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May 18, 2007

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Docketing Division
Public Utilities Commission of Ohio
180 East Broad Street
Columbus, Ohio 43215

RE: *In the Matter of the Application of The Columbus Southern Power Company and Ohio Power Company to Adjust the Transmission Component of Each Company's Standard Service Tariff to Combine That Component With its Transmission Cost Recovery Rider, Case No. 06-273-EL-UNC*

and,

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company to Update each Company's Transmission Cost Recovery Rider, Case No. 06-1294-EL-UNC.

Dear Docketing Division:

Enclosed please find the Staff's Biennial Review of Controllable RTO Costs for Columbus Southern Power Company and Ohio Power Company in response to the Commission's Finding and Order in Case No. 06-273-EL-UNC.

Sincerely,

Robert Fortney

Robert Fortney
Chief, Rates and Tariffs Division
Public Utilities Commission of Ohio

Enclosure
Cc: Parties of Record

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Staff's Biennial Review of Controllable RTO Costs for Columbus Southern Power Company and Ohio Power Company

(Case Nos. 06-273-EL-UNC and 06-1294-EL-UNC)

Introduction

Pursuant to Commission Order dated May 26, 2006, in Case No. 06-273-EL-UNC, on November 1, 2006, Columbus Southern Power Company and Ohio Power Company (jointly as Companies or AEP) filed a detailed report on the RTO costs identified by the Commission as costs that may be controllable by the Companies. The Staff has performed its initial biennial review of the costs and the results of that review are herein reported.

The Staff finds that after further review, there are certain costs that are not controllable by the company and thus will require no further review in regard to future biennial review requirements. However, for the remainder of the costs that are still considered to be controllable by the company, the following report will address each of the cost categories as well as how the company manages the costs to ensure they are being minimized. In addition, both controllable and non-controllable costs will continue to be audited by the Staff, each time the Rider is updated, to ensure that only those costs incurred to provide service to retail customers in Ohio are included in the Rider.

Non-Controllable RTO Costs

After further review, Staff has determined that the following costs are not controllable by the Companies. As a result, these costs will not be required to be included in future biennial reviews. However, these costs will continue to be subject to

Staff's annual audit of the accuracy of the actual costs proposed and included in each update filing to ensure the Companies pass through only the actual costs incurred to provide service to their Ohio retail customers.

Reactive Supply

Reactive supply cost is driven by the amount of voltage support needed for the transmission system. The rate charged to AEP is a cost based FERC-approved rate. AEP must purchase reactive supply service from PJM Interconnection (PJM). As a result, AEP has no control over this cost.

Synchronous Condensing

Synchronous condensing cost is incurred when PJM must pay for a generation unit to spin its turbine without producing energy so that it is ready to come on line instantaneously for spinning reserves, system reliability or reactive power. Synchronous condensing costs are allocated to all Load Serving Entities (LSEs) in PJM based on a Load Ratio Share (LRS) allocation methodology. As a result, AEP has no control over this cost.

Blackstart Service

Blackstart service is required to ensure the power grid can be reenergized following a complete system blackout. AEP is required to purchase this service from PJM. Blackstart service charges are based upon FERC-approved cost-based rates. As a result, AEP has no control over this cost.

Load Response Program

This is a FERC-approved demand side response (DSR) program initiated by PJM. According to the PJM tariff, costs incurred under this program are charged to the LSEs[1]

[1] According to PJM business rules, if the day-ahead LMP is less than $75/MWh, PJM shall recover day-ahead LMP less an amount equal to applicable generation and transmission charges from the LSE that otherwise would have the load that was reduced. If the day-ahead LMP is greater than or equal to $75/MWh, PJM shall recover an amount equal to applicable generation and transmission charges from all LSEs in the zone of the load reduction. PJM shall recover the remaining amount, LMP less an amount

in the zone where the Load Response Customers are located. AEP has no control over the costs associated with this program.

Controllable RTO Costs

After further review, Staff has determined that the following costs are controllable by the Companies. Following is a discussion of each cost, including how the Companies manage each of the costs to ensure they are being minimized.

Attachment L&M of the November 1, 2006 update filing in Case No. 06-1294-EL-UNC describes the process by which AEP strives to minimize the costs associated with operating within PJM as follows:

> The Commercial Operations group continually strives to minimize the costs associated with operating within PJM. For example, there is a daily morning meeting involving Fuels, Generation and Commercial Operations personnel and others who may have input in the daily and longer-term operations. During this meeting, operational issues are discussed that affect both the real-time, day-ahead and longer-term resource commitment. Topics such as unit outages, weather, load forecasts, transmission outages as well as known or anticipated transmission congestion associated with the dispatch of the generating fleet are discussed.
>
> There is continual interaction among individuals from the morning meeting throughout the day to effectively optimize AEP's system while taking into account fuel markets, operational constraints, environmental constraints, market conditions, system conditions, and regulatory requirements in conjunction with PJM's dispatch signals. With communication being vital to staying informed on all aspects that may affect the market, information is continually exchanged among the parties listed above, plus other individuals who may obtain and provide information useful to making economic decisions. For example, throughout the day, various departments within Commercial Operations provide

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equal to the generation and transmission charges, from the LSE that otherwise would have the load that was reduced.

analysis of the market conditions, transmission congestion and potential revised bid and offer strategies. Commercial Operations further refines the intra-day and day-ahead plans after PJM market awards are released based on this analysis. The entire Commercial Operations group works as a team with American Electric Power Service Corporation (AEPSC) Fuels, Generation operations and plant engineering and is responsible for the daily planning and execution necessary to ensure the proper mix of the AEP system generation fleet and market purchases are utilized for the benefit of the customers on the AEP system. In addition, Commercial Operations continually monitors and reviews PJM market settlement data to ensure billing accuracy from PJM.

A weekly meeting is held to review and discuss the PJM operating results, including areas for further analysis and positive outcomes, of the previous week. As a result of the morning and weekly meetings and on-going daily analyses, there is consistent research and development of new business processes which minimize the overall costs associated with the operating within PJM.

Following is a detailed discussion of each of the costs identified as being controllable by the Companies:

Net Congestion

Net congestion includes congestion costs and credits and Financial Transmission Rights (FTRs) costs and credits. Congestion costs and credits are driven by the difference in locational marginal prices (LMP) between generation sources and load. The costs arise when the transmission system is constrained requiring an out-of-merit order dispatch of generation units.

AEP is allocated "annual FTRs" once a year by PJM based on the peak demand of its previous planning year. To date, this annual allocation of FTRs to AEP has effectively hedged the Companies' congestion costs related to its native load customers in Ohio. FTRs typically generate a positive revenue stream for AEP, but can result in a negative revenue stream. To date, AEP has been allocated a sufficient quantity of FTRs to hedge the congestion costs related to its native load customers. In fact, the FTRs allocated to AEP have generated surplus revenues for the Companies. This is due in part to the operating experience AEP has gained in PJM since it filed its original rider. As a

result, the November 1, 2006 update filing reflected a decrease in rates for Rider TCRR. For the year ending December 31, 2005, AEP realized approximately $40 Million in net congestion revenues and $43 Million for the nine months ending September 2006. These revenues are flowed through to retail customers in Rider TCRR.

Although AEP is allocated annual FTRs, it evaluates its FTR position on a daily basis. AEP participates in the monthly FTR auctions to better hedge against congestion costs if necessary; however, this participation is utilized for off-system sales only and the cost or revenues associated with the monthly auctions are not reflected in the TCRR Rider.

Beginning June 2007, AEP will be allocated Auction Revenue Rights (ARRs) instead of FTRs. Following the ARR allocation, PJM will hold an annual auction. During this auction, AEP has the option to auction off their rights or convert their ARRs to FTRs. Converting the ARRs to FTRs would allow AEP to essentially maintain the current position and strategy. If AEP decides not to convert to FTRs, they will receive the auction price of their ARRs, which could be higher or lower than the revenue they would receive if they converted the ARRS to FTRs. As a result, by not converting to FTRs, AEP would incur more risk. AEP has stated that they intend to convert their ARRs to FTRs and maintain their current strategy. AEP's primary strategy is to fully hedge congestion costs from AEP generating units to the AEP load. Although AEP's FTR strategy has produced positive results to date, *Staff recommends and expects that AEP will continue to evaluate all of its options in the future and provide details of any analysis performed by AEP to determine the strategy chosen is optimal.*

Regulation Service

The cost of regulation service is driven by the Companies' load on the PJM system. The Company must secure 1% of its daily peak load for regulation service. The Companies have the option of buying regulation service in the regulation market, purchasing the service through a bilateral agreement, or the Companies can fulfill their obligation through self-supply. The Companies have indicated that they fulfill their regulation obligation by purchasing it from the regulation market. This ensures AEP is

receiving the lower regulation market clearing price (RMCP) when AEP's cost of providing regulation service is higher than the market price.

AEP indicates that it continually analyzes the options above to ensure its customers benefit by receiving the lower cost of AEP generation or third-party supply. AEP's Commercial Operations group, as discussed above, is primarily responsible for monitoring this cost for the appropriate strategy and is responsible for the day to day bidding for regulation service.

AEP is required to bid its generation for regulation service in at cost-based rates subject to the guidelines furnished in PJM Manual 15: Cost Development Guidelines. Because AEP is required to bid in at cost-based rates, the strategy adopted by the Companies of purchasing regulation service from the market should result in the least cost solution for AEP. If the market price for regulation service is lower than AEP's cost based offer, then AEP will purchase this service from the market.

If AEP obtained Regulation Service by self-scheduling its generation resources it would be at risk of providing Regulation at a cost that is higher than the Regulation Market Clearing Price (RMCP). Self-Scheduling essentially removes AEP from market and eliminates the possible benefits to be gained from procuring this service from the market. The third option available to AEP is to enter into bilateral contracts with other parties to procure regulation service. Similar to self-scheduling, procuring regulation service through bilateral agreements essentially removes AEP from market and eliminates any possible benefits to be gained from procuring this service from the market. AEP indicates that presently, there is no actively traded bilateral market for regulation.

At this point in time, it appears the strategy AEP has adopted for procuring regulation service results in the least cost to its retail customers. *The Staff recommends the companies continue to analyze the options it has available to secure its regulation service obligations and report to the Staff in the next biennial report, the options it has pursued for the previous twenty-four months. Additionally the companies should report to Staff why they believe the option(s) chosen were optimal at the time.*

Operating Reserves

Operating reserve charges in PJM provide for make-whole payments to generators called on by PJM, for reliability purposes, once the normal bidding process for energy has closed. These make-whole charges accrue for the operation of units needed that were not part of the economic dispatch. Each day, after the daily bids are cleared (4:00 p.m. Eastern Time), PJM makes a determination as to whether additional generation should be brought on line for the next day for reliability reasons due to changes in weather, generation, or transmission facilities. PJM will call on these units to operate and pay them for their start-up and operational costs for the duration of time they are kept running. According to the PJM Operating Agreement, generation which is scheduled by PJM under these conditions is guaranteed to be made whole for the day based on their costs.

To fund the make-whole payments to generators, PJM allocates the Day-Ahead costs to LSE's in PJM proportionately by megawatts based on the LSE's cleared Day-Ahead demand bids. The Real-Time costs are allocated to the LSE's proportionately by megawatts based on deviations from day-ahead scheduled quantities.

As a result, to the degree AEP is serving load in PJM it is obligated to pay these charges. AEP has no control over the amount of Day-ahead charges assessed to it by PJM since it is allocated proportionately to all LSE's in PJM based on their day-ahead load as a percentage of all loads cleared day-ahead. However, AEP does have some control over the real-time costs allocated to it since the allocation is based on deviations between what AEP demand bids cleared day-ahead and what actually occurred in real-time. The more accurately AEP can forecast its real-time needs, the less it will be allocated real-time operating reserve costs.

AEP strives to minimize this cost by continually monitoring day ahead and real-time LMP's and forecasting its needs as accurately as possible. However, there will inevitably be a variance between the day-ahead and real-time as a result of unpredicted weather conditions, unexpected variations in industrial loads, and unexpected operational events. Staff notes however, that AEP has minimized its deviations between day-ahead and real-time to approximately 2.3% on an average monthly basis during 2005 and 2006.

The operating reserve costs substantially decreased during the 2006 timeframe. AEP reports that this decrease is a result of efforts put forth by the PJM Reserve Markets

Working Group, whereby, the efforts of this group have resulted in PJM changing many of their methodologies and objectives in their dispatch function.

Staff believes AEP is effectively minimizing its allocation of the operating reserve costs. *In its future biennial review filings, the company should continue to provide the information necessary for Staff to continue to monitor the magnitude of the AEP deviations between day-ahead and real-time market operations.*

Spinning Reserves

AEP must secure an amount based on 3% of their daily peak load in the form of spinning reserves. AEP has the option of buying spinning reserves in the market, purchasing the service through a bilateral agreement or AEP can fulfill their obligation through self-supply. AEP has indicated that it fulfils its spinning reserve obligation by purchasing it from the PJM spinning market. This strategy ensures that AEP is receiving the lower market price for spinning reserve when such price is lower than AEP's cost of providing spinning reserve.

There are two cost tiers associated with spinning reserves. Tier 1 reserves are uneconomic megawatts on baseload units which are not being used to provide energy during the hour. These units are not paid for spinning reserves unless there is a spinning event. If there are not enough Tier 1 megawatts available to provide adequate spinning reserves, then PJM will clear Tier 2 reserves. Tier 2 reserves are generally provided by combustion turbines or combined cycle units and are specifically bid into the reserve market. When a spinning event occurs, PJM will pay both Tier 1 and Tier 2 spinning reserves at a rate of LMP plus $50/MWh.

Generally, PJM has sufficient spinning reserves from its Tier 1 resources and as a result they do not have to call on Tier 2 units very often. This keeps the Companies spinning reserve costs low. Similar to Regulation service, AEP buys spinning reserve at the market, thus ensuring that their native load customers are receiving spinning reserve service at the lowest possible cost. AEP generation provides Tier 2 spinning reserve service to PJM using cost based rates according to the terms of the PJM tariff.

The Staff agrees that the strategy adopted by the Companies of purchasing spinning reserve service from the market should result in the least cost solution. If the

market price for spinning reserve service is lower than AEP's cost based offer, then AEP should purchase this service from the market. *The Staff recommends the companies continue to analyze the options it has available to secure spinning reserve requirements and report to the Staff in the next biennial report, the options it has pursued for the previous twenty-four months. Additionally, the companies should report why they believe the option(s) chosen were optimal at the time.*

Conclusion

Further Staff review of costs associated with Reactive Supply, Synchronous Condensing, Blackstart Service, and Load Response reveal that these costs are not controllable by the Companies and as such will not be required to be included in future biennial reviews of controllable costs.

Following Staff's review of the remaining controllable RTO costs and the management actions taken by the Company to minimize these costs, Staff finds that the Companies appear to have sufficient procedures and strategies in place to minimize the controllable costs, as discussed above.

The Companies have been operating in PJM since October 2004 and have gained valuable operating experience since that time. Such experience with the PJM markets has already enabled AEP to better analyze the PJM markets and make better business decisions, benefiting the Companies and their customers. As AEP continues to gain experience in PJM, these benefits will hopefully continue to increase. Staff will continue to review all costs and the Companies' procedures in place for minimizing the controllable costs as long as Rider TCRR is in effect.

In addition, all controllable and non-controllable costs in Rider TCRR will continue to be audited by the Staff each time Rider TCRR is updated to ensure that only those costs incurred to provide service to retail customers in Ohio are included in the Rider.