EXHIBIT NO. ______

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Power Company and Columbus Southern Power Company for Authority to Merge and Related Approvals.	))))	Case No. 10-2376-EL-UNC
In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan.	))))))	Case No. 11-346-EL-SSO Case No. 11-348-EL-SSO
In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority	))))	Case No. 11-349-EL-AAM Case No. 11-350-EL-AAM
In the Matter of the Application of Columbus Southern Power Company to Amend its Emergency Curtailment Service Riders	))))	Case No. 10-343-EL-ATA
In the Matter of the Application of Ohio Power Company to Amend its Emergency Curtailment Service Riders	))))	Case No. 10-344-EL-ATA
In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company.	))))	Case No. 10-2929-EL-UNC
In the Matter of the Application of Columbus Southern Power Company for Approval of a Mechanism to Recover Deferred Fuel Costs Ordered Under Ohio Revised Code 4928.144	)))))	Case No. 11-4920-EL-RDR
In the Matter of the Application of Ohio Power Company for Approval of a Mechanism to Recover Deferred Fuel Costs Ordered Under Ohio Revised Code 4928.144	)))))	Case No. 11-4921-EL-RDR

TESTIMONY OF KELLY D. PEARCE
IN SUPPORT OF THE STIPULATION AND RECOMMENDATION
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

Filed September 13, 2011

INDEX TO TESTIMONY OF
KELLY D. PEARCE
IN SUPPORT OF THE STIPULATION AND RECOMMENDATION

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
TESTIMONY OF KELLY D. PEARCE
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

PERSONAL BACKGROUND

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kelly D. Pearce. My business address is 155 West Nationwide Boulevard, Columbus, Ohio 43215.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by American Electric Power Service Corporation (AEPSC) as Director-Contracts and Analysis.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Science degree in Mechanical Engineering from Oklahoma State University in 1984. I received Master of Science and Doctor of Philosophy degrees in Nuclear Engineering from the University of Michigan in 1986 and 1991 respectively. I received a Master of Science in Industrial Administration degree from Carnegie Mellon University in 1994.

From 1986 to 1988 I worked for a subsidiary of Olen Corporation. From 1991 to 1996 I worked for the United States Department of Energy within the Office of Fossil Energy. My responsibilities included serving as a Contracting Officer's Representative in the oversight and administration of government-funded research of advanced generation and environmental remediation technologies and projects. I also supported strategic studies for deployment and commercialization of these technologies as well as administration and support of Government research and development solicitations. I was promoted twice during this time.

In 1996 I joined AEPSC as a Rate Consultant I. In 2001, I was promoted to Senior Regulatory Consultant. My responsibilities included preparation of class cost-of-service studies and rate design for AEP operating companies and the preparation of special contracts and regulated pricing for retail customers. In 2003 I transferred to Commercial Operations as Manager of Cost Recovery Analysis. In 2007 I was promoted to Director of Commercial Analysis. During this period, I was responsible for analyzing the financial impacts of Commercial Operations-related activities. I also supported settlement of AEP's generation pooling agreements among the operating companies.

In 2010 I transferred to Regulatory Services in my current position of Director-Contracts and Analysis. My group is responsible for performing financial analyses concerning AEP's generation resources and load obligations, various settlement support for AEP's power pools and regulatory support in areas that relate to commercial operations. In addition, my group is responsible for AEP's formula rate contracts. I am a registered Professional Engineer in Ohio and West Virginia.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS?

A. Yes. I submitted testimony to the Virginia State Corporation Commission (VASCC) in Case Numbers PUE-2001-00011 and PUE-2011-00034 and submitted testimony and testified before the VASCC in Case No. PUE-2001-00306. I also submitted testimony and testified before the Indiana Utility Regulatory Commission in Cause No. 43992. My testimony in these proceedings was on behalf of operating companies that are affiliates of Columbus Southern Power Company (CSP) and Ohio Power Company (OPCo), hereby collectively referred to as AEP Ohio or the Company.

PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony in this proceeding is to support a portion of the September 7, 2011 Stipulation and Recommendation (Stipulation) which includes numerous provisions that, taken as whole, provide an agreement to resolve matters in the above referenced cases. I support the reasonableness of the compromise provisions of the Stipulation concerning the establishment of capacity charges found in Paragraph IV.2.b. More specifically, I substantiate the capacity charge proposed by AEP Ohio in Case No. 10-2929-EL-UNC (*Ohio Capacity Charge Docket*) for approval by the Commission and compare that proposal to the negotiated charge reflected in the Stipulation.

Q. WHAT WERE THE RATES FILED BY THE COMPANY IN THE *OHIO CAPACITY CHARGE DOCKET*?

A. The capacity compensation rates proposed by the Company are $327.59/MW-day for CSP and $379.23/MW-day for OPCo for the current PJM PY ending May 31, 2012. The rate for a merged CSP and OPCO during this period would be $355.72/MW-day.

Q. WHAT DID THE STIPULATION PROVIDE ON THE LEVEL OF CAPACITY CHARGES?

A. In Paragraph IV.2.b, the Stipulation provides for the charging of an interim rate of $255/MW-Day to be charged to CRES providers for all shopping above the thresholds set forth in Paragraph IV.2.b.3 until the expiration of the state compensation mechanism on May 31, 2015, after which the capacity charge will be the PJM RPM-based capacity rate for all Standard Service Offer (SSO) load.

Q. IS THE LEVEL OF CAPACITY CHARGES INCLUDED IN THE STIPULATION A REASONABLE NEGOTIATION OUTCOME FOR THE *OHIO CAPACITY CHARGE DOCKET*?

A. Yes. The level of recovery in the Stipulation would not necessarily be a reasonable outcome for the *Ohio Capacity Charge Docket* to determine the cost-based level of capacity charges absent the other negotiated terms included in the total package found in the agreement. In light of the intervenor positions advocating for a pure RPM-based capacity charge, it is my opinion that the hybrid approach taken in the Stipulation is reasonable and appropriate result of negotiations. The relationship between AEP Ohio's litigation position in the *Ohio Capacity Charge Docket* and the Stipulation package is further addressed in the testimony of Company witnesses Hamrock and Munczinski.

EXHIBITS

Q. ARE YOU SPONSORING ANY EXHIBITS IN THIS PROCEEDING?

A. Yes, I am sponsoring five Exhibits identified as follows:

Exhibit KDP-1: Template for CSP populated with 2010 data,

Exhibit KDP-2: Template for OPCo populated with 2010 data,

Exhibit KDP-3: Energy credit for CSP and OPCo,

Exhibit KDP-4: Merged CSP and OPCO Capacity Value

Exhibit KDP-5: PJM Capacity Values

Q. WERE THESE EXHIBITS PREPARED UNDER YOUR SUPERVISION AND DIRECTION?

A. Yes.

APPLICABLE MARKET AND CAPACITY OBLIGATION

Q. WHAT WAS THE RATIONALE FOR THE FORMULA RATES PROPOSED IN YOUR FILED TESTIMONY IN THE *OHIO CAPACITY CHARGE DOCKET*?

A. As explained by Company witness Munczinski, CSP and OPCo elected to utilize the Fixed Resource Requirement (FRR) option to provide or "self-supply" capacity to meet their load serving entity (LSE) obligations rather than acquire this capacity through the PJM RPM market. Since the Company is self-supplying its own generation resources to satisfy these load obligations, the costs to provide this capacity is the actual embedded capacity cost of CSP's and OPCo's generation.

Q. SO IF CRES PROVIDERS DO NOT AVAIL THEMSELVES OF THIS OPTION, HOW IS THE CAPACITY OBLIGATION OF THESE CUSTOMERS MET?

A. If CRES providers choose not to self-supply, then CSP and OPCo *must* commit the capacity necessary to serve all customer load, *including load already committed to a CRES provider for the future period*. In short, in that situation, shopping customers' capacity obligations continue to be met by the capacity resources of AEP Ohio.

Q. HOW IS AEP OHIO IMPACTED BY THIS RESULT?

A. AEP Ohio incurs the costs associated with continuing to maintain and provide the capacity resources for shopping customers, but no longer receives these customers' bypassable generation revenues.

<u>RATE CALCULATION</u>

Q. PLEASE GENERALLY DESCRIBE THE DEVELOPMENT OF THE FRR-BASED REIMBURSEMENT RATES PROPOSED BY CSP AND OPCO.

A. CSP and OPCo utilized a cost based rate approach for this capacity that is based upon the average cost of serving CSP's and OPCo's LSE obligation load, both the load served by CSP and OPCo or by a CRES provider, on a $/MW-day basis. By CRES providers paying a rate that is based upon average costs, they are neither subsidizing nor being subsidized by CSP and OPCo.

Q. PLEASE PROVIDE AN EXAMPLE OF THE SUBSIDIZATION THAT CAN OCCUR.

A. Under FRR, the Company is providing its own generation resources to provide the capacity obligation. The costs associated with these assets tend to be fairly constant or “fixed” over the near term. If switched load is still served using these assets, but the CRES providers are allowed to pay a rate that is above or below those costs, then the CRES providers are inappropriately subsidizing or being subsidized by AEP Ohio.

Q. WHAT ARE SOME OF THE ADVANTAGES OF THE RATE APPROACH PROPOSED BY THE COMPANY IN THE *OHIO CAPACITY CHARGE DOCKET*?

A. This cost based rate calculation is formulaic in nature and is currently utilized in many states by AEP for other wholesale sales. As previously stated, these rates use an average allocation of cost between the parties based on common cost allocation mechanisms.

Second, this rate approach provides a high degree of transparency. The bulk of the input information can be tied back to the Federal Energy Regulatory Commission (FERC) Form 1 (FF1) annual reports of CSP and OPCO and the various work papers are readily available to the affected parties upon request for rate verification. Following approval, the rates are simply updated using the next year’s accounting information. As a result, updating the rate becomes a straightforward, fairly mechanical process and the updates are readily available for regulatory review. Under the Company’s proposal, rates will be known prior to the beginning of a given PJM Planning Year (PY).

Q. WHAT IS THE SOURCE OF THE RATE TEMPLATE THAT WAS PREVIOUSLY PROPOSED IN THIS PROCEEDING?

A. The template selected for this rate development was modeled after the recently FERC-approved template utilized by the Cities of Minden, Louisiana and Prescott, Arkansas and Southwestern Electric Power Company (SWEPCo), an AEP Ohio-affiliated operating company. These cities are full requirements customers taking both capacity and energy from SWEPCO under long term agreements. This rate template was the subject of a lengthy negotiation between the seller and purchasers and FERC Staff. In addition, it adopted various modifications originating from FERC Staff. As such, this template represented a fair and reasonable formula for calculation of capacity costs. The capacity portion of this rate template, with certain modifications, was used to develop the proposed CSP and OPCo capacity rates.

CAPACITY RATE

Q. PLEASE DESCRIBE THE CAPACITY PORTION OF THE PREVIOUSLY PROPOSED RATE IN DETAIL.

A. The templates for CSP and OPCO are provided in Exhibits KDP-1 and KDP-2 for CSP and OPCo, respectively. These Exhibits utilize common cost allocation principles in that they are used to compute an average per unit cost that includes the cost of capital on assets and actual expenses incurred. The final daily charge calculation that would be used to compute the individual CRES providers' bills based on their applicable MW capacity is shown on page 1 of each of these Exhibits. The cost based capacity rate calculation, before application of the loss factor, is shown on page 2 of these Exhibits. As seen throughout these Exhibits, the specific references for the inputs are clearly shown. The FF1 annual reports are utilized heavily throughout these templates for source data. In certain instances, additional detail is obtained from the Company's books and records (CBR), such as the income statements.

Q. ARE THERE ANY ITEMS IN PARTICULAR TO NOTE?

A. Yes. As shown on page 6, line 4 of Exhibits KDP-1 and KDP-2, the annual production costs are reduced by the amount of revenues that are collected from other wholesale entities related to capacity transactions. These revenues include capacity transactions with affiliates and non-affiliates alike. As a result, CRES providers would get the benefit of these transactions and are not paying for any capacity cost that is associated with transactions to other wholesale entities, including affiliates and PJM RPM market participants.

Also, as shown on page 5, line 8 of these Exhibits, only 50% of the non-pollution control construction work in progress (CWIP) is included, which, as previously explained, is a result of the templates used to develop these rates.

<u>PROPOSED CAPACITY RATES</u>

Q. PLEASE PROVIDE THE CAPACITY COMPENSATION RATES PREVIOUSLY PROPOSED BY THE COMPANY.

A. As seen on page 1 of Exhibits KDP-1 and KDP-2, the capacity compensation rates proposed by the Company are $327.59/MW-day for CSP and $379.23/MW-day for OPCo, based on information contained in the 2010 FF1s. If approved by the Commission, these capacity rates would have been applicable for the remainder of the PJM PY 2011/2012 that runs through May 31, 2012.

Q. IF THE COMMISSION ADOPTED AN ENERGY CREDIT USING AEP OHIO'S METHODOLOGY, WHAT WOULD BE THE LEVEL OF THE RESULTING ENERGY CREDIT?

A. The 2010 energy credits using the AEP Ohio methodology is shown in Exhibit KDP-3. As shown on page 2 of this Exhibit, the energy credits, if adopted, would be $7.73/MW-day and $9.94/MW-day for CSP and OPCo respectively. These credits would only reduce the capacity rates to $319.86/MW-day for CSP and $369.29/MW-day for OPCo for the PJM PY 2011/2012.

Q. PART OF THE STIPULATION INCLUDES APPROVAL OF A CSP AND OPCO MERGER. WHAT WOULD THESE RATES CORRESPOND TO ON A MERGED BASIS?

A. As shown in Exhibit KDP-4, the current merged rate would be $355.72/MW-day. If the Commission were to adopt an energy credit using the AEP Ohio methodology, this rate would be reduced to $338.14/MW-day.

<u>RATE COMPARISONS</u>

Q. WOULD YOU COMPARE THE PREVIOUSLY PROPOSED RATES WITH THE JOINT STIPULATION AND RECOMMENDATION RATES?

A. Yes. First allow me to illustrate the Stipulation rates in Table I below that will allow the comparison. Every value shown in Table I for the January through May 2012 timeframe in the first line of the table is less than the capacity rates filed by AEP Ohio in the *Ohio Capacity Charge Docket*. The ultimate result of this is that AEP Ohio will be receiving as little as 38% and no more than 71% of its true cost of capacity for the first 5 months of 2012 for CSP, OPCO or the merged Company.

Table I - Stipulation Capacity Charges
Values based on Unforced Capacity (UCAP) MW

Time Period	Billed RPM Capacity Rate	Maximum RPM Rate Threshold	Interim Rate	Weighted Average Rate at 100% Shopping
	($/MW-day)	(%)	($/MW-day)	($/MW-day)
(a)	(b)	(c)	(d)	(e) = (b)*(c)+(d)*(1-(c))
Jan - May 2012	$145.79	21%	$255.00	**$232.07**
Jun - Dec 2012	$20.01	21%	$255.00	**$205.65**
Jan - May 2013	$20.01	29% [1]	$255.00	**$186.85**
Jun - Dec 2013	$33.71	31% [1]	$255.00	**$186.40**
Jan - May 2014	$33.71	31%	$255.00	**$186.40**
Jun - Dec 2014	$153.89	41%	$255.00	**$213.54**
Jan - May 2015	$153.89	41%	$255.00	**$213.54**

[1] Assumes securitization is completed on May 31, 2013. Percentage will change from 29% to 31% based on actual date of securitization.

This reduction varies from 62% when comparing the RPM rate of $145.79/MW-day to the pre-merger OPCO proposed rate of $379.23/MW-day and 22% when comparing the $255/MW-day interim rate to the pre-merger CSP rate of $327.59/MW-day. This latter comparison is somewhat distorted, however, since the interim rate will only be applicable per customer class once the RPM allocation has reached the maximum. Consequently, the highest average rate CSP could be compensated from shopping load is the $232.07/MW-day shown in Table I which assumes all load shops. This is a reduction for CSP's capacity costs of 29%.

Using the Company's rates proposed in the *Ohio Capacity Charge Docket* for the January through May 2012 timeframe as a proxy for the future periods shows even greater reductions. For example, from June 2012 through May 2013, for the 21% to 31% of load that AEP Ohio would provide under the Stipulation at a rate of only $20.01/MW-day, this represents less than 6% of the proposed rate of $355.72/MW-day for merged CSP and OPCO.

Exhibit KDP-5 includes various PJM RPM market information, including the maximum potential clearing prices in the PJM Base Residual Auctions, based on 150% of Net Cost of New Entry (CONE).

It should be noted that, while the previously proposed capacity rates represented large increases relative to the current and future RPM prices shown in column (l) of Exhibit KDP-5, the AEP Ohio proposed capacity rates were much closer to the maximum rate that could have occurred in the current PY based on the PJM supply curve utilized. That value was $322.69/MW-day including all appropriate multipliers that are currently used to bill for capacity. Furthermore, the Maximum RPM rate used in the supply curve increases dramatically and was $627.04/MW-day in the most recent auction, including the impacts of the PJM billing multipliers shown in Exhibit KDP-5.

In addition, the Net CONE value is trending upward significantly. As shown in Exhibit KDP-7, column (d), the $342.23/MW-day Net CONE value used for the PJM PY 2014/2015 RPM auction is nearly twice the $171.40/MW-day Net CONE value used for the current period auction. If one accepts the economically simplifying assumption that the RPM capacity prices will tend, on average, to clear near the Net CONE value, then the Company's proposed capacity compensation rates approach these same future values.

CONCLUSION

Q. WHAT IS YOUR OPINION ON THE LEVEL OF CAPACITY CHARGE AGREED TO IN THE STIPULATION VERSUS THE CAPACITY CHARGE LEVEL AEP OHIO FILED IN THE *OHIO CAPACITY CHARGE DOCKET*?

A. My testimony supports and substantiates the validity of AEP Ohio's filed rates in the *Ohio Capacity Charge Docket*. Thus, from the viewpoint of AEP Ohio's litigation position, the level of recovery in the Stipulation would not necessarily be a reasonable outcome for the *Ohio Capacity Charge Docket* to determine the cost-based level of capacity charges absent the other negotiated terms included in the total package found in the Stipulation. In light of the intervenor positions advocating for a pure RPM-based capacity charge and the total package provided in the Stipulation, it is my opinion that the hybrid approach taken in the Stipulation is reasonable and appropriate result of negotiations. The relationship between AEP Ohio's litigation position in the *Ohio Capacity Charge Docket* and the Stipulation package is further addressed in the testimony of Company witnesses Hamrock and Munczinski.

Q. DOES THIS COMPLETE YOUR TESTIMONY IN SUPPORT OF THE STIPULATION?

A. Yes it does.

B-1 | Exhibit KDP-1

CAPACITY (FIXED) CHARGE CALCULATION | Page 1

CSP

12 Months Ending 12/31/2010 (actuals)

	RATE $/MW/Day (1)	Loss Factor (2)	Final FRR Rate (1) x (2) (Note A) (3)
Capacity Daily Charge:			
1. Reference	P.2		Col (1) x (2)
2. Amount	$316.78211	1.034126	**$327.59**

Note A: Final Rate that will be applied to CRES providers demand that will be metered at or adjusted to transmission level.

DETERMINATION OF RATES APPLICABLE TO
CSP'S CAPACITY REQUIREMENTS
12 Months Ending 12/31/2010 (actuals)

1. Capacity Daily Rates

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

$$\frac{477{,}093{,}822}{4{,}126.2 \quad /365} = \$316.78211$$

Where: Annual Production Fixed Cost, P.4

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

B-3 | Exhibit KDP-1
Generator Step Up Transformer Workpaper | Page 3
12 Months Ending 12/31/2010 (actuals)

		Reference	
1.	GSU & Associated Investment	Note A	13,680,915
2.	Total Transmission Investment	FF1, P.207, L.58, Col.g	658,515,757
3.	Percent (GSU to Total Trans. Investment)	L.1 / L.2	2.08%
4.	Transmission Depreciation Expense	FF1, P.336, L.7, Col.b	13,952,264
5.	GSU Related Depreciation Expense	L.3 x L.4	289,864
6.	Station Equipment Acct. 353 Investment	FF1, P.207, L.50, Col.g	335,003,384
7.	Percent (GSU to Acct. 353)	L.1 / L.6	4.08%
8.	Transmission O&M (Accts 562 & 570)	FF1,P.321, L. 93, Col.b, and L.107, Col.b	2,640,539
9.	GSU & Associated Investment O&M	L.7 x L.8	107,835

Note A: Workpapers -- tab WP-16

ANNUAL PRODUCTION FIXED COST
12 Months Ending 12/31/2010 (actuals)

		Reference	PRODUCTION Amount
1.	Return on Rate Base	P.5, L.19, Col.(2)	$129,071,540
2.	Operation & Maintenance Expense	P.14, L.15, Col.(2)	$217,843,953
3.	Depreciation Expense	P.16, L.11, Col.(2)	$59,590,261
4.	Taxes Other Than Income Taxes	P.17, L.5, Col.(2)	$55,511,568
5.	Income Tax	P.18, L.5, Col.(2)	$45,891,012
6.	Sales for Resale	Note A	$30,785,441
7.	Ancillary Service Revenue	Note B	$29,070
8.	Annual Production Fixed Cost	Sum (L.1 : L.5) - (L.6 + L.7)	$477,093,822

Note A: Capacity related revenues associated with sales as reported in Account 447(includes pool capacity payments).
Note B: Workpapers -- tab WP-2

		Reference	Amount	Demand	Energy
1.	ELECTRIC PLANT		(1)	(2)	(3)
2.	Gross Plant in Service	P.6, L.4, Col.(2)	2,803,938,830	2,787,065,908	16,872,922
3.	Less: Accumulated Depreciation	P.6, L.11, Col.(2)	1,090,873,378	1,080,899,054	9,974,324
4.	Net Plant in Service	L.2 - L.3	1,713,065,452	1,706,166,853	6,898,598
5.	Less: Accumulated Deferred Taxes	P.6, L.12, Col.(2)	369,950,829	352,760,604	17,190,225
6.	Plant Held for Future Use	Note A	5,366,165	5,366,165	0
7.	Pollution Control CWIP	Note B	22,821,421	22,821,421	0
8.	Non-Pollution Control CWIP (50%)	Note B	27,563,093	27,563,093	0
9.	Subtotal - Electric Plant	L.4 - L.5 + L.6 + L.7 + L.8	1,398,865,301	1,409,156,928	(10,291,627)
10.	WORKING CAPITAL				
11.	Materials & Supplies				
12.	Fuel	P.9, L.2, Col.(2)	70,686,727	0	70,686,727
13.	Nonfuel	P.9, L.8, Col.(2)	30,166,105	30,166,105	0
14.	Total M & S	L.12 + L.13	100,852,832	30,166,105	70,686,727
15a.	Prepayments Nonlabor (Note C)		4,515,509	4,488,336	27,172
15b.	Prepayments Labor (Note C)		52,736,870	37,951,915	14,784,955
15c	Prepayments Total (Note C)		57,252,378	42,440,251	14,812,128
16.	Cash Working Capital	P.8, L.7, Col.(2)	22,405,305	13,931,878	8,473,427
17.	Total Rate Base	L.9 + L.14 + L.15c + L.16	1,579,375,817	1,495,695,162	83,680,655
18.	Weighted Cost of Capital	P.11, L.4, Col.(4)	8.63%	8.63%	8.63%
19.	Return on Rate Base	L.17 x L.18	136,292,792	129,071,540	7,221,252

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 12/31/2010 (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	5,337,756,728		2,743,754,332	2,743,754,332	0
3.	Allocated General & Intangible Plant			P.7, Col(3), L.28	60,184,497	43,311,575	16,872,922
4.	Total	L.2 + L.3	5,337,756,728		2,803,938,830	2,787,065,908 99%	16,872,922
5.				Col.(2), L.4	2,803,938,830	2,787,065,908	16,872,922
6.				Col.(1), L.4	5,337,756,728	5,337,756,728	5,337,756,728
7.			100.00%		52.53%	52.21%	0.32%
8.	ACCUMULATED PROVISION FOR DEPRECIATION (Note A)						
9.	Plant in Service (Note D)		2,133,446,971	FF1, P.200, L.22	1,055,295,684	1,055,295,684	0
10.	Allocated General Plant		92,514,436	Note B	35,577,694	25,603,370	9,974,324
11.	Total	L.9 + L.10			1,090,873,378	1,080,899,054	9,974,324
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	374,334,133	Exhibit KDP-1, P.6	369,950,829	352,760,604	17,190,225

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.

	Account	Description	Year End Balance	Exclusions	100% Production (Energy Related)	100% Production (Demand Related)	Labor
1	190	Excluded Items	-	-			
2	190	100% Production (Energy)	(206,781)		(206,781)		
3	190	100% Production (Demand)	25,062,248			25,062,248	
4	190	Labor Related	4,922,369				4,922,369
5	190	Total	29,777,836	-	(206,781)	25,062,248	4,922,369
6		Production Allocation		0.00%	100.00%	100.00%	38.46%
7		(Gross Plant or Wages/Salaries)		-	(206,781)	25,062,248	1,892,964
8		Demand Related			-	25,062,248	1,362,266
9		Energy Related			(206,781)	-	530,699
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)	(33,077,639)			(33,077,639)	
14	281	Labor Related	-				-
15	281	Total	(33,077,639)	-	-	(33,077,639)	-
16		Production Allocation		0.00%	100.00%	100.00%	38.46%
17		(Gross Plant or Wages/Salaries)		-	-	(33,077,639)	-
18		Demand Related			-	(33,077,639)	-
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)	(320,077,272)			(320,077,272)	
24	282	Labor Related	34,944				34,944
25	282	Total	(320,042,329)	-	-	(320,077,272)	34,944
26		Production Allocation		0.00%	100.00%	100.00%	38.46%
27		(Gross Plant or Wages/Salaries)		-	-	(320,077,272)	13,438
28		Demand Related			-	(320,077,272)	9,671
29		Energy Related			-		3,767
30		Allocation Basis			Direct	B-6, L. 7	B-7, Note B
31	283	Excluded Items	-	-			
32	283	100% Production (Energy)	(16,215,566)		(16,215,566)		
33	283	100% Production (Demand)	(22,696,852)			(22,696,852)	
34	283	Labor Related	(12,079,584)				(12,079,584)
35	283	Total	(50,992,002)	-	(16,215,566)	(22,696,852)	(12,079,584)
36	283	Production Allocation		0.00%	100.00%	100.00%	38.46%
37		(Gross Plant or Wages/Salaries)		-	(16,215,566)	(22,696,852)	(4,645,369)
38		Demand Related			-	(22,696,852)	(3,343,025)
39		Energy Related			(16,215,566)	0	(1,302,345)
40		Allocation Basis			Direct	B-6, L. 7	B-7, Note B

	Summary Production Related ADIT	Total	Demand	Energy
41				
42	100% Production (Energy)	(16,422,347)	-	(16,422,347)
43	100% Production (Demand)	(350,789,515)	(350,789,515)	0
44	Labor Related	(2,738,967)	(1,971,089)	(767,878)
45	Total	(369,950,829)	(352,760,604)	(17,190,225)

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

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	3,247,961	Note B	1,249,048	898,873	350,175
4. General Offices	0		0	0	0
5. Total Land	3,247,961		1,249,048	898,873	350,175
6					
7. Structures	59,827,362	Note B	23,007,432	16,557,222	6,450,209
8. General Offices	0		0	0	0
9. Total Structures	59,827,362		23,007,432	16,557,222	6,450,209
10					
11. Office Equipment	5,273,610	Note B	2,028,039	1,459,472	568,567
12. General Offices			0	0	0
13. Total Office Equipment	5,273,610		2,028,039	1,459,472	568,567
14. Transportation Equipment	39,411	Note B	15,156	10,907	4,249
15. Stores Equipment	301,966	Note B	116,125	83,569	32,556
16. Tools, Shop & Garage Equipment	10,611,280	Note B	4,080,713	2,936,672	1,144,041
17. Lab Equipment	631,927	Note B	243,016	174,886	68,130
18. Communications Equipment	14,715,288	Note B	5,658,966	4,072,456	1,586,510
19. Miscellaneous Equipment	1,608,064	Note B	618,403	445,032	173,371
20. Subtotal	96,256,868		37,016,897	26,639,088	10,377,809
21. PERCENT		Note C	38.46%	27.67%	10.78%
22. Other Tangible Property					
23. Fuel Exploration	0	Note D	0		0
24. Rail Car Facility	0	Note D	0		0
25. Total Other Tangible Property	0		0	0	0
26. TOTAL GENERAL PLANT FF1, P.207	96,256,868		37,016,897	26,639,088	10,377,809
27. INTANGIBLE PLANT	60,243,856	Note B	23,167,600	16,672,487	6,495,113
28. TOTAL GENERAL AND INTANGIBLI	156,500,724		60,184,497	43,311,575	16,872,922
29. PERCENT		Note E	38.46%	27.67%	10.78%
30. Total General and Intangible	156,500,724		60,184,497	43,311,575	16,872,922
31. Exclude Other Tangible (Railcar and Fuel Exploration)	0		0	0	0
32. Net General and Intangible	156,500,724		60,184,497	43,311,575	16,872,922
33. PERCENT			38.46%	27.67%	10.78%

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).	96,047,425
b. Production wages and salaries in electric operation and maintenance expense, FF1, P.354, Col.(b), L.20.	36,936,353
c. Ratio (b / a)	38.456%

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 12/31/2010 (actuals)

	Reference	Amount (1)	PRODUCTION Demand (2)	Energy (3)
1. Total Production Expense Excluding Fuel Used In Electric Generation	P.14, L.12	752,357,301	197,761,039	554,596,263
2. Less Fuel Handling / Sale of Fly Ash	P.14, L.1 thru 3	(8,543,902)	0	(8,543,902)
3. Less Purchased Power	P.14, L.11	(591,825,260)	(106,281,091)	(485,544,169)
4. Other Production O&M	Sum (L.1 thru L.3)	151,988,140	91,479,948	60,508,192
5. Allocated A&G	P.10, L.17	27,254,303	19,975,079	7,279,224
6. Total O&M for Cash Working Capital Calculation	L.4 + L.5	179,242,443	111,455,027	67,787,416
7. O&M Cash Requirements	=45 / 360 x L.6	22,405,305	13,931,878	8,473,427

PRODUCTION-RELATED MATERIALS & SUPPLIES
12 Months Ending 12/31/2010 (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	70,686,727		70,686,727	0	70,686,727
3. Non-Fuel						
4. Production	Functional Breakdown	30,166,105	100% Col. 1	30,166,105	30,166,105	0
5. Transmission	Furnished from	1,237,214	0	0	0	0
6. Distribution	CSPs Books by	7,963,538	0	0	0	0
7. General	Accounting Dept.	0	Note B	0	0	0
8. Total	L.4 + L.5 + L.6 + L.7	39,366,858		30,166,105	30,166,105	0

Note A: Year end balance.

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

B-10
PRODUCTION-RELATED
ADMINISTRATIVE & GENERAL EXPENSE ALLOCATION
12 Months Ending 12/31/2010 (actuals)

			System			Production		
					Allocation			
			Reference	Amount	Factor %	Amount	Demand	Energy
		Account		(1)	(2)	(3)	(4)	(5)
1.	ADMINISTRATIVE & GENERAL EXPENSE							
2.	RELATED TO WAGES AND SALARIES							
3.	A&G Salaries	920	FF1, P.323	20,956,051				
4.	Outside Services	923	FF1, P.323	16,432,396				
5.	Employee Pensions & Benefits	926	FF1, P.323	17,838,776				
6.	Office Supplies	921	FF1, P.323	4,006,445				
7.	Injuries & Damages	925	FF1, P.323	3,538,231				
8.	Franchise Requirements	927	FF1, P.323	0				
9.	Duplicate Charges - Cr.	929	FF1, P.323	0				
10.	Total		Ls. 3 thru 9	62,771,899	Note A	24,139,793	17,372,123	6,767,671
11.	MISCELLANEOUS GENERAL EXPENSES	930	FF1, P.323	787,260	Note A, C & D	302,752	217,874	84,877
12.	ADM. EXPENSE TRANSFER - CR.	922	FF1, P.323	(2,551,430)	Note B	(981,187)	(706,108)	(275,079)
13.	PROPERTY INSURANCE	924	FF1, P.323	2,509,274	Note E	1,318,129	1,310,197	7,932
14.	REGULATORY COMM. EXPENSES	928	FF1, P.323	292,655	Note C	0	0	0
15.	RENTS	931	FF1, P.323	2,494,546	Note B	959,312	690,366	268,946
16.	MAINTENANCE OF GENERAL PLANT	935	FF1, P.323	3,940,842	Note B	1,515,505	1,090,628	424,877
17.	TOTAL A & G EXPENSE		L.10 thru 16	70,245,045		27,254,303	19,975,079	7,279,224

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.

COMPOSITE COST OF CAPITAL
12 Months Ending 12/31/2010 (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	1,442,745,000	48.44%	Note D	5.95%	2.88%
2.	Preferred Stock	Note B	0	0.00%	Note E	0.00%	0.00%
3.	Common Stock	Note C	1,535,416,257	51.56%	Note F	11.15%	5.75%
4.	Total		2,978,161,257	100.00%			8.63%

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 11.15%. The return on equity cannot be changed absent a Section 205/206 filing with the Commission.

		Reference	Debt Balance (1)	Interest & Cost Booked (2)
	12 Months Ending 12/31/2009 (Actual)			
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.	0	
4.	Other Long Term Debt (Acc 224)	FF1, 112.21.c.	1,442,745,000	
5.	Total Long Term Debt Balance		1,442,745,000	
	Costs and Expenses (actual)			
6.	Interest Expense (Acc 427)	FF1, 117.62.c.		82,229,719
7.	Amortization Debt Discount and Expense (Acc 428)	FF1, 117.63.c.		1,862,634
8.	Amortization Loss on Reacquired Debt (Acc 428.1)	FF1, 117.64.c.		743,541
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		966,667
12.	Sub-total Costs and Expense			85,802,561
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		85,802,561
16.	Embedded Cost of Long Term Debt = L.15, Col.(2) / L.15, Col.(1)			5.95%

LONG TERM DEBT
Limit on Hedging (Gain)/Loss on Interest Rate Derivatives of LTD
12 Months Ending 12/31/2010 (actuals)

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

	Limit on Hedging (G)/L on Interest Rate Derivatives of LTD			
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)	2,978,161,257	
7.	5 basis point Limit on (G)/L Recovery			0.0005
8.	Amount of (G)/L Recovery Limit	L. 6 * L.7		1,489,081
9.	Hedge (Gain) / Loss Recovery (Lesser of Line 5 or Line 8)			0
	To be subtracted or added to actual Interest Expenses on Exhibit KDP-1, Page 12, Line 14			

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.

			(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. L.9	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..

B-13b
COMMON EQUITY
12 Months Ending 12/31/2010 (actuals)

		Source	Balances
1.	Total Proprietary Capital	WP-12a, col. a	1,486,215,161
	<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	2,134,800
4.	Accumulated Comprehensive Other Income (Acc 219)	WP-12a, col.f	(51,335,895)
5.	Total Balance of Common Equity	L.1-2-3-4	1,535,416,257

ANNUAL FIXED COSTS
PRODUCTION O & M EXPENSE
EXCLUDING FUEL USED IN ELECTRIC GENERATION
12 Months Ending 12/31/2010 (actuals)

	Account No.	Total Company (1)	(Demand) Fixed (2)	(Energy) Variable (3)
1. Coal Handling	501.xx	8,699,618		8,699,618
2. Lignite Handling	501.xx	0		0
3. Sale of Fly Ash (Revenue & Expense)	501.xx	(155,717)		(155,717)
4. Rents	507	0		
5. Hydro O & M Expenses	535-545	0		
6. Other Production Expenses	557	9,086,718	9,086,718	
7. System Control of Load Dispatching	Note C	8,645,979	8,645,979	
8. Other Steam Expenses	Note A	134,255,442	73,747,250	60,508,192
9. Combustion Turbine	Note A	0		0
10. Nuclear Power Expense-Other	Note A	0		
11. Purchased Power	555	591,825,260	106,281,091	485,544,169
12. Total Production Expense Excluding Fuel Used In Electric Generation above		752,357,301	197,761,039	554,596,263
13. A & G Expense P.10, L.17		27,254,303	19,975,079	7,279,224
14. Generator Step Up related O&M	Note B	107,835	107,835	0
15. Total O & M		779,719,439	217,843,953	561,875,487

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)

NOTE C: Pursuant to FERC Order 668, expenses were booked in Account 556 are now being recorded in the following accounts: 561.4, 561.8 and 575.7

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 12/31/2010 (actuals)

		Depreciation Expense (1)	Demand (2)	Energy (3)
	PRODUCTION PLANT			
1.	Steam	46,596,737	46,596,737	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	9,078,943	9,078,943	0
9.	Production Related General & Intangible Plant	5,036,802	3,624,718	1,412,084
10.	Generator Step Up Related Depreciation (Note A)	289,864	289,864	0
11.	Total Production	61,002,345	59,590,261	1,412,084

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

		SYSTEM			PRODUCTION
		REFERENCE	AMOUNT	%	AMOUNT
			(1)		(2)
	PRODUCTION RELATED TAXES OTHER THAN INCOME				
1	Labor Related	Note A	6,217,882	Note B	2,391,172
2	Property Related	Note A	101,818,306	Note C	53,485,446
3	Other	Note A	(699,927)	Note C	(367,674)
4	Production		2,623		2,623
5	Gross Receipts / Commission Assessments	Note A	79,921,316	Note D	0
6	TOTAL TAXES OTHER THAN INCOME TAXES	Sum L.1 : L.5	187,260,200		55,511,568

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)	96,047,425	100.00%
(2) Production W & S	36,936,353	38.46%

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

Note D: Not allocated to wholesale

PRODUCTION-RELATED INCOME TAX
12 Months Ending 12/31/2010 (actuals)

		Reference	Amount (1)	Demand (2)	Energy (3)
1.	Return on Rate Base	P.5, L.19	136,292,792	129,071,540	7,221,252
2.	Effective Income Tax Rate	P.19, L.2	36.8399%	36.8399%	36.8399%
3.	Income Tax Calculated	L.1 x L.2	50,210,098	47,549,798	2,660,300
4.	ITC Adjustment	P.19, L.13	(1,668,828)	(1,658,786)	(10,042)
5.	Income Tax	L.3 + L.4	48,541,270	45,891,012	2,650,258

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

1.	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		35.61%
2.	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		36.84%
3.	where WCLTD and WACC from Exhibit KDP-1-11 and FIT, SIT & p as shown below.		
4.	GRCF=1 / (1 - T)		1.5530
5.	Federal Income Tax Rate	FIT	35.0000%
6.	State Income Tax Rate (Composite)	SIT	0.9384%
7.	Percent of FIT deductible for state purposes	p	0.0000%
8.	Weighted Cost of Long Term Debt	WCLTD	2.881%
9.	Weighted Average Cost of Capital	WACC	8.630%
10.	Amortized Investment Tax Credit (enter negative)	FF1, P.114, L.19, Col.c	(2,045,599)
11.	Gross Plant Allocation Factor	L.19	52.530%
12.	Production Plant Related ITC Amortization		(1,074,559)
13.	ITC Adjustment	L.12 x L.4	(1,668,828)
14.	Gross Plant Allocator		Total
15.	Gross Plant	P.6, L.4, Col.1	5,337,756,728
16.	Production Plant Gross	P.6, L.4, Col.2	2,803,938,830
17.	Demand Related Production Plant	P.6, L.4, Col.3	2,787,065,908
18.	Energy Related Production Plant	P.6, L.4, Col.4	16,872,922
19.	Production Plant Gross Plant Allocator	L.16 / L.15	52.530%
20.	Production Plant - Demand Related	L.17 / L.16	99.398%
21.	Production Plant - Energy Related	L.18 / L.16	0.602%

ENERGY CHARGE:		RATE $/MWh (1)	BILLING MWh (2)	AMOUNT, $ (1) X (2) (3)
1.	Reference	P.21	Note A	
2.	JANUARY, 2010	$28.4160560	0	$0.00
	FEBRUARY, 2010	$28.5408586	0	$0.00
	MARCH, 2010	$27.9008777	0	$0.00
	APRIL, 2010	$29.4964545	0	$0.00
	MAY, 2010	$29.8472052	0	$0.00
	JUNE, 2010	$29.2051774	0	$0.00
	JULY, 2010	$29.6660303	0	$0.00
	AUGUST, 2010	$30.2993170	0	$0.00
	SEPTEMBER, 2010	$32.6553106	0	$0.00
	OCTOBER, 2010	$33.6568845	0	$0.00
	NOVEMBER, 2010	$38.6615184	0	$0.00
	DECEMBER, 2010	$41.2771838	0	$0.00

Note A: Workpapers -- tab WP-4b

ENERGY CHARGE! **$0.00**

DETERMINATION OF MONTHLY RATE APPLICABLE
TO COLUMBUS SOUTHERN POWER COMPANY ENERGY REQUIREMENTS
12 Months Ending 12/31/2010 (actuals)

1. Monthly Energy Rate

		Actual Annual Energy Related Costs ($)	Net MWh Gen. and MWh Purchased, less MWh sold (MWh)	Monthly Energy Rate ($/MWh) (1) / (2)
		(1)	(2)	(3)
2.	JANUARY, 2010	58,200,061	2,048,140	$28.4160560
	FEBRUARY, 2010	52,171,034	1,827,942	$28.5408586
	MARCH, 2010	48,079,741	1,723,234	$27.9008777
	APRIL, 2010	44,933,601	1,523,356	$29.4964545
	MAY, 2010	51,267,171	1,717,654	$29.8472052
	JUNE, 2010	58,092,456	1,989,115	$29.2051774
	JULY, 2010	65,398,793	2,204,501	$29.6660303
	AUGUST, 2010	64,767,638	2,137,594	$30.2993170
	SEPTEMBER, 2010	55,061,815	1,686,152	$32.6553106
	OCTOBER, 2010	50,311,931	1,494,848	$33.6568845
	NOVEMBER, 2010	59,240,006	1,532,273	$38.6615184
	DECEMBER, 2010	77,179,301	1,869,781	$41.2771838

Where: Actual Monthly Energy Related Costs: From P.22
Net kWh Generated; from Company's Monthly Financial and Operating Reports, kWh Purchased, less kWh Sold; from Company's Monthly Financial and Operating Reports.

DETERMINATION OF ACTUAL
MONTHLY ENERGY RELATED COSTS
MONTH OF JANUARY, 2010

	FOSSIL FUEL EXPENSE	Account	Reference	Amount
1.	Coal-conventional	501	Note A	24,886,990
2.	Coal-combined cycle	501	Note A	
3.	Coal-inventory adjustment	501	Note A	
4.	Gas-conventional	501	Note A	0
5.	Gas-combined cycle	501	Note A	
6.	Oil-conventional	501	Note A	0
7.	Oil-combined cycle	501	Note A	
8.	Lignite	501	Note A	0
9.	Natural gas purchased	547	Note A	0
10.	Oil-combustion turbine	547	Note A	
11.	Amortization of Gas Connect. Fac.	501	Note A	
12.	Total Fossil Fuel			24,886,990
	PURCHASED POWER			
13.	Energy Related	555	Note A & B	46,810,582
	OTHER PRODUCTION EXPENSE			
14.	Energy Related		P.23, L.8	3,847,113
	TOTAL PRODUCTION COST			
15.	Energy Related		L.12, 13 & 14	75,544,685
16.	Off-system sales for resale revenues net of margins		Note C	18,891,526
17.	SUBTOTAL ENERGY RELATED COSTS		L.15 - L.16	56,653,159
18.	12th of Energy related A & G Expense		P.10	606,602
19.	12th of Energy related return		P.5	601,771
20.	12th of Energy related dep. exp.		P.16	117,674
21.	12th of Energy related income tax		P.18	220,855
22.	Total Energy Related Costs		L.17 thru 21	58,200,061

Note A: From Company's monthly Financial and Operating Reports.
Note B: Net of Purchased and Interchange Power included in Account 555
Note C: Off-System Sales for Resale Revenues:
Energy related revenues net of OSS Margins

DETERMINATION OF ACTUAL
MONTHLY ENERGY RELATED COSTS
MONTH OF FEBRUARY, 2010

	FOSSIL FUEL EXPENSE	Account	Reference	Amount
1.	Coal-conventional	501	Note A	28,937,282
2.	Coal-combined cycle	501	Note A	
3.	Coal-inventory adjustment	501	Note A	
4.	Gas-conventional	501	Note A	0
5.	Gas-combined cycle	501	Note A	
6.	Oil-conventional	501	Note A	0
7.	Oil-combined cycle	501	Note A	
8.	Lignite	501	Note A	0
9.	Natural gas purchased	547	Note A	
10.	Oil-combustion turbine	547	Note A	
11.	Amortization of Gas Connect. Fac.	501	Note A	
12.	Total Fossil Fuel			28,937,282
	PURCHASED POWER			
13.	Energy Related	555	Note A & B	34,344,079
	OTHER PRODUCTION EXPENSE			
14.	Energy Related		P.23, L.8	4,586,963
	TOTAL PRODUCTION COST			
15.	Energy Related		L.12, 13 & 14	67,868,324
16.	Off-system sales for resale revenues net of margins		Note C	17,244,192
17.	SUBTOTAL ENERGY RELATED COSTS		L.15 - L.16	50,624,133
18.	12th of Energy related A & G Expense		P.10	606,602
19.	12th of Energy related return		P.5	601,771
20.	12th of Energy related dep. exp.		P.16	117,674
21.	12th of Energy related income tax		P.18	220,855
22.	Total Energy Related Costs		L.17 thru 21	52,171,034

Note A: From Company's monthly Financial and Operating Reports.
Note B: Net of Purchased and Interchange Power included in Account 555
Note C: Off-System Sales for Resale Revenues:
Energy related revenues net of OSS Margins

DETERMINATION OF ACTUAL
MONTHLY ENERGY RELATED COSTS
MONTH OF MARCH, 2010

	FOSSIL FUEL EXPENSE	Account	Reference	Amount
1.	Coal-conventional	501	Note A	23,775,297
2.	Coal-combined cycle	501	Note A	
3.	Coal-inventory adjustment	501	Note A	
4.	Gas-conventional	501	Note A	0
5.	Gas-combined cycle	501	Note A	
6.	Oil-conventional	501	Note A	0
7.	Oil-combined cycle	501	Note A	
8.	Lignite	501	Note A	0
9.	Natural gas purchased	547	Note A	
10.	Oil-combustion turbine	547	Note A	
11.	Amortization of Gas Connect. Fac.	501	Note A	
12.	Total Fossil Fuel			23,775,297
	PURCHASED POWER			
13.	Energy Related	555	Note A & B	33,962,448
	OTHER PRODUCTION EXPENSE			
14.	Energy Related		P.23, L.8	4,963,074
	TOTAL PRODUCTION COST			
15.	Energy Related		L.12, 13 & 14	62,700,820
16.	Off-system sales for resale revenues net of margins		Note C	16,167,980
17.	SUBTOTAL ENERGY RELATED COSTS		L.15 - L.16	46,532,840
18.	12th of Energy related A & G Expense		P.10	606,602
19.	12th of Energy related return		P.5	601,771
20.	12th of Energy related dep. exp.		P.16	117,674
21.	12th of Energy related income tax		P.18	220,855
22.	Total Energy Related Costs		L.17 thru 21	48,079,741

Note A: From Company's monthly Financial and Operating Reports.
Note B: Net of Purchased and Interchange Power included in Account 555
Note C: Off-System Sales for Resale Revenues:
Energy related revenues net of OSS Margins

	FOSSIL FUEL EXPENSE	Account	Reference	Amount
1.	Coal-conventional	501	Note A	24,553,120
2.	Coal-combined cycle	501	Note A	
3.	Coal-inventory adjustment	501	Note A	
4.	Gas-conventional	501	Note A	0
5.	Gas-combined cycle	501	Note A	
6.	Oil-conventional	501	Note A	0
7.	Oil-combined cycle	501	Note A	
8.	Lignite	501	Note A	0
9.	Natural gas purchased	547	Note A	
10.	Oil-combustion turbine	547	Note A	
11.	Amortization of Gas Connect. Fac.	501	Note A	
12.	Total Fossil Fuel			24,553,120
	PURCHASED POWER			
13.	Energy Related	555	Note A & B	29,160,375
	OTHER PRODUCTION EXPENSE			
14.	Energy Related		P.23, L.8	5,742,077
	TOTAL PRODUCTION COST			
15.	Energy Related		L.12, 13 & 14	59,455,572
16.	Off-system sales for resale revenues net of margins		Note C	16,068,872
17.	SUBTOTAL ENERGY RELATED COSTS		L.15 - L.16	43,386,699
18.	12th of Energy related A & G Expense		P.10	606,602
19.	12th of Energy related return		P.5	601,771
20.	12th of Energy related dep. exp.		P.16	117,674
21.	12th of Energy related income tax		P.18	220,855
22.	Total Energy Related Costs		L.17 thru 21	44,933,601

Note A: From Company's monthly Financial and Operating Reports.
Note B: Net of Purchased and Interchange Power included in Account 555
Note C: Off-System Sales for Resale Revenues:
Energy related revenues net of OSS Margins

DETERMINATION OF ACTUAL
MONTHLY ENERGY RELATED COSTS
MONTH OF MAY, 2010

	FOSSIL FUEL EXPENSE	Account	Reference	Amount
1.	Coal-conventional	501	Note A	30,547,847
2.	Coal-combined cycle	501	Note A	
3.	Coal-inventory adjustment	501	Note A	
4.	Gas-conventional	501	Note A	0
5.	Gas-combined cycle	501	Note A	
6.	Oil-conventional	501	Note A	0
7.	Oil-combined cycle	501	Note A	
8.	Lignite	501	Note A	0
9.	Natural gas purchased	547	Note A	
10.	Oil-combustion turbine	547	Note A	
11.	Amortization of Gas Connect. Fac.	501	Note A	
12.	Total Fossil Fuel			30,547,847
	PURCHASED POWER			
13.	Energy Related	555	Note A & B	26,927,133
	OTHER PRODUCTION EXPENSE			
14.	Energy Related		P.23, L.8	6,171,064
	TOTAL PRODUCTION COST			
15.	Energy Related		L.12, 13 & 14	63,646,044
16.	Off-system sales for resale revenues net of margins		Note C	13,925,774
17.	SUBTOTAL ENERGY RELATED COSTS		L.15 - L.16	49,720,270
18.	12th of Energy related A & G Expense		P.10	606,602
19.	12th of Energy related return		P.5	601,771
20.	12th of Energy related dep. exp.		P.16	117,674
21.	12th of Energy related income tax		P.18	220,855
22.	Total Energy Related Costs		L.17 thru 21	51,267,171

Note A: From Company's monthly Financial and Operating Reports.
Note B: Net of Purchased and Interchange Power included in Account 555
Note C: Off-System Sales for Resale Revenues:
Energy related revenues net of OSS Margins

DETERMINATION OF ACTUAL
MONTHLY ENERGY RELATED COSTS
MONTH OF JUNE, 2010

	FOSSIL FUEL EXPENSE	Account	Reference	Amount
1.	Coal-conventional	501	Note A	33,933,497
2.	Coal-combined cycle	501	Note A	
3.	Coal-inventory adjustment	501	Note A	
4.	Gas-conventional	501	Note A	0
5.	Gas-combined cycle	501	Note A	
6.	Oil-conventional	501	Note A	0
7.	Oil-combined cycle	501	Note A	
8.	Lignite	501	Note A	0
9.	Natural gas purchased	547	Note A	
10.	Oil-combustion turbine	547	Note A	
11.	Amortization of Gas Connect. Fac.	501	Note A	
12.	Total Fossil Fuel			33,933,497
	PURCHASED POWER			
13.	Energy Related	555	Note A & B	44,229,537
	OTHER PRODUCTION EXPENSE			
14.	Energy Related		P.23, L.8	4,960,398
	TOTAL PRODUCTION COST			
15.	Energy Related		L.12, 13 & 14	83,123,433
16.	Off-system sales for resale revenues net of margins		Note C	26,577,878
17.	SUBTOTAL ENERGY RELATED COSTS		L.15 - L.16	56,545,555
18.	12th of Energy related A & G Expense		P.10	606,602
19.	12th of Energy related return		P.5	601,771
20.	12th of Energy related dep. exp.		P.16	117,674
21.	12th of Energy related income tax		P.18	220,855
22.	Total Energy Related Costs		L.17 thru 21	58,092,456

Note A: From Company's monthly Financial and Operating Reports.
Note B: Net of Purchased and Interchange Power included in Account 555
Note C: Off-System Sales for Resale Revenues:
Energy related revenues net of OSS Margins

DETERMINATION OF ACTUAL
MONTHLY ENERGY RELATED COSTS
MONTH OF JULY, 2010

	FOSSIL FUEL EXPENSE	Account	Reference	Amount
1.	Coal-conventional	501	Note A	38,159,508
2.	Coal-combined cycle	501	Note A	
3.	Coal-inventory adjustment	501	Note A	
4.	Gas-conventional	501	Note A	0
5.	Gas-combined cycle	501	Note A	
6.	Oil-conventional	501	Note A	0
7.	Oil-combined cycle	501	Note A	
8.	Lignite	501	Note A	0
9.	Natural gas purchased	547	Note A	
10.	Oil-combustion turbine	547	Note A	
11.	Amortization of Gas Connect. Fac.	501	Note A	
12.	Total Fossil Fuel			38,159,508
	PURCHASED POWER			
13.	Energy Related	555	Note A & B	62,488,771
	OTHER PRODUCTION EXPENSE			
14.	Energy Related		P.23, L.8	4,111,779
	TOTAL PRODUCTION COST			
15.	Energy Related		L.12, 13 & 14	104,760,058
16.	Off-system sales for resale revenues net of margins		Note C	40,908,166
17.	SUBTOTAL ENERGY RELATED COSTS		L.15 - L.16	63,851,892
18.	12th of Energy related A & G Expense		P.10	606,602
19.	12th of Energy related return		P.5	601,771
20.	12th of Energy related dep. exp.		P.16	117,674
21.	12th of Energy related income tax		P.18	220,855
22.	Total Energy Related Costs		L.17 thru 21	65,398,793

Note A: From Company's monthly Financial and Operating Reports.
Note B: Net of Purchased and Interchange Power included in Account 555
Note C: Off-System Sales for Resale Revenues:
Energy related revenues net of OSS Margins

DETERMINATION OF ACTUAL
MONTHLY ENERGY RELATED COSTS
MONTH OF AUGUST, 2010

	FOSSIL FUEL EXPENSE	Account	Reference	Amount
1.	Coal-conventional	501	Note A	38,356,765
2.	Coal-combined cycle	501	Note A	
3.	Coal-inventory adjustment	501	Note A	
4.	Gas-conventional	501	Note A	0
5.	Gas-combined cycle	501	Note A	
6.	Oil-conventional	501	Note A	0
7.	Oil-combined cycle	501	Note A	
8.	Lignite	501	Note A	0
9.	Natural gas purchased	547	Note A	
10.	Oil-combustion turbine	547	Note A	
11.	Amortization of Gas Connect. Fac.	501	Note A	
12.	Total Fossil Fuel			38,356,765
	PURCHASED POWER			
13.	Energy Related	555	Note A & B	53,834,354
	OTHER PRODUCTION EXPENSE			
14.	Energy Related		P.23, L.8	4,078,587
	TOTAL PRODUCTION COST			
15.	Energy Related		L.12, 13 & 14	96,269,706
16.	Off-system sales for resale revenues net of margins		Note C	33,048,969
17.	SUBTOTAL ENERGY RELATED COSTS		L.15 - L.16	63,220,737
18.	12th of Energy related A & G Expense		P.10	606,602
19.	12th of Energy related return		P.5	601,771
20.	12th of Energy related dep. exp.		P.16	117,674
21.	12th of Energy related income tax		P.18	220,855
22.	Total Energy Related Costs		L.17 thru 21	64,767,638

Note A: From Company's monthly Financial and Operating Reports.
Note B: Net of Purchased and Interchange Power included in Account 555
Note C: Off-System Sales for Resale Revenues:
Energy related revenues net of OSS Margins

DETERMINATION OF ACTUAL
MONTHLY ENERGY RELATED COSTS
MONTH OF SEPTEMBER, 2010

	FOSSIL FUEL EXPENSE	Account	Reference	Amount
1.	Coal-conventional	501	Note A	22,451,183
2.	Coal-combined cycle	501	Note A	
3.	Coal-inventory adjustment	501	Note A	
4.	Gas-conventional	501	Note A	0
5.	Gas-combined cycle	501	Note A	
6.	Oil-conventional	501	Note A	0
7.	Oil-combined cycle	501	Note A	
8.	Lignite	501	Note A	0
9.	Natural gas purchased	547	Note A	
10.	Oil-combustion turbine	547	Note A	
11.	Amortization of Gas Connect. Fac.	501	Note A	
12.	Total Fossil Fuel			22,451,183
	PURCHASED POWER			
13.	Energy Related	555	Note A & B	40,916,081
	OTHER PRODUCTION EXPENSE			
14.	Energy Related		P.23, L.8	5,175,118
	TOTAL PRODUCTION COST			
15.	Energy Related		L.12, 13 & 14	68,542,383
16.	Off-system sales for resale revenues net of margins		Note C	15,027,470
17.	SUBTOTAL ENERGY RELATED COSTS		L.15 - L.16	53,514,913
18.	12th of Energy related A & G Expense		P.10	606,602
19.	12th of Energy related return		P.5	601,771
20.	12th of Energy related dep. exp.		P.16	117,674
21.	12th of Energy related income tax		P.18	220,855
22.	Total Energy Related Costs		L.17 thru 21	55,061,815

Note A: From Company's monthly Financial and Operating Reports.
Note B: Net of Purchased and Interchange Power included in Account 555
Note C: Off-System Sales for Resale Revenues:
Energy related revenues net of OSS Margins

DETERMINATION OF ACTUAL
MONTHLY ENERGY RELATED COSTS
MONTH OF OCTOBER, 2010

	FOSSIL FUEL EXPENSE	Account	Reference	Amount
1.	Coal-conventional	501	Note A	15,957,210
2.	Coal-combined cycle	501	Note A	
3.	Coal-inventory adjustment	501	Note A	
4.	Gas-conventional	501	Note A	0
5.	Gas-combined cycle	501	Note A	
6.	Oil-conventional	501	Note A	0
7.	Oil-combined cycle	501	Note A	
8.	Lignite	501	Note A	0
9.	Natural gas purchased	547	Note A	
10.	Oil-combustion turbine	547	Note A	
11.	Amortization of Gas Connect. Fac.	501	Note A	
12.	Total Fossil Fuel			15,957,210
	PURCHASED POWER			
13.	Energy Related	555	Note A & B	36,631,693
	OTHER PRODUCTION EXPENSE			
14.	Energy Related		P.23, L.8	7,163,340
	TOTAL PRODUCTION COST			
15.	Energy Related		L.12, 13 & 14	59,752,242
16.	Off-system sales for resale revenues net of margins		Note C	10,987,212
17.	SUBTOTAL ENERGY RELATED COSTS		L.15 - L.16	48,765,030
18.	12th of Energy related A & G Expense		P.10	606,602
19.	12th of Energy related return		P.5	601,771
20.	12th of Energy related dep. exp.		P.16	117,674
21.	12th of Energy related income tax		P.18	220,855
22.	Total Energy Related Costs		L.17 thru 21	50,311,931

Note A: From Company's monthly Financial and Operating Reports.
Note B: Net of Purchased and Interchange Power included in Account 555
Note C: Off-System Sales for Resale Revenues:
Energy related revenues net of OSS Margins

DETERMINATION OF ACTUAL
MONTHLY ENERGY RELATED COSTS
MONTH OF NOVEMBER, 2010

	FOSSIL FUEL EXPENSE	Account	Reference	Amount
1.	Coal-conventional	501	Note A	21,577,674
2.	Coal-combined cycle	501	Note A	
3.	Coal-inventory adjustment	501	Note A	
4.	Gas-conventional	501	Note A	0
5.	Gas-combined cycle	501	Note A	
6.	Oil-conventional	501	Note A	0
7.	Oil-combined cycle	501	Note A	
8.	Lignite	501	Note A	0
9.	Natural gas purchased	547	Note A	
10.	Oil-combustion turbine	547	Note A	
11.	Amortization of Gas Connect. Fac.	501	Note A	
12.	Total Fossil Fuel			21,577,674
	PURCHASED POWER			
13.	Energy Related	555	Note A & B	33,620,297
	OTHER PRODUCTION EXPENSE			
14.	Energy Related		P.23, L.8	10,155,721
	TOTAL PRODUCTION COST			
15.	Energy Related		L.12, 13 & 14	65,353,692
16.	Off-system sales for resale revenues net of margins		Note C	7,660,588
17.	SUBTOTAL ENERGY RELATED COSTS		L.15 - L.16	57,693,104
18.	12th of Energy related A & G Expense		P.10	606,602
19.	12th of Energy related return		P.5	601,771
20.	12th of Energy related dep. exp.		P.16	117,674
21.	12th of Energy related income tax		P.18	220,855
22.	Total Energy Related Costs		L.17 thru 21	59,240,006

Note A: From Company's monthly Financial and Operating Reports.
Note B: Net of Purchased and Interchange Power included in Account 555
Note C: Off-System Sales for Resale Revenues:
Energy related revenues net of OSS Margins

DETERMINATION OF ACTUAL
MONTHLY ENERGY RELATED COSTS
MONTH OF DECEMBER, 2010

	FOSSIL FUEL EXPENSE	Account	Reference	Amount
1.	Coal-conventional	501	Note A	35,105,944
2.	Coal-combined cycle	501	Note A	
3.	Coal-inventory adjustment	501	Note A	
4.	Gas-conventional	501	Note A	0
5.	Gas-combined cycle	501	Note A	
6.	Oil-conventional	501	Note A	0
7.	Oil-combined cycle	501	Note A	
8.	Lignite	501	Note A	0
9.	Natural gas purchased	547	Note A	
10.	Oil-combustion turbine	547	Note A	
11.	Amortization of Gas Connect. Fac.	501	Note A	
12.	Total Fossil Fuel			35,105,944
	PURCHASED POWER			
13.	Energy Related	555	Note A & B	42,618,819
	OTHER PRODUCTION EXPENSE			
14.	Energy Related		P.23, L.8	8,096,859
	TOTAL PRODUCTION COST			
15.	Energy Related		L.12, 13 & 14	85,821,622
16.	Off-system sales for resale revenues net of margins		Note C	10,189,223
17.	SUBTOTAL ENERGY RELATED COSTS		L.15 - L.16	75,632,399
18.	12th of Energy related A & G Expense		P.10	606,602
19.	12th of Energy related return		P.5	601,771
20.	12th of Energy related dep. exp.		P.16	117,674
21.	12th of Energy related income tax		P.18	220,855
22.	Total Energy Related Costs		L.17 thru 21	77,179,301

Note A: From Company's monthly Financial and Operating Reports.
Note B: Net of Purchased and Interchange Power included in Account 555
Note C: Off-System Sales for Resale Revenues:
Energy related revenues net of OSS Margins

DETERMINATION OF MONTHLY ENERGY RELATED
OTHER PRODUCTION EXPENSE
MONTH OF JANUARY, 2010

		ACCOUNT	REFERENCE	AMOUNT
	ENERGY RELATED PRODUCTION COSTS NOT INCLUDED ON PAGE 22, L. 1 THRU 13			
1.	Sale of Fly Ash (Revenue & Expense)	501	Note A	(23,530)
2.	Fuel Handling	501	Note A	775,558
3.	Lignite Handling	501	Note A	0
4.	Other Steam Expense		Note B	3,095,085
5.	Combustion Turbine			
6.	Rents	507		
7.	Hydro O & M	535-545		
8.	Total Energy Related Production Expense Other Than Fuel	L.1 thru 7		3,847,113

Note A: From CSP's monthly Financial and Operating Reports.

Note B: Workpapers -- tab WP-14

DETERMINATION OF MONTHLY ENERGY RELATED
OTHER PRODUCTION EXPENSE
MONTH OF FEBRUARY, 2010

		ACCOUNT	REFERENCE	AMOUNT
	ENERGY RELATED PRODUCTION COSTS NOT INCLUDED ON PAGE 22, L. 1 THRU 13			
1.	Sale of Fly Ash (Revenue & Expense)	501	Note A	(16,866)
2.	Fuel Handling	501	Note A	786,220
3.	Lignite Handling	501	Note A	0
4.	Other Steam Expense		Note B	3,817,609
5.	Combustion Turbine			
6.	Rents	507		
7.	Hydro O & M	535-545		
8.	Total Energy Related Production Expense Other Than Fuel	L.1 thru 7		4,586,963

Note A: From CSP's monthly Financial and Operating Reports.

Note B: Workpapers -- tab WP-14

DETERMINATION OF MONTHLY ENERGY RELATED
OTHER PRODUCTION EXPENSE
MONTH OF MARCH, 2010

		ACCOUNT	REFERENCE	AMOUNT
	ENERGY RELATED PRODUCTION COSTS NOT INCLUDED ON PAGE 22, L. 1 THRU 13			
1.	Sale of Fly Ash (Revenue & Expense)	501	Note A	(11,314)
2.	Fuel Handling	501	Note A	663,483
3.	Lignite Handling	501	Note A	0
4.	Other Steam Expense		Note B	4,310,905
5.	Combustion Turbine			
6.	Rents	507		
7.	Hydro O & M	535-545		
8.	Total Energy Related Production Expense Other Than Fuel	L.1 thru 7		4,963,074

Note A: From CSP's monthly Financial and Operating Reports.

Note B: Workpapers -- tab WP-14

DETERMINATION OF MONTHLY ENERGY RELATED
OTHER PRODUCTION EXPENSE
MONTH OF APRIL, 2010

		ACCOUNT	REFERENCE	AMOUNT
	ENERGY RELATED PRODUCTION COSTS NOT INCLUDED ON PAGE 22, L. 1 THRU 13			
1.	Sale of Fly Ash (Revenue & Expense)	501	Note A	(14,210)
2.	Fuel Handling	501	Note A	747,454
3.	Lignite Handling	501	Note A	0
4.	Other Steam Expense		Note B	5,008,833
5.	Combustion Turbine			
6.	Rents	507		
7.	Hydro O & M	535-545		
8.	Total Energy Related Production Expense Other Than Fuel	L.1 thru 7		5,742,077

Note A: From CSP's monthly Financial and Operating Reports.

Note B: Workpapers -- tab WP-14

DETERMINATION OF MONTHLY ENERGY RELATED
OTHER PRODUCTION EXPENSE
MONTH OF MAY, 2010

		ACCOUNT	REFERENCE	AMOUNT
	ENERGY RELATED PRODUCTION COSTS NOT INCLUDED ON PAGE 22, L. 1 THRU 13			
1.	Sale of Fly Ash (Revenue & Expense)	501	Note A	(17,610)
2.	Fuel Handling	501	Note A	713,306
3.	Lignite Handling	501	Note A	0
4.	Other Steam Expense		Note B	5,475,368
5.	Combustion Turbine			
6.	Rents	507		
7.	Hydro O & M	535-545		
8.	Total Energy Related Production Expense Other Than Fuel	L.1 thru 7		6,171,064

Note A: From CSP's monthly Financial and Operating Reports.

Note B: Workpapers -- tab WP-14

DETERMINATION OF MONTHLY ENERGY RELATED
OTHER PRODUCTION EXPENSE
MONTH OF JUNE, 2010

		ACCOUNT	REFERENCE	AMOUNT
	ENERGY RELATED PRODUCTION COSTS NOT INCLUDED ON PAGE 22, L. 1 THRU 13			
1.	Sale of Fly Ash (Revenue & Expense)	501	Note A	(11,332)
2.	Fuel Handling	501	Note A	819,246
3.	Lignite Handling	501	Note A	0
4.	Other Steam Expense		Note B	4,152,484
5.	Combustion Turbine			
6.	Rents	507		
7.	Hydro O & M	535-545		
8.	Total Energy Related Production Expense Other Than Fuel	L.1 thru 7		4,960,398

Note A: From CSP's monthly Financial and Operating Reports.

Note B: Workpapers -- tab WP-14

DETERMINATION OF MONTHLY ENERGY RELATED
OTHER PRODUCTION EXPENSE
MONTH OF JULY, 2010

		ACCOUNT	REFERENCE	AMOUNT
	ENERGY RELATED PRODUCTION COSTS NOT INCLUDED ON PAGE 22, L. 1 THRU 13			
1.	Sale of Fly Ash (Revenue & Expense)	501	Note A	(6,603)
2.	Fuel Handling	501	Note A	723,666
3.	Lignite Handling	501	Note A	0
4.	Other Steam Expense		Note B	3,394,716
5.	Combustion Turbine			
6.	Rents	507		
7.	Hydro O & M	535-545		
8.	Total Energy Related Production Expense Other Than Fuel	L.1 thru 7		4,111,779

Note A: From CSP's monthly Financial and Operating Reports.

Note B: Workpapers -- tab WP-14

DETERMINATION OF MONTHLY ENERGY RELATED
OTHER PRODUCTION EXPENSE
MONTH OF AUGUST, 2010

		ACCOUNT	REFERENCE	AMOUNT
	ENERGY RELATED PRODUCTION COSTS NOT INCLUDED ON PAGE 22, L. 1 THRU 13			
1.	Sale of Fly Ash (Revenue & Expense)	501	Note A	(7,379)
2.	Fuel Handling	501	Note A	1,016,426
3.	Lignite Handling	501	Note A	0
4.	Other Steam Expense		Note B	3,069,541
5.	Combustion Turbine			
6.	Rents	507		
7.	Hydro O & M	535-545		
8.	Total Energy Related Production Expense Other Than Fuel	L.1 thru 7		4,078,587

Note A: From CSP's monthly Financial and Operating Reports.

Note B: Workpapers -- tab WP-14

DETERMINATION OF MONTHLY ENERGY RELATED
OTHER PRODUCTION EXPENSE
MONTH OF SEPTEMBER, 2010

		ACCOUNT	REFERENCE	AMOUNT
	ENERGY RELATED PRODUCTION COSTS NOT INCLUDED ON PAGE 22, L. 1 THRU 13			
1.	Sale of Fly Ash (Revenue & Expense)	501	Note A	(21,077)
2.	Fuel Handling	501	Note A	582,174
3.	Lignite Handling	501	Note A	0
4.	Other Steam Expense		Note B	4,614,021
5.	Combustion Turbine			
6.	Rents	507		
7.	Hydro O & M	535-545		
8.	Total Energy Related Production Expense Other Than Fuel	L.1 thru 7		5,175,118

Note A: From CSP's monthly Financial and Operating Reports.

Note B: Workpapers -- tab WP-14

DETERMINATION OF MONTHLY ENERGY RELATED
OTHER PRODUCTION EXPENSE
MONTH OF OCTOBER, 2010

		ACCOUNT	REFERENCE	AMOUNT
	ENERGY RELATED PRODUCTION COSTS NOT INCLUDED ON PAGE 22, L. 1 THRU 13			
1.	Sale of Fly Ash (Revenue & Expense)	501	Note A	(8,986)
2.	Fuel Handling	501	Note A	629,403
3.	Lignite Handling	501	Note A	0
4.	Other Steam Expense		Note B	6,542,922
5.	Combustion Turbine			
6.	Rents	507		
7.	Hydro O & M	535-545		
8.	Total Energy Related Production Expense Other Than Fuel	L.1 thru 7		7,163,340

Note A: From CSP's monthly Financial and Operating Reports.

Note B: Workpapers -- tab WP-14

DETERMINATION OF MONTHLY ENERGY RELATED
OTHER PRODUCTION EXPENSE
MONTH OF NOVEMBER, 2010

		ACCOUNT	REFERENCE	AMOUNT
	ENERGY RELATED PRODUCTION COSTS NOT INCLUDED ON PAGE 22, L. 1 THRU 13			
1.	Sale of Fly Ash (Revenue & Expense)	501	Note A	(6,874)
2.	Fuel Handling	501	Note A	425,181
3.	Lignite Handling	501	Note A	0
4.	Other Steam Expense		Note B	9,737,414
5.	Combustion Turbine			
6.	Rents	507		
7.	Hydro O & M	535-545		
8.	Total Energy Related Production Expense Other Than Fuel	L.1 - 8		10,155,721

Note A: From CSP's monthly Financial and Operating Reports.

Note B: Workpapers -- tab WP-14

DETERMINATION OF MONTHLY ENERGY RELATED
OTHER PRODUCTION EXPENSE
MONTH OF DECEMBER, 2010

		ACCOUNT	REFERENCE	AMOUNT
	ENERGY RELATED PRODUCTION COSTS NOT INCLUDED ON PAGE 22, L. 1 THRU 13			
1.	Sale of Fly Ash (Revenue & Expense)	501	Note A	(9,936)
2.	Fuel Handling	501	Note A	817,501
3.	Lignite Handling	501	Note A	0
4.	Other Steam Expense		Note B	7,289,294
5.	Combustion Turbine			
6.	Rents	507		
7.	Hydro O & M	535-545		
8.	Total Energy Related Production Expense Other Than Fuel	L.1 - 8		8,096,859

Note A: From CSP's monthly Financial and Operating Reports.

Note B: Workpapers -- tab WP-14

CAPACITY (FIXED) CHARGE CALCULATION
OPCo
12 Months Ending 12/31/2010 (actuals)

	RATE $/MW/Day (1)	Loss Factor (2)	Final FRR Rate (1) x (2) (Note A) (3)
Capacity Daily Charge:			
1. Reference	P.2		Col (1) x (2)
2. Amount	$366.71683	1.034126	**$379.23**

Note A: Final Rate that will be applied to CRES providers demand that will be metered at or adjusted to transmission level.

DETERMINATION OF RATES APPLICABLE TO
OPCo'S CAPACITY REQUIREMENTS
12 Months Ending 12/31/2010 (actuals)

1. Capacity Daily Rates

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

$$\frac{660{,}504{,}310}{4{,}934.6 \quad /365} = \$366.71683$$

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 12/31/2010 (actuals)

		Reference	
1.	GSU & Associated Investment	Note A	46,501,375
2.	Total Transmission Investment	FF1, P.207, L.58, Col.g	1,232,468,069
3.	Percent (GSU to Total Trans. Investment)	L.1 / L.2	3.77%
4.	Transmission Depreciation Expense	FF1, P.336, L.7, Col.b	26,883,115
5.	GSU Related Depreciation Expense	L.3 x L.4	1,014,308
6.	Station Equipment Acct. 353 Investment	FF1, P.207, L.50, Col.g	672,249,191
7.	Percent (GSU to Acct. 353)	L.1 / L.6	6.92%
8.	Transmission O&M (Accts 562 & 570)	FF1,P.321, L. 93, Col.b, and L.107, Col.b	5,697,368
9.	GSU & Associated Investment O&M	L.7 x L.8	394,103

Note A: Workpapers -- tab WP-16

B-4
ANNUAL PRODUCTION FIXED COST
12 Months Ending 12/31/2010 (actuals)

		Reference	PRODUCTION Amount
1.	Return on Rate Base	P.5, L.19, Col.(2)	$311,327,830
2.	Operation & Maintenance Expense	P.14, L.15, Col.(2)	$338,656,260
3.	Depreciation Expense	P.16, L.11, Col.(2)	$256,957,852
4.	Taxes Other Than Income Taxes	P.17, L.6, Col.(2)	$89,767,677
5.	Income Tax	P.18, L.5, Col.(2)	$123,339,938
6.	Sales for Resale	Note A	$459,510,726
7.	Ancillary Service Revenue	Note B	$34,520
8.	Annual Production Fixed Cost	Sum (L.1 : L.5) - (L.6 + L.7)	$660,504,310

Note A: Capacity related revenues associated with sales as reported in Account 447 (includes pool capacity demand).
Note B: Workpapers -- tab WP-2

		Reference	Amount (1)	Demand (2)	Energy (3)
1.	ELECTRIC PLANT				
2.	Gross Plant in Service	P.6, L.4, Col.(2)	6,974,795,044	6,912,623,064	62,171,980
3.	Less: Accumulated Depreciation	P.6, L.11, Col.(2)	2,650,730,162	2,616,814,774	33,915,388
4.	Net Plant in Service	L.2 - L.3	4,324,064,883	4,295,808,290	28,256,592
5.	Less: Accumulated Deferred Taxes	P.6, L.12, Col.(2)	1,108,268,425	914,813,350	193,455,075
6.	Plant Held for Future Use (Note A)	FF1, P.214	0	0	0
7.	Pollution Control CWIP	Note B	10,860,321	10,860,321	0
8.	Non-Pollution Control CWIP (50%)	Note B	21,859,033	21,859,033	0
9.	Subtotal - Electric Plant	L.4 - L.5 + L.6 + L.7 + L.8	3,248,515,812	3,413,714,294	(165,198,482)
10.	WORKING CAPITAL				
11.	Materials & Supplies				
12.	Fuel	P.9, L.2, Col.(2)	246,970,049	0	246,970,049
13.	Nonfuel	P.9, L.8, Col.(2)	86,030,030	86,030,030	0
14.	Total M & S	L.12 + L.13	333,000,078	86,030,030	246,970,049
15a.	Prepayments Nonlabor (Note C)		2,063,691	2,045,295	18,395
15b.	Prepayments Labor (Note C)		119,416,864	73,652,528	45,764,336
15c	Prepayments Total (Note C)		121,480,555	75,697,823	45,782,732
16.	Cash Working Capital	P.8, L.7, Col.(2)	57,175,703	34,871,445	22,304,258
17.	Total Rate Base	L.9 + L.14 + L.15c + L.16	3,760,172,148	3,610,313,592	149,858,556
18.	Weighted Cost of Capital	P.11, L.4, Col.(4)	8.62%	8.62%	8.62%
19.	Return on Rate Base	L.17 x L.18	324,250,568	311,327,830	12,922,739

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.

B-6
PRODUCTION-RELATED
ELECTRIC PLANT IN SERVICE, ACCUMULATED DEPRECIATION AND ADIT
12 Months Ending 12/31/2010 (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	9,857,157,173		6,835,535,931	6,835,535,931	0
3.	Allocated General & Intangible Plant			P.7, Col(3), L.28	139,259,113	77,087,133	62,171,980
4.	Total	L.2 + L.3	9,857,157,173		6,974,795,044	6,912,623,064 99%	62,171,980
5.				Col.(2), L.4	6,974,795,044	6,912,623,064	62,171,980
6.				Col.(1), L.4	9,857,157,173	9,857,157,173	9,857,157,173
7.			100.00%		70.76%	70.13%	0.63%
8.	ACCUMULATED PROVISION FOR DEPRECIATION (Note A)						
9.	Plant in Service (Note D)		3,730,181,093	FF1, P.200, L.22	2,574,763,033	2,574,763,033	0
10.	Allocated General Plant		114,807,581	Note B	75,967,129	42,051,741	33,915,388
11.	Total	L.9 + L.10			2,650,730,162	2,616,814,774	33,915,388
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	1,119,993,270	Exhibit KDP-2, P.6	1,108,268,425	914,813,350	193,455,075

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.

B-6a
PRODUCTION-RELATED ADIT
For the Year Ending December 31, 2010

	Account	Description	Year End Balance	Exclusions	100% Production (Energy Related)	100% Production (Demand Related)	Labor
1	190	Excluded Items	-	-			
2	190	100% Production (Energy)	2,000,069		2,000,069		
3	190	100% Production (Demand)	76,275,232			76,275,232	
4	190	Labor Related	(290,784)				(290,784)
5	190	Total	77,984,517	-	2,000,069	76,275,232	(290,784)
6		Production Allocation		0.00%	100.00%	100.00%	63.71%
7		(Gross Plant or Wages/Salaries)		-	2,000,069	76,275,232	(185,252)
8		Demand Related			-	76,275,232	(114,257)
9		Energy Related			2,000,069	-	(70,994)
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)	(268,593,585)			(268,593,585)	
14	281	Labor Related	-				-
15	281	Total	(268,593,585)	-	-	(268,593,585)	-
16		Production Allocation		0.00%	100.00%	100.00%	63.71%
17		(Gross Plant or Wages/Salaries)		-	-	(268,593,585)	-
18		Demand Related			-	(268,593,585)	-
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)	(604,649,577)			(604,649,577)	
24	282	Labor Related	2,526				2,526
25	282	Total	(604,647,051)	-	-	(604,649,577)	2,526
26		Production Allocation		0.00%	100.00%	100.00%	63.71%
27		(Gross Plant or Wages/Salaries)		-	-	(604,649,577)	1,609
28		Demand Related			-	(604,649,577)	993
29		Energy Related			-	-	617
30		Allocation Basis			Direct	B-6, L. 7	B-7, Note B
31	283	Excluded Items	-	-			
32	283	100% Production (Energy)	(187,567,517)		(187,567,517)		
33	283	100% Production (Demand)	(105,151,176)			(105,151,176)	
34	283	Labor Related	(32,018,457)				(32,018,457)
35	283	Total	(324,737,151)	-	(187,567,517)	(105,151,176)	(32,018,457)
36	283	Production Allocation		0.00%	100.00%	100.00%	63.71%
37		(Gross Plant or Wages/Salaries)		-	(187,567,517)	(105,151,176)	(20,398,227)
38		Demand Related			-	(105,151,176)	(12,580,979)
39		Energy Related			(187,567,517)	0	(7,817,249)
40		Allocation Basis			Direct	B-6, L. 7	B-7, Note B

	Summary Production Related ADIT	Total	Demand	Energy
41				
42	P Plant (Energy Related)	(185,567,448)	-	(185,567,448)
43	P Plant (Demand Related)	(902,119,106)	(902,119,106)	0
44	Labor Related	(20,581,870)	(12,694,243)	(7,887,626)
45	Total	(1,108,268,425)	(914,813,350)	(193,455,075)

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

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	4,967,489	Note B	3,164,674	1,951,870	1,212,804
4. General Offices	0		0	0	0
5. Total Land	4,967,489		3,164,674	1,951,870	1,212,804
6					
7. Structures	66,480,839	Note B	42,353,423	26,122,246	16,231,177
8. General Offices	0		0	0	0
9. Total Structures	66,480,839		42,353,423	26,122,246	16,231,177
10					
11. Office Equipment	3,259,985	Note B	2,076,862	1,280,943	795,920
12. General Offices			0	0	0
13. Total Office Equipment	3,259,985		2,076,862	1,280,943	795,920
14. Transportation Equipment	31,743	Note B	20,223	12,473	7,750
15. Stores Equipment	269,697	Note B	171,818	105,972	65,846
16. Tools, Shop & Garage Equipment	17,522,052	Note B	11,162,899	6,884,921	4,277,978
17. Lab Equipment	570,347	Note B	363,355	224,106	139,249
18. Communications Equipment	34,416,189	Note B	21,925,767	13,523,117	8,402,650
19. Miscellaneous Equipment	2,032,090	Note B	1,294,598	798,467	496,131
20. Subtotal	129,550,430		82,533,618	50,904,114	31,629,505
21. PERCENT		Note C	63.71%	39.29%	24.41%
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	143,823,966		96,807,154	50,904,114	45,903,041
27. INTANGIBLE PLANT	66,635,508	Note B	42,451,959	26,183,020	16,268,939
28. TOTAL GENERAL AND INTANGIBLI	210,459,474		139,259,113	77,087,133	62,171,980
29. PERCENT		Note E	66.17%	36.63%	29.54%
30. Total General and Intangible	210,459,474		139,259,113	77,087,133	62,171,980
31. Exclude Other Tangible (Railcar and Fuel Exploration)	(14,273,536)		(14,273,536)	0	(14,273,536)
32. Net General and Intangible	196,185,938		124,985,577	77,087,133	47,898,444
33. PERCENT			63.71%	39.29%	24.41%

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).	191,278,172
b. Production wages and salaries in electric operation and maintenance expense, FF1, P.354, Col.(b), L.20.	121,858,951
c. Ratio (b / a)	63.708%

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)

B-8
PRODUCTION-RELATED CASH REQUIREMENT
12 Months Ending 12/31/2010 (actuals)

			PRODUCTION	
	Reference	Amount	Demand	Energy
		(1)	(2)	(3)
1. Total Production Expense Excluding Fuel Used In Electric Generation	P.14, L.12	785,996,598	295,412,424	490,584,174
2. Less Fuel Handling / Sale of Fly Ash	P.14, L.1 thru 3	(33,746,277)	0	(33,746,277)
3. Less Purchased Power	P.14, L.11	(362,926,322)	(59,290,595)	(303,635,727)
4. Other Production O&M	Sum (L.1 thru L.3)	389,323,999	236,121,829	153,202,170
5. Allocated A&G	P.10, L.17	68,081,627	42,849,733	25,231,894
6. Total O&M for Cash Working Capital Calculation	L.4 + L.5	457,405,626	278,971,562	178,434,065
7. O&M Cash Requirements	=45 / 360 x L.6	57,175,703	34,871,445	22,304,258

PRODUCTION-RELATED MATERIALS & SUPPLIES
12 Months Ending 12/31/2010 (actuals)

	SYSTEM		PRODUCTION			
	Reference	Amount	Reference	Amount	Demand	Energy
1. Material & Supplies (Note A)		(1)		(2)	(3)	(4)
2. Fuel	FF1, P.227, L.1	246,970,049		246,970,049	0	246,970,049
3. Non-Fuel						
4. Production	Functional Breakdown	86,030,030	100% Col. 1	86,030,030	86,030,030	0
5. Transmission	Furnished from	13,675,590	0	0	0	0
6. Distribution	OPCs Books by	13,274,923	0	0	0	0
7. General	Accounting Dept.	0	Note B	0	0	0
8. Total	L.4 + L.5 + L.6 + L.7	112,980,543		86,030,030	86,030,030	0

Note A: Year end balance.

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

B-10
PRODUCTION-RELATED
ADMINISTRATIVE & GENERAL EXPENSE ALLOCATION
12 Months Ending 12/31/2010 (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	31,166,460				
4.	Outside Services	923	FF1, P.323	25,688,470				
5.	Employee Pensions & Benefits	926	FF1, P.323	33,929,111				
6.	Office Supplies	921	FF1, P.323	789,501				
7.	Injuries & Damages	925	FF1, P.323	6,155,580				
8.	Franchise Requirements	927	FF1, P.323	0				
9.	Duplicate Charges - Cr.	929	FF1, P.323	0				
10.	Total		Ls. 3 thru 9	97,729,122	Note A	62,260,990	38,400,601	23,860,389
11.	MISCELLANEOUS GENERAL EXPENSES	930	FF1, P.323	1,899,442	Note A, C & D	1,210,091	746,346	463,745
12.	ADM. EXPENSE TRANSFER - CR.	922	FF1, P.323	(3,410,884)	Note B	(2,256,951)	(1,249,339)	(1,007,612)
13.	PROPERTY INSURANCE	924	FF1, P.323	3,522,751	Note E	2,492,652	2,470,433	22,219
14.	REGULATORY COMM. EXPENSES	928	FF1, P.323	578,106	Note C	134,370	134,370	0
15.	RENTS	931	FF1, P.323	873,943	Note B	578,280	320,108	258,172
16.	MAINTENANCE OF GENERAL PLANT	935	FF1, P.323	5,534,601	Note B	3,662,195	2,027,215	1,634,980
17.	TOTAL A & G EXPENSE		L.10 thru 16	106,727,081		68,081,627	42,849,733	25,231,894

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.

		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	2,734,580,000	45.49%	Note D	5.65%	2.57%
2.	Preferred Stock	Note B	18,902,783	0.31%	Note E	3.87%	0.01%
3.	Common Stock	Note C	3,258,446,556	54.20%	Note F	11.15%	6.04%
4.	Total		6,011,929,339	100.00%			8.62%

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 11.15%. The return on equity cannot be changed absent a Section 205/206 filing with the Commission.

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

		Reference	Debt Balance (1)	Interest & Cost Booked (2)
	12 Months Ending 12/31/2010 (Actual)			
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.	2,837,580,000	
5.	Total Long Term Debt Balance		2,734,580,000	
	Costs and Expenses (actual)			
6.	Interest Expense (Acc 427)	FF1, 117.62.c.		140,107,499
7.	Amortization Debt Discount and Expense (Acc 428)	FF1, 117.63.c.		3,175,310
8.	Amortization Loss on Reacquired Debt (Acc 428.1)	FF1, 117.64.c.		594,470
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			154,377,279
13.	Less: Total Hedge (Gain) / Loss	P. 12a, L. 4, Col. (1)		(2,097,665)
14.	Plus: Allowed Hedge Recovery	P. 12a, L. 9, Col. (6)		(2,097,665)
15.	Total LTD Cost Amount	L. 12 - L. 13 + L. 14		154,377,279
16.	Embedded Cost of Long Term Debt = L.15, Col.(2) / L.15, Col.(1)			5.65%

		(1)	(2)	(3)	(4)	(5)	(6)
	HEDGE AMT BY ISSUANCE FERC Form 1, p. 256-257 (i)	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 - 6.00%	(418,450)	-	(418,450)	(2,266,605)	Jun-06	Jun-16
2.	SUN Cash Flow Hedge - 5.375%	(1,679,215)	-	(1,679,215)	(14,623,145)	Sep-09	Sep-19
4.	Total Hedge Amortization	(2,097,665)	-	(2,097,665)			

	<u>Limit on Hedging (G)/L on Interest Rate Derivatives of LTD</u>			
5.	Hedge (Gain) / Loss prior to Application of Recovery Limit			(2,097,665)
	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)	6,011,929,339	
7.	5 basis point Limit on (G)/L Recovery			0.0005
8.	Amount of (G)/L Recovery Limit	L. 6 * L.7		(3,005,965)
9.	Hedge (Gain) / Loss Recovery (Lesser of Line 5 or Line 8)			(2,097,665)
	To be subtracted or added to actual Interest Expenses on Exhibit KDP-2, Page 12, Line 14			

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.

B-13a
PREFERRED STOCK
12 Months Ending 12/31/2010 (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)	16,615,800
3.	Plus: Premium on Preferred Stock	Note A	FF1, P.112, L.6	727,710
4.	Less: Discount on Pfd Stock	Note A	FF1, P. 112. L.9	0
5.	Plus: Paid-in-Capital Pfd Stock	Note A		1,559,273
6.	Total Preferred Stock		L.2 + L.3 - L.4 + L.5	18,902,783
7.	Average Cost Rate		L.1 / L.6	3.87%

Note A: Workpaper -- tab WP-12b.

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

COMMON EQUITY
12 Months Ending 12/31/2010 (actuals)

		Source	Balances
1.	Total Proprietary Capital	WP-12a, col. a	3,148,530,292
	<u>Less:</u>		
2.	Preferred Stock (Acc 204, pfd portion of Acc 207-213)	WP-12a, col.b+c+d	18,902,783
3.	Unappropriated Undistributed Subsidiary Earnings (Acc 216.1)	WP-12a, col.e	0
4.	Accumulated Comprehensive Other Income (Acc 219)	WP-12a, col.f	(128,819,047)
5.	Total Balance of Common Equity	L.1-2-3-4	3,258,446,556

ANNUAL FIXED COSTS
PRODUCTION O & M EXPENSE
EXCLUDING FUEL USED IN ELECTRIC GENERATION
12 Months Ending 12/31/2010 (actuals)

	Account No.	Total Company (1)	(Demand) Fixed (2)	(Energy) Variable (3)
1. Coal Handling	501.xx	35,107,375		35,107,375
2. Lignite Handling	501.xx	0		0
3. Sale of Fly Ash (Revenue & Expense)	501.xx	(1,361,098)		(1,361,098)
4. Rents	507	0		
5. Hydro O & M Expenses	535-545	0		
6. Other Production Expenses	557	10,771,997	10,771,997	
7. System Control of Load Dispatching	Note C	12,098,923	12,098,923	
8. Other Steam Expenses	Note A	366,453,080	213,250,909	153,202,170
9. Combustion Turbine	Note A	0		0
10. Nuclear Power Expense-Other	Note A	0		
11. Purchased Power	555	362,926,322	59,290,595	303,635,727
12. Total Production Expense Excluding Fuel Used In Electric Generation above		785,996,598	295,412,424	490,584,174
13. A & G Expense P.10, L.17		68,081,627	42,849,733	25,231,894
14. Generator Step Up related O&M	Note B	394,103	394,103	0
15. Total O & M		854,472,328	338,656,260	515,816,069

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)

NOTE C: Pursuant to FERC Order 668, expenses were booked in Account 556 are now being recorded in the following accounts: 561.4, 561.8 and 575.7

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 12/31/2010 (actuals)

		Depreciation Expense (1)	Demand (2)	Energy (3)
	PRODUCTION PLANT			
1.	Steam	245,450,826	245,450,826	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	3,013,680	3,013,680	0
9.	Production Related General & Intangible Plant	12,126,173	7,479,038	4,647,135
10.	Generator Step Up Related Depreciation (Note A)	1,014,308	1,014,308	0
11.	Total Production	261,604,987	256,957,852	4,647,135

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

		SYSTEM REFERENCE	SYSTEM AMOUNT (1)	%	PRODUCTION AMOUNT (2)
	PRODUCTION RELATED TAXES OTHER THAN INCOME				
1	Labor Related	Note A	10,863,950	Note B	6,921,174
2	Property Related	Note A	95,823,331	Note C	67,803,331
3	Other	Note A	(1,993,078)	Note C	(1,410,276)
4	Production		16,453,447		16,453,447
5	Gross Receipts / Commission Assessments	Note A	84,145,040	Note D	0
6	TOTAL TAXES OTHER THAN INCOME TAXES	Sum L.1 : L.5	205,292,690		89,767,677

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)	191,278,172	100.00%
(2) Production W & S	121,858,951	63.71%

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

Note D: Not allocated to wholesale

PRODUCTION-RELATED INCOME TAX
12 Months Ending 12/31/2010 (actuals)

		Reference	Amount (1)	Demand (2)	Energy (3)
1.	Return on Rate Base	P.5, L.19	324,250,568	311,327,830	12,922,739
2.	Effective Income Tax Rate	P.19, L.2	39.7482%	39.7482%	39.7482%
3.	Income Tax Calculated	L.1 x L.2	128,883,662	123,747,110	5,136,552
4.	ITC Adjustment	P.19, L.13	(410,834)	(407,172)	(3,662)
5.	Income Tax	L.3 + L.4	128,472,828	123,339,938	5,132,890

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 12/31/2010 (actuals)

1.	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		36.14%
2.	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		39.75%
3.	where WCLTD and WACC from Exhibit KDP-2-11 and FIT, SIT & p as shown below.		
4.	GRCF=1 / (1 - T)		1.5660
5.	Federal Income Tax Rate	FIT	35.0000%
6.	State Income Tax Rate (Composite)	SIT	1.7608%
7.	Percent of FIT deductible for state purposes	p	0.0000%
8.	Weighted Cost of Long Term Debt	WCLTD	2.568%
9.	Weighted Average Cost of Capital	WACC	8.623%
10.	Amortized Investment Tax Credit (enter negative)	FF1, P.114, L.19, Col.c	(370,753)
11.	Gross Plant Allocation Factor	L.19	70.759%
12.	Production Plant Related ITC Amortization		(262,340)
13.	ITC Adjustment	L.12 x L.4	(410,834)

14.	<u>Gross Plant Allocator</u>		Total
15.	Gross Plant	P.6, L.6, Col.2	9,857,157,173
16.	Production Plant Gross	P.6, L.5, Col.2	6,974,795,044
17.	Demand Related Production Plant	P.6, L.5, Col.3	6,912,623,064
18.	Energy Related Production Plant	P.6, L.5, Col.4	62,171,980
19.	Production Plant Gross Plant Allocator	L.16 / L.15	70.759%
20.	Production Plant - Demand Related	L.17 / L.16	99.109%
21.	Production Plant - Energy Related	L.18 / L.16	0.891%

12 Months Ending 12/31/2010 (actuals)

ENERGY CHARGE:		RATE $/MWh (1)	BILLING MWh (2)	AMOUNT, $ (1) X (2) (3)
1.	Reference	P.21	Note A	
2.	JANUARY, 2010	$30.3087477	0	$0.00
	FEBRUARY, 2010	$30.6064772	0	$0.00
	MARCH, 2010	$30.0751328	0	$0.00
	APRIL, 2010	$31.9933973	0	$0.00
	MAY, 2010	$31.2096230	0	$0.00
	JUNE, 2010	$27.3308892	0	$0.00
	JULY, 2010	$26.7024178	0	$0.00
	AUGUST, 2010	$28.2650701	0	$0.00
	SEPTEMBER, 2010	$30.7221111	0	$0.00
	OCTOBER, 2010	$28.7035646	0	$0.00
	NOVEMBER, 2010	$28.5213821	0	$0.00
	DECEMBER, 2010	$37.9346673	0	$0.00

Note A: Workpapers -- tab WP-4b

ENERGY CHARGES **$0.00**

DETERMINATION OF MONTHLY RATE APPLICABLE
TO OHIO POWER COMPANY ENERGY REQUIREMENTS
12 Months Ending 12/31/2010 (actuals)

1. Monthly Energy Rate

		Actual Annual Energy Related Costs ($)	Net MWh Gen. and MWh Purchased, less MWh sold (MWh)	Monthly Energy Rate ($/MWh) (1) / (2)
		(1)	(2)	(3)
2.	JANUARY, 2010	87,530,601	2,887,965	$30.3087477
	FEBRUARY, 2010	79,327,320	2,591,847	$30.6064772
	MARCH, 2010	75,530,603	2,511,397	$30.0751328
	APRIL, 2010	75,135,553	2,348,471	$31.9933973
	MAY, 2010	76,549,290	2,452,746	$31.2096230
	JUNE, 2010	71,734,070	2,624,652	$27.3308892
	JULY, 2010	76,562,024	2,867,232	$26.7024178
	AUGUST, 2010	78,910,024	2,791,786	$28.2650701
	SEPTEMBER, 2010	73,038,487	2,377,392	$30.7221111
	OCTOBER, 2010	67,576,062	2,354,274	$28.7035646
	NOVEMBER, 2010	72,129,345	2,528,957	$28.5213821
	DECEMBER, 2010	107,971,009	2,846,236	$37.9346673

Where: Actual Monthly Energy Related Costs: From P.22
Net MWh Generated; from Company's Monthly Financial and Operating Reports, MWh Purchased, less MWh Sold; from Company's Monthly Financial and Operating Reports.

DETERMINATION OF ACTUAL
MONTHLY ENERGY RELATED COSTS
MONTH OF JANUARY, 2010

	FOSSIL FUEL EXPENSE	Account	Reference	Amount
1.	Coal-conventional	501	Note A	127,962,704
2.	Coal-combined cycle	501	Note A	
3.	Coal-inventory adjustment	501	Note A	
4.	Gas-conventional	501	Note A	0
5.	Gas-combined cycle	501	Note A	
6.	Oil-conventional	501	Note A	0
7.	Oil-combined cycle	501	Note A	
8.	Lignite	501	Note A	0
9.	Natural gas purchased	547	Note A	
10.	Oil-combustion turbine	547	Note A	
11.	Amortization of Gas Connect. Fac.	501	Note A	
12.	Total Fossil Fuel			127,962,704
	PURCHASED POWER			
13.	Energy Related	555	Note A & B	24,954,199
	OTHER PRODUCTION EXPENSE			
14.	Energy Related		P.23, L.8	12,706,882
	TOTAL PRODUCTION COST			
15.	Energy Related		L.12, 13 & 14	165,623,785
16.	Off-system sales for resale revenues net of margins		Note C	82,087,739
17.	SUBTOTAL ENERGY RELATED COSTS		L.15 - L.16	83,536,046
18.	12th of Energy related A & G Expense		P.10	2,102,658
19.	12th of Energy related return		P.5	1,076,895
20.	12th of Energy related dep. exp.		P.16	387,261
21.	12th of Energy related income tax		P.18	427,741
22.	Total Energy Related Costs		L.17 thru 21	87,530,601

Note A: From Company's monthly Financial and Operating Reports.
Note B: Net of Purchased and Interchange Power included in Account 555
Note C: Off-System Sales for Resale Revenues:
Energy related revenues net of OSS Margins

DETERMINATION OF ACTUAL
MONTHLY ENERGY RELATED COSTS
MONTH OF FEBRUARY, 2010

	FOSSIL FUEL EXPENSE	Account	Reference	Amount
1.	Coal-conventional	501	Note A	105,877,673
2.	Coal-combined cycle	501	Note A	
3.	Coal-inventory adjustment	501	Note A	
4.	Gas-conventional	501	Note A	0
5.	Gas-combined cycle	501	Note A	
6.	Oil-conventional	501	Note A	0
7.	Oil-combined cycle	501	Note A	
8.	Lignite	501	Note A	0
9.	Natural gas purchased	547	Note A	
10.	Oil-combustion turbine	547	Note A	
11.	Amortization of Gas Connect. Fac.	501	Note A	
12.	Total Fossil Fuel			105,877,673
	PURCHASED POWER			
13.	Energy Related	555	Note A & B	22,843,126
	OTHER PRODUCTION EXPENSE			
14.	Energy Related		P.23, L.8	14,789,648
	TOTAL PRODUCTION COST			
15.	Energy Related		L.12, 13 & 14	143,510,447
16.	Off-system sales for resale revenues net of margins		Note C	68,177,681
17.	SUBTOTAL ENERGY RELATED COSTS		L.15 - L.16	75,332,765
18.	12th of Energy related A & G Expense		P.10	2,102,658
19.	12th of Energy related return		P.5	1,076,895
20.	12th of Energy related dep. exp.		P.16	387,261
21.	12th of Energy related income tax		P.18	427,741
22.	Total Energy Related Costs		L.17 thru 21	79,327,320

Note A: From Company's monthly Financial and Operating Reports.
Note B: Net of Purchased and Interchange Power included in Account 555
Note C: Off-System Sales for Resale Revenues:
Energy related revenues net of OSS Margins

DETERMINATION OF ACTUAL
MONTHLY ENERGY RELATED COSTS
MONTH OF MARCH, 2010

	FOSSIL FUEL EXPENSE	Account	Reference	Amount
1.	Coal-conventional	501	Note A	102,073,303
2.	Coal-combined cycle	501	Note A	
3.	Coal-inventory adjustment	501	Note A	
4.	Gas-conventional	501	Note A	0
5.	Gas-combined cycle	501	Note A	
6.	Oil-conventional	501	Note A	0
7.	Oil-combined cycle	501	Note A	
8.	Lignite	501	Note A	0
9.	Natural gas purchased	547	Note A	
10.	Oil-combustion turbine	547	Note A	
11.	Amortization of Gas Connect. Fac.	501	Note A	
12.	Total Fossil Fuel			102,073,303
	PURCHASED POWER			
13.	Energy Related	555	Note A & B	22,451,338
	OTHER PRODUCTION EXPENSE			
14.	Energy Related		P.23, L.8	15,145,132
	TOTAL PRODUCTION COST			
15.	Energy Related		L.12, 13 & 14	139,669,773
16.	Off-system sales for resale revenues net of margins		Note C	68,133,725
17.	SUBTOTAL ENERGY RELATED COSTS		L.15 - L.16	71,536,048
18.	12th of Energy related A & G Expense		P.10	2,102,658
19.	12th of Energy related return		P.5	1,076,895
20.	12th of Energy related dep. exp.		P.16	387,261
21.	12th of Energy related income tax		P.18	427,741
22.	Total Energy Related Costs		L.17 thru 21	75,530,603

Note A: From Company's monthly Financial and Operating Reports.
Note B: Net of Purchased and Interchange Power included in Account 555
Note C: Off-System Sales for Resale Revenues:
Energy related revenues net of OSS Margins

	FOSSIL FUEL EXPENSE	Account	Reference	Amount
1.	Coal-conventional	501	Note A	69,914,068
2.	Coal-combined cycle	501	Note A	
3.	Coal-inventory adjustment	501	Note A	
4.	Gas-conventional	501	Note A	0
5.	Gas-combined cycle	501	Note A	
6.	Oil-conventional	501	Note A	0
7.	Oil-combined cycle	501	Note A	
8.	Lignite	501	Note A	0
9.	Natural gas purchased	547	Note A	
10.	Oil-combustion turbine	547	Note A	
11.	Amortization of Gas Connect. Fac.	501	Note A	
12.	Total Fossil Fuel			69,914,068
	PURCHASED POWER			
13.	Energy Related	555	Note A & B	18,756,389
	OTHER PRODUCTION EXPENSE			
14.	Energy Related		P.23, L.8	18,094,614
	TOTAL PRODUCTION COST			
15.	Energy Related		L.12, 13 & 14	106,765,071
16.	Off-system sales for resale revenues net of margins		Note C	35,624,072
17.	SUBTOTAL ENERGY RELATED COSTS		L.15 - L.16	71,140,999
18.	12th of Energy related A & G Expense		P.10	2,102,658
19.	12th of Energy related return		P.5	1,076,895
20.	12th of Energy related dep. exp.		P.16	387,261
21.	12th of Energy related income tax		P.18	427,741
22.	Total Energy Related Costs		L.17 thru 21	75,135,553

Note A: From Company's monthly Financial and Operating Reports.
Note B: Net of Purchased and Interchange Power included in Account 555
Note C: Off-System Sales for Resale Revenues:
Energy related revenues net of OSS Margins

DETERMINATION OF ACTUAL
MONTHLY ENERGY RELATED COSTS
MONTH OF MAY, 2010

	FOSSIL FUEL EXPENSE	Account	Reference	Amount
1.	Coal-conventional	501	Note A	71,981,474
2.	Coal-combined cycle	501	Note A	
3.	Coal-inventory adjustment	501	Note A	
4.	Gas-conventional	501	Note A	0
5.	Gas-combined cycle	501	Note A	
6.	Oil-conventional	501	Note A	0
7.	Oil-combined cycle	501	Note A	
8.	Lignite	501	Note A	0
9.	Natural gas purchased	547	Note A	
10.	Oil-combustion turbine	547	Note A	
11.	Amortization of Gas Connect. Fac.	501	Note A	
12.	Total Fossil Fuel			71,981,474
	PURCHASED POWER			
13.	Energy Related	555	Note A & B	18,706,736
	OTHER PRODUCTION EXPENSE			
14.	Energy Related		P.23, L.8	17,909,228
	TOTAL PRODUCTION COST			
15.	Energy Related		L.12, 13 & 14	108,597,438
16.	Off-system sales for resale revenues net of margins		Note C	36,042,703
17.	SUBTOTAL ENERGY RELATED COSTS		L.15 - L.16	72,554,736
18.	12th of Energy related A & G Expense		P.10	2,102,658
19.	12th of Energy related return		P.5	1,076,895
20.	12th of Energy related dep. exp.		P.16	387,261
21.	12th of Energy related income tax		P.18	427,741
22.	Total Energy Related Costs		L.17 thru 21	76,549,290

Note A: From Company's monthly Financial and Operating Reports.
Note B: Net of Purchased and Interchange Power included in Account 555
Note C: Off-System Sales for Resale Revenues:
Energy related revenues net of OSS Margins

	FOSSIL FUEL EXPENSE	Account	Reference	Amount
1.	Coal-conventional	501	Note A	89,123,853
2.	Coal-combined cycle	501	Note A	
3.	Coal-inventory adjustment	501	Note A	
4.	Gas-conventional	501	Note A	0
5.	Gas-combined cycle	501	Note A	
6.	Oil-conventional	501	Note A	0
7.	Oil-combined cycle	501	Note A	
8.	Lignite	501	Note A	0
9.	Natural gas purchased	547	Note A	
10.	Oil-combustion turbine	547	Note A	
11.	Amortization of Gas Connect. Fac.	501	Note A	
12.	Total Fossil Fuel			89,123,853
	PURCHASED POWER			
13.	Energy Related	555	Note A & B	26,866,126
	OTHER PRODUCTION EXPENSE			
14.	Energy Related		P.23, L.8	14,672,311
	TOTAL PRODUCTION COST			
15.	Energy Related		L.12, 13 & 14	130,662,290
16.	Off-system sales for resale revenues net of margins		Note C	62,922,775
17.	SUBTOTAL ENERGY RELATED COSTS		L.15 - L.16	67,739,515
18.	12th of Energy related A & G Expense		P.10	2,102,658
19.	12th of Energy related return		P.5	1,076,895
20.	12th of Energy related dep. exp.		P.16	387,261
21.	12th of Energy related income tax		P.18	427,741
22.	Total Energy Related Costs		L.17 thru 21	71,734,070

Note A: From Company's monthly Financial and Operating Reports.
Note B: Net of Purchased and Interchange Power included in Account 555
Note C: Off-System Sales for Resale Revenues:
Energy related revenues net of OSS Margins

DETERMINATION OF ACTUAL
MONTHLY ENERGY RELATED COSTS
MONTH OF JULY, 2010

	FOSSIL FUEL EXPENSE	Account	Reference	Amount
1.	Coal-conventional	501	Note A	108,083,112
2.	Coal-combined cycle	501	Note A	
3.	Coal-inventory adjustment	501	Note A	
4.	Gas-conventional	501	Note A	0
5.	Gas-combined cycle	501	Note A	
6.	Oil-conventional	501	Note A	0
7.	Oil-combined cycle	501	Note A	
8.	Lignite	501	Note A	0
9.	Natural gas purchased	547	Note A	
10.	Oil-combustion turbine	547	Note A	
11.	Amortization of Gas Connect. Fac.	501	Note A	
12.	Total Fossil Fuel			108,083,112
	PURCHASED POWER			
13.	Energy Related	555	Note A & B	35,098,492
	OTHER PRODUCTION EXPENSE			
14.	Energy Related		P.23, L.8	12,000,350
	TOTAL PRODUCTION COST			
15.	Energy Related		L.12, 13 & 14	155,181,954
16.	Off-system sales for resale revenues net of margins		Note C	82,614,485
17.	SUBTOTAL ENERGY RELATED COSTS		L.15 - L.16	72,567,469
18.	12th of Energy related A & G Expense		P.10	2,102,658
19.	12th of Energy related return		P.5	1,076,895
20.	12th of Energy related dep. exp.		P.16	387,261
21.	12th of Energy related income tax		P.18	427,741
22.	Total Energy Related Costs		L.17 thru 21	76,562,024

Note A: From Company's monthly Financial and Operating Reports.
Note B: Net of Purchased and Interchange Power included in Account 555
Note C: Off-System Sales for Resale Revenues:
Energy related revenues net of OSS Margins

DETERMINATION OF ACTUAL
MONTHLY ENERGY RELATED COSTS
MONTH OF AUGUST, 2010

		Account	Reference	Amount
	FOSSIL FUEL EXPENSE			
1.	Coal-conventional	501	Note A	101,866,119
2.	Coal-combined cycle	501	Note A	
3.	Coal-inventory adjustment	501	Note A	
4.	Gas-conventional	501	Note A	0
5.	Gas-combined cycle	501	Note A	
6.	Oil-conventional	501	Note A	0
7.	Oil-combined cycle	501	Note A	
8.	Lignite	501	Note A	0
9.	Natural gas purchased	547	Note A	
10.	Oil-combustion turbine	547	Note A	
11.	Amortization of Gas Connect. Fac.	501	Note A	
12.	Total Fossil Fuel			101,866,119
	PURCHASED POWER			
13.	Energy Related	555	Note A & B	31,461,251
	OTHER PRODUCTION EXPENSE			
14.	Energy Related		P.23, L.8	14,067,658
	TOTAL PRODUCTION COST			
15.	Energy Related		L.12, 13 & 14	147,395,028
16.	Off-system sales for resale revenues net of margins		Note C	72,479,560
17.	SUBTOTAL ENERGY RELATED COSTS		L.15 - L.16	74,915,469
18.	12th of Energy related A & G Expense		P.10	2,102,658
19.	12th of Energy related return		P.5	1,076,895
20.	12th of Energy related dep. exp.		P.16	387,261
21.	12th of Energy related income tax		P.18	427,741
22.	Total Energy Related Costs		L.17 thru 21	78,910,024

Note A: From Company's monthly Financial and Operating Reports.
Note B: Net of Purchased and Interchange Power included in Account 555
Note C: Off-System Sales for Resale Revenues:
Energy related revenues net of OSS Margins

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DETERMINATION OF ACTUAL
MONTHLY ENERGY RELATED COSTS
MONTH OF SEPTEMBER, 2010

	FOSSIL FUEL EXPENSE	Account	Reference	Amount
1.	Coal-conventional	501	Note A	79,937,665
2.	Coal-combined cycle	501	Note A	
3.	Coal-inventory adjustment	501	Note A	
4.	Gas-conventional	501	Note A	0
5.	Gas-combined cycle	501	Note A	
6.	Oil-conventional	501	Note A	0
7.	Oil-combined cycle	501	Note A	
8.	Lignite	501	Note A	0
9.	Natural gas purchased	547	Note A	
10.	Oil-combustion turbine	547	Note A	
11.	Amortization of Gas Connect. Fac.	501	Note A	
12.	Total Fossil Fuel			79,937,665
	PURCHASED POWER			
13.	Energy Related	555	Note A & B	23,282,940
	OTHER PRODUCTION EXPENSE			
14.	Energy Related		P.23, L.8	15,518,730
	TOTAL PRODUCTION COST			
15.	Energy Related		L.12, 13 & 14	118,739,335
16.	Off-system sales for resale revenues net of margins		Note C	49,695,403
17.	SUBTOTAL ENERGY RELATED COSTS		L.15 - L.16	69,043,932
18.	12th of Energy related A & G Expense		P.10	2,102,658
19.	12th of Energy related return		P.5	1,076,895
20.	12th of Energy related dep. exp.		P.16	387,261
21.	12th of Energy related income tax		P.18	427,741
22.	Total Energy Related Costs		L.17 thru 21	73,038,487

Note A: From Company's monthly Financial and Operating Reports.
Note B: Net of Purchased and Interchange Power included in Account 555
Note C: Off-System Sales for Resale Revenues:
Energy related revenues net of OSS Margins

DETERMINATION OF ACTUAL
MONTHLY ENERGY RELATED COSTS
MONTH OF OCTOBER, 2010

	FOSSIL FUEL EXPENSE	Account	Reference	Amount
1.	Coal-conventional	501	Note A	87,807,644
2.	Coal-combined cycle	501	Note A	
3.	Coal-inventory adjustment	501	Note A	
4.	Gas-conventional	501	Note A	0
5.	Gas-combined cycle	501	Note A	
6.	Oil-conventional	501	Note A	0
7.	Oil-combined cycle	501	Note A	
8.	Lignite	501	Note A	0
9.	Natural gas purchased	547	Note A	
10.	Oil-combustion turbine	547	Note A	
11.	Amortization of Gas Connect. Fac.	501	Note A	
12.	Total Fossil Fuel			87,807,644
	PURCHASED POWER			
13.	Energy Related	555	Note A & B	23,045,833
	OTHER PRODUCTION EXPENSE			
14.	Energy Related		P.23, L.8	13,748,270
	TOTAL PRODUCTION COST			
15.	Energy Related		L.12, 13 & 14	124,601,747
16.	Off-system sales for resale revenues net of margins		Note C	61,020,240
17.	SUBTOTAL ENERGY RELATED COSTS		L.15 - L.16	63,581,507
18.	12th of Energy related A & G Expense		P.10	2,102,658
19.	12th of Energy related return		P.5	1,076,895
20.	12th of Energy related dep. exp.		P.16	387,261
21.	12th of Energy related income tax		P.18	427,741
22.	Total Energy Related Costs		L.17 thru 21	67,576,062

Note A: From Company's monthly Financial and Operating Reports.
Note B: Net of Purchased and Interchange Power included in Account 555
Note C: Off-System Sales for Resale Revenues:
Energy related revenues net of OSS Margins

DETERMINATION OF ACTUAL
MONTHLY ENERGY RELATED COSTS
MONTH OF NOVEMBER, 2010

	FOSSIL FUEL EXPENSE	Account	Reference	Amount
1.	Coal-conventional	501	Note A	80,646,856
2.	Coal-combined cycle	501	Note A	
3.	Coal-inventory adjustment	501	Note A	
4.	Gas-conventional	501	Note A	0
5.	Gas-combined cycle	501	Note A	
6.	Oil-conventional	501	Note A	0
7.	Oil-combined cycle	501	Note A	
8.	Lignite	501	Note A	0
9.	Natural gas purchased	547	Note A	
10.	Oil-combustion turbine	547	Note A	
11.	Amortization of Gas Connect. Fac.	501	Note A	
12.	Total Fossil Fuel			80,646,856
	PURCHASED POWER			
13.	Energy Related	555	Note A & B	25,118,636
	OTHER PRODUCTION EXPENSE			
14.	Energy Related		P.23, L.8	13,747,660
	TOTAL PRODUCTION COST			
15.	Energy Related		L.12, 13 & 14	119,513,153
16.	Off-system sales for resale revenues net of margins		Note C	51,378,362
17.	SUBTOTAL ENERGY RELATED COSTS		L.15 - L.16	68,134,791
18.	12th of Energy related A & G Expense		P.10	2,102,658
19.	12th of Energy related return		P.5	1,076,895
20.	12th of Energy related dep. exp.		P.16	387,261
21.	12th of Energy related income tax		P.18	427,741
22.	Total Energy Related Costs		L.17 thru 21	72,129,345

Note A: From Company's monthly Financial and Operating Reports.
Note B: Net of Purchased and Interchange Power included in Account 555
Note C: Off-System Sales for Resale Revenues:
Energy related revenues net of OSS Margins

DETERMINATION OF ACTUAL
MONTHLY ENERGY RELATED COSTS
MONTH OF DECEMBER, 2010

	FOSSIL FUEL EXPENSE	Account	Reference	Amount
1.	Coal-conventional	501	Note A	87,184,566
2.	Coal-combined cycle	501	Note A	
3.	Coal-inventory adjustment	501	Note A	
4.	Gas-conventional	501	Note A	0
5.	Gas-combined cycle	501	Note A	
6.	Oil-conventional	501	Note A	0
7.	Oil-combined cycle	501	Note A	
8.	Lignite	501	Note A	0
9.	Natural gas purchased	547	Note A	
10.	Oil-combustion turbine	547	Note A	
11.	Amortization of Gas Connect. Fac.	501	Note A	
12.	Total Fossil Fuel			87,184,566
	PURCHASED POWER			
13.	Energy Related	555	Note A & B	31,050,659
	OTHER PRODUCTION EXPENSE			
14.	Energy Related		P.23, L.8	24,547,962
	TOTAL PRODUCTION COST			
15.	Energy Related		L.12, 13 & 14	142,783,187
16.	Off-system sales for resale revenues net of margins		Note C	38,806,733
17.	SUBTOTAL ENERGY RELATED COSTS		L.15 - L.16	103,976,454
18.	12th of Energy related A & G Expense		P.10	2,102,658
19.	12th of Energy related return		P.5	1,076,895
20.	12th of Energy related dep. exp.		P.16	387,261
21.	12th of Energy related income tax		P.18	427,741
22.	Total Energy Related Costs		L.17 thru 21	107,971,009

Note A: From Company's monthly Financial and Operating Reports.
Note B: Net of Purchased and Interchange Power included in Account 555
Note C: Off-System Sales for Resale Revenues:
Energy related revenues net of OSS Margins

DETERMINATION OF MONTHLY ENERGY RELATED
OTHER PRODUCTION EXPENSE
MONTH OF JANUARY, 2010

		ACCOUNT	REFERENCE	AMOUNT
	ENERGY RELATED PRODUCTION COSTS NOT INCLUDED ON PAGE 22, L. 1 THRU 13			
1.	Sale of Fly Ash (Revenue & Expense)	501	Note A	(41,290)
2.	Fuel Handling	501	Note A	3,695,339
3.	Lignite Handling	501	Note A	0
4.	Other Steam Expense		Note B	9,052,833
5.	Combustion Turbine			
6.	Rents	507		
7.	Hydro O & M	535-545		
8.	Total Energy Related Production Expense Other Than Fuel	L.1 thru 7		12,706,882

Note A: From OPC's monthly Financial and Operating Reports.

Note B: Workpapers -- tab WP-14

DETERMINATION OF MONTHLY ENERGY RELATED
OTHER PRODUCTION EXPENSE
MONTH OF FEBRUARY, 2010

		ACCOUNT	REFERENCE	AMOUNT
	ENERGY RELATED PRODUCTION COSTS NOT INCLUDED ON PAGE 22, L. 1 THRU 13			
1.	Sale of Fly Ash (Revenue & Expense)	501	Note A	(107,175)
2.	Fuel Handling	501	Note A	3,286,083
3.	Lignite Handling	501	Note A	0
4.	Other Steam Expense		Note B	11,610,740
5.	Combustion Turbine			
6.	Rents	507		
7.	Hydro O & M	535-545		
8.	Total Energy Related Production Expense Other Than Fuel	L.1 thru 7		14,789,648

Note A: From OPC's monthly Financial and Operating Reports.

Note B: Workpapers -- tab WP-14

DETERMINATION OF MONTHLY ENERGY RELATED
OTHER PRODUCTION EXPENSE
MONTH OF MARCH, 2010

		ACCOUNT	REFERENCE	AMOUNT
	ENERGY RELATED PRODUCTION COSTS NOT INCLUDED ON PAGE 22, L. 1 THRU 13			
1.	Sale of Fly Ash (Revenue & Expense)	501	Note A	(29,486)
2.	Fuel Handling	501	Note A	3,152,454
3.	Lignite Handling	501	Note A	0
4.	Other Steam Expense		Note B	12,022,164
5.	Combustion Turbine			
6.	Rents	507		
7.	Hydro O & M	535-545		
8.	Total Energy Related Production Expense Other Than Fuel	L.1 thru 7		15,145,132

Note A: From OPC's monthly Financial and Operating Reports.

Note B: Workpapers -- tab WP-14

DETERMINATION OF MONTHLY ENERGY RELATED
OTHER PRODUCTION EXPENSE
MONTH OF APRIL, 2010

		ACCOUNT	REFERENCE	AMOUNT
	ENERGY RELATED PRODUCTION COSTS NOT INCLUDED ON PAGE 22, L. 1 THRU 13			
1.	Sale of Fly Ash (Revenue & Expense)	501	Note A	(104,898)
2.	Fuel Handling	501	Note A	1,910,738
3.	Lignite Handling	501	Note A	0
4.	Other Steam Expense		Note B	16,288,773
5.	Combustion Turbine			
6.	Rents	507		
7.	Hydro O & M	535-545		
8.	Total Energy Related Production Expense Other Than Fuel	L.1 thru 7		18,094,614

Note A: From OPC's monthly Financial and Operating Reports.

Note B: Workpapers -- tab WP-14

DETERMINATION OF MONTHLY ENERGY RELATED
OTHER PRODUCTION EXPENSE
MONTH OF MAY, 2010

		ACCOUNT	REFERENCE	AMOUNT
	ENERGY RELATED PRODUCTION COSTS NOT INCLUDED ON PAGE 22, L. 1 THRU 13			
1.	Sale of Fly Ash (Revenue & Expense)	501	Note A	(93,312)
2.	Fuel Handling	501	Note A	2,227,323
3.	Lignite Handling	501	Note A	0
4.	Other Steam Expense		Note B	15,775,217
5.	Combustion Turbine			
6.	Rents	507		
7.	Hydro O & M	535-545		
8.	Total Energy Related Production Expense Other Than Fuel	L.1 thru 7		17,909,228

Note A: From OPC's monthly Financial and Operating Reports.

Note B: Workpapers -- tab WP-14

DETERMINATION OF MONTHLY ENERGY RELATED
OTHER PRODUCTION EXPENSE
MONTH OF JUNE, 2010

		ACCOUNT	REFERENCE	AMOUNT
	ENERGY RELATED PRODUCTION COSTS NOT INCLUDED ON PAGE 22, L. 1 THRU 13			
1.	Sale of Fly Ash (Revenue & Expense)	501	Note A	(196,955)
2.	Fuel Handling	501	Note A	2,871,651
3.	Lignite Handling	501	Note A	0
4.	Other Steam Expense		Note B	11,997,616
5.	Combustion Turbine			
6.	Rents	507		
7.	Hydro O & M	535-545		
8.	Total Energy Related Production Expense Other Than Fuel	L.1 thru 7		14,672,311

Note A: From OPC's monthly Financial and Operating Reports.

Note B: Workpapers -- tab WP-14

DETERMINATION OF MONTHLY ENERGY RELATED
OTHER PRODUCTION EXPENSE
MONTH OF JULY, 2010

		ACCOUNT	REFERENCE	AMOUNT
	ENERGY RELATED PRODUCTION COSTS NOT INCLUDED ON PAGE 22, L. 1 THRU 13			
1.	Sale of Fly Ash (Revenue & Expense)	501	Note A	(103,833)
2.	Fuel Handling	501	Note A	3,429,937
3.	Lignite Handling	501	Note A	0
4.	Other Steam Expense		Note B	8,674,246
5.	Combustion Turbine			
6.	Rents	507		
7.	Hydro O & M	535-545		
8.	Total Energy Related Production Expense Other Than Fuel	L.1 thru 7		12,000,350

Note A: From OPC's monthly Financial and Operating Reports.

Note B: Workpapers -- tab WP-14

DETERMINATION OF MONTHLY ENERGY RELATED
OTHER PRODUCTION EXPENSE
MONTH OF AUGUST, 2010

		ACCOUNT	REFERENCE	AMOUNT
	ENERGY RELATED PRODUCTION COSTS NOT INCLUDED ON PAGE 22, L. 1 THRU 13			
1.	Sale of Fly Ash (Revenue & Expense)	501	Note A	(183,813)
2.	Fuel Handling	501	Note A	3,029,102
3.	Lignite Handling	501	Note A	0
4.	Other Steam Expense		Note B	11,222,369
5.	Combustion Turbine			
6.	Rents	507		
7.	Hydro O & M	535-545		
8.	Total Energy Related Production Expense Other Than Fuel	L.1 thru 7		14,067,658

Note A: From OPC's monthly Financial and Operating Reports.

Note B: Workpapers -- tab WP-14

DETERMINATION OF MONTHLY ENERGY RELATED
OTHER PRODUCTION EXPENSE
MONTH OF SEPTEMBER, 2010

		ACCOUNT	REFERENCE	AMOUNT
	ENERGY RELATED PRODUCTION COSTS NOT INCLUDED ON PAGE 22, L. 1 THRU 13			
1.	Sale of Fly Ash (Revenue & Expense)	501	Note A	(143,920)
2.	Fuel Handling	501	Note A	2,649,589
3.	Lignite Handling	501	Note A	0
4.	Other Steam Expense		Note B	13,013,061
5.	Combustion Turbine			
6.	Rents	507		
7.	Hydro O & M	535-545		
8.	Total Energy Related Production Expense Other Than Fuel	L.1 thru 7		15,518,730

Note A: From OPC's monthly Financial and Operating Reports.

Note B: Workpapers -- tab WP-14

DETERMINATION OF MONTHLY ENERGY RELATED
OTHER PRODUCTION EXPENSE
MONTH OF OCTOBER, 2010

		ACCOUNT	REFERENCE	AMOUNT
	ENERGY RELATED PRODUCTION COSTS NOT INCLUDED ON PAGE 22, L. 1 THRU 13			
1.	Sale of Fly Ash (Revenue & Expense)	501	Note A	(102,557)
2.	Fuel Handling	501	Note A	3,048,516
3.	Lignite Handling	501	Note A	0
4.	Other Steam Expense		Note B	10,802,311
5.	Combustion Turbine			
6.	Rents	507		
7.	Hydro O & M	535-545		
8.	Total Energy Related Production Expense Other Than Fuel	L.1 thru 7		13,748,270

Note A: From OPC's monthly Financial and Operating Reports.

Note B: Workpapers -- tab WP-14

DETERMINATION OF MONTHLY ENERGY RELATED
OTHER PRODUCTION EXPENSE
MONTH OF NOVEMBER, 2010

		ACCOUNT	REFERENCE	AMOUNT
	ENERGY RELATED PRODUCTION COSTS NOT INCLUDED ON PAGE 22, L. 1 THRU 13			
1.	Sale of Fly Ash (Revenue & Expense)	501	Note A	(148,205)
2.	Fuel Handling	501	Note A	2,677,542
3.	Lignite Handling	501	Note A	0
4.	Other Steam Expense		Note B	11,218,323
5.	Combustion Turbine			
6.	Rents	507		
7.	Hydro O & M	535-545		
8.	Total Energy Related Production Expense Other Than Fuel	L.1 - 8		13,747,660

Note A: From OPC's monthly Financial and Operating Reports.

Note B: Workpapers -- tab WP-14

DETERMINATION OF MONTHLY ENERGY RELATED
OTHER PRODUCTION EXPENSE
MONTH OF DECEMBER, 2010

		ACCOUNT	REFERENCE	AMOUNT
	ENERGY RELATED PRODUCTION COSTS NOT INCLUDED ON PAGE 22, L. 1 THRU 13			
1.	Sale of Fly Ash (Revenue & Expense)	501	Note A	(105,657)
2.	Fuel Handling	501	Note A	3,129,101
3.	Lignite Handling	501	Note A	0
4.	Other Steam Expense		Note B	21,524,517
5.	Combustion Turbine			
6.	Rents	507		
7.	Hydro O & M	535-545		
8.	Total Energy Related Production Expense Other Than Fuel	L.1 - 8		24,547,962

Note A: From OPC's monthly Financial and Operating Reports.

Note B: Workpapers -- tab WP-14

Energy Credit For CSP and OPCo
2010 Energy Credit Applicable to PJM 2011/2010 Planning Year
(LMPs, Cost Rates and Margins are in $/MWh)

I. Day-Ahead Market Revenues (Load Including CRES Switched-load)										
2010	**CSP**					**OPCo**				
Month	**Σ MWh**	**Σ Revenues**	**LMP**	**MLR**	**CSP Revenue**	**Σ MWh**	**Σ Revenues**	**LMP**	**MLR**	**OPCO Revenue**
	(1)	(2)	(3)=(2)/(1)	(4)	(5)=(2)x(4)	(6)	(7)	(8)=(7)/(6)	(9)	(10)=(7)x(9)
1	2,062,943	$85,076,991	$41.24	0.18036	$15,344,486	2,887,965	$118,281,913	$40.96	0.21001	$24,840,385
2	1,841,822	$71,096,275	$38.60	0.18441	$13,110,864	2,591,847	$99,657,314	$38.45	0.21223	$21,150,272
3	1,738,816	$58,200,851	$33.47	0.18880	$10,988,321	2,511,397	$83,612,011	$33.29	0.21728	$18,167,218
4	1,540,888	$48,810,994	$31.68	0.18891	$9,220,885	2,348,471	$74,074,851	$31.54	0.21740	$16,103,873
5	1,739,193	$59,415,948	$34.16	0.18891	$11,224,267	2,452,746	$82,695,874	$33.72	0.21740	$17,978,083
6	2,020,224	$81,631,776	$40.41	0.18891	$15,421,059	2,624,656	$104,099,301	$39.66	0.21740	$22,631,188
7	2,246,768	$102,301,000	$45.53	0.18855	$19,288,854	2,867,263	$128,319,975	$44.75	0.21955	$28,172,651
8	2,193,824	$97,372,436	$44.38	0.18663	$18,172,618	2,791,917	$121,721,816	$43.60	0.22780	$27,728,230
9	1,767,977	$57,469,744	$32.51	0.18663	$10,725,578	2,377,573	$76,100,574	$32.01	0.22780	$17,335,711
10	1,616,348	$49,319,631	$30.51	0.18663	$9,204,523	2,354,614	$71,531,088	$30.38	0.22780	$16,294,782
11	1,665,349	$54,635,037	$32.81	0.18663	$10,196,537	2,530,053	$82,701,616	$32.69	0.22780	$18,839,428
12	2,060,493	$79,292,367	$38.48	0.18663	$14,798,334	2,857,506	$109,395,943	$38.28	0.22780	$24,920,396
	22,494,645	$844,623,050	$37.55	0.18671	$157,696,325	31,196,008	$1,152,192,276	$36.93	0.22059	$254,162,214

II. Energy Production Costs Based on Formula Rate										
2010	**CSP**					**OPCo**				
Month	**Σ MWh**	**Σ Cost**	**Cost Rate**	**MLR**	**CSP Cost**	**Σ MWh**	**Σ Cost**	**Cost Rate**	**MLR**	**OPCo Cost**
	(1)	(2)=(1)x(3)	(3)	(4)	(5)=(2)x(4)	(6)	(7)=(6)x(8)	(8)	(9)	(10)=(7)x(9)
1	2,062,943	$59,378,228	$28.78	0.18036	$10,709,457	2,887,965	$91,019,034	$31.52	0.21001	$19,114,907
2	1,841,822	$53,342,439	$28.96	0.18441	$9,836,879	2,591,847	$82,370,613	$31.78	0.21223	$17,481,515
3	1,738,816	$49,172,621	$28.28	0.18880	$9,283,791	2,511,397	$78,517,955	$31.26	0.21728	$17,060,381
4	1,540,888	$46,192,477	$29.98	0.18891	$8,726,221	2,348,471	$76,805,778	$32.70	0.21740	$16,697,576
5	1,739,193	$52,614,533	$30.25	0.18891	$9,939,411	2,452,746	$78,547,686	$32.02	0.21740	$17,076,267
6	2,020,224	$59,821,612	$29.61	0.18891	$11,300,901	2,624,656	$74,273,263	$28.30	0.21740	$16,147,007
7	2,246,768	$67,383,561	$29.99	0.18855	$12,705,170	2,867,263	$79,753,374	$27.82	0.21955	$17,509,853
8	2,193,824	$67,507,022	$30.77	0.18663	$12,598,835	2,791,917	$81,623,527	$29.24	0.22780	$18,593,839
9	1,767,977	$58,322,226	$32.99	0.18663	$10,884,677	2,377,573	$75,414,281	$31.72	0.22780	$17,179,373
10	1,616,348	$55,072,153	$34.07	0.18663	$10,278,116	2,354,614	$70,396,570	$29.90	0.22780	$16,036,339
11	1,665,349	$64,839,629	$38.93	0.18663	$12,101,020	2,530,053	$74,555,363	$29.47	0.22780	$16,983,712
12	2,060,493	$85,941,357	$41.71	0.18663	$16,039,235	2,857,506	$111,297,796	$38.95	0.22780	$25,353,638
	22,494,645	$719,587,858	$31.99	0.18678	$134,403,715	31,196,008	$974,575,239	$31.24	0.22085	$215,234,408

III. Energy Value (I. Revenue less II. Costs)										
2010	**CSP**					**OPCo**				
Month	**Σ MWh**	**Σ Energy Value**	**Margin**	**MLR**	**CSP Value**	**Σ MWh**	**Σ Energy Value**	**Margin**	**MLR**	**OPCo Value**
	(1)	(2)	(3)=(2)/(1)	(4)	(5)=(2)x(4)	(6)	(7)	(8)=(7)/(6)	(9)	(10)=(7)x(9)
1	2,062,943	$25,698,763	$12.46	0.18036	$4,635,029	2,887,965	$27,262,879	$9.44	0.21001	$5,725,477
2	1,841,822	$17,753,836	$9.64	0.18441	$3,273,985	2,591,847	$17,286,701	$6.67	0.21223	$3,668,757
3	1,738,816	$9,028,230	$5.19	0.18880	$1,704,530	2,511,397	$5,094,056	$2.03	0.21728	$1,106,836
4	1,540,888	$2,618,517	$1.70	0.18891	$494,664	2,348,471	($2,730,927)	($1.16)	0.21740	($593,704)
5	1,739,193	$6,801,415	$3.91	0.18891	$1,284,855	2,452,746	$4,148,189	$1.69	0.21740	$901,816
6	2,020,224	$21,810,164	$10.80	0.18891	$4,120,158	2,624,656	$29,826,039	$11.36	0.21740	$6,484,181
7	2,246,768	$34,917,439	$15.54	0.18855	$6,583,683	2,867,263	$48,566,601	$16.94	0.21955	$10,662,797
8	2,193,824	$29,865,414	$13.61	0.18663	$5,573,782	2,791,917	$40,098,289	$14.36	0.22780	$9,134,390
9	1,767,977	($852,482)	($0.48)	0.18663	($159,099)	2,377,573	$686,292	$0.29	0.22780	$156,337
10	1,616,348	($5,752,522)	($3.56)	0.18663	($1,073,593)	2,354,614	$1,134,518	$0.48	0.22780	$258,443
11	1,665,349	($10,204,592)	($6.13)	0.18663	($1,904,483)	2,530,053	$8,146,254	$3.22	0.22780	$1,855,717
12	2,060,493	($6,648,990)	($3.23)	0.18663	($1,240,901)	2,857,506	($1,901,853)	($0.67)	0.22780	($433,242)
	22,494,645	$125,035,191	$5.56	0.18629	**$23,292,610**	31,196,008	$177,617,037	$5.69	0.21917	**$38,927,806**

Energy Credit For CSP and OPCo
2010 Energy Credit Applicable to PJM 2011/2010 Planning Year

	IV. Jurisdistional Allocations	**CSP**	**OPCo**	**Merged CSP/OPCo[1]**
(1)	2010 Energy Value	$23,292,610	$38,927,806	$122,413,746
(2)	Ohio Retail Jurisdictional Allocation (including shopping customers)	100.00%	91.971%	-
(3)	2010 Net Energy Value [(1)x(2)]	$23,292,610	$35,802,293	$116,264,546

	V. Preliminary Energy Credit	**CSP**	**OPCo**	**Merged CSP/OPCo[1]**
(4)	2010 Net Energy Value	$23,292,610	$35,802,293	$116,264,546
(5)	Energy Value Shared	50.00%	50.00%	50.00%
(6)	Preliminary Energy Credit	$11,646,305	$17,901,146	$58,132,273

[1] The Merged CSP/OPCo values are estimates only that include the impact of the merged Company's ability to retain a greater share of the Energy Value.

VI. <u>CSP Capacity Daily Rate WITH Energy Credit</u>

(7) CSP Preliminary Energy Credit

$$\$/\text{MW-DAY} = \frac{\text{(Energy Credit)}}{\text{(CSP 5 CP Demand) (365)}} = \left(\frac{\$11{,}646{,}305}{4{,}126 \quad \text{x} \quad 365} \right) = \mathbf{\$7.73}$$

(8) CSP Energy credit cap based on 40% of the Annual Production Fixed Cost

$/MW-Day = 40% x Capacity Rate without Energy Credit = 40% x $327.59 = $131.04

(9) CSP Final Energy Credit and Resulting Capacity Rate

Final Rate =	Capacity Rate	-	Lesser of (7) or (8) above		
$/MW-Day =	$327.59	-	$7.73	=	**<u>$319.86</u>**

VI. <u>OPCo Capacity Daily Rate WITH Energy Credit</u>

(10) OPCo Preliminary Energy Credit

$$\$/\text{MW-DAY} = \frac{\text{(Energy Credit)}}{\text{(OPCo 5 CP Demand) (365)}} = \left(\frac{\$17{,}901{,}146}{4{,}935 \quad \text{x} \quad 365} \right) = \mathbf{\$9.94}$$

(11) OPCo Energy credit cap based on 40% of the Annual Production Fixed Cost

$/MW-Day = 40% x Capacity Rate without Energy Credit = 40% x $379.23 = $151.69

(12) OPCo Final Energy Credit and Resulting Capacity Rate

Final Rate =	Capacity Rate	-	Lesser of (10) or (11) above		
$/MW-Day =	$379.23	-	$9.94	=	**<u>$369.29</u>**

Merged CSP and OPCo Capacity Charge
2010 Energy Credit Applicable to PJM 2011/2010 Planning Year

I. Merged CSP and OPCo Capacity Daily Rate

$$\$/\text{MW-day} = \frac{\text{(Annual Production Fixed Cost of CSP + OPCo)}}{\text{(CSP+OPCo 5 CP Demandx365) (Note A)}}$$

$$\$/\text{MW-day} = \frac{\$477{,}093{,}822 + \$660{,}504{,}310}{4{,}126.2 + 4{,}934.6} \;/\; 365$$

$$\$/\text{MW-day} = \frac{\$1{,}137{,}598{,}132}{9{,}060.8} \;/\; 365 = \$343.98$$

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

Final FRR Rate =	RATE $/MW/Day	x	LOSS FACTOR		
Final FRR Rate =	$343.98	x	1.034126	=	**$355.72**

II. Merged CSP and OPCo Capacity Daily Rate WITH Energy Credit

(7) AEP-Ohio Preliminary Energy Credit

$$\$/\text{MW-DAY} = \frac{\text{(Energy Credit)}}{\text{(CSP + OPCo 5 CP Demand) (365)}} = \frac{(\$58{,}132{,}273)}{9{,}060.8 \times 365} = \mathbf{\$17.58}$$

(8) AEP-Ohio Energy credit cap based on 40% of the Annual Production Fixed Cost

$/MW-Day = 40% x Capacity Rate without Energy Credit = 40% x $355.72 = $142.29

(9) AEP-Ohio Final Energy Credit and Resulting Capacity Rate

Final Rate =	Capacity Rate	-	Lesser of (7) or (8) above		
$/MW-Day =	$355.72	-	$17.58	=	**$338.14**

PJM Capacity Market Values

Values based on Unforced Capacity (UCAP) MW

PJM PY (a)	RPM Reserve Margin Cleared (%) (b)	Gross CONE ($/MW-day) (c)	Net CONE ($/MW-day) (d)	Gross to Net Adjustment ($/MW-day) (e)=(d)-(c)	150% NCONE ($/MW-day) (f)=1.5x(d)	RPM BRA Clearing ($/MW-day) (g)	Final Zonal Capacity Price[2] ($/MW-day) (h)	Scaling Factor (i)	FPR (j)	Losses (k)	Billed RPM Capacity Rate ($/MW-day) (l)=(h)x(i)x(j)x(k)	Maximum RPM Rate ($/MW-day) (m)=(f)x(i)x(j)x(k)
2007/2008	19.20%	$210.26	**$171.87**	**($38.39)**	**$257.81**	$40.80	$40.80	1.02635	1.07900	1.034126	**$46.73**	**$295.24**
2008/2009	17.50%	$210.73	**$172.25**	**($38.48)**	**$258.38**	$111.92	$111.92	1.03811	1.07960	1.034126	**$129.71**	**$299.45**
2009/2010	17.80%	$210.73	**$172.27**	**($38.46)**	**$258.41**	$102.04	$104.82	1.07964	1.07950	1.034126	**$126.33**	**$311.44**
2010/2011	16.50%	$210.93	**$174.29**	**($36.64)**	**$261.44**	$174.29	$182.85	1.07870	1.08330	1.034126	**$220.96**	**$315.93**
2011/2012	18.10%	$210.35	**$171.40**	**($38.95)**	**$257.10**	$110.00	$116.16	1.12037	1.08330	1.034126	**$145.79**	**$322.69**
2012/2013[1,3]	20.90%	$330.51	**$276.09**	**($54.42)**	**$414.14**	$16.46	$16.52 [3]	1.08177	1.08270	1.034126	**$20.01**	**$501.60**
2013/2014[1]	20.30%	$357.41	**$317.95**	**($39.46)**	**$476.93**	$27.73	TBD	1.08812	1.08040	1.034126	**$33.71**	**$579.81**
2014/2015[1]	20.60%	$374.72	**$342.23**	**($32.49)**	**$513.35**	$125.99	TBD	1.09276	1.08090	1.034126	**$153.89**	**$627.04**

PY = Planning Year
RPM = Reliabiity Pricing Model

CONE = Cost of New Entry
NCONE = Net Cost of New Entry

BRA= Base Residual Auction
FPR = Forecast Pool Requirement

Notes

[1] Future planning periods utilize preliminary scaling factors.
[2] Includes the affects of incremental auctions and ILR.
[3] Columns (h) through (m) include the results of the first and second incremental auctions but are not yet final.

RPM data sourced from the RPM Auction User Information page at: http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx

CERTIFICATE OF SERIVICE

I hereby certify that a copy of the testimony of Kelly D. Pearce was served on the persons stated below via electronic mail, this 13th day of September 2011.

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