans (Jt. Ex. 1, at 7). Registration procedures were mutually resolved by the OSPO working group (as part of the pro forma tariff) after the plan was proposed and we have also approved that uniform tariff. It appears to us that AEP has accepted to modify supplier registration terms to comply with what was adopted by the OSPO working group, to which Shell was also a supporting party. We do not believe that there is any further disagreement on this issue. Accordingly, the Commission will approve the stipulation's treatment of supplier registration conditioned upon certain modifications so that AEP's supplier registration requirements are in full compliance with our orders in 00-813.

5. Overall OSP Conclusion

While the settlement provides several express modifications to the operational support aspects of the transition plan filing, which the company argues benefit customers and suppliers alike, the settlement also states that AEP will abide by Commission determinations related to OSP issues when not resolved by the OSPO (Jt. Ex. 1, at 7). Thus, the settlement sets out not only its own provisions enhancing the development of a competitive retail market, but expressly encompasses such measures that the Commission has adopted to reach the same goal. We believe the companies' OSP set forth in the stipulation, subject to modifications to comply with 00-813, is reasonable and appropriately addresses operational support systems and technical implementation procedures. Accordingly, we find the transition plan meets the statutory requirements of Section 4928.34(A)(9), Revised Code. The Commission directs its staff to finalize a bill format that includes a "price to compare" (which is the price for an electric supplier to beat in order for the customer to save money) for residential and small commercial customers.[25] As part of our approval of AEP's transition plans, the companies must meet staff's requirements regarding billing format.

D. Employee Assistance Plan (EAP)

AEP's EAP was presented in the testimony of Melinda S. Ackerman, Vice President of Human Resources for American Electric Power Service Corporation (AEP Ex. 5). Ms. Ackerman stated that, in the event of job displacement due to organizational restructuring, AEP's EAP consists of programs to help individuals locate new positions, a relocation assistance program, an educational assistance program, professional outplacement services, and a re-employment workshop (AEP Ex. 5, at 2-3). Additionally, the EAP includes programs designed to help deal with the emotional and financial issues associated with displacement, such as, counseling, severance, extended medical and life benefits, and early retirement (*Id.* at 3). Ms. Ackerman noted that the programs being sponsored as the EAP are existing already and the companies have not identified any eligible employees (*Id.*). Finally, Ms. Ackerman noted that the companies are not seeking cost recovery in the transition charge of any costs associated with the EAP (*Id.*).

UWUA points out that the EAP is lacking a disparate/adverse impact statement in accordance with Rule 4901:1-20-03, Appendix C, Part (C)(8), O.A.C. UWUA assert that, to the extent AEP seeks to "downsize" during the MDP, the Commission's regulations will require submission and approval of a disparate/adverse impact statement (UWUA Br. 2 and 4). Despite the fact that AEP has proposed no staffing changes and is not seeking any related transition cost, UWUA states that the filing of the statement is necessary before any staff downsizing takes place, not vice versa, so that the Commission can ensure the availability of reliable, safe, and efficient electric service (*Id.* at 4). Therefore, UWUA states that any approval of the transition plan (including the EAP) should include a condition requiring AEP to file and obtain approval of a disparate/adverse impact statement prior to carrying out proposed staffing changes during the MDP (*Id.* at 6-7). Additionally, UWUA states that the Commission should clarify that "downsizing" during the MDP gives rise to the requirement of advance filing and approval of a disparate/adverse impact statement (*Id.* at 5-7).

AEP responds by stating that, since it did not identify any positions affected by SB 3, no disparate/adverse impacts could be explained and, therefore, its EAP filing satisfies the Commission's filing requirements (AEP Reply Br. at 62). Next, AEP states that the UWUA would expand the requirement to apply to any downsizing, rather than just for employees that are adversely and directly affected by electric restructuring (*Id.* at 62-63). Lastly, AEP states that the UWUA's suggestion should be rejected because the Commission should not establish procedures for addressing speculative events; rather, the Commission can determine what procedures, if any, are appropriate when such a change occurs (*Id.*).

Section 4928.31(A)(4), Revised Code, requires a utility to file, as part of its transition plan, an employee assistance plan "for providing severance, retraining, early retirement,

[25] We recognize that AEP already proposed a chart that reflects the companies' prices to compare, but by tariff service (AEP Ex. 9D at Attach. I). This information should be helpful for finalizing the bill format that includes the "price to compare" information.

retention, outplacement, and other assistance for the utility's employees whose employment is affected by electric industry restructuring...." Rule 4901:1-20-03, O.A.C., Appendix C, Part (B)(3), defines "employee affected by restructuring" as an employee who is "directly and adversely affected by electric restructuring during the [MDP]...." Part (A) of the rule requires the utility to explain "how it would mitigate any necessary reductions in the electric utility workforce." Part (C) requires the EAP to provide the following components: notification of employees; outplacement assistance; relocation assistance; employee assistance, such as counseling; early retirement programs; severance packages; and "other assistance."

To the extent UWUA argues that the EAP is deficient because no disparate/adverse impact statement was included, we disagree. Since the companies concluded that no employees would be directly and adversely affected by electric restructuring during the MDP, we do not believe a disparate/adverse impact statement was required in the filing. We find that AEP's EAP satisfies the filing requirements of Rule 4901:1-20-03, O.A.C. UWUA does also seek a further requirement for AEP. UWUA states that any approval of the transition plan (including the EAP) should include a condition requiring AEP to file and obtain Commission approval of a disparate/adverse impact statement prior to carrying out proposed staffing changes during the MDP. On this point, UWUA is seeking a Commission requirement upon AEP to file, during the MDP, statements regarding what effect planned staffing changes will have on service delivery. AEP is correct in noting that UWUA's request would apply to any staff changes, not just those directly and adversely affected by electric restructuring. For that reason, we agree that UWUA's request is somewhat over-broad. However, we do not believe such a condition upon approval of the EAP is unwarranted. Rather, we find it appropriate to require AEP to provide a disparate/adverse impact statement (in this docket) should the company subsequently determine that a reduction in the staffing level is necessary due to electric restructuring during the MDP. Moreover, we will require AEP to provide the Commission with all terms and conditions related to the sale of corporate assets (including the sale of affiliate coal mines) that could have an impact on employment levels. We will of course be monitoring the service delivery and will take all necessary steps to ensure that just, reasonable, reliable and safe electric service is provided. Pursuant to Section 4928.34(A)(10), Revised Code, the Commission finds that the companies' EAP, with the above-noted conditions, sufficiently provides severance, retraining, early retirement, retention, outplacement, and other assistance for the company's employees whose employment is affected by electric industry restructuring.

E. Consumer Education Plan

Section 4928.31(A)(5), Revised Code, requires each utility's transition plan to include a consumer education plan consistent with Section 4928.42, Revised Code, and the applicable Commission rules. Section 4928.42, Revised Code, provides that, prior to the starting date of competitive retail electric service, the Commission shall prescribe and adopt a general plan by which each electric utility shall provide during its MDP consumer education on electric restructuring. Utilities are required to spend up to $16 million in the first year on consumer education within their certified service territories and an additional $17 million in decreasing amounts over the remaining years of the MDP. As part of its transition plan, AEP filed an education plan (AEP Ex. 2, Part E). AEP's education plan targets residential customers, small and mid-sized commercial customers, elected officials, community leaders, civic organizations, trade associations, and consumer groups (AEP Ex. 9A, at 25). Industrial customers' needs will be addressed on an individual basis (*Id.*). A special effort will target low-income, special needs, and hard-to-reach customers (*Id.*). The plan also describes the methods, timelines, and spending that will be used for AEP's education campaign. Some opposition to AEP's education plan was raised by the Coalition for Choice in Electricity (CCE)[26] and OCC.

As noted earlier, on November 30, 1999, the Commission issued rules for the electric transition plan proceedings. At that same time, the Commission adopted in Case No. 99-1141-EL-ORD a general plan for the electric utilities' consumer education. After the companies filed their transition plans, various intervenors filed preliminary objections. Separate staff reports were filed in each of the transition plan proceedings. In each staff report, the staff stated that the consumer education plans are consistent with the requirements issued by the Commission on November 30, 1999.[27] After reviewing all of the education plans filed in all of the transition cases and after considering the objections and comments submitted, we found in our July 19, 2000 Finding and Order in these proceedings that AEP's education plan is in compliance with Section 4928.42, Revised Code, and we approved AEP's education plan subject to a few contingencies. First, we noted that, with regard to provisions for the funding of local community-based organizations (CBO), although we did not require funding of the CBOs, we did encourage AEP to provide CBO funding. Second, we required AEP to include an unaffiliated energy marketer representative on the advisory board (we allowed AEP's operating companies to have a combined advisory group and a combined service territory-specific campaign). Third, we required that the plans for AEP include further details on how the territory-specific campaign will be managed and operated, how materials and information will be disseminated, and how funds will be allocated to activities, as well as other matters. Further, we conditioned our approval on the Commission staff's continuing supervision of the general and territory-specific plans as further details are developed for each of the consumer education programs. With the conditions to AEP's education plan set forth in our July 19, 2000 order, we find that AEP's transition plan complies with Section 4928.31(A)(5), Revised Code. Additionally, the Commission finds that the companies' consumer education plan sufficiently complies with Section 4928.34(A)(10), Revised Code,

F. <u>Independent Transmission Plan</u>

Section 4928.34(A)(13), Revised Code, requires that any transmission plan included in the transition plan must reasonably comply with Section 4928.12, Revised Code, and any rules adopted by the Commission unless the Commission, for good cause shown, authorizes the company to defer compliance until an order is issued under Section 4928.35(G), Revised Code.[28] Pursuant to Section 4928.12(A), Revised Code, no entity shall own or control transmission facilities (as defined by federal law) in Ohio as of the date of competitive retail electric service unless the entity is a member of, and transfers control of

[26] The CCE group includes various marketers, low-income representatives, IEU, OCRM, OPAE, city of Cleveland, AMP-Ohio, and OMA.

[27] The staff's only recommendation for the AEP consumer education plan was the inclusion of an energy marketer representative in the advisory group.

[28] Section 4928.35(G), Revised Code, governs requirements for utilities that do not have an independent transmission plan with respect to transfer of control and operation of transmission facilities.

those facilities to, one or more qualifying transmission entities. Section 4928.12(B), Revised Code, sets forth the specifications that such entities must meet.

Both existing federal[29] and state requirements are designed to achieve the same key objectives for transmission service in the development of competitive wholesale and retail energy markets. These shared objectives include: corporate separation of generation and transmission, with decisions to provide service, pricing, and expansion of facilities made on an independent basis from the transmission provider's ownership of generation facilities; creation of RTOs with sufficient scope and configuration to increase economic supply options to customers; elimination of pancaked transmission charges within a single RTO; and improved reliability of transmission service.

AEP's witness Craig Baker (AEP Exs. 6A, 6B, and 6C) explained that the company will satisfy the requirements of the Ohio statute by transferring control and operation, and ultimately ownership, of its transmission facilities to the Alliance RTO. The Alliance RTO is currently composed of FirstEnergy Corporation, AEP, Consumers Energy Company, The Detroit Edison Company, and Virginia Electric and Power Company (AEP Ex. 6A at 4).[30] As presently configured, the Alliance RTO would serve a nine-state area with a population of approximately 26 million people and a connected load of 67,000 megawatts (AEP Ex. 2, Part G at 8). The Alliance transmission system has connected generation capacity of 72,000 megawatts and will be one of the largest RTOs in the nation (*Id.*). The FERC conditionally approved the Alliance RTO in December 1999, but required that the participants modify certain aspects of the entity's independence, governance configuration, and tariff design. 89 FERC ¶61,298 (1999). AEP claims that, upon final operational implementation, the Alliance RTO will minimize pancaked transmission rates within Ohio to the extent reasonably possible and be consistent with Section 4928.12(B)(3), Revised Code (AEP Ex. 6C at 8). Until the Alliance RTO is operational and the transfer has occurred, AEP proposes that retail customers or their suppliers use AEP's OATT to transmit power and energy from alternative suppliers to the customers' load (AEP Ex. 8B at 2). Thereafter, transmission service to retail customers will cease under AEP's OATT, but be offered by the Alliance RTO OATT (*Id.*).

Additionally, in March 2000, the FERC conditionally approved the merger between American Electric Power Corporation and Central and South West Company. 90 FERC ¶61,242 (2000). That merger transaction will also impact the transferring of control, operation, and ultimately ownership of AEP's transmission facilities to the Alliance RTO.

Although the Alliance RTO may not be operational before customer choice commences in Ohio (January 1, 2001), AEP asserts that the settlement will provide benefits to participants in the Ohio retail generation market (AEP Initial Br. at 69-71). The stipulation obligates AEP to transfer control and operation, and ultimately ownership, of AEP's transmission facilities to a FERC-approved RTO no later than December 15, 2001 (Jt. Ex 1, at 5). Additionally, AEP identified three transmission-related benefits of the stipulation that are specific to the period of time before that RTO becomes operational:

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29 Order No. 888, FERC Stats. & Regs. ¶ 31,089 (2000) and Order No. 2000, FERC Stats. & Regs., ¶ 31,036 (1996).

30 The Dayton Power & Light Company and Illinois Power Company have also announced their intention to join the Alliance RTO.

(1) AEP will provide two full-time equivalent positions in the System Control Center to assist transmission uses with reservations, scheduling, and tagging;
(2) AEP or its affiliates will provide transmission services for all power, including transmission of default service power and power for affiliated and nonaffiliated energy service providers only under the proposed *pro forma* transmission tariff; and
(3) AEP or its affiliates will comply with OASIS and conduct requirements promulgated by FERC.

(*Id.* at 5, 8).

Next, AEP listed four other transmission-related benefits of the stipulation. First, AEP will account for partial megawatt-hours when the load served by imports across AEP interfaces does not result in whole megawatts (Jt. Ex. 1, at 5). Second, AEP is required to make a unilateral filing at FERC to extend rollover rights to retail customers or their supplier, requesting an effective date of January 1, 2001 (*Id.*). Third, AEP will work with RTOs/ISOs and transmission-level customers to develop and implement resolutions for reciprocity and interface/seam issues and, if no other filing on this subject is made by September 1, 2000, AEP will file a proposal with the FERC (*Id.* at 5). Fourth, AEP will fund up to $10 million for costs imposed by PJM and/or the MISO on generation originating in the MISO or PJM (*Id.* at 5-6).

In Shell's reply brief it argues that the $10 million fund will not promote competition because the commitment may not reach $10 million in the short time period and because the dollars are available for only certain transmission costs (Shell Reply Br. at 30). Shell estimates that the fund will only (at best) benefit 6 percent of the AEP load (Tr. III, 162-164; Shell Reply Br. at 31).

Pursuant to Section 4928.34(A)(13), Revised Code, as an alternative to approving an independent transmission plan that complies with Section 4928.12, Revised Code, the Commission may, for good cause shown, authorize a company "to defer compliance until an order is issued under division (G) of section 4928.35 of the Revised Code." Because the Commission cannot determine, at this time, whether the Alliance ISO (or any other FERC-approved RTO as allowed by the stipulation) is compliant with the requirements of Section 4928.12, Revised Code, (due to changes that will occur as a result of the FERC's ongoing proceeding addressing the Alliance RTO, for instance), the Commission will defer approval of AEP's independent transmission plan until the opportunity is available to address the changes to the FERC-approved RTO. The Commission will exercise this later decision process through an order issued under Section 4928.35(G), Revised Code. We will authorize AEP to defer compliance with this provision until an order is issued pursuant to Section 4928.35(G), Revised Code.

We will, however, address Shell's arguments against Section VIII of the stipulation ($10 million transmission fund). On balance, we find the $10 million fund to be a unique benefit offered by the stipulation. It is one of several beneficial aspects of the stipulation. While on its own, this term of the stipulation may not create effective competition, it can (in conjunction with all of the other terms of the plans and stipulation) collectively "jump start" competition and spur the development of effective competition in AEP's territory. For these reasons, we reject Shell's criticism of the $10 million transmission fund.

G. Section 4928.34(A)(14), Revised Code

Section 4928.34(A)(14), Revised Code, states that one of the findings the Commission must make in approving a utility's transition plan is that the utility is in compliance with Sections 4928.01 through 4928.11, Revised Code, and any rules or orders adopted or issued by the Commission under those sections. We wish to make clear that we have a continuing obligation to ensure that the transition plan and its implementation are in keeping with the policy of the state, as set forth in these provisions of the statute. For example, through the monitoring of markets and enforcement with fair standards of competition, we intend to make, as a top priority, enforcement of the overarching policies of SB 3 to ensure open markets. We believe that this prerequisite is thereby satisfied.

H. Accounting Authority

The signatory parties also seek from the Commission the authority to implement various accounting entries on the regulatory books. These requested accounting approvals have been identified either in the companies' filings or in the transition plan settlement agreement and include:

(1) Requested amortization of regulatory assets during the MDP and thereafter until such regulatory assets are fully amortized.

(2) Requested amortization (on a per kilowatt-hour basis) of regulatory assets as of the beginning of the MDP that exceed the amounts on the attachment to the stipulation. Such amortization will occur during the MDP and recovered through existing frozen and unbundled rates.

(3) Requested deferral of certain new regulatory assets actual costs, plus a carrying charge, as regulatory assets for future recovery in future distribution rates.

(4) Addressing the issue of potential violations of Internal Revenue Code normalization rules with respect to amortization or regulatory liabilities of investment tax credits and deferred income taxes. The signatory parties ask that the Commission adopt certain specific language found in the settlement.

(Jt. Ex. 1, at 4, 10).

The requested accounting authority is reasonable and shall be granted. Additionally, we will approve the following language contained in the agreement:

> The base rates in the [MDP] embodied in this opinion and order include the amortization of regulatory liabilities related to [investment tax credits] no more rapidly than ratably, and the amortization of "excess

deferred taxes" using the Average Rate Assumption Method in order to avoid any potential normalization violations.

IV. THREE-PART TEST FOR EVALUATING STIPULATIONS

Rule 4901-1-30, O.A.C., authorizes parties to Commission proceedings to enter into stipulations. Although not binding on the Commission, the terms of such agreements are accorded substantial weight. *See, Consumers Counsel v. Pub. Util. Comm.* (1992), 64 Ohio St.3d 123, at 125, citing *Akron v. Pub. Util. Comm.* (1978), 55 Ohio St.2d 155. This concept is particularly valid where the stipulation is supported or unopposed by the vast majority of parties in the proceeding in which it is offered.

The standard of review for considering the reasonableness of a stipulation has been discussed in a number of prior Commission proceedings. *See, e.g., Ohio-American Water Co.*; Case No. 99-1038-WW-AIR (June 29, 2000); *Cincinnati Gas & Electric Co.*, Case No. 91-410-EL-AIR (April 14, 1994); *Western Reserve Telephone Co.*, Case No. 93-230-TP-ALT (March 30, 1004); *Ohio Edison Co.*, Case No. 91-698-EL-FOR et al. (December 30, 1993); *Cleveland Electric Illum. Co.*, Case No. 88-170-EL-AIR (January 30, 1989); *Restatement of Accounts and Records (Zimmer Plant)*, Case No. 84-1187-EL-UNC (November 26, 1985). The ultimate issue for our consideration is whether the agreement, which embodies considerable time and effort by the signatory parties, is reasonable and should be adopted. In considering the reasonableness of a stipulation, the Commission has used the following criteria:

(1) Is the settlement a product of serious bargaining among capable, knowledgeable parties?

(2) Does the settlement, as a package, benefit ratepayers and the public interest?

(3) Does the settlement package violate any important regulatory principle or practice?

The Ohio Supreme Court has endorsed the Commission's analysis using these criteria to resolve issues in a manner economical to ratepayers and public utilities. *Indus. Energy Consumers of Ohio Power Co. v. Pub. Util. Comm.* (1994), 68 Ohio St.3d 547 *(citing Consumers' Counsel, supra*, at 126). The court stated in that case that the Commission may place substantial weight on the terms of a stipulation, even though the stipulation does not bind the Commission. *Id.*

AEP, OCC, the staff, and IEU-OH all state that the stipulations comport with this criteria (AEP Ex. 18, at 3; AEP Initial Br. at 9-14, AEP Reply Br. at 64; OCC Initial Br. at 12-13; Staff Initial Br. at 3-6; IEU-OH Br. at 3-4). Shell argues the stipulations are not in the public interest (Shell Initial Br. at 9-10).

Based on our three-prong standard of review, we find that the first criterion, that the process involved serious bargaining by knowledgeable, capable parties, is met. Counsel for the applicant and the staff, as well as the numerous intervenors, have been involved in many cases before the Commission, including a number of prior cases involving rate issues. Further, there have been few settlements in major case before this Commission in which the overwhelming majority of intervenors either supported or did not oppose the resolution of issues presented by the stipulations.

The stipulations also meet the second criterion. The stipulated resolution of these proceedings advances the public interest by resolving the extensive and complex issues raised in this proceeding without incurring the extensive time and expense of litigation that would otherwise have been required. In the case of the ANM stipulation, it will defer to an already pending proceeding the debate of pole attachments. We believe that such an agreement is in the interest of bringing the bigger restructuring issues to the forefront for resolution so that competitive choice can effectively begin on January 1, 2001. For that reason, we believe that the ANM stipulation advances the public interest.

Adoption of the stipulations also reduce significantly the number of possible appeals, and provides additional lead time to put in place the mechanisms necessary to get the customer choice program up and running. Additional evidence that the public interest is served by the stipulations is found in the support offered by representatives of residential, commercial, and industrial customers, including OCC and the Commission's staff. As indicated above, the agreement provides that certain rates will be decreased and the prior rate plan freezes extended. Some of the stipulations' tangible benefits include:

(1) Freezing, for the most part, base distribution rates for an additional 2 years beyond the MDP for OP and three additional years beyond the MDP for CSP;

(2) Absorption by both companies of the first $40 million in consumer education, customer choice implementation, and transition plan filing costs;

(3) Providing an additional shopping incentive of 2.5 mills/kilowatt-hour to the first 25 percent of the CSP residential class load that switches during the MDP, with the unused portion being credited to the RTC;

(4) Providing assistance to transmission users with reservations, scheduling, and tagging for the period of time before AEP transfers control and operation, and ultimately ownership, of AEP's transmission facilities to an RTO;

(5) Accounting for partial megawatt-hours when load imports across AEP interfaces does not result in whole megawatt-hours;

(6) Providing a fund (up to $10 million) for reimbursement of certain transmission costs incurred by suppliers or customers;

(7) Requiring the companies to reduce charges to residential customers during the MDP by 5 percent of transition costs;

(8) Revising tariffs and schedules to equalize bill impacts within the commercial class;

(9) Providing additional commitments to resolve interface, seam, and reciprocity issues impacting transmission;

(10) Providing a credit to suppliers for consolidated bills during the first year of the MDP;

(11) Providing commercial and industrial customers only a 90-day advance notice of intent to switch suppliers;

(12) For the first 20 percent of OP residential customers on its standard service offer, charging no RTC when they switch between 2006 and 2007; and

(13) Negotiating with signatory marketers (as well as Shell) regarding a load shaping service.

(Jt. Ex. 1).

We believe that the terms of these agreements, considered in their totality, provide a sufficient basis for concluding that the settlement is in the public interest. Although it will undoubtedly take some time for a fully competitive electric retail market to develop, the stipulations presented in this proceeding provide an opportunity to "jump start" the market by providing the resources necessary for retail customers to begin to shop for competitive generation services. For all these reasons, we find that the stipulations should be approved, subject to the modifications and clarifications described above.

Finally, the stipulations meet the third criterion because they do not violate any important regulatory principle or practice. Indeed, the agreements balance the interests of a broad range of parties that represent a diverse spectrum of views. As indicated in the description of stipulations provided above, the stipulations provide substantial benefits to all customer classes and shareholders. Further, the policies of the state embodied in SB 3 will be implemented more quickly and efficiently than would otherwise be possible.

V. GROSS RECEIPTS/EXCISE TAX ISSUE

As part of their applications in these cases, the companies have included a public utilities excise tax credit rider. The companies intend that the credit rider become effective on April 30, 2002, the date on which the companies contend that ratepayer liability for the public utility excise tax ends. Prior to the effective date of the credit rider, the companies would collect through their respective rates an amount, which specifically represents the ratepayers' obligation for this tax. On the effective date of the public utilities excise tax credit rider, each of the companies will begin crediting back to their customers that amount included in their respective rates representing the public utilities excise tax. The parties opposing the companies with regard to this issue (staff, OCC, and IEU-Ohio) argue that the companies will have recovered this tax expenditure fully by April 30, 2001. Therefore, it is the position of these parties that the public utilities excise tax credit rider should become effective on April 30, 2001. As noted earlier, the parties signing the stipulation in this case have reserved this issue for Commission decision.

The companies note that the public utilities excise tax is popularly referred to as the "gross receipts tax". The companies state that, contrary to this popular usage, the tax is not a "gross receipts" tax, but an "excise" tax. That is, the tax is not a tax on the gross receipts of utility companies but an assessment on the particular utility company for the privilege of doing business in a particular year, referred to as the privilege year. The amount of the tax is determined by the gross receipts of the particular utility for the year immediately prior to the privilege year, referred to as the measurement year. Because the amount of the gross revenues is not determined until the end of the measurement year, the companies argue that it is not possible for the companies' customers to have paid the tax for a particular privilege year until after the measurement year has expired.

Earl Goldhammer, a witness for AEP, testified that SB 3 provides for the final year for which electric utilities will be liable for the public utility excise tax. Mr. Goldhammer further testified that, under SB 3, Ohio electric companies' final annual public utility excise tax reports will be filed on or before August 1, 2001. These reports are for the privilege year May 1, 2001 through April 30 2002. Mr. Goldhammer notes that the last public utility excise tax lien attaches on May 1, 2001. According to Mr. Goldhammer, the report each of the companies files will indicate that company's taxable gross receipts for the preceding twelve months-May 1, 2000 through April 30, 2001. The tax the Tax Commissioner assesses is 4.75 percent times the taxable gross receipts during the measurement period -- May 1, 2000 through April 30, 2001. In accordance with statutory law, in December 2001, any tax deficiency or refund based on the assessment will be paid by or to the companies (Tr. II, 8).

Mr. Goldhammer argues that AEP does not become exempt from the public utility excise tax until the end of the privilege year ending April 30, 2002. Further. Mr. Goldhammer states the companies' tax liability for the last privilege year is not fixed as the companies receive rate payments from customers during the May 1, 2000 - April 30, 2001 measurement period. The intent of the General Assembly that the electric companies' public utility excise tax obligation continues through April 30, 2002 is evidenced, Mr. Goldhammer concludes, by the manner in which the liability for the new corporate franchise tax was implemented. The companies contend that it is recognition of the fact that electric utilities will be paying the existing public utility excise tax for the privilege of doing business and owning property in Ohio through April 30, 2002, i.e. one third of the privilege year, that the payment the General Assembly requires for the 2002 franchise tax year equals only two-thirds of the tax liability for 2002. (*Id.* at 5).

As a corollary to the above arguments, the companies cite Section 4928.34(A)(6), Revised Code, as follows:

> To the extent such total annual amount of the tax-related adjustment is greater than or less than the comparable amount of the total annual tax reduction experienced by the electric utility as a result of the provisions of Sub. S.B. No. 3 of the 123rd General Assembly, such difference shall be addressed by the Commission through accounting procedures, refunds, or an annual surcharge or credit to customers, or through other appropriate

> means to avoid placing the financial responsibility for the difference upon the electric utility or its shareholders (Emphasis added.)

Because the companies are required to pay the public utility excise tax until April 30, 2002, they argue, it is clear that the Ohio General Assembly intended that their shareholders be held harmless for the amounts the companies owe after April 30, 2001.

In their brief, the companies note that Sections 5727.33(A) and (B), Revised Code, provide that the tax is based on "the entire gross receipts actually received from all sources", excluding receipts derived wholly from interstate commerce, from business done for or with the federal government, from the sale of merchandise, and from sales to other public utilities. AEP argues that not only are rentals and other operating and non-operating receipts includable gross receipts for purposes of calculating the public utility excise tax, but not all of the gross receipts from Ohio jurisdictional utility service derive from rates which are based, in part, on recovery of a test year level of that tax expense. William Forrester, a witness for the companies, testified that when the companies' electric fuel component (EFC) increases, that increase causes an increase in the companies' public utility excise tax expense, but there is no automatic change to base rates to compensate for this increased public utility excise tax expense (AEP Ex. 9D at 5). Consequently, the companies' note their EFC rates have fluctuated since a test year level of public utility excise tax was determined in their most recent base rate cases, there has been a breach in the relationship between gross receipts from jurisdictional service and any assumed amount that customers pay in their rates for this tax expense. The companies also argue that even the Staff recognized that the disconnect caused by EFC revenues has an impact on the companies' public utility excise tax obligation and is not built into base rates as part of the test year excise tax expense (Tr. II, 83, 114).

Finally, the companies cite this Commission's decision in the FirstEnergy transition plan cases for the proposition that this Commission has already determined this issue in the companies' favor. In AEP's view, the Commission adopted in *FirstEnergy, supra*, a stipulation pursuant to which the companies can recover from ratepayers amounts representing the public utilities excise tax through April 30, 2002.

For the most part, the three parties opposing AEP with regard to this issue, staff, OCC, and IEU-Ohio, find no fault with the facts as set forth above. These parties agree that the tax is not in reality a "gross receipts tax", but an excise tax. The parties also agree with the companies' description of the method used to determine and assess the tax. The parties agree that the tax is an appropriate expense in the privilege year. The parties further agree that the companies' public utility excise tax obligation continues through April 30, 2002. The parties agree to the above, but consider these matters irrelevant to the issue at hand. According to staff, OCC, and IEU-Ohio, the issue to be resolved by the Commission in these proceedings is the liability of the companies' ratepayers for payment of the public utility excise tax through April 30, 2002. These parties contend that the ratepayer's liability ends on April 30, 2001.

The issue as viewed by staff, OCC, and IEU-Ohio is primarily a question not of tax law, but of regulatory law. These parties, looking at the Commission's ratemaking process, argue that the ratepayers have paid through the rates charged by the companies in the "measurement year" amounts representing the companies' public utility excise tax obligation for the subsequent privilege year. That is to say, the companies' ratepayers have furnished the companies' monies in the year 2001 to reflect the companies' public utility excise tax obligation in the privilege year ending April 30, 2002. According to staff, if rates were intended merely to repay the companies for current expenditures for the public utility excise tax, all that would be required would be the inclusion of the current year's payments in the cost of service. The ratemaking treatment could have stopped at that point. It did not and so staff argues that the current payments for the tax were included in the cost of service calculation, but the revenue increase was also "grossed up" explicitly to reflect this tax. In fact, staff notes, the Commission, in arriving at the rate to be charged by a company seeking a rate increase, also calculates the "tax on tax" effect, i.e., the Commission recognizes that the revenues provided to a company to pay the gross receipts tax will themselves be subject to the tax (Staff Ex. 1, at 3). The Commission would not have made these calculations, staff argues, if the Commission's only concern was to recompense the company for the then-current (test year) tax expenditure since the test year tax expenditure was not affected by the increase. Nor, staff argues, did the Commission make these calculations to reflect the next year's tax expenditure since the increased revenues the companies enjoyed in first year after an increase did not have an impact on the companies' tax payments until the following year. Staff contends that because the rates are calculated to meet a company's cost of service and then grossed up to include the ultimate tax, the rates provide not the return of a fixed dollar value, but rather a percentage of whatever the revenues are. Each dollar, staff argues, includes the tax that will ultimately be owed. Staff concludes, therefore, that the ratepayers' tax obligation tracks the payments made dollar-for-dollar and in advance. Because the companies' revenues, grossed up to include the ultimate tax increase before the taxes increase, staff argues, it is clear, as a matter of fact, that ratepayers prepay this tax expense. OCC's analysis and conclusions with regard to this coincide with those of staff in regard to the ultimate merits of the companies' proposed specific recovery of the public utility excise tax obligation through a tariff rider. IEU-Ohio states that, on balance, it believes staff and OCC have the better of the argument.

Staff is not persuaded by the companies' arguments regarding the Commission's decision in the FirstEnergy transition plan cases. Staff notes that the *FirstEnergy* settlement is a so-called "blackbox" settlement. That is, FirstEnergy will obtain certain cash flows without agreement as to what those flows represent. In Staff's opinion, FirstEnergy could allocate more of these cash flows to excise taxes and lower its earnings or not. Staff is indifferent to FirstEnergy's choice because, as staff views the matter, there are no new monies extracted from the ratepayers and the "blackbox" settlement values are reasonable, in and of themselves, without any specific recovery of the public utilities' excise tax. However, staff notes, in the AEP situation, the companies seek additional cash flows from the ratepayers specifically for this excise tax. Staff opposes the companies recovering additional cash flows representing a specific recovery of this excise tax as a double recovery of this expense item.

OCC argues that the companies' position regarding base rates not fully recovering the gross receipts tax associated with fuel revenues or regarding base rates not always fully recovering gross receipts tax expenses are not relevant to the issue with regard to the date ratepayer funding of the Ohio gross receipts tax must cease. OCC notes there is no dispute that the tax expense embedded in base rates does not track changes in the companies' respective EFC-related revenues or that base rates do not always fully recover gross receipts tax expenses. However, if under-recoveries of the public utilities excise tax had been a serious problem over the years since the companies' last rate cases, OCC argues, they should have sought rate relief.

The issue-before us is purely one of fact, i.e., when does the liability of the companies' ratepayers for the public utility excise tax end. The companies' position is that the obligation of ratepayers to fund this tax ends on April 30, 2002. Staff's position with regard to this question is that ratepayers' obligation to fund the tax terminates on April 30, 2001. Of the two positions before us, the Commission finds staff's position to be the more reasonable. As staff argues the Commission's rate case process "grosses up" the revenues awarded in a rate proceeding to include the tax effect of the rate increase allowed by the Commission. Through the rate case process, the Commission even accounts for the increase in gross revenues caused by the tax itself, the so-called "tax on tax" effect. Thus, as argued by staff and OCC, the companies' customers pay in the measurement year amounts representing the companies public utilities tax obligation in the subsequent privilege year. For the purposes of illustration, assume that the measurement year for the public utilities excise tax is 2000 and the privilege year is 2001. If the Commission granted the companies a rate increase effective January 1, 2000, the ratepayers would be paying for the whole year of 2000, the measurement year, an amount that represents the companies' public utilities tax obligation for the privilege year of 2001. It is clear the ratepayers are not paying the companies' public utilities tax obligation for the privilege year of 2000 in 2000. The measurement year for privilege year 2000 is 1999. In 1999, the rate increase was not in effect.

We do not find the companies' arguments related to our adoption of the stipulation in the FirstEnergy transition plan cases to be relevant to the resolution of any issue before us in these cases. Stipulations are filed in a myriad of cases before this Commission for a number of different reasons. Sometimes a party is unsure how a particular issue will be resolved by the Commission so it will reach agreement with the other parties in the case on that issue, often giving up something in return, through the vehicle of a stipulation. Sometimes, in so-called "black box" stipulations, dollar figures will be agreed to and each of the parties may claim victory as to the same issue. Sometimes various issues are compromised just to reach settlement on issues vital to one or more of the parties. In adopting stipulations, the Commission views the stipulation as a whole; we do not, for the most part, dissect the document approving some pieces and rejecting others. If we find that the stipulation on balance is reasonable, we will generally adopt the stipulation. In making our determination, we use the three-part test delineated earlier.

In adopting the stipulation in the FirstEnergy transition plan cases, we were not passing favorably or negatively on the resolution of any particular issue contained in the stipulation. We found that the stipulation as a whole met the three-part and was reasonable. The case before us is the first case requiring a decision on the issue of ratepayer responsibility for a company's public utility excise tax obligation beyond April 30, 2001. Contrary to the arguments of the companies, our decision with respect to this issue in the cases now before us is not influenced by our decision in the FirstEnergy transition plan cases. Based upon the above findings, we are directing the companies to implement the public utilities excise tax credit rider in their respective transition plans to be effective April 30, 2001.

VI. FILED MOTIONS

A. Motions to Reject Transition Plans as Inadequate

On January 14 and 18, 2000, OCC and CCE each filed motions to reject the transition plans of AEP. Both argued that the plans should be rejected, pursuant to Section 4928.31(A), Revised Code, because the plans contain a number of substantive deficiencies that needed to be corrected and/or require plan refiling. Section 4928.31(A), Revised Code, grants the Commission authority to reject a plan or to require refiling in whole or in part of any substantially inadequate transition plan. Rule 4901:1-20-14, O.A.C., states that the Commission shall conduct an adequacy review of transition plan filings within 30 days and notify the utility of any inadequacies or if refiling is deemed necessary. If no ruling is issued in that 30-day period, the transition plan application is deemed minimally adequate. In these proceedings, the Commission did not require AEP to refile or notify it of inadequacies in the first 30-day period. Thus, by virtue of the rule, the transition plan applications were deemed minimally adequate. We, therefore, find that the motions to reject the transition plans were, in effect, already ruled upon (and denied).

B. OCTA Motion to Intervene and Subsequent Conditional Withdrawal

As noted earlier, the OCTA filed a motion to intervene in these proceedings on the ground that AEP proposed pole attachment tariffs that were improper. However, OCTA filed two days later a notice of conditional withdrawal of its intervention request, stating that, if the Commission accepts AEP's subsequent request to withdraw its originally proposed pole attachment tariffs, OCTA will withdraw its motion to intervene in these proceedings. OCTA stated grounds for intervention in these proceedings. Inasmuch as we accept AEP's withdrawal of its originally proposed pole attachment tariffs (by virtue of our acceptance of the proposed stipulations and AEP's withdrawal of new pole attachment provisions), we conclude that the condition precedent to OCTA's withdrawal from these proceedings has taken place and, therefore, we grant OCTA's withdrawal from these proceedings.

C. Motion for Protective Order

On December 30, 1999, as supplemented on January 18, 2000, AEP filed a motion for a protective order with respect to 70 pages of its transition plan filing. AEP filed the information under seal with our docketing division. AEP argues that the information is highly proprietary, competitively sensitive, and confidential. Additionally, the companies state that the information is a trade secret, as defined in Section 1333.61(D), Revised Code. They request a protective order, pursuant to Rule 4901-1-24(D), O.A.C., for the following:

(1) Three pages of the direct testimony of Edward Kahn (AEP Ex. 12, Attach. EPK-2). Those pages reveal: historic and forecasted operation and maintenance expenses by generating unit and a forecast of heat rates by generating unit.

(2) Projected emission allowance balances for the years ending 1999 and 2000 (AEP Ex. 2, Part F).

(3) Two attachments to the direct testimony of Oliver Sever (AEP Ex. 23, Attach. OJS-1 and OJS-2). Those pages address historic and forecasted fixed and variable operating and maintenance expenses by generating unit and projected fuel costs by generating unit.

(4) Study regarding customer switching (AEP Ex. 2, Part H).

At the hearing, the same information was placed into the record, as AEP Exhibit 4. We find AEP's motion for a protective order to be reasonable. In accordance with Rule 4901-1-24(F), O.A.C., our docketing Division shall maintain these items under seal for a period of 18 months from the date of this decision. Any party wishing to extend this confidential treatment should file an appropriate motion at least 45 days in advance of the expiration of the protective order.

D. Motion for Compliance Tariff Review Process

On June 27, 2000, CCE filed a motion for a "compliance tariff filing, service, review, and comment procedures" in these transition plan proceedings, as well as the other pending transition plan dockets. The motion states that, because of the broad-sweeping changes that will be subject to the provisions of the tariffs ultimately approved in these proceedings, it is necessary to allow interested parties adequate time to review and comment of the proposed tariffs prior to final approval. CCE requests that the Commission order each of the applicants in the transition plan cases to serve tariffs and associated workpapers simultaneous with their filing with the Commission. CCE asks that a two-week period be provided after the date of receipt of the tariffs and workpapers in order for intervenors to review the documents and submit comments to the Commission for its consideration prior to approval of the tariffs.

CCE's motion shall be granted, subject to modification. We believe that, instead of receiving formal filings with respect to FirstEnergy's compliance tariffs, a more informal process will be beneficial to all interested parties. Accordingly, the companies and other interested parties should observe the following timelines for distributing and reviewing AEP's proposed tariffs pursuant to this decision: (1) within 14 days following the issuance of this decision, AEP should distribute (via electronic mail, fax, or overnight delivery) to all intervenors a working draft of its proposed compliance tariffs, as well as associated workpapers and UNB schedules that reflect the rates embodied in the compliance tariffs; (2) within 14 days thereafter, interested parties should circulate (via electronic mail, fax, or overnight delivery) comments to AEP and the staff regarding the working draft[31]; and (3) within 14 days thereafter, AEP shall formally file its proposed tariffs in the form of an application for approval of compliance tariffs.

Finally, to the extent any other motions or objections have been raised and they were not directly addressed above, they are denied.

31 Neither the working draft nor the informal comments are to be filed formally in the dockets of these proceedings.

FINDINGS OF FACT AND CONCLUSIONS OF LAW:

(1) On December 30, 1999, CSP and OP filed transition plan applications, as well as applications for receipt of transition revenues. AEP supplemented those filings on January 14 and February 28, 2000.

(2) A technical conference was conducted on January 10, 2000, and preliminary objections were filed on February 10, 11, 14 and 15, 2000.

(3) A procedural/settlement conference was conducted on March 3, 2000. On March 28, 2000, the Staff Report of Exceptions and Recommendations was filed. AEP made a supplemental filing on April 18, 2000 in accordance with the attorney examiner's directive. A second prehearing conference was conducted on April 28, 2000.

(4) Intervention was granted to a number of parties. On May 8, 2000, a Stipulation and Recommendation was filed by AEP, the Commission staff, APAC, Columbia Energy companies, Enron, NewEnergy, WPS, Exelon, IEU-Ohio, Kroger, MAPSA, NEMA, OCC, OCRM, OHA, OPAE, OREC, Strategic, WSOS, ODOD, and OMA. The stipulation purports to resolve all issues in these proceedings, except for one issue related to AEP's proposed gross receipts/excise tax rider. Dynegy and OEC later stated that they do not oppose the stipulation.

(5) Evidentiary hearings were conducted on May 9 and 31 and June 7, 8, and 12, 2000. Local public hearings were held on June 5, 2000, in East Liverpool and on June 22, 2000, in Columbus, Ohio. AEP filed proof of the newspaper notices it provided for the filing of the transition plan applications and for the public hearings, in accordance with Commission directives.

(6) On June 19, 2000, AEP and ANM filed a second settlement agreement in these dockets.

(7) AEP's transition plans, as modified by the settlement agreement described above, satisfy the 15 prerequisites set forth in Section 4928.34(A), Revised Code, to the extent set forth herein.

(8) Under the stipulations, CSP can recover $191,156,000 as transition costs during the MDP. OP can recover $425,230,000 as transition costs during the MDP.

(9) The stipulations provide appropriate shopping incentives to achieve a 20 percent load switching as contemplated by Section 4928.40(A), Revised Code.

(10) AEP's transition plans, as modified by the settlement agreements, satisfies the requirements of SB 3, and are approved for the reasons and to the extent set forth herein.

(11) Our docketing division shall maintain the items filed under seal on January 18, 2000, and AEP Exhibit 4 for a period of 18 months from the date of this decision. Any party wishing to extend this confidential treatment should file an appropriate motion at least 45 days in advance of the expiration of the protective order.

ORDER:

It is, therefore,

ORDERED, That AEP's transition plans and the settlement agreements filed on December 30, 1999 and May 8, 2000, respectively, are approved, to the extent set forth herein, and subject to final approval of AEP's compliance tariffs. It is, further,

ORDERED, That the tariff amendments and accounting authority requested by AEP are approved in accordance with the discussion set forth in this Opinion and Order. It is, further,

ORDERED, That CCE's motion for a compliance tariff review process is granted in part. AEP and other interested intervenors shall follow the timelines for informal review and comments with respect to the companies' compliance tariffs, and AEP shall file an application for approval of compliance tariffs in accordance with the directives set forth in this Opinion and Order. It is, further,

ORDERED, That AEP's request for a protective order is granted. It is, further,

ORDERED, That our Docketing Division shall maintain the items filed under seal on January 18, 2000, and AEP Exhibit 4 for a period of 18 months from the date of this decision. Any party wishing to extend this confidential treatment should file an appropriate motion at least 45 days in advance of the expiration of the protective order. It is, further,

ORDERED, That OCTA's request to intervene and subsequent request to withdraw from these proceedings are granted. It is, further, ORDERED, That a copy of this Opinion and Order be served upon all parties of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Ronda Hartman Fergus

Craig A. Glazer – Abstain – Not Voting

Judith A. Jones

Donald L. Mason

GLP/SJD;geb

Entered in the Journal
SEP 2 8 2000

A True Copy

Gary E. Vigorito
Secretary

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Continuation of the Rate Freeze and Extension of the Market Development Period for the Monongahela Power Company.	))))	Case No. 04-880-EL-UNC

OPINION AND ORDER

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The Commission, coming now to consider the application, testimony, and other evidence presented in this proceeding, hereby issues its opinion and order.

APPEARANCES:

Mr. Gary A. Jack, 1310 Fairmont Avenue, Fairmont, West Virginia 26555-1392, and Porter, Wright, Morris & Arthur, by Mr. Daniel R. Conway and Ms. Kathleen M. Trafford, 41 South High Street, 30th Floor, Columbus, Ohio 43215, on behalf of the Monongahela Power Company.

Jim Petro, Attorney General of the State of Ohio, Duane W. Luckey, Senior Deputy Attorney General, Public Utilities Section, by Mr. Thomas McNamee and Mr. Thomas Lindgren, Assistant Attorneys General, 180 East Broad Street, 9th Floor, Columbus, Ohio 43215-3793, on behalf of the Staff of the Public Utilities Commission of Ohio.

Janine L. Migden-Ostrander, Ohio Consumers' Counsel, by Ms. Ann M. Hotz and Mr. Jeffrey Small, 10 West Broad Street, Columbus, Ohio 43215-3485, on behalf of the Residential Consumers of the State of Ohio.

McNees, Wallace & Nurick, LLC, by Samuels C. Randazzo and Mr. Sean Urvan, Fifth Third Center, Suite 1700, 21 East State Street, Columbus, Ohio 43215, on behalf of the Industrial Energy Users-Ohio.

Mr. David C. Rinebolt, Executive Director and Counsel for Ohio Partners for Affordable Energy, 231 West Lima Street, P.O. Box 1793, Findlay, Ohio 45839, on behalf of Ohio Partners for Affordable Energy.

I. HISTORY OF THE PROCEEDINGS

On June 22, 1999, the Ohio General Assembly passed legislation requiring the restructuring of the electric utility industry and providing for retail competition with regard to the generation component of electric service (amended Substitute Senate Bill No. 3 of the 123rd General Assembly, referred to hereafter as SB 3). On January 3, 2000, Monongahela Power Company (Mon Power or Company) filed an application for approval of its electric transition plan (ETP) in Case No. 00-02-EL-ETP. On October 5, 2000, the Commission approved a Stipulation and Recommendation submitted to the Commission by Mon Power, the Commission's Staff (Staff), and various other parties to the proceeding, which established a ETP for Mon Power.

On April 24, 2003, Mon Power filed an application under Case No. 03-1104-EL-ATA (03-1104) seeking approval of a market-based standard service offer (MBSSO) and a competitive bidding process (CBP) to comply with Section 4928.14, Revised Code, which governs establishment of rates for generation service subsequent to the end of the market development period (MDP). Mon Power proposed to issue a Request for Proposal (RFP) for generation service as part of its CBP.

By entry on July 24, 2003, the Commission issued a Finding and Order in 03-1104, finding, among other things, that only the RFP portion of the Mon Power application could proceed at that time. Mon Power's RFP was limited to its large commercial, industrial and street lighting customer classes (C&I customers).

On October 8, 2003, Mon Power filed a motion for approval and expedited treatment of its application in 03-1104. Mon Power stated that the lowest and winning bid was submitted by Allegheny Energy Supply Company, LLC (AE Supply). Mon Power submitted that AE Supply is an unregulated affiliate of Mon Power and primarily is in the business of generation of electric power for the wholesale market.

On October 22, 2003, the Commission issued a second Finding and Order in 03-1104, finding, among other things, that Mon Power's April 24, 2003 application to modify its generation rates beginning January 1, 2004, should be denied, given that neither condition prescribed by Section 4928.40(B)(2), Revised Code, for early termination of the MDP, had been met.[1] Accordingly, Mon Power's market development period was to remain in place until December 31, 2005, or until Mon Power could demonstrate, through a subsequent application, that it has met either of the conditions set forth in Section 4928.40(B)(2), Revised Code. On November 21, 2003, Mon Power timely filed an application for rehearing in 03-1104 raising seven assignments of error. Industrial Energy Users-Ohio (IEU-Ohio), on November 21, 2003, filed an application for rehearing requesting a clarification of the Commission's October 22, 2003 Order in 03-1104.

On December 17, 2003, the Commission issued an Entry on Rehearing in 03-1104 denying Mon Power and IEU-Ohio's applications for rehearing, and finding, among other things, that some of Mon Power's arguments actually go to the constitutionality of provisions of SB 3 that enacted electric restructuring legislation. Accordingly, if Mon Power believed that establishment by SB 3 of a MDP under Section 4928.40, Revised Code, and the caps placed on retail unbundled rates under Sections 4928.34 and 4928.35, Revised Code, were unlawful or unconstitutional, those were issues beyond the Commission's jurisdiction. See *The East Ohio Gas Co. v. City of Cleveland*, 137 Ohio St. 225, 28 N.E.2d 599 (1940). Additionally, with regard to Mon Power's argument that the Commission erred in not establishing a MBSSO as Section 4928.14, Revised Code, requires, the Commission modified its October 22, 2003 Order to reflect that the docket should remain open so that it can review the company's application to establish a MBSSO and CBP. Further, considering the current state of competition in Mon Power's service territory, the Commission encouraged the company to modify its initial

1 The Commission is authorized by this statute to issue an order permitting an earlier termination date if 20 percent of the utility's load has switched electric generation suppliers or if it finds that effective competition exists in the utility's territory.

application to provide for a rate stabilization plan for the Commission's consideration as other electric utilities have done.

On February 13, 2004, Mon Power filed its Notice of Appeal to the Supreme Court of Ohio, under Case No. 04-0305, based on the Commission's October 22, 2003 Order in 03-1104 and the December 17, 2003 Entry on Rehearing denying its request for rehearing in that case. The record of that case was transmitted to the Supreme Court of Ohio on March 15, 2004, and oral arguments heard before the Court on October 26, 2004. Supreme Court Case No. 04-0305 is still pending.

On February 2, 2004, Mon Power filed a Complaint for Declaratory and Injunctive Relief and a Motion for Preliminary Injunction in the United States District Court for the Southern Division of Ohio, Eastern Division (District Court), in Case No. C2-04-084. Mon Power filed this action against the commissioners of the Public Utilities Commission of Ohio (PUCO). Mon Power raised two separate, but related, constitutional claims against the commissioners. In Count One, Mon Power asserted that the PUCO has unlawfully prevented it from recovering, through retail rates chargeable to C&I customers, the wholesale power rates approved by the Federal Energy Regulatory Commission (FERC), consequently violating the federal "filed-rate" doctrine. Because the Supremacy Clause of the Constitution provides that federal law, if constitutionally enacted, supersedes state law, Mon Power submitted that the actions of the PUCO are unconstitutional.

In Count Two, Mon Power contended that the provisions of SB 3 are unconstitutional in requiring a rate freeze for a five-year period. Mon Power asserted that the rates it is permitted to charge are so low as to constitute a confiscatory taking of private property, in violation of the Due Process Clause of the Fourteenth Amendment. Mon Power requested a declaration that certain provisions of SB 3 are unconstitutional because they provide no mechanism for utilities to demonstrate a need for higher rates. As part of the relief sought, Mon Power requested "a remand to the PUCO with instructions directing the Commissioners to determine if the [frozen] rates chargeable are unconstitutionally confiscatory."

On May 19, 2004, the District Court issued its Opinion and Order concerning Mon Power's motion for preliminary injunction, which was granted under Count Two and denied under Count One as moot.[2] The District Court noted that SB 3 included a rate-freeze provision[3] which, under binding precedent from the United States Supreme Court and the Sixth Circuit Court of Appeals, must fail if no provision is made for consideration by the PUCO of a claim that a frozen rate is confiscatory. Further, Mon Power, as an Ohio public utility, is required to provide electric services to Ohio customers within its service area during the transition period established under SB 3. The District Court found that "the rate freeze is unconstitutional only to the extent that it

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2 *See Monongahela Power Co. v. Alan R. Schriber, et al.*, 322 F. Supp. 2d 902, 917; 2004 U.S. Dist. LEXIS 11739 (May 19, 2004 Opinion and Order).

3 *See* Ohio Revised Code § 4928.40, *et seq.*

fails to provide a mechanism by which the PUCO may review claims by utilities that rates are confiscatory."[4] Further, the District Court found that "it is for the PUCO . . . to determine, after appropriate fact finding, whether such claims have merit." The PUCO was directed to "consider *all relevant provisions* of the Ohio Restructuring Act—including tax reductions, transition fees and other benefits to Mon Power—to determine whether the rates, together with these beneficial provisions of law are confiscatory."[5]

The District Court, however, "did not find that the fixed rates for electricity during the transition period are confiscatory as a matter of law or that Mon Power has or has not recovered the costs of wholesale energy in the retail rates" it is permitted to charge its C&I customers. The District Court stated that "[t]hese matters are to be determined by the PUCO." The District Court also found that the PUCO must address whether Mon Power's Power Sales Agreement (PSA) with AE Supply, which Mon Power claims expired by its terms on December 31, 2003, is still in full force and effect, as part of considering and adjudicating Mon Power's claims that the frozen rates are confiscatory.[6]

By its Entry on Remand issued June 9, 2004, the Commission ordered that Mon Power file an application for hearing on whether its frozen rates are confiscatory and whether Mon Power's PSA with AE Supply is still in effect. Further, Mon Power was ordered to submit, with its application, prefiled testimony and to provide any financial information in support of its claims. On June 16, 2004, IEU-Ohio filed a motion to intervene and a memorandum in support.

On June 18, 2004, Mon Power filed its application in this matter. The application seeks authority to amend Mon Power's filed Electric Service schedules to increase the rates for approximately 70 C&I customers located in the Ohio area served by Mon Power.[7] Further, Mon Power's application seeks approval to apply a retail surcharge to its C&I customers that would enable it to recover the difference in price between the power it purchases for those customers beginning January 1, 2004, and the frozen unbundled generation rate for those customers established in Mon Power's electric transition plan, Case No. 00-02-EL-ETP. On June 28, 2004, Mon Power supplemented its application with prefiled testimony of three witnesses and supporting exhibits.

On June 30, 2004, the Ohio Consumers' Counsel (OCC) filed a motion to intervene and memorandum in support. An amended motion was filed on July 1, 2004.

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4 Specifically, the court found that Sections 4928.34(A)(6), 4928.35(A) and 4928.40, Revised Code, are unconstitutional to the extent the PUCO may not examine whether the frozen rates are confiscatory. Further, the court emphasized that this finding leaves the remainder of the Ohio Restructuring Act intact. *See Schriber*, 322 F. Supp. 2d 920, 922-23.

5 *Id.*

6 *Id.* at 920.

7 These customers are defined as those customers on Rate Schedules C (with a demand greater than 300 kilowatt), D, K, P, and CSH.

By entry on July 15, 2004, the Attorney Examiner issued a procedural schedule for this matter, which included a prehearing conference set for August 9, 2004. The entry also granted IEU-Ohio's motion to intervene and ordered Mon Power to publish notice of the evidentiary hearing set for August 31, 2004.

By entry July 28, 2004, the Commission ordered, among other things, an amended procedural schedule that included an expedited timeframe for discovery in this proceeding. By this entry, the Commission granted the motion of OCC to intervene for the limited purpose of addressing issues that directly affect residential customers, should such issues arise during this proceeding.

On July 27, 2004, Ohio Partners for Affordable Energy (OPAE) filed a motion to intervene and a memorandum in support. OPAE also filed a motion to admit David C. Rinebolt to practice *pro hac vice* before the Commission in this proceeding. By entry issued on September 20, 2004, the Attorney Examiner granted OPAE's motion for admission of David C. Rinebolt *pro hac vice*. By the same entry, OPAE's motion to intervene was granted for the limited purpose of addressing issues that directly affect OPAE members or residential customers, should such issues arise during this proceeding.

A prehearing conference was held on Monday, August 9, 2004, at the offices of the Commission. A local public hearing was held as scheduled in Marietta on September 23, 2004, at Washington State Community College. The testimony was mainly directed to the economic impact of an increase in rates for Mon Power's large commercial and industrial users and for street lighting. The witnesses also requested that the Commission consider a rate stabilization plan to help the customers absorb the impact of any rate increases.

The hearing on the application commenced on September 29, 2004, and continued through October 5, 2004. On October 8, 2004, Staff filed supplemental direct testimony and Mon Power and IEU-Ohio filed rebuttal testimony. The hearing reconvened on October 12, 2004, to hear the supplemental and rebuttal testimony.

Post hearing briefs were filed on October 22, 2004, and reply briefs were timely filed on November 2, 2004. Letters from consumers and other interested groups, expressing opposition to Mon Power's application, have been filed in the docket of this case.

II. UNITED STATES COURTS REMAND ORDER

On May 19, 2004, the District Court issued its Opinion and Order concerning Mon Power's motion for preliminary injunction, which was granted under Count Two and denied under Count One as moot. In its May 19, 2004 Opinion and Order, the District Court acknowledged several important jurisprudential principles that bear on the relief sought by Mon Power. First, the "rates chargeable to consumers of electricity are the primary responsibility of state government under a longstanding statutory scheme enacted by Congress." Second, the District Court stated that utility regulation is "highly complex and traditionally entrusted in the first instance to an administrative agency, such as the PUCO." Third, "statutory enactments involving utility regulation, such as the Ohio Restructuring Act, contain many components. Modification or elimination of one part of the Ohio Restructuring Act may adversely impact the unitary system enacted by the Ohio Legislature."[8] Last and "most importantly, decisions of the PUCO are reviewable under Ohio law by the Ohio Supreme Court." The District Court stated that it was "most reluctant to permit a bypass" of the review by the Ohio Supreme Court.[9]

The District Court noted that the Ohio Restructuring Act included a rate-freeze provision[10] which, under binding precedent from the United States Supreme Court and the Sixth Circuit Court of Appeals, must fail if no provision is made for consideration by the PUCO of a claim that a frozen rate is confiscatory. The District Court also noted that Mon Power, as an Ohio public utility, is required to provide electric services to Ohio customers within its service area during the transition period established under SB 3. Further, the District Court stated that Mon Power "cannot, consistent with the Constitution, be required to provide such service and in return receive a rate that is confiscatory, that is a rate that does not permit recovery of actual costs together with a fair return."[11]

The District Court granted relief under Count Two of Mon Power's Complaint, which Mon Power submitted as an alternative remedy. Count Two sought declaratory and injunctive relief for alleged violations of the Due Process Clause of the Fourteenth Amendment. As part of its claim, Mon Power requested a remand to the Commission with instructions directing the Commissioners to determine if the rates chargeable are unconstitutionally confiscatory.[12]

In determining whether to grant the preliminary injunction, the District Court considered whether Mon Power has shown a strong likelihood of success on the merits of its Due Process claim regarding the rate freeze during the transition period to competition. The District Court noted that "state-imposed regulatory price controls, as a general matter, are presumptively constitutional so long as they are not 'arbitrary, discriminatory, or demonstrably irrelevant to the policy the legislature is free to adopt.'"[13] The District Court also noted that due to the mandatory obligation for public utilities to provide service within a geographic area, "the regulated utilities must be permitted to charge rates that are 'just and reasonable.'"[14] Further, "to preserve the Due

8 "Ohio Restructuring Act" refers to SB 3.

9 *See Schriber*, 322 F. Supp. 2d 902, 905; 2004 U.S. Dist. LEXIS 11739 (May 19, 2004 Opinion and Order).

10 *See* Ohio Revised Code § 4928.40, *et seq.*

11 *See Schriber*, 322 F. Supp 2d at 906.

12 *Id.* at 917.

13 *See Schriber*, 322 F. Supp. 2d at 918, citing *In re Permian Basin Area Rate Cases*, 390 U.S. 747, 769-70 (1968) (citations omitted).

14 *Id.*

Process Clause of the Fourteenth Amendment, state-prescribed rates must allow a utility to recover its costs with a reasonable rate of return on the value of the property being used by the state to provide a public service."[15] The District Court identified the criteria for "just and reasonable compensation" established by the Supreme Court:

> The guiding principle has been that the Constitution protects utilities from being limited to a charge for their property serving the public which is so "unjust" as to be confiscatory. *Covington & Lexington Turnpike Road Co. v. Sandford,* 164 U.S. 578, 597, 17 S.Ct. 198, 205-206, 41 L.Ed. 560 (1896) (A rate is too low if it is so unjust as to destroy the value of [the] property for all the purposes for which it was acquired," and in doing so "practically deprive[s] the owner of the property without due process of law"); *FPC v. Natural Gas Pipeline Co.,* 315 U.S. 575, 585, 62 S.Ct. 736, 742, 86 L.ED. 1037 (1942) ("By long standing usage in the field of rate regulation, the 'lowest reasonable rate' is one which is not confiscatory in the constitutional sense"); *FPC v. Texaco Inc.,* 417 U.S. 380, 391-392, 94 S.Ct. 2315, 2392, 41 L.Ed.2d 141 (1974) ("All that is protected against, in a constitutional sense, is that the rates fixed by the Commission be higher than a confiscatory level"). If the rate does not afford sufficient compensation, the State has taken the use of the utility property without paying just compensation and so violated the Fifth and Fourteenth Amendments.

Duquesne Light Co. v. Barasch, 488 U.S. 299, 307-08 (1989).[16]

Last, the District Court noted the Court of Appeals for the Sixth Circuit, in *Michigan Bell Tel. Co. v. Engler,*[17] "recently addressed a due process claim that is virtually indistinguishable in all material respects from Mon Power's claim here."[18] In *Michigan Bell,* the court reviewed a public utility deregulation scheme that froze local telephone rates during a three-year, eight-month transition period, "unless the Michigan Public Service Commission determined that a requisite number of customers had switched providers or that the rates then charged were demonstrably competitive."[19] The Sixth Circuit held in *Michigan Bell* that "[t]he Due Process Clause requires a mechanism through which a regulated utility may challenge the imposition of rates which may be confiscatory."[20] Based on this ground, the Sixth Circuit determined that the section at

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15 *Id.* citing *Michigan Bell Tel. Co. v. Engler,* 257 F.3d 587, 593 (6th Cir. 2001).

16 Under the Fifth Amendment of the U.S. Constitution, private property may not be "taken" by the federal government without just compensation. The Fifth Amendment is applicable to the states through the Due Process clause of the Fourteenth Amendment.

17 *See Michigan Bell,* 257 F.3d at 593 (6th Cir 2001).

18 *See Schriber,* 322 F. Supp. 2d at 919.

19 *See Michigan Bell,* 257 F.3d at 593-94.

20 *Id.* at 594.

issue in the Michigan statute "was constitutionally deficient because it did not 'include any provisions which adequately safeguard against imposition of confiscatory rates.'"[21]

The District Court stated the relief afforded in its May 19, 2004 Opinion and Order was designed to be narrow in recognition of the jurisprudential principles that it acknowledged. The District Court found that "the rate freeze is unconstitutional only to the extent that it fails to provide a mechanism by which the PUCO may review claims by utilities that rates are confiscatory."[22] Further, the District Court found that "it is for the PUCO . . . to determine, after appropriate fact finding, whether such claims have merit." The District Court, however, "did not find that the fixed rates for electricity during the transition period are confiscatory as a matter of law or that Mon Power has or has not recovered the costs of wholesale energy in the retail rates" it is permitted to charge its large commercial and industrial customers. "These matters are to be determined by the PUCO."[23]

In its case before the District Court, Mon Power contended that the previous PSA with AE Supply expired by its terms on December 31, 2003 for C&I customers. The District Court also found that the PUCO must also address whether the PSA is still in full force and effect, as part of considering and adjudicating Mon Power's claims that the frozen rates are confiscatory.[24]

The District Court agreed with the Commission's argument that the rate is not confiscatory if "other benefits of the Restructuring Act exceed the economic harm cause by the rate freeze."[25] The District Court, quoting *Duquesne Light Co. v. Barasch*, stated: "'[i]t is not the theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unreasonable, judicial inquiry . . . is at an end.'"[26] The District Court further noted that "if the combined effect of all aspects of the Restructuring Act provides Mon Power with a rate which is not confiscatory, the rate freeze is not unconstitutional."

The District Court, in its May 19, 2004 Opinion and Order, emphasized that "its determination that the rate freeze provisions are unconstitutional for failing to provide a mechanism by which a utility may present a confiscation claim leaves the remainder of the Restructuring Act intact."[27] Further, the District Court noted that in the absence of the rate provisions, the Commission still has authority to set rates charged by Mon Power to its large commercial and industrial consumers through Section 4905.04, Revised Code, which vests the Commission "with the power to regulate electric utility

21 *Id.*

22 *See* n.2 *supra*; *Schriber*, 322 F. Supp. 2d at 919-20, 923.

23 *Id.* at 920-21, 923.

24 *Id.* at 920, 923.

25 *Id.* at 920-21.

26 *Id.*

27 *Id.* at 920.

companies," and Section 4909.15, Revised Code, "which directs and authorizes the Commission to fix and determine rates."

In its determination of whether Mon Power's frozen rates are confiscatory, the Commission is to "weigh and analyze all component parts of the Restructuring Act and to determine the overall effect on revenues" for Mon Power following the enactment of electric restructuring.[28] The PUCO was directed to "consider all relevant provisions of the Ohio Restructuring Act—including tax reductions, transition fees and other benefits to Mon Power—to determine whether the rates, together with these beneficial provisions of law are confiscatory."[29] Last, the District Court directed the Commission "to exercise its residual authority to set rates and determine whether the rates chargeable by Mon Power are confiscatory."[30]

Mon Power subsequently filed a motion for expedited reconsideration of the District Court's May 19, 2004 Opinion and Order. Mon Power contended, first, that the Commission does not have the authority to determine whether the Power Supply Agreement between Mon Power and its affiliate supplier, Allegheny Energy Supply Company, LLC, is enforceable under Ohio contract law. Second, Mon Power contended that its claim under the filed-rate rate doctrine is not moot and must be adjudicated by the court.

On June 14, 2004, the District Court issued its Opinion and Order regarding Mon Power's motion for expedited reconsideration. The District Court found "that the precise argument made by Mon Power is correct and that the language of the Opinion erroneously directed the PUCO to exercise authority" that it "arguably does not possess."[31] The District Court stated that it was "the Court's intention that the PUCO engage in its traditional role of considering all relevant costs and expenditures made by Mon Power in setting a rate which is not confiscatory (citations omitted)."[32] The District Court noted that "the PUCO has always had the authority to disallow any unreasonable expenditures which did not ultimately benefit electric-power customers."[33] The District Court modified its May 19, 2004 Opinion and Order to state: "the PUCO is directed to engage in rate-making activities as described both in this Order and the Court's previous Opinion and Order. Rather than determine whether the Power Supply Agreement [PSA] is still in effect, the PUCO shall instead exercise its traditional rate making authority to determine whether reasonable costs incurred in the purchase of wholesale power result in a rate which may be confiscatory." The District Court also retained jurisdiction over Count One of Mon Power's Complaint, its claim under the federal filed-

28 *Id.* at 921.

29 *Id.* at 906.

30 *Id.* at 920.

31 *See Schriber*, 322 F. Supp. 2d at 902, 923; 2004 U.S. Dist. LEXIS 16895 (June 14, 2004).

32 *Id.* at 924.

33 *Id.*

rate doctrine, pending further decision of the PUCO.[34] The District Court also recognized the PUCO's ability to conduct what is termed a *Pike County* analysis. *See Pike County Light and Power Co. – Elec. Div. v. Pennsylvania Pub. Util. Comm'n,* 77 Pa. 268, 465 A.2d 735 (1983). The District Court stated "the PUCO has the authority to determine whether cheaper alternatives of wholesale power were available to Mon Power. If this Court were to simply grant the relief requested by Mon Power under Count One, it would effectively deprive the PUCO of its *Pike County* discretionary authority."[35]

III. POSITIONS OF THE PARTIES AND THE COMMISSION'S DETERMINATION REGARDING WHETHER MON POWER'S C&I RATES ARE CONFISCATORY

At the hearing in this proceeding, Mon Power, Staff, and IEU-Ohio put forth testimony supporting their positions regarding the issue of whether Mon Power's C&I rates are confiscatory. Each party has taken a different approach in formulating its position on whether Mon Power's rates for C&I customers are confiscatory. Set forth below are the positions of these parties and the Commission's review and consideration of the arguments raised by the parties regarding whether Mon Power's rates established in its ETP proceeding and any benefits received from SB 3 are insufficient to permit Mon Power to recover its validly incurred costs with a reasonable rate of return on the value of the property being used to provide electric service. If the established rates and other benefits of SB 3 do not afford sufficient compensation for Mon Power to recover its validly incurred costs with a reasonable rate of return, then the rates are confiscatory and the State has taken the use of utility property without paying just compensation, which violates the Fifth and Fourteenth Amendments of the United States Constitution. See *Duquesne Light Co. v. Barasch,* 488 U.S. 299, 307-08 (1989) (hereafter *Duquesne*); *Pacific Gas and Electric Co. v. Lynch,* 216 F. Supp. 2d 1016 (N.D. Cal. 2002) (hereafter *PG&E v. Lynch*); and *Michigan Bell Tel. Co v. Engler,* 257 F.3d 587, 593 (6th Cir.2001).

As noted earlier, the District Court in *Schriber* remanded the issue of whether Mon Power's frozen rates imposed under SB 3 are confiscatory. The District Court directed the Commission to "engage in its traditional role of considering all relevant costs and expenditures by Mon Power in setting a rate which is not confiscatory." Further, the District Court stated that "In the course of such analysis, the PUCO has always had the authority to disallow any unreasonable expenditure which did not ultimately benefit electric-power customers" and directed the Commission to use its traditional rate-making authority to consider whether the pass-through of costs incurred under the power supply agreement is permissible (*Schriber,* June 14, 2004 Order at 3).[36]

34 *Id.* at 925.

35 *Id.*

36 *See* 322 F. Supp. 2d 902, 924; 2004 U.S. Dist. LEXIS 16895.

A) Mon Power's Position

Mon Power presented its confiscation claim through Company witnesses Howells and Menhorn. Ms. Menhorn testified to the magnitude of Mon Power's underrecovery of its wholesale power costs and the lack of any offsetting benefits to Mon Power from SB 3 (MP Exs. 2, 3). Mr. Howells testified as to the effect of these losses on Mon Power's ability to earn any return on investment in 2004 or 2005 (MP Ex. 1). Mon Power also provided the testimony of Company witnesses Reeping, Mader, and Blankenship, who testified to Mon Power's efforts to obtain power to meet its default service obligations in Ohio during the years since the start of competition in Ohio (MP Exs. 5, 6, 7). Mon Power argues through this testimony that the current rates being paid by C&I customers in Ohio are constitutionally confiscatory because they do not allow Mon Power to recover its actual wholesale costs, and there are no offsetting benefits to Mon Power from SB 3 or its delivery business in Ohio to compensate for these losses and allow Mon Power to earn a constitutionally minimal rate of return.

As background, Mon Power witness Menhorn testified that the Company transferred its generation assets to its affiliate, AE Supply, at net book value as set forth in the ETP Stipulation (MP Ex. 3, at CAM-1, p. 5). The transfer of these generation assets was supported by the Commission Staff and IEU-Ohio, as signatories to the ETP Stipulation (*Id.* at 15). Mon Power argues that the Commission approved the transfer of the Ohio generation assets to an affiliate, Allegheny Energy Supply, LLC (AE Supply), and made an express finding that such transfer complied with the statutory corporate separation requirements. Mon Power contends that its transfer of 352 megawatts (MW) of Ohio jurisdictional generation assets to AE Supply is in conformity with the requirement in SB 3 that there be structural separation of its generation assets from its transmission and distribution assets pursuant to Section 4928.17(A), Revised Code. Mr. Mader testified that because Mon Power transferred its Ohio jurisdictional generation assets to AE Supply in June 2001, it no longer owns generation assets with which it can supply power to meet its default generation service obligations in Ohio. Consequently, it must purchase power at wholesale. (MP Ex. 6, at 21-29.)

Mon Power also asserts that, with the approval of its ETP stipulation, it had a reasonable belief that the MDP for its C&I customers ended on December 31, 2003. It argues that IEU-Ohio and all other interested parties to its ETP stipulation had agreed to the early termination of the MDP for Mon Power's C&I customers. Mon Power also notes that the Commission subsequently approved Mon Power's compliance tariff, which established December 31, 2003 as the end of the MDP for Mon Power's C&I customers (MP Ex. 3, at CAM-3A, CAM-3-B). Mr. Mader testified that the PSA, which requires AE Supply to supply generation to Mon Power's Ohio customers during the MDPs, was only in effect for C&I customers through December 31, 2003, and continued for the other customer classes through December 31, 2005, when the MDP for those customers expires (MP Ex. 7, at 4 & MP Ex. 6, at 27-38). The price for generation under the PSA was $24.24 per megawatt hour (MWh), which represents the weighted average rate volume times price for residential, small commercial, large commercial and industrial, and special contract customer Eramet, whose contract expired in September of 2004 (MP Ex. 6, at 30, 38). In conjunction with the PSA, Mon Power entered into a Facilities Lease Agreement (FLA) with AE Supply that involved the leaseback to Mon Power of 247 MW of generating assets that had been transferred to AE Supply as part of the transfer of Mon Power's Ohio generation assets. Mon Power witnesses testified that the sole purpose of the FLA is to avoid the double taxation associated with West Virginia's Business and Occupation Tax that otherwise would be imposed, once, on generation capacity located in West Virginia owned by AE Supply and, again, on sales to consumers by Mon Power. Mon Power asserts that the FLA was not intended to create any additional rights or liabilities beyond those created in the PSA. (Tr. I, at 143-147; Tr. II, at 134; Tr. III, at 121; MP Ex. 10, at 9-10.)

During the period June 1, 2001 through December 31, 2003, Mon Power contends that, through the PSA, AE Supply sold power to Mon Power to provide default service to its C&I customers at rates that were well below the market rates AE Supply could have received through the sale of this generation to third parties. The Company asserts that purchasing power at prices based on the frozen retail rates enabled Mon Power to recover its actual costs through the frozen rates. Mon Power's position is that, since January 1, 2004, it has not been permitted to recover its actual costs for purchasing wholesale power to serve its C&I customers through the frozen retail rates paid by these customers (MP Ex. 2, at CAM-6). Mon Power argues that the current frozen rates, therefore, are presumptively unconstitutional. Mon Power witness Menhorn has forecasted the magnitude of the underrecovery of its purchased power costs to be $16.4 million in 2004 and $28.2 million in 2005. This is based on projected purchased power costs of $47.45 per MWh for 2004 and $47.38 per MWh for 2005 (MP Ex. 1 at 4 & MP Ex. 3, at CAM-6).

Company witness Howells also provided testimony regarding Mon Power's electric operations for calendar year 2003. The Company contends that 2003 Mon Power Ohio operations produced a net operating income of $4.8 million utilizing an average rate base of $59.3 million, resulting in an overall rate of return of 8 percent (MP Ex. 1, at JRH-1). The Company's position is that it will be operating at a significant loss in 2004 and 2005 if the Commission does not grant some relief by way of a surcharge to cover the higher cost of purchased power to serve C&I customers.

Mon Power also contends that SB 3 did not provide any benefits to Mon Power that may be applied to offset the losses due to the underrecovery of its wholesale power purchase costs. Company witnesses Menhorn testified that the cost of purchased power under the PSA was actually slightly higher than the generation revenues received by Mon Power in each year from 2001 through 2003. Therefore, Mon Power claims there were no offsetting profits that Mon Power earned during that period from the sale of retail generation service that could be used to offset projected losses in 2004 and 2005. Further, Ms. Menhorn stated that Mon Power realized no gain on the transfer of generation assets at book value to offset losses resulting from its inability to recover purchased power costs (MP Ex. 3, at 15-16). Mr. Howells also testified that the .08 cent per kWh regulatory asset transition charge that could be imposed on shopping customers did not provide any benefit to the Company inasmuch as no customers have shopped (MP Ex. 11, at 6).

Mon Power also argues that the generation it continues to own and operate is to meet the service requirements of its West Virginia customers. Company witness Howells testified that, to the extent that there are opportunities to sell excess energy from these remaining assets, the net revenues from such sales would be properly included in future West Virginia remaking determinations for the benefit of those customers (MP Ex. 11, at 8-9).

Lastly, Mon Power asserts that there is no source of supply that would allow Mon Power to purchase wholesale power at rates that could be recovered through the currently frozen retail rates. The Company argues that no unaffiliated supplier will supply power to Mon Power at wholesale rates at or near the currently frozen retail rates. Mon Power refers to the results of Mon Power's 2003 and 2004 RFPs to purchase power. Mon Power witness Blankenship testified that both RFPs produced bids that were substantially higher than the frozen rates. The 2003 RFP produced two conforming bids with AE Supply providing the lower bid. The Commission issued an order on October 22, 2003 rejecting the bid.[37] Mon Power's 2004 RFP conducted in March of 2004 produced bid prices even higher than the 2003 RFP (MP Ex. 7, at 6-11). Mon Power argues that because the Commission denied Mon Power's motion for approval of the winning bid from the October 2003 RFP process, Mon Power had no viable option other than to purchase power on the PJM spot market to satisfy its default service. Mon Power asserts that the rates Mon Power currently is paying for wholesale power purchased from AE Supply are competitively determined and approved by the FERC.

Based on all the arguments set forth above, Mon Power asserts that providing service to the C&I customers at the current frozen rates is confiscatory. The Company is proposing to implement a Purchased Power Recovery Surcharge (PPRS) to its C&I customers for the difference in price between the power it purchases for these customers and the unbundled generation rate established through the ETP. The proposed PPRS would include costs incurred by Mon Power to purchase capacity, energy, and ancillary services over and above the unbundled generation rate. Since actual purchased power costs won't be known until the following month's books are closed, Mon Power proposes that customers be billed on forecasted costs and that an account be established to track any over- or underrecovery of actual costs. Such over- or underrecovery would be reconciled to insure dollar-for-dollar recovery and passed through to customers on a two-month calendar lag basis. The Company is also requesting a recovery factor to recover those costs from the beginning of 2004 to when the PPRS is implemented (MP Ex. 3, at 16-17).

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[37] *In the Matter of the Application of the Monongahela Power Company for Approval of a Market-Based Standard Service Offer and Competitive Bidding Process*, Case No. 03-1104-EL-ATA, Finding and Order (Oct. 22, 2003) and Entry on Rehearing (Dec. 17, 2003).

Mon Power has put forth a straight-forward argument in support of confiscation. It states that its net operating income for 2003 amounts to $4.8 million constituting an approximate 8 percent return (MP Ex. 1, at JRH-1). With all other things being constant, Mon Power argues that the addition of $44.6 million of projected purchased power costs in 2004 and 2005 to serve the needs of C&I customers through the PJM spot market would make it impossible for the Company to recover it costs of providing service and a reasonable rate of return under the current rates. Mon Power argues that it used the most economical option available to it to provide generation to the C&I customers after 2003 inasmuch as the PSA had expired with regard to these customers at the end of 2003.

The Staff and IEU-Ohio do not support the Company's approach. Staff has taken the position that the best way to determine if Mon Power's rates are confiscatory is to look at Mon Power's costs and revenues for the last year prior to restructuring when it owned and operated generating plants to serve Ohio customers. IEU-Ohio argues that the Company's approach fails to consider all the benefits Mon Power and other Allegheny Energy, Inc. (AE) affiliates obtained through electric restructuring. Staff's and IEU-Ohio's positions are set forth in more detail in subsequent sections of this order.

IEU-Ohio also disagrees with Mon Power's argument that it was not entitled to purchase power under the PSA for C&I customers after 2003. Its position is that the language in the PSA permits Mon Power to purchase power for "Default Service" obligations through 2005.

The Commission finds two problems with Mon Power's approach. First, it is a rather limited focused approach inasmuch as it compares actual and projected purchased power costs for 2004 and 2005 with the unbundled generation rates for these customers established in the ETP. As noted by the case law cited above, this Commission's review is to consider the total effect of Mon Power's rates. As stated by the District Court, if the combined effect of all aspects of SB 3 provides Mon Power with a rate which is not confiscatory, the rate freeze is not unconstitutional. See *Schriber*, May 19, 2004 Opinion and Order at 29, citing to *Duquesne* at 310; and *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944). The argument has been made by Mon Power that it was not practical under the timeframe in which the Commission needed to act in this matter to perform a full-blown rate case analysis. However, without all the traditional information that is filed as part of a rate case filing, it is difficult to ascertain the total effect of the frozen rates. Staff witness Fortney showed, through his cost-of-service study, that there may be higher revenue returns from residential and small commercial customers that would offset lower revenue returns from C&I customers. See Staff Ex. 6, at Revised RBF II. Additionally, IEU-Ohio has raised several issues regarding the benefits that Mon Power and its affiliates have obtained from SB 3, most notably Mon Power's transfer of generation assets to AE Supply at book value. IEU-Ohio's arguments are addressed more fully below. Mon Power approach does not recognize these offsetting factors in its analysis of confiscatory rates.

The second problem the Commission has with Mon Power's approach concerns the Company's foundational premise for its argument that its current rates are confiscatory. The premise being that it had no ability to supply its C&I customers with generation through the PSA after December 31, 2003. Mon Power witness Mader, who "negotiated" the PSA for Mon Power with AE Supply, testified that the intent of the contract was that it would expire for C&I customers on December 31, 2003, and that AE Supply was under the same understanding (MP Ex. 6, at 30-38). Mon Power argues that that intent was consistent with its ETP stipulation, the Commission's ETP Order, and its tariffs approved by the Commission. Mr. Mader testified that the intent of the PSA was to fulfill the terms of the ETP stipulation and that the stipulation contemplated the end of the MDP for C&I customers on December 31, 2003. (Tr. III, at 89-90; MP Ex. 6, at 27-30.) To support its arguments, Mon Power states that the price of power supplied by AE Supply from 2001 through 2005 increased in 2004 which reflects that C&I customers are no longer served at capped rates under the ETP stipulation after 2003. (MP Ex. 6, at 30-36.)

The Commission understands Mon Power's position that it believes the PSA expired at the end of 2003 for its C&I customers. However, there is a major difference between Mon Power's position and the position of the other parties to this proceeding and the Commission as to whether the MDP for C&I customers ended on December 31, 2003. We believe that the answer to whether the MDP for C&I customers ended on December 31, 2003 has a major impact on whether the PSA should have ended for these customer at the end of 2003. The issue of the end of the MDP is currently before the Supreme Court of Ohio in Case No. 04-0305, with arguments conducted on October 26, 2004. The Commission's determination that the MDP has not ended for these customers has been fully discussed in our October 22, 2003 Finding and Order in 03-1104 and argued before the Ohio Supreme Court.

The Commission recognizes that, pursuant to the District Court's ruling in *Schriber*, we are without authority to make a determination, as between Mon Power and AE Supply, that the PSA is still in effect for C&I customers.[38] Mon Power and AE Supply have agreed that the contract has expired for Mon Power's Ohio C&I customers. However, the District Court recognized the Commission's ability to determined if Mon Power's actions in the cancellation of the contract and in the use of spot-market purchased power costs to supply power to C&I customers is reasonable and prudent. Such a review has been permitted by this District Court as well as various Federal District Courts citing the so-called "Pike County exception" to the federal filed-rate doctrine. The exception was described by the Federal Court in *PG&E v. Lynch* as follows:

> Finally, the court must consider defendants' claim to the right to conduct a review of the prudence of PG&E's wholesale purchases, under the so-called "Pike County exception," which receives it name from a Pennsylvania state court decision: *Pike County Light & Power Co. v. Pennsylvania Pub. Util. Comm'n, 77 Pa. Commw. 268, 465 A.2d 735 (Pa. Commw.*

[38] *See Schriber*, 322 F. Supp. 2d at 902, 924.

> *Ct. 1983).* Under the Pike County exception, state commissions are not prevented from conducting a review of a utility's purchasing options and may disallow wholesale costs, when setting or adjusting retail rates, that were imprudently incurred. "The Supreme Court has never squarely decided the question of whether imprudence is an escape hatch from [a] Commission's otherwise existing obligation to respect FERC's authority to determine the just and reasonable rate. But the Court has twice said that it would assume arguendo that such escape hatch existed; the Third Circuit has so held; and FERC has concurred, citing prior cases of its own." Patch V, *167 F.3d at 35, citing MP&L, 487 U.S. at 373-74; Nantahala, 476 U.S. at 972; Kentucky W. Va. Gas Co. v Pennsylvania Pub. Util. Comm'n, 837 F.2d 600, 609 (3d Cir. 1988); Palisades Generating Co, 48 F.E.R.C. P61, 144 at 61, 574 and n. 10 (1989).* The First Circuit must also be added to this list.

(216 F. Supp. 2d 1016, 1050.)

The Commission has reviewed the provisions of the PSA. The agreement acknowledges that Mon Power maintains "Default Service" obligations in its Ohio franchised service territory and desires to purchase electric energy and capacity through this agreement with AE Supply (MP Ex. 6, at 1C, Original Sheet No. 1). "Default Service" according to the PSA "means AP's [Mon Power's] obligation to provide generation service to all retail customers within its Ohio Jurisdiction, according to statutory and regulatory requirements as well as the ETP settlement less any amounts of such obligation as AP may have satisfied through a selection of an alternative power supplier pursuant to that settlement" (*Id.* at Original Sheet No. 2). The agreement provides that AE Supply will provide Mon Power firm power, through any means available including purchases, in amounts equal to the "Contract Quantity" as specified in the agreement. Under the provision addressing "Contract Quantity," the agreement states that AE Supply will be responsible to meet all Default Service Schedules provided by Mon Power that meet the notification guidelines of the Mon Power Control area operator and AE Supply (*Id.* at Original Sheet No. 5). The PSA also states that the "Transition Period" shall be from January 1, 2001 through December 31, 2005, and that the term of PSA shall commence June 1, 2001, and shall remain in effect through the Transition Period, except for service to special contract customer Eramet Marietta, Inc. (*Id.* at Original Sheet Nos. 5, 8, 13).

Reviewing Mon Power purchasing options under the circumstances of this case and the PSA, we find that Mon Power has acted imprudently by purchasing generation through the PJM spot market to serve C&I customers. From a review of the PSA provisions cited above, it is clear to the Commission that Mon Power could have received power from AE Supply for C&I customers under the terms of contract. The determining language in the agreement centers around the definition of Default Service and AE Supply's obligation to meet all Default Service Schedules provided by Mon Power. As stated above, Default Service is the generation service provided to all retail customers within Mon Power's Ohio Jurisdiction, according to statutory and regulatory requirements as well as the ETP settlement. In our October 22, 2003 Finding and Order in 03-1104, we clearly stated that Mon Power could not end its MDP for C&I customers at the end of 2003 because the statutory requirements of Section 4928.40(B)(2), Revised Code, had not been satisfied.[39] With no early termination of the MDP, Mon Power retained its statutory obligation under SB 3 to supply generation to C&I customers under fixed rates. Further, Default Service is not only defined by the approved ETP settlement but is also defined by statutory requirements. The Default Service obligation in the PSA is defined in terms of statutory requirements "as well as" the ETP settlement. The use of the language "as well as" recognizes two distinct obligations under which Mon Power is required to serve its Ohio customers and under which it is entitled to purchase power from AE Supply under the PSA. We also believe these findings are consistent with the basic intent of the contract which was to ensure that Mon Power had adequate power to fulfill its obligations under SB 3 and the ETP with, for the most part, power priced at the level of the Shopping Credits established by this Commission (MP Ex. 6, at 16, 26, & 1C, Original Sheet No. 11). To quote from Mr. Mader's testimony:

> We had been given a fixed price obligation on which we had to deliver. And my primary concern was just making sure we had sufficient power to meet the obligation that allowed us to continue to provide the service at capped rates.

(Mon Power Ex. 6, at 23.)

While parties could debate whether Mon Power was entitled to receive power from AE Supply under the ETP settlement provisions, it is clear that Mon Power was entitled to do so under its ongoing statutory obligation to provide power to C&I customers. Consequently, Mon Power could have, and should have, enforced its rights under the PSA to receive power for C&I customers under the definition of Default Service through the end of 2005. It chose not to. Assuming arguendo that the terms of the PSA did not provide power for C&I customers after 2003, the Commission would seriously question whether Mon Power acted prudently when it entered into the agreement. Given Mon Power's concern about providing service under capped rates quoted above, it would have been imprudent for Mon Power to enter into an agreement that did not provide power to meet its obligations to C&I customers at capped rates under all circumstances.

We are not persuaded by Mon Power's arguments that it relied on its belief that the ETP provided for the end of the MDP in 2003 for C&I customers. First of all, the Commission's order approving an ETP for Mon Power cannot be construed to approve actions beyond the authority granted by SB 3. As has been cited to the Commission so often, the Commission is a creature of statute and has only those powers given to it by the legislature. Secondly, it is hard to believe that Mon Power, based upon its understanding of SB 3, did not appreciate the risk that its MDP might not end for C&I customers at the end of 2003. Section 4928.40(B)(2), Revised Code, was cited in the Commission's ETP Order as well as Ms. Menhorn's testimony. (Tr. I, at 207-208; MP Ex. 3, at 5-6.) Staff witness Hess also testified on this subject. When asked on cross-

39 *See* n.1 *supra.*

examination if anyone on Staff communicated to Mon Power during the June 2000 to 2001 period that there was even a possibility that the MDP for C&I customers would not end at the end of 2003, Mr. Hess stated:

> Yes, I think everybody understood that to some extent, based upon the criteria in the statute, it was a risky – there was risk associated with ending the market development period, and I did have those conversations with the company.

(Tr. V, at 136-137.)

We are also not persuaded by Mon Power's argument that AE Supply's weighted average price for power specified in the PSA substantiates its claim that the contract was not meant to cover C&I customers after 2003. Mon Power argues that the contract specifies the weighted average price for power in years 2001, 2002, and 2003 to be \$24.24/MWh. However, Mon Power asserts that, with the end of service to C&I customers under the PSA, the weighted price changes for the remaining customers to \$23.95/MWh for the first 3 Quarters of 2004, and increases to \$32.93/MWh thereafter (MP Ex. 6, at 1C, Original Sheet Nos. 12, 13). Mon Power argues that the change in weighted average prices supports its argument that the contract contemplated the expiration of service for C&I customers at the end of 2003. The Commission finds that the prices specified in the PSA do not alter the fact that other contract provisions entitle Mon Power to receive power for C&I customers after 2003 as discussed above.

Further, Mon Power's choice to end the PSA with AE Supply for C&I customers was, not only imprudent, it shows a lack of arm's length negotiation with AE Supply. Mr. Mader negotiated the PSA for Mon Power, with Dave Benson negotiating on behalf of AE Supply (MP Ex. 6, at 22-23). However, Allegheny Power (the trade name for Mon Power) and AE Supply do not have any employees. The work performed for Allegheny Power and AE Supply is performed by employees of the Allegheny Energy Service Corporation (AESC), another affiliate under the umbrella of AE, the parent company of Mon Power and AE Supply. (Tr. I, at 135; MP Ex. 6, at 11; and Tr. III, at 110.) In addition, the record shows that there is considerable commingling of the corporate officers of Mon Power and the various other affiliates of AE. (IEU Exs. 14, 15). Further, as set forth in our discussion of AE's business model and the transfer of generation assets to AE Supply below, it is hard to believe that, in practice, AE and its affiliated companies operate in a manner other than what is in the best interest of AE's operations as a whole. Had Mon Power had its and its customer's best interest in mind, it would have enforced the provisions of the PSA that allowed Mon Power to cover power supplies for default service through 2005.

Using the cost of power purchased through the PSA, there is no evidence to support a finding that Mon Power rates are confiscatory. To the contrary, the Company's own testimony shows that, for the year 2003, when the PSA was in effect for all customer classes, Mon Power earned an overall rate of return of 8 percent based on a net operating income of \$4.8 million (MP Ex. 1, at 3 & JRH-1). The Commission further finds our determination that Mon Power's frozen rates are not confiscatory, under the *Pike County* exception, also addresses the issue raised by Mon Power concerning the federal filed-rate doctrine.

B) Staff's Position

In the Staff's view, the most reasonable way to approach the question of whether Monongahela's property might have been confiscated as a result of the SB 3 rate freeze is to consider what rates the Company might have sought had the rate freeze not existed (Staff Ex. 5, at 8). Staff argues that this approach is essentially a rate case analysis emulating the results of a rate increase case that, but for the SB 3 rate freeze, might have been available to Mon Power in 2003. It is Staff's belief that a review of Mon Power's rates under traditional ratemaking standards will assure Mon Power that its property is not confiscated, despite electric restructuring. According to Staff, if the utility's rates are too low to offer a reasonable opportunity to achieve a reasonable return on investment, the analysis would identify the amount by which the rates would need to be adjusted to address the problem.

The Staff used the year 2000 annual report that Monongahela filed with the Commission to obtain revenue and expense information. Staff noted that annual reports for 2001 and 2002 were available but could not be used because those annual reports did not include any generation-related amounts which Mon Power transferred to AE Supply on June 1, 2001. Staff contends that the year 2000 data, although older, included generating plant costs which are pivotal to providing a fair opportunity for return to Mon Power. Staff witness Hess stated that the income statements in the 2000 annual report are for the 12 months ended December 31, 2000, and the balance sheets are based on a valuation at December 31, 2000 (Staff Ex. 5, at 9).

Mon Power's data for the year 2000 reflect costs and investment for Mon Power as a whole, including those costs and investment necessary to support the Company's operations, both gas and electric, in West Virginia. Staff argues that it was necessary to utilize a variety of allocation factors to separate the Ohio-related costs and investment from the various other activities included in the Mon Power aggregate. Staff witness Hess testified that the 2000 balance sheet and income statement data were allocated to the Ohio jurisdiction based on demand, energy, number of customers, labor, and direct assignment. The allocation factors for demand, energy, and number of customers were based on 2003 statistics. The labor and direct assignments were based on 2000 statistics. (*Id.*) The Staff's preference was to use current information when possible, and would have preferred to use 2003 generation cost and investment data in its analysis, had such data been available.

After making certain corrections to his prefiled testimony relating to opportunity sales revenues and pass-through revenues, Mr. Hess calculated Mon Power's Ohio jurisdiction total operating revenues to be $75,572,764 and total operating expenses to be $65,564,906 for the 12 months ending 2000 (Staff Ex. 6, at Second Revised JEH 1). This resulted in a net operating income of $10,007,858 (*Id.*). Mr. Hess also calculated Mon Power's Ohio jurisdictional rate base to be $87,432,676 as of December 31, 2000 (*Id.*).

After arriving at revenue and expense data and a rate base, Mr. Hess applied Staff witness Cahaan's rate of return recommendation. Staff witness Cahaan calculated a rate of return, looking at all debt, whether short or long term or even preferred stock, as a block. He used a risk premium approach to evaluate the cost of capital for AE as well as for Mon Power separately. For Mon Power, Mr. Cahaan calculated a weighted average cost of equity of 12.5 percent and a 6.81 percent cost of debt resulting in an overall cost of capital of 8.9 percent. For AE, Mr. Cahaan calculated a weighted average cost of equity of 15 percent and an 8.75 percent cost of debt, resulting in an overall cost of capital of 10.24 percent. Mr. Cahaan recommended the use of a 9.5 percent rate of return to determine if Mon Power's rates were confiscatory, finding that the overall costs of capital for Mon Power and its parent formed a range within which a reasonable return could be found (Staff Ex. 3, at 5, 6). Applying the net operating income to the rate base, Mr. Hess arrived at a rate of return earned by Mon Power's Ohio jurisdiction of 11.45 percent. Staff believes that Mon Power earned $1,701,754 above Staff's recommended rate of return of 9.5 percent (Staff Ex. 6, at Second Revised JEH 1).

Staff also presented the testimony of Staff witness Fortney who performed a simplified cost-of-service study to determine a revenue requirement by customer class. Based upon the revised data used by Staff witness Hess, Mr. Fortney calculated that residential and small commercial customers provide approximately $9.6 million more than their revenue requirement, while the larger commercial and industrial customers under Rate Schedule P and customer under special contract were contributing $8.5 million less than their revenue requirement (Staff Ex. 6, at Supplemental Revised RBF II). Mr. Fortney did note, however, that the service data provided by the Company was for the 12-month period ending December 2003 and, therefore, it did not create a perfect match with the revenue requirement calculation performed by Staff witness Hess who used the 2000 income statement and the December 31, 2000, balance statement (Staff Ex. 4, at 3). The end result of the Staff's review is that the overall rates of Monongahela are not confiscatory.

In addition to the Staff's analysis above, Staff reviewed Mon Power's calculated under-recovered purchased power expenses for 2004 and 2005 for C&I customers. Staff witness Tufts performed a purchased power comparison for costs incurred by Mon Power for January through May 2004 with those presented by Ms. Menhorn (Staff Ex. 2B). Mr. Tuft's purchased power cost calculations vary only by $1,653 from Ms. Menhorn's approximate figure of $8.1 million. (Tr. V, at 9, 82.) Mr. Tuft also had no significant disagreement with Ms. Menhorn's forecasted purchased power costs for the remainder of 2004 and 2005. (Tr. V, at 10-11.)

As discussed earlier, Staff's approach to determine if Mon Power's current rates are confiscatory involved a rate case analysis emulating the results of a rate increase case that, but for the SB 3 rate freeze, might have been available to Mon Power in 2003. This approach was supported by IEU-Ohio and OPAE. Under its approach, Staff determined that Mon Power's overall rates were not confiscatory. Staff believes that the current rates give AE a return of its expenses and a reasonable return on the investment it has in the Ohio operation of its subsidiary, Mon Power, including those generation assets formerly owned by Mon Power which have been transferred to AE Supply (Staff Ex. 6, at 2).

There are several problems with Staff's approach as argued by Mon Power. One problem, as Staff itself concedes, is the mixing of the year 2000 balance sheet and income statement data with 2003 allocation factors. Mon Power argues that Staff's analysis applies 2003 allocation factors for rate base, revenues, and expenses to 2000 test-year data. The Company contends that a correct application of the test-year concept requires a matching of all inputs. Staff argues that it used the most up-to-date information available when possible. Staff recognized that using 2003 generation production costs would have been preferable, but states that Mon Power did not possess this information. Staff also conceded that changes in the data from 2000 to 2003 would affect the results of its analysis. (Tr. VI, at 13-15.)

A bigger problem with Staff's approach is that it does not reflect the way Mon Power is structured today. Staff performs a simplified rate case analysis, as if Mon Power still owns generation assets designated to serve its Ohio load, as opposed to the reality of the situation that Mon Power purchases power for its Ohio customers through the PSA and now on the spot market. The Company transferred, in 2001, its generation assets allocated to its Ohio load as part of its approved ETP to comply with the structural separation requirements of Section 4928.17(A), Revised Code (*See* ETP Order at 6). The Commission does not believe it is reasonable to determine whether current rates are confiscatory based on an assumption or supposition that Mon Power owns generation to serve its Ohio customers. Staff also assumes that the cost of producing power in 2004-2005 from these generation assets as well as all other costs of service would be same in 2004-2005 as they were in 2000.

The Commission also notes that there was much discussion at the hearing involving Staff's accounting of Mon Power's Sales for Resale and Off-System Opportunity Sales for 2000. IEU-Ohio, in cross-examination of Staff Witness Hess, pointed out what it believed to be accounting errors in Staff's analysis regarding the allocation of costs and revenues from off-system sales, which Staff corrected in its supplemental testimony (Staff Ex. 6). However, Mon Power takes issue with Staff's allocation of a share of the benefits from off-system sales that Mon Power makes from its West Virginia jurisdictional generating assets, which the Company argues should go to West Virginia customers. The Commission finds that the arguments relating to off-system sales emphasize one of the shortcomings of the Staff's approach in using 2000 data. As argued by Mon Power, these sales have little relevance to Mon Power's Ohio operations after it transferred its Ohio generation assets in 2001 to AE Supply. After 2001, Mon Power's Ohio operations owned no generation (with the exception of a small amount from Ohio Valley Electric Corporation (OVEC), from which to make off-system sales.

We recognize that Staff was attempting to make a good faith effort to ascertain the cost to provide service to Mon Power's Ohio customers and to determine whether those costs can be recovered under the current rate structure. However, the Commission finds Staff's approach does not appropriately reflect the current state of operations for Mon Power. With respect to its Ohio jurisdiction operations, Mon Power does not have own generation assets but receives power through purchased power agreements. Additionally, expense and revenue requirements from 2000 may not accurately reflect economic operating conditions today. Consequently, we cannot afford much weight to Staff's analysis in our determination of whether current rates are confiscatory.

C) IEU-Ohio's Position

IEU-Ohio presented its case through witnesses Robert C. Smith and J. Bertram Solomon. Mr. Smith testified as to whether Mon Power has properly presented its financial operating results for its Ohio operations for the test year ending December 31, 2003. Mr. Smith also testified as to whether the 2003 financial results, as presented or as corrected, serve as a proper gauge to measure against the 2004 and 2005 increases in purchased power costs claimed by Mon Power (IEU-Ohio Exs. 29, 29A). Mr. Solomon testified as to whether Mon Power's current rates are confiscatory (IEU-Ohio Exs. 30, 30A).

IEU-Ohio contends that Mon Power failed to satisfy its burden of proof since it did not offer clear and convincing evidence that the rates established by SB 3 are confiscatory. IEU-Ohio further contends that Mon Power's confiscation analysis is flawed for several reasons that will be discussed in more detail below. Last, IEU-Ohio submits that Mon Power's confiscation claim cannot be sustained in view of the traditional cost-of-service analysis submitted by the Commission's Staff as supplemented by IEU-Ohio's expert witnesses.

1. Data provided to the Commission

IEU-Ohio submits that Mon Power failed to provide the Commission with the information required to evaluate the rates established by SB 3 based on a traditional regulation approach, as specified by Judge Sargus in *Schriber*. IEU-Ohio contends that Mon Power elected "to take a short cut" in the data that it chose to provide to the Commission and that short cut caused Mon Power to, among other things, not include in its revenue data "the allowance that Mon Power received for transition costs" in the ETP. (Tr. I, at 204-205.) After a review of the evidence presented in this case, we find that Mon Power did not provide the Commission with the traditional cost-of-service data that is necessary to perform a complete rate case analysis. Rather, the Company focused on the cost of power from the spot market to determine whether its rates are confiscatory.

2. Mon Power's Risk analysis

IEU-Ohio argues that Mon Power's claim that it did not appreciate the risk that the MDP for its large commercial and industrial customers might not end on December 31, 2003, is contrary to Mon Power's description of its understanding of the law in 2000. (Tr. I, at 207-208.) This claim also is in direct conflict with the testimony of Mr. Hess offered during Mon Power's cross-examination of Mr. Hess, in which he stated that he had conversations with the company that, based upon the criteria in the statute, there would be risks associated with trying to end the MDP early. (Tr. V, at 136-138.) IEU-Ohio contends that if the Commission's decision, to not let the MDP end early, is viewed as a change in law or regulation, this possibility was addressed in the PSA. (Tr. III, at 90-94; IEU Ex. 4, at Original Sheet No. 23, Article 18.6.) After a review of the evidence presented, including the terms of PSA, we find that Mon Power was aware that the MDP for its large C&I customers might not end on December 31, 2003.

3. Allegheny Energy, Inc.'s Business Model

IEU-Ohio contends that it is not possible to appreciate the full significance of Mon Power's confiscation claim without an understanding of AE's business plan, organizational structure, and its objective to become a national energy player that brought AE, Mon Power's parent, to the brink of bankruptcy. IEU-Ohio submits that AE's investments in unregulated businesses were enabled by the regional generation strength provided by the transfer of generation assets from its regulated businesses such as Mon Power's utility operations in Ohio. (Tr. III, at 27-33; IEU Ex. 25D, at 5.)

IEU-Ohio submits that AE reorganized in anticipation of electric deregulation into three principal business segments: regulated utility operations, unregulated generation operations, and other unregulated operations. IEU-Ohio asserts that Mon Power is one of three regulated electric public utility companies in the regulated utility operations segment. (Tr. I, at 50.) Mon Power also does business as Allegheny Power (*Id.* at 46), but has no employees. (*Id.* at 135; IEU Request for Admissions 101.) The unregulated generation operations segment consists primarily of AE Supply and includes Allegheny Generating Company (AGC). IEU-Ohio contends that AE Supply also has no employees, which Mon Power witness Mader confirmed (Tr. III, at 110), and since 1999, AE Supply and their affiliates have had common officers (IEU Exs. 14, 15).

IEU-Ohio asserts that AE Supply was established as an unregulated energy company to develop, own, operate and control electric generating capacity and, through its energy and marketing trading division, to supply and trade energy and energy-related commodities in domestic retail and wholesale markets, including sales to AE's regulated business units, such as Mon Power. IEU-Ohio further asserts that AE Supply was given the responsibility to operate the generating assets owned by Mon Power. (Tr. II, at 163-164.)

IEU-Ohio contends that the transfer of the "low cost," "legacy" generating assets from the operating companies like Mon Power was part of AE's plan to grow the business of AE Supply and the earnings of AE. (Tr. III, at 44; IEU Ex. 25E, at 8.) IEU-Ohio further contends that AE Supply made representations to the investing public in March 2001, prior to the transfer of Mon Power's generating assets to AE Supply, and in November 2001 that the POLR contracts[40] provided AE Supply with financial stability and stable and predictable cash flows. (IEU Ex. 25E, at 11, 13; IEU Ex. 25F, at 9.)

IEU-Ohio submits that AE Supply's representations to the investing public in April 2002 indicated that its average POLR revenue from West Penn, Potomac Edison, and Mon Power was $29.5/MWh, its average generation cost was $16.8/MWh, and its average margin was $12.7/MWh, and its total POLR margin was $411.5 million (IEU Ex. 25G, at 12). IEU-Ohio contends that this information indicates that neither AE Supply nor AE were behaving in 2001 and 2002 as though the default supply contracts between Mon Power and AE Supply could, or would, be viewed as obstacles to the successful implementation of AE's business plan to become a national energy player. IEU-Ohio submits that AE and AE Supply's behavior indicated, rather, that the default supply contracts between AE Supply and each of its affiliate operating utilities, including Mon Power, were valuable and provided a financially stable foundation from which AE's business plan was launched.

IEU-Ohio asserts that AE clearly understood that the POLR arrangements between AE Supply and its affiliated operating companies presented business and financial risks. IEU-Ohio contends that AE demonstrated that understanding as it described the business and financial risks in the AE 2002 10-K, at 22:

> In connection with regulations governing the transition to market competition, West Penn, Monongahela with respect to its Ohio customers, and Potomac Edison (together, the P[O]LR Companies) are required to provide electricity at capped rates to retail customers who do not choose an alternate electricity generation supplier and to those who return to utility service from alternate suppliers. The P[O]LR Companies' capped rates may be below current market rates through the transition periods. We have structured our operations so that AE Supply owns the generating assets that were previously owned by the P[O]LR companies. The capped rates reflect the historical costs of operating and maintaining AE Supply's generating assets. The P[O]LR Companies satisfy their P[O]LR obligations by sourcing power from AE Supply under long-term power sales agreements. Those agreements provide for the supply of a significant portion of the P[O]LR Companies' energy needs at the mandated capped rates with a specified remaining portion priced on the basis of market prices. The amount of

[40] "POLR" or "provider of last resort" contracts are the power sales agreements (PSAs) between AE Supply and AE's electric distribution utilities, such as Mon Power. These contracts provide default service to electric customers who do not shop for another electric generation supplier, or for electric customers who return to the electric distribution utility for generation supply.

> supply priced at market rates increases of over each contract term. Power to be supplied by AE Supply under these agreements amounts to the majority of AE Supply's normal operating capacity....
>
> These power supply agreements present risks for both AE Supply and the Distribution Companies [POLR Companies]. At times, AE Supply may not be able to earn as much as it otherwise could by selling power otherwise priced at capped rates into competitive wholesale markets. Conversely, the P[O]LR Companies may at times pay market prices for a portion of their supply that exceed the amount they can charge retail customers for the power. Also, the demand for power required to meet the P[O]LR contract obligations could exceed AE Supply's available generation capacity, which may require AE Supply to buy power at prices that are higher than the sale price in the P[O]LR contracts. Although AE Supply believes it currently owns or controls sufficient capacity to meet aggregate P[O]LR contract demand, there may intermittently occur periods of peak demand that exceed AE Supply's available capacity. These periods of peak demand often occur when the market price for power is very high. A shortage of available capacity could be further exacerbated by sales of AE Supply's generating assets used to hedge those contractual obligations.
>
> Should AE Supply's cost of generation exceed the amounts to which it is entitled under the P[O]LR contracts, for example, due to fuel price increases and increased environmental compliance costs, AE Supply would have to absorb the difference, absent regulatory relief. Similarly, if AE Supply is required to purchase power to meet the P[O]LR obligations, it may not receive its marginal costs from the Distribution Companies. Even if AE Supply can charge the Distribution Companies prices reflecting higher market prices, those companies might not be able to pass the costs on to their retail customers while state retail rate freezes remain in effect.

(IEU-Ohio's *Request for Administrative Notice*, No. 16: Allegheny Energy, Inc.'s Annual Report Pursuant to Section 13 or 15(d) of The Securities Exchange Act of 1934, For the Fiscal Year Ended December 31, 2002 [AE 2002 10-K]), notice granted October 12, 2004 (Tr. VI, at 120-121).

IEU-Ohio argues that the AE 2003 10-K, at 93, documents the ongoing positive financial contributions (both in absolute and relative terms) that the POLR [default supply] contracts have made to AE Supply and its parent/shareholder, AE. IEU-Ohio contends that the AE 2003 10-K, at 93, also shows that AE's financial problems stem from the non-POLR business and energy trading operations of AE Supply. (Tr. V, at 46-50, 53-55; IEU-Ohio's Request for Administrative Notice, No. 19: Allegheny Energy, Inc.'s Annual Report Pursuant to Section 13 or 15(d) of The Securities Exchange Act of 1934, for the Fiscal Year Ended December 31, 2003 [AE 2003 10-K], notice granted October 12, 2004 (Tr. at VI, 120-121).

The information provided in IEU-Ohio's arguments concerning AE's business model supports the determination reached by the Commission above that negotiations between Mon Power and AE Supply regarding the end of the PSA were not at arm's length.

4. Transfer of Mon Power Generation to AE Supply

Mon Power, which serves customers both in Ohio and West Virginia, obtained authorization from this Commission to transfer its generating assets to AE Supply as part of Mon Power's ETP proceeding.[41] IEU-Ohio asserts that the representations Mon Power made to secure transfer authority from this Commission did not include any plans by Mon Power to transfer only a portion of its generating assets or to divest generation. IEU-Ohio argues that, in the ETP proceeding, Mon Power's witness, Regis Binder, made it clear that AE would keep its generating assets (IEU Ex. 13, at 5). IEU-Ohio, further, submits that Mon Power did not obtain any transfer authority from the West Virginia Commission. (Tr. III, at 118.) The West Virginia Commission held that Mon Power "may not sell, transfer, or otherwise dispose of its generating assets prior to the start date of the Plan[42] without the consent of the Commission pursuant to § 24-2-12 of the Code."[43] IEU-Ohio contends that the transfer proposed by Mon Power, as part of its Ohio ETP plan, did not involve a partial transfer of generating assets. IEU-Ohio asserts that Ohio's consideration of the proposed generation asset transfer was in the context of corporate separation requirements that did not, and do not, contemplate partial corporate separation. IEU-Ohio submits the information filed by AE, AE Supply and Mon Power with the Securities Exchange Commission (SEC) indicated that the transfer would also involve assumption of responsibility for debt by the transferee "to comply with the Commission's [SEC's] debt to equity requirements and a commitment made by Mon Power . . . not to engage in any transaction if the result would be made in non-compliance with the Commission's [SEC's] debt to equity requirements."[44] IEU-Ohio argues that the generating asset transfer that Mon Power claims to have made pursuant to the Commission's authorization is different than the transfer Mon Power proposed in its ETP Plan to meet Ohio's corporate separation requirements. IEU-Ohio contends that, Mon Power seems to invite the Commission to ignore the debt assumption commitment aspect of the transfer, as described to the SEC, based on "complications" that left the debt assumption incomplete (Mon Power Ex. 11, at 6), as well as the equity value conferred on AE Supply (IEU Ex. 30, at 35-36). IEU-Ohio submits that the Commission, in this context, must not skip over the question of whether the generating asset transfer that Mon Power says it implemented is the type of transaction approved by this Commission and the SEC.

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41 *See* Case No. 00-02-EL-ETP.

42 West Virginia's electric restructuring plan: West Virginia Plan for Customer Choice of Electric Power Suppliers, Open Access to Electricity Transport Systems and Deregulation of Power Supply Plan.

43 *See In Re Petition for Consent and Approval for Monongahela Power Company and The Potomac Edison Company to Transfer Their West Virginia Generation Assets to an Affiliate, Allegheny Energy Supply LLC, at Book Value*, Case No. 00-0801-E-PC (June 23, 2000, at 3).

44 *See* IEU Ex. 43, at 12 of 22.

IEU-Ohio raises questions, as discussed above, concerning the transfer of Mon Power's generation assets. Mon Power asserts that this Commission, in its ETP Order at page 6, observed "the subject portion of the Ohio generation assets will be transferred to an unregulated affiliate or other party at book value on or after January 1, 2001." Mon Power further asserts, that nothing in the ETP indicates that the structural separation, through the transfer of generation assets, was contingent upon the transfer of the West Virginia portion of its generation assets. Mon Power submits that the June 1, 2001, transfer of the Ohio portion of its generation assets fulfills both the ETP and statutory requirements. Mon Power also contends that IEU-Ohio has misrepresented Mon Power's U-1 filing with the SEC. Mon Power asserts that in Amendment No. 3 to its Form U-1 Application-Declaration that Mon Power, AE Supply, AE, and AESC filed with the SEC on April 1, 2001, the companies specifically requested the SEC to authorize the transfer of the Ohio (and FERC) jurisdictional portions of Mon Power's generation assets, but reserve jurisdiction over the proposed transfer of the West Virginia share of Mon Power's assets (IEU Ex. 43, at 14 of 22). Mon Power further asserts that the SEC specifically approved the transfer of the Ohio (and FERC) generation assets, in its April 25, 2001 Order in *Allegheny Energy, Inc., et al.*, Release Nos. 3527384, 70-9747, 2001 SEC LEXIS 810. The Commission notes that the ETP did not address the transfer of debt associated with the assets that were to be transferred under the ETP. After a review of the evidence presented, we find that the Ohio jurisdictional allocation of Mon Power's generation assets has been transferred to meet the statutory structural separation requirements and the ETP. However, had Mon Power transferred the associated debt, this would have been better for Mon Power's financial position. Further, the transfer of the assets without the associated debt reinforces the integrated nature of AE and its affiliated subsidiaries.

5. Power Sales Agreement and the Facilities Lease Agreement

IEU-Ohio contends that the PSA did not end on December 31,.2003 for Mon Power's large commercial and industrial customers, based on the terms of the PSA. IEU-Ohio asserts that Mon Power's suggestion that a termination of the PSA left it with no alternative but to use the purchased power market or the PJM spot market is false. This argument has been addressed by the Commission above.

In addition to this argument, IEU-Ohio argues that AE Supply owns or controls sufficient generation assets to supply power to meet Mon Power's default generation service obligations at cost-based rates, apart from the PSA, without resorting to AE Supply FERC Rate Schedule No. 1 for purchases at PJM spot market prices. First, IEU-Ohio contends that the FLA is a separate part of AE Supply FERC Rate Schedule 10. (Tr. II, at 31-33; IEU Exs. 4, 5.) IEU-Ohio asserts that the FLA provides Mon Power with the "exclusive right" to operate or arrange for the operation of a fixed amount of 245 MW (generator nameplate; 247 MW operating capacity rating) of generation capacity such that the leased capacity plus Mon Power's owned capacity is sufficient to meet its West Virginia and "Ohio loads." (IEU Ex. 4: AE Supply Company, LLC, Electric Rate Schedule, FERC No. 10, at Original Sheet Nos. 26-45.) IEU-Ohio further asserts that

Section 1.4 of the FLA defines Ohio Loads as the Standard Offer Service provided by Mon Power in Ohio. IEU-Ohio submits that Mon Power admitted that its default generation supply obligation in Ohio is known as the Standard Service Offer (IEU Request for Admission 62). IEU-Ohio contends that, as of December 2001, the total load of Mon Power's Ohio retail customers was less than the FLA's capacity of 245 MW: 46.1 MW (residential), 36.7 MW (small to medium commercial and industrial), 149 MW (large industrial and commercial), for a 231.8 MW total. IEU-Ohio further contends that, under the terms of the FLA, AE Supply is only entitled to any real-time energy in excess of the Ohio loads (IEU Ex. 4, at Section 3.4).

IEU-Ohio submits that AE described the relationship between the FLA and the PSA in the transmittal letter that AE submitted to FERC with AE Supply FERC Rate Schedule 10:

> The Facilities Lease Agreement ("Lease") is a lease by which Monongahela leases certain facilities from AE Supply. During the period the lease is in effect, the Power Sales Agreement will operate to provide any additional requirements of Monongahela Power's customers in excess of those available from the leased facilities.

IEU Ex. 4. transmittal letter at 3.

IEU-Ohio asserts that the above transmittal letter identifies a sequential supply relationship between the FLA and the PSA, which indicates that the FLA is the primary source and the PSA is a supplemental supply option (*Id.*).

Mon Power asserts that the FLA is not a separate and independent source through which it can provide power to large commercial and industrial customers without incurring market-based costs. Rather, the FLA and PSA work in concert under AE Supply FERC Rate Schedule 10. (Tr. I, at 93-94.) Mon Power argued that, but for the double tax problem in West Virginia, the FLA would not exist. (Tr. I, at 142-147, 161-167; Tr. II, at 124.) Mon Power states that, even though the facilities are leased to Mon Power, the facilities are still owned and operated by AE Supply (Tr. II, at 164). More importantly, Mon Power argues that the parties to the PSA intended, and interpret, the FLA to provide power for Ohio default service only to the extent that "Ohio Load" customers have a right to receive power under the PSA (Tr. I, at 144-145; MP Ex. 11, at 9-10).

In regard to the FLA, we are not persuaded by IEU-Ohio's argument that the FLA is a separate source of cost-based generation for Mon Power's large commercial and industrial customers. We agree with Mon Power that the PSA and FLA work in concert. The evidence is clear that the sole purpose of the FLA is to avoid double taxation, and was entered into with the approval of the State of West Virginia. The intent of such a transaction was not to provide Mon Power with generating assets to use for purposes other than as a source of generation in concert with the PSA. Mr. Howells testified that the final pricing of power for Ohio customers is determined by the PSA, even though the power was obtained from the facilities under FLA. Mr. Howells also believed that the termination provisions of the FLA are consistent with PSA. (Tr. I, at 145). Further, the leased facilities are still owned and operated by AE Supply and the FLA was submitted to FERC as part of the AE Supply Rate Schedule 10. We agree with Mon Power that this testimony supports Mon Power's position that the FLA was used to provide power to Ohio customers served through the PSA and not as an independent source of generation. If the PSA did not include power for the C&I customers after December 31, 2003, neither would the FLA. Consequently, we cannot agree with IEU-Ohio that, even if the PSA was cancelled for C&I customers, Mon Power could still use the power from the FLA to serve those customers.

6. Mon Power's Generation Supply Options

First, IEU-Ohio contends that Mon Power holds a 3.5 percent interest in the OVEC that it has not elected to transfer to AE Supply[45] (IEU Requests for Admission 47, 48).[46] IEU-Ohio submits that, in 2003, Mon Power used approximately 79,212 MWh of supply from OVEC to meet the electricity requirements of its Ohio customers and this supply was priced at $26.36/kWh. (Tr. II, at 53, 57-58; IEU Ex. 17, at 1, IEU Ex. 19.) IEU-Ohio further submits that Mon Power has the discretion to, and has used, the OVEC supply prior to using any generation supply available under AE Supply FERC Rate Schedule No. 1. (Tr. II, at 32; Tr. III, at 151-154.) IEU-Ohio argues that Mon Power is entitled to approximately 78 MWs of OVEC power, and that this power should be used to provide default service to Ohio's large commercial and industrial customers.

Mon Power, first, asserts that its total company entitlement from OVEC's excess capacity is approximately 78 MW and that the Ohio portion, approximately 14.9 percent, averages only 9 MW per hour. (Tr. II, at 53-55, 60.) Mon Power further asserts that the price of the OVEC generation is below current market rates and is, therefore, being used to serve Mon Power's Ohio customers that are still under capped rates. (Tr. II, at 59-62.)

We find there is some merit to IEU-Ohio's argument that it would be more prudent to use the 9 MW to serve the large C&I customers to offset the amount of energy purchased on the spot market. If Mon Power was concerned about providing power at least cost, it would have used the Ohio OVEC power it owns to supply C&I customers rather than customers under capped rates, inasmuch as it can obtain power under the PSA for the capped rate customers. Accordingly, we find Mon Power's actions with regard to the allocation of OVEC power to capped-rate customers to be imprudent.

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45 IEU-Ohio notes that the AE 2001 10-K, at 3, states that Mon Power's entitlement to capacity in OVEC "will not be transferred unless tax changes and implementation authorization related to the deregulated power market in West Virginia have been enacted or the West Virginia Public Service Commission otherwise takes regulatory action, and the Securities and Exchange Commission approves the transfer."

46 *See* Notice of filing of Mon Power Company's Admissions, Part 1 of 2, filed September 27, 2004, in this docket.

Second, IEU-Ohio contends that Mon Power continues to own substantial amounts of generating capacity, i.e., approximately 2,200 MW. (Tr. II, at 27.) IEU-Ohio asserts that Mon Power's total company peak demand, including West Virginia and Ohio loads, was 2,080 MW in 2002 and 2,049 MW in 2003 (IEU Request for Admission 9).[47] IEU-Ohio further asserts that the AE 2003 10-K filed with the SEC, at 29-30, show that Mon Power owned generation of 2,117 MW, with 161 MW of PURPA generation project capacity available to Mon Power, for total of 2,278 MW of generation capacity (IEU Ex. 30, at 28).[48] IEU-Ohio submits that this capacity could be used to provide default service to Ohio's large C&I customers.

We are not persuaded by IEU-Ohio's arguments. Based on the evidence presented in this case, we find that Mon Power's remaining generation assets are allocated to its West Virginia jurisdiction to serve its West Virginia customers; therefore, we cannot require that West Virginia generation assets be used to serve Mon Power Ohio's large C&I customers. Benefits derived from these assets belong to West Virginia customers.

IEU-Ohio next submits that Mon Power is required, in West Virginia, to purchase 161 MW of generation from PURPA-qualified facilities.[49] The PURPA purchase requirements result in excess generation from the generating facilities owned by Mon Power in West Virginia. IEU-Ohio contends that this excess capacity could be used to serve Ohio's large C&I customers. Mon Power, first, asserts that it is obligated to use its remaining generation to meet the service requirements of its West Virginia customers (MP Ex. 11, at 8). Mon Power, next, asserts that the PURPA purchases are made at a higher cost than under its generation costs for its West Virginia customers, and higher than the capped rates for Ohio's large C&I customers. (Tr. VI, at 88-90; 2000 FERC Form 1, at 326-327.2; MP Ex. 1, at CAM-6, line 2.) Mon Power argues that any excess generation, therefore, should be sold through off-system sales, and those revenues used to offset the prices paid by its West Virginia customers; anything else would confiscate West Virginia assets (MP Ex. 11, at 8-9).

The Commission notes that IEU-Ohio has not proposed that the large C&I customers pay for power at the PURPA purchase rate. After a review of the evidence, the Commission finds that it is unlikely, in a rate case proceeding, that Mon Power's Ohio customers would pay for high PURPA generation capacity from West Virginia; therefore, we could not reasonably expect that any excess West Virginia generation capacity be used to serve Mon Power Ohio's large C&I customers, or that any revenue received from the West Virginia off-system sales be allocated to Ohio.

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47 *Id.*

48 *See* IEU-Ohio's Request for Administrative Notice, No. 19: Allegheny Energy, Inc.'s Annual Report Pursuant to Section 13 or 15(d) of The Securities Exchange Act of 1934, for the Fiscal Year Ended December 31, 2003 [AE 2003 10-K] at 36, 322.

49 A "PURPA-qualified facility" is defined in the Public Utility Regulatory Policies Act of 1978. *See* 16 USCS §§ 2601 et seq.

Last, IEU-Ohio argues that AE Supply and AE have been willing and able to use the integrated resources of AE's subsidiaries to address the generation supply and price needs of Mon Power and its operating company affiliates. IEU-Ohio asserts that Mon Power can obtain below-market wholesale supplies from AE Supply because AE Supply has offered such arrangements to other affiliates in other states and to Mon Power for their West Virginia customers. (IEU Ex. 13, at 8-10; Tr. III, at 175, 183; IEU Ex. 1, at 5-6.) Mon Power submits that there is no legal authority that could allow this Commission to import to Ohio the agreements or proposals made in other jurisdictions. Mon Power asserts that the other settlements are irrelevant to the issues before this Commission.

After a review of the evidence presented, we are not persuaded by IEU-Ohio's argument. It is clear from the evidence presented that the settlements in Pennsylvania and West Virginia dealt with specific issues, under the relevant law in each state, at the time that the settlement agreements were negotiated.

7. Prior Period Earnings

IEU-Ohio submits that Mon Power realized excessive earnings for the period 2000 through 2003 from its Ohio MDP rates. IEU-Ohio contends that the case law regarding the test for confiscation permits the Commission to look beyond a static test year. IEU-Ohio further submits that, as the U.S. District Court has already held, "[I]f the combined effect of all aspects of the restructuring act provides Mon Power with a rate which is not confiscatory, the rate freeze is not unconstitutional."[50] IEU-Ohio further contends that when the rates that have been in place for some time are challenged as confiscatory, then the results of the entire period those rates have been in effect should be considered. IEU-Ohio asserts that Mon Power made no attempt to consider its earnings during the earlier years of the MDP (IEU Ex. 30, at 36). IEU-Ohio further asserts that the only earnings "analysis" provided by Mon Power is the Summary Income Statement for 2003 attached to the June 28, 2004 direct testimony of Mon Power witness John R. Howells at Exhibit JRH-1 (IEU Ex. 30, at 36-37). IEU-Ohio argues that, based on IEU witness Smith's testimony, Mon Power's overall rate of return in its Ohio jurisdiction, as reported, was 15.18 percent in 2002, 34.11 percent in 2001, and 63.09 percent in 2000 (IEU Ex. 29, at 23). Finally, IEU-Ohio argues that the Commission should consider Mon Power's profits for the years 2000 through 2003, under the capped MDP rates, in determining whether there is confiscation.

The Ohio Supreme Court, in *City of Marietta v. Public Utilities Commission of Ohio, et al.*, 148 Ohio St. 173 (1947), states that "the law does not require the company to give up for the benefit of future subscribers any part of its accumulations from past operations. Profits of the past cannot be used to sustain confiscatory rates for the future" (citations omitted). Accordingly, IEU-Ohio's argument is not well-taken.

50 *See Schriber*, 322 F. Supp. 2d at 921.

8. <u>Other Benefits</u>

IEU-Ohio asserts that Mon Power's confiscation claim also ignores benefits derived by Mon Power and its affiliates as a result of Ohio's restructuring legislation (including AE's acknowledgment that the generation assets transferred from Mon Power to AE Supply had a market value in excess of the book value) and the excess earnings obtained by Mon Power in the period 2000 through 2003.

IEU-Ohio argues that Mon Power and the Allegheny Energy system as a whole have received benefits as a result of SB 3. IEU-Ohio asserts that the transfer of the Ohio portion of Mon Power's generation assets at book value, and without the corresponding transfer of the associated debt, provided a benefit to AE Supply. Further, AE Supply was able to enter the market and make sales in Ohio to ultimate customers. (Tr. I, at 186.) IEU-Ohio contends that the ability of AE Supply to enter the market, and subsequently sell its "book of business," was a direct result of Ohio's electric restructuring, and a benefit that Mon Power failed to recognize in its confiscation analysis. (Tr. I, at 185.) Last, IEU-Ohio asserts that implicit in the current rates is a transition cost that Mon Power has collected to its benefit.

Mon Power asserts that it has received no benefits that offset its losses (MP Ex. 3, at 14-16). Further, Mon Power asserts that the examination of benefits should be limited to Mon Power only. Last, Mon Power submits that IEU-Ohio never quantified the alleged value of these benefits to Mon Power or AE Supply and, further, none of the alleged benefits would have provided revenues actually available to sustain Mon Power's operations in Ohio. Consequently, Mon Power argues that IEU-Ohio cannot present any benefits that offset Mon Power's losses cognizable by the Due Process Clause. *PG&E v. Lynch*, 216 F. Supp. 2d 1016, 1049.

As we found above, the corporate structure described in this proceeding is not one of arm's length transactions, under which Mon Power makes its own decisions. Rather, the evidence presented indicates that the revenues and expenses are allocated within the AE system, by AE, the parent. It is, therefore, not possible to look only at Mon Power in reviewing whether it received any benefits under SB 3. Accordingly, we find that, although not easily quantifiable, the Allegheny Energy system has benefited from the transfer of Mon Power's Ohio jurisdictional generation assets at book value and from the transfer of the same generation assets without the corresponding transfer of the associated debt and possibly from AE Supply's ability to sell its "book of business." We do not find, however, that Mon Power has received any benefit, at the present time, from the regulatory transitions costs that were approved in its ETP. There is only a benefit to the extent that customers shop for a new generation supplier. In this case, there has been little or no shopping.

D) Conclusions

Based upon our discussion above, we find that Mon Power's application to amend its tariffs to increase certain rates for C&I customers and to establish a PPRS should be denied. We find that Mon Power was entitled to receive power for C&I customers until the end of the MDP from AE Supply under the terms of the PSA. Consequently, Mon Power's failure to enforce it rights under the PSA was imprudent and resulted in the purchase of much higher priced spot market power purchases. Using the cost of power that could have been purchased through the PSA, there is no evidence to support a finding that Mon Power's rates are confiscatory. This decision concludes this matter, but the Commission will begin consideration of Case No. 04-1047-EL-ATA, *Application for Approval of a Standard Service Offer and Competitive Bidding Process for Monongahela Power Company*, filed June 30, 2004, to establish two standard service offerings, in accordance with our rules and Section 4928.14, Revised Code, which will provide benefits to Mon Power and its customers through the promotion of competition.

IV. FINDINGS OF FACT AND CONCLUSIONS OF LAW

(1) On June 18, 2004, Mon Power filed its application in this matter. Mon Power's application seeks authority to amend Mon Power's filed Electric Service schedules to increase the rates for approximately 70 C&I customers located in the Ohio area served by Mon Power.

(2) Mon Power's application also seeks approval to apply a retail surcharge to its C&I customers that would enable it to recover the difference in price between the power it purchases for those customers beginning January 1, 2004, and the frozen unbundled generation rate for those customers established in Mon Power's electric transition plan, Case No. 00-02-EL-ETP.

(3) The Commission's determination is based upon whether Mon Power's rates established in its ETP proceeding and any benefits received from SB 3 are insufficient to permit Mon Power to recover its validly incurred costs with a reasonable rate of return on the value of the property being used to provide electric service. If the established rates and other benefits of SB 3 do not afford sufficient compensation to recover its validly incurred costs with a reasonable rate of return, it can be said that the rates are confiscatory and the State has taken the use of utility property without paying just compensation, which violates the Fifth and Fourteenth Amendments of the United States Constitution.

(4) Reviewing Mon Power's purchasing options under the circumstances of this case and the PSA, the Commission finds that Mon Power has acted imprudently by purchasing generation through the PJM spot market to serve its Ohio C&I customers. From a review of the PSA provisions, it is clear to the Commission that Mon Power could have received power from AE Supply for its Ohio C&I customers under the terms of contract. With no early termination of the MDP, Mon Power retained its statutory obligation under SB 3 to supply generation to C&I customers under fixed rates.

(5) Mon Power could have, and should have, enforced its rights under the PSA to receive power for its Ohio C&I customers under the definition of Default Service through the end of 2005.

(6) If Mon Power had purchased power for its Ohio C&I customers through the PSA, there is no evidence to support a finding that Mon Power rates are confiscatory. For the year 2003, when the PSA was in effect for all customer classes, Mon Power earned an overall rate of 8 percent based on a net operating income of $4.8 million.

(7) The Commission finds our determination that Mon Power's frozen rates are not confiscatory, under the *Pike County* exception, also addresses the issue raised by Mon Power concerning the federal filed-rate doctrine.

(8) Mon Power did not provide the Commission with the traditional cost-of-service data that is necessary to perform a complete rate case analysis. Rather, Mon Power focused on the cost of power from the spot market to determine whether its rates are confiscatory.

(9) Staff's approach to determine whether Mon Power's costs for its Ohio customers can be recovered under the current rate structure does not appropriately reflect the current state of operations for Mon Power.

(10) Negotiations between Mon Power and AE Supply regarding the end of the PSA were not arm's length negotiations, otherwise Mon Power would have enforced the terms of the PSA to provide default service to its large C&I customers in Ohio through December 31, 2005.

(11) The Ohio jurisdictional allocation of Mon Power's generation assets has been transferred to meet the statutory structural separation requirements and the ETP.

(12) The FLA is not a separate source of cost-based generation for Mon Power's large commercial and industrial customers in Ohio.

(13) The Commission should not consider Mon Power's profits for the years 2000 through 2003, under the capped MDP rates, in determining whether there is confiscation.

(14) Although not easily quantifiable, the Allegheny Energy system has benefited from the transfer of Mon Power's Ohio jurisdictional generation assets at book value and from the transfer of the same generation assets without the corresponding transfer of the associated debt, and possibly from AE Supply's ability to sell its "book of business."

(15) Mon Power's application to amend its tariffs to increase certain rates for its Ohio C&I customers and to establish a PPRS should be denied.

It is, therefore,

ORDERED, That Mon Power's application to amend its tariffs to increase certain rates and to establish a Purchased Power Recovery Surcharge is denied. It is, further,

ORDERED, That Mon Power continue to serve its large commercial and industrial customers and street lighting customers in its Ohio service territory under the rates established in its Electric Transition Plan for the duration of the Market Development Period. It is, further,

ORDERED, That a copy of this Opinion and Order be served upon Mon Power, all parties of record in this proceeding, and the District Court.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Ronda Hartman Fergus

Judith A. Jones

Donald L. Mason

Clarence D. Rogers, Jr.

JKS/RRG:ct

Entered in the Journal

DEC 0 8 2004

Reneé J. Jenkins
Secretary

Abbreviations & Acronyms

AGC	Allegheny Generating Company (unregulated subsidiary of Mon Power and AE Supply)
AE	Allegheny Energy, Inc. (Mon Power's parent holding company)
AESC	Allegheny Energy Service Corporation (AESC employees are assigned to work for the Mon Power, AE Supply, and AE's other subsidiaries)
AE Supply	Allegheny Energy Supply Company, LLC
CPB	Competitive bidding process under Section 4928.14, Revised Code
District Court	The United States District Court for the Southern Division of Ohio, Eastern Division
C&I customers	Large commercial, industrial, and street lighting customers
ETP	Electric transition plan
FERC	Federal Energy Regulatory Commission
FLA	Facilities Lease Agreement
IEU-Ohio	Industrial Energy Users of Ohio
kWh	Kilowatt-hour
MBSSO	Market-based standard service offer
MDP	Market development period
MW	Megawatt – one million watts
MWh	Megawatt-hour – One thousand kilo-watt hours or one million watt-hours
Mon Power	The Monongahela Power Company
OCC	Ohio Consumers' Counsel
OPAE	Ohio Partners for Affordable Energy

OVEC	Ohio Valley Electric Corporation
PJM	PJM Interconnection, LLC, a regional transmission organization
POLR	Provider of last resort
PPRS	Purchased power recovery surcharge
PSA	Power sales agreement
PUCO	Public Utilities Commission of Ohio
PURPA	Public Utility Regulatory Policies Act of 1978
RFP	Request for proposal
SEC	U.S. Securities and Exchange Commission
Staff	The Commission's Staff
SB 3	Amended Substitute Senate Bill 3 of the 123rd General Assembly that enacted the Ohio electric restructuring legislation, or the "Ohio Restructuring Act."

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Edison Company on Behalf of Pennsylvania Power Company for Eligible Facility Determinations Under the Public Utility Holding Company Act.	)	Case No. 05-678-EL-UNC

ENTRY

The Commission finds:

(1) By Commission Order dated December 21, 2000, in Case No. 00-2320-EL-UNC, this Commission made a determination that allowing the fossil generating plants, as listed in attachment A to the application filed by Ohio Edison Company, the Cleveland Electric Illuminating Company, and the Toledo Edison Company (collectively, "Ohio Operating Companies"), to be eligible facilities under the Public Utilities Holding Company Act of 1935 (PUHCA) will benefit consumers, was in the public interest, and did not violate state law (PUHCA Section 32 [C]).

(2) At the time the Commission made its determination in Case No. 00-2320-EL-UNC, FirstEnergy Corp. ("First Energy"), parent company of the Ohio Operating Companies, was not a registered holding company subject to PUHCA. Therefore, no determination from this Commission was required for the portion of the fossil generating assets owned by Pennsylvania Power Company ("Penn Power"), a wholly owned subsidiary of Ohio Edison Company (applicant). The Penn Power fossil generating assets are listed on attachment A to the application in Case No. 05-678-EL-UNC, and referred to collectively as the PP fossil assets.

(3) On May 23, 2005, applicant, on behalf of Penn Power, filed this application (Case No. 05-678-EL-UNC) in furtherance of the completion of the transition plan of Ohio Operating Companies as approved by this Commission on July 19, 2000, in Case No. 99-1212-EL-ETP (the "transition plan").

The transition plan approved by this Commission included a plan to transfer control of Ohio Operating Companies' fossil plants to the competitive services unit of FirstEnergy to be effective no later than January 1, 2001. In order to effectuate that provision of the transition plan, FirstEnergy Generation Corp. ("Genco"), an Ohio corporation and a wholly owned subsidiary of FirstEnergy Solutions Corp. ("FES"), was established. A FirstEnergy subsidiary, FES provides energy-related products and services, and through Genco, currently operates FirstEnergy's non-nuclear generation businesses. Genco, as lessee under the master facility lease ("master lease"), dated as of January 1, 2001, with utility subsidiaries as lessors, leases the fossil generation assets to be transferred, and operates and maintains those fossil assets.

(4) As an exempt wholesale generator ("EWG"), Genco is exempt from all provisions of PUHCA. Under Section 32 of PUHCA, an EWG must, in general, be exclusively engaged in the business of owning or operating "eligible facilities".

(5) Genco intends to exercise a purchase option under the master lease to acquire the fossil and hydro-electric generation assets to be transferred by the utility subsidiaries. Such a transfer of the ownership interest to Genco is contemplated by and in accordance with the Amended Substitute Senate Bill ("SB3").

(6) Applicant states that Penn Power will be transferring its ownership interest in the PP fossil assets to Genco. Because FirstEnergy is now a registered holding company, applicant, on behalf of Penn Power, requests the Commission to expand the scope of its findings in Case No. 00-2320-EL-UNC to include the PP fossil assets; making a separate determination that the transfer of the PP fossil assets to Genco will benefit consumers, is in the public interest, and does not violate state law.

(7) Applicant states that Penn Power is a Pennsylvania electric public utility engaged in the production, generation, purchase, transmission, distribution, and sale of electric energy and related utility services to more than 157,000 residential, commercial, and industrial customers located within six counties and 114 municipalities of the Commonwealth of Pennsylvania. It is subject to the jurisdiction of the Pennsylvania Public Utility Commission, and is a wholly owned subsidiary of applicant.

(8) Applicant further states that the proposed transfer of PP fossil assets to Genco will not adversely affect either the availability or reliability of electric supply to the customers of applicant or Penn Power or any other electricity customer.

(9) This transaction to separate the fossil plants from the operating companies is being implemented in accordance with the transition plan, as approved by this Commission. Further, Section 4928.17(E), Revised Code, provides that "an electric utility may divest itself of any generating asset at any time without Commission approval." In addition, the corporate separation requirement included in the transition plan in accordance with SB3 was one element of the overall policy of the legislation to provide

> competitive electric services for the benefit of customers and the economy of the state. Therefore, the Commission is satisfied that a determination allowing the PP fossil assets to be eligible facilities under the PUHCA will benefit consumers, is in public interest, and does not violate Ohio Law.

It is, therefore,

ORDERED, That the application for a determination that allowing the PP fossil assets, as listed in attachment A to the application, to be eligible facilities under the PUHCA will benefit consumers, is in the public interest, and does not violate state law, and effectuates the transfer of the PP fossil assets to Genco, is approved. It is, further,

ORDERED, That a copy of this entry be served upon all parties of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Ronda Hartman Fergus

Judith A. Jones

Donald L. Mason, Esq.

Clarence D. Rogers, Jr.

RR:djb

Entered in the Journal
SEP 1 4 2006

Reneé J. Jenkins
Secretary

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of The Dayton Power and Light Company for the Creation of a Rate Stabilization Surcharge Rider and Distribution Rate Increase.	)))))	Case No. 05-276-EL-AIR

OPINION AND ORDER

The Commission, considering the above-entitled application, hereby issues its opinion and order in this matter.

APPEARANCES:

Faruki, Ireland & Cox, P.L.L., by Charles J. Faruki and Jeffrey S. Sharkey, 500 Courthouse Plaza, S.W., 10 Ludlow Street, Dayton, Ohio 45402, on behalf of Dayton Power and Light Company.

Jim Petro, Attorney General of the State of Ohio, by Duane W. Luckey, Senior Deputy Attorney General, by Werner L. Margard, III, Steven A. Reilly and Steven L. Beeler, Assistant Attorneys General, 180 East Broad Street, Columbus, Ohio 43215, on behalf of the staff of the Public Utilities Commission of Ohio.

Janine L. Migden-Ostrander, Ohio Consumers' Counsel, by Jeffrey L. Small and Ann M. Hotz, Assistant Consumers' Counsel, Office of Consumers' Counsel, 10 West Broad Street, Columbus, Ohio 43215, on behalf of the residential consumers of Dayton Power and Light Company.

McNees, Wallace & Nurick, LLC, by Samuel C. Randazzo, Lisa G. McAlister and Daniel J. Neilsen, 21 East State Street, Columbus, Ohio 43215, on behalf of Industrial Energy Users-Ohio.

Craig I. Smith, 2824 Coventry Road, Cleveland, Ohio 44120, on behalf of Cargill, Inc.

David C. Rinebolt, 231 W. Lima Street, Findlay, Ohio 45839, on behalf of Ohio Partners for Affordable Energy.

Vorys, Sater, Seymour & Pease, by M. Howard Petricoff, 52 East Gay Street, Columbus, Ohio 43215, on behalf of Honda of America Mfg., Inc.

OPINION:

I. HISTORY OF THE PROCEEDING

The Dayton Power & Light Company (DP&L) is a public utility as defined in Section 4905.02, Revised Code, and, as such, is subject to the jurisdiction of this Commission.

On September 3, 2003, in Case No. 02-2279-EL-ATA et al., the Commission approved a stipulation (the RSP Stipulation) which extended DP&L's market development period to December 31, 2005 and provided for a rate stabilization period from January 1, 2006 through December 31, 2008. In addition, among other terms, the RSP Stipulation provided that all customers would be assessed a rate stabilization surcharge (the RSS Rider) of up to 11 percent of the tariffed generation charges as of January 1, 2004. The RSS rider would permit DP&L to recover costs associated with fuel price increases or actions taken in compliance with environmental and tax laws, regulations or court or administrative orders, and costs associated with physical security and cyber security relating to the generation of electricity from plants owned by DP&L and its affiliates, which costs are imposed by final rule, regulation or administrative or court order. The RSP Stipulation provided that adjustments to the RSS Rider be made by application by DP&L to the Commission under Section 4909.18, Revised Code. *In the Matter of the Continuation of the Rate Freeze and Extension of the Market Development Period for the Dayton Power and Light Company*, Case No. 02-2279-EL-ATA, et al., Opinion and Order (September 2, 2003).

On March 1, 2005, DP&L filed a notice of intent to file an application for an increase in rates to establish the RSS Rider. Further, on March 23, 2005, the Commission issued an entry establishing the date certain and test period for DP&L's application. On April 4, 2005, DP&L filed its application to increase rates. The Commission accepted DP&L's application for filing by entry dated May 4, 2005.

Motions to intervene were filed by Industrial Energy Users-Ohio (IEU-Ohio), Ohio Partners for Affordable Energy (OPAE), the Ohio Consumers' Counsel (OCC), Cargill, Inc. (Cargill), and Honda of America Mfg., Inc. (Honda). Those motions were granted on September 1, 2005 and October 12, 2005.

On August 26, 2005, a written report of the staff's investigation was filed. The staff concluded that, with minor adjustments, DP&L had justified an increase in the RSS Rider in excess of the 11 percent cap contained in the RSP Stipulation. By entry issued on September 1, 2005, the attorney examiner ordered that objections to the staff report be filed in accordance with Section 4909.19, Revised Code, which requires that objections be filed within 30 days of the filing of the staff report. Objections were timely filed by DP&L, the OCC, IEU-Ohio, Honda, OPAE and Cargill.

A public hearing was held on October 27, 2005 in Dayton, Ohio. Two witnesses testified at the public hearing: Ellis Jacobs, on behalf of the Community Action Partnership of the Greater Dayton Area, and Mr. Maurice Campbell, a residential customer of DP&L.

On November 3, 2005, a partial stipulation was filed with the Commission by DP&L, Cargill, Honda and IEU-Ohio. The evidentiary hearing commenced on November 4, 2005, during which testimony was received by witnesses on behalf of DP&L, OPAE and the staff regarding the company's application and the staff report. The hearing continued on November 8, 2005, during which additional testimony was received by witnesses on behalf of DP&L. The hearing was then adjourned to allow for further discovery related to the stipulation.

The hearing continued on November 14, 2005 at which time DP&L presented witnesses supporting the stipulation. The hearing concluded on November 15, 2005, following testimony by a witness on behalf of OCC in opposition to the stipulation.

Post hearing briefs were timely filed on November 22 by staff, DP&L, OCC, OPAE, IEU-Ohio and Cargill. OPAE filed its reply brief on November 29, 2005. Reply briefs were filed on December 1, 2005 by DP&L, OCC, IEU-Ohio and staff.

II. SUMMARY OF THE STIPULATION

The stipulation was intended by the signatory parties to resolve all outstanding issues in this proceeding. The stipulation includes, *inter alia,* the following provisions:

1. DP&L's rate stabilization period is extended through December 31, 2010.

2. DP&L will provide a market-based standard service offer (MBSSO) at rates fixed in the stipulation throughout the extended rate stabilization period.

3. The 5 percent residential generation discount established in Am. Sub. Senate Bill 3 will continue through December 31, 2008, and the 2.5 percent residential generation discount provided for by the RSP Stipulation will take effect from January 1, 2006, through December 31, 2008.

4. DP&L will implement an unavoidable RSS Rider equal to 11 percent of DP&L's January 1, 2004, tariffed generation rates.

5. Beginning on January 1 of each year from 2007 through 2010, DP&L will implement an Environmental Investment Rider (EIR) which will recover environmental plant investments and incremental operations and maintenance, depreciation, and tax costs during the rate stabilization period and will increase each year by 5.4% of DP&L's tariffed generation rates. All increases to the EIR shall be cumulative. The increases in 2009 and 2010 will be avoidable for switching customers. DP&L would implement the EIR through an ATA filing, which would be subject to review by the Commission staff for the limited purpose of confirming that the filing implements the rates provided for by the stipulation.

6. The provisions of the RSP Stipulation that were not superseded by this stipulation will remain in effect, including Section IX.F. of the RSP Stipulation, which provides that the Commission may terminate the rate stabilization period and trigger a competitive bidding process if market-based rates do not reasonably reflect the rates established by the stipulation.

7. The Voluntary Enrollment Procedure established by the RSP Stipulation will continue in 2006, as provided by the RSP Stipulation, and one additional time in 2007.

8. If subsequent legislation affects the terms of the stipulation, then the parties will engage in good faith negotiations to comply with the legislation and preserve the economic benefits of the stipulation.

III. EVALUATION OF THE STIPULATION

Rule 4901-1-30, Ohio Administrative Code, authorizes parties to Commission proceedings to enter into stipulations. Although not binding on the Commission, the terms of such agreements are accorded substantial weight. *See Consumers' Counsel v. Pub. Util. Comm.*, 64 Ohio State 3d 123, 125 (1992), *citing Akron v. Pub. Util. Comm.*, 55 Ohio St. 2d 155 (1978).

The standard of review for considering the reasonableness of a stipulation has been discussed in a number of prior Commission proceedings. *See, e.g., Dominion Retail v. Dayton Power and Light,* Case No., 03-2405-EL-CSS et al., Opinion and Order (February 9, 2005); *Cincinnati Gas & Electric Co.*, Case No. 91-410-EL-AIR, Order on Remand (April 14, 1994); *Ohio Edison Co.*, Case Nos. 91-698-EL-FOR et al., Opinion and Order (December 30,1993); *Cleveland Electric Illum. Co.*, Case No. 88-179-EL-AIR, Opinion and Order (January 31, 1989). The ultimate issue for our consideration is whether the agreement, which embodies considerable time and effort by the signatory parties, is reasonable and should be adopted. In considering the reasonableness of a stipulation, the Commission has used the following criteria:

(1) Is the settlement a product of serious bargaining among capable, knowledgeable parties?

(2) Does the settlement, as a package, benefit ratepayers and the public interest?

(3) Does the settlement package violate any important regulatory principle or practice?

The Ohio Supreme Court has endorsed the Commission's analysis using these criteria to resolve issues in a manner economical to ratepayers and public utilities. *Indus. Energy Consumers of Ohio Power Co. v. Pub. Util. Comm.*, 68 Ohio St. 3d 547 (1997) (*quoting Consumers' Counsel*, at 126). The Court stated in that case that the Commission may place substantial weight on the terms of a stipulation, even though the stipulation does not bind the Commission.

(1) <u>Is the settlement a product of serious bargaining among capable, knowledgeable parties?</u>

OCC argues that the signatory parties are capable, knowledgeable parties who have breached their obligations under the RSP Stipulation. OCC further asserts that the stipulation is not the result of serious bargaining among capable, knowledgeable parties because the signatory parties did not include all of the signatory parties to the RSP Stipulation approved in Case No. 02-2779-EL-ATA. Finally, OCC argues that this stipulation cannot alter the RSP Stipulation without the agreement of all of the signatory parties to that stipulation (OCC brief at 12-13).

OPAE states that the issue is not whether the proposed settlement involved capable and knowledgeable parties; instead, OPAE argues that signatory parties lacked diversity of interests. OPAE concludes that the stipulation represents an accommodation among three self-interested parties which excludes significant consumer groups (OPAE brief at 2-3). In its reply brief, OCC concurred with OPAE's argument, noting that only two of the six parties to the RSP Stipulation also signed the stipulation in this case (OCC reply at 6).

DP&L notes that, although its witness testified that the stipulation was the product of serious bargaining among capable, knowledgeable parties, OCC's witness conceded that he did not offer an opinion on this issue (DP&L brief at 5-6; Tr. III at 20-21). Therefore, DP&L argues that based upon the evidence presented at the hearing, it is undisputed that this criterion is established. In its reply brief, DP&L argues that the Commission has rejected the proposition that this criterion is satisfied only if a representative of each customer class signs the proposed stipulation (DP&L reply at 2, *quoting Dominion Retail v. Dayton Power and Light, supra,* at 17).

The Commission has previously held that it will not require any individual party's approval of stipulations in order to meet the first criterion of our three-prong standard of review. *Dominion Retail v. Dayton Power and Light,* at 18. In considering whether there was serious bargaining among capable and knowledgeable parties, the Commission evaluates the level of negotiations that appear to have occurred and takes notice of the experience and sophistication of the negotiating parties. In this case, it is clear from the record that all parties participated in negotiations. Neither OCC nor OPAE argue that they were kept away from the negotiating table. The signatory parties all routinely participate in complex cases before the Commission and are all represented by counsel who practice before the Commission on a regular basis. Moreover, although no parties representing residential consumers signed the stipulation, the signatory parties do represent a diversity of interests including the utility and industrial and commercial consumers as well as a competitive retail electric service provider. Therefore, the Commission finds that the first prong of the test is met by the stipulation.

(2) Does the settlement, as a package, benefit ratepayers and the public interest?

DP&L argues that the stipulation provides below-market prices and that the stipulation protects its standard service offer customers from volatility and rate shock (DP&L brief at 7-9). DP&L argues that there is no dispute that the stipulation will provide residential customers $262 million in savings versus projected market rates from 2006 through 2010 (*id.* at 8).

Moreover, DP&L states that the stipulation will promote competition. According to DP&L, conducting Voluntary Enrollment Procedure (VEP) one additional time in 2007 will promote competition (DP&L brief at 9). Moreover, the fact that the increases in the EIR for 2009 and 2010 are avoidable will increase the shopping credits and promote competition. Finally, DP&L argues that shopping customers impose costs on DP&L because of its statutory provider of last resort obligation. DP&L argues that the value of these costs substantially exceeds the unavoidable portions of the rate stabilization charge and the EIR. In support of this, DP&L cites the testimony of its witness Strunk, who testified that the right of switching customers to return to DP&L's MBSSO is equivalent to granting customers a financial option to purchase generation from DP&L at a fixed price (*id.* at 10-13; DP&L Ex. 13C at 2-4). According to DP&L, Mr. Strunk's testimony established that the value of this option provided to switching customers substantially exceeds the price of the unavoidable portions of the rate stabilization charge and the EIR (DP&L brief at 13; DP&L Ex. 13C at 6). Therefore, DP&L argues that the stipulation promotes competition because the stipulation does not require switching customers to pay full value for their ability to return to the MBSSO.

IEU-Ohio argues that the stipulation will benefit customers, CRES providers and DP&L by eliminating the uncertainty on issues regarding price and reliability of supply for the period after December 31, 2008. IEU-Ohio states that the stipulation protects DP&L's customers from price volatility and potential price increases that may occur if the rate stabilization period ends on December 31, 2008. IEU-Ohio acknowledges that customers will see higher prices on their total bill than they would have under the RSP Stipulation; however, such increases are a result of known, measurable and justifiable increases in costs beyond the control of DP&L (IEU-Ohio brief at 5).

OCC states that, unlike many other stipulations approved by the Commission, the stipulation provides a complex solution to a simple compliance case and that the signatory parties propose to disturb a settlement that resolved the complex legal issues in Case No. 02-2279-EL-ATA (OCC brief at 13). Citing the testimony of its expert witness, OCC argues that residential customers would pay in excess of $20 million more under the stipulation compared with the RSP Stipulation (OCC Ex. 1B at 5-6). OCC alleges that the average generation rate, using DP&L's market forecasts, would be a mere 0.36 percent above that proposed in the stipulation (*id.* at 14-15.) Further, OCC argues that the fact that the new charges are unavoidable would make it impossible for a marketer to compete with only the avoidable portion of DP&L's generation rate (*id.* at 16.)

OPAE contends that the stipulation fails to benefit ratepayers and that the stipulation is not in the public interest. OPAE argues that the stipulation raises customer rates above those contemplated by the RSP Stipulation. On the other hand, OPAE states that the benefit of protection of customers from a volatile market is unproven and speculative (OPAE brief at 5-7). OPAE further argues that the stipulation makes generation-related charges unavoidable despite the fact that such charges should be included as part of DP&L's market-based standard service offer (*id.* at 8-9). Finally, OPAE argues that, under the provisions of Am. Sub. Senate Bill 3, it is unreasonable and unlawful to charge customers for environmental compliance costs associated with generation (*id.* at 10-11).

The stipulation presented in this case would extend the rate stabilization plan approved by the Commission in Case No. 02-2279-EL-ATA. Therefore, in determining whether this settlement, as a package, benefits ratepayers and the public interest, the Commission will be guided by the three goals the Commission set forth for the rate stabilization plans: (1) rate certainty for customers; (2) financial stability for the utility; and (3) the further development of competitive markets. *In the Matter of the Application of The Cincinnati Gas & Electric Company to Modify its Nonresidential Generation Rates to Provide for Market-Bases Standard Service Offer Pricing and to Establish an Alternative Competitive-Bid Service Rate Option Subsequent to the Market Development Period,* Case No. 03-93-El-ATA, Opinion and Order (September 29, 2004) at 15.

Although DP&L alleges a $262 million savings to residential consumers as the result of stipulation, the Commission finds that the comparison between rates to be paid under the stipulation and projected market rates from 2006 through 2010 is not the relevant comparison for the review and evaluation of the stipulation filed in this case. The RSP stipulation, which was approved by the Commission, establishes the price to be offered customers from 2006 through 2008, unless and until otherwise ordered by this Commission. Therefore, the proper comparison is between: (1) the price residential customers would pay from 2006 through 2008 under the RSP stipulation plus projected market prices in 2009 and 2010, and (2) the prices for 2006 through 2010 provided under the stipulation filed in this case. According to OCC's witness Haugh, the total generation revenue paid by residential customers under this comparison is substantially equal; under both scenarios, residential customers would pay $1.66 billion from 2006 through 2010 (OCC Exhibit 1b, Schedule MPH-1, Scenario I and Scenario III, Schedule MPH -3, and Schedule MPH-5).

Nonetheless, the Commission's review cannot end with this comparison. The projected market prices for 2009 and 2010 are simply projections. According to the testimony at the hearing, it is undisputed that the current markets for power for 2009 and 2010 are not liquid and that this lack of financial liquidity makes such markets difficult to predict (Tr. III at 24). The Commission finds that there is significant value in providing predictable, stable rates for 2009 and 2010 rather than relying on projected market rates. Because of the unpredictable nature of the market for 2009 and 2010, the Commission finds that, although it is difficult to quantify the value of stable, predictable rates precisely, the known rates do have value for customers. Further, the Commission notes that DP&L's witness Shrunk testified that the value was consistent with that provided by an option purchased in the futures market (DP&L Ex. 13C at 2, 6). Moreover, this value is enhanced because the Commission retains the authority to terminate the rate stabilization period, at any time, in the event that market rates are substantially below the prices provided for by the stipulation (Signatory Parties Ex. 1 at 6; OCC Ex. 2 at 14-15. *See also, Dayton Power and Light Company*, Case No. 02-2279-EL-ATA at 26-27).

Moreover, the Commission must review the settlement package for benefits to *all* ratepayers and the public interest. No commercial and industrial customers have opposed the stipulation. Instead, representative of commercial and industrial customers are signatory parties to the stipulation and these parties agree that the stipulation benefits ratepayers by eliminating uncertainty and providing for stable, predictable rates through 2010.

Therefore, the Commission finds that the stipulation, as presented, meets the first goal for rate stabilization plans: the stipulation provides rate certainty to customers for the period January 1, 2006 through December 31, 2010. The second goal established by the Commission for rate stabilization plans is to provide financial stability for the utility. *Cincinnati Gas and Electric Co.*, Case No. 03-93-EL-ATA at 15. The testimony of DP&L witness Seger-Lawson established that the increases in the EIR provided for by the stipulation should recover revenues of $374,318,805 between January 1, 2006, and December 31, 2010 (DP&L Ex. 11F, Attachment A). The Commission finds that this revenue should provide financial stability to the utility by recovering environmental compliance costs incurred by DP&L and thus meets the second goal for rate stabilization plans.

Nonetheless, the Commission is concerned by the impact of the stipulation on competition. The third goal for rate stabilization plans is to further the development of competitive markets. *Cincinnati Gas and Electric Co.*, Case No. 03-93-EL-ATA at 15. The Commission notes that, as presented, the stipulation provides that the increases to the EIR scheduled for 2009 and 2010 are avoidable. The Commission believes that the entire EIR should be avoidable to customers who shop for the duration of the stipulation. Making the entire EIR avoidable would promote competitive markets by increasing the shopping credit to customers who switch to competitive provider. Therefore, the Commission will modify the stipulation to provide that all increases in the EIR be avoidable from 2007 through 2010. The Commission finds that, as modified, the stipulation meets the goal of promoting the development of competitive markets.

In addition, the Commission believes that the stipulation does not specifically address whether DP&L is committed to financially support the Voluntary Enrollment Procedure (VEP). At the hearing, DP&L's witness Segar-Lawson testified that DP&L is committing the resources to support VEP in the amount of $500,000 per year (Tr. III at 139-140). Therefore, in order to clarify this provision of the stipulation, the Commission orders DP&L to commit up to $500,000 to support VEP in 2007, in addition to the funds already committed to support VEP in 2006 by the RSP Stipulation.

The Commission finds that the value of extending stable, predictable rates through 2010 is a significant benefit to ratepayers and the public interest and that such value outweighs the burden of the increased rates. Moreover, the Commission finds that the stipulation, as modified, meets the three goals established by the Commission for rate stabilization plans. Therefore, upon careful consideration of the record in this proceeding, the Commission finds that the stipulation, as a package and as modified by the Commission, benefits ratepayers and the public interest.

3) <u>Does the settlement package violate any important regulatory principle or practice?</u>

The OCC argues in its post-hearing brief that approval of the stipulation would violate important regulatory principles and practices. Specifically, OCC argues that the stipulation is a collateral attack on the Commission's order approving the RSP stipulation in Case No. 02-2279-EL-ATA and is therefore illegal (OCC brief at 16-17). Further, OCC argues that the settlement package violates DP&L's tariffs (*id.* at 18-20). Finally, OCC argues that approval of this stipulation undermines the settlement process (*id.* at 20-21).

DP&L asserts that the stipulation does not violate any important regulatory principles or practices. DP&L argues that the stipulation provides market-based rates and provides for competitive bidding through the voluntary enrollment process (DP&L brief at 25-26). Moreover, DP&L argues that the stipulation is not barred by the doctrine of collateral estoppel because several important facts and events have occurred since the RSP stipulation was approved by the Commission. DP&L states that, although the RSP Stipulation included several provisions designed to promote competition, there has been very little customer switching to competitive providers since the Commission approved the RSP Stipulation; DP&L cites to undisputed testimony at the hearing that only 0.03 percent of its load have switched to competitive providers unaffiliated with DP&L (*id.* at 26-27; DP&L Ex. 11E at 3). Moreover, DP&L argues that fuel and environmental cost increases have greatly exceeded expectations at the time the RSP Stipulation was approved, noting that the staff report demonstrates that the increase in such costs exceeded 11 percent in the first year of the RSP Stipulation alone (DP&L brief at 27; Staff Ex. 2, Schedule A-1).

The Commission finds that the stipulation does not represent an improper collateral attack on the Commission's order approving the RSP Stipulation in Case No. 02-2279-EL-ATA. The Commission finds that, based upon the evidence in the record in this proceeding, the competitive market in DP&L's service territory has not developed as the Commission expected when it approved the RSP Stipulation. According to the testimony at hearing, only 0.03 percent of DP&L's total load has switched to a competitive supplier not affiliated with DP&L (DP&L Ex. 11E at 3). In addition to this testimony, the Commission notes that, in 2005, there were four rounds of competitive bidding under the Voluntary Enrollment Program and that none of the rounds of competitive bidding produced a single bidder (*In the Matter of the Commission's Selection of Generation Providers for The Dayton Power and Light Company's Voluntary Enrollment Procedure,* Case No. 05-302-EL-UNC, Reports of the VEP Oversight Group dated March 8, 2005, May 12, 2005, July 7, 2005, and August 31, 2005). Similarly, the Commission finds that the record in this proceeding demonstrates that fuel and environmental costs vastly exceeded the Commission's expectations at the time the RSP Stipulation was approved. The Commission believes in the precedential value upon all of its prior decisions, including the decision to adopt the RSP Stipulation in Case No. 02-2279-EL-ATA; however, in light of the changed circumstances enumerated above, the Commission finds that extension and modification of the RSP Stipulation is clearly needed. *Consumers' Counsel v. Pub. Util. Comm.* (1984), 10 Ohio State 3d 49.

The Commission finds that the stipulation does not violate any important regulatory principles or practices. OCC alleges that the "settlement package" violates DP&L's tariff. At the hearing, the OCC elicited testimony from DP&L's witness Seger-Lawson that DP&L had offered to waive the tariff provision requiring sixty days notice to return to its standard offer service for Cargill and Honda (Tr. III at 104-107). The OCC believes that such waivers are improper and, therefore, the "settlement package" violates DP&L's tariffs. The Commission notes that DP&L's witness Segar-Lawson also testified at the hearing that DP&L will apply the waiver in a non-discriminatory fashion to any similarly situated customer (*id.* at 107). To the extent that OCC or any other party believes that DP&L has applied such waiver in a discriminatory fashion, they may file a complaint with the Commission under Section 4905.26, Revised Code. However, the Commission finds that this waiver is not part of the stipulation presented to the Commission for review and, therefore, is not relevant to this proceeding.

IV. RATE STABILIZATION SURCHARGE RIDER

The stipulation proposed a RSS Rider amounting to 11 percent of DP&L tariffed generation rates as of January 1, 2004. The staff recommended that DP&L be authorized to increase its revenue by $76,250,127, an increase of 11 percent over current generation revenue and of 7.30 percent over total current revenue (Staff Ex. 2 at 2; Staff Ex. 3 at 2). Adding the increase of $76,250,127 to the test-year revenue of $1,043,610,976 produces a new pro forma revenue total of $1,119,817,954.

The Commission finds the recommended increase of $76,250,127 in revenue to be fair, reasonable and supported by the record and, therefore, will authorize DP&L to implement the RSS Rider proposed by the stipulation.

V. TARIFFS

As part of its investigation in this proceeding, the staff reviewed the proposed tariff provisions for the RSS Rider, including the methodology used to calculate the rates to be included in the RSS Rider and the placement of the rider in DP&L's Distribution Service Tariff, and has recommended that they be approved by the Commission. The tariffs filed by DP&L do not reflect the 2.5 percent generation reduction for residential customers provided in the stipulation. The Commission directs DP&L to make this adjustment in the final tariffs. Otherwise, the Commission finds that the tariffs filed on April 4, 2005, are reasonable, and they will be approved by the Commission.

VI. <u>OTHER ISSUES</u>

OCC objected that the staff report failed to require DP&L to reduce its generation rates for residential customers by the additional 2.5 percent provided for by the RSP Stipulation, as modified by the Commission. The OCC states that the Commission had ruled, in adopting the RSP Stipulation, that the additional 2.5 percent reduction will take effect if "insufficient competition" has been experienced in the DP&L service territory (OCC brief at 6-7). OCC notes the testimony of its witness Haugh, who testified that residential competition has not developed in areas served by DP&L (OCC Ex. 1-A at 11). Because the stipulation includes the additional 2.5 percent reduction in generation rates sought by the OCC, the Commission finds that, in light of our adoption of the modified stipulation in this case, the OCC's objection is moot.

OCC objected to the staff report's conclusion that the placement of the RSS Rider in the company's Distribution Service Tariff is reasonable. OCC argues that DP&L agreed in the RSP Stipulation that the RSS is a generation charge and that the tariffs should conform to that agreement (OCC brief at 9). In the staff report, the staff concluded that, since the rider is unavoidable, its placement in the Distribution Service Tariff is reasonable (staff report at 27). The Commission agrees with the staff's conclusion that placement of the rider in the Distribution Service Tariff reduces confusion as to whether the charges are avoidable; therefore, the Commission finds that this objection should be denied.

Finally, OCC objected to the failure of the staff report to evaluate DP&L's application for compliance with the requirements of Section 4909.18, Revised Code. Staff argues that OCC has failed to identify with any particularity either DP&L's or the staff's failure to comply with such requirements (staff brief at 6; staff reply at 3). Further, staff argues that the process for adjusting the RSS Rider was set forth in the RSP Stipulation, of which the OCC was a signatory party. Staff notes that the Commission specifically found that the RSS mechanism was "reasonable and legally sustainable" (*id.* at 4, *quoting Dayton Power and Light*, Case No. 02-2279-EL-ATA at 28) and that this finding was upheld by the Supreme Court in *Constellation NewEnergy, Inc. v. Pub. Util. Comm'n*, (2004) 104 Ohio St. 3d 530, 539. Finally, the staff notes that, in this proceeding, the Commission has granted to DP&L waivers of a number of the Commission's Standard Filing Requirements (staff reply at 5; Entry (March 23, 2005)). The Commission finds that the RSP Stipulation clearly stated that adjustments to the RSS Rider should be made by application of the company under Section 4909.18, Revised Code, and that the parties intended that such application be limited to the rider only, rather than a general rate proceeding. Therefore, the Commission finds that OCC objection should be denied.

OPAE objected to the failure of the staff report to require DP&L to provide increased funding for energy efficiency services to low-income customers. OPAE believes that such services could mitigate the impact of the rate increases resulting from the stipulation. OPAE cites to the testimony of its witness Donnellan, the chief executive officer of the Community Action Partnership of the Greater Dayton Area, who testified for the need for $1 million in funding for these services (OPAE brief at 12).

DP&L disagrees with OPAE's objection. DP&L argues that past contributions of funds by DP&L for energy efficiency funding occurred in the context of settlements and that OPAE declined to participate in the settlement in this case. DP&L also argues that witness Donnellan provided no basis for arriving at the $1 million figure for funding energy efficiency programs and that witness Donnellan provided no plan on how his organization would spend these funds (DP&L brief at 21). The staff also disagreed with OPAE's objection. The staff argues that the RSS Rider sought in this proceeding was previously authorized subject to review and verification, by the Commission in the RSP Stipulation and that there was no provision in that case for the funds recommended by OPAE (staff brief at 6). Therefore, the staff concludes that such funding is beyond the limited scope of this proceeding (*id.* at 6-7; staff reply at 9).

The Commission will not order DP&L to provide such funding at this time. The Commission believes that, absent a provision in the stipulation, the question of funding for energy efficiency programs is properly left to general rate cases. Although, as provided for in the RSP Stipulation, this case was brought pursuant to Section 4909.18, Revised Code, the scope of this proceeding remains a limited one, and the Commission finds that OPAE's recommendation is outside of the scope of this proceeding and its objection should be denied.

Although the stipulation purports to have resolved all outstanding issues in this proceeding, there are a number of objections to the staff report which have not been addressed on brief or withdrawn. To the extent that any such objection is not specifically addressed in this opinion and order, the Commission finds that the objection should be denied.

FINDINGS OF FACT AND CONCLUSIONS OF LAW:

(1) DP&L is an electric light company within the meaning of Sections 4905.03(A)(4) and 4928.01(A)(7), Revised Code, and, as such, is a public utility as defined by Section 4905.02, Revised Code, subject to the jurisdiction and supervision of the Commission.

(2) On March 1, 2005, DP&L filed a notice of intent to file an application for an increase in rates to be charged. In that notice, DP&L requested a test period beginning October 1, 2004, and ending September 30, 2005, and a date certain of March 31, 2005.

(3) DP&L's application was filed pursuant to, and this Commission has jurisdiction over the application under, the provisions of Section 4909.18, Revised Code. The application complies with the requirements of this statute.

(4) By entry of March 23, 2005, the Commission approved the requested test year and date certain.

(5) On April 4, 2005, DP&L filed its application for an increase in rates. By entry dated May 4, 2005, the Commission accepted DP&L's application for filing.

(6) Intervention was granted to: the Ohio Consumers' Counsel; Industrial Energy Users-Ohio; Ohio Partners for Affordable Energy; Cargill, Inc.; and Honda of America Mfg., Inc.

(7) A motion was granted to admit David C. Rinebolt to practice *pro hac vice* on behalf of OPAE.

(8) On August 26, 2005, staff filed its written report of investigation with the Commission. Objections to the staff report were filed by several parties.

(9) A prehearing conference was held on October 6, 2005.

(10) The local public hearing was held on October 27, 2005, pursuant to published notice. Two public witnesses gave unsworn testimony.

(11) The evidentiary hearing commenced on November 4, 2005, and continued on November 8, 2005, November 14, 2005, and November 15, 2005.

(12) On November 3, 2005, a stipulation which purports to resolve all of the issues raised by these proceedings was filed by four parties.

(13) The ultimate issue for the Commission's consideration is whether the agreement, which embodies considerable time and effort by the signatory parties, is reasonable and should be adopted. In considering the reasonableness of the stipulation, the Commission has used the following criteria:

(a) Is the settlement a product of serious bargaining among capable, knowledgeable parties?

(b) Does the settlement, as a package, benefit ratepayers and the public interest?

(c) Does the settlement package violate any important regulatory principle or practice?

(14) The stipulation was the product of serious bargaining among capable, knowledgeable parties representing a diversity of interests including the utility and industrial and commercial consumers as well as a competitive retail electric service provider.

(15) As modified by this Opinion and Order, the stipulation, as a package, benefits ratepayers and the public interest. The stipulated resolution of this case is for many reasons advantageous and meets the three goals established by the Commission for the consideration of rate stabilization plans.

(16) The stipulation does not violate any important regulatory principles or practices. In light of the changed circumstances since the approval of the RSP Stipulation, extension and modification of the RSP Stipulation is clearly needed.

(17) The stipulation submitted by the parties is reasonable and, as indicated herein, shall be adopted as modified by the Commission.

(18) DP&L is authorized to implement the RSS Rider to increase its revenue by $76,250,127, an increase of 11 percent over current generation revenue and of 7.30 percent over total current revenue. This RSS Rider is fair, reasonable and supported by the record in this proceeding.

ORDER:

ORDERED, That the stipulation presented in these proceedings be adopted as modified by the Commission. It is, further,

ORDERED, That the application of The Dayton Power and Light Company for authority to increase its rates and charges for service is granted to the extent provided in this opinion and order. It is, further

ORDERED, That DP&L is authorized to file in final form four complete, printed copies of tariffs consistent with this opinion and order, and to cancel and withdraw its superseded tariffs. One copy shall be filed with this case docket, one copy shall be filed with the applicant's TRF docket and the remaining two copies shall be designated for distribution to the Rates and Tariff Division of the Commission's Utilities Department. The applicant shall also update its tariffs previously filed electronically with the Commission's docketing division. It is, further,

ORDERED, That the effective date of the new tariffs shall be a date not earlier than both January 1, 2006, and the date upon which four complete, printed copies of final tariffs are filed with the Commission. The new tariffs shall be effective for services rendered on or after such effective date. It is, further,

ORDERED, That DP&L shall notify all affected customers of the tariff changes via a bill message or a bill insert within 30 days of the effective date of the tariffs. It is, further, ORDERED, That a copy of this entry be served upon all parties of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Ronda Hartman Fergus

Judith A. Jones

Donald L. Mason

Clarence D. Rogers, Jr.

GAP:ct

Entered in the Journal

DEC 2 8 2005

Reneé J. Jenkins
Secretary

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of a Post-Market Development Period Rate Stabilization Plan.	))))	Case No. 04-169-EL-UNC

OPINION AND ORDER

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OPINION AND ORDER

The Commission, having considered the evidence, the arguments of the parties, and the applicable law, hereby issues its opinion and order in this proceeding.

APPEARANCES

Marvin I. Resnik and Sandra K. Williams, 1 Riverside Plaza, Columbus, Ohio 43215-2373, and Daniel Conway, Porter, Wright, Morris & Arthur, 41 South High Street, Columbus, Ohio 43215, on behalf of Columbus Power Company and Ohio Power Company.

Jim Petro, Attorney General of the state of Ohio, Duane W. Luckey, Senior Deputy Attorney General, by William Wright, Steven Nourse, and Thomas McNamee, Assistant Attorneys General, 180 East Broad Street, 9th Floor, Columbus, Ohio 43215, on behalf of the staff of the Public Utilities Commission of Ohio.

Michael R. Smalz, Ohio State Legal Services Association, 555 Buttles Avenue, Columbus, Ohio 43215, and Joseph V. Maskovyak, Legal Aid Society of Columbus, 40 West Gay Street, Columbus, Ohio 43215, on behalf of Appalachian People's Action Coalition.

Robert P. Mone, Scott A. Campbell, and Kurt P. Helfrich, Thompson Hine LLP, 10 West Broad Street, Suite 700, Columbus, Ohio 43215-3435, on behalf of Buckeye Power Inc. and Ohio Rural Electric Cooperatives Inc.

Joseph Condo, Calpine Corporation, 250 Parkway Drive, Suite 380, Lincolnshire, Illinois 60069, on behalf of Calpine Corporation.

Stephen J. Smith, Gregory J. Dunn, and Christopher L. Miller, Schottenstein, Zox & Dunn, 41 South High Street, Columbus, Ohio 43215, on behalf of City of Dublin.

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Michael L. Kurtz, Boehm, Kurtz & Lowry, 36 East Seventh Street, Suite 2110, Cincinnati, Ohio 45202, on behalf of The Kroger Company.

Ellis Jacobs, Advocates for Basic Legal Equality Inc., 333 West First Street, Suite 500B, Dayton, Ohio 45402, on behalf of Lima/Allen Council on Community Affairs and WSOS Community Action.

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David C. Rinebolt, Ohio Partners for Affordable Energy, 337 South Main Street, 4th Floor, Suite 5, P.O. Box 1793, Findlay, Ohio 45839-1793, on behalf of Ohio Partners for Affordable Energy.

Craig A. Glazer and Janine Durand, PJM Interconnection L.L.C., 955 Jefferson Avenue, Valley Forge Corporate Center, Norristown, Pennsylvania 19403-2497, on behalf of PJM Interconnection L.L.C.

Shawn P. Leyden, 80 Park Plaza, 19th Floor, Newark, New Jersey 07102, on behalf of PSEG Energy Resources and Trade LLC.

Peter J.P. Brickfield and Emily W. Streett, Brickfield, Burchette, Ritts & Stone PC, 1025 Thomas Jefferson Street NW, 8th Floor – West, Washington, DC 20007, on behalf of Wheeling-Pittsburgh Steel Corporation.

OPINION

I. Background

In June 1999, the Ohio General Assembly passed legislation (Amended Substitute Senate Bill No. 3 of the 123rd General Assembly, referred to as SB3) requiring the restructuring of the Ohio electric utility industry and providing for competition for the generation component of electric service. That legislation was signed by the governor in July 1999. Pursuant to SB3, the Commission received and reviewed proposed plans by Columbus Southern Power Company and Ohio Power Company (collectively AEP) to transition from the then-existing regulatory framework to the restructured SB3 framework. *In the Matter of the Applications of Columbus Southern Power Company and Ohio Power Company for Approval of Their Electric Transition Plans and for Receipt of Transition Revenues,* Case Nos. 99-1729-EL-ETP and 99-1730-EL-ETP, Opinion and Order (September 28, 2000) and Entry on Rehearing (November 21, 2000).

Ohio electric choice (a short-hand term for the competitive electric generation component in Ohio) began on January 1, 2001. Under Section 4928.40, Revised Code, a period of time was established to allow a competitive electric market to develop for the generation component of electric service (market development period, MDP). The default expiration date of the MDPs was December 31, 2005, unless otherwise determined by the Commission in conformance with certain statutory criteria. Since electric choice began, three competitive retail electric service providers have been certified to serve customers in AEP's service territories, with only one actually serving customers (nonresidential) (Tr. I, 34, 127). There has been at most 3.4 percent shopping in Columbus Southern's service territory and zero percent shopping in Ohio Power's territory (Tr. II, 175; OCC Ex. 8; GMEC Ex. 5, at first set discovery requests 25 and 26 and third set discovery requests 1 and 2). AEP's MDP is currently scheduled to expire on December 31, 2005.

In September 2003, the Commission (while addressing a proposed stipulated plan for the competitive market in The Dayton Power and Light Company service territory) encouraged all other electric distribution utilities (EDUs) in the state to consider continuation of their MDPs, a plan for rate stabilization, and/or a market-based standard service offer as a means for allowing time for their competitive electric markets to grow. *In the Matter of the Continuation of the Rate Freeze and Extension of the Market Development Period for The Dayton Power and Light Company,* Case No. 02-2779-EL-ATA, Opinion and Order at 29 (September 2, 2003). Then later that month, the Commission elaborated further that such proposals should balance three objectives: rate certainty, financial stability for the EDU, and further competitive market development. *In the Matter of the Application of FirstEnergy Corp. on Behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Approval of Tariff Adjustments,* Case No. 03-1461-EL-UNC, Entry at 4-5 (September 23, 2003).

On February 9, 2004, AEP filed an application with the Commission for approval of a rate stabilization plan (RSP) to follow its competitive electric MDP. AEP proposes a plan to substitute for a post-MDP, market-based standard service offer and to eliminate a competitive bidding process from 2006 through 2008.

Twenty-five entities filed motions to intervene in this proceeding. Those requests were all granted and the intervenors are:

Appalachian People's Action Coalition (APAC)[1]	Buckeye Power Inc.
Calpine Corporation	City of Dublin
City of Upper Arlington	Constellation NewEnergy Inc.[2]
Constellation Power Source Inc.	Green Mountain Energy Company (Green Mountain or GMEC)
Industrial Energy Users-Ohio (IEU-Ohio)	The Kroger Company
Lima/Allen Council on Community Affairs	MidAmerican Energy Company
National Energy Marketers Association (NEMA)	Ohio Consumers' Counsel (OCC)
Ohio Energy Group (OEG)[3]	Ohio Hospital Association
Ohio Manufacturers' Association	Ohio Partners for Affordable Energy (OPAE)
Ohio Rural Electric Cooperatives Inc.	PJM Interconnection L.L.C. (PJM)
PSEG Energy Resources and Trade LLC (PSEG)	Strategic Energy LLC
Wheeling-Pittsburgh Steel Corporation	WPS Energy Services Inc.
WSOS Community Action	

By entry dated March 11, 2004, the Commission established a procedural schedule for this proceeding. A technical conference was held on March 24, 2004. Objections to the application were filed on April 8, 2004. By entry dated April 27, 2004, the examiner slightly modified that procedural schedule, changing deadlines for prefiling expert testimony, discovery cut-off, the local hearing dates (to be held in Canton and Columbus), and the evidentiary hearing date. In May 2004, the parties prefiled their expert testimony under the revised schedule.

Pursuant to the revised schedule, the local, public hearing in Canton, Ohio, was conducted on May 19, 2004. However, the examiner discovered after that hearing that the Commission had not properly sent any of the publication notices to the newspapers in AEP's service territory. Therefore, the examiner scheduled another local hearing in Canton, Ohio, for July 7, 2004, and rescheduled the local hearing in Columbus for July 1, 2004.

On May 24, 2004, OCC filed a motion to dismiss the application on various legal grounds. On May 25, 2004, AEP filed a motion to extend the time to respond to OCC's motion. IEU-Ohio supported an extension of the time to respond to OCC's motion. By

1 Appalachian People's Action Coalition, Lima/Allen Council on Community Affairs, Ohio Partners for Affordable Energy, and WSOS Community Action are collectively referenced in this decision as the low-income advocates or LIA.

2 Constellation NewEnergy Inc., MidAmerican Energy Company, Strategic Energy LLC, and WPS Energy Services Inc. are collectively referenced in this decision as the Ohio Marketers Group or OMG.

3 OEG is composed of AK Steel Corporation, BP Products North America Inc., The Procter and Gamble Co., Ford Motor Company, and International Steel Group Inc.

entry dated June 1, 2004, the examiner granted the request to defer a ruling on OCC's motion to dismiss, stating that all parties shall have the opportunity to argue the legality of AEP's proposal in post-hearing briefs.

The evidentiary hearing began on June 8, 2004, and continued to June 14, 2004. AEP presented the testimony of five witnesses. The staff and OCC each presented the testimony of two witnesses. APAC, Lima/Allen Council on Community Affairs, and WSOS Community Action jointly sponsored the testimony of one witness and OEG presented the testimony of one witness. At the July 1 and 7, 2004 local hearings, three people provided testimony in opposition to AEP's proposed RSP. The parties filed post-hearing briefs on July 13 and 30, 2004.

II. The Law

Section 4928.14, Revised Code, states in pertinent part:

(A) After its market development period, an electric distribution utility in this state shall provide consumers, on a comparable and nondiscriminatory basis within its certified service territory, a market-based standard service offer of all competitive retail electric services necessary to maintain essential electric service to consumers, including a firm supply of electric generation service....

(B) After that market development period, each electric distribution utility also shall offer customers within its certified territory an option to purchase competitive retail electric service the price of which is determined through a competitive bidding process....At the election of the electric distribution utility, and approval of the commission, the competitive bidding option under this division may be used as the market-based standard offer required in division (A) of this section. The commission may determine at any time that a competitive bidding process is not required, if other means to accomplish generally the same option for customers is readily available in the market and a reasonable means for customer participation is developed.

Also relevant, the Commission approved a request filed by AEP to temporarily waive the need for it to propose a market-based standard service offer and/or competitive bidding process (CBP). *In the Matter of the Request for a Temporary Waiver by Columbus Southern Power Company and Ohio Power Company from the Requirements of Chapter 4901:1-35, Ohio Administrative Code,* Case No. 04-888-EL-UNC, Entry (June 23, 2004). The Commission agreed that AEP need not make such proposal(s) until 30 days after the final order is issued in this proceeding.

III. Certain Elements of the Approved Electric Transition Plan

In moving to electric choice in Ohio, the Commission had to address a number of financial and regulatory concerns so that each of the electric utilities could transition into utilities providing monopoly distribution service, while competing to provide the generation component. In the course of making that transition, the bundled rates and services of the electric utilities had to be separated, or unbundled, into generation, distribution and transmission components in the electric transition plan (ETP) proceedings.

Most of the parties to the AEP ETP proceedings agreed upon a resolution of the issues. The Commission reviewed that proposed resolution and approved it, with some minor modifications and with a reservation of a ruling upon the independent transmission plan. For purposes of better understanding the proposed RSP, several relevant components of the ETP are:

(1) All distribution rates effective December 31, 2005 will be frozen through 2007 for Ohio Power and 2008 for Columbus Southern. However, during that period, distribution rates can adjust to reflect costs of complying with certain changes (e.g., environmental, tax and regulatory changes) and for relief from storm damage or emergencies.

(2) Columbus Southern and Ohio Power agreed to absorb the first $20 million of actual consumer education, customer choice implementation and transition plan filing costs, but the remainder of such were permitted to be deferred, plus a carrying charge, as regulatory assets for recovery in future distribution rates (via a rider).

(3) Regulatory asset recovery was approved for the companies' MDP and for the subsequent three years for Columbus Southern and the subsequent two years for Ohio Power. Recorded regulatory assets at the beginning of the MDP, which exceeded specific regulatory asset dollar amounts in the stipulation, were amortized during the MDP and recovered through existing frozen and unbundled rates.

(4) Columbus Southern made available to the first 25 percent of the switching residential customers a shopping incentive. Any unused portion of that incentive as of December 31, 2005, will be credited to Columbus Southern's regulatory transition cost recovery.

(5) AEP reduced by five percent its generation component (including the regulatory transition costs). AEP agreed to not seek to reduce that five percent reduction for residential customers during the MDP. The first 20 percent of Ohio Power residential customer load as of December 31, 2005, that switches will not be charged the regulatory transition charge in 2006 and 2007.

(6) AEP shall transfer, by no later than December 15, 2001, operational control of its transmission facilities to a Federal Energy Regulatory Commission (FERC) approved regional transmission organization (RTO). AEP established a fund (up to $10 million) for costs associated with transmission charges imposed by PJM and/or the Midwest

Independent System Operator (MISO) on generation originating in the service territories of PJM or MISO as such costs may be incurred.

IV. Elements of the Proposed Rate Stabilization Plan

AEP proposes a plan from 2006 through 2008 to substitute for a post-MDP market-based standard service offer and to eliminate a competitive bidding process (Tr. I, 27). The RSP states that all provisions of the approved ETP that are not changed by the RSP will not be changed. The RSP proposal can be quickly summarized as follows:

(1) Keeps distribution rates in effect on December 31, 2005, frozen through 2008, except for changes allowed by 12 categories.

(2) Continues to defer pre-2006 consumer education, customer choice implementation and transition plan filing expenses beyond $20 million. Defer post-2005 consumer education, customer choice implementation and transition plan filing expenses and all RSP filing costs. All will be recovered as distribution regulatory assets, along with carrying charges, after the RSP.

(3) Allows deferral and recovery in RSP distribution rates of: (a) RTO administrative charges from the date of integration in PJM through 2005, along with a carrying cost; (b) full carrying charges for construction expenses in Accounts 101 (electric plant in service) and 106 (completed construction not classified) from 2002 through 2005; and (c) 2004 and 2005 equity carrying charges for expenditures from 2002 through 2005 in Account 107 (construction work in progress).

(4) Increases generation rates for all customer classes by three percent for Columbus Southern and seven percent for Ohio Power each year of the plan. Also, generation rates can be adjusted in the event that any of five situations arise, but the sum of the generation increases shall not be greater than seven percent for Columbus Southern and 11 percent for Ohio Power in any one of the years. As an alternative to the increases for residential customers, AEP offers that the Commission can terminate the five percent residential generation rate discount on June 30, 2004 (which will, instead, increase generation rates for residential customers by 1.6 percent for Columbus Southern and 5.7 percent for Ohio Power each year of the plan). These generation rate increases are avoidable for customers who choose another competitive generation supplier.

(5) Allows adjustments of transmission components for changes in costs directly or indirectly imposed on the companies during the RSP.

(6) Recovers amortized generation-related transition regulatory assets under the ETP rates.

(7) Makes the Columbus Southern 2.5 mills per kilowatt-hour (kWh) shopping incentive available during the RSP to the first 25 percent of the Columbus Southern residential load. Any unused portion will not be credited to the regulatory asset charge, but will become income to Columbus Southern. Still for 2006 and 2007, the first 20 percent of Ohio Power residential load that switches will not be charged the regulatory asset charge.

(8) Includes other terms addressing post-RSP Commission action, functional separation, an allowance for AEP to participate in the CBPs of other companies, and minimum stay requirements for all categories of customers.

AEP provided estimated revenue amounts expected from the fixed generation rate increases and the new deferrals to be recovered during the RSP (AEP Ex. 3, at 10):

Company	2006	2007	2008	Total
Columbus Southern	$48 million	$74 million	$100 million	$222 million
Ohio Power	$112 million	176 million	$247 million	$535 million

If the potential four percent generation increase were also added to the calculation, AEP acknowledges that the total estimated revenue amount combined for both companies becomes $1.17 billion (Tr. II, 78).

V. OCC's Motion to Dismiss

As noted earlier, OCC filed, on May 24, 2004, a motion to dismiss the application in this proceeding on two grounds, namely that the application will violate several statutes and it illegally proposes to repudiate the ETP stipulation. In the context of describing the various components of the RSP, we will also explain and address the legal and policy arguments raised by the parties, including the specific arguments made by OCC.

VI. Positions of the Intervening Parties and Commission Discussion

Of the parties who have expressed a position in this proceeding, nearly all agree that a competitive market has not adequately developed in AEP's service territories (AEP Ex. 1, at 4; AEP Ex. 2, at 24; Tr. I, 201; Staff Ex. 2, at 3; Tr. IV, 151; OEG Ex. 2, at 5; Tr. III, 208; GMEC Initial Br. 2, 5; IEU-Ohio Initial Br. 8-10; LIA Reply Br. 2, 9). Moreover, many also believe that some action needs to be taken by the Commission to avoid a "flash-cut" in 2006 to a freely competitive electric generation market (OEG Ex. 2, at 5; Tr. III, 208; 7/7/04 Tr. 6-7, 9; IEU-Ohio Reply Br. 7). Some of these parties openly fear that, without some Commission action, generation rates will escalate and fluctuate dramatically, which could hurt consumers, hurt the development of a competitive market, and harm the market participants (AEP Ex. 1, at 4; Staff Ex. 2, at 7; Staff Initial Br. 1, 12). The disagreement here is over the specific approach that the Commission should take to spur competition in AEP's service territories, while balancing the interests of the different market participants. As already noted, the Commission has determined that the objectives of an RSP are to develop a plan providing for: rate certainty, financial stability for the EDU, and further competitive market development.

A. Market-Based Standard Service Offer and Competitive Bidding Process

AEP has not conducted any studies or surveyed the market to determine the impact of its RSP upon shopping or participation by competitive suppliers (Tr. II, 177; GMEC Ex. 2). However, AEP believes that the proposed rate increases will create some opportunity for increased shopping (Tr. II, 178). Staff also agreed (Tr. IV, 23, 243-244). Moreover in AEP's view, its RSP will cover AEP's need to spend approximately $1.3 billion on environmental controls after 2005 and address AEP's environmental expenditures of roughly $1.0 billion between 2002 and 2004 (AEP Ex. 3, at 8, 11; Tr. I, 234-235). Additionally, AEP states that the RSP addresses transmission expenses, customer switching and future uncertainty (AEP Initial Br. 11). It is for those reasons that AEP believes its RSP is a reasonable proposal and good substitute for a market-based standard service offer and CBP.

AEP's RSP contains no CBP; instead, AEP seeks to substitute its RSP for a CBP. AEP takes the position that a CBP is not practical and not worth the effort (Tr. I, 96-97, 104-105). As noted earlier, the Commission has waived, temporarily, the current requirement for the filing of a CBP while the proposed RSP is under consideration. AEP believes that its proposed increased generation rates are reasonable substitutes for market-based rates. In AEP's view, if the market exceeds those rates, customers will benefit by having a fixed rate and, if the market rates fall below the increase levels, customers can avoid them by switching to another supplier (AEP Initial Br. 23, 65-66). Staff concurs that the generation rates constitute a reasonable proxy of market-based rates because of prices in the current wholesale market, prices in AEP's area, and shopping levels (Tr. IV, 20-21, 26-27, 244; Staff Initial Br. 4, 6). Moreover, staff believes that a next step (RSP) that provides generation rate stability and gradual, predictable increases is the best approach (Staff Reply Br. 3).

OEG and IEU-Ohio agree with the Commission's stated objectives and the concept of an RSP. However, neither agrees with AEP's RSP. Instead, they each advocate that their own proposed rate plan be adopted by the Commission (OEG Ex. 2, at 7-9; OEG Initial Br. 15-18; IEU-Ohio Initial Br. 6, 14, 37-40). OEG's rate plan basically provides: (a) no new transmission and distribution deferrals beyond that authorized in the ETP decision; (b) no transmission and distribution increases except for costs to comply with environmental (distribution-related), tax and regulatory laws or regulations, relief from storm damage expenses, or an emergency; (c) transmission and distribution rate increases after 2005 only upon a fully evaluated rate case; and (d) fixed generation rate increases after 2005 through a monthly rider designed to recover incremental environmental and governmentally mandated costs that have passed an earnings test (OEG Ex. 2, at 7-9; OEG Initial Br. 15-18). OEG's plan also addresses allowed components of rate base, components of operating expenses and rate of return (OEG Initial Br. 23-26).[4] OEG considers its plan to appropriately balance several things: (a) new environmental and

[4] Green Mountain disagrees with OEG's proposed RSP because the increases are cost-based, not market-based (GMEC Reply Br. 6).

generation-related costs are balanced with timely recovery, while the rates increase to reasonable levels based upon earned returns; (b) allows gradual and steady monthly rate increases when needed for financial stability; (c) ensures market development through moderate generation rate increases; and (d) ensures that earned returns do not increase through piecemeal, single-issue, distribution rate increases (*Id.* at 18; OEG Reply Br. 23-24).

IEU-Ohio recommends various modifications to AEP's RSP that focus upon the price certainty and financial stability objectives identified by the Commission (IEU-Ohio Initial Br. 38-40). In particular, IEU-Ohio recommends that: (a) AEP establish its standard service offer prices as the current generation charge[5] of each rate schedule; (b) AEP continue to collect transition costs; and (c) AEP be permitted to seek adjustment of the current generation charges (either as confiscatory or as requiring increases due to increased jurisdictional costs from fuel prices, environmental actions, tax laws, or judicial/administrative orders).[6] In the alternative, IEU-Ohio urges the Commission to consider extending and lowering the current fixed rates, as was found to be acceptable in Virginia (IEU-Ohio Reply Br. 11). AEP responds to both OEG's and IEU-Ohio's proposed plans, stating among other things that those parties simply want to keep AEP's low rates for another period of time and their plans do not take into account all three Commission goals (AEP Reply Br. 14, 25-26).

OCC argues that AEP's proposed RSP does not meet the requirements of Sections 4928.02 or 4928.14, Revised Code, because the RSP is not a market-based standard service offer and/or a CBP (OCC Motion to Dismiss 3-4, 11; OCC Initial Br. 35-36; OCC Reply Br. 22). Thus, in OCC's view, the Commission has no authority to approve the RSP. Similarly, OCC argues that the generation rate component of the RSP is improper because it contains no CBP, as required by Section 4928.14(B), Revised Code (OCC Initial Br. 35). Also, OCC contends that, since the RSP addresses service during the MDP that conflicts with the approved ETP, it violates Section 4928.33(C), Revised Code (OCC Motion to Dismiss 12). OMG, NEMA, PSEG, Green Mountain, and LIA concur with these criticisms (OMG/NEMA Initial Br. 2-6, 15; OMG/NEMA Reply Br. 3-5; PSEG Br. 3-4, 8-9; GMEC Initial Br. 6; GMEC Reply Br. 4; LIA Initial Br. 9-11). In their view, the RSP cannot be an acceptable substitute because it is not based on market prices. OCC, OMG and NEMA acknowledge that the RSP was proposed as an alternative to the market-based standard service offer, but argue that, legally, an alternative cannot be substituted because the statute does not allow for such (OCC Initial Br. 38; OMG/NEMA Initial Br. 5-6; OMG/NEMA Reply Br. 4-5). LIA and Green Mountain state that, instead of illegally seeking RSP proposals, the Commission should have followed the path set forth in Section 4928.06, Revised Code, and provided an evaluation to the legislature (LIA Initial Br. 12-14; LIA Reply Br. 8; GMEC Reply Br. 6). OCC recommends that a CBP be filed as soon as

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5 In IEU-Ohio's proposal, it references the "little g" instead of current generation charges. When AEP's rates were unbundled prior to the start of electric choice, the amounts that were categorized as generation-related (or the "big G") were the amounts not distribution-related, transmission-related, other unbundled amounts, and tax valuation adjustments. Section 4928.34(A)(4). Revised Code. For AEP, the "little g" is the difference between the "big G" and the amounts allotted for the regulatory transition charge. The "little g" is what is reflected in AEP's charges as the current generation charges.

6 Green Mountain also disagrees with IEU-Ohio's proposed RSP because the MDP rates are not market-based rates (GMEC Reply Br. 5).

possible and recommends a particular format (OCC Ex. 10, at 10, Attach. A; OCC Reply Br. 24-25).

PSEG and OEG argue that the Commission's goals for a RSP are not fulfilled by AEP's proposal. Specifically, PSEG states that rate certainty is not assured because of the many exceptions that are contained in the RSP for possible future events (PSEG Br. 6). OEG states that rate stability is not included in the RSP because the $1.17 billion potential increase cannot constitute stability (OEG Initial Br. 5). Next, they both contend that the RSP really just provides financial stability to AEP and PSEG believes it will benefit AEP's competitive activities, rather than financial stability of its regulated functions (PSEG Br. 7; OEG Initial Br. 5). Moreover, PSEG claims that the RSP will do nothing to foster development of the competitive electric market (PSGE Br. 8). OCC quantifies the impact on the residential class for some of the costs over the three years as $266 million if the additional generation increase is not included and $410 million if it is included (OCC Ex. 5, at 3-4, Schedule FRP-1). OCC recommends that the entire RSP be rejected (OCC Initial Br. 64)

If the RSP is not rejected for failure to use market-based rates, OMG, NEMA and PSEG recommend that the Commission require a competitive bid to test the market (as it did with the FirstEnergy EDUs) and establish a basis for that market's prices (OMG/NEMA Reply Br. 6-8, 11; PSEG Br. 9).[7] Moreover, OMG and NEMA point out that, pursuant to Section 4928.14(B), Revised Code, AEP must either provide for a competitively bid generation service or demonstrate that such would be duplicative to available services. They argue that AEP cannot make such a demonstration and, therefore, a CBP must be scheduled like the Commission has done with other EDUs (OMG/NEMA Reply Br. 8-9). If the Commission decides to require a CBP, Green Mountain advocates a retail CBP (bidding for customers) as done in Pennsylvania, instead of a wholesale CBP (bidding to provide generation) (GMEC Reply Br. 10-12). IEU-Ohio took the opposite position, stating that providing customers with a CBP in the current state of the market would elevate form over substance (IEU-Ohio Initial Br. 40). Instead, IEU-Ohio believes the Commission should ask the legislature to delay the CBP option until the Commission concludes that the market is sufficiently mature to warrant the time and resources needed for CBPs (*Id.*).

Commission Discussion

At the outset, we will note that AEP proposed an RSP because we requested it. All parties to this proceeding are aware of the direction that this Commission has taken and the concerns it has with the post-MDP competitive electric environment. In fact, many of

[7] The Commission ordered a CBP for the FirstEnergy EDUs in *In the Matter of the Applications of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Continue and Modify Certain Regulatory Accounting Practices and Procedures, for Tariff Approvals and to Establish Rates and Other Charges Including Regulatory Transition Charges Following the Market Development Period*, Case No. 03-2144-EL-ATA (June 9, 2004). On December 8, 2004, the CBP took place (an auction). The Commission concluded, on December 9, 2004, that the CBP auction price should be rejected because the previously approved RSP price is more favorable for consumers than the clearing price of the auction, which represented the best available market-based price to cover FirstEnergy's retail load. *In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Approval of a Competitive Bid Process to Bid Out Their Retail Electric Load*, Case No. 04-1371-EL-ATA, Finding and Order.

the parties in this proceeding have participated in several other proceedings involving the MDPs and post-MDP activities for other EDUs. Many of the parties readily acknowledge that a competitive electric generation market has not developed thus far in AEP's service territories and will not adequately develop by the time AEP's MDP expires in December 2005. With so few participants, so very little shopping having taken place in Columbus Southern's territory and no shopping at all having taken place in Ohio Power's territory, we do not want to simply allow market forces to be unfettered. We believe, in AEP's territory, a controlled transition is not only appropriate, but very much needed. We also believe that many, if not all parties, agree with this fundamental starting point.

The difference of opinion occurs with the manner in which to handle the near term. OCC, OMG, NEMA and LIA argue that Section 4928.14, Revised Code, provides the only mechanisms available to the Commission (adoption of a market-based standard service offer and a service developed through a CBP) and the proposed RSP is neither. Even with those two mechanisms identified in Section 4928.14, Revised Code, the parties disagree what should be done. However, AEP, staff, OEG and IEU-Ohio believe greater flexibility is available, namely, the Commission can adopt an RSP. We agree. AEP takes the position that a CBP is not practical and not worth the effort. Staff and IEU-Ohio agreed. We also agree and, as is within our authority, we conclude that a CBP is not warranted for AEP at the conclusion of its MDP. The record reflects that, in the past several years, only three competitive suppliers have been certified to provide competitive electric service in AEP's territory and only one is actually serving customers (Tr. I, 34, 127). Plus, there has been at most 3.4 percent shopping in Columbus Southern's service territory and zero percent shopping in Ohio Power's territory (Tr. II, 175; OCC Ex. 8; GMEC Ex. 5, at first set discovery requests 25 and 26 and third set discovery requests 1 and 2). This level of inactivity leads us to seriously doubt the efficacy of initiating a competitive bid. Instead, we conclude that an RSP (and in particular the one we adopt today) will accomplish, generally, the same as a CBP for customers and provide a reasonable means for customers to participate in that competitive environment as it continues to develop. As further explained in this decision, we agree to increase generation rates (which are avoidable to customers who choose another competitive generation supplier). These components of the RSP, along with continuation of the unaffected provisions of the ETP, we believe will prompt the competitive market and continue to provide customers a reasonable means for customer participation. Therefore, we conclude that, at this time, a CBP is not required for AEP between 2006 and 2008.

Many parties argue that AEP's proposed RSP is not a market-based standard service offer because it is not based upon the market. OMA and NEMA have argued that the RSP is not based upon a willing buyer and a willing seller. AEP proposes its RSP as a substitute for a market-based standard service offer (Plan at 3). Staff presented evidence that the RSP is a reasonable proxy of market-based rates based upon its evaluation (Tr. IV, 20-21, 26-27, 244). OCC's witness acknowledged that the Commission has the discretion to determine an appropriate proxy for a market-based standard service offer, given that both the retail electric choice market and the wholesale market have not sufficiently developed (Tr. III, 147). For the period involved (2006 through 2008), we conclude that the generation rates that we approve in this RSP today will constitute an appropriate market-based standard service offer, as required by Section 4928.14(A), Revised Code. We will evaluate any subsequent, additional generation rate adjustments (which are limited to only the enumerated categories). Additionally, we conclude that the RSP that we approve today complies with the requirements of Section 4928.14, Revised Code. None of the arguments raised to the contrary convinces us otherwise. Finally, we note that there is greater flexibility under Section 4928.14, Revised Code, than what some parties have advocated in this proceeding. The Ohio Supreme Court recently recognized, in *Constellation NewEnergy, Inc. v. Pub. Util. Comm.*, ____ Ohio St.3d ___, 2004-Ohio-6767 (December 17, 2004), that an RSP could satisfy Section 4928.14, Revised Code.

Next, we conclude that our decision today will fulfill our previously identified RSP goals. Throughout this decision, as we address the various components of the proposed RSP, we specifically explain how and why we believe that various approved components are acceptable, including how they meet or fulfill our intended goals.

B. Generation Rates and Charges (Provisions Two and Three of the RSP)

1. Three and Seven Percent Increases

AEP proposes in the RSP that, for all customer classes, the generation rates will increase each year (2006, 2007, and 2008) by three percent for Columbus Southern and by seven percent for Ohio Power. These increases will generate $151 million for Columbus Southern and $376 million for Ohio Power (AEP Ex. 3, at 10). AEP contends that the three and seven percent generation rate increases are reasonable to address the Commission's three objectives of a RSP. These generation rate increases are based upon the companies' judgment (AEP Ex. 2, at 12). Given that AEP has low generation rates currently, AEP contends that fixed increases will spur market competition and be preferable to customers, rather than imposition of full market-based rates (*Id.* at 13). AEP further notes that the generation rate increases complement the companies' substantial investments to comply with environmental requirements. AEP noted that it plans to spend $1.3 billion beyond normal capital expenditures after 2005 on generation-related environmental controls (AEP Ex. 2, at 14; AEP Ex. 3, at 11). Next, AEP points to other EDU generation rates and contends that its increased rates would still be below the current lowest average residential generation rates of those EDUs (AEP Ex. 5, at 13; Tr. III, 31).[8] When that comparison is made, AEP argues that its proposed generation rate increases are reasonable (AEP Ex. 5, 13; AEP Initial Br. 24, 67-68).

Staff supports the fixed generation rate increases as reasonable in magnitude and because they are completely avoidable if a competitor can beat the price and customers shop (Staff Ex. 2, at 8; Tr. IV, 152, 154-155, 163-164, 248-249; Staff Reply Br. 4). Staff evaluated this portion of the plan in the context of the current market, the expectation that generation rates will rise and the magnitude of the proposed numbers for company financial integrity (Tr. IV 156, 158; Staff Ex. 2, at 8). Moreover, staff noted that AEP's rates are low compared to the Ohio market and keeping them frozen would impede supplier entry in the territory (Tr. IV, 248).

8 Staff notes that AEP is distinguishable from other EDUs in Ohio because it has lower cost generation supplies and has an infrastructure to allow it to move power within a seven-state region (Staff Initial Br. 4). Staff suggests that AEP's proposal here should be evaluated separately from the other RSPs (*Id.*).

OEG, Green Mountain, LIA, OCC, and IEU-Ohio disagree with the proposed fixed, generation rate increases. OEG and IEU-Ohio object to the three and seven percent generation rate increases on the ground that they will generate excessive earnings, while AEP has been already receiving very healthy returns (OEG Ex. 2, at 14-16; OEG Reply Br. 4, 6; IEU-Ohio Initial Br. 7). OEG contends that the fixed generation increases will engender 3.6 times more revenues than the companies' projected costs for the environmental expenditures identified (OEG Ex. 2, at 15). OEG and OCC are also skeptical that customers will really avoid the increased generation rates on the ground that the market is defective now and even AEP anticipates that it will remain defective for a period of time (OEG Reply Br. 22-23; OCC Reply Br. 20). Thus, in OEG's and OCC's view, customers will only have an option to shop in a defective market or take generation service from AEP at increasing rates (*Id.*). Moreover, OCC highlights that the identified projected costs for the environmental expenditures are not costs just for these companies; rather, they will be allocated throughout the entire AEP system, but AEP did not account for such allocation (Tr. I, 79; OCC Ex. 10, at 8; OCC Initial Br. 28). AEP and staff respond that, after the MDP, generation service is no longer subject to cost-based regulation and, thus, AEP's generation rates and charges need not be cost-based (AEP Initial Br. 31; Staff Initial Br. 4; Tr. IV, 154, 158, 165-166, 245). OEG counters by noting that AEP justified many aspects of the proposed RSP by relying solely on the cost of service for those items (e.g., additional generation-related expenses to be recovered through generation rate increases and deferrals) (OEG Reply Br. 17-18).

Green Mountain argues that the RSP's rates are below market (GMEC Initital Br. 8). Green Mountain further argues that AEP should be required to prove the cost basis of its generation rates (and distribution and transmission rates) since AEP has justified its RSP by pointing to various costs/expenses and Section 4905.33(B), Revised Code, prohibits service for less than actual cost for purposes of destroying competition (*Id.* at 18).

IEU-Ohio contends that justification for the fixed generation rate increases is weak because it is not clear that AEP will spend all estimated amounts on environmental compliance, the estimated expenditures only modestly affect production costs during the RSP period, and those expenditures will be allocated among the various operating companies as production costs (Tr. I, 58-60; IEU-Ohio Initial Br. 5-6). IEU-Ohio points out that the proposed fixed generation rate increases will allow AEP to collect $527 million more than current generation rates allow, in addition to the $702 million in transition costs allowed under the ETP decision (IEU-Ohio Initial Br. 3). IEU-Ohio points out that this RSP asks the Commission to approve generation rate increases on the basis that the current generation rates are below market, while in 1999, AEP claimed that the generation component was at above-market prices and, therefore, asked for regulatory transition costs (IEU-Ohio Initial Br. 17-18, 22; IEU-Ohio Reply Br. 7).

IEU-Ohio acknowledges that electric generation service (after the MDP) shall not be subject to traditional cost-of-service supervision or regulation, but it also believes that the Commission has a duty to ensure that the standard service offer prices are just and reasonable (IEU-Ohio Initial Br. 25-29; IEU-Ohio Reply Br. 3-5). In IEU-Ohio's view, the RSP's proposed generation rates are too high and not reasonable, particularly since AEP's financial condition has been very favorable over the last few years. Next, IEU-Ohio contends that these rate increases will simply fund investments and growth on earnings and are not necessary for financial stability (IEU-Ohio Initial Br. 30-31). IEU-Ohio also noted that, in Virginia, price caps have been extended and Ohio should realize that raising retail prices in Ohio (while other states extend rate caps) will not benefit Ohio as it strives to compete in the global economy (IEU-Ohio Reply Br. 8).

OCC argues that this portion of the RSP violates Section 4928.38, Revised Code, because it seeks recovery of additional generation-related costs not authorized in the ETP at the time when AEP is supposed to be on its own with respect to recovery of generation-related costs (OCC Motion to Dismiss 5). OCC further argues that these fixed generation rate increases are not cost-based or justified because a complete picture of current costs has not been made (some prior costs may no longer exist, while some new costs and benefits have developed) (Tr. I, 173-174, 222; OCC Initial Br. 28-31; OCC Reply Br. 16, 17). OCC supports OEG's estimated rates of return and argues that they demonstrate that the fixed generation rate increases alone will cause extremely high returns for AEP that should not be permitted (OCC Initial Br. 32, 39; OCC Reply Br. 16-17). In other words, OCC states that AEP should not be earning higher returns on equity than they could possibly be allowed in a regulatory environment when a developed competitive market is absent (*Id.* at 39).

LIA also disagrees with the generation rate increases in the RSP (LIA Initial Br. 16). On legal grounds, LIA argues that, since the RSP involves an increase in rates, AEP has violated Sections 4909.17 and 4909.19, Revised Code, by not following rate increase procedures (*Id.* at 9). Moreover, LIA contends that AEP's actions/inactions regarding RTO membership have caused a competitive market to not develop and, therefore, AEP does not have "clean hands" and should not be rewarded with excessive increases in rates (LIA Reply Br. 2). From a public policy perspective, LIA contends that the companies already have high profit margins and do not need rate increases, and yet do not propose any programs to mitigate the impact of the RSP on low-income customers (LIA Initial Br. 16, 20, 31; LIA Reply Br. 3-4, 6). LIA notes that AEP is the only Ohio utility to ever terminate funding for low-income energy efficiency programs (APAC Ex. 1, at 7; Tr. IV, 182; LIA Initial Br. 32). LIA further contends that the RSP will exacerbate the already high amounts of percentage of income payment plan (PIPP) arrearages for AEP customers (*Id.* at 26). If the Commission proceeds with an RSP, LIA and OCC argue the Commission must consider the impact of the RSP on the low-income consumers and vulnerable populations in order to promote rate stability and certainty (*Id.* at 20, 34; OCC Initial Br. 62). Specifically, LIA urges: (a) the Commission to allow PIPP customer pools to participate in CBPs during the RSP; (b) AEP to negotiate with the Ohio Department of Development, Commission staff, and low-income intervenors to develop "an approach to arrearages that reinforces good payment behavior by PIPP program participants and reduces the PIPP debt to a manageable level that can conceivably be repaid"; and (c) the Commission require funding by AEP of $1.5 million per year for a low-income energy efficiency program in AEP's service territory (APAC Ex. 1, at 8, 12; Tr. IV, 197, 201; LIA Initial Br. 29, 32; LIA Reply Br. 7-8). OCC supports these three recommendations (OCC Initial Br. 62).

Commission Discussion

Certainly, to some extent, the generation rate increases will provide additional funds to the companies and assist in their financial stability. As noted, AEP will be incurring large generation-related expenses above normal capital expenditure levels during the RSP period. However, we also believe that the RSP package as a whole supports our goals of helping to develop the competitive market and providing some rate stability. We reach this conclusion because we believe that the generation rate increases are a reasonable approximation of the future market conditions. With the RSP's structured, periodic generation rate increases, customers will not be subjected to significant swings in generation rates in an emerging competitive market for AEP. We believe this provision is not only very important to spurring a competitive market, but also to protecting customers from the risks and dangers associated with price volatility and a nascent competitive market.

We also accept our staff's conclusion that the percentage increases are reasonable in magnitude. Many of the parties object to this provision because they contend that AEP is already earning too much. However, these parties seem to forget that, with the expiration of the MDP, generation rates are subject to the market (not the Commission's traditional cost-of-service rate regulation) and that the plan was an option that AEP voluntarily proposed. Section 4928.05(A)(1), Revised Code. We make this observation to point out that, under the statutory scheme, company earnings levels would not come into play for establishing generation rates - market tolerances would otherwise dictate, just as AEP argued (AEP Reply Br. 26-27). We are strongly committed to encouraging the competitive market in AEP's service territories as it is the policy of this state, per Section 4928.02, Revised Code. Given that commitment, we do not feel that the earnings levels evidence or cost-based analyses and arguments presented by OEG, OCC, IEU-Ohio or LIA justify rejection of this provision. We believe that this provision will establish generation rates that are appropriate for the RSP period, spur the competitive market, and also protect customers from dramatic or volatile generation rate price changes. We do not agree that this provision violates any of the cited statutes.

While we have found the proposed generation rate increases to be reasonable, both in concept and in number, it is also appropriate to point out that these increases will be avoidable during the rate stabilization period. Customers who choose another competitive generation supplier can avoid AEP's increased generation rates (because those customers will pay, instead, the rates of their chosen supplier). We believe this is an important point to note.

We do realize that rate increases can be difficult for some customers to handle, as LIA has argued. We are not ignoring these concerns. In fact, we believe that the structured nature of the generation rate increases will be more helpful to the low-income customers in AEP's territory than would otherwise likely occur without the RSP. Ideally, we agree that rate increases are not preferred, but we are weighing and balancing several competing interests and we believe that the proposed generation rate increases will result in the most balanced and reasonable generation rates for all customers in AEP's service territories during the three years following the MDP. For these additional reasons, we accept this provision. Despite that conclusion, we agree that low-income customers, in particular, can be disproportionately affected by the RSP. To alleviate that concern, we conclude that low-income customers should receive some additional assistance. Therefore, we have provided for additional funding of low-income and economic development programs during the RSP period as set forth in Section VI.G of this decision.

2. Elimination of Five Percent Residential Discount

For all residential customers, AEP proposes an additional generation rate increase each year of 1.6 percent for Columbus Southern and 5.7 percent for Ohio Power, if the five percent generation discount terminates on June 30, 2004. This would end the five percent residential rate reduction 18 months earlier than what was agreed upon in the ETP stipulation (Tr. I, 28). If elimination of the five percent discount to residential customers is included, AEP calculates that the generation rate increases will be 8.5 percent for Columbus Southern residential customer and 13.2 percent for Ohio Power residential customers in 2006 (AEP Ex. 2, at 11). This would amount to roughly a $6 million increase for residential rates (Tr. I, 29). AEP supports this proposal by noting that Section 4928.40(C), Revised Code, allows the Commission to terminate the discount if it is "unduly discouraging market entry by [...] alternative suppliers." Despite the proposed June 30, 2004 date having passed, AEP has noted that the alternative is still viable, but the later termination of the discount (still prior to the end of the MDP) will result in reduced fixed increases for residential customers (AEP Initial Br. at footnote 11). AEP, staff and Green Mountain believe that the current generation rates, along with the existing temporary discount, unduly discourages market entry because of the small price differential between AEP's generation rates and others' generation supplies (AEP Ex. 2, at 12; Tr. IV, 23; GMEC Br. at 16-17). Staff and Green Mountain urge the Commission to eliminate the temporary discount (Staff Ex. 2, at 9; GMEC Initial Br. 17).

OCC opposes elimination of the five percent discount on the ground that the ETP stipulation requires the companies to retain the discount for residential customers through the MDP (OCC Initial Br. 32; OCC Reply Br. 17).[9] The ETP stipulation states that the companies will "not seek to reduce the [five percent] reduction in the generation component rate reduction for residential customers during the market development period" (OCC Ex. 1, at 6). OCC also contends that AEP has not demonstrated that the discount is unduly discouraging market entry, as required by Section 4928.40(C), Revised Code (OCC Ex. 10, at 5; OCC Reply Br. 18). In fact, AEP could not say that elimination of the discount would result in suppliers entering the residential market (AEP Ex. 2, at 12; Tr. I, 137-138). AEP contends that its RSP does not ask to remove the five percent discount during the MDP; it only noted that it was an option that the Commission could consider in the context of the RSP's proposed generation rate increases (AEP Initial Br. 27-28, 68, 78).

IEU-Ohio states that the Commission should consider elimination of AEP's five percent residential discount in a "stand-alone" proceeding that is "focused on the

[9] OCC argues that the Commission lacks authority to approve any portion of the RSP that impacts any term in the ETP decision (OCC Motion to Dismiss 2; OCC Initial Br. 2-3). Staff disagrees with that argument because the Commission retains ongoing jurisdiction over its orders, including the authority to change or modify its earlier decisions as it deems necessary in the best interests of the utility and customers (Staff Initial Br. at footnote 1).

residential customer sector and the full range of conditions that are affecting market entry by alternate suppliers" (IEU-Ohio Initial Br. 41).

Commission Discussion

OCC correctly cites the ETP stipulation. We also believe that AEP's argument that its RSP does not ask to remove the five percent discount is an attempt at "hair-splitting". AEP's RSP proposed eliminating the five percent discount and it previously agreed that it would not make such a request during the MDP.

Notwithstanding the language in the ETP stipulation and our acceptance of that stipulation, we have the ability to evaluate the impact of the five percent residential discount under Section 4928.40(C), Revised Code. Section 4928.40(C), Revised Code, gives the Commission the flexibility to eliminate the five percent residential discount if it unduly discourages market entry in AEP's service territories. We believe that an early ending to the discount is not warranted and, rather, it is appropriate that the five percent residential discount in both companies' territories, end effective December 31, 2005. We further note that ending the five percent residential discount on December 31, 2005, is in keeping with SB3 (including Section 4928.40, Revised Code) and is consistent with the timing required of the residential discounts of four other EDUs. *Ohio Edison*, Case No. 03-2144-EL-ATA, *supra* at 24-25 and *In the Matter of the Application of The Cincinnati Gas & Electric Company to Modify its Nonresidential Generation Rates to Provide for Market-Based Standard Service Offer Pricing and to Establish an Alternative Competitive-Bid Service Rate Option Subsequent to the Market Development Period*, Case No. 03-93-EL-ATA, Opinion and Order at 36-37 (September 29, 2004).

3. Additional Generation Rate Increases

AEP's RSP allows generation rates to further increase, after a Commission hearing, for: (a) increased expenditures incurred through an affiliate pooling arrangement for complying with changes in laws/rules/regulations related to environmental requirements, security, taxes, and new generation-related regulatory requirements imposed by statute/rule/ regulation/administrative order/court order; or (b) customer load switches that materially jeopardize either company's ability to recover the anticipated generation revenues. Total generation rate increases cannot be greater than seven percent for Columbus Southern and 11 percent for Ohio Power in any given year (if the five percent residential discount is not eliminated).[10] The additional generation adjustments are effectively capped at four percent. The RSP proposes a 90-day time frame, after which the proposed increase will become effective on an interim basis until the Commission's final order is implemented.

AEP points out that this aspect of the RSP only gives the company the flexibility to ask for additional, limited generation rate increases in the event of changes in the two enumerated categories; it does not pre-approve or guarantee rate increases (AEP Ex. 2, 16-

[10] If the five percent residential discount would have been eliminated as of June 30, 2004, any additional generation rate increases would be at most four percent above the residential customers' fixed annual increase, which would be at most 5.6 percent for Columbus Southern residential customers and 9.7 percent for Ohio Power residential customers (AEP Ex. 2, at 18).

17; AEP Initial Br. 35). AEP characterizes this provision as a means to manage the risk it faces relative to the fixed generation rate increases (AEP Reply Br. 28). At this point in time, AEP does not expect to ask for additional rate increases (Tr. I, 198). Also, AEP mentions that any additional increases that might be authorized by the Commission could be avoided for customers who choose another competitive supplier (AEP Initial Br. 35).

Staff, Green Mountain and IEU-Ohio do not fully support or fully object to this provision. They believe that any request for additional generation rate increases should be evaluated by looking at the company's overall financial health (not just the events that triggered the proposed further increase) and not be limited to four percent (Staff Ex. 2, at 9-10; GMEC Reply Br. 12-13; IEU-Ohio Initial Br. 42; Tr. IV, 33, 153, 231, 245). Staff recognizes that the proposed additional generation increases would be sought for many of the same reasons that AEP had based its proposed three and seven percent increases and, thus, believes automatic additional increases should only be considered after looking at the whole company (Tr. IV, 153, 245-247). AEP responded by stating that a look at the overall financial health of the company is contrary to Section 4928.05(A)(1), Revised Code, because generation pricing will not be subject to cost-of-service ratemaking principles (AEP Initial Br. 38). Additionally, AEP predicts that holding generation rates down because of a strong "wires business" is likely to result in rate shock in 2009, which is what the Commission is trying to avoid today (*Id.*; Tr. I, 247).

OCC argues that the proposed four percent additional increase does not result from changes in market prices and, thus, is not market-based (OCC Ex. 10, at 9). Like staff, OCC characterizes this provision as improper single-issue ratemaking and also criticizes the ambiguity of the phrase "materially jeopardizes either or both companies' ability to recover the increased revenues" (*Id.*).

OEG worries that this portion of the RSP could permit recovery twice for the same expenses; essentially that the same costs used to justify the fixed increases arguably could justify the proposed additional increases (OEG Ex. 2, at 16-17). Plus, because the companies will continue to have very high earnings, OEG believes that the additional generation rate increases are not needed to maintain financial stability (OEG Initial Br. 8). AEP notes that this criticism is really a concern over the Commission's ability to judge any proposed additional generate rate increase and not a sufficient basis for rejecting this portion of the RSP (AEP Initial Br. 39).

Commission Discussion

We find this portion of the RSP to be acceptable. We agree with AEP that this portion of the RSP will allow AEP to seek additional generation rate increases; it does not pre-approve them (although it does limit any approved amount). We understand staff's and IEU-Ohio's preference that subsequent generation rate increases be viewed in the context of the company's overall financial health, but that position ignores the requirements of Section 4928.05(A)(1), Revised Code. Thus, we find this portion of the RSP to appropriately temper potentially large generation rate increases (by limiting the dollar amounts), while also recognizing AEP's interest in financial stability. This provision is a compromise position that takes into consideration the competing interests. We understand the criticism raised with the phrase "materially jeopardizes either or both companies' ability to recover the increased revenues." In the event that further increases are requested by AEP, we will evaluate this. Similarly, we understand OEG's concern that AEP could request further generation-related rate increases for items that it is already recovering. But, as AEP states, the concern does not justify rejecting the provision; it is really a question of whether the proposed further increase is properly evaluated. For these reasons, none of the comments raised in this proceeding convinces us that this portion of the RSP should be rejected.

C. Distribution Rates and Charges (Provision One of the RSP)

Under the RSP, AEP distribution rates and charges in effect on December 31, 2005, would remain in effect through 2008 (except for the universal service fund rider, energy efficiency fund rider, and certain cost-based charges such as right-of-way charges). These "frozen" distribution charges could be also adjusted in the event of an emergency, changes in transmission/distribution allocations under the FERC's seven-factor test, or if the companies experience increased distribution-related expenses due to: (a) changes in laws/rules/regulations related to environmental requirements; (b) security; (c) taxes; (d) O&M due to new requirements imposed by federal or state legislative or regulatory bodies after March 31, 2004; and (e) major storm damage service restoration. Furthermore, the "frozen" distribution rates will be adjusted, if the Commission approves, to recover certain deferred RTO administrative costs (deferred in 2004 and 2005) plus carrying costs and certain deferred carrying costs on certain environmental expenditures since 2002, plus carrying costs.

AEP points out that the RSP only freezes distribution rates for an additional one-year period for Ohio Power, because the ETP froze them previously (AEP Ex. 2, at 5). AEP acknowledges that, in addition to what is contained within the ETP, the RSP would add some additional categories for which the "frozen" distribution rates would/could be adjusted (*Id.*; Tr. I, 31-32). AEP contends that, at least with the proposed adjustments for security expenses and the specified O&M expenses, they are justified because of the unforeseen security issues that previously developed and the likelihood that O&M expenditures will be needed since the ETP was approved (AEP Ex. 2, at 6).

Staff, IEU-Ohio and OEG state that a distribution rate case should be conducted, instead of freezing distribution charges from 2006 to 2008 (Staff Ex. 2, at 7-8; Tr. IV, 230; IEU-Ohio Initial Br. 42; OEG Ex. 2, at 22-23). They reach this conclusion because these distribution rates were established in 1991 and 1994 rate cases (Staff Ex. 2, at 8). More specifically, OEG believes that AEP's returns on common equity have been very high over the last several years and the proposed RSP will only perpetuate them (OEG Ex. 2, at 11-14). AEP took issue with OEG's rate of return calculations, alleging a number of errors (AEP Initial Br. 31-35).

OCC also opposes this provision. OCC contends that the additional exceptions to the distribution rate freeze (security and O&M expenses) are unwarranted (OCC Ex. 10, at 6). In OCC's view, AEP accepted the risk that increasesd expenses for these two items would occur when it signed the ETP stipulation and AEP should not now be permitted to illegally attempt to modify the ETP or violate Sections 4909.18 and 4909.19, Revised Code

(OCC Ex. 10, at 6-7; OCC Motion to Dismiss at 9).[11] Moreover, OCC contends that these exceptions to the distribution rate freeze constitute single-issue ratemaking, which is not appropriate public policy because the exceptions do not recognize other cost-related changes (OCC Ex. 10, at 6-7; Tr. III, 187-188). In response, AEP states that OCC's position conflicts with its position that the Commission set a post-MDP generation rate at something other than market levels (AEP Initial Br. 14).

LIA disagrees with the distribution rate provision in the RSP because it will also allow rate increases (LIA Initial Br. 16).

Commission Discussion

We find that Provision One of the RSP is acceptable. The additional exceptions to the distribution rate freeze are, in the context of considering the RSP as a package, reasonable. We understand OCC's contention that the additional exceptions to the rate freeze can be considered single-issue ratemaking, but we also must point out that OCC previously agreed to other exceptions to the distribution rate freeze, which can also be considered single-issue ratemaking. The next question then is whether the additional exceptions are justified. We do accept AEP's contention that, in 1999 and 2000, security expenses and the specified O&M expenses were not fully foreseeable. In this respect, we believe that allowing for these additional exceptions to the distribution rate freeze during the RSP is acceptable. We view the extension of the distribution rate freeze as a positive aspect of the RSP, which meets our goal of fostering a competitive market and still balancing rate stability with financial certainty for AEP.

We appreciate the position taken by staff, IEU-Ohio and OEG about the need for a distribution rate case. They have correctly noted that a rate proceeding has not taken place for either company for a period of time. AEP believes that, after the RSP, it would be appropriate for the Commission to initiate rate proceedings (Tr. I, 102). AEP explained that a rate proceeding at this point would frustrate the Commission's goals of rate stability and financial stability over the next few years (*Id.*). We agree that embarking on a rate proceeding at this point could run counter to our ultimate goals. Therefore, we do not accept that position.

D. Deferral Requests (Provisions One, Five and Six of the RSP)

The companies propose to defer the costs of several items during the RSP (AEP Ex. 2, at 8-9; AEP Ex. 4, at 4-6, 10-12). These items are:

(a) RTO administrative charges (adjusted for net congestion costs) from the time of integration into PJM[12] through 2005, plus a carrying charge (based on the weighted average cost of capital).

(b) The 2004 and 2005 equity carrying charges on expenditures begun in 2002 through 2005 for expenditures located in Account 107, construction work in process (CWIP).

[11] OCC contends that, after the MDP, EDU distribution rates can only be adjusted through properly filed applications under Chapter 4909, Revised Code (OCC Motion to Dismiss 10).

[12] AEP integrated into PJM on October 1, 2004.

(c) The full carrying charges (based on the weighted average cost of capital) on expenditures begun in 2002 through 2005 for all functions in Accounts 101 (electric plant in service) and 106 (completed construction not classified), except line extension expenditures, which are already subject to carrying cost deferrals.

(d) Consumer education, customer choice implementation, and transition plan filings through 2005, plus a carrying charge.

(e) Consumer education, customer choice implementation, and transition plan filing costs incurred after 2005, and all RSP filing costs, plus a carrying charge.

Most of the expenditures in the second and third categories are associated with environmental control equipment (nitrogen oxide burners, flue gas desulphurization, and selective catalytic reduction) for generation facilities (Tr. II, 14-18; OCC Ex. 3). AEP estimated the total amounts of these proposed deferrals over the RSP as follows (AEP Ex. 4, at 3, 6-7; AEP Ex. 3, at 4-5, 7; AEP Ex. 2, at 8):

Proposed Deferral	Columbus Southern	Ohio Power
RTO Admin. Costs[13]	$11.9 million	$15.6 million
RTO Admin. Costs Carrying Costs	2.5 million	3.2 million[14]
CWIP Carrying Costs	1.0 million	9.0 million
In-Service Plant Carrying Costs	13.0 million	50.0 million
Addl. Carrying Costs for CWIP and		
In-Service Plant	2.0 million	9.0 million[15]
Pre-2006 Education, Choice		
Impl. and Transition Plan		
Filing Costs[16]	40.6 million	45.5 million
Post-2005 Education, Choice		
Impl., Transition Plan Filing		
and all RSP Filing Costs[17]	18.2 million	19.7 million
Total	$89.2 million	$152 million

13 These estimates do not include an adjustment for congestion costs, as those are unknown (AEP Ex. 3, at 3; AEP Ex. 2, at 8).

14 AEP's estimate of the RTO administrative costs totaled $14.4 million for Columbus Southern and $18.8 million for Ohio Power, while the revenues to be produced by this aspect of the RSP are estimated to be $48 million for Columbus Southern and $60 million for Ohio Power (AEP Ex. 3, at 7, 10). However, we note that AEP's brief reflects instead that the anticipated revenues to be produced by this aspect of the RSP will be $16.8 million for Columbus Southern and $20.7 million for Ohio Power (AEP Initial Br. Attachment A at 3 and Attachment B at 3).

15 AEP's estimates of the carrying costs of the CWIP and in-service plant totaled $16 million for Columbus Southern and $68 million for Ohio Power, while the revenues to be produced by this aspect of the RSP are estimated to be $23 million for Columbus Southern and $99 million for Ohio Power (AEP Ex. 3, at 7, 10).

16 These estimates were made by AEP in May 2000 (OCC Ex. 1, at 4). They do not include carrying charges. No updated estimates were presented as evidence in this proceeding.

17 The companies did not estimate RSP filing costs (AEP Ex. 3, at 5).

In AEP's view, these are new, significant costs that cannot be capitalized and were not built into current rates (AEP Ex. 4, at 7). It should be noted, however, that AEP would amortize these new deferrals over the three-year RSP and begin recovering those amounts as regulatory assets through distribution charges in 2006, except for the consumer education, customer choice implementation, transition plan filing costs incurred, and all RSP filing costs, plus a carrying charge (AEP Ex. 2, at 21; AEP Ex. 4, at 4).

1. Regional Transmission Organization Administrative Costs

Staff calculated an average of the RTO deferral rider to be .27 mills/kWh for both companies and found it to be a reasonable level for what it considers to be a new service (Tr. IV, 63-64, 67-68, 112, 253). OMG and NEMA do not fully object to this proposed deferral, but contend that recovery of it during the RSP will cause some shopping customers to be charged twice for those same costs (OMG/NEMA Initial Br. 9-11). OCC also agrees with this criticism, but still otherwise objects to the deferral, as detailed further below (OCC Initial Br. 8-9; OCC Reply Br. 8). More specifically, OMG and NEMA explain that any shopping customer will pay the pre-2006 RTO administrative charges to his/her generation supplier as part of the cost of receiving that generation supply and, then, also pay AEP when it assesses the deferral during the RSP. OMG and NEMA state that an easy solution is to require that AEP customers who shop after October 1, 2004, get a credit for PJM administrative charges until the end of the MDP, but impose the deferrals upon them during the RSP (OMG/NEMA Initial Br. 11-12). Green Mountain agrees (GMEC Reply Br. 9). AEP responds to this suggestion, stating that it is impossible to segregate how much each customer's bill will recover the deferral and, thus, the suggestion is not possible (AEP Reply Br. 19-20).

OCC objects to the RTO administrative cost deferral for several other reasons. OCC first contends that this proposed deferral should be rejected because it violates the intent of the distribution service rate cap (set forth in Section 4928.34(A)(6), Revised Code); it is simply an attempt to recover costs that were to be recovered by the capped distribution rates (OCC Ex. 10, at 7; OCC Initial Br. 5-6, 9; OCC Reply Br. 2-3; OCC Motion to Dismiss 7). OCC also considers this provision to violate the part of the ETP decision which freezes distribution rates beyond the MDP. OCC points out that a utility can recover transmission costs through an increase to the transmission component, which will correspondingly decrease the distribution component during the MDP (OCC Initial Br. at 6). AEP even acknowledged this possibility (Tr. I, 171). Second, OCC argues that AEP is proposing single-issue ratemaking contrary to Chapter 4909, Revised Code (OCC Initial Br. 7; OCC Reply Br. 12-13). OCC does not believe that the Commission should consider this single ($33.2 million) charge in isolation of overall transmission rates.

OCC next contends that the proposed deferral of the RTO administrative charges would improperly allow AEP to recover transmission-related expenses through nonbypassable distribution rates (OCC Reply Br. 7-8). AEP acknowledges that the RTO administrative charges are transmission-rated (AEP Ex. 2, at 7; AEP Ex. 4, at 16; Tr. I, 240). However, AEP contends that these costs benefit all customers (switching and non-switching customers) because all customers benefit with AEP's participation in an RTO. AEP explains that the only means to allocate cost recovery among all customers in a competitively neutral fashion is a nonbypassable distribution charge (AEP Ex. 2, at 7; AEP Ex. 4, at 18). AEP also explained that, without the requested authority or FERC authority, the RTO administrative charges would not be recovered (Tr. I, 237). Moreover, AEP stated that, while the RTO administrative costs could be recovered via a change in state transmission charges (and thereby reduce distribution rates), AEP would effectively not be able to recover those transmission expenses (Tr. I, 238). Finally, in OCC's view, it "strains credibility that the companies did not know there would be RTO administrative costs when they agreed to join an RTO in the ETP stipulation" (OCC Initial Br. 10). OCC also does not consider the RTO administrative costs to be a new service, as staff indicated, or rate stabilization charges. OCC believes these are MDP-incurred transmission charges proposed to be recovered through a distribution rider after the MDP (*Id.*).

LIA argues that a deferral of the pre-2006 RTO administrative costs is tantamount to an increase in the MDP-capped distribution rates (LIA Initial Br. 4, 6). LIA states that Section 4928.38, Revised Code, prohibits the creation of new deferrals associated with distribution service construction, and Section 4928.34(A)(6), Revised Code, and the ETP decision are also violated (*Id.* at 5, 7). In LIA's view, this deferral constitutes a "back door" attempt to raise distribution rates, regardless of when the deferral is collected (*Id.* at 6).

OEG contends that the RTO administrative cost deferral proposes to adjust frozen distribution rate under circumstances not permitted by the ETP decision (OEG Initial Br. 13). OEG also believes that the effect of the deferral request is to avoid a rebalancing of transmission and distribution rate levels, which is required by Section 4928.34(A)(1), Revised Code, to remain at the MDP levels (*Id.*). Next, OEG takes issue with the dollar amounts in this proposed deferral for two reasons. OEG points out that AEP does not plan to recognize, in the amount of RTO administrative deferrals, the benefit that AEP will receive from making additional off-system sales as a member of PJM (Tr. I, 173). Further, OEG highlights that these administrative costs will include costs related to the companies' efforts to participate in the MISO (Tr. I, 248; OEG Initial Br. 14).

IEU-Ohio states that these RTO administrative costs were considered when transition costs were developed in the ETP proceeding and the companies' current financial condition does not justify creation of new regulatory assets (IEU-Ohio Initial Br. at 44). For this reason, IEU-Ohio contends that the proposed deferral should be denied. IEU-Ohio also noted that, in July 2004, an AEP affiliate in Virginia agreed to forego recovery of RTO administrative costs, certain congestion costs, and ancillary service cost increases, except through a base rate case (IEU-Ohio Reply Br. 7-8, Attachment). That affiliate also agreed to not seek to defer such Virginia-specific costs. Furthermore, that affiliate agreed to not seek to recover development and implementation costs that were then being deferred, other than through a base rate case. IEU-Ohio makes the point that other treatment of RTO administrative costs has been agreeable to an AEP company.

Commission Discussion

The RTO administrative charges involved in this proposed deferral will be charges incurred from October 2004 through 2005. We do not believe that this proposed deferral is a rate increase. Accord, *Consumers' Counsel v. Pub. Util. Comm.* (1983), 6 Ohio St.3d 377. Recovery of the deferred RTO administrative charges would be based upon accruals during AEP's MDP. As a result, we will not approve the proposed deferral of 2004 and 2005 RTO administrative charges.

The Commission recognizes that AEP's expenditures for RTO membership during the MDP have been and will continue to be instrumental in enabling AEP to efficiently fulfill its provider of last resort (POLR) responsibilities during the rate stabilization period. AEP is required to provide that function after the MDP. Section 4928.14(A) and (B), Revised Code. The Commission has also recognized in other cases that the POLR responsibility of the EDU is one for which the EDU incurs necessary costs and which warrants compensation during rate stabilization periods. See, *Dayton, supra* at 28, and *Ohio Edison,* Case No. 03-2144-EL-ATA, *supra* at 23-24. The Supreme Court of Ohio recently upheld an earlier Commission conclusion that the existence of POLR costs makes it reasonable to apply a charge to customers during a RSP period. *Constellation, supra.* Our staff also made this argument in this proceeding (but in relation to the CWIP and in-service plant deferrals). We believe the proposed RTO administrative charge amounts for collection during the rate stabilization period constitute reasonable and not excessive compensation to AEP for part of the cost of fulfilling its POLR responsibilities and, accordingly, approve the collection of these amounts as part of a POLR charge. This POLR charge will be established as part of a separate unavoidable rider that is applicable to all distribution customers.

We reach this conclusion based upon the specific circumstances before us in this proceeding. Nothing in this decision is intended to be precedent-setting or to be construed as ruling upon the other RTO charge-related deferral requests that we have recently received from other EDUs. See, *In the Matter of the Application of The Dayton Power and Light Company for Authority to Modify its Accounting Procedures,* Case No. 04-1645-EL-AAM, and *In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company to Modify their Accounting Procedures,* Case No. 04-1931-EL-AAM.

2. Carrying Costs of Construction Work in Progress and In-Service Plant Expenditures

Staff supports the CWIP and in-service plant deferrals as well (Staff Ex. 2, at 11). Staff considers such deferrals to be equivalent to POLR charges (Tr. IV, 108-109, 147, 148, 171). Staff reaches this conclusion because the RSP is providing an option to switch and avoid charges for AEP customers and creating a risk for AEP that customers will switch, for which it is reasonable, in staff's view, for AEP to collect POLR charges (Tr. IV, 149-150). AEP concurs that these costs function as POLR costs (AEP Initial Br. 47, 79; AEP Reply Br. 16). Moreover, staff noted that, when compared to similar charges proposed by other EDUs, staff felt that AEP's proposed levels were reasonable (*Id.*). Staff calculated the amounts per kWh to be .38 mills for Columbus Southern and 1.16 mills for Ohio Power, for an average of .84 mills (Tr. IV, 108-109). Staff also stated that allowing AEP to recover a part of what it would be able to obtain under traditional regulatory process when competition has not really arrived is reasonable (Staff Ex. 2, at 11). Staff further acknowledges that, if these costs are allowed as rate stabilization charges, it is fair for the charges to be bypassable (that is to say, a customer who chooses another supplier and is not returning would not be subject to the charge while purchasing another's generation) (Tr. IV, 254-255).

OCC objects to this portion of the RSP for a host of reasons. OCC argues that, if these generation-related deferrals are permitted for recovery after the MDP, then the rate freeze is meaningless (OCC Initial Br. at 14, 51; OCC Reply Br. 2-3). OCC believes that, after the MDP, new distribution deferrals are not permitted under Ohio law because distribution rates are subject to rate regulation under Chapter 4909, Revised Code (OCC Initial Br. 14-15, 52). Additionally, OCC contends that AEP assumed the risk of these expenditures when it agreed to freeze distribution rates in the ETP proceeding (*Id.* at 15, 17-19). OCC points to OEG's evidence that AEP does not need the deferrals to provide financial stability. OCC also claims that distribution rates should not be increased to recover generation costs, per the ETP decision and Sections 4928.15, 4928.17(A), 4928.34(A)(6) and 4928.38, Revised Code (*Id.* at 15-16; OCC Motion to Dismiss 8; OCC Reply Br. 10-11). Like the RTO administrative costs, OCC contends that the Commission should not approve these single-issue ratemaking deferrals without looking at the full picture and because shopping customers will then pay a portion of AEP's generation costs even though they will be taking generation service from a competitor (OCC Initial Br. 15, 22; OCC Reply Br. 12-13).

OEG and OCC argue that these deferrals constitute retroactive ratemaking (a rate increase during the MDP) because the deferral relates to amounts in existence prior to the date of the decision in this case (OEG Ex. 2, at 18-19; OCC Initial Br. 17-19). Also, OEG and LIA contend that these two deferrals take away one of the primary incentives of implementing electric choice in Ohio (a cap on distribution rates during the MDP) contrary to Section 4928.34(A)(6), Revised Code (OEG Initial Br. 9-11; LIA Initial Br. 4). Further, OEG, LIA and OCC believe these deferrals violate the ETP decision because they are generation-related expenses used to adjust distribution rates during the period allowed by the ETP decision for frozen distribution rates (LIA Initial Br. 5, 7; OEG Initial Br. 12-13; OCC Initial Br. 16). AEP disagrees, noting that the Commission has allowed deferrals for periods that precede the date of a decision (AEP Initial Br. 46). Also, AEP argues that accounting deferrals are not rate increases and, thus, cannot constitute retroactive ratemaking (*Id.*; AEP Initial Br. 70; AEP Reply Br. 17).

OEG also argues that these deferrals do not recover distribution-related costs and should not be deferred for recovery in distribution charges (OEG Ex. 2, at 20-22). AEP agrees that these deferrals are not recovering distribution costs and, thus, argues that the distribution rate freeze cannot preclude them (AEP Initial Br. 47). In AEP's and staff's view, recovery of these deferrals will function as POLR charges, not distribution service charges (*Id.*; AEP Reply Br. 16; Tr. IV, 108, 147).

Green Mountain has a different point of view. It argues that generation-related increases should not be as limited as set forth in the RSP (GMEC Initial Br. 15-16). Instead, Green Mountain contends that any generation-related costs that AEP seeks to recover should be included in generation rates. However, if the Commission accepts another recovery mechanism (such as the proposed deferrals), then the established recovery mechanism should be bypassable (*Id.*; GMEC Reply Br. 9).

IEU-Ohio states that these CWIP and in-service plant expenditures were considered when transition costs were developed in the ETP proceeding and the companies' current financial condition does not justify creation of new regulatory assets (IEU-Ohio Initial Br. at 44). For this reason, IEU-Ohio contends that these proposed deferrals should be denied.

Commission Discussion

Similar to our reasoning for the RTO administrative charges, we do not believe that this proposed deferral is a rate increase. However, recovery of the deferred CWIP and in-service plant carrying charges would be based upon accruals during AEP's MDP. The Commission recognizes that AEP's expenditures for CWIP and in-service plant during the MDP have been and will continue to be instrumental in enabling AEP to efficiently fulfill its POLR responsibilities during the rate stabilization period, which warrants compensation during rate stabilization period. Section 4928.14(A) and (B), Revised Code, requires AEP to provide that function after the MDP. We believe these carrying charge amounts proposed for collection during the rate stabilization period constitute a reasonable and not excessive compensation to AEP for part of the cost of fulfilling its POLR responsibilities and, accordingly, approve the collection of these amounts as part of a POLR charge. As noted earlier, this POLR charge will be established as part of a separate unavoidable rider that is applicable to all distribution customers.

3. Consumer Education, Customer Choice Implementation, Transition Plan Filing Costs, and all Rate Stabilization Plan Filing Costs

Staff supports this deferral provision (Staff Ex. 2, at 10). IEU-Ohio does not believe that the Commission needs to address most of this deferral because it was already addressed in the ETP decision (IEU-Ohio Initial Br. 43). Also, IEU-Ohio does not believe that the Commission should authorize increases for isolated categories of costs, even if expected (*Id.* at 44). OCC argues that, aside from the agreement in the ETP decision to allow some of these deferrals, the Commission should reject additional deferrals in this case (OCC Initial Br. at 52). OCC reaches this conclusion because new distribution deferrals and rate riders for single issues have no basis in Ohio law; the Commission can only adjust regulated distribution rates through a properly filed rate case.

Commission Discussion

We already allowed deferral for most of the costs in this category (in the ETP proceeding). This RSP provision would further defer those costs and also allow deferral of the RSP filing costs. In the context of considering the RSP package and our stated RSP goals, we are willing to accept this provision of AEP's plan.

E. Transmission Rates and Charges (Provision Four of the RSP)

This part of the proposed RSP states the AEP may adjust state transmission charges (attributable to the applicable company, affiliated company or RTO open access transmission tariff [OATT]) to reflect FERC-approved rates and charges during the RSP, whether imposed directly on the companies or through an approved RTO. These include RTO administrative changes imposed, amortization of RTO start-up costs, and/or surcharges for recovery of lost transmission revenues. Such rate changes would be effective 30 days after filing, unless delayed by the Commission (but no longer than a period of 60 days).

AEP characterizes this portion of the RSP as an affirmation of the companies' existing right to make a filing for recovery of FERC-approved costs (AEP Initial Br. 40, 60). AEP believes the proposed expedited review process of such applications is warranted because the Commission should look at new transmission charges and should allow the pass-through of FERC-approved transmission charges (Tr. I, 242-243). Furthermore, AEP believes these costs will be significant, new costs, which are not currently in rates (AEP Ex. 3, at 4; AEP Initial Br. 40). A preliminary estimate of at least some of the anticipated costs in this area is $10.4 million per year for Columbus Southern and $13.1 million per year Ohio Power (AEP Ex. 3, at 4).

Staff expressly supports this provision of the RSP (Staff Ex. 2, at 10). IEU-Ohio recommends that this provision be rejected because transmission costs were taken into consideration when the ETP decision was issued and there are indications that AEP's integration into PJM will create additional transmission revenues. Thus, IEU-Ohio believes that there is no need for this provision (IEU-Ohio Initial Br. 43). Similarly, OEG and OCC argue that this provision will allow AEP to be reimbursed for RTO expenses, but it does not take into account certain savings that will simultaneously be realized, e.g., off-system sales (OEG Reply Br. 19; OCC Reply Br. 13-14). OEG contends that the corresponding savings should be recognized so that the provision is truly a "pass through" (*Id.*). Also, OCC contends that there should be no authorization for additional transmission charges that have not been authorized by FERC or that AEP selects apart from charges in the PJM RTO OATT (OCC Initial Br. 46).

Commission Discussion

We find that this provision of AEP's RSP is reasonable, except as discussed below. In concept, any FERC-approved transmission rates and charges during the RSP should be passed through. We will look at them and ensure that "pass through" is appropriate. Despite IEU-Ohio's, OEG's and OCC's comments, we believe this aspect of Provision Four is appropriate. We do, however, have concerns with the Commission review process set forth in Provision Four. If viewed in isolation, we would not necessarily believe that the 30-day/60-day automatic process was problematic. However, we and our staff will be receiving similar types of applications from more than just AEP. For that reason, we believe that the time period proposed is not as workable as it should be. Therefore, we conclude that the applications to adjust state transmission charges (attributable to the applicable company, affiliate company or RTO OATT) to reflect FERC-approved rates and charges during the RSP (whether imposed directly on the companies or through an approved RTO) shall be automatically approved on the 61st day after filing, unless the Commission rejects, modifies or suspends the filing. We believe this approval process fairly and adequately balances: (1) the desire for a definitive conclusion from the Commission in a prompt manner, (2) the ability of other interested persons to participate, and (3) the concerns for adequate amounts of time to review the anticipated applications in the context of other Commission work.

F. Current Regulatory Asset Recovery (Provision Five of the RSP)

The RSP proposes that AEP continue to recover amortized generation-related transition regulatory assets under the approved ETP. Staff accepts this provision, describing this term as simply continuing practices established in the ETP decision (Staff Ex. 2, at 10). OCC supports this portion of the RSP because it continues one part of the ETP decision. However, OCC does argue that, if the Commission will not require AEP to keep the rest of the ETP bargain, the Commission should revisit this and other aspects of the ETP decision (OCC Ex. 10, at 4; OCC Initial Br. 47). To this argument, AEP contends that an examination of the regulatory assets recovery should not be a consequence of filing the RSP as requested (AEP Reply Br. 42). OCC notes that the bulk of the transition regulatory assets for Ohio Power (associated with mining operations) may no longer represent a liability to Ohio Power (Tr. II, 27, 36). IEU-Ohio is not opposed to this provision, if the Commission accepts its proposed RSP (IEU-Ohio Reply Br. 10, Footnote 11).

Commission Discussion

We also agree with Provision Five and find it appropriate to allow AEP to continue to recover amortized generation-related transition regulatory assets under the approved ETP. We note that no direct opposition to this portion of the RSP was raised by any of the parties.

G. Shopping Incentives and Credits (Provision Seven of the RSP)

AEP proposes in the RSP that Ohio Power will still not charge the regulatory asset charge rider, from January 1, 2006 to December 31, 2007, to the first 20 percent of the Ohio Power residential customer load that switches, as was agreed in the ETP stipulation.[18] Columbus Southern will, through the MDP and 2008, make available to the first 25 percent of the residential class load an incentive of 2.5 mills/kWh that the qualifying customers will receive as a credit. Any unused amount of the incentive money at December 31, 2005, will not be credited to regulatory asset charge recovery. Thus, as proposed under the RSP, Columbus Southern will receive as income any unused shopping incentive balance and not offset the incentive balance against the transition regulatory asset.

18 Although both the ETP stipulation and the RSP state that there will be no shopping incentive for Ohio Power customers, the provision to not charge certain shopping Ohio Power customers the regulatory asset charge rider was included in the RSP's Provision Seven under the heading "Shopping Incentives". Nothing in our decision should be construed as converting that term into a shopping incentive or characterizing it otherwise. We have simply chosen to discuss the entirety of Provision Seven at one time.

Columbus Southern's unused shopping incentive through January 2004 was roughly $12.9 million (Tr. II, 108; OCC Ex. 4). The RSP extends the Columbus Southern shopping incentive through 2008. As a trade off, AEP also proposes to alter the manner in which the unused portion of Columbus Southern's shopping incentive is handled (AEP Ex. 2, at 23-24; AEP Ex. 4, at 5; Tr. I, 33). To be clear, AEP's proposal to extend this shopping incentive is tied to the new proposed treatment of its unused balance (AEP Reply Br. 32). AEP argues that the extended shopping incentive, along with increased generation rates, should result in more shopping (AEP Initial Br. 48).

Staff believes that the unused Columbus Southern shopping incentive should be treated as a regulatory liability and flowed back to customers (Staff Ex. 2, at 12). IEU-Ohio concurs (IEU-Ohio Initial Br. 45). AEP believes that this position does not adequately acknowledge that the companies are proposing to extend the shopping incentive (AEP Initial Br. 49).

OCC believes Provision Seven of the plan violates the ETP decision by altering the treatment of the unused Columbus Southern shopping incentive (OCC Ex. 10, at 8; OCC Initial Br. 53). AEP points out that the effect of OCC's position is that no shopping incentive would be available to Columbus Southern residential customers during the RSP (AEP Initial Br. 49).

Green Mountain contends that the RSP's shopping incentive will be inadequate to spur shopping. AEP calculated that the average residential price to compare for the generation component (under the RSP and its shopping incentive terms) will be as follows (GMEC Ex. 5, at fourth set discovery request 1):

Company	2006	2007	2008
Columbus Southern			
With Three Percent Increase	4.26	4.38	4.51
With Termin. of Resid. Discount	4.20	4.27	4.33
Ohio Power			
With Seven Percent Increase	3.73	3.98	3.94
With Termin. of Resid. Discount	3.69	3.89	3.79

In Green Mountain's view, the residential incentive values may be at their highest during the RSP, but they will still not spur shopping (GMEC Initial Br. 10; GMEC Reply Br. 8). In addition to greater shopping incentives, Green Mountain also advocates for shopping credits (avoidable charges) set at market prices (GMEC Initial Br. 11). Green Mountain further advocates that the $10 switching fees be waived, market support generation be provided, a voluntary enrollment process be instituted, new partial payment priority changes be made, and reasonable/nondiscriminatory credit arrangements be created (*Id.* at 10-15, 19-20). AEP states in response to these additional requests that there is no evidence to support them and they should be rejected (AEP Reply Br. 40-14).

Commission Discussion

First, we accept again the term of this provision related to Ohio Power's residential customers who shop in 2006 and 2007. We continue to believe that this term will be beneficial to Ohio Power customers in the near future. No arguments were raised against this part of Provision Seven, except those raised by Green Mountain (in relation to the amount and impact), which we address further below.

The first criticism raised about Provision Seven of the RSP is that AEP proposes to not credit the unused Columbus Southern shopping incentive to regulatory asset charge recovery (and instead extends the incentive through 2008, with any remaining amounts becoming income to Columbus Southern). AEP correctly notes that, if the Commission does not accept this aspect of Provision Seven, there will be no shopping incentive for Columbus Southern's residential customers. Shopping credits and incentives were established to promote customer switching and effective competition. Sections 4928.37 and 4928.40, Revised Code. Accord, *Constellation, supra*. Shopping credits and incentives are not mandated by statute after the MDP. Certainly, however, the idea of having a Columbus Southern shopping incentive during the RSP is attractive, particularly since we are trying to spur further development of the competitive market in AEP's service territories. However, we must weigh that against AEP's clear statements that its proposed extension of the Columbus Southern shopping incentive is contingent upon any remaining amounts at the end of the RSP becoming income to Columbus Southern.

We do not agree that the unused amount of the Columbus Southern shopping incentive at the end of the RSP should become income to that company on the basis that it is a fair trade-off to offering to extend that incentive during the period, as AEP has argued. Under the ETP, Columbus Southern was not going to receive income if that shopping incentive was not completely used during the MDP. Instead, AEP previously agreed to flow those dollars back to customers (by making a reduction to the remaining regulatory asset amounts equivalent to the amount of the unused shopping incentive). Moreover, we do not believe that Columbus Southern should earn income when customers have not shopped sufficiently to utilize the same shopping incentive over an extended period. Furthermore, as explained below, we do not believe that the RSP must include a shopping incentive for Columbus Southern customers either. Therefore, the proposed Columbus Southern shopping incentive portion of Provision Seven of the RSP is rejected.

As previously noted, the ETP decision requires that the unused balance of the Columbus Southern shopping incentive at the end of the MDP be credited back to Columbus Southern customers (via an adjustment to the level of regulatory asset recovery). We agree that customers should benefit in the event that Columbus Southern customers do not shop sufficiently by the end of this year (which is the end of the MDP). We believe that most parties, if not all, would agree that sufficient shopping is very unlikely to occur by the end of the MDP and, thus, an unused dollar amount will exist. However, we conclude a redirected application of the unused shopping incentive monies is more appropriate, while yet still in line with the goal of benefiting customers. LIA and OCC have asked in this proceeding for specific dollars targeted to low-income customer issues because that segment of the customer base may be disproportionately affected by the RSP. As we noted in section VI.B.1 of this decision, we believe that it is appropriate to assist the AEP low-income customers. Therefore, we conclude that $14 million should be should be allotted by AEP for the benefit of the Columbus Southern and Ohio Power low-income customers, as well as for economic development during the RSP period. We will require AEP to work with our Service Monitoring and Enforcement Department staff to develop the details for the use of those sums. Our staff will consult with the Ohio Department of Development in relation to the use of that money in AEP's service territories.

Green Mountain has alleged that the shopping incentives (as identified for Columbus Southern customers above and a zero incentive for Ohio Power customers) will not be sufficient to spur shopping in either company's territory. As we have already noted, shopping incentives are not mandated after the MDP. In any event, the shopping incentives are only one manner of further developing the competitive market and we believe that, in the full context of the proposed RSP, our decision to require monetary assistance for low-income and economic development issues is an appropriate conclusion. With regard to Green Mountain's argument related to partial payment priority, the Commission is not willing to alter its established payment priority scheme just because AEP is seeking to establish a RSP. Green Mountain has also asked for several other specific alterations (establish other credits via avoidable charges, waiver of the $10 switching fees, provision of market support generation and institution of a voluntary enrollment process). We do not believe that these items are needed at this point. Accordingly, we will not adopt them.

H. Other Items (Provisions Eight through Eleven of the RSP)

1. Additional Future Proceedings

AEP recommends (in Provision Eight) that the Commission conduct a proceeding to determine the "manner in which electric generation service should be provided to the companies' customers" after the RSP and report the results to the legislature by December 31, 2005. AEP explains that this provision is intended to avoid facing the same situations at the end of the RSP as we face today (AEP Ex. 2, at 24-25). Staff and IEU-Ohio agree (Staff Ex. 2, at 13; IEU-Ohio Initial Br. 45). OMG and NEMA also appear to agree. Specifically, OMG and NEMA state that, if the Commission approves a RSP for AEP, it should establish a re-opener during 2007 in order to make adjustments to assist market development and to plan for the end of the rate stabilization period (to meet the statutory goals of market-base rates) (OMG/NEMA Initial Br. 12). OCC disagrees that the Commission should complete a report by 2005, arguing that any report completed by that date will not likely provide any valuable information for the post-RSP period (OCC Initial Br. 55-56).

<u>Commission Discussion</u>

This provision of the RSP is acceptable as a recommendation on steps the Commission should consider by the end of the RSP period. The Commission has a mandate to consider all possible options for implementation at the end of the rate stabilization period.

2. Functional Versus Structural Separation

In Provision Nine, the companies would continue functional separation (one corporate entity with separate groups to handle each function). AEP explained that it has not yet received authorization from the Securities and Exchange Commission to structurally separate, although AEP has made that request (AEP Ex. 2, at 25-26). At this point, AEP "does not contemplate structurally separating" the generation assets (*Id.*) because restructuring has slowed down. Staff concurs with this provision, particularly since structural separation could limit or preclude options in the future (Staff Ex. 2, at 13; Tr. IV, 250). IEU-Ohio does not oppose this provision (IEU-Ohio Initial Br. 45).

OCC, OMG, NEMA and Green Mountain state that AEP must structurally separate per Section 4928.17, Revised Code (OCC Initial Br. 56; OMG/NEMA Initial Br. 13-14; GMEC Initial Br. 21). PSEG states that it makes little sense for the Commission to approve the RSP based upon risks/volatility of the competitive market and not protect customers by requiring AEP to implement corporate separation (PSEG Br. 7-8). Green Mountain argues that to continue functional separation seeks something that AEP never lawfully had (because the ETP approved only structural separation) (GMEC Initial Br. 21). Green Mountain states that the Commission should not permit AEP to continue functional separation if the RSP is not implemented (*Id.*).

<u>Commission Discussion</u>

We are willing to accept this term of the RSP for several reasons. First and foremost, AEP has been unable to structurally separate, as it had planned, because it does not have the necessary federal authority to do so. We simply cannot force structural separation when other agencies also must give their approval and that approval has not been forthcoming. Second, we would be remiss if we did not recognize that many expectations surrounding a competitive electric market in Ohio and around the country have changed from 2000, which is when we approved AEP's plan in its ETP proceeding to structurally separate its generation functions from the remainder of its functions. Third, Sections 4928.17(C) and (D), Revised Code, allow the Commission to modify a previously approved corporate separation plan. OCC, OMG and NEMA seem to have overlooked that aspect of the corporate separation statute. More specifically, we conclude that good cause has been shown to allow AEP to operate on a functional separation basis for the RSP period and such functional separation can still provide compliance with the state's policies associated with competitive retail electric service, as enumerated in Section 4928.02, Revised Code.

3. Participation in Other CBPs

Provision 10 of the RSP allows the companies to submit bids in other EDU's CBPs. AEP argues that Section 4928.14(B), Revised Code, compels the Commission to grant this provision of the RSP and the Commission has acknowledged such previously (AEP Initial Br. 52). Staff agrees with this provision and IEU-Ohio believes current law already allows AEP to participate in the CBPs of other EDUs (Staff Ex. 2, 13; IEU-Ohio Initial Br. 46).

Green Mountain contends that AEP should not be permitted to participate in other CBPs until it has structurally separated (GMEC Initial Br. 21-22).

Commission Discussion

AEP correctly notes that we have refused to limit participation in CBPs to non-EDU affiliate participants because of the language in Section 4928.14(B), Revised Code. *In the Matter of the Commission's Promulgation of Rules for the Conduct of a Competitive Bidding Process for Electric Distribution Utilities Pursuant to Section 4928.14, Revised Code,* Case No. 01-2164-EL-ORD, Finding and Order at 9 (December 17, 2003). We find this provision of the RSP to be reasonable. Nothing that Green Mountain has argued on this provision convinces us that this aspect of the RSP should not be approved.

4. Minimum Stay Requirements

Also, the RSP addresses in Provision 11 the topic of minimum stay. It provides that, during the RSP, residential and small commercial customers that return to the standard service must remain through April 15 of the following year, if the customer took generation service from the company between May 16 and September 15. During the RSP, a 12-month minimum stay would be required for large commercial and industrial customers that return under the standard service tariff.

This RSP provision corresponds with AEP's current minimum stay tariff provisions, but those tariff provisions have not been in effect due to a Commission moratorium.[19] AEP believes that minimum stay requirements are needed to avoid seasonal impacts of switching when AEP's prices are essentially annual average rates (AEP Ex. 5, at 5). Staff finds AEP's approach to be reasonable, but also recommends that the alternative mentioned in those tariffs be more fully detailed (Staff Ex. 2, at 14).

OMG and NEMA argue that, before the minimum stay provisions are triggered, the Commission should require that shopping customers be able to return to the standard service offer three times (OMA/NEMA Initial Br. 15). They note that AEP agreed to such a term in its ETP and, since no real shopping has taken place, it makes sense to require this term during the RSP (*Id.*). AEP points out that the Commission did not accept this part of the ETP settlement and nothing was presented in this proceeding to warrant its acceptance now (AEP Reply Br. 39).

IEU-Ohio contends that this topic should be addressed by the Commission on a generic basis, not in this RSP proceeding (IEU-Ohio Initial Br. 46). OCC contends that AEP has not demonstrated a need for the minimum stay or any harm from the moratorium (any alleged harm will only occur if customers actually shop and then return to AEP) and, therefore, the moratorium should remain in place (OCC Initial Br.60).

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19 The Commission issued a moratorium on any minimum stay requirements for residential and small commercial customers on March 21, 2002, in *In the Matter of the Establishment of Electronic Data Exchange Standards and Uniform Business Practices for the Electric Utility Industry,* Case No. 00-813-EL-EDI. That moratorium has continued indefinitely. While another proposal is pending before the Commission on the matter, we have not issued a definitive ruling on the matter.

Commission Discussion

We are willing to accept this provision of the RSP. We realize that we still have not addressed the pending minimum stay proposal (which differs from AEP's minimum stay requirements) in the generic proceeding. For the short three-year period of the RSP, we are willing to allow AEP to implement these minimum stay requirements. It will allow us the opportunity to evaluate participation, gaming of enrollments, and the impact of our originally approved minimum stay requirements. We consider this approval to essentially test the debate that has been raised with us for quite a period of time.

VII. Conclusion

Based upon the foregoing, we conclude that the proposed RSP should be adopted (with the exception of the RSP's proposed elimination of the five percent residential discount in Provision Two, the proposed deferral of RTO administrative charges, the proposed deferral of CWIP and in-service plant carrying charges, the proposed review period associated with FERC-approved transmission rate changes, and the proposed treatment of the Columbus Southern shopping incentive) for the reasons set forth herein. We also conclude that OCC's motion to dismiss the application should be denied. Additionally, we conclude that, AEP shall allot $14 million for low-income customers and economic development, and work with our Service Monitoring and Enforcement Department staff to work out the details for those dollars. AEP is, furthermore, allowed to establish a POLR charge.

As we have already mentioned, we believe certain changes are warranted as the MDP ends for AEP. This decision will move AEP to market-based rates for the 2006-2008 period in an appropriate and balanced fashion and conforms with the state's electric policy (Section 4928.02, Revised Code) and this Commission's stated goals. Circumstances are not the same as when we issued our ETP decision and we recognize that fact and have reached conclusions today that we believe are most appropriate for the 2006-2008 period. To the extent any arguments were raised in this proceeding and they are not expressly addressed in this decision, they have been rejected.

As noted earlier in this Order, AEP will be held forth as the POLR to consumers who either fail to choose an alternative supplier or who choose to return to AEP's system after taking service from another energy company. Consistent with Ohio law, the POLR designation places expectations upon EDUs; the companies must have sufficient capacity to meet unanticipated demand. Additionally, the Commission is among many state agencies that have been charged by the Governor to enhance the business climate in Ohio as it competes on a regional, national, and global basis for economic development projects. One of the Commission's roles in this endeavor has been to focus on reliable energy. We believe that, consistent with Section 4928.02, Revised Code, Ohio consumers are entitled to a future secure in the knowledge that electricity will be available at competitive prices. We also feel strongly that electric generators of the future should be both environment-friendly and capable of taking advantage of Ohio's vast fuel resources. With the recognition that new technologies must be forthcoming to replace the utilities' aging generation fleet, we urge AEP to move forward with a plan to construct an integrated gasification combined-cycle (IGCC) facility in Ohio. AEP should engage the Ohio Power

Siting Board in pursuit of such a plant. We are encouraged by emerging information that suggests that the IGCC technology will be economically attractive. It is worth noting that the Commission is exploring regulatory mechanisms by which utilities, given their POLR responsibilities, might recover the costs of these new facilities.

FINDINGS OF FACT AND CONCLUSIONS OF LAW

(1) On February 9, 2004, AEP filed an application with the Commission for approval of a rate stabilization plan for the period 2006 through 2008.

(2) Twenty-five entities filed motions to intervene in this proceeding. All those requests were granted.

(3) A technical conference was held on March 24, 2004. Objections to the application were filed on April 8, 2004.

(4) A local, public hearing in Canton, Ohio, was conducted on May 19, 2004. However, the Commission had not properly sent any of the publication notices to the newspapers in AEP's service territory. Therefore, the examiner scheduled another local hearing in Canton, Ohio, for July 7, 2004 and rescheduled the local hearing in Columbus, Ohio, for July 1, 2004. At the July 1 and 7, 2004 local hearings, three people provided testimony.

(5) On May 24, 2004, OCC filed a motion to dismiss the application on various legal grounds. By entry dated June 1, 2004, the examiner deferred a ruling on OCC's motion to dismiss, stating that all parties shall have the opportunity to argue the legality of AEP's proposal in post-hearing briefs.

(6) The evidentiary hearing began on June 8, 2004, and continued through June 14, 2004. AEP presented the testimony of five witnesses. The staff and OCC each presented the testimony of two witnesses. APAC, Lima/Allen Council on Community Affairs, and WSOS Community Action jointly sponsored the testimony of one witness and OEG presented the testimony of one witness.

(7) The parties filed post-hearing briefs on July 13 and 30, 2004.

(8) AEP's MDP will end on December 31, 2005.

(9) AEP's proposed elimination of the five percent residential discount in provision two is precluded by the ETP decision.

(10) OCC's motion to dismiss the application should be denied.

(11) We adopt all provisions of the proposed RSP with the exception of the:

(a) RSP's proposed elimination of the five percent residential discount in Provision Two,
(b) Proposed deferral of RTO administrative charges in Provisions One and Six,
(c) Proposed deferral of CWIP and in-service plant carrying charges in Provisions One and Six,
(d) Proposed review period associated with FERC-approved transmission rate changes in Provision Four, and
(e) Proposed treatment of the Columbus Southern shopping incentive in Provision Seven.

(12) Our adopted provisions of the proposed RSP, our decision to require AEP to allot $14 million for low-income customers and economic development, our decisions to require AEP to work with our Service Monitoring and Enforcement Department staff to work out the details for those dollars, and our decision to allow AEP to establish a POLR charge, taken together, appropriately balance three objectives: (a) rate certainty, (b) financial stability for AEP, and (c) the further development of the competitive electric market. Moreover, the combination of the approved components of the RSP, along with the additional conditions of our decision and continuation of the unaffected provisions of the ETP, will prompt the competitive market and continue to provide customers a reasonable means for customer participation in the electric competitive market.

ORDER

It is, therefore,

ORDERED, That OCC's motion to dismiss this application is denied. It is, further,

ORDERED, That AEP's application is approved, subject to the modifications set forth in this decision. It is, further,

ORDERED, That AEP work with our Service Monitoring and Enforcement staff to work out the details for the allotted low-income and economic development dollars. It is, further, ORDERED, That a copy of this opinion and order be served upon all 28 parties to this proceeding and any interested persons of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Ronda Hartman Fergus

Judith A. Jones

Donald L. Mason

Clarence D. Rogers, Jr.

GLP;geb

Entered in the Journal

JAN 2 6 2005

Reneé J. Jenkins
Secretary

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of a Post-Market Development Period Rate Stabilization Plan.	)	Case No. 04-169-EL-UNC

ENTRY

The Commission finds:

(1) On February 9, 2004, Columbus Southern Power Company (CSP) and Ohio Power Company (OP) (jointly AEP-Ohio)[1] filed an application with the Commission for approval of a rate stabilization plan (RSP) to continue to allow the competitive electric market to develop beyond the market development period (MDP) approved in the companies' electric transition plan (ETP) cases.[2] As agreed to in the ETP cases, the MDP terminated for CSP and OP on December 31, 2005.

(2) By Opinion and Order issued January 26, 2005, in this proceeding (04-169 Order), the Commission found that there was very little retail electric shopping in the CSP territory (only 3.4 percent), no shopping in the OP territory and that it was very unlikely that the situation would change dramatically by the end of the MDP. Further, although three suppliers had been certified to operate in AEP-Ohio territory, only one supplier was actually providing retail electric service to consumers. Accordingly, the Commission concluded that it would be ineffective to direct AEP-Ohio to conduct a competitive bid process for the years 2006 through 2008. Further, the Commission found, among other things, that, because neither the retail electric choice market nor the wholesale market had developed sufficiently to determine a market-based standard service offer, the RSP served as a

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1 CSP and OP are electric utility operating companies of American Electric Power Corporation and therefore, will be referred to jointly as AEP-Ohio.

2 Case No. 99-1729-EL-ETP and 99-1730-EL-ETP (ETP case), *In the Matter of the Applications of Columbus Southern Power Company and Ohio Power Company for Approval of Their Electric Transition Plans and for Receipt of Transition Revenues* (Order issued September 28, 2000 and entry on rehearing issued November 21, 2000).

reasonable proxy. The Commission concluded that the RSP would provide Ohio consumers rate certainty, provide financial stability for the electric distribution companies and allow for the further development of the competitive electric market (04-169 Order at 13-15). Applications for rehearing were filed by 12 parties to the proceeding. By entry issued March 23, 2006, the Commission denied all the issues raised on rehearing. The Commission's decision was appealed, as of right, to the Ohio Supreme Court.

(3) On July 5, 2006, the Ohio Supreme Court (Court) issued its decision in *Ohio Consumers' Counsel v. Pub. Util. Comm.*, 2005-Ohio-767, the appeal of the 04-169 Order and rehearing. Citing its decision in *Ohio Consumers' Counsel v. Pub. Util. Comm.*, 109 Ohio St. 3d 328 (2006) (FirstEnergy RSP decision), the Court vacated and remanded the Commission's decision in AEP-Ohio's RSP case for further proceedings not inconsistent with its FirstEnergy RSP decision. In the FirstEnergy RSP decision, the Court concluded that FirstEnergy's RSP, as adopted by the Commission, did not comply with Sections 4928.14, Revised Code, as the RSP failed to provide an option for customer participation in the electric market through competitive bids or other reasonable means. Thus, the Court remanded that aspect of the case back to the Commission for further consideration.

(4) The Commission, therefore, finds that AEP-Ohio's RSP shall remain effective as the Section 4928.18(A), Revised Code, standard service offer. As ordered by the Court, the Commission will follow the provisions of Section 4928.14(B), Revised Code, to provide an option for customers to purchase electric service at a price determined through a competitive bid process, or through another means if the Commission is satisfied that the option would be readily available and accessible to customers.

(5) Accordingly, AEP-Ohio is directed to file, in a new docket, its plan for complying with the requirements of Section 4928.14, Revised Code, within 45 days of this entry.

It is, therefore,

ORDERED, That AEP-Ohio is directed to file its plan for complying with the requirements of Section 4928.14, Revised Code, within 45 days of this entry. It is, further,

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IN THE SUPREME COURT OF OHIO
On Appeal From the Public Utilities Commission of Ohio

The Office of the Ohio Consumers' Counsel, Appellant, v. The Public Utilities Commission of Ohio, Appellee.	)))))))))))	Case No. 06-0788 PUCO Appeal from the Public Utilities Commission of Ohio Public Utilities Commission of Ohio Case No. 05-276-EL-AIR

FILED
APR 21 2006
MARCIA J MENGEL, CLERK
SUPREME COURT OF OHIO

NOTICE OF APPEAL OF APPELLANT, THE OFFICE OF THE OHIO CONSUMERS' COUNSEL

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Notice Of Appeal of Appellant, The Office of the Ohio Consumers' Counsel

Appellant, the Office of the Ohio Consumers' Counsel, pursuant to R.C. 4903.11, R.C. 4903.13, and S. Ct. Prac. R. II (3)(B), hereby gives notice to the Supreme Court of Ohio and to the Public Utilities Commission of Ohio ("Appellee" or "PUCO") of this appeal to the Supreme Court of Ohio from Appellee's Opinion and Order entered in its Journal on December 28, 2005 and Entry on Rehearing entered in its Journal on February 22, 2006 in Case No. 05-276-EL-AIR before the PUCO.

Pursuant to R.C. Chapter 4911, Appellant is the statutory representative of the residential customers of the Dayton Power and Light Company ("DP&L" or the "Company"). Appellant was a party of record in the case before the PUCO. On January 27, 2006, Appellant timely filed an Application for Rehearing from the December 28, 2005 Opinion and Order pursuant to R.C. 4903.10. Appellant's Application for Rehearing was denied with respect to the issues raised in this appeal by an Entry on Rehearing entered in Appellee's Journal on February 22, 2006.

Appellant files this Notice of Appeal, complaining and alleging that Appellee's December 28, 2005 Opinion and Order and February 22, 2006 Entry on Rehearing result in a final order that is unlawful and unreasonable, and that Appellee erred as a matter of law, in the following respects that were raised in Appellant's Application for Rehearing:

1) The PUCO, As A Creature Of Statute, Erred When It Approved An Increase In Electric Utility Distribution Rates By Consideration Of Only Generation Costs And Without A Proceeding Pursuant To The Statutory Requirements For An Increase In Distribution Rates;

    a) The PUCO erred when it approved an increase in distribution rates as the result of cases that involved only generation service;

    b) The PUCO erred when it illegally increased distribution rates based upon the evaluation of selected generation costs;

i) The PUCO's earlier order must be followed, which did not permit the adjustment of distribution rates;

ii) Statutory requirements, including those contained in R.C. 4928.15 as well as Chapters 4905 and 4909 regarding the fixation of distribution rates, were not followed; and these requirements must be met before any distribution increase can be lawfully authorized.

2) The PUCO Failed To Respect The Outcome Of Its Own Prior Order Without Any Showing That The Commission's Prior Order Was In Error, And The PUCO Erred When It Failed To Apply The Doctrine Of Collateral Estoppel That Applies To Administrative Decisions;

3) The PUCO Erred When It Approved A Settlement Regarding Electric Rates Extending Through The End Of 2010 That Contains Illegal Terms, And The Order Is Against The Manifest Weight Of The Evidence, Demonstrating Willful Disregard For The PUCO's Duty;

a) The PUCO erred when it permitted parties to violate the Commission's earlier order approving a stipulation that was negotiated by capable, knowledgeable parties;

b) The PUCO erred when it approved a settlement that, as a package, does not benefit ratepayers and the public interest, especially as provided for under R.C. Chapter 4928;

c) The PUCO erred when it approved a settlement that violates important regulatory principles and practices;

i) The collateral attack on the earlier Commission order is illegal and bad public policy;

ii) The settlement package includes the violation of DP&L's tariffs;

iii) Expenditures on a third round of the Voluntary Enrollment Program do not satisfy the requirements of R.C. 4928.14(B) and are bad public policy;

WHEREFORE, Appellant respectfully submits that the Appellee's December 28, 2005 Opinion and Order and February 22, 2006 Entry on Rehearing are unreasonable and unlawful, and should be reversed. This case should be remanded to Appellee with instructions to correct the errors complained of herein.

Respectfully submitted,

JANINE L. MIGDEN-OSTRANDER
OHIO CONSUMERS' COUNSEL

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CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing Notice of Appeal of the Office of the Ohio Consumers' Counsel was served to all parties to the proceedings and upon the Chairman of the Public Utilities Commission of Ohio, pursuant to section 4903.13 of the Ohio Revised Code, by leaving a copy at the office of the Chairman in Columbus and upon all parties on the service list by hand-delivery or regular U.S. Mail this 21st day of April 2006.

Jeffrey L. Small
Counsel for Appellant
Office of the Ohio Consumers' Counsel

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CERTIFICATE OF FILING

I hereby certify that a Notice of Appeal of the Office of the Ohio Consumers' Counsel was filed with the docketing division of the Public Utilities Commission in accordance with sections 4901-1-02(A) and 4901-1-36 of the Ohio Administrative Code.

Jeffrey L. Small
Counsel for Appellant
Office of the Ohio Consumers' Counsel

APPENDIX E. CASE INFORMATION STATEMENT
IN THE SUPREME COURT OF OHIO
Case Information Statement

Case Name:	Case No.:
The Office of the Ohio Consumers' Counsel v. Pub. Util. Comm.	On Appeal from PUCO Case No. 05-276-EL-AIR

I. Has this case previously been decided or remanded by this Court? Yes ☐ No ☒
If so, please provide the Case Name: ____
Case No.: ____
Any Citation: ____

II. Will the determination of this case involve the interpretation or application of any particular case decided by the Supreme Court of Ohio or the Supreme Court of the United States? Yes ☒ No ☐
If so, please provide the Case Name and Citation: See attachment

Will the determination of this case involve the interpretation or application of any particular constitutional provision, statute, or rule of court? Yes ☒ No ☐
If so, please provide the appropriate citation to the constitutional provision, statute, or court rule, as follows:
U.S. Constitution: Article ____, Section ____ **Ohio Revised Code:** See attachment
Ohio Constitution: Article ____, Section ____ **Court Rule:** ____
United States Code: Title ____, Section ____ **Ohio Adm. Code:** ____

III. Indicate up to three primary areas or topics of law involved in this proceeding (e.g., jury instructions, UM/UIM, search and seizure, etc.):
1) Regulatory law (esp. R.C. 4905, 4909, and 4928)
2) Collateral estoppel
3) ____

IV. Are you aware of any case now pending or about to be brought before this Court that involves an issue substantially the same as, similar to, or related to an issue in this case? Yes ☒ No ☐
If so, please identify the Case Name: See attachment
Case No.: ____
Court where Currently Pending: ____
Issue: ____

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Appendix E, Section II (cont.)

Ohio Supreme Court Cases:

Canton Storage and Transfer Co. v. Pub. Util. Comm. (1995), 72 Ohio St. 3d 1.

Constellation NewEnergy v. Pub. Util. Comm., 104 Ohio St. 3d 530, 2004 Ohio 6767.

Consumers' Counsel v. Pub. Util. Comm. (1984), 10 Ohio St.3d 49.

Consumers' Counsel v. Pub. Util. Comm. (1985), 16 Ohio St.3d 9.

Consumers' Counsel v. Pub. Util. Comm. (1992), 64 Ohio St. 3d 123.

Spercel v. Sterling Industries (1972), 31 Ohio St. 2d 36.

State, ex rel., Ormet Corp. v. Industrial Commission of Ohio (1990), 54 Ohio St.3d 102.

Ohio Revised Code Sections:

R.C. 4905.35
R.C. 4909.18
R.C. 4928.02
R.C. 4928.10
R.C. 4928.14
R.C. 4928.34

Appendix E, Section IV (cont.)

Related Pending Cases:

Case Name: *Office of the Ohio Consumers' Counsel v. Pub. Util. Comm.*
Case No.: 2006-0536 and 2006-0600
Court where Currently Pending: Ohio Supreme Court
Issue: Whether PUCO's Opinion and Order was unreasonable and unlawful by granting electric distribution utilities (including DP&L) authority to charge customers in violation of previous PUCO orders.

Case Name: *Office of the Consumers' Counsel v. Pub. Util. Comm.*
Case Nos.: 2005-1621 and 2005-1679 (consolidated)
Court where Currently Pending: Ohio Supreme Court
Issue: Whether PUCO's Finding and Order was unreasonable and unlawful by granting electric distribution utilities (including DP&L) authority to charge customers in violation of previous PUCO orders.

Case Name: *Office of the Consumers' Counsel v. Pub. Util. Comm.*
Case No.: 2005-0945
Court where Currently Pending: Ohio Supreme Court
Issue: Whether PUCO's Finding and Order was unreasonable and unlawful by granting DP&L authority to increase distribution rates in a manner that conflicted with statutory protections and earlier PUCO orders.

Case Name: *Office of the Ohio Consumers' Counsel v. Pub. Util. Comm.*
Case No.: 2004-1993
Court where Currently Pending: Ohio Supreme Court
Issue: Whether the PUCO violated provisions of Ohio law by approving a Rate Stabilization Plan for FirstEnergy Corp. in violation of previous PUCO orders.

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IN THE SUPREME COURT OF OHIO
On Appeal from the Public Utilities Commission of Ohio

Office of the Ohio Consumers' Counsel, Appellant, v. The Public Utilities Commission of Ohio, Appellee.	)	Case No. 05-0767 Appeal from the Public Utilities Commission of Ohio Public Utilities Commission of Ohio Case No. 04-169-EL-UNC

NOTICE OF APPEAL
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APR 29 2005
MARCIA J. MENGEL, CLERK
SUPREME COURT OF OHIO

<u>**NOTICE OF APPEAL OF APPELLANT**</u>
<u>**OFFICE OF THE OHIO CONSUMERS' COUNSEL**</u>

Appellant, the Office of the Ohio Consumers' Counsel, pursuant to R.C. 4903.11 and 4903.13, and S. Ct. Prac. R. II (3)(B), hereby gives notice to the Supreme Court of Ohio and to the Public Utilities Commission of Ohio ("Appellee," "PUCO" or "Commission") of this appeal to the Supreme Court of Ohio from Appellee's Opinion and Order entered in its Journal on January 26, 2005 and Entry on Rehearing entered in its Journal on March 23, 2005 in PUCO Case No. 04-169-EL-UNC.

Pursuant to R.C. Chapter 4911, Appellant is the statutory representative of the residential customers of the following electric distribution companies: Ohio Power Company and Columbus Southern Power Company, collectively referred to as "Companies." Appellant was and is a party of record in PUCO Case No. 04-169-EL-UNC. On February 25, 2005, Appellant timely filed an Application for Rehearing from the January 26, 2005 Opinion and Order pursuant to R.C. 4903.10. Appellant's Application for Rehearing was denied with respect to the issues raised in this appeal by an Entry on Rehearing entered in Appellee's Journal on March 23, 2005 in the case below.

Appellant complains and alleges that Appellee's January 26, 2005 Opinion and Order and March 23, 2005 Entry on Rehearing in PUCO Case No. 04-169-EL-UNC are unlawful, unjust and unreasonable, and the Commission erred as a matter of law, in the following respects that were raised in Appellant's Application for Rehearing:

1. The Commission acted unlawfully and unreasonably in failing to dismiss the Companies' Application in PUCO Case No. 04-169-EL-UNC for a so-called Post-Market Development Period Rate Stabilization Plan ("RSP"). As set forth in OCC's Motion to Dismiss in Case No. 04-169-EL-UNC filed at the PUCO on May 24, 2004 and OCC's Application for Rehearing, there is no basis in Ohio law for the Companies' RSP. The Companies' RSP violates R.C. 4909.15, 4909.18, 4928.02, 4928.14, 4928.15, 4928.17, 4928.34, 4928.38 and 4928.40.

2. The Commission's Opinion and Order violates R.C. 4928.14(A), which requires that a market-based standard service offer be available to customers at the end of the Market Development Period ("MDP"), and R.C. 4928.14(B), which requires that an option to purchase competitive retail electric service at a price determined through a competitive bidding process ("CBP") also be available to customers at the end of the MDP.

3. Neither R.C. 4928.14(A) and (B) nor the evidentiary record supports the Commission's finding that increasing generation rates by 7 percent annually for the years 2006, 2007 and 2008 for Ohio Power Company and 3 percent annually for the years 2006, 2007 and 2008 for Columbus Southern Power Company results in market-based standard service offers pursuant to R.C. 4928.14.

4. The Commission acted unlawfully in violation of R.C. 4928.14(A) and (B) and unreasonably without regard to the evidence of record in approving the Companies' request for the opportunity to seek additional 4 percent generation rate increases (above the 7 percent and 3 percent annual increases referenced above) during the years 2006, 2007 and 2008.

5. The Commission acted unlawfully and unreasonably in approving a Provider of Last Resort ("POLR") charge for the Companies when there is no basis in Ohio law for such a charge and when the amount of revenues to be recovered by the charge is the same amount requested by the Companies in deferrals for regional transmission organization ("RTO") adminstrative charges incurred during the MDP and for carrying charges on construction work in progress and in-service generation plant expenditures incurred during the MDP. Such deferrals during the MDP violate R.C. 4928.34(A)(6); therefore, the creation of a charge to recover amounts equal to such deferrals, regardless of the name given to the charge, violates R.C. 4928.34(A)(6).

A. The establishment of a POLR charge set at an amount that includes transmission costs incurred during the MDP is unlawful, because there is no provision in Ohio law for POLR charges and because the deferral of expenses incurred during the MDP for recovery after the MDP violates the rate cap provisions of R.C. 4928.34(A)(6).

B. The establishment of a POLR charge including an amount for various carrying costs associated with generation plant during the MDP is unlawful, because R.C. 4928.14(A) and (B) do not allow for POLR charges associated with generation service.

C. The establishment of a POLR charge violates the distribution rate freeze agreed to in the Stipulation and Recommendation approved by the Commission in its September 28, 2000 Opinion and Order in the Companies' electric transition plan ("ETP") cases, PUCO Case Nos. 99-1729-EL-ETP and 99-1730-EL-ETP. The approval of this provision of the Companies' RSP conflicts with the Commission's previous Opinion and Order approving the Stipulation and Recommendation in the ETP cases and the doctrine of collateral estoppel, which bars relitigation of the ETP.

6. The Commission acted unreasonably and unlawfully by adding two new exceptions to the Companies' distribution rate freezes. The two new exceptions (for security costs and operating and maintenance expenses associated with new requirements imposed on the Companies by federal or state legislative regulatory bodies after January 31, 2004) were not included in the list of exceptions to the distribution rate freeze in the ETP Stipulation and Recommendation, which the Commission approved in PUCO Case Nos. 99-1729-EL-ETP and 99-1730-EL-ETP in its Opinion and Order dated September 28, 2000. The approval of this provision of the Companies' RSP conflicts with the Commission's previous Opinion and Order approving the Stipulation and Recommendation in the ETP cases and the doctrine of collateral estoppel, which bars relitigation of the ETP cases.

7. The Commission acted unreasonably and unlawfully in violation of R.C. 4928.34(A)(6), the ETP Stipulation and Recommendation and the doctrine of collateral estoppel in granting deferrals of certain costs (RSP filing costs, ETP filing costs, customer choice education costs and customer choice implementation costs) incurred during the MDP and during the period of the Commission-approved ETP Stipulation's distribution rate freezes for recovery after the MDP and distribution rate freezes approved by the Commission in PUCO Case Nos. 99-1729-EL-ETP and 99-1730-EL-ETP, Opinion and Order (September 28, 2000).

8. The Commission violated R.C. 4928.17(A) and R.C. 4928.02 in allowing the Companies to avoid the corporate separation requirements of Ohio law.

9. The Commission acted unreasonably and unlawfully in failing to enforce the Commission-approved ETP Stipulation with respect to the unused Columbus Southern Power Company shopping incentives, which were to be credited to regulatory transition cost recovery for all customers. PUCO Case Nos. 99-1729-EL-ETP and 99-1730-EL-ETP, Opinion and Order (September 28, 2000). To the extent that the Commission redirected the use of the unused shopping incentives to another public benefit, the Commission acted unreasonably in allowing the Companies to retain a portion of these funds and failing to designate the redirection of the entire amount of the unused Columbus Southern Power Company shopping incentives.

WHEREFORE, Appellant respectfully submits that the Appellee's January 26, 2005 Opinion and Order and March 23, 2005 Entry on Rehearing are unlawful, unjust and unreasonable and should be reversed. This case should be remanded to Appellee with instructions to correct the errors complained of herein.

Respectfully submitted,

By: Colleen Mooney

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CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing Notice of Appeal of the Office of the Ohio Consumers' Counsel was served upon the Chairman of the Public Utilities Commission of Ohio by leaving a copy at the office of the Chairman in Columbus and upon all parties of record to the proceedings before the Public Utilities Commission and pursuant to R.C. 4903.13 by hand-delivery or regular U.S. Mail this 29th day of April 2005.

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CERTIFICATE OF FILING

I hereby certify that this Notice of Appeal has been filed with the Docketing Division of the Public Utilities Commission of Ohio in accordance with Rules 4901-1-02(A) and 4901-1-36 of the Ohio Administrative Code.

Colleen L. Mooney
Colleen L. Mooney
Counsel for Appellant, Office of the Ohio Consumers' Counsel

In The Supreme Court of Ohio
Case Information Statement

Case Name: Office of the Ohio Consumers' Counsel, Appellant, v. Public Utilities Commission of Ohio, Appellee
Case No.: PUCO Case No. 04-169-EL-UNC

05-0767

I. Has this case previously been decided or remanded by this Court? No
If so, please provide the Case Name: ______________________
Case No.: ______________________
Any Citation: ______________________

II. Will the determination of this case involve the interpretation or application of any particular case decided by the Supreme Court of Ohio or the Supreme Court of the United States? No
If so, please provide the Case Name and Citation: n/a

Will the determination of this case involve the interpretation or application of any particular constitutional provision, statute, or rule of court? Yes
If so, please provide the appropriate citation to the constitutional provision, statute, or court rule, as follows:
U.S. Constitution: Article _____, Section _____
Ohio Revised Code: R.C. 4928.14(A) and (B), 4928.15, 4928.17, 4928.02, 4928.34(A)(6), 4928.40, 4928.02, 4909.18 and 4909.19, 4905.33, 4905.34, 4905.35, 4903.09, 4903.13
Ohio Constitution: Article _____, Section _____
Court Rule: ____________
United States Code: Title _____, Section_______
Ohio Admin. Code: _______

III. Indicate up to three primary areas or topics of law involved in this proceeding (e.g., jury instructions, UM/UIM, search and seizure, etc.):
1) Statutory interpretation (R.C. Chapters 4903, 4905, 4909 and 4928)
2) Administrative law
3) Regulatory law, authority of the Public Utilities Commission of Ohio

FILED
APR 29 2005
MARCIA J. MENGEL, CLERK
SUPREME COURT OF OHIO

IV. Are you aware of any case now pending or about to be brought before this Court that involves an issue substantially the same as, similar to, or related to an issue in this case?
Yes

If so, please identify the Case Name: *Industrial Energy Users-Ohio v. Pub. Util. Comm.*, Case No. GEN-2005-656, Court where Currently Pending: Ohio Supreme Court, Issue: PUCO's Opinion and Order was unreasonable and unlawful with respect to law and evidence;

Case Name: *Office of the Ohio Consumers' Counsel v. Pub. Util. Comm.*, Case No. GEN-2004-1993, Court where Currently Pending: Ohio Supreme Court, Issue: Whether the PUCO violated the Ohio Revised Code in approving a Rate Stabilization Plan for FirstEnergy Corp.;

Case Name: *City of Maumee, City of Northwood, City of Oregon, City of Perrysburg, City of Sylvania, City of Toledo, Village of Holland, Board of County Commissioners of Lucas County v. Pub. Util. Comm.*, Case No. GEN-2005-118, Court where Currently Pending: Ohio Supreme Court, Issue: Whether the PUCO violated the provisions of Ohio law in approving a Rate Stabilization Plan for FirstEnergy Corp.;

Case Name: *Office of Ohio Consumers' Counsel v. Pub. Util. Comm.*, Case No. GEN-2005-518, Court where Currently Pending: Ohio Supreme Court, Issue: Whether the PUCO violated the Ohio Revised Code in approving a Rate Stabilization Plan for Cincinnati Gas & Electric Company;

Case Name: *Monongahela Power Company v. Pub. Util. Comm.*, Case No. GEN-2005-392, Court where Currently Pending: Ohio Supreme Court, Issue: the PUCO's authority to set post-market development period generation rates.

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