FILE

72

RECEIVED-DOCKETING DIV
2011 JAN -7 PM 4:56
PUCO

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Commission's Review)
of the Capacity Charges of Ohio Power)
Company and Columbus Southern Power)
Company)

Case No 10-2929-EL-UNC

OHIO POWER COMPANY'S AND COLUMBUS SOUTHERN POWER COMPANY'S INITIAL COMMENTS

By Entry dated December 8, 2010 (Entry), the Commission invited comments regarding the review of the capacity charges of Ohio Power Company and Columbus Southern Power Company (collectively AEP Ohio or the Companies). Paragraph 5 of the Commission's Order sought comments regarding three specific issues. In addition to providing comments on the three specific issues that the Commission sought comments (Specific Comments), the Companies will also briefly reference the basic premise of the Entry which the Companies have addressed in their application for rehearing (General Comments). The Commission invited initial comments within 30 days and reply comments within 45 days of its Entry. In accordance with this schedule, AEP Ohio files the following initial comments.

GENERAL COMMENTS

AEP Ohio filed an application for rehearing challenging the Commission's December 8, 2010 Entry, insofar as the Entry purported to modify, establish or further investigate making changes to wholesale electricity rates that are regulated by the FERC under federal law. In the application for rehearing, AEP Ohio demonstrated in detail how the Entry misapprehends the POLR charges approved by the Commission in Case Nos. 08-917-EL-SSO and 08-918-EL-SSO. As a related matter, the application for rehearing also demonstrates the lack of factual and legal basis for the Entry, in particular with respect to Finding 4. For purposes of providing additional comments in response to the Entry, AEP Ohio incorporates its entire application for rehearing by reference as part of these comments.

SPECIFIC COMMENTS

> The Commission sought public comment regarding the following issues: (1) what changes to the current state mechanism are appropriate to determine the Companies' FRR capacity charges to Ohio competitive retail electric service (CRES) providers; (2) the degree to which AEP-Ohio's capacity charges are currently being recovered through retail rates approved by the Commission or other capacity charges; and (3) the impact of AEP-Ohio's capacity charges upon CRES providers and retail competition in Ohio.

COMMENT:

(1) what changes to the current state mechanism are appropriate to determine the Companies' FRR capacity charges to Ohio competitive retail electric service (CRES) providers

The Reliability Assurance Agreement (RAA) essentially provides alternatives for pricing Fixed Resource Requirement (FRR) capacity charges to CRES providers: 1) the PJM capacity auction price; 2) a state compensation mechanism under certain circumstances; or 3) a method based on the FRR Entity's cost or such other basis shown to be just and reasonable. The Commission's adoption of the PJM capacity auction price as the state compensation mechanism attempts to override AEP Ohio's November 24, 2010, request at FERC for a cost base method of determining a capacity rate and would have the effect of reducing the three alternatives envisioned in RAA to a single alternative – the PJM capacity auction rate. The use of the PJM capacity auction price in section 8.1 of the RAA is merely a backstop mechanism for compensation if no others exist. This does not mean that the PJM capacity auction price is the appropriate means for compensation of capacity costs; it only means that PJM recognizes the need for some compensation mechanism to exist. As stated in the RAA, AEP Ohio - the FRR entity, may at any time make a filing with FERC to change the basis for the compensation of capacity costs.

AEP Ohio opposes the Commission establishing a wholesale capacity charge as a legal matter, as outlined in its application for rehearing. In any case, it should not adopt an RPM-based charge because that would result in the following:

- The Commission would remove itself from the clearing process that sets capacity prices applicable to Ohio "electric light companies / public utilities";
- Administrative control over a Reliability Pricing Model (RPM) based capacity compensation mechanism would reside exclusively in the hands of PJM;
- Resulting clearing prices, i.e. "compensation", would be solely influenced by PJM and the RPM auction participants; and
- There is no guarantee that future RPM prices will continue to clear below AEP Ohio's cost-based formula for capacity compensation.

An RPM-based compensation mechanism would be distinctly unrelated to AEP Ohio's capacity costs or its obligations within the PJM market. As a Load Serving Entity (LSE), AEP Ohio has opted out of the PJM RPM market through its FRR election. As an LSE, AEP Ohio in no way participates in or is any part of the PJM RPM market for purposes of meeting its LSE obligation. Per PJM's Capacity Market manual: "The FRR Alternative allows an LSE, subject to certain conditions, to avoid direct participation in the RPM Base Residual Auctions and the Incremental Auctions." [PJM Manual 18: Revision 10, Section 11.1.1] AEP Ohio's load is not included in the RPM base residual auction because it has opted out. Therefore the resulting clearing prices for the unconstrained Locational Deliverability Area which the Commission has purported to adopt "as the State compensation mechanism" are in no way related to AEP Ohio's capacity obligation in PJM. AEP Ohio's LSE FRR capacity obligation is in no way used by PJM for establishing the demand curves that clear the RPM base residual and incremental auctions.

AEP Ohio has demonstrated, as detailed in Attachment 1 – the Companies' November 24, 2010 FERC filing, that the Companies' FRR capacity charges to Ohio CRES providers should be $299.81/MW-day for CSP and $387.78/MW-day for OPCo through May 2011 based upon 2009 actual costs. In order to ensure that the Companies continue to receive fair and appropriate compensation for the capacity resources that have been dedicated through the FRR process, these charges should be updated on an annual basis to reflect current costs as discussed in Attachment 1.

(2) the degree to which AEP-Ohio's capacity charges are currently being recovered through retail rates approved by the Commission or other capacity charges

AEP Ohio's capacity charges for non-shopping customers are collected through the base generation and fuel adjustment clause (FAC) rates currently approved by the Commission. Customers that take service from a CRES provider avoid paying these base generation and FAC rates including associated capacity costs. For customers that take service from a CRES provider, AEP Ohio does not charge any base generation or FAC rates and therefore does not recover any capacity costs through retail rates. AEP Ohio's only method of recovering capacity costs related to load served by a CRES provider is through capacity charges to the CRES providers themselves – for those CRES providers who have not opted to self-supply capacity resources and instead have chosen to rely on AEP Ohio's capacity resources.

(3) the impact of AEP-Ohio's capacity charges upon CRES providers and retail competition in Ohio.

The impact of AEP Ohio's capacity charges upon CRES providers and retail competition in Ohio must be a secondary consideration when determining what an appropriate capacity charge should be. The primary consideration must be whether the capacity charges that AEP Ohio charges CRES providers provides reasonable compensation to AEP Ohio for the capacity resources that the Companies have dedicated through the FRR process to serve retail load in Ohio. AEP Ohio's filing at FERC is designed to enable the Companies to recover their costs, as the current RPM auction methodology is not appropriately compensating them for meeting their FRR capacity obligations. Under an RPM based compensation mechanism, CRES providers in AEP Ohio's service territory would be effectively using AEP Ohio's capacity resources to cover their capacity obligations while paying a rate that is in no way related to the cost of those resources. AEP Ohio retains all the risk of FRR resource penalties in PJM with no mechanism to pass along any incurred penalties to CRES providers; essentially CRES providers get the benefit of AEP Ohio's resources without any of the associated risks. Unlike the PJM capacity auction rate, the Companies proposed a cost based approach that will likely result in more stable capacity rates for CRES providers and reduce the entry and exit of CRES providers as the PJM auction rate experiences significant changes. The table below shows the volatility of PJM auction rates in recent years.

PJM Auction Rates by Planning Year
($/MW-day)

	PY08/09	PY09/10	PY10/11	PY11/12	PY12/13	PY13/14
RPM Clearing Price	$126.99	$113.17	$197.24	$116.33	$17.40	$30.17
Maximum Potential RPM Rate*	$270.39	$261.88	$264.49	$255.01	$437.82	$518.95

* based upon 150% of net CONE

Although recent PJM auction rates are quite low, there is no guarantee that these rates will remain low in the future. PJM auction rates are capped at 1.5 times the net cost of a new entry. With little incentive at the recent RPM auction rates to add new capacity, it is not unexpected that capacity supplies will remain flat or be reduced in coming years. Consequently, when demand rebounds with economic recovery, PJM auction rates, in all likelihood, will rise dramatically with a direct negative impact on shopping in Ohio under a FRR-based mechanism.

The CRES providers are sophisticated and knowledgeable entities and were, or should have been, aware of the provision in the RAA that provided AEP Ohio the ability to change the capacity compensation to a cost-based method. In addition, as clearly laid out below in Section 9 of the RAA, CRES providers have and will continue to have the option to avoid compensating AEP Ohio for capacity by providing "to the FRR Entity Capacity resources sufficient to meet the capacity obligation ... for the switched load."

> 9. Notwithstanding the foregoing, in lieu of providing the compensation described above, such alternative retail LSE may, for any Delivery Year subsequent to those addressed in the FRR Entity's then-current FRR Capacity Plan, provide to the FRR Entity Capacity Resources sufficient to meet the capacity obligation described in paragraph D.2 for the switched

> load. Such Capacity Resources shall meet all requirements applicable to Capacity Resources pursuant to this Agreement and the PJM Operating Agreement, all requirements applicable to resources committed to an FRR Capacity Plan under this Agreement, and shall be committed to service to the switched load under the FRR Capacity Plan of such FRR Entity. The alternative retail LSE shall provide the FRR Entity all information needed to fulfill these requirements and permit the resource to be included in the FRR Capacity Plan. The alternative retail LSE, rather than the FRR Entity, shall be responsible for any performance charges or compliance penalties related to the performance of the resources committed by such LSE to the switched load. For any Delivery Year, or portion thereof, the foregoing obligations apply to the alternative retail LSE serving the load during such time period. PJM shall manage the transfer accounting associated with such compensation and shall administer the collection and payment of amounts pursuant to the compensation mechanism.
>
> Such load shall remain under the FRR Capacity Plan until the effective date of any termination of the FRR Alternative and, for such period, shall not be subject to Locational Reliability Charges under Section 7.2 of this Agreement.

The fact that the CRES providers did not avail themselves of this option should in no way limit AEP Ohio's right to collect cost based capacity charges.

CONCLUSION

As outlined in its application for rehearing, AEP Ohio's position is that the Commission should grant rehearing to reverse and vacate the interim rate established in Finding 4 of the Entry and to narrowly tailor its review of the Companies' current capacity charges as proposed in Finding 5 to be consistent with its limited authority under both federal and state law. If the Commission proceeds with this investigation over AEP Ohio's objection, it should do so in a manner consistent with the comments outlined above.

Respectfully submitted,

Steven T. Nourse
American Electric Power Corporation
1 Riverside Plaza, 29th Floor
Columbus, Ohio 43215-2373
Telephone: (614) 716-1608
Facsimile: (614) 716-2950
stnourse@aep.com

Counsel for Columbus Southern Power
Company and Ohio Power Company

CERTIFICATE OF SERVICE

I certify that Columbus Southern Power Company's and Ohio Power Company's foregoing Comments was served by First-Class U.S. Mail upon counsel for all parties of record identified below this 7th day of January, 2011.

Steven T. Nourse

Thomas W. McNamee
Assistant Attorney General
Public Utilities Section
180 East Broad Street, 6th Floor
Columbus, Ohio 43215-3793

Samuel C, Randazzo
Joseph E. Oliker
McNees Wallace & Nurick LLC
21 East State Street, 17th Floor
Columbus, OH 43215

Jody M. Kyler
Jeffrey L. Small
Assistant Consumers' Counsel
Office of the Ohio Consumers' Counsel
10 West Broad Street, Suite 1800
Columbus, Ohio 43215-3485

David C. Rinebolt
Colleen L. Mooney
Ohio Partners for Affordable Energy
231 West Lima Street
Findlay, Ohio 45839-1793

David F. Boehm
Michael L. Kurtz
Boehm Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, Ohio 45202

AMERICAN® ELECTRIC POWER

American Electric Power
801 Pennsylvania Avenue N.W.
Suite 320
Washington, DC 20004
AEP.com

November 24, 2010

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1A
Washington, D.C. 20426

Monique Rowtham-Kennedy
Senior Counsel – Regulatory Services
(202) 383-3436
(202) 383-3459 (F)

Re: PJM Interconnection, L.L.C., Dkt. No. ER11-___-000
(Related to Docket Nos. ER11-1995, -1997, -2034)

Dear Secretary Bose:

Pursuant to a Deficiency Letter issued in the above-captioned dockets on November 19, 2010, American Electric Power Service Corporation ("AEPSC") on behalf of Columbus Southern Power Company ("CSPCo") and Ohio Power Company ("OPCo") (CSP and OPCo are herein collectively referred to as the "AEP Ohio Companies") hereby resubmits the tariff records filed in the above-captioned dockets. The records were originally submitted as OPCo and CSPCo rate schedules and are now being submitted as Schedule 8.1 – Appendix to the PJM Interconnection, L.L.C. Reliability Assurance Agreement ("RAA"). In order to ensure a complete record in this new docket, the prior transmittal letter and attachments are largely being resubmitted. AEP separately will withdraw all of its filings in the above-referenced dockets.

The tariff records submitted herewith are formula rate templates under which each of the AEP Ohio Companies will calculate their respective capacity costs ("Capacity Compensation Formulae") under Section D.8 of Schedule 8.1 of the Reliability Assurance Agreement ("RAA"). Consistent with the AEP Ohio Companies' capacity obligations under the RAA, AEP proposes that the AEP Ohio Companies recover capacity costs calculated pursuant to these Capacity Compensation Formulas from Competitive Retail Electric Service Providers ("Ohio CRES Providers") in Ohio, a retail choice state. The Capacity Compensation Formulas filed herewith are identical to those filed on November 1, 2010 and amended on November 5, 2010 in the above-captioned dockets, but for the covers and the inclusion of the rate schedule number. Minor edits have been made to the covers to reflect their new placement in the PJM RAA. AEP stresses, however, that no changes were made to the formula rates that originally were submitted on November 1st.

The Deficiency Letter suggests that the Capacity Compensation Formulae should be filed under Attachment M-2 or whatever other section PJM designates for such provision of the PJM Open Access Transmission Tariff as in *Commonwealth Edison Company and Commonwealth Edison Company of Indiana, Inc.*, 133 FERC ¶ 61,118 (2010). PJM has designated Schedule 8.1 – Appendix to the RAA for the filing of the Capacity Compensation Formulae.[1]

AEP respectfully requests waiver of the Commission rules so that the Commission maintains the schedule currently being considered in the above-captioned dockets in the new docket established to consider this filing and issues an order accepting the Capacity Compensation Formulas and permitting the new capacity rates to become effective on January 1, 2011. AEP further requests that the Commission establish a date for interventions and protests no later than December 10, 2010 (the date previously requested by several parties to this proceeding) and, in light of the short-time before the requested effective date specify that any protests or comments be electronically served on counsel for AEP no later than 12:00 pm on December 10th.

As in the captioned dockets, the AEP Ohio Companies submit with this filing

1. This letter of transmittal;
2. Tariff Records – Schedule 8.1 – Appendix (OPCo) and Schedule 8.1 – Appendix (CSPCo)
3. Attachment A, which populates the Capacity Compensation Formulas with OPCo and CSP Form 1 cost data to illustrate the implementation of the formulas;
4. Attachment B, which compares OPCo and CSP actual compensation under the current rates to the compensation that OPCo and CSP would receive under the applicable Capacity Compensation Formula; and
6. Attachment C, which is a copy of Section D.8 of Schedule 8.1 of the PJM Reliability Assurance Agreement.

I. Background

The PJM Capacity Market is designed to ensure the adequate availability of necessary resources that can be called upon to ensure the reliability of the grid. The basis for the capacity market design is the Reliability Pricing Model ("RPM"). The PJM Capacity Market also contains an alternative method of participation, known as the Fixed Resource Requirement ("FRR") Alternative. The FRR Alternative provides a Load

---

[1] Pursuant to section 16.4 of the RAA, the PJM Board of Directors will take up the issue of incorporating Schedule 8.1 – Appendix into the RAA at its December 1, 2010 meeting.

Serving Entity ("LSE") with the option to submit a FRR Capacity Plan and meet a fixed capacity resource requirement as an alternative to the requirement to participate in the RPM, which includes a variable capacity resource requirement. The RAA sets forth the rules of participation the PJM Capacity Market and also establishes capacity obligations of PJM Load Serving Entities. Section D.8 of Schedule 8.1 the RAA provides:

> ... In a state regulatory jurisdiction that has implemented retail choice, the FRR Entity must include in its FRR Capacity Plan all load, including expected load growth, in the FRR Service Area, notwithstanding the loss of any such load to or among alternative retail LSEs. In the case of load reflected in the FRR Capacity Plan that switches to an alternative retail LSE, where the state regulatory jurisdiction requires switching customers or the LSE to compensate the FRR Entity for its FRR capacity obligations, such state compensation mechanism will prevail. In the absence of a state compensation mechanism, the applicable alternative retail LSE shall compensate the FRR Entity at the capacity price in the unconstrained portions of the PJM Region, as determined in accordance with Attachment DD to the PJM Tariff, provided that the FRR Entity may, at any time, make a filing with FERC under Sections 205 of the Federal Power Act proposing to change the basis for compensation to a method based on the FRR Entity's cost or such other basis shown to be just and reasonable, and a retail LSE may at any time exercise its rights under Section 206 of the FPA. (Emphasis supplied.)

The AEP Ohio Companies participate in the PJM Capacity market as FRR entities. Ohio has not established a compensation mechanism for capacity sales. Therefore, beginning in June 2007, when the PJM RPM market commenced, the AEP Ohio Companies began receiving capacity compensation from Ohio CRES Providers based on the RPM clearing price mechanism. Pursuant to Section D.8 of Schedule 8.1 of the RAA, the AEP Ohio Companies now elect to change the basis for this compensation to a cost-based method; *i.e.* the Capacity Compensation Formulas.

II. The Capacity Compensation Formulas

AEP's proposed Capacity Compensation Formulas are designed to recover from Ohio CRES Providers the appropriate share of the AEP Ohio Companies' respective total generation revenue requirement through annually-adjusting formulas that track actual capacity costs. The formulas are fairly standard cost-of-service trackers and are consistent with formulas utilized by other AEP utilities, which are on file with the Commission.

One significant difference, however, is that AEP is not proposing the typical two-step formula rate process, under which the utility initially projects the next year's costs and then, several months after the end of that rate year, makes a true-up calculation based on actual costs. Instead, the Capacity Compensation Formulas are based on actual data from the prior year, as shown on the most current FERC Forms 1 submitted by OPCo and

CSP. The rates will adjust each June 1 and remain in effect through the following May 31. Thus, for example, during January through May 2011, the daily capacity charges will be based on 2009 costs, as set out in the Forms 1 filed in 2010. Beginning in June 2011, the AEP Ohio Companies' capacity charges will reflect 2010 costs, as set out in the AEP Ohio Companies' Forms 1 filed in 2011. This methodology is particularly appropriate for the FRR capacity market, as it provides the Ohio CRES Providers with certainty as to the daily capacity charges; *i.e.*, they will not be subject to potential surcharges after the true-up calculations are performed. It also avoids the need for the projection and true-up review processes.

The formulas use year-end plant balances, including construction work in progress ("CWIP"), for the AEP Ohio Companies to determine their respective annual net revenue requirements. The formulas do not recover costs related to energy or fuel, because those are separate products that are not included within the RPM capacity obligations. Nor do the formulas include transmission costs; those costs are recovered under the PJM open access transmission tariff.

The formula templates consist of several exhibits that set out the underlying calculations that produce the $/MW-Day charge that will be assessed to the CRES Ohio Providers. These exhibits show the source of the input data, which in most cases are FERC Form 1 data (identified as "FF1" in the formula, with page and line referenced), but in certain cases the data are derived from referenced workpapers. The templates are virtually identical for OPCo and CSP, so in the following discussion, AEP describes the OPCo formula rate template, but that discussion equally applies to CSP.

Exhibit OP-1.1 to the OPCo Capacity Compensation Formula shows the hourly capacity charge, and OP-1.2 shows that the charge is derived by dividing the annual production fixed cost divided by OPCo's 5-CP/365. Exhibit OP-1.3 shows the calculation of the costs for generator step-up transformers and associated equipment. The derivation of the annual production fixed cost (consisting of return on rate base, operation and maintenance ("O&M") expenses, depreciation expenses, taxes other than income taxes, and income taxes) is shown on Exhibit OP-1.4. Exhibits OP1.5 through 1.19 show the calculation of the various other cost components that feed into the annual production fixed cost, including return on rate base, accumulated depreciation and accumulated deferred income taxes, general plant allocations and administrative and general expense allocations, cash working capital requirements, production-related materials and supplies, the composite cost of capital (long-term debt, preferred stock, and common stock – each of which has a separate schedule), fixed production O&M costs, depreciation, and taxes (income and production-related other than income).

The formula rate templates submitted with this filing closely adhere to the capacity-charge portion of formula rate templates that an AEP utility affiliate, Southwestern Electric Power Company ("SWEPCO"), submitted on October 25, 2010, in connection with a settlement in Docket Nos. ER08-1501 and ER09-86, which SWEPCO expects will be uncontested. Although that submission was made as part of a settlement and AEP understands that settlements do not establish precedent and cannot be used for that purpose, AEP references that submission because the SWEPCO formulas were carefully reviewed by FERC Trial Staff, who offered many helpful suggestions to make the formulas more transparent and user-friendly.

A. Specific Formula Components

The Capacity Compensation Formulas are intended to permit the AEP Ohio Companies to recover 100% of CWIP expenditures for Pollution Control Facilities and Fuel Conversion Facilities (as defined in Section 35.25 of the Commission's regulations), and 50% of all other CWIP expenditures. AEP will file annually with the Commission the AEP Ohio Companies' CWIP expenditures with supporting workpapers showing the derivation of the CWIP expenditures.

AEP proposes to make this filing by June 1 each year, in conjunction with the annual update to the capacity charges, and AEP will revise the CWIP expenditures if subsequently required by the Commission. This process is very similar to that used by SWEPCO for its adjustment to CWIP costs, as accepted for filing in *Southwestern Electric Power Company*, Docket Nos. ER10-207 and ER10-208, by Letter Order issued December 16, 2009. AEP will adjust the AEP Ohio Companies' respective production invested capital each year to ensure that the formulas will not include a charge for capitalized AFUDC and corresponding amounts of CWIP included in rate base.

AEP proposes a similar process for the recovery of costs related to Post-Employment Benefits other than Pensions ("PBOPs") and Post Employment Benefits ("PEBs"). Like the CWIP process, AEP will file annually with the Commission the AEP Ohio Companies' respective PBOP and PEB expenditures, with supporting workpapers; again, AEP will revise the PBOP and PEB costs if subsequently required by the Commission. AEP proposes to provide the revised costs in conjunction with the annual filing for the revised CWIP costs discussed above. This process also is consistent with SWEPCO's Commission-approved practice for certain of its wholesale requirements contracts, as evidenced by Letter Order issued June 25, 2010, in *Southwestern Electric Power Co.*, Docket No. ER109-1298.

AEP proposes an initial rate of return on common equity ("ROE") of 11.1%. This is the same ROE that was included in the contacts accepted for filing in *Southwestern Electric Power Co.*, Docket Nos. ER10-207 and ER10-208. Any changes to the ROE will require prior approval of the Commission under Sections 205 or 206.

Finally, consistent with Section D.8 of Schedule 8.1, AEP has the unilateral right under Section 205 to request that the Commission change the formulas or any components, such as ROE or CWIP. Likewise, Ohio CRES Providers will have the unilateral right under Section 206 to request that the Commission change the formulas or any components.

B. Cost Support

In Attachment A, AEP shows OPCo's and CSP's Capacity Compensation Formula populated with 2009 costs derived from each of the companies' FERC Forms 1. The daily capacity charges shown on this exhibit are the rates that AEP proposes that OPCo and CSP charge beginning on January 1, 2011.

The cost-of-service data set out in Attachment B show the implementation of the formula using 2009 cost data. Attachment B includes two tables that show a comparison between the compensation that OPCo and CSP each received under the existing RPM clearing price mechanism and the compensation that they each would have received had the capacity charges been derived pursuant to the new Capacity Compensation Formulas. Because the level of load served by Ohio CRES Providers is dynamic, AEP has annualized the load data for September 2010, the last month for which such data are available, as the basis for a twelve-month comparison. The tables confirm that the AEP Ohio Companies have not been fully recovering from Ohio CRES Providers a fully-allocated share of their respective capacity costs.

C. AEP Ohio Companies' Merger

On October 18, 2010, CSP and OPCo filed with the Public Utilities Commission of Ohio an application to enable the merger of CSP into OPCo, with OPCo being the sole surviving company. These companies intend to file an application with this Commission under Section 203 of the Federal Power Act for authority to merge the two companies. Upon consummation of the merger transaction, OPCo will own all of the CSP generation and assume all of CSP's utility obligations, including to supply FRR capacity. The merger transaction is expected to close on a timetable that will enable the surviving company to commence operations in 2011. Once the surviving company (OPCo) begins such operations, OPCo will file a single FERC Form 1 that will reflect, among other things, the generating capacity currently owned separately by OPCo and CSP.

AEP proposes that the OPCo and CSP rates be derived from their respective FERC Forms 1 until the year in which the merged company files a single FERC Form 1. Thus, for example, if OPCo commences operations as the surviving company in 2011, and then submits a consolidated FERC Form 1 in the Spring of 2012, the existing OPCo and CSP rates would continue to be charged through May 31, 2012, and then, beginning on June 1, 2012, the rates for all Ohio CRES Providers would be calculated under the OPCo Capacity Compensation Formula based on the costs derived from OPCo's then recently-filed FERC Form 1.

III. *COMPLIANCE WITH 18 C.F.R. § 35.13*

In compliance with the requirements of 18 C.F.R. § 35.13, AEP states as follows:

A. General Information – 18.C.F.R. § 35.13(b)

The documents provided with this filing include this Transmittal Letter and the documents listed on page 2 above. The persons upon whom this filing has been served are set out below in Section IV. A description of and the reasons for the rate changes proposed are discussed in this Transmittal Letter. AEP further states that there are no costs included in the cost-of-service data that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

B. Cost of Service Information

As discussed above, AEP submits herewith cost-of-service data in Attachment A that provide detailed information sufficient to permit the Commission to assess the reasonableness of the capacity charges under each of the AEP Ohio Companies Capacity Compensation Formulas. AEP requests waiver of those provisions in Section 35.13 that would require AEP to submit any additional cost-of-service data specified in the regulations.

In accordance with Section 35.13(c)(1), as described above, Attachment B compares the compensation that each of the AEP Ohio Companies has received under the existing RPM clearing price mechanism with the compensation that would have been received had the Capacity Compensation Formulas been in effect.

C. Effective Date

AEP requests waiver of Section 35.3 as necessary to permit the new formula rates to become effective on January 1, 2011.

IV. CORRESPONDENCE AND SERVICE

AEP requests that any correspondence or communications with respect to this filing be sent to the following:

Mr. J.T. Salway
American Electric Power
Service Corporation
155 W. Nationwide Boulevard
Columbus, Ohio 43215
(614) 583-6110
jtsalway@aep.com

Monique Rowtham-Kennedy
Senior Counsel
American Electric Power
Service Corporation
801 Pennsylvania Avenue, N.W.
Suite 320
Washington, D.C. 20004-2684
(202) 383-3436
(202) 383-3459 [Fax]
mrowtham-kennedy@aep.com

A copy of this filing has been served on the Public Utilities Commission of Ohio, PJM and those listed on the service lists of the captioned dockets. In addition, the filing has been posted on AEP Ohio's website at www.aepohio.com/service/choice/cres/. This site posts information applicable to Ohio CRES Providers.

If you have any questions concerning this filing, please do not hesitate to contact the undersigned.

Respectfully submitted,

AMERICAN ELECTRIC POWER
SERVICE CORPORATION

By: */s/ Monique Rowtham-Kennedy*
Monique Rowtham-Kennedy
Its Attorney

Cc: Service Lists

Attachment A, Part 1

Populated Capacity Compensation Formulas with 2009 OPCo FERC Form 1 cost data to illustrate the implementation of the formulas

CAPACITY (FIXED) CHARGE CALCULATION
12 Months Ending 12/31/2009 (actuals)

	RATE $/MW/Day (1)	CAPACITY MW (2)	Amount $ (1) x (2) (3)
Capacity Daily Charge:			
1. Reference	P.2		Col (1) x (2)
2. Amount	$387.77897	0	$0.00

DETERMINATION OF RATES APPLICABLE TO
OPC'S CAPACITY REQUIREMENTS
12 Months Ending 12/31/2009 (actuals)

1. Capacity Daily Rates

$$\$/MW = \frac{\text{Annual Production Fixed Cost}}{\text{(OPC 5 CP Demand/365) (Note A)}}$$

$$\frac{649,778,730}{4,590.8 \quad /365} = \$387.77897$$

Where: Annual Production Fixed Cost, P.4

Note A: Average of demand at time of PJM five highest daily peaks.

Generator Step Up Transformer Workpaper
12 Months Ending 12/31/2009 (actuals)

		Reference	
1.	GSU & Associated Investment	Note A	40,703,527
2.	Total Transmission Investment	FF1, P.207, L.58, Col.g	1,164,348,564
3.	Percent (GSU to Total Trans. Investment)	L.1 / L.2	3.50%
4.	Transmission Depreciation Expense	FF1, P.336, L.7, Col.b	25,505,773
5.	GSU Related Depreciation Expense	L.3 x L.4	891,636
6.	Station Equipment Acct. 353 Investment	FF1, P.207, L.50, Col.g	618,945,996
7.	Percent (GSU to Acct. 353)	L.1 / L.6	6.58%
8.	Transmission O&M (Accts 562 & 570)	FF1,P.321, L. 93, Col.b, and L.107, Col.b	5,406,295
9.	GSU & Associated Investment O&M	L.7 x L.8	355,532

Note A: Workpapers – tab WP-16

ANNUAL PRODUCTION FIXED COST
12 Months Ending 12/31/2009 (actuals)

		Reference	PRODUCTION Amount
1.	Return on Rate Base	P.5, L.19, Col.(2)	$297,934,517
2.	Operation & Maintenance Expense	P.14, L.15, Col.(2)	$315,740,096
3.	Depreciation Expense	P.16, L.11, Col.(2)	$228,619,407
4.	Taxes Other Than Income Taxes	P.17, L.6, Col.(2)	$81,746,087
5.	Income Tax	P.18, L.5, Col.(2)	$121,398,986
6.	Sales for Resale	Note A	$395,417,383
7.	Ancillary Service Revenue	Note B	$242,979
8.	Annual Production Fixed Cost	Sum (L.1 : L.5) - (L.6 + L.7)	$649,778,730

Note A: Capacity related revenues associated with sales as reported in Account 447 (includes pool capacity demand).

Note B: Workpapers -- tab WP-2

RETURN ON PRODUCTION-RELATED INVESTMENT
12 Months Ending 12/31/2009 (actuals)

		Reference	Amount (1)	Demand (2)	Energy (3)
1.	ELECTRIC PLANT				
2.	Gross Plant in Service	P.6, L.4, Col.(2)	6,864,412,910	6,784,128,742	80,284,169
3.	Less: Accumulated Depreciation	P.6, L.11, Col.(2)	2,364,441,611	2,319,865,618	44,575,993
4.	Net Plant in Service	L.2 - L.3	4,499,971,299	4,464,263,123	35,708,176
5.	Less: Accumulated Deferred Taxes	P.6, L.12, Col.(2)	951,311,415	832,516,848	118,794,567
6.	Plant Held for Future Use (Note A)	FF1, P.214	0	0	0
7.	Pollution Control CWIP	Note B	43,903,509	43,903,509	0
8.	Non-Pollution Control CWIP (50%)	Note B	29,607,052	29,607,052	0
9.	Subtotal - Electric Plant	L.4 - L.5 + L.6 + L.7 + L.8	3,622,170,446	3,705,256,836	(83,086,391)
10.	WORKING CAPITAL				
11.	Materials & Supplies				
12.	Fuel	P.9, L.2, Col.(2)	327,108,625	0	327,108,625
13.	Nonfuel	P.9, L.8, Col.(2)	79,263,930	79,263,930	0
14.	Total M & S	L.12 + L.13	406,372,555	79,263,930	327,108,625
15a.	Prepayments Nonlabor (Note C)		2,493,523	2,464,359	29,164
15b.	Prepayments Labor (Note C)		99,194,239	50,576,880	48,617,359
15c	Prepayments Total (Note C)		101,687,762	53,041,240	48,646,522
16.	Cash Working Capital	P.8, L.7, Col.(2)	60,432,542	39,414,563	21,017,979
17.	Total Rate Base	L.9 + L.14 + L.15c + L.16	4,190,663,305	3,876,976,569	313,686,736
18.	Weighted Cost of Capital	P.11, L.4, Col.(4)	7.68%	7.68%	7.68%
19.	Return on Rate Base	L.17 x L.18	322,040,442	297,934,517	24,105,925

Note A: Workpaper (WP) 19

Note B: Workpapers -- tab WP-3. CWIP balances in the formula cannot be changed absent an annual informational filing with the Commission.

Note C: Prepayments include amounts booked to Account 165. Nonlabor related prepayments allocated to the production function based on gross plant on P.6, L.6. Labor related prepayments allocated to production function based on wages and salaries on P.7, Note B.

PRODUCTION-RELATED
ELECTRIC PLANT IN SERVICE, ACCUMULATED DEPRECIATION AND ADIT
12 Months Ending 12/31/2009 (actuals)

		System			PRODUCTION		
		Reference	Amount	Reference	Amount	Demand	Energy
			(1)		(2)	(3)	(4)
1.	GROSS PLANT IN SERVICE (Note A)						
2.	Plant in Service (Note C)	FF1, P.204-207, L.100	9,623,507,282		6,715,457,552	6,715,457,552	0
3.	Allocated General & Intangible Plant			P.7, Col(3), L.28	148,955,358	68,671,190	80,284,169
4.	Total	L.2 + L.3	9,623,507,282		6,864,412,910	6,784,128,742	80,284,169
5.						99%	
6.				Col.(2), L.4	6,864,412,910	6,784,128,742	80,284,169
7.				Col.(1), L.4	9,623,507,282	9,623,507,282	9,623,507,282
			100.00%		71.33%	70.50%	0.83%
8.	ACCUMULATED PROVISION FOR DEPRECIATION (Note A)						
9.	Plant in Service (Note D)		3,386,073,144	FF1, P.200, L.22	2,281,737,473	2,281,737,473	0
10.	Allocated General Plant		120,628,128	Note B	82,704,138	38,128,145	44,575,993
11.	Total	L.9 + L.10			2,364,441,611	2,319,865,618	44,575,993
12.	ACCUMULATED DEFERRED TAXES (Note A)	FF1, P.234 (Acct. 190), L.8, P.274-275 (Acct.282), L.5, P.276-277 (Acct. 283), L.9	951,311,415	Exhibit B, P.6a	951,311,415	832,516,848	118,794,567

Note A: Excludes ARO amounts.
Note B: (% From P.7, Col.(3), L.29)
Note C; Includes Generator Step-Up Transformers and Other Generation related investments previously included in the transmission accounts
Note D: Includes Accumulated Depreciation associated with the Generator Step-Up Transformers and Other Generation Investments.

PRODUCTION-RELATED ADIT
For the Year Ending December 31, 2009

	Account	Description	Year End Balance	Exclusions	100% Production (Energy Related)	100% Production (Demand Related)	Labor
1	190	Excluded Items	-	-			
2	190	100% Production (Energy)	3,962,260		3,962,260		
3	190	100% Production (Demand)	73,651,393			73,651,393	
4	190	Labor Related	-				-
5	190	Total	77,613,653	-	3,962,260	73,651,393	-
6		Production Allocation		0.00%	100.00%	100.00%	66.35%
7		(Gross Plant or Wages/Salaries)		-	3,962,260	73,651,393	-
8		Demand Related			-	73,651,393	-
9		Energy Related			3,962,260	-	-
10		*Allocation Basis*			*Direct*	*B-6, L. 7*	*B-7, Note B*
11	281	Excluded Items		-			
12	281	100% Production (Energy)			-		
13	281	100% Production (Demand)	(234,470,859)			(234,470,859)	
14	281	Labor Related	-				-
15	281	Total	(234,470,859)	-	-	(234,470,859)	-
16		Production Allocation		0.00%	100.00%	100.00%	66.35%
17		(Gross Plant or Wages/Salaries)		-	-	(234,470,859)	-
18		Demand Related			-	(234,470,859)	-
19		Energy Related			-	-	-
20		Allocation Basis			Direct	B-6, L. 7	B-7, Note B
21	282	Excluded Items	-	-			
22	282	100% Production (Energy)	-		-		
23	282	100% Production (Demand)	(550,453,396)			(550,453,396)	
24	282	Labor Related	-				-
25	282	Total	(550,453,396)	-	-	(550,453,396)	-
26		Production Allocation		0.00%	100.00%	100.00%	66.35%
27		(Gross Plant or Wages/Salaries)		-	-	(550,453,396)	-
28		Demand Related			-	(550,453,396)	-
29		Energy Related			-	-	-
30		Allocation Basis			Direct	B-6, L. 7	B-7, Note B
31	283	Excluded Items	-	-			
32	283	100% Production (Energy)	(122,756,827)		(122,756,827)		
33	283	100% Production (Demand)	(121,243,987)			(121,243,987)	
34	283	Labor Related	-				-
35	283	Total	(244,000,813)	-	(122,756,827)	(121,243,987)	-
36	283	Production Allocation		0.00%	100.00%	100.00%	66.35%
37		(Gross Plant or Wages/Salaries)		-	(122,756,827)	(121,243,987)	-
38		Demand Related			-	(121,243,987)	0
39		Energy Related			(122,756,827)	0	0
40		Allocation Basis			Direct	B-6, L. 7	B-7, Note B

41	Summary Production Related ADIT	Total	Demand	Energy
42	P Plant (Energy Related)	(118,794,567)	-	(118,794,567)
43	P Plant (Demand Related)	(832,516,848)	(832,516,848)	0
44	Labor Related	0	0	0
45	Total	(951,311,415)	(832,516,848)	(118,794,567)

Source: Balances for Accounts 190, 281, 282 and 283 from WP-8a and 8ai.

PRODUCTION-RELATED GENERAL PLANT ALLOCATION
12 Months Ending 12/31/2009 (actuals)

General Plant Accounts 101 and 106

1. GENERAL PLANT	Total System (Note A) (1)	Allocation Factor (2)	Related to Production (1) x (2) (3)	Demand (4)	Energy (5)
2					
3. Land	4,968,407	Note B	3,296,564	1,680,843	1,615,721
4. General Offices	0		0	0	0
5. Total Land	4,968,407		3,296,564	1,680,843	1,615,721
6					
7. Structures	66,461,163	Note B	44,097,331	22,484,223	21,613,108
8. General Offices	0		0	0	0
9. Total Structures	66,461,163		44,097,331	22,484,223	21,613,108
10					
11. Office Equipment	3,227,863	Note B	2,141,704	1,092,006	1,049,696
12. General Offices			0	0	0
13. Total Office Equipment	3,227,863		2,141,704	1,092,006	1,049,698
14. Transportation Equipment	31,743	Note B	21,062	10,739	10,323
15. Stores Equipment	269,697	Note B	178,945	91,240	87,705
16. Tools, Shop & Garage Equipment	16,023,187	Note B	10,631,469	5,420,744	5,210,725
17. Lab Equipment	570,347	Note B	378,428	192,952	185,476
18. Communications Equipment	33,062,228	Note B	21,936,962	11,185,157	10,751,805
19. Miscellaneous Equipment	2,059,713	Note B	1,366,630	696,813	669,817
20. Subtotal	126,674,348		84,049,095	42,854,717	41,194,378
21. PERCENT		Note C	66.35%	33.83%	32.52%
22. Other Tangible Property					
23. Fuel Exploration	14,273,536	Note D	14,273,536		14,273,536
24. Rail Car Facility	0	Note D	0		0
25. Total Other Tangible Property	14,273,536		14,273,536	0	14,273,536
26. TOTAL GENERAL PLANT FF1, P.207	140,947,884		98,322,631	42,854,717	55,467,914
27. INTANGIBLE PLANT	76,310,966	Note B	50,632,727	25,816,473	24,816,254
28. TOTAL GENERAL AND INTANGIBLE	217,258,850		148,955,358	68,671,190	80,284,169
29. PERCENT		Note E	68.56%	31.61%	36.95%
30. Total General and Intangible	217,258,850		148,955,358	68,671,190	80,284,169
31. Exclude Other Tangible (Railcar and Fuel Exploration)	(14,273,536)		(14,273,536)	0	(14,273,536)
32. Net General and Intangible	202,985,314		134,681,822	68,671,190	66,010,633
33. PERCENT			66.35%	33.83%	32.52%

PRODUCTION-RELATED GENERAL PLANT ALLOCATION
12 Months Ending 12/31/2009 (actuals)

NOTE A: Data from OPC's Books excluding ARO amounts.

NOTE B: Allocation factors based on wages and salaries in electric operations and maintenance expenses excluding administrative and general expenses:

a. Total wages and salaries in electric operation and maintenance expenses excluding administrative and general expense, FF1, P.354, Col.(b), Ln.28 - L.27 (see workpaper 9a).	149,923,567
b. Production wages and salaries in electric operation and maintenance expense, FF1, P.354, Col.(b), L.20.	99,475,075
c. Ratio (b / a)	66.351%

NOTE C: L.20, Col.(3) / L.20, Col.(1)

NOTE D: Directly assigned to Production

NOTE E: L.26, Col.(3) / L.26, Col.(1)

PRODUCTION-RELATED CASH REQUIREMENT
12 Months Ending 12/31/2009 (actuals)

	Reference	Amount (1)	PRODUCTION Demand (2)	Energy (3)
1. Total Production Expense Excluding Fuel Used In Electric Generation	P.14, L.12	733,531,163	278,870,566	454,660,597
2. Less Fuel Handling / Sale of Fly Ash	P.14, L.1 thru 3	0	0	0
3. Less Purchased Power	P.14, L.11	(319,505,447)	(68,059)	(319,437,388)
4. Other Production O&M	Sum (L.1 thru L.3)	414,025,716	278,802,507	135,223,209
5. Allocated A&G	P.10, L.17	69,434,624	36,513,997	32,920,626
6. Total O&M for Cash Working Capital Calculation	L.4 + L.5	483,460,340	315,316,504	168,143,835
7. O&M Cash Requirements	=45 / 360 x L.6	60,432,542	39,414,563	21,017,979

PRODUCTION-RELATED MATERIALS & SUPPLIES
12 Months Ending 12/31/2009 (actuals)

	SYSTEM		PRODUCTION			
	Reference	Amount (1)	Reference	Amount (2)	Demand (3)	Energy (4)
1. Material & Supplies (Note A)						
2. Fuel	FF1, P.227, L.1	327,108,625		327,108,625	0	327,108,625
3. Non-Fuel						
4. Production	Functional Breakdown	79,263,930	100% Col. 1	79,263,930	79,263,930	0
5. Transmission	Furnished from	14,263,625	0	0	0	0
6. Distribution	OPCs Books by	12,705,530	0	0	0	0
7. General	Accounting Dept.	0	Note B	0	0	0
8. Total	L.4 + L.5 + L.6 + L.7	106,233,085		79,263,930	79,263,930	0

Note A: Year end balance.

Note B: Column (1) times % from P.7, Col.(3), L.29.

PRODUCTION-RELATED
ADMINISTRATIVE & GENERAL EXPENSE ALLOCATION
12 Months Ending 12/31/2009 (actuals)

			System			Production		
		Account	Reference	Amount (1)	Allocation Factor % (2)	Amount (3)	Demand (4)	Energy (5)
1.	ADMINISTRATIVE & GENERAL EXPENSE							
2.	RELATED TO WAGES AND SALARIES							
3.	A&G Salaries	920	FF1, P.323	24,973,943				
4.	Outside Services	923	FF1, P.323	21,531,837				
5.	Employee Pensions & Benefits	926	FF1, P.323	39,643,136	Note F			
6.	Office Supplies	921	FF1, P.323	852,476				
7.	Injuries & Damages	925	FF1, P.323	8,594,719				
8.	Franchise Requirements	927	FF1, P.323	0				
9.	Duplicate Charges - Cr.	929	FF1, P.323	0				
10.	Total		Ls. 3 thru 9	95,596,111	Note A	63,428,522	32,340,757	31,087,765
11.	MISCELLANEOUS GENERAL EXPENSES	930	FF1, P.323	1,287,756	Note A, C & D	854,433	435,656	418,777
12.	ADM. EXPENSE TRANSFER - CR.	922	FF1, P.323	(2,821,096)	Note B	(1,934,178)	(891,692)	(1,042,486)
13.	PROPERTY INSURANCE	924	FF1, P.323	3,622,786	Note E	2,584,120	2,553,897	30,223
14.	REGULATORY COMM. EXPENSES	928	FF1, P.323	243,481	Note C	0	0	0
15.	RENTS	931	FF1, P.323	1,416,657	Note B	971,278	447,777	523,501
16.	MAINTENANCE OF GENERAL PLANT	935	FF1, P.323	5,149,337	Note B	3,530,449	1,627,603	1,902,846
17.	TOTAL A & G EXPENSE		L.10 thru 16	104,495,032		69,434,624	36,513,997	32,920,626

Note A: % from Note B, P.7
Note B: General Plant % from P.7, Col.(3), L.29
Note C: Excluding all items not related to wholesale service and also excludes FERC assessment of annual charges.
Note D: Excludes general advertising and company dues and memberships.
Note E: % Plant from P.6, L.7.
Note F: Post-Employment Benefits other than pensions (PBOPs) and Post-Employment Benefits (PEBs) accrual estimates and funding commitments included in the formula rate calculation cannot be changed absent an annual informational filing with the Commission.

COMPOSITE COST OF CAPITAL
12 Months Ending 12/31/2009 (actuals)

		Reference	Total Company Capitalization $ (1)	Weighted Cost Ratios % (2)	Reference	Cost of Capital % (3)	Weighted Cost of Capital (2 x 3) (4)
1.	Long Term Debt	Note A	3,248,580,000	49.08%	Note D	4.31%	2.11%
2.	Preferred Stock	Note B	55,422,793	0.84%	Note E	1.32%	0.01%
3.	Common Stock	Note C	3,314,357,278	50.08%	Note F	11.10%	5.56%
4.	Total		6,618,360,071	100.00%			7.68%

Note A: P.12, L.5, Col.1.

Note B: P.13a, L.6(2).

Note C: P.13b, L.5.

Note D: P.12, L.16 (2).

Note E: P.13a, L.7.

Note F: Return on Equity of 11.1%. The return on equity cannot be changed absent a Section 205/206 filing with the Commission.

LONG TERM DEBT
12 Months Ending 12/31/2009 (actuals)

		Reference	Debt Balance (1)	Interest & Cost Booked (2)
	<u>12 Months Ending 12/31/2009 (Actual)</u>			
1.	Bonds (Acc 221)	FF1, 112.18.c.	0	
2.	Less: Reacquired Bonds (Acc 222)	FF1, 112.19.c.	(303,000,000)	
3.	Advances from Assoc Companies (Acc 223)	FF1, 112,20.c.	200,000,000	
4.	Other Long Term Debt (Acc 224)	FF1, 112,21.c.	3,351,580,000	
5.	Total Long Term Debt Balance		3,248,580,000	
	<u>Costs and Expenses (actual)</u>			
6.	Interest Expense (Acc 427)	FF1, 117,62.c.		119,078,994
7.	Amortization Debt Discount and Expense (Acc 428)	FF1, 117;63.c.		3,354,846
8.	Amortization Loss on Reacquired Debt (Acc 428.1)	FF1, 117.64.c.		626,793
9.	Less: Amortiz Premium on Reacquired Debt (Acc 429)	FF1, 117.65.c.		0
10.	Less: Amortiz Gain on Reacquired Debt (Acc 429.1)	FF1, 117,66.c.		0
11.	Interest on LTD Assoc Companies (portion Acc 430)	WP-13, L.7		10,500,000
12.	Sub-total Costs and Expense			133,560,633
13.	Less: Total Hedge (Gain) / Loss	P. 12a, L. 4, Col. (1)		(7,185,191)
14.	Plus: Allowed Hedge Recovery	P. 12a, L. 9, Col. (6)		(769,578)
15.	Total LTD Cost Amount	L. 12 - L. 13 + L. 14		139,976,246
16.	Embedded Cost of Long Term Debt = L.15, Col.(2) / L.15, Col.(1)			4.31%

LONG TERM DEBT
Limit on Hedging (Gain)/Loss on Interest Rate Derivatives of LTD
12 Months Ending 12/31/2009 (actuals)

		(1)	(2)	(3)	(4)	(5)	(6)
	HEDGE AMT BY ISSUANCE FERC Form 1, p. 256-257 (l)	Total Hedge (Gain) / Loss	Excludable Amounts (Note A)	Net Includable Hedge Amount Subject to Limit	Unamortized Balance	Amortization Period Beginning	Ending
1.	SUN Cash Flow Hedge - 5.300%	138,641	-	138,641		Nov-05	Nov-10
2.	SUN Cash Flow Hedge - 6.000%	(418,450)	-	(418,450)	(2,685,056)	Jun-06	Jun-16
3.	SUN Cash Flow Hedge - 5.375%	(6,905,382)	(6,415,613)	(489,769)		Sep-09	Oct-21
4.	Total Hedge Amortization	(7,185,191)	(6,415,613)	(769,578)			

<u>Limit on Hedging (G)/L on Interest Rate Derivatives of LTD</u>

5.	Hedge (Gain) / Loss prior to Application of Recovery Limit Enter a hedge Gain as a negative value and a hedge Loss as a positive value			(769,578)
6.	Total Capitalization	B-11, L.4, col.(1)	6,618,360,071	
7.	5 basis point Limit on (G)/L Recovery			0.0005
8.	Amount of (G)/L Recovery Limit	L. 6 * L.7		(3,309,180)
9.	Hedge (Gain) / Loss Recovery (Lesser of Line 5 or Line 8) To be subtracted or added to actual Interest Expenses on Exhibit B, Page 12, Line 14			(769,578)

Note A: Annual amortization of net gains or net loss on interest rate derivative hedges on long term debt shall not cause the composite after-tax weighted average cost of captial to increase/decrease by more than 5 basis points. Hedge gains/losses shall be amortized over the life of the related debt issuance. The unamortized balance of the g/l shall remain in Acc 219 Other Comprehensive Income and shall not flow through the rate calculation. Hedge-related ADIT shall not flow through rate base. Amounts related to the ineffective portion of pre-issuance hedges, cash settlements of fair value hedges issued on Long Term Debt, post-issuance cash flow hedges, and cash flow hedges of variable rate debt issuances are not recoverable in this calculation and are to be recorded in the "Excludable"column below.

PREFERRED STOCK
12 Months Ending 12/31/2009 (actuals)

			(1) Reference	(2) Amount
1.	Preferred Stock Dividends		FF1, P.118, L.29	732,063
2.	Preferred Stock Outstanding	Note A & B	FF1, P.251, L. 15 (f)	16,626,400
3.	Plus: Premium on Preferred Stock	Note A	FF1, P.112, L.6	727,834
4.	Less: Discount on Pfd Stock	Note A	FF1, P. 112, L.9	0
5.	Plus: Paid-In-Capital Pfd Stock	Note A		38,068,559
6.	Total Preferred Stock		L.2 + L.3 - L.4 + L.5	55,422,793
7.	Average Cost Rate		L.1 / L.6	1.32%

Note A: Workpaper – tab WP-12b.

Note B: Preferred stock outstanding excludes pledged and Reacquired (Treasury) preferred stock..

B-13b
COMMON EQUITY
12 Months Ending 12/31/2009 (actuals)

		Source	Balances
1.	Total Proprietary Capital	WP-12a, col. a	3,251,321,953
	Less:		
2.	Preferred Stock (Acc 204, pfd portion of Acc 207-213)	WP-12a, col.b+c+d	55,422,793
3.	Unappropriated Undistributed Subsidiary Earnings (Acc 216.1)	WP-12a, col.e	0
4.	Accumulated Comprehensive Other Income (Acc 219)	WP-12a, col.f	(118,458,118)
5.	Total Balance of Common Equity	L.1-2-3-4	3,314,357,278

ANNUAL FIXED COSTS
PRODUCTION O & M EXPENSE
EXCLUDING FUEL USED IN ELECTRIC GENERATION
12 Months Ending 12/31/2009 (actuals)

	Account No.	Total Company (1)	(Demand) Fixed (2)	(Energy) Variable (3)
1. Coal Handling	501.xx	0		0
2. Lignite Handling	501.xx	0		0
3. Sale of Fly Ash (Revenue & Expense)	501.xx	0		0
4. Rents	507	0		
5. Hydro O & M Expenses	535-545	0		
6. Other Production Expenses	557	9,065,135	9,065,135	
7. System Control of Load Dispatching	556	2,945,170	2,945,170	
8. Other Steam Expenses	Note A	402,015,411	266,792,202	135,223,209
9. Combustion Turbine	Note A	0		0
10. Nuclear Power Expense-Other	Note A	0		
11. Purchased Power	555	319,505,447	68,059	319,437,388
12. Total Production Expense Excluding Fuel Used In Electric Generation above		733,531,163	278,870,566	454,660,597
13. A & G Expense P.10, L.17		69,434,624	36,513,997	32,920,626
14. Generator Step Up related O&M	Note B	355,532	355,532	0
15. Total O & M		803,321,319	315,740,096	487,581,223

NOTE A: *Amounts recorded in Accounts 500, 502-509, 510-514, 546, 548-550 and 551-554 classified into Fixed* and Variable Components in accordance with P.15 and WP-14

NOTE B: FF1, P.321, L.93 & L.107 (ACCTS. 562 & 570) times GSU Investment to Account 353 ratio (See P.3, L.9)

CLASSIFICATION OF FIXED AND VARIABLE PRODUCTION EXPENSES

Line No.	Description	FERC Account No.	Energy Related	Demand Related
1	POWER PRODUCTION EXPENSES			
2	Steam Power Generation			
3	Operation supervision and engineering	500	-	xx
4	Fuel	501	xx	-
5	Steam expenses	502	-	xx
6	Steam from other sources	503	xx	-
7	Steam transferred-Cr.	504	xx	-
8	Electric expenses	505	-	xx
9	Miscellaneous steam power expenses	506	-	xx
10	Rents	507	-	xx
11	Allowances	509	xx	-
12	Maintenance supervision and engineering	510	xx	-
13	Maintenance of structures	511	-	xx
14	Maintenance of boiler plant	512	xx	-
15	Maintenance of electric plant	513	xx	-
16	Maintenance of miscellaneous steam plant	514	-	xx
17	Total steam power generation expenses			
18	Hydraulic Power Generation			
19	Operation supervision and engineering	535	-	xx
20	Water for power	536	-	xx
21	Hydraulic expenses	537	-	xx
22	Electric expenses	538	-	xx
23	Misc. hydraulic power generation expenses	539	-	xx
24	Rents	540	-	xx
25	Maintenance supervision and engineering	541	-	xx
26	Maintenance of structures	542	-	xx
27	Maintenance of reservoirs, dams and waterways	543	-	xx
28	Maintenance of electric plant	544	xx	-
29	Maintenance of miscellaneous hydraulic plant	545	-	xx
30	Total hydraulic power generation expenses			
31	Other Power Generation			
32	Operation supervision and engineering	546	-	xx
33	Fuel	547	xx	-
34	Generation expenses	548	-	xx
35	Miscellaneous other power generation expenses	549	-	xx
36	Rents	550	-	xx
37	Maintenance supervision and engineering	551	-	xx
38	Maintenance of structures	552	-	xx
39	Maintenance of generation and electric plant	553	-	xx
40	Maintenance of misc. other power generation plant	554	-	xx
41	Total other power generation expenses			
42	Other Power Supply Expenses			
43	Purchased power	555	xx	xx
44	System control and load dispatching	556	-	xx
45	Other expenses	557	-	xx
46	Station equipment operation expense (Note A)	562	-	xx
47	Station equipment maintenance expense (Note A)	570	-	xx

Note A: Restricted to expenses related to Generator Step-up Transformers and Other Generator related expenses.
See Note D, Page 6

PRODUCTION-RELATED DEPRECIATION EXPENSE
12 Months Ending 12/31/2009 *(actuals)*

	PRODUCTION PLANT	Depreciation Expense (1)	Demand (2)	Energy (3)
1.	Steam	217,078,035	217,078,035	0
2.	Nuclear	0	0	0
3.	Hydro	0	0	0
4.	Conventional	0	0	0
5.	*Pump Storage*	0	0	0
6.	Other Production	0	0	0
7.	Int. Comb.	0	0	0
8.	Other	2,998,687	2,998,687	0
9.	Production Related General & Intangible Plant	15,005,670	7,651,049	7,354,621
10.	Generator Step Up Related Depreciation (Note A)	891,636	891,636	0
11.	Total Production	235,974,027	228,619,407	7,354,621

Note: Lines 1 through 8 will be Depreciation Expense reported on P.336 of the FF1 excluding the amortization of acquisition adjustments.

Line 9 will be total General & Intangible Plant (from P.336 of the FF1, adjusted for amortization adjustments) times ratio of Production Related General Plant to total General Plant computed on P.7, L.33, Col.(3)

Depreciation expense excludes amounts associated with ARO.

Note A: Line 10, see P.3, L.5

PRODUCTION RELATED
TAXES OTHER THAN INCOME TAXES
12 Months Ending 12/31/2009 (actuals)

		SYSTEM			PRODUCTION
		REFERENCE	AMOUNT (1)	%	AMOUNT (2)
	PRODUCTION RELATED TAXES OTHER THAN INCOME				
1	Labor Related	Note A	7,986,075	Note B	2,701,739
2	Property Related	Note A	88,052,879	Note C	62,073,218
3	Other	Note A	(2,737,876)	Note C	(1,930,076)
4	Production	Note E	19,124,886	pg 6, col 3, line 4	18,901,207
5	Gross Receipts / Commission Assessments	Note A	81,010,982	Note D	0
6	TOTAL TAXES OTHER THAN INCOME TAXES	Sum L.1 : L.5	193,436,946		81,746,087

Note A: Taxes other than Income Taxes will be those reported in FERC-1, Pages 262 & 263.

Note B: Total (Col. (1), L.1) allocated on the basis of wages & salaries in Electric O & M Expenses (excl. A & G), P.354, Col.(b) and Services shown on Worksheets WP-9a and WP-9b.

	Amount	%
(1) Total W & S (excl. A & G)	149,923,567	100.00%
(2) Production W & S	99,475,075	66.35%
(3) Production Demand W & S	50,720,072	50.99%

Note C: Allocated on the basis of Gross Plant Investment from Schedule B-6, Ln.7

Note D: Not allocated to wholesale

Note E: Classified based on gross production plant in service

PRODUCTION-RELATED INCOME TAX
12 Months Ending 12/31/2009 (actuals)

		Reference	Amount (1)	Demand (2)	Energy (3)
1.	Return on Rate Base	P.5, L.19	322,040,442	297,934,517	24,105,925
2.	Effective Income Tax Rate	P.19, L.2	40.9090%	40.9090%	40.9090%
3.	Income Tax Calculated	L.1 x L.2	131,743,423	121,881,938	9,861,485
4.	ITC Adjustment	P.19, L.13	(488,667)	(482,952)	(5,715)
5.	Income Tax	L.3 + L.4	131,254,756	121,398,986	9,855,770

Note A: Classification based on Production Plant classification of P.19, L.20 and L.21.

COMPUTATION OF EFFECTIVE INCOME TAX RATE
12 Months Ending 12/31/2009 (actuals)

1.	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		36.08%
2.	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		40.91%
3.	where WCLTD and WACC from Exhibit B-11 and FIT, SIT & p as shown below.		
4.	GRCF=1 / (1 - T)		1.5644
5.	Federal Income Tax Rate	FIT	35.0000%
6.	State Income Tax Rate (Composite)	SIT	1.6600%
7.	Percent of FIT deductible for state purposes	p	0.0000%
8.	Weighted Cost of Long Term Debt	WCLTD	2.115%
9.	Weighted Average Cost of Capital	WACC	7.685%
10.	Amortized Investment Tax Credit (enter negative)	FF1, P.114, L.19, Col.c	(437,912)
11.	Gross Plant Allocation Factor	L.19	71.330%
12.	Production Plant Related ITC Amortization		(312,361)
13.	ITC Adjustment	L.12 x L.4	(488,667)
14.	<u>Gross Plant Allocator</u>		Total
15.	Gross Plant	P.6, L.6, Col.2	9,623,507,282
16.	Production Plant Gross	P.6, L.5, Col.2	6,864,412,910
17.	Demand Related Production Plant	P.6, L.5, Col.3	6,784,128,742
18.	Energy Related Production Plant	P.6, L.5, Col.4	80,284,169
19.	Production Plant Gross Plant Allocator	L.16 / L.15	71.330%
20.	*Production Plant - Demand Related*	L.17 / L.16	98.830%
21.	Production Plant - Energy Related	L.18 / L.16	1.170%

Attachment A, Part 2

Populated Capacity Compensation Formulas with 2009 CSP FERC Form 1 cost data to illustrate the implementation of the formulas

CAPACITY (FIXED) CHARGE CALCULATION
12 Months Ending 12/31/2009 (actuals)

	RATE $/MW/Day (1)	CAPACITY MW (2)	Amount $ (1) x (2) (3)
Capacity Daily Charge:			
1. Reference	P.2		Col (1) x (2)
2. Amount	$299.80517	0	$0.00

DETERMINATION OF RATES APPLICABLE TO
CSP'S CAPACITY REQUIREMENTS
12 Months Ending 12/31/2009 (actuals)

1. Capacity Daily Rates

$$\$/MW = \frac{\text{Annual Production Fixed Cost}}{\text{(CSP 5 CP Demand/365) (Note A)}}$$

$$\frac{415{,}260{,}737}{3{,}794.8 \quad /365} = \$299.80517$$

Where: Annual Production Fixed Cost, P.4

Note A: Average of demand at time of PJM five highest daily peaks.

Generator Step Up Transformer Workpaper
12 Months Ending 12/31/2009 (actuals)

		Reference	
1.	GSU & Associated Investment	Note A	8,954,491
2.	Total Transmission Investment	FF1, P.207, L.58, Col.g	619,883,849
3.	Percent (GSU to Total Trans. Investment)	L.1 / L.2	1.44%
4.	Transmission Depreciation Expense	FF1, P.336, L.7, Col.b	12,769,913
5.	GSU Related Depreciation Expense	L.3 x L.4	184,467
6.	Station Equipment Acct. 353 Investment	FF1, P.207, L.50, Col.g	309,136,250
7.	Percent (GSU to Acct. 353)	L.1 / L.6	2.90%
8.	Transmission O&M (Accts 562 & 570)	FF1,P.321, L. 93, Col.b, and L.107, Col.b	2,561,238
9.	GSU & Associated Investment O&M	L.7 x L.8	74,189

Note A: Workpapers – tab WP-16

ANNUAL PRODUCTION FIXED COST
12 Months Ending 12/31/2009 (actuals)

		Reference	PRODUCTION Amount
1.	Return on Rate Base	P.5, L.19, Col.(2)	$125,285,005
2.	Operation & Maintenance Expense	P.14, L.15, Col.(2)	$157,813,367
3.	Depreciation Expense	P.16, L.11, Col.(2)	$55,060,009
4.	Taxes Other Than Income Taxes	P.17, L.5, Col.(2)	$50,322,027
5.	Income Tax	P.18, L.5, Col.(2)	$43,014,129
6.	Sales for Resale	Note A	$16,031,652
7.	Ancillary Service Revenue	Note B	$202,147
8.	Annual Production Fixed Cost	Sum (L.1 : L.5) - (L.6 + L.7)	$415,260,737

Note A: Capacity related revenues associated with sales as reported in Account 447(includes pool capacity payments).

Note B: Workpapers -- tab WP-2

RETURN ON PRODUCTION-RELATED INVESTMENT
12 Months Ending 12/31/2009 (actuals)

		Reference	Amount (1)	Demand (2)	Energy (3)
1.	ELECTRIC PLANT				
2.	Gross Plant in Service	P.6, L.4, Col.(2)	2,763,563,767	2,738,296,895	25,266,872
3.	Less: Accumulated Depreciation	P.6, L.11, Col.(2)	1,043,595,854	1,029,081,569	14,514,285
4.	Net Plant in Service	L.2 - L.3	1,719,967,912	1,709,215,326	10,752,587
5.	Less: Accumulated Deferred Taxes	P.6, L.12, Col.(2)	321,423,744	298,276,409	23,147,336
6.	Plant Held for Future Use	Note A	5,366,165	5,366,165	0
7.	Pollution Control CWIP	Note B	4,303,976	4,303,976	0
8.	Non-Pollution Control CWIP (50%)	Note B	19,175,206	19,175,206	0
9.	Subtotal - Electric Plant	L.4 - L.5 + L.6 + L.7 + L.8	1,427,389,515	1,439,784,264	(12,394,749)
10.	WORKING CAPITAL				
11.	Materials & Supplies				
12.	Fuel	P.9, L.2, Col.(2)	72,012,385	0	72,012,385
13.	Nonfuel	P.9, L.8, Col.(2)	29,561,203	29,561,203	0
14.	Total M & S	L.12 + L.13	101,573,588	29,561,203	72,012,385
15a.	Prepayments Nonlabor (Note C)		6,113,535	6,057,640	55,895
15b.	Prepayments Labor (Note C)		58,219,536	35,368,378	22,851,158
15c	Prepayments Total (Note C)		64,333,071	41,426,018	22,907,053
16.	Cash Working Capital	P.8, L.7, Col.(2)	22,757,391	12,364,628	10,392,764
17.	Total Rate Base	L.9 + L.14 + L.15c + L.16	1,616,053,565	1,523,136,112	92,917,453
18.	Weighted Cost of Capital	P.11, L.4, Col.(4)	8.23%	8.23%	8.23%
19.	Return on Rate Base	L.17 x L.18	132,927,896	125,285,005	7,642,891

Note A: Workpaper (WP) 19

Note B: Workpapers -- tab WP-3. CWIP balances in the formula cannot be changed absent an annual informational filing with the Commission.

Note C: Prepayments include amounts booked to Account 165. Nonlabor related prepayments allocated to the production function based on gross plant on P.6, L.7. Labor related prepayments allocated to production function based on wages and salaries on P.7, Note B.

PRODUCTION-RELATED
ELECTRIC PLANT IN SERVICE, ACCUMULATED DEPRECIATION AND ADIT
12 Months Ending 12/31/2009 (actuals)

		System			PRODUCTION		
		Reference	Amount	Reference	Amount	Demand	Energy
			(1)		(2)	(3)	(4)
1.	GROSS PLANT IN SERVICE (Note A)						
2.	Plant in Service (Note C)	FF1, P.204-207, L.100	5,203,969,164		2,699,194,242	2,699,194,242	0
3.	Allocated General & Intangible Plant			P.7, Col(3), L.28	64,369,525	39,102,853	25,266,872
4.	Total	L.2 + L.3	5,203,969,164		2,763,563,767	2,738,296,896	25,266,872
5.						99%	
6.				Col.(2), L.4	2,763,563,767	2,738,296,895	25,266,872
7.				Col.(1), L.4	5,203,969,164	5,203,969,164	5,203,969,164
			100.00%		53.10%	52.62%	0.49%
8.	ACCUMULATED PROVISION FOR DEPRECIATION (Note A)						
9.	Plant in Service (Note D)		2,036,388,269	FF1, P.200, L.22	1,006,619,467	1,006,619,467	0
10.	Allocated General Plant		86,877,538	Note B	36,976,387	22,462,102	14,514,285
11.	Total	L.9 + L.10			1,043,595,854	1,029,081,569	14,514,285
12.	ACCUMULATED DEFERRED TAXES (Note A)	FF1, P.234 (Acct. 190), L.8, P.274-275 (Acct.282), L.5, P.276-277 (Acct. 283), L.9	321,423,744	Exhibit B, P.6a	321,423,744	298,276,409	23,147,336

Note A: Excludes ARO amounts.
Note B: (% From P.7, Col.(3), L.29)
Note C: Includes Generator Step-Up Transformers and Other Generation related investments previously included in the transmission accounts
Note D: Includes Accumulated Depreciation associated with the Generator Step-Up Transformers and Other Generation investments.

PRODUCTION-RELATED ADIT
For the Year Ending December 31, 2009

	Account	Description	Year End Balance	Exclusions	100% Production (Energy Related)	100% Production (Demand Related)	Labor
1	190	Excluded Items	-	-			
2	190	100% Production (Energy)	(203,148)		(203,148)		
3	190	100% Production (Demand)	26,852,105		-	26,852,105	
4	190	Labor Related	-				-
5	190	Total	26,648,957	-	(203,148)	26,852,105	-
6		Production Allocation		0.00%	100.00%	100.00%	42.56%
7		(Gross Plant or Wages/Salaries)		-	(203,148)	26,852,105	-
8		Demand Related			-	26,852,105	-
9		Energy Related			(203,148)	-	-
10		Allocation Basis			Direct	B-6, L. 7	B-7, Note B
11	281	Excluded Items		-			
12	281	100% Production (Energy)			-		
13	281	100% Production (Demand)	(19,682,408)			(19,682,408)	
14	281	Labor Related	-				-
15	281	Total	(19,682,408)	-	-	(19,682,408)	-
16		Production Allocation		0.00%	100.00%	100.00%	42.56%
17		(Gross Plant or Wages/Salaries)		-	-	(19,682,408)	-
18		Demand Related			-	(19,682,408)	-
19		Energy Related			-	-	-
20		Allocation Basis			Direct	B-6, L. 7	B-7, Note B
21	282	Excluded Items	-	-			
22	282	100% Production (Energy)	-		-		
23	282	100% Production (Demand)	(272,337,132)			(272,337,132)	
24	282	Labor Related	-				-
25	282	Total	(272,337,132)	-	-	(272,337,132)	-
26		Production Allocation		0.00%	100.00%	100.00%	42.56%
27		(Gross Plant or Wages/Salaries)		-	-	(272,337,182)	-
28		Demand Related			-	(272,337,132)	-
29		Energy Related			-		-
30		Allocation Basis			Direct	B-6, L. 7	B-7, Note B
31	283	Excluded Items	-	-			
32	283	100% Production (Energy)	(22,944,187)		(22,944,187)		
33	283	100% Production (Demand)	(33,108,974)			(33,108,974)	
34	283	Labor Related	-				-
35	283	Total	(56,053,161)	-	(22,944,187)	(33,108,974)	-
36	283	Production Allocation		0.00%	100.00%	100.00%	42.56%
37		(Gross Plant or Wages/Salaries)		-	(22,944,187)	(33,108,974)	-
38		Demand Related			-	(33,108,974)	0
39		Energy Related			(22,944,187)	0	0
40		Allocation Basis			Direct	B-6, L. 7	B-7, Note B

41	Summary Production Related ADIT	Total	Demand	Energy
42	100% Production (Energy)	(23,147,336)	-	(23,147,336)
43	100% Production (Demand)	(298,276,409)	(298,276,409)	0
44	Labor Related	0	0	0
45	Total	(321,423,744)	(298,276,409)	(23,147,336)

Source: Balances for Accounts 190, 281, 282 and 283 from WP-8a and 8al.

PRODUCTION-RELATED GENERAL PLANT ALLOCATION
12 Months Ending 12/31/2009 (actuals)

General Plant Accounts 101 and 106

1. GENERAL PLANT	Total System (Note A) (1)	Allocation Factor (2)	Related to Production (1) x (2) (3)	Demand (4)	Energy (5)
2					
3. Land	3,117,122	Note B	1,326,658	805,945	520,713
4. General Offices	0		0	0	0
5. Total Land	3,117,122		1,326,658	805,945	520,713
6					
7. Structures	58,974,649	Note B	25,099,817	15,248,143	9,851,674
8. General Offices	0		0	0	0
9. Total Structures	58,974,649		25,099,817	15,248,143	9,851,674
10					
11. Office Equipment	5,067,274	Note B	2,156,650	1,310,165	846,485
12. General Offices			0	0	0
13. Total Office Equipment	5,067,274		2,156,650	1,310,165	846,485
14. Transportation Equipment	40,258	Note B	17,134	10,409	6,725
15. Stores Equipment	301,966	Note B	128,518	78,075	50,443
16. Tools, Shop & Garage Equipment	10,353,142	Note B	4,406,334	2,676,849	1,729,485
17. Lab Equipment	631,927	Note B	268,950	163,387	105,563
18. Communications Equipment	15,606,820	Note B	6,642,317	4,035,209	2,607,108
19. Miscellaneous Equipment	1,621,537	Note B	690,132	419,255	270,877
20. Subtotal	95,714,695		40,736,510	24,747,437	15,989,073
21. PERCENT		Note C	42.56%	25.86%	16.70%
22. Other Tangible Property					
23. Fuel Exploration	3,036	Note D	3,036		3,036
24. Rail Car Facility	0	Note D	0		0
25. Total Other Tangible Property	3,036		3,036	0	3,036
26. TOTAL GENERAL PLANT FF1, P.207	95,717,731		40,739,546	24,747,437	15,992,109
27. INTANGIBLE PLANT	55,521,109	Note B	23,629,979	14,355,216	9,274,763
28. TOTAL GENERAL AND INTANGIBLE	151,238,840		64,369,525	39,102,653	25,266,872
29. PERCENT		Note E	42.56%	25.85%	16.71%
30. Total General and Intangible	151,238,840		64,369,525	39,102,653	25,266,872
31. Exclude Other Tangible (Railcar and Fuel Exploration)	(3,036)		(3,036)	0	(3,036)
32. Net General and Intangible	151,235,804		64,366,489	39,102,653	25,263,836
33. PERCENT			42.56%	25.86%	16.70%

PRODUCTION-RELATED GENERAL PLANT ALLOCATION
12 Months Ending 12/31/2009 (actuals)

NOTE A: *Data from CSP's Books excluding ARO amounts (WP-9a).*

NOTE B: Allocation factors based on wages and salaries in electric operations and maintenance expenses excluding administrative and general expenses:

a. Total wages and salaries in electric operation and maintenance expenses excluding administrative and general expense, FF1, P.354, Col.(b), Ln.28 - L.27 (see workpaper 9a).	75,465,793
b. Production wages and salaries in electric operation and maintenance expense, FF1, P.354, Col.(b), L.20.	32,118,506
c. Ratio (b / a)	42.560%

NOTE C: *L.20, Col.(3) / L.20, Col.(1)*

NOTE D: Directly assigned to Production

NOTE E: L.26, Col.(3) / L.26, Col.(1)

PRODUCTION-RELATED CASH REQUIREMENT
12 Months Ending 12/31/2009 (actuals)

	Reference	Amount (1)	PRODUCTION Demand (2)	Energy (3)
1. Total Production Expense Excluding Fuel Used In Electric Generation	P.14, L.12	686,604,795	139,331,818	547,272,977
2. Less Fuel Handling / Sale of Fly Ash	P.14, L.1 thru 3	0	0	0
3. Less Purchased Power	P.14, L.11	(633,837,229)	(58,822,157)	(475,016,072)
4. Other Production O&M	Sum (L.1 thru L.3)	152,767,566	80,509,661	72,257,905
5. Allocated A&G	P.10, L.17	29,291,563	18,407,360	10,884,204
6. Total O&M for Cash Working Capital Calculation	L.4 + L.5	182,059,129	98,917,021	83,142,109
7. O&M Cash Requirements	=45 / 360 x L.6	22,757,391	12,364,628	10,392,764

PRODUCTION-RELATED MATERIALS & SUPPLIES

12 Months Ending 12/31/2009 (actuals)

	SYSTEM			PRODUCTION		
	Reference	Amount (1)	Reference	Amount (2)	Demand (3)	Energy (4)
1. Material & Supplies (Note A)						
2. Fuel	FF1, P.227, L.1	72,012,385		72,012,385	0	72,012,385
3. Non-Fuel						
4. Production	Functional Breakdown	29,561,203	100% Col. 1	29,561,203	29,561,203	0
5. Transmission	Furnished from	1,343,532	0	0	0	0
6. Distribution	CSPs Books by	6,437,103	0	0	0	0
7. General	Accounting Dept.	0	Note B	0	0	0
8. Total	L.4 + L.5 + L.6 + L.7	37,341,838		29,561,203	29,561,203	0

Note A: Year end balance.

Note B: **Column (1) times %** from P.7, Col.(3), L.29.

PRODUCTION-RELATED
ADMINISTRATIVE & GENERAL EXPENSE ALLOCATION
12 Months Ending 12/31/2009 (actuals)

			System			Production		
		Account	Reference	Amount (1)	Allocation Factor % (2)	Amount (3)	Demand (4)	Energy (5)
1.	ADMINISTRATIVE & GENERAL EXPENSE							
2.	RELATED TO WAGES AND SALARIES							
3.	A&G Salaries	920	FF1, P.323	16,502,049				
4.	Outside Services	923	FF1, P.323	13,561,064				
5.	Employee Pensions & Benefits	926	FF1, P.323	21,317,346	Note F			
6.	Office Supplies	921	FF1, P.323	3,432,900				
7.	Injuries & Damages	925	FF1, P.323	3,732,154				
8.	Franchise Requirements	927	FF1, P.323	0				
9.	Duplicate Charges - Cr.	929	FF1, P.323	0				
10.	Total		Ls. 3 thru 9	58,545,513	Note A	24,917,176	15,137,188	9,779,987
11.	MISCELLANEOUS GENERAL EXPENSES	930	FF1, P.323	1,352,127	Note A, C & D	575,470	349,598	225,872
12.	ADM. EXPENSE TRANSFER - CR.	922	FF1, P.323	(2,388,983)	Note B	(1,016,787)	(617,669)	(399,118)
13.	PROPERTY INSURANCE	924	FF1, P.323	3,010,064	Note E	1,598,492	1,583,877	14,615
14.	REGULATORY COMM. EXPENSES	928	FF1, P.323	113,326	Note C	0	0	0
15.	RENTS	931	FF1, P.323	2,833,394	Note B	1,205,935	732,571	473,364
16.	MAINTENANCE OF GENERAL PLANT	935	FF1, P.323	4,725,579	Note B	2,011,277	1,221,794	789,484
17.	TOTAL A & G EXPENSE		L.10 *thru* 16	68,191,020		29,291,563	18,407,360	10,884,204

Note A: % from Note B, P.7
Note B: *General Plant % from P.7, Col.(3), L.29*
Note C: Excluding all items not related to wholesale service and also excludes FERC assessment of annual charges.
Note D: Excludes general advertising and company dues and memberships.
Note E: *% Plant from P.6, L.7.*
Note F: Post-Employment Benefits other than pensions (PBOPs) and Post-Employment Benefits (PEBs) accrual estimates and funding commitments included in the formula rate calculation cannot be changed absent an annual informational filing with the Commission.

COMPOSITE COST OF CAPITAL
12 Months Ending 12/31/2009 (actuals)

		Reference	Total Company Capitalization $ (1)	Weighted Cost Ratios % (2)	Reference	Cost of Capital % (3)	Weighted Cost of Capital (2 x 3) (4)
1.	Long Term Debt	Note A	1,542,745,000	52.29%	Note D	5.60%	2.93%
2.	Preferred Stock	Note B	0	0.00%	Note E	0.00%	0.00%
3.	Common Stock	Note C	1,407,763,882	47.71%	Note F	11.10%	5.30%
4.	Total		2,950,508,882	100.00%			8.23%

Note A: P.12, L.5, Col.1.

Note B: P.13a, L.6(2).

Note C: P.13b, L.5.

Note D: P.12, L.16 (2).

Note E: P.13a, L.7.

Note F: Return on Equity of 11.1%. The return on equity cannot be changed absent a Section 205/206 filing with the Commission.

LONG TERM DEBT
12 Months Ending 12/31/2009 (actuals)

		Reference	Debt Balance (1)	Interest & Cost Booked (2)
	<u>12 Months Ending 12/31/2009 (Actual)</u>			
1.	Bonds (Acc 221)	FF1, 112.18.c.	0	
2.	*Less: Reacquired Bonds (Acc 222)*	FF1, 112.19.c.	0	
3.	Advances from Assoc Companies (Acc 223)	FF1, 112.20.c.	100,000,000	
4.	Other Long Term Debt (Acc 224)	FF1, 112.21.c.	1,442,745,000	
5.	*Total Long Term Debt Balance*		1,542,745,000	
	<u>Costs and Expenses (actual)</u>			
6.	Interest Expense (Acc 427)	FF1, 117.62.c.		79,206,255
7.	Amortization Debt Discount and Expense (Acc 428)	FF1, 117.63.c.		1,841,488
8.	Amortization Loss on Reacquired Debt (Acc 428.1)	FF1, 117.64.c.		743,496
9.	Less: *Amortiz Premium on Reacquired Debt (Acc 429)*	FF1, 117.65.c.		0
10.	Less: Amortiz Gain on Reacquired Debt (Acc 429.1)	FF1, 117.66.c.		0
11.	Interest on LTD Assoc Companies (portion Acc 430)	WP-13, L.7		4,640,001
12.	Sub-total Costs and Expense			86,431,240
13.	Less: Total Hedge (Gain) / Loss	P. 12a, L. 4, Col. (1)		0
14.	Plus: Allowed Hedge Recovery	P. 12a, L. 9, Col. (6)		0
15.	Total LTD Cost Amount	L. 12 - L. 13 + L. 14		86,431,240
16.	Embedded Cost of Long Term Debt = L.15, Col.(2) / L.15, Col.(1)			5.60%

LONG TERM DEBT
Limit on Hedging (Gain)/Loss on Interest Rate Derivatives of LTD
12 Months Ending 12/31/2009 (actuals)

	HEDGE AMT BY ISSUANCE FERC Form 1, p. 256-257 (i)	(1) Total Hedge (Gain) / Loss	(2) Excludable Amounts (Note A)	(3) Net Includable Hedge Amount Subject to Limit	(4) Unamortized Balance	(5) Amortization Period Beginning	(6) Ending
1.	-	-	-	-			
2.	-	-	-	-	-		
3.	-	-	-	-			
4.	Total Hedge Amortization	-	-	-			

<u>Limit on Hedging (G)/L on Interest Rate Derivatives of LTD</u>

5.	Hedge (Gain) / Loss prior to Application of Recovery Limit			0
	- *Enter a hedge Gain as a negative value and a hedge Loss as a positive value*			
6.	Total Capitalization	B-11, L.4, col.(1)	2,950,508,882	
7.	5 basis point Limit on (G)/L Recovery			0.0005
8.	Amount of (G)/L Recovery Limit	L.6 * L.7		1,475,254
9.	Hedge (Gain) / Loss Recovery (Lesser of Line 5 or Line 8) To be subtracted or added to actual Interest Expenses on Exhibit B, Page 12, Line 14			0

Note A: Annual amortization of net gains or net loss on interest rate derivative hedges on long term debt shall not cause the composite after-tax weighted average cost of captial to increase/decrease by more than 5 basis points. Hedge gains/losses shall be amortized over the life of the related debt issuance. The unamortized balance of the g/l shall remain in Acc 219 Other Comprehensive Income and shall not flow through the rate calculation. Hedge-related ADIT shall not flow through rate base. Amounts related to the ineffective portion of pre-issuance hedges, cash settlements of fair value hedges issued on Long Term Debt, post-issuance cash flow hedges, and cash flow hedges of variable rate debt issuances are not recoverable in this calculation and are to be recorded in the "Excludable"column below.

PREFERRED STOCK
12 Months Ending 12/31/2009 (actuals)

			(1) Reference	(2) Amount
1.	Preferred Stock Dividends		FF1, P.118, L.29	0
2.	Preferred Stock Outstanding	Note A & B	FF1, P.251, L. 12 (f)	0
3.	Plus: Premium on Preferred Stock	Note A	FF1, P.112, L.6	0
4.	Less: Discount on Pfd Stock	Note A	FF1, P. 112. L9	0
5.	Plus: Paid-in-Capital Pfd Stock	Note A		0
6.	Total Preferred Stock		L.2 + L.3 - L.4 + L.5	0
7.	Average Cost Rate		L.1 / L.6	0.00%

Note A: Workpaper – tab WP-12b.

Note B: Preferred stock outstanding excludes pledged and Reacquired (Treasury) preferred stock..

COMMON EQUITY
12 Months Ending 12/31/2009 (actuals)

		Source	Balances
1.	Total Proprietary Capital	WP-12a, col. a	1,359,835,151
	<u>Less:</u>		
2.	Preferred Stock (Acc 204, pfd portion of Acc 207-213)	WP-12a, col.b+c+d	0
3.	Unappropriated Undistributed Subsidiary Earnings (Acc 216.1)	WP-12a, col.e	2,064,800
4.	Accumulated Comprehensive Other Income (Acc 219)	WP-12a, col.f	(49,993,531)
5.	Total Balance of Common Equity	L.1-2-3-4	1,407,763,882

ANNUAL FIXED COSTS
PRODUCTION O & M EXPENSE
EXCLUDING FUEL USED IN ELECTRIC GENERATION
12 Months Ending 12/31/2009 (actuals)

	Account No.	Total Company (1)	(Demand) Fixed (2)	(Energy) Variable (3)
1. Coal Handling	501.xx	0		0
2. Lignite Handling	501.xx	0		0
3. Sale of Fly Ash (Revenue & Expense)	501.xx	0		0
4. Rents	507	0		
5. Hydro O & M Expenses	535-545	0		
6. Other Production Expenses	557	7,633,702	7,633,702	
7. System Control of Load Dispatching	556	932,635	932,635	
8. Other Steam Expenses	Note A	144,201,229	71,943,324	72,257,905
9. Combustion Turbine	Note A	0		0
10. Nuclear Power Expense-Other	Note A	0		
11. Purchased Power	555	533,837,229	58,822,157	475,015,072
12. Total Production Expense Excluding Fuel Used In Electric Generation above		686,604,795	139,331,818	547,272,977
13. A & G Expense P.10, L17		29,291,563	18,407,360	10,884,204
14. Generator Step Up related O&M	Note B	74,189	74,189	0
15. Total O & M		715,970,547	157,813,367	558,157,181

NOTE A: Amounts recorded in Accounts 500, 502-509, 510-514, 546, 548-550 and 551-554 classified into Fixed and Variable Components in accordance with P.15 and WP-14

NOTE B: FF1, P.321, L.93 & L.107 (ACCTS. 562 & 570) times GSU Investment to Account 353 ratio (See P.3, L.9)

CLASSIFICATION OF FIXED AND VARIABLE PRODUCTION EXPENSES

Line No.	Description	FERC Account No.	Energy Related	Demand Related
1	POWER PRODUCTION EXPENSES			
2	Steam Power Generation			
3	Operation supervision and engineering	500	-	xx
4	Fuel	501	xx	-
5	Steam expenses	502	-	xx
6	Steam from other sources	503	xx	-
7	Steam transferred-Cr.	504	xx	-
8	Electric expenses	505	-	xx
9	Miscellaneous steam power expenses	506	-	xx
10	Rents	507	-	xx
11	Allowances	509	xx	-
12	Maintenance supervision and engineering	510	xx	-
13	Maintenance of structures	511	-	xx
14	Maintenance of boiler plant	512	xx	-
15	Maintenance of electric plant	513	xx	-
16	Maintenance of miscellaneous steam plant	514	-	xx
17	Total steam power generation expenses			
18	Hydraulic Power Generation			
19	Operation supervision and engineering	535	-	xx
20	Water for power	536	-	xx
21	Hydraulic expenses	537	-	xx
22	Electric expenses	538	-	xx
23	Misc. hydraulic power generation expenses	539	-	xx
24	Rents	540	-	xx
25	Maintenance supervision and engineering	541	-	xx
26	Maintenance of structures	542	-	xx
27	Maintenance of reservoirs, dams and waterways	543	-	xx
28	Maintenance of electric plant	544	xx	-
29	Maintenance of miscellaneous hydraulic plant	545	-	xx
30	Total hydraulic power generation expenses			
31	Other Power Generation			
32	Operation supervision and engineering	546	-	xx
33	Fuel	547	xx	-
34	Generation expenses	548	-	xx
35	Miscellaneous other power generation expenses	549	-	xx
36	Rents	550	-	xx
37	Maintenance supervision and engineering	551	-	xx
38	Maintenance of structures	552	-	xx
39	Maintenance of generation and electric plant	553	-	xx
40	Maintenance of misc. other power generation plant	554	-	xx
41	Total other power generation expenses			
42	Other Power Supply Expenses			
43	Purchased power	555	xx	xx
44	System control and load dispatching	556	-	xx
45	Other expenses	557	-	xx
46	Station equipment operation expense (Note A)	562	-	xx
47	Station equipment maintenance expense (Note A)	570	-	xx

Note A: Restricted to expenses related to Generator Step-up Transformers and Other Generator related expenses.
See Note D, Page 6

PRODUCTION-RELATED DEPRECIATION EXPENSE
12 Months Ending 12/31/2009 (actuals)

		Depreciation Expense (1)	Demand (2)	Energy (3)
	PRODUCTION PLANT			
1.	Steam	41,998,016	41,998,016	0
2.	Nuclear	0	0	0
3.	Hydro	0	0	0
4.	Conventional	0	0	0
5.	Pump Storage	0	0	0
6.	Other Production	0	0	0
7.	Int. Comb.	0	0	0
8.	Other	9,033,531	9,033,531	0
9.	Production Related General & Intangible Plant	6,327,561	3,843,995	2,483,567
10.	Generator Step Up Related Depreciation (Note A)	184,467	184,467	0
11.	Total Production	57,543,575	55,060,009	2,483,567

Note: Lines 1 through 8 will be Depreciation Expense reported on P.336 of the FF1 excluding the amortization of acquisition adjustments.

Line 9 will be total General & Intangible Plant (from P.336 of the FF1, adjusted for amortization adjustments) times ratio of Production Related General Plant to total General Plant computed on P.7, L.33, Col.(3)

Depreciation expense excludes amounts associated with ARO.

Note A: Line 10, see P.3, L.5

PRODUCTION RELATED
TAXES OTHER THAN INCOME TAXES
12 Months Ending 12/31/2009 (actuals)

		SYSTEM			PRODUCTION
		REFERENCE	AMOUNT	%	AMOUNT
			(1)		(2)
	PRODUCTION RELATED TAXES OTHER THAN INCOME				
1	Labor Related	Note A	4,832,729	Note B	1,249,522
2	Property Related	Note A	93,070,919	Note C	48,973,351
3	Other	Note A	178,402	Note C	93,874
4	Production	Note E	5,328	*pg 6, col* 3, line 4	5,279
5	Gross Receipts / Commission Assessments	Note A	76,981,582	Note D	0
6	TOTAL TAXES OTHER THAN INCOME TAXES	Sum L.1 : L.5	175,068,960		50,322,027

Note A: Taxes other than Income Taxes will be those reported in FERC-1, Pages 262 & 263.

Note B: Total (Col. (1), L.1) allocated on the basis of wages & salaries in Electric O & M Expenses (excl. A & G), P.354, Col.(b) and Services shown on Worksheets WP-9a and WP-9b.

	Amount	%
(1) Total W & S (excl. A & G)	75,465,793	100.00%
(2) Production W & S	32,118,506	42.56%
(3) Production Demand W & S	19,511,998	60.75%

Note C: Allocated on the basis of Gross Plant Investment from Schedule B-6, Ln.7

Note D: Not allocated to wholesale

Note E: Classified based on gross production plant in service

PRODUCTION-RELATED INCOME TAX
12 Months Ending 12/31/2009 (actuals)

		Reference	Amount (1)	Demand (2)	Energy (3)
1.	Return on Rate Base	P.5, L.19	132,927,896	125,285,005	7,642,891
2.	Effective Income Tax Rate	P.19, L.2	35.6248%	35.6248%	35.6248%
3.	Income Tax Calculated	L.1 x L.2	47,355,319	44,632,553	2,722,766
4.	ITC Adjustment	P.19, L.13	(1,633,357)	(1,618,424)	(14,934)
5.	Income Tax	L.3 + L.4	45,721,962	43,014,129	2,707,832

Note A: Classification based on Production Plant classification of P.19, L.20 and L.21.

COMPUTATION OF EFFECTIVE INCOME TAX RATE
12 Months Ending 12/31/2009 (actuals)

1.	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		35.62%
2.	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		35.62%
3.	where WCLTD and WACC from Exhibit B-11 *and FIT, SIT & p as shown below.*		
4.	GRCF=1 / (1 - T)		1.5533
5.	Federal Income Tax Rate	FIT	35.0000%
6.	State Income Tax Rate (Composite)	SIT	0.9550%
7.	Percent of FIT deductible for state purposes	p	0.0000%
8.	Weighted Cost of Long Term Debt	WCLTD	2.929%
9.	Weighted Average Cost of Capital	WACC	8.225%
10.	Amortized Investment Tax Credit (enter negative)	FF1, P.114, L.19, Col.c	(1,980,124)
11.	Gross Plant Allocation Factor	L.19	53.105%
12.	Production Plant Related ITC Amortization		(1,051,543)
13.	ITC Adjustment	L.12 x L.4	(1,633,357)
14.	<u>Gross Plant Allocator</u>		Total
15.	Gross Plant	P.6, L.4, Col.1	5,203,969,164
16.	Production Plant Gross	P.6, L.4, Col.2	2,763,563,767
17.	Demand Related Production Plant	P.6, L.4, Col.3	2,738,296,895
18.	Energy Related Production Plant	P.6, L.4, Col.4	25,266,872
19.	Production Plant Gross Plant Allocator	L.16 / L.15	53.105%
20.	Production Plant - Demand Related	L.17 / L.16	99.086%
21.	Production Plant - Energy Related	L.18 / L.16	0.914%

Attachment B

Comparison of OPCo and CSP actual compensation under the current rates to the compensation that OPCo and CSP would receive under the applicable Capacity Compensation Formula

Annual Billing
Based Upon Actual September 2010 Data

		A	B	C	D	E	F	G
Line	*Columbus Southern Power Company*	*Annual Billing Demand MW-Day*	*$/MW/Day Current Rate*	($) *Annual Billing September 2010 Rate* (A) x (B)	*$/MW/Day Proposed Rate*	($) *Annual Billing Using Proposed Rate* (A) x (D)	($) *Increase (Decrease)*	% *Increase (Decrease)*
1	Aggregate load served by Ohio CRES Providers	61,038.72 [1]	208.20 [2]	12,708,425	310.04 [3]	18,924,220	6,215,796	48.9%
	Ohio Power Company							
2	Aggregate load served by Ohio CRES Providers	137.64 [1]	208.20 [2]	28,657	401.01 [4]	55,195	26,538	92.6%

Note 1: September 2010 FRR Demand times 12
Note 2: September 2010 RPM clearing price x scaling factor x pool requirement x transmission losses (174.29 x 1.06633 x 1.0833 x 1.034126)
Note 3: Source, Rate Schedule 39, pg. 1 x transmission losses (299.80517 x 1.034126)
Note 4: Source, Rate Schedule 101, pg. 1 x transmission losses (387.77897 x 1.034126)

Attachment C

Copy of Section D of Schedule 8.1 of the PJM Reliability Assurance Agreement

PJM Reliability Assurance Agreement

Excerpt – Section D
Effective Date: 9/17/2010

D. FRR Capacity Plans

1. Each FRR Entity shall submit its initial FRR Capacity Plan as required by subsection C.1 of this Schedule, and shall annually extend and update such plan by no later than one month prior to the Base Residual Auction for each succeeding Delivery Year in such plan. Each FRR Capacity Plan shall indicate the nature and current status of each resource, including the status of each Planned Generation Capacity Resource or Planned Demand Resource, the planned deactivation or retirement of any Generation Capacity Resource or Demand Resource, and the status of commitments for each sale or purchase of capacity included in such plan.

2. The FRR Capacity Plan of each FRR Entity that commits that it will not sell surplus Capacity Resources as a Capacity Market Seller in any auction conducted under Attachment DD of the PJM Tariff, or to any direct or indirect purchaser that uses such resource as the basis of any Sell Offer in such auction, shall designate Capacity Resources in a megawatt quantity no less than the Forecast Pool Requirement for each applicable Delivery Year times the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast for such Delivery Year, as determined in accordance with procedures set forth in the PJM Manuals. If the FRR Entity is not responsible for all load within a Zone, the Preliminary Forecast Peak Load for such entity shall be the FRR Entity's Obligation Peak Load last determined prior to the Base Residual Auction for such Delivery Year, times the Base Zonal FRR Scaling Factor. The FRR Capacity Plan of each FRR Entity that does not commit that it will not sell surplus Capacity Resources as set forth above shall designate Capacity Resources at least equal to the Threshold Quantity. To the extent the FRR Entity's allocated share of the Final Zonal Peak Load Forecast exceeds the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast, such FRR Entity's FRR Capacity Plan shall be updated to designate additional Capacity Resources in an amount no less than the Forecast Pool Requirement times such increase; provided, however, any excess megawatts of Capacity Resources included in such FRR Entity's previously designated Threshold Quantity, if any, may be used to satisfy the capacity obligation for such increased load.

3. As to any FRR Entity, the Base Zonal FRR Scaling Factor for each Zone in which it serves load for a Delivery Year shall equal ZPLDY/ZWNSP, where:

ZPLDY = Preliminary Zonal Peak Load Forecast for such Zone for such Delivery Year; and

ZWNSP = Zonal Weather-Normalized Summer Peak Load for such Zone for the summer concluding four years prior to the commencement of such Delivery Year.

4. Capacity Resources identified and committed in an FRR Capacity Plan shall meet all requirements under this Agreement and the PJM Operating Agreement applicable to Capacity Resources, including, as applicable, requirements and milestones for Planned Generation Capacity Resources and Planned Demand Resources. A Capacity Resource submitted in an FRR Capacity Plan must be on a unit-specific basis, and may not include "slice of system" or similar agreements that are not unit specific. An FRR Capacity Plan may include bilateral transactions that commit capacity for less than a full Delivery Year only if the resources included in such plan in the aggregate satisfy all obligations for all Delivery Years. All demand response, load management, energy efficiency, or similar programs on which such FRR Entity intends to rely for a Delivery Year must be included in the FRR Capacity Plan submitted three years in advance of such Delivery Year and must satisfy all requirements applicable to Demand Resources or Energy Efficiency Resources, as applicable, including, without limitation, those set forth in Schedule 6 to this Agreement and the PJM Manuals; provided, however, that previously uncommitted Unforced Capacity from such programs may be used to satisfy any increased capacity obligation for such FRR Entity resulting from a Final Zonal Peak Load Forecast applicable to such FRR Entity.

5. For each LDA for which the Office of the Interconnection has established a separate Variable Resource Requirement Curve for any Delivery Year addressed by such FRR Capacity Plan, the plan must include a minimum percentage of Capacity Resources for such Delivery Year located within such LDA. Such minimum percentage ("Percentage Internal Resources Required") will be calculated as the LDA Reliability Requirement less the CETL for the Delivery Year, as determined by the RTEP process as set forth in the PJM Manuals. Such requirement shall be expressed as a percentage of the Unforced Capacity Obligation based on the Preliminary Zonal Peak Load Forecast multiplied by the Forecast Pool Requirement.

6. An FRR Entity may reduce such minimum percentage as to any LDA to the extent the FRR Entity commits to a transmission upgrade that increases the capacity emergency transfer limit for such LDA. Any such transmission upgrade shall adhere to all requirements for a Qualified Transmission Upgrade as set forth in Attachment DD to the PJM Tariff. The increase in CETL used in the FRR Capacity Plan shall be that approved by PJM prior to inclusion of any such upgrade in an FRR Capacity Plan. The FRR Entity shall designate specific additional Capacity Resources located in the LDA from which the CETL was increased, to the extent of such increase.

7. The Office of the Interconnection will review the adequacy of all submittals hereunder both as to timing and content. A Party that seeks to elect the FRR Alternative that submits an FRR Capacity Plan which, upon review by the Office of the Interconnection, is determined not to satisfy such Party's capacity obligations hereunder, shall not be permitted to elect the FRR Alternative. If a previously approved FRR Entity submits an FRR Capacity Plan that, upon review by the Office of the Interconnection, is determined not to satisfy such Party's capacity obligations hereunder, the Office of the Interconnection shall notify the FRR Entity, in writing, of the insufficiency within five

(5) business days of the submittal of the FRR Capacity Plan. If the FRR Entity does not cure such insufficiency within five (5) business days after receiving such notice of insufficiency, then such FRR Entity shall be assessed an FRR Commitment Insufficiency Charge, in an amount equal to two times the Cost of New Entry for the relevant location, in $/MW-day, times the shortfall of Capacity Resources below the FRR Entity's capacity obligation (including any Threshold Quantity requirement) in such FRR Capacity Plan, for the remaining term of such plan.

8. In a state regulatory jurisdiction that has implemented retail choice, the FRR Entity must include in its FRR Capacity Plan all load, including expected load growth, in the FRR Service Area, notwithstanding the loss of any such load to or among alternative retail LSEs. In the case of load reflected in the FRR Capacity Plan that switches to an alternative retail LSE, where the state regulatory jurisdiction requires switching customers or the LSE to compensate the FRR Entity for its FRR capacity obligations, such state compensation mechanism will prevail. In the absence of a state compensation mechanism, the applicable alternative retail LSE shall compensate the FRR Entity at the capacity price in the unconstrained portions of the PJM Region, as determined in accordance with Attachment DD to the PJM Tariff, provided that the FRR Entity may, at any time, make a filing with FERC under Sections 205 of the Federal Power Act proposing to change the basis for compensation to a method based on the FRR Entity's cost or such other basis shown to be just and reasonable, and a retail LSE may at any time exercise its rights under Section 206 of the FPA.

9. Notwithstanding the foregoing, in lieu of providing the compensation described above, such alternative retail LSE may, for any Delivery Year subsequent to those addressed in the FRR Entity's then-current FRR Capacity Plan, provide to the FRR Entity Capacity Resources sufficient to meet the capacity obligation described in paragraph D.2 for the switched load. Such Capacity Resources shall meet all requirements applicable to Capacity Resources pursuant to this Agreement and the PJM Operating Agreement, all requirements applicable to resources committed to an FRR Capacity Plan under this Agreement, and shall be committed to service to the switched load under the FRR Capacity Plan of such FRR Entity. The alternative retail LSE shall provide the FRR Entity all information needed to fulfill these requirements and permit the resource to be included in the FRR Capacity Plan. The alternative retail LSE, rather than the FRR Entity, shall be responsible for any performance charges or compliance penalties related to the performance of the resources committed by such LSE to the switched load. For any Delivery Year, or portion thereof, the foregoing obligations apply to the alternative retail LSE serving the load during such time period. PJM shall manage the transfer accounting associated with such compensation and shall administer the collection and payment of amounts pursuant to the compensation mechanism.

Such load shall remain under the FRR Capacity Plan until the effective date of any termination of the FRR Alternative and, for such period, shall not be subject to Locational Reliability Charges under Section 7.2 of this Agreement.