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August 31, 2011

Chairman Todd A. Snitchler
Public Utilities Commission of Ohio
Ohio Power Siting Board
180 East Broad Street
Columbus, Ohio 43215-3793

Matthew J. Satterwhite
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RE:

In the Matter of the Commission Review of the Capacity Charges of Columbus Southern Power Company and Ohio Power Company	Case No. 10-2929-EL-UNC

Dear Chairman Snitchler:

Attached please find the testimony of Columbus Southern Power Company and Ohio Power Company (AEP Ohio) witnesses in the above listed docket required to be filed today in the procedural schedule issued in the August 11, 2011 Entry. Those witnesses providing pre-filed direct testimony are:

Richard E. Munczinski
William A. Klun
Frank C. Graves
Dana E. Horton
Kelly D. Pearce

Please contact me if there are any questions.

Cordially,

Matthew J. Satterwhite
Senior Counsel

Testimony attached

This is to certify that the images appearing are an accurate and complete reproduction of a case file document delivered in the regular course of business.
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CERTIFICATE OF SERVICE

I hereby certify that this letter and the testimony accompanying it was served by electronically pursuant to the August 11, 2011 Entry in this case, upon counsel for the entities below on this August 31, 2011.

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FILE

EXHIBIT NO. ______

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

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

DIRECT TESTIMONY OF
KELLY D. PEARCE
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

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Filed: August 31, 2011

INDEX TO DIRECT TESTIMONY OF
KELLY D. PEARCE

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT 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 Companies.

PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to first discuss the market structure and capacity obligations that require the use of CSP's and OPCo's generation capacity and the costs associated with this capacity used to support generation service to switching customers. I will then introduce, describe and support the formula rates proposed by CSP and OPCo. These rates, if adopted, would be utilized to compensate AEP Ohio for capacity that is used by Competitive Retail Electric Service (CRES) providers to serve the former AEP Ohio generation customers in cases where the CRES providers choose not to provide their own capacity. In addition, I will explain some of the specific shortcomings of the use of the PJM Interconnection, L.L.C (PJM) Reliability Pricing Model (RPM) capacity clearing prices as a pricing mechanism for this capacity.

EXHIBITS

Q. ARE YOU SPONSORING ANY EXHIBITS IN THIS PROCEEDING?

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

Exhibit KDP-1: Formula Template for CSP,

Exhibit KDP-2: Formula Template for OPCo,

Exhibit KDP-3: Formula Template for CSP populated with 2010 data,

Exhibit KDP-4: Formula Template for OPCo populated with 2010 data,

Exhibit KDP-5: Energy credit for CSP and OPCo,

Exhibit KDP-6: Merged CSP and OPCO Capacity Value

Exhibit KDP-7: PJM Capacity Values

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

A. Yes.

APPLICABLE MARKET AND CAPACITY OBLIGATION

Q. WHAT IS THE RATIONALE FOR THE FORMULA RATES PROPOSED?

A. As explained by AEP Ohio witnesses Munczinski and Horton, 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 Companies are self-supplying their 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. UNDER THE FRR OPTION HOW LONG IS THE COMMITMENT TO PROVIDE CAPACITY TO CRES PROVIDERS?

A. In accordance with PJM rules AEP Ohio must make this commitment three years in advance. The Companies are then fully committed and locked-in to providing the capacity resources needed for all of the loads that are contained in their forecasted load requirement, plus the additional capacity necessary to satisfy the required Installed Reserve Margin (IRM).

Q. HOW DOES RETAIL CHOICE IMPACT THIS PROCESS?

A. At the time the Companies complete their PJM FRR capacity plan, they must include all forecasted retail loads within the AEP Zone, which are then used to determine the capacity obligation. Subsequently, if CRES providers sign up any of these loads, the CRES providers are required and obligated to reimburse the Companies for their capacity costs that have already been committed to serve this load during the PJM Planning Year (PY) that is for the 12-month period from June to May.

Q. IS THERE ANY EXCEPTION THAT ALLOWS AEP OHIO TO REDUCE ITS CAPACITY OBLIGATION TO ACCOUNT FOR LOADS SERVED BY CRES PROVIDERS?

A. Yes, there is one exception. If a CRES provider notifies AEP Ohio prior to the submittal of its capacity plan for a future planning year, which occurs three years before delivery, that the CRES provider will supply its own generation capacity for that year, then AEP Ohio may reduce its own capacity resources by an equivalent amount for that year. The CRES provider may elect this option for load it has already signed up for the applicable planning year and/or for load it anticipates serving or hopes to sign up in the three years prior to the applicable planning year.

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

A. It is unchanged. 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 continues to maintain and provide the capacity resources for shopping customers, but no longer receive these customers' generation revenues.

Q. IS THERE ANY COMPENSATION MADE TO AEP OHIO FOR THIS CAPACITY COMMITMENT?

A. Under the Commission's current interim compensation mechanism, CRES providers reimburse AEP Ohio a capacity payment that is based on the RPM clearing price.

Q. DO THESE PAYMENTS PROVIDE AN APPROPRIATE LEVEL OF COMPENSATION?

A. No, they do not provide an appropriate level of compensation. CRES providers have chosen to use the capacity of AEP Ohio, as opposed to self supplying capacity, and as such should fairly compensate the Companies for the cost of that capacity. The formula rate that I describe below provides fair and appropriate compensation for use of the Companies' capacity.

FORMULA RATE DESCRIPTION

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

A. CSP and OPCo utilized a formula 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 $/MegaWatt-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 Companies are providing their 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 FORMULA RATE APPROACH?

A. Formula rates are currently utilized in many states by AEP for other wholesale sales. As previously stated, the formula rates use an average allocation of cost between the parties based on common cost allocation mechanisms.

Second, the formula 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 the companies and the various work papers are readily available to the affected parties upon request for rate verification. What are approved as the rates are the formulas themselves. 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 Companies proposal, rates will be known prior to the beginning of a given PJM PY.

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

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

Q. HOW ARE THE RATES UPDATED?

A. Under AEP Ohio's proposal, the Companies will utilize a given year's FF1 annual report shortly after it is available to update the capacity rates that will be available for the subsequent PJM PY. For example, once the 2011 FF1 becomes available, currently required by FERC no later than April 18, 2012, AEP Ohio will update the capacity rates and have them available no later than May 31, 2012. These are the rates that will be in effect for the PJM PY 2012/2013 that runs from June 1, 2012 through May 31, 2013. The same process will be used for each subsequent year as long as such rates are in effect.

CAPACITY RATE

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

A. The blank or unpopulated formula rate templates for the Companies 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. This is the same calculation performed today by AEP to bill CRES providers for load they are currently serving. 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 Companies' 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 will 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.

Q. ARE THERE ANY DIFFERENCES RELATIVE TO THE FERC-APPROVED TEMPLATES FOR MINDEN AND PRESCOTT?

A. Yes. The Company has made three significant modifications to the templates relative to the capacity portion of the rates approved at FERC:

- the peaks used to determine the capacity rates,
- the Return on Equity (ROE), and
- the elimination of a post-period reconciliation and the resulting use of end-of-year account balances rather than annual average amounts.

Q. PLEASE DESCRIBE THE FIRST CAPACITY MODIFICATION.

A. As noted on page 2 of Exhibits KDP-1 and KDP-2, the denominator is based on the average CSP and OPCo peak demands that are coincident with the PJM five highest daily summer peak demands. This is appropriate in order to be consistent with the demands used to charge CRES providers today through the PJM settlement process.

Q. PLEASE DESCRIBE THE SECOND CAPACITY MODIFICATION.

A. The ROE approved in the original template was 11.10%. The ROE has been modified to a fixed 11.15% to be consistent with the ROE proposed in CSP's and

OPCo's pending distribution proceedings, Case Numbers 11-0351-EL-AIR and 11-0352-EL-AIR supported by AEP Ohio witness Avera. Unlike the other formula inputs that will be updated annually, AEP Ohio proposes that the ROE remain fixed for the term that this rate is applicable, absent any appropriate regulatory filing or filings to modify the ROE.

Q. PLEASE DESCRIBE THE THIRD CAPACITY MODIFICATION.

A. The capacity formula rates are traditionally reconciled for other wholesale customers between the rates charged and revenues collected during a period and the actual costs incurred by the seller during that same period, computed after the fact. This is performed by collecting or crediting the difference between these revenues and actual costs in a subsequent period, commonly referred to as a "true-up". This is appropriate for the other wholesale customers so that no under- or over-collection occurs and the seller ultimately collects the precise costs incurred to serve these customers. However, the formula rates for other wholesale customers are generally applied under long-term contracts.

Because it would be impractical and administratively burdensome to perform such a true-up with CRES providers, who can enter and leave the market at will and are likely to have load that is changing over the period due to customer switching, AEP Ohio is not proposing any such reconciliation. This results in a benefit to CRES providers as well since it would not result in a source of uncertainty regarding their capacity rate over the period.

In other words, as an example, the 2011 FF1 actual accounting data will be used to determine the capacity rate charged to CRES providers for the PJM PY

2012/2013 with no subsequent reconciliation or true-up. This will provide rate certainty for CRES providers during the planning year. However, since there is no true-up, the lag between the historic costs and actual costs for the rate-effective period should be minimized as much as practical. Consequently, CSP and OPCo propose to utilize only the end-of-year rate base balances for the formula calculations rather than average annual values from the historic period. The end-of-year rate base balances will be closer to the rate base in effect during the applicable PJM PY than an average rate base which uses more dated balances. Even this end-of-year balance may potentially understate the average rate base for the PJM PY in which these capacity rates are in effect.

ENERGY CREDIT

Q. IS AEP OHIO PROPOSING AN ENERGY CREDIT AS ON OFFSET TO THE CAPACITY RATES?

A. No, it is not.

Q. WHY IS SUCH AN ENERGY CREDIT OFFSET UNWARRANTED?

A. PJM has completely separated the markets for capacity and energy in contrast to traditional generation sources that combine the sourcing of enough power to satisfy the peak and on-going customer demands, measured in MegaWatts (MWs) or kiloWatts (kWs) with enough of that power integrated over time to satisfy customers' energy requirements, measured in MegaWatt-hours (MWhs) or kiloWatt-hours (kWhs). As a result, obtaining capacity through PJM's RPM market or through a FRR plan does not provide any rights or a call option on energy at any price. Energy must be separately procured by all PJM load-serving entities. Consequently, the capacity rates proposed by AEP Ohio are appropriate for charging CRES providers.

Q. IF THE PUBLIC UTILITIES COMMISSION OF OHIO SHOULD CHOOSE TO ADOPT AN ENERGY CREDIT, DO YOU HAVE ANY COMMENTS REGARDING HOW SUCH A CREDIT SHOULD BE DETERMINED?

A. Yes I do. While AEP Ohio is not proposing an energy credit, it is only proposing a methodology to be used should the Commission choose to adopt such a credit. In addition to the formula rate template proposed by AEP Ohio for capacity, the Companies have also included a template for the calculation of the energy costs, including fuel, used to serve formula rate customers' energy requirements. This calculation can be easily adapted for the purpose of determining the amount of such an energy credit if such a capacity rate reduction is adopted by this Commission. It is part of the same template accepted by FERC for the Cities of Minden and Prescott and therefore is consistent with the capacity portion of the formula and has also undergone the same regulatory scrutiny.

Q. HOW WOULD SUCH AN ENERGY CREDIT BE DETERMINED?

A. The formula rate templates are generally offered to customers under long term, multi-year agreements for full requirements service and therefore require these other wholesale customers to purchase energy for their own load at a rate tied to the applicable operating company's energy cost. Such a right and obligation will not exist for CRES providers once they become the Load Serving Entity (LSE) for shopping customers. CRES providers compensate AEP Ohio for the Companies' capacity in only one-year, short-term, increments. AEP Ohio's proposal is straightforward. Simply put, the energy credit is the difference between market-based revenues and the Companies' energy cost.

Q. PLEASE EXPLAIN.

A. The credit is calculated as the difference between the revenues that the CSP and OPCo historic load shapes, including all shopping and non-shopping load, would be valued at using the hourly Locational Marginal Prices (LMP) that settle in the PJM Day-Ahead (DA) market, less the cost-basis of this energy. The 2010 energy cost-basis rates are provided in Exhibits KDP-1 through KDP-4. The energy credit revenues and final energy credit are provided in KDP-5.

Q. PLEASE DESCRIBE THE REVENUE CALCULATION.

A. The previous year's hourly load for CSP and OPCo would be collected following the end of a given year along with the hourly AEP GenHub prices based on the actual PJM DA LMPs. The total market-based revenue is simply the product of the hourly loads and the hourly LMPs summed across the entire year. This represents a fair and reasonable proxy for the energy revenue that could have been obtained by CSP and OPCo by selling equivalent generation into the market rather than utilizing it to directly serve load.

Q. WHY DID CSP AND OPCO SELECT THE ENTIRE LOAD SHAPE OF SHOPPING AND NON-SHOPPING LOAD?

A. First, attempting to provide an individual energy credit for each CRES provider for the load they serve would be administratively burdensome and extremely difficult to compute on an ongoing basis. In addition, given that there will be a lag between the time period for which the energy credit is computed and the time period to which it is applied, it would provide gaming opportunities for CRES providers.

Q. PLEASE DESCRIBE THE COST BASIS OF THE ENERGY.

A. The cost basis would be the energy rate computed using the same formula rates described for capacity, which provides for a consistent and straightforward solution. All of the formula rate benefits described previously during the capacity discussion apply equally well to energy -- they provide the same level of transparency and have already undergone, and easily accommodate, regulatory scrutiny.

Q. IS AEP OHIO PROPOSING ANY MODIFICATIONS TO THE ORIGINAL TEMPLATES USED FOR SUCH AN ENERGY COST COMPUTATION?

A. Yes. AEP Ohio is proposing the following two modifications to the template used for the other wholesale customers if an energy credit is adopted:

- no deferrals of costs, and
- no off-system sales (OSS) margin sharing.

Q. PLEASE DESCRIBE THE FIRST ENERGY MODIFICATION.

A. From an economic dispatch perspective, the cost-basis of the energy credit should be the actual, non-deferred cost, particularly of fuel. No consideration should be given for fuel costs that are deferred for later collection. This most accurately reflects the actual commercial operation of AEP Ohio's generation units in the PJM energy market. As a consequence, this also would lead to the most accurate determination of a suitable proxy for the energy value of the load shape associated with the CSP and OPCo loads. It would eliminate timing differences between when deferrals are incurred and when they are recovered. For long-term contracts, customers likely incur both sides of the transaction. For CRES providers, their load may vary greatly from period to period and elimination of the deferrals will ensure that they would neither be advantaged nor disadvantaged by the timing differences of such deferrals and subsequent recoveries.

Q. PLEASE DESCRIBE THE SECOND ENERGY MODIFICATION.

A. AEP Ohio would determine an energy credit for the load shape only, which makes this consistent with retail customers taking service under CSP's and OPCo's standard service offers. While it may be viewed by some as reasonable to provide an energy credit based on CSP and OPCo loads, it would not be reasonable to provide yet an additional credit for other sales that would be made beyond that load. As stated previously, the capacity component of the rate already includes a credit for other capacity sales. Consequently, CRES providers would not be charged for surplus capacity that may be utilized to generate other OSS.

Q. ONCE THE VALUE OF THE ENERGY BASED ON THE LOAD SHAPE IS COMPUTED, DOES AEP OHIO PROPOSE ANY ADJUSTMENTS TO THAT ENERGY CREDIT?

A. Yes. The energy value is computed as though it were the result of an incremental energy sale. Consequently, it would be appropriate to apply the same type of sharing to this value for purposes of obtaining and providing an energy credit if one is adopted.

First, the energy value of such a credit must be treated as though it were an OSS for purposes of sharing through the AEP Interconnection Agreement (IA). The IA requires that OSS are shared between the AEP operating companies that are part of this agreement. As a result, while AEP-Ohio retains the generation revenues from its non-shopping customers, it would only receive an allocated share from any resulting incremental energy sale. The IA allocator for such sales is the Member Load Ratio (MLR) for CSP and OPCo.

Second, OPCo would subsequently allocate a portion of its MLR-share of such an energy sale to the West Virginia jurisdiction due to its firm, full requirements wholesale contract with Wheeling Power Company, an AEP Operating Company.

Third, AEP Ohio proposes that any energy credit be further reduced by 50% to reflect the margin sharing percentage used above the base in the Minden and Prescott templates. CRES providers who purchase capacity on a year-to-year basis should not receive the full offset received by long term full requirements wholesale customers.

Q. SHOULD THERE BE ANY LIMITS TO THE ENERGY CREDIT IF IT IS ADOPTED?

A. Yes. The energy credit computed as described above should further be capped at 40% of the capacity charge that would be applicable with no energy credit. The reason for this is that in high price wholesale periods, the energy credit could get so large as to greatly reduce any capacity payment whatsoever from CRES providers. Such a result would be a clear subsidy to these CRES providers. Wholesale markets are volatile and the capacity rates proposed have a lag. Consequently, CRES providers could simply wait until a high energy price market period has come and gone and subsequently obtain capacity at extremely low rates due to an excessive energy credit, perhaps when the value of such energy is much lower.

In addition, the energy credit is only a proxy. AEP Ohio would utilize information from the previous year as though it did not serve the entire internal load of CSP and OPCo and instead sold an equivalent hour-by-hour amount of energy into that market during the period. However, that clearly did not happen, at least up through 2011, since AEP Ohio did serve or is serving most of that energy. In a very strong wholesale market, retail choice may be less and AEP Ohio will serve much if not most of the load. Clearly, daily market-based revenues cannot be extracted from generation that is serving the AEP Ohio load. Consequently, applying no cap whatsoever could result in an overstated proxy for the energy credit, with the amount of the overstatement likely to correlate somewhat with the level of wholesale prices. In consideration of AEP Ohio's exposure to the variations in historic-versus-current pricing and amount of energy served without seeking any true-up, the energy credit cap and resulting capacity charge floor affords some protection for the Companies through the collection of at least 60% of the capacity costs they incur. In return, CRES providers may still get the benefit of very large energy credits for capacity.

Q. HOW WAS THE 40% CAP ON THE ENERGY CREDIT AND RESULTING 60% FLOOR ON THE CAPACITY CHARGE TO CRES PROVIDERS OBTAINED?

A. While AEP Ohio proposes no energy credit, the 40% energy credit cap and resulting 60% floor of the capacity rate were selected by AEP Ohio as fair and reasonable values if the Commission should adopt this credit. Further, as will be shown later, this level of credit cap represents more than twice the largest energy credit adjustment that has ever been determined for the computation of similar credits for new entrants in the PJM market.

PROPOSED CAPACITY RATES

Q. PLEASE PROVIDE THE CAPACITY COMPENSATION RATES PROPOSED BY THE COMPANIES.

A. The formula rate templates shown in Exhibits KDP-1 and KDP-2 have been populated with information from the 2010 CSP and OPCo FF1s. These populated templates are shown in Exhibits KDP-3 and KDP-4 for CSP and OPCo respectively. As seen on page 1 of Exhibits KDP-3 and KDP-4, the capacity compensation rates proposed by the Companies are $327.59/MW-day for CSP and $379.23/MW-day for OPCo. If approved by the Commission, these capacity rates would be applicable for the remainder of the PJM PY 2011/2012 that runs through May 31, 2012. These rates would be updated each spring as previously described for the subsequent PJM PY. The first update would occur using 2011 FF1 information for the PJM PY that begins June 1, 2012.

Q. IF THE COMMISSION ADOPTS AN ENERGY CREDIT USING AEP OHIO'S METHODOLOGY, WHAT IS THE RESULTING ENERGY CREDIT?

A. The 2010 energy credits using the AEP Ohio methodology is shown in Exhibit KDP-5. 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 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. ARE THERE ANY OTHER BENEFITS THAT RESULT FROM THE PROPOSED RATES?

A. Yes. Another benefit to AEP Ohio's proposal is that the individual Companies' rates can be easily combined into a single AEP-Ohio rate. The Companies are currently seeking regulatory approval for their merger. If approved by the Commission, the rates can easily be combined to provide a single merged rate applicable to CRES providers. For example, as shown in Exhibit KDP-6, 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. Following the merger, AEP Ohio would only file one FF1 and it would be the basis for computing the updated FRR capacity compensation rate.

In addition, AEP Ohio's Electric Security Plan (ESP) is currently under consideration by the Commission. This proposal includes various non-bypassable riders related to capacity costs. To the extent these riders are adopted by the Commission, some costs will be born directly by all end-use customers. In that event, the formula rates as proposed are well positioned to accommodate corresponding adjustments as necessary to ensure that any capacity-related amounts collected through non-bypassable riders are removed from the capacity charges. For example, any costs collected through the proposed non-bypassable Environmental Investment Carrying Cost Rider (EICCR) would be removed from the CRES provider capacity charge. All such adjustments will be readily available for regulatory inspection.

RATE COMPARISONS

Q. WOULD YOU COMPARE THE PROPOSED RATES WITH THE PJM RATES?

A. Yes. The past, present and future RPM rates are shown in Table I below.

Table I - PJM Capacity Market Values

Values based on Unforced Capacity (UCAP) MW

All Capacity Values are expressed in $/MW-day

PJM Planning Year	Gross CONE ($/MW-day)	Net CONE ($/MW-day)	RPM BRA Clearing ($/MW-day)	Final Zonal Capacity Price[2] ($/MW-day)	Billed RPM Capacity Rate ($/MW-day)
2007/2008	$210.26	$171.87	$40.80	$40.80	$46.73
2008/2009	$210.73	$172.25	$111.92	$111.92	$129.71
2009/2010	$210.73	$172.27	$102.04	$104.82	$126.33
2010/2011	$210.93	$174.29	$174.29	$182.85	$220.96
2011/2012	$210.35	$171.40	$110.00	$116.16	$145.79
2012/2013[1,3]	$330.51	$276.09	$16.46	$16.52 [3]	$20.01 [3]
2013/2014[1]	$357.41	$317.95	$27.73	TBD	$33.71
2014/2015[1]	$374.72	$342.23	$125.99	TBD	$153.89

CONE = Cost of New Entry

BRA= Base Residual Auction

Notes

[1] Future planning periods utilize preliminary scaling factors.

[2] Includes the affects of incremental auctions and ILR.

[3] Include the first and second incremental auction results but are not yet final.

Exhibit KDP-7 includes these same values along with various other 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).

The current capacity rate charged to CRES providers is shown in the last column of Table I above and column (l) of Exhibit KDP-7 and is $145.79/MW-day.

Consequently the capacity rates proposed by AEP Ohio would represent a 125% ($327.59/$145.79) increase for CSP and a 160% ($379.23/$145.79) increase for OPCo.

It should be noted that, while the proposed capacity rates represent large increases relative to the current and future RPM prices shown in column (l) of Exhibit KDP-7, the AEP Ohio proposed capacity rates are 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-7.

In addition, the Net CONE value is trending upward significantly. As shown in Table I and 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 referenced by AEP Ohio witness Horton that the RPM capacity prices will tend, on average, to clear near the NCONE value, then the Companies' proposed capacity compensation rates approach these same future values.

Q. DO YOU HAVE ANY COMPARISONS TO MAKE REGARDING AEP OHIO'S PROPOSED CAP ON THE ENERGY CREDIT IF SUCH A CREDIT IS ADOPTED?

A. Yes. As mentioned earlier, AEP Ohio proposes that if the Commission adopts an energy credit, then the energy credit should be capped at no more than 40% of the capacity rate without the credit. As shown in Table I and Exhibit KDP-7, the Gross-to-Net Adjustments (shown in column (e) in Exhibit KDP-7) are always less than 20% of the Gross CONE values (shown in column (c) of Exhibit KDP-7). This adjustment is the result of an energy credit being applied to the Gross CONE. Consequently, capping the AEP Ohio energy credit at 40% of the capacity rates without the energy credit will provide the potential for more than twice the energy adjustments that have thus far ever been made in reducing Gross CONE to Net CONE.

CRES PROVIDER SELF-SUPPLY OPTION

Q. HOW WILL THE CRES PROVIDER SELF-SUPPLY OPTION BE ACCOMMODATED AND SETTLED?

A. As stated previously, CSP's and OPCo's capacity rates are avoidable or by-passable by CRES providers if they supply capacity to meet their own loads prior to the Companies submitting their FRR plan three years prior to the delivery year.

Q. IF A CRES PROVIDER COMMITS LESS CAPACITY THAN IT NEEDS FOR A GIVEN PJM PLANNING YEAR, HOW WILL THE COST OF THE SHORTFALL BE COMPENSATED?

A. The cost of any shortfall would be addressed in the same manner as though the CRES provider did not provide any capacity. The MWs of the shortfall will be compensated at the Companies' proposed rates. For example, if a CRES provider serves 100 MW of capacity and chooses to self-supply none of it, the provider would pay for 100 MW at the proposed capacity rates. If the CRES Provider self-supplies 100 MW and then serves 150 MW during the PY, the CRES provider will compensate CSP and OPCo for 50 MW at the proposed capacity rates.

Q. IF A CRES PROVIDER COMMITS MORE CAPACITY THAN IT SUBSEQUENTLY NEEDS FOR A GIVEN PJM PY FOR THE LOAD IT SERVES AND THE OBLIGATION REMAINS WITH OR GOES BACK TO CSP AND OPCO, HOW WILL CSP AND OPCO ACCOMMODATE THIS LOAD?

A. If a CRES provider commits capacity to serve load, and then AEP Ohio must wind up serving a portion of that load as currently required, AEP Ohio will make their best efforts to provide or obtain the shortfall capacity necessary to serve this load at the least expensive cost possible. This will benefit all customers.

Q. SHOULD THE CRES PROVIDER WHO OVER-COMMITTED CAPACITY MAKE THIS CAPACITY AVAILABLE TO AEP OHIO?

A. Yes. In the event of this scenario, since CSP and OPCo by direction of the CRES provider reduced their own capacity obligations and then subsequently are required to reacquire these obligations, the CRES provider should be obligated to make the capacity available to AEP Ohio. This availability should be in the form of a call option, which is the right, but not an obligation, to purchase this capacity from the CRES provider. The strike price of the call option, which is the price at which the transaction occurs if the holder of the call option elects to exercise it, should be the lower of the final RPM price or the applicable capacity rate of the Companies. In other words, AEP Ohio may unilaterally obtain the capacity from another source or purchase it from the CRES provider at the strike price.

Q. WHY SHOULD THE STRIKE PRICE BE SET AT THE LOWER OF RPM PRICE OR THE CAPACITY RATE?

A. The CRES provider may unilaterally, and with no input from AEP Ohio whatsoever, provide however much capacity that it believes it will serve during the applicable planning year. There should be no incentives for CRES providers to (a) supply capacity with which they have no earnest interest in serving load but instead commit it only to cause AEP Ohio to lower its own obligations and then (b) to sell this capacity to AEP Ohio when the Companies become short capacity for reasons created by the same CRES providers. Such actions, I believe, are not inconsistent with actions alleged years ago in the California energy market that generation owners purposely withheld generation from the spot market only until the market was higher and then sold it back into that market. Similarly, CRES providers should not be given the incentive to purposely create a capacity shortage for AEP Ohio and then profit from it.

Consequently, AEP Ohio should be under no obligation to purchase the capacity, even at the strike price, if they can provide or acquire capacity less expensively. If capacity is not available at a lower rate, the CRES provider should be under the obligation to sell the surplus capacity to AEP Ohio at the lower of the RPM price or CSP's and OPCo's capacity rate if such capacity cannot be located at a less expensive price elsewhere. If AEP Ohio does not exercise the option to purchase the excess capacity from the CRES provider, the CRES provider may dispose of the surplus capacity in anyway it sees fit, such as selling it to a third party, provided such disposition is permitted by all applicable PJM and/or state rules. This combination would provide the most benefit to the Ohio customers.

Q. IS THIS TREATMENT CONSISTENT WITH THE REST OF THE CSP AND OPCO PROPOSAL?

A. Yes it is. Some may argue that the payments between CSP and OPCo and CRES providers for this capacity should somehow be "symmetrical" in that they should be at the same rate, whether it be at an RPM rate or a CSP and OPCo or other rate. The fact is that the obligations and opportunities of AEP Ohio and CRES providers regarding serving load are not symmetrical. CSP and OPCo *must* provide capacity for all of the loads within their service territories that CRES Providers *choose* not to serve. Subsequently, CSP and OPCo then *must* accept back load obligations which CRES providers *choose* not to sign up during the applicable planning year for whatever reason.

Q. DOES AEP OHIO HAVE ANY PROPOSALS REGARDING THE ABILITY OF CRES PROVIDERS TO SELF-SUPPLY THEIR OWN CAPACITY?

A. In addition to the constraints described above, AEP Ohio proposes that each individual CRES provider be limited to supplying no more capacity for a given PJM PY than twice the capacity that is required to serve the load that the CRES provider is actually serving on January 1 of the year in which the FRR Plan for that planning year is submitted to PJM.

For example, if a CRES provider is currently serving load that requires 100 MW of capacity on January 1, 2012, that CRES provider may elect to self-supply up to 200 MW of capacity into the applicable FRR plan for the 2015/2016 PY that will be submitted during the first quarter of 2012. This limit would allow each CRES provider to self-supply approximately 25% more load each planning year.

OTHER ISSUES

Q. DO YOU HAVE ANY OTHER COMMENTS YOU WOULD LIKE TO MAKE ABOUT THE CSP AND OPCO FORMULA RATE PROPOSAL?

A. Yes. I understand that there is an open question regarding these capacity payments in terms of the appropriate jurisdictional forum, either this Commission or the FERC. While this appears to be a legal question best argued among the attorneys, it is my layman's understanding that much of these arguments may depend on whether these transactions are considered wholesale or retail.

Simply that I believe these to be wholesale transactions for capacity between AEP Ohio and the CRES providers. As such, it is hoped that, speaking from an operational rather than a legal viewpoint, the Commission will either affirm these transactions as wholesale and/or to designate them as wholesale transactions going forward.

Under AEP Ohio's proposal, CRES providers may self-supply their own capacity rather than obtain it from AEP Ohio as previously described. If these capacity transactions are designated as retail, it is assumed that the option to provide capacity, rather than purchase capacity from AEP Ohio, must then be eliminated. This is assumed since it is not clear how such an option could be accommodated if it is retail customers, rather than CRES providers, who are supplying their own capacity.

Q. DO YOU HAVE ANY OTHER COMMENTS?

A. Yes. CSP and OPCo were required to make an initial minimum five-year commitment under either RPM or FRR. Consequently, there is no cause for concern regarding AEP Ohio frequently moving between these two capacity options based on the applicable rates. Should the Companies choose to move to the RPM market, under the current PJM rules, it will be for a minimum of five years and cannot begin until the next auction period.

Further, for those who may suggest that AEP Ohio should move to RPM, this does not appear to me to be the forum to discuss such a move. Right now, PJM does allow a self-supply option, the Companies chose that option for reasons stated by AEP Ohio witness Horton, and AEP Ohio is currently locked into that option through at least PJM PY 2014/2015. Attempting to include a lengthy debate into this proceeding on the appropriate past, present and future option for AEP Ohio, i.e., RPM or FRR, would simply cloud the fundamental question that must now be determined within the scope of this proceeding, namely, the appropriate reimbursement for the Companies for their own capacity provided to CRES providers while they are under the FRR plan.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes it does.

EXHIBIT KDP-1

B-1

Exhibit KDP-1

CAPACITY (FIXED) CHARGE CALCULATION

CSP

12 Months Ending 12/31/2###

	RATE $/MW/Day (1)	LOSS FACTOR (2)	Final FRR Rate (1) x (2) (3)
Capacity Daily Charge:			
1. Reference	P.2		Col (1) x (2)
2. Amount	$	#	$

B-2

DETERMINATION OF RATES APPLICABLE TO

CSP'S CAPACITY REQUIREMENTS

12 Months Ending 12/31/2###

1. Capacity Daily Rates

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

$$\frac{\$}{\# \quad /365} = \$$$

Where: Annual Production Fixed Cost, P.4

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

B-3
Generator Step Up Transformer Workpaper
12 Months Ending 12/31/2###

Exhibit KDP-1

		Reference	
1.	GSU & Associated Investment	Note A	$
2.	Total Transmission Investment	FF1, P.207, L.58, Col.g	$
3.	Percent (GSU to Total Trans. Investment)	L.1 / L.2	%
4.	Transmission Depreciation Expense	FF1, P.336, L.7, Col.b	$
5.	GSU Related Depreciation Expense	L.3 x L.4	$
6.	Station Equipment Acct. 353 Investment	FF1, P.207, L.50, Col.g	$
7.	Percent (GSU to Acct. 353)	L.1 / L.6	%
8.	Transmission O&M (Accts 562 & 570)	FF1,P.321, L. 93, Col.b, and L.107, Col.b	$
9.	GSU & Associated Investment O&M	L.7 x L.8	$

Note A: Workpapers -- tab WP-16

B-4

ANNUAL PRODUCTION FIXED COST

12 Months Ending 12/31/2###

		Reference	PRODUCTION Amount
1.	Return on Rate Base	P.5, L.19, Col.(2)	$
2.	Operation & Maintenance Expense	P.14, L.15, Col.(2)	$
3.	Depreciation Expense	P.16, L.11, Col.(2)	$
4.	Taxes Other Than Income Taxes	P.17, L.5, Col.(2)	$
5.	Income Tax	P.18, L.5, Col.(2)	$
6.	Sales for Resale	Note A	$
7.	Ancillary Service Revenue	Note B	$
8.	Annual Production Fixed Cost	Sum (L.1 : L.5) - (L.6 + L.7)	$

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

Note B: Workpapers -- tab WP-2

B-5

RETURN ON PRODUCTION-RELATED INVESTMENT

12 Months Ending 12/31/2###

		Reference	Amount (1)	Demand (2)	Energy (3)
1.	ELECTRIC PLANT				
2.	Gross Plant in Service	P.6, L.4, Col.(2)	$	$	$
3.	Less: Accumulated Depreciation	P.6, L.11, Col.(2)	$	$	$
4.	Net Plant in Service	L.2 - L.3	$	$	$
5.	Less: Accumulated Deferred Taxes	P.6, L.12, Col.(2)	$	$	$
6.	Plant Held for Future Use	Note A	$	$	$
7.	Pollution Control CWIP	Note B	$	$	$
8.	Non-Pollution Control CWIP (50%)	Note B	$	$	$
9.	Subtotal - Electric Plant	L.4 - L.5 + L.6 + L.7 + L.8	$	$	$
10.	WORKING CAPITAL				
11.	Materials & Supplies				
12.	Fuel	P.9, L.2, Col.(2)	$	$	$
13.	Nonfuel	P.9, L.8, Col.(2)	$	$	$
14.	Total M & S	L.12 + L.13	$	$	$
15a.	Prepayments Nonlabor (Note C)		$	$	$
15b.	Prepayments Labor (Note C)		$	$	$
15c	Prepayments Total (Note C)		$	$	$
16.	Cash Working Capital	P.8, L.7, Col.(2)	$	$	$
17.	Total Rate Base	L.9 + L.14 + L.15c + L.16	$	$	$
18.	Weighted Cost of Capital	P.11, L.4, Col.(4)	%	%	%
19.	Return on Rate Base	L.17 x L.18	$	$	$

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.

B-6

PRODUCTION-RELATED

ELECTRIC PLANT IN SERVICE, ACCUMULATED DEPRECIATION AND ADIT

12 Months Ending 12/31/2###

		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	$		$	$	$
3.	Allocated General & Intangible Plant			P.7, Col(3), L.28	$	$	$
4.	Total	L.2 + L.3	$		$	$ %	$
5.				Col.(2), L.4	$	$	$
6.				Col.(1), L.4	$	$	$
7.			%		%	%	%
8.	ACCUMULATED PROVISION FOR DEPRECIATION (Note A)						
9.	Plant in Service (Note D)		$	FF1, P.200, L.22	$	$	$
10.	Allocated General Plant		$	Note B	$	$	$
11.	Total	L.9 + L.10			$	$	$
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	$	Exhibit KDP-1, P	$	$	$

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
12 Months Ending 12/31/2###

	Account	Description	Year End Balance	Exclusions	100% Production (Energy Related)	100% Production (Demand Related)	Labor
1	190	Excluded Items	$	$			
2	190	100% Production (Energy)	$		$		
3	190	100% Production (Demand)	$			$	
4	190	Labor Related	$				$
5	190	Total	$	$	$	$	$
6		Production Allocation		%	%	%	%
7		(Gross Plant or Wages/Salaries)		$	$	$	$
8		Demand Related			$	$	$
9		Energy Related			$	$	$
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)	$			$	
14	281	Labor Related	$				$
15	281	Total	$	$	$	$	$
16		Production Allocation		%	%	%	%
17		(Gross Plant or Wages/Salaries)		$	$	$	$
18		Demand Related			$	$	$
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)	$			$	
24	282	Labor Related	$				$
25	282	Total	$	$	$	$	$
26		Production Allocation		%	%	%	%
27		(Gross Plant or Wages/Salaries)		$	$	$	$
28		Demand Related			$	$	$
29		Energy Related			$		$
30		Allocation Basis			Direct	B-6, L. 7	B-7, Note B
31	283	Excluded Items	$	$			
32	283	100% Production (Energy)	$		$		
33	283	100% Production (Demand)	$			$	
34	283	Labor Related	$				$
35	283	Total	$	$	$	$	$
36	283	Production Allocation		%	%	%	%
37		(Gross Plant or Wages/Salaries)		$	$	$	$
38		Demand Related			$	$	$
39		Energy Related			$	$	$
40		Allocation Basis			Direct	B-6, L. 7	B-7, Note B

41	Summary Production Related AD	Total	Demand	Energy
42	100% Production (Energy)	$	$	$
43	100% Production (Demand)	$	$	$
44	Labor Related	$	$	$
45	Total	$	$	$

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

B-7

PRODUCTION-RELATED GENERAL PLANT ALLOCATION

12 Months Ending 12/31/2###

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	$	$	$
4. General Offices	0		$	$	$
5. Total Land	3,247,961		$	$	$
6			$	$	$
7. Structures	59,827,362	Note B	$	$	$
8. General Offices	0		$	$	$
9. Total Structures	59,827,362		$	$	$
10			$	$	$
11. Office Equipment	5,273,610	Note B	$	$	$
12. General Offices			$	$	$
13. Total Office Equipment	5,273,610		$	$	$
14. Transportation Equipment	39,411	Note B	$	$	$
15. Stores Equipment	301,966	Note B	$	$	$
16. Tools, Shop & Garage Equipment	10,608,244	Note B	$	$	$
17. Lab Equipment	631,927	Note B	$	$	$
18. Communications Equipment	14,715,288	Note B	$	$	$
19. Miscellaneous Equipment	1,608,064	Note B	$	$	$
20. Subtotal	96,253,833		$	$	$
21. PERCENT		Note C	%	%	%
22. Other Tangible Property					
23. Fuel Exploration	3,036	Note D	$	$	$
24. Rail Car Facility	0	Note D	$	$	$
25. Total Other Tangible Property	3,036		$	$	$
26. TOTAL GENERAL PLANT FF1, P.207	96,256,868		$	$	$
27. INTANGIBLE PLANT	60,243,856	Note B	$	$	$
28. TOTAL GENERAL AND INTANGI	156,500,724		$	$	$
29. PERCENT		Note E	%	%	%
30. Total General and Intangible	156,500,724		$	$	$
31. Exclude Other Tangible (Railcar and Fuel Exploration)	(3,036)		$	$	$
32. Net General and Intangible	156,497,689		$	$	$
33. PERCENT			%	%	%

B-7

PRODUCTION-RELATED GENERAL PLANT ALLOCATION

12 Months Ending 12/31/2###

Exhibit KDP-1
Page 7

2 of 2

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).	$
b. Production wages and salaries in electric operation and maintenance expense, FF1, P.354, Col.(b), L.20.	$
c. Ratio (b / a)	%

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 12/31/2###

		PRODUCTION		
	Reference	Amount (1)	Demand (2)	Energy (3)
1. Total Production Expense Excluding Fuel Used In Electric Generation	P.14, L.12	$	$	$
2. Less Fuel Handling / Sale of Fly Ash	P.14, L.1 thru 3	$	$	$
3. Less Purchased Power	P.14, L.11	$	$	$
4. Other Production O&M	Sum (L.1 thru L.3)	$	$	$
5. Allocated A&G	P.10, L.17	$	$	$
6. Total O&M for Cash Working Capital Calculation	L.4 + L.5	$	$	$
7. O&M Cash Requirements	=45 / 360 x L.6	$	$	$

B-9

PRODUCTION-RELATED MATERIALS & SUPPLIES

12 Months Ending 12/31/2###

	SYSTEM		PRODUCTION			
	Reference	Amount (1)	Reference	Amount (2)	Demand (3)	Energy (4)
1. Material & Supplies (Note A)						
2. Fuel	FF1, P.227, L.1	$		$	$	$
3. Non-Fuel						
4. Production	Functional Breakdown	$	100% Col. 1	$	$	$
5. Transmission	Furnished from	$	%	$	$	$
6. Distribution	CSPs Books by	$	%	$	$	$
7. General	Accounting Dept..	$	Note B	$	$	$
8. Total	L.4 + L.5 + L.6 + L.7	$		$	$	$

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 12/31/2###

			System			Production		
					Allocation			
		Account	Reference	Amount (1)	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	$				
4.	Outside Services	923	FF1, P.323	$				
5.	Employee Pensions & Benefits	926	FF1, P.323	$				
6.	Office Supplies	921	FF1, P.323	$				
7.	Injuries & Damages	925	FF1, P.323	$				
8.	Franchise Requirements	927	FF1, P.323	$				
9.	Duplicate Charges - Cr.	929	FF1, P.323	$				
10.	Total		Ls. 3 thru 9	$	Note A	$	$	$
11.	MISCELLANEOUS GENERAL EXPENS	930	FF1, P.323	$	Note A, C & D	$	$	$
12.	ADM. EXPENSE TRANSFER - CR.	922	FF1, P.323	$	Note B	$	$	$
13.	PROPERTY INSURANCE	924	FF1, P.323	$	Note E	$	$	$
14.	REGULATORY COMM. EXPENSES	928	FF1, P.323	$	Note C	$	$	$
15.	RENTS	931	FF1, P.323	$	Note B	$	$	$
16.	MAINTENANCE OF GENERAL PLANT	935	FF1, P.323	$	Note B	$	$	$
17.	TOTAL A & G EXPENSE		L.10 thru 16	$		$	$	$

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.

B-11
COMPOSITE COST OF CAPITAL
12 Months Ending 12/31/2###

		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	$	%	Note D	%	%
2.	Preferred Stock	Note B	$	%	Note E	%	%
3.	Common Stock	Note C	$	%	Note F	11.15%	%
4.	Total		$	%			%

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 12/31/2###

Exhibit KDP-1

		Reference	Debt Balance (1)	Interest & Cost Booked (2)
	12 Months Ending 12/31/2010 (Actual)			
1.	Bonds (Acc 221)	FF1, 112.18.c.	$	
2.	Less: Reacquired Bonds (Acc 222)	FF1, 112.19.c.	$	
3.	Advances from Assoc Companies (Acc 223)	FF1, 112.20.c.	$	
4.	Other Long Term Debt (Acc 224)	FF1, 112.21.c.	$	
5.	Total Long Term Debt Balance		$	
	Costs and Expenses (actual)			
6.	Interest Expense (Acc 427)	FF1, 117.62.c.		$
7.	Amortization Debt Discount and Expense (Acc 428)	FF1, 117.63.c.		$
8.	Amortization Loss on Reacquired Debt (Acc 428.1)	FF1, 117.64.c.		$
9.	Less: Amortiz Premium on Reacquired Debt (Acc 429)	FF1, 117.65.c.		$
10.	Less: Amortiz Gain on Reacquired Debt (Acc 429.1)	FF1, 117.66.c.		$
11.	Interest on LTD Assoc Companies (portion Acc 430)	WP-13, L.7		$
12.	Sub-total Costs and Expense			$
13.	*Less: Total Hedge (Gain) / Loss*	*P. 12a, L. 4, Col. (1)*		$
14.	Plus: Allowed Hedge Recovery	P. 12a, L. 9, Col. (6)		$
15.	Total LTD Cost Amount	L. 12 - L. 13 + L. 14		$
16.	Embedded Cost of Long Term Debt = L.15, Col.(2) / L.15, Col.(1)			%

B-12a
LONG TERM DEBT
Limit on Hedging (Gain)/Loss on Interest Rate Derivatives of LTD
12 Months Ending 12/31/2###

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

	<u>Limit on Hedging (G)/L on Interest Rate Derivatives of LTD</u>			
5.	Hedge (Gain) / Loss prior to Application of Recovery Limit			$
	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)	$	
7.	5 basis point Limit on (G)/L Recovery			0.0005
8.	Amount of (G)/L Recovery Limit	L. 6 * L.7		$
9.	Hedge (Gain) / Loss Recovery (Lesser of Line 5 or Line 8)			$
	To be subtracted or added to actual Interest Expenses on Exhibit B, Page 12, Line 14			

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 12/31/2###

			(1) Reference	(2) Amount
1.	Preferred Stock Dividends		FF1, P.118, L.29	$
2.	Preferred Stock Outstanding	Note A & B	FF1, P.251, L. 12 (f)	$
3.	Plus: Premium on Preferred Stock	Note A	FF1, P.112, L.6	$
4.	Less: Discount on Pfd Stock	Note A	FF1, P. 112. L.9	$
5.	Plus: Paid-in-Capital Pfd Stock	Note A		$
6.	Total Preferred Stock		L.2 + L.3 - L.4 + L.5	$
7.	Average Cost Rate		L.1 / L.6	%

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 12/31/2###

Exhibit KDP-1
Page 13b

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

B-14
ANNUAL FIXED COSTS
PRODUCTION O & M EXPENSE
EXCLUDING FUEL USED IN ELECTRIC GENERATION
12 Months Ending 12/31/2###

	Account No.	Total Company (1)	(Demand) Fixed (2)	(Energy) Variable (3)
1. Coal Handling	501.xx	$		$
2. Lignite Handling	501.xx	$		$
3. Sale of Fly Ash (Revenue & Expense)	501.xx	$		$
4. Rents	507	$		
5. Hydro O & M Expenses	535-545	$		
6. Other Production Expenses	557	$	$	
7. System Control of Load Dispatching	Note C	$	$	
8. Other Steam Expenses	Note A	$	$	$
9. Combustion Turbine	Note A	$		$
10. Nuclear Power Expense-Other	Note A	$		
11. Purchased Power	555	$	$	$
12. Total Production Expense Excluding Fuel Used In Electric Generation above		$	$	$
13. A & G Expense P.10, L.17		$	$	$
14. Generator Step Up related O&M	Note B	$	$	$
15. Total O & M		$	$	$

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

B-15

CLASSIFICATION OF FIXED AND VARIABLE PRODUCTION EXPENSES

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

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

B-16

PRODUCTION-RELATED DEPRECIATION EXPENSE

12 Months Ending 12/31/2###

Exhibit KDP-1

		Depreciation Expense (1)	Demand (2)	Energy (3)
	PRODUCTION PLANT			
1.	Steam	$	$	$
2.	Nuclear	$	$	$
3.	Hydro	$	$	$
4.	Conventional	$	$	$
5.	Pump Storage	$	$	$
6.	Other Production	$	$	$
7.	Int. Comb.	$	$	$
8.	Other	$	$	$
9.	Production Related General & Intangible Plant	$	$	$
10.	Generator Step Up Related Depreciation (Note A)	$	$	$
11.	Total Production	$	$	$

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

B-17
PRODUCTION RELATED
TAXES OTHER THAN INCOME TAXES
12 Months Ending 12/31/2###

		SYSTEM			PRODUCTION
		REFERENCE	AMOUNT (1)	%	AMOUNT (2)
	PRODUCTION RELATED TAXES OTHER THAN INCOME				
1	Labor Related	Note A	$	Note B	$
2	Property Related	Note A	$	Note C	$
3	Other	Note A	$	Note C	$
4	Production		$		$
5	Gross Receipts / Commission Assessments	Note A	$	Note D	$
6	TOTAL TAXES OTHER THAN INCOME TAXES	Sum L.1 : L.5	$		$

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)	$	%
(2) Production W & S	$	%

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

Note D: Not allocated to wholesale

B-18
PRODUCTION-RELATED INCOME TAX
12 Months Ending 12/31/2###

Exhibit KDP-1
Page 18

		Reference	Amount (1)	Demand (2)	Energy (3)
1.	Return on Rate Base	P.5, L.19	$	$	$
2.	Effective Income Tax Rate	P.19, L.2	%	%	%
3.	Income Tax Calculated	L.1 x L.2	$	$	$
4.	ITC Adjustment	P.19, L.13	$	$	$
5.	Income Tax	L.3 + L.4	$	$	$

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

B-19

COMPUTATION OF EFFECTIVE INCOME TAX RATE

12 Months Ending 12/31/2###

1.	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		%
2.	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		%
3.	where WCLTD and WACC from Exhibit KDP-1-11 and FIT, SIT & p as shown below.		
4.	GRCF=1 / (1 - T)		#
5.	Federal Income Tax Rate	FIT	%
6.	State Income Tax Rate (Composite)	SIT	%
7.	Percent of FIT deductible for state purposes	p	%
8.	Weighted Cost of Long Term Debt	WCLTD	%
9.	Weighted Average Cost of Capital	WACC	%
10.	Amortized Investment Tax Credit (enter negative)	FF1, P.114, L.19, Col.c	$
11.	Gross Plant Allocation Factor	L.19	%
12.	Production Plant Related ITC Amortization		$
13.	ITC Adjustment	L.12 x L.4	$
14.	<u>Gross Plant Allocator</u>		Total
15.	Gross Plant	P.6, L.4, Col.1	$
16.	Production Plant Gross	P.6, L.4, Col.2	$
17.	Demand Related Production Plant	P.6, L.4, Col.3	$
18.	Energy Related Production Plant	P.6, L.4, Col.4	$
19.	Production Plant Gross Plant Allocator	L.16 / L.15	%
20.	Production Plant - Demand Related	L.17 / L.16	%
21.	Production Plant - Energy Related	L.18 / L.16	%

B-20

ENERGY CHARGE CALCULATION

12 Months Ending 12/31/2### (actuals)

		RATE $/MWh (1)	BILLING MWh (2)	AMOUNT, $ (1) X (2) (3)
ENERGY CHARGE:				
1.	Reference	P.21	Note A	
2.	JANUARY, 2###	$	#	$
	FEBRUARY, 2###	$	#	$
	MARCH, 2###	$	#	$
	APRIL, 2###	$	#	$
	MAY, 2###	$	#	$
	JUNE, 2###	$	#	$
	JULY, 2###	$	#	$
	AUGUST, 2###	$	#	$
	SEPTEMBER, 2###	$	#	$
	OCTOBER, 2###	$	#	$
	NOVEMBER, 2###	$	#	$
	DECEMBER, 2###	$	#	$

Note A: Workpapers -- tab WP-4b

ENERGY CHARGES $

B-21 Exhibit KDP-1

DETERMINATION OF MONTHLY RATE APPLICABLE

12 Months Ending 12/31/2### (actuals)

1. Monthly Energy Rate

		Actual Annual Energy Related Costs ($) (1)	Net MWh Gen. and MWh Purchased, less MWh sold (MWh) (2)	Monthly Energy Rate ($/MWh) (1) / (2) (3)
2.	JANUARY, 2###	$	#	$
	FEBRUARY, 2###	$	#	$
	MARCH, 2###	$	#	$
	APRIL, 2###	$	#	$
	MAY, 2###	$	#	$
	JUNE, 2###	$	#	$
	JULY, 2###	$	#	$
	AUGUST, 2###	$	#	$
	SEPTEMBER, 2###	$	#	$
	OCTOBER, 2###	$	#	$
	NOVEMBER, 2###	$	#	$
	DECEMBER, 2###	$	#	$

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.

B-22
DETERMINATION OF ACTUAL
MONTHLY ENERGY RELATED COSTS
MONTH OF ____________, 2###

	FOSSIL FUEL EXPENSE	Account	Reference	Amount
1.	Coal-conventional	501	Note A	$
2.	Coal-combined cycle	501	Note A	
3.	Coal-inventory adjustment	501	Note A	
4.	Gas-conventional	501	Note A	$
5.	Gas-combined cycle	501	Note A	
6.	Oil-conventional	501	Note A	$
7.	Oil-combined cycle	501	Note A	
8.	Lignite	501	Note A	$
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			$
	PURCHASED POWER			
13.	Energy Related	555	Note A & B	$
	OTHER PRODUCTION EXPENSE			
14.	Energy Related		P.23, L.8	$
	TOTAL PRODUCTION COST			
15.	Energy Related		L.12, 13 & 14	$
16.	Off-system sales for resale revenues net of margins		Note C	$
17.	SUBTOTAL ENERGY RELATED COSTS		L.15 - L.16	$
18.	12th of Energy related A & G Expense		P.10	$
19.	12th of Energy related return		P.5	$
20.	12th of Energy related dep. exp.		P.16	$
21.	12th of Energy related income tax		P.18	$
22.	12th of Losses and Imbalance Ancillary Svc. Rev.		Note D	$
23.	Total Energy Related Costs		L.17 thru 21 - L.22	$

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

B-23

DETERMINATION OF MONTHLY ENERGY RELATED
OTHER PRODUCTION EXPENSE
MONTH OF ______________, 2###

		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	$
2.	Fuel Handling	501	Note A	$
3.	Lignite Handling	501	Note A	$
4.	Other Steam Expense		Note B	$
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		$

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

Note B: Workpapers -- tab WP-14

EXHIBIT KDP-2

B-1

CAPACITY (FIXED) CHARGE CALCULATION

OPCO

12 Months Ending 12/31/2###

	RATE $/MW/Day (1)	LOSS FACTOR (2)	Final FRR Rate (1) x (2) (3)
Capacity Daily Charge:			
1. Reference	P.2		Col (1) x (2)
2. Amount	$	#	$

B-2
DETERMINATION OF RATES APPLICABLE TO
OPCO'S CAPACITY REQUIREMENTS
12 Months Ending 12/31/2###

Exhibit KDP-2
Page 2

1. *Capacity Daily Rates*

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

$$\frac{\text{\$}}{\#\qquad\text{/365}} = \qquad \text{\$}$$

Where: Annual Production Fixed Cost, P.4

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

B-3
Generator Step Up Transformer Workpaper
12 Months Ending 12/31/2###

		Reference	
1.	GSU & Associated Investment	Note A	$
2.	Total Transmission Investment	FF1, P.207, L.58, Col.g	$
3.	Percent (GSU to Total Trans. Investment)	L.1 / L.2	%
4.	Transmission Depreciation Expense	FF1, P.336, L.7, Col.b	$
5.	GSU Related Depreciation Expense	L.3 x L.4	$
6.	Station Equipment Acct. 353 Investment	FF1, P.207, L.50, Col.g	$
7.	Percent (GSU to Acct. 353)	L.1 / L.6	%
8.	Transmission O&M (Accts 562 & 570)	FF1,P.321, L. 93, Col.b, and L.107, Col.b	$
9.	GSU & Associated Investment O&M	L.7 x L.8	$

Note A: Workpapers -- tab WP-16

B-4

ANNUAL PRODUCTION FIXED COST

12 Months Ending 12/31/2###

		Reference	PRODUCTION Amount
1.	Return on Rate Base	P.5, L.19, Col.(2)	$
2.	Operation & Maintenance Expense	P.14, L.15, Col.(2)	$
3.	Depreciation Expense	P.16, L.11, Col.(2)	$
4.	Taxes Other Than Income Taxes	P.17, L.6, Col.(2)	$
5.	Income Tax	P.18, L.5, Col.(2)	$
6.	Sales for Resale	Note A	$
7.	Ancillary Service Revenue	Note B	$
8.	Annual Production Fixed Cost	Sum (L.1 : L.5) - (L.6 + L.7)	$

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

Note B: Workpapers -- tab WP-2

B-5
RETURN ON PRODUCTION-RELATED INVESTMENT
12 Months Ending 12/31/2###

		Reference	Amount (1)	Demand (2)	Energy (3)
1.	ELECTRIC PLANT				
2.	Gross Plant in Service	P.6, L.4, Col.(2)	$	$	$
3.	Less: Accumulated Depreciation	P.6, L.11, Col.(2)	$	$	$
4.	Net Plant in Service	L.2 - L.3	$	$	$
5.	Less: Accumulated Deferred Taxes	P.6, L.12, Col.(2)	$	$	$
6.	Plant Held for Future Use (Note A)	FF1, P.214	$	$	$
7.	Pollution Control CWIP	Note B	$	$	$
8.	Non-Pollution Control CWIP (50%)	Note B	$	$	$
9.	Subtotal - Electric Plant	L.4 - L.5 + L.6 + L.7 + L.	$	$	$
10.	WORKING CAPITAL				
11.	Materials & Supplies				
12.	Fuel	P.9, L.2, Col.(2)	$	$	$
13.	Nonfuel	P.9, L.8, Col.(2)	$	$	$
14.	Total M & S	L.12 + L.13	$	$	$
15a.	Prepayments Nonlabor (Note C)		$	$	$
15b.	Prepayments Labor (Note C)		$	$	$
15c	Prepayments Total (Note C)		$	$	$
16.	Cash Working Capital	P.8, L.7, Col.(2)	$	$	$
17.	Total Rate Base	L.9 + L.14 + L.15c + L.1	$	$	$
18.	Weighted Cost of Capital	P.11, L.4, Col.(4)	%	%	%
19.	Return on Rate Base	L.17 x L.18	$	$	$

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 12/31/2###

		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	$	$	$	$	$
3.	Allocated General & Intangible Plant			P.7, Col(3), L.28	$	$	$
4.	Total	L.2 + L.3	$		$	$	$
						%	
5.				Col.(2), L.4	$	$	$
6.				Col.(1), L.4	$	$	$
7.			%		%	%	%
8.	ACCUMULATED PROVISION FOR DEPRECIATION (Note A)						
9.	Plant in Service (Note D)		$	FF1, P.200, L.22	$	$	$
10.	Allocated General Plant		$	Note B	$	$	$
11.	Total	L.9 + L.10			$	$	$
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	$	Exhibit KDP-2, P	$	$	$

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
12 Months Ending 12/31/2###

	Account	Description	Year End Balance	Exclusions	100% Production (Energy Related)	100% Production (Demand Related)	Labor
1	190	Excluded Items	$	$			
2	190	100% Production (Energy)	$		$		
3	190	100% Production (Demand)	$			$	
4	190	Labor Related	$				$
5	190	Total	$	$	$	$	$
6		Production Allocation		%	%	%	%
7		(Gross Plant or Wages/Salaries)		$	$	$	$
8		Demand Related			$	$	$
9		Energy Related			$	$	$
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)	$			$	
14	281	Labor Related	$				$
15	281	Total	$	$	$	$	$
16		Production Allocation		%	%	%	%
17		(Gross Plant or Wages/Salaries)		$	$	$	$
18		Demand Related			$	$	$
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)	$			$	
24	282	Labor Related	$				$
25	282	Total	$	$	$	$	$
26		Production Allocation		%	%	%	%
27		(Gross Plant or Wages/Salaries)		$	$	$	$
28		Demand Related			$	$	$
29		Energy Related			$	$	$
30		Allocation Basis			Direct	B-6, L. 7	B-7, Note B
31	283	Excluded Items	$	$			
32	283	100% Production (Energy)	$		$		
33	283	100% Production (Demand)	$			$	
34	283	Labor Related	$				$
35	283	Total	$	$	$	$	$
36	283	Production Allocation		%	%	%	%
37		(Gross Plant or Wages/Salaries)		$	$	$	$
38		Demand Related			$	$	$
39		Energy Related			$	$	$
40		Allocation Basis			Direct	B-6, L. 7	B-7, Note B

41	Summary Production Related AD	Total	Demand	Energy
42	P Plant (Energy Related)	$	$	$
43	P Plant (Demand Related)	$	$	$
44	Labor Related	$	$	$
45	Total	$	$	$

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

B-7
PRODUCTION-RELATED GENERAL PLANT ALLOCATION
12 Months Ending 12/31/2###

Exhibit KDP-2
Page 7
———
1 of 2

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	$	Note B	$	$	$
4. General Offices	$		$	$	$
5. Total Land	$		$	$	$
6					
7. Structures	$	Note B	$	$	$
8. General Offices	$		$	$	$
9. Total Structures	$		$	$	$
10					
11. Office Equipment	$	Note B	$	$	$
12. General Offices	$		$	$	$
13. Total Office Equipment	$		$	$	$
14. Transportation Equipment	$	Note B	$	$	$
15. Stores Equipment	$	Note B	$	$	$
16. Tools, Shop & Garage Equipment	$	Note B	$	$	$
17. Lab Equipment	$	Note B	$	$	$
18. Communications Equipment	$	Note B	$	$	$
19. Miscellaneous Equipment	$	Note B	$	$	$
20. Subtotal	$		$	$	$
21. PERCENT		Note C	%	%	%
22. Other Tangible Property					
23. Fuel Exploration	$	Note D	$	$	$
24. Rail Car Facility	$	Note D	$	$	$
25. Total Other Tangible Property	$		$	$	$
26. TOTAL GENERAL PLANT FF1, P.207	$		$	$	$
27. INTANGIBLE PLANT	$	Note B	$	$	$
28. TOTAL GENERAL AND INTANGII	$		$	$	$
29. PERCENT		Note E	%	%	%
30. Total General and Intangible	$		$	$	$
31. Exclude Other Tangible (Railcar and Fuel Exploration)	$		$	$	$
32. Net General and Intangible	$		$	$	$
33. PERCENT			%	%	%

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).	$
b. Production wages and salaries in electric operation and maintenance expense, FF1, P.354, Col.(b), L.20.	$
c. Ratio (b / a)	%

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 12/31/2###

			PRODUCTION	
	Reference	Amount (1)	Demand (2)	Energy (3)
1. Total Production Expense Excluding Fuel Used In Electric Generation	P.14, L.12	$	$	$
2. Less Fuel Handling / Sale of Fly Ash	P.14, L.1 thru 3	$	$	$
3. Less Purchased Power	P.14, L.11	$	$	$
4. Other Production O&M	Sum (L.1 thru L.3)	$	$	$
5. Allocated A&G	P.10, L.17	$	$	$
6. Total O&M for Cash Working Capital Calculation	L.4 + L.5	$	$	$
7. O&M Cash Requirements	=45 / 360 x L.6	$	$	$

B-9

PRODUCTION-RELATED MATERIALS & SUPPLIES

12 Months Ending 12/31/2###

	SYSTEM		PRODUCTION			
	Reference	Amount (1)	Reference	Amount (2)	Demand (3)	Energy (4)
1. Material & Supplies (Note A)						
2. Fuel	FF1, P.227, L.1	$		$	$	$
3. Non-Fuel						
4. Production	Functional Breakdown	$	100% Col. 1	$	$	$
5. Transmission	Furnished from	$	%	$	$	$
6. Distribution	OPCs Books by	$	%	$	$	$
7. General	Accounting Dept.	$	Note B	$	$	$
8. Total	L.4 + L.5 + L.6 + L.7	$		$	$	$

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 12/31/2###

			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	$				
4.	Outside Services	923	FF1, P.323	$				
5.	Employee Pensions & Benefits	926	FF1, P.323	$				
6.	Office Supplies	921	FF1, P.323	$				
7.	Injuries & Damages	925	FF1, P.323	$				
8.	Franchise Requirements	927	FF1, P.323	$				
9.	Duplicate Charges - Cr.	929	FF1, P.323	$				
10.	Total		Ls. 3 thru 9	$	Note A	$	$	$
11.	MISCELLANEOUS GENERAL EXPENS	930	FF1, P.323	$	Note A, C & D	$	$	$
12.	ADM. EXPENSE TRANSFER - CR.	922	FF1, P.323	$	Note B	$	$	$
13.	PROPERTY INSURANCE	924	FF1, P.323	$	Note E	$	$	$
14.	REGULATORY COMM. EXPENSES	928	FF1, P.323	$	Note C	$	$	$
15.	RENTS	931	FF1, P.323	$	Note B	$	$	$
16.	MAINTENANCE OF GENERAL PLANT	935	FF1, P.323	$	Note B	$	$	$
17.	TOTAL A & G EXPENSE		L.10 thru 16	$		$	$	$

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.

B-11
COMPOSITE COST OF CAPITAL
12 Months Ending 12/31/2###

		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	$	%	Note D	%	%
2.	Preferred Stock	Note B	$	%	Note E	%	%
3.	Common Stock	Note C	$	%	Note F	11.15%	%
4.	Total		$	%			%

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 12/31/2###

		Reference	Debt Balance (1)	Interest & Cost Booked (2)
	12 Months Ending 12/31/2010 (Actual)			
1.	Bonds (Acc 221)	FF1, 112.18.c.	$	
2.	Less: Reacquired Bonds (Acc 222)	FF1, 112.19.c.	$	
3.	Advances from Assoc Companies (Acc 223)	FF1, 112.20.c.	$	
4.	Other Long Term Debt (Acc 224)	FF1, 112.21.c.	$	
5.	Total Long Term Debt Balance		$	
	Costs and Expenses (actual)			
6.	Interest Expense (Acc 427)	FF1, 117.62.c.		$
7.	Amortization Debt Discount and Expense (Acc 428)	FF1, 117.63.c.		$
8.	Amortization Loss on Reacquired Debt (Acc 428.1)	FF1, 117.64.c.		$
9.	Less: Amortiz Premium on Reacquired Debt (Acc 429)	FF1, 117.65.c.		$
10.	Less: Amortiz Gain on Reacquired Debt (Acc 429.1)	FF1, 117.66.c.		$
11.	Interest on LTD Assoc Companies (portion Acc 430)	WP-13, L.7		$
12.	Sub-total Costs and Expense			$
13.	Less: Total Hedge (Gain) / Loss	P. 12a, L. 4, Col. (1)		$
14.	Plus: Allowed Hedge Recovery	P. 12a, L. 9, Col. (6)		$
15.	Total LTD Cost Amount	L. 12 - L. 13 + L. 14		$
16.	Embedded Cost of Long Term Debt = L.15, Col.(2) / L.15, Col.(1)			%

B-12a
LONG TERM DEBT
Limit on Hedging (Gain)/Loss on Interest Rate Derivatives of LTD
12 Months Ending 12/31/2###

Exhibit KDP-2
Page 12a

		(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%	$	$	$	$	Jun-06	Jun-16
2.	SUN Cash Flow Hedge - 5.375%	$	$	$	$	Sep-09	Sep-19
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 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)	$	
7.	5 basis point Limit on (G)/L Recovery			0.0005
8.	Amount of (G)/L Recovery Limit	L. 6 * L.7		$
9.	Hedge (Gain) / Loss Recovery (Lesser of Line 5 or Line 8) 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 12/31/2###

			(1) Reference	(2) Amount
1.	Preferred Stock Dividends		FF1, P.118, L.29	$
2.	Preferred Stock Outstanding	Note A & B	FF1, P.251, L. 15 (f)	$
3.	Plus: Premium on Preferred Stock	Note A	FF1, P.112, L.6	$
4.	Less: Discount on Pfd Stock	Note A	FF1, P. 112. L.9	$
5.	Plus: Paid-in-Capital Pfd Stock	Note A		$
6.	Total Preferred Stock		L.2 + L.3 - L.4 + L.5	$
7.	Average Cost Rate		L.1 / L.6	%

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 12/31/2###

Exhibit KDP-2

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

B-14
ANNUAL FIXED COSTS
PRODUCTION O & M EXPENSE
EXCLUDING FUEL USED IN ELECTRIC GENERATION
12 Months Ending 12/31/2###

	Account No.	Total Company (1)	(Demand) Fixed (2)	(Energy) Variable (3)
1. Coal Handling	501.xx	$		$
2. Lignite Handling	501.xx	$		$
3. Sale of Fly Ash (Revenue & Expense)	501.xx	$		$
4. Rents	507	$		
5. Hydro O & M Expenses	535-545	$		
6. Other Production Expenses	557	$	$	
7. System Control of Load Dispatching	Note C	$	$	
8. Other Steam Expenses	Note A	$	$	$
9. Combustion Turbine	Note A	$		$
10. Nuclear Power Expense-Other	Note A	$		
11. Purchased Power	555	$	$	$
12. Total Production Expense Excluding Fuel Used In Electric Generation above		$	$	$
13. A & G Expense P.10, L.17		$	$	$
14. Generator Step Up related O&M	Note B	$	$	$
15. Total O & M		$	$	$

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

CLASSIFICATION OF FIXED AND VARIABLE PRODUCTION EXPENSES

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

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

B-16 Exhibit KDP-2

PRODUCTION-RELATED DEPRECIATION EXPENSE Page 16

12 Months Ending 12/31/2###

		Depreciation Expense (1)	*Demand* (2)	*Energy* (3)
	PRODUCTION PLANT			
1.	Steam	$	$	$
2.	Nuclear	$	$	$
3.	Hydro	$	$	$
4.	*Conventional*	$	$	$
5.	Pump Storage	$	$	$
6.	Other Production	$	$	$
7.	Int. Comb.	$	$	$
8.	Other	$	$	$
9.	*Production Related General & Intangible Plant*	$	$	$
10.	Generator Step Up Related Depreciation (Note A)	$	$	$
11.	Total Production	$	$	$

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

B-17
PRODUCTION RELATED
TAXES OTHER THAN INCOME TAXES
12 Months Ending 12/31/2###

		SYSTEM			PRODUCTION
		REFERENCE	AMOUNT (1)	%	AMOUNT (2)
	PRODUCTION RELATED TAXES OTHER THAN INCOME				
1	Labor Related	Note A	$	Note B	$
2	Property Related	Note A	$	Note C	$
3	Other	Note A	$	Note C	$
4	Production		$		$
5	Gross Receipts / Commission Assessments	Note A	$	Note D	$
6	TOTAL TAXES OTHER THAN INCOME TAXES	Sum L.1 : L.5	$		$

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)	$	%
(2) Production W & S	$	%

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

Note D: Not allocated to wholesale

B-18
PRODUCTION-RELATED INCOME TAX
12 Months Ending 12/31/2###

		Reference	Amount (1)	Demand (2)	Energy (3)
1.	Return on Rate Base	P.5, L.19	$	$	$
2.	Effective Income Tax Rate	P.19, L.2	%	%	%
3.	Income Tax Calculated	L.1 x L.2	$	$	$
4.	ITC Adjustment	P.19, L.13	$	$	$
5.	Income Tax	L.3 + L.4	$	$	$

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

B-19
COMPUTATION OF EFFECTIVE INCOME TAX RATE
12 Months Ending 12/31/2###

1. T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = %

2. EIT=(T/(1-T)) * (1-(WCLTD/WACC)) = %

3. where WCLTD and WACC from Exhibit KDP-2-11
and FIT, SIT & p as shown below.

4. GRCF=1 / (1 - T) #

5.	Federal Income Tax Rate	FIT	%
6.	State Income Tax Rate (Composite)	SIT	%
7.	Percent of FIT deductible for state purposes	p	%
8.	Weighted Cost of Long Term Debt	WCLTD	%
9.	Weighted Average Cost of Capital	WACC	%
10.	Amortized Investment Tax Credit (enter negative)	FF1, P.114, L.19, Col.c	$
11.	Gross Plant Allocation Factor	L.19	%
12.	Production Plant Related ITC Amortization		$
13.	ITC Adjustment	L.12 x L.4	$

14.	Gross Plant Allocator		Total
15.	Gross Plant	P.6, L.6, Col.2	$
16.	Production Plant Gross	P.6, L.5, Col.2	$
17.	Demand Related Production Plant	P.6, L.5, Col.3	$
18.	Energy Related Production Plant	P.6, L.5, Col.4	$
19.	Production Plant Gross Plant Allocator	L.16 / L.15	%
20.	Production Plant - Demand Related	L.17 / L.16	%
21.	Production Plant - Energy Related	L.18 / L.16	%

B-20
ENERGY CHARGE CALCULATION
12 Months Ending 12/31/2### (actuals)

ENERGY CHARGE:		RATE $/MWh (1)	BILLING MWh (2)	AMOUNT, $ (1) X (2) (3)
1.	Reference	P.21	Note A	
2.	JANUARY, 2010	$	#	$
	FEBRUARY, 2010	$	#	$
	MARCH, 2010	$	#	$
	APRIL, 2010	$	#	$
	MAY, 2010	$	#	$
	JUNE, 2010	$	#	$
	JULY, 2010	$	#	$
	AUGUST, 2010	$	#	$
	SEPTEMBER, 2010	$	#	$
	OCTOBER, 2010	$	#	$
	NOVEMBER, 2010	$	#	$
	DECEMBER, 2010	$	#	$

Note A: Workpapers -- tab WP-4b

ENERGY CHARGES **$**

B-21
DETERMINATION OF RATE APPLICABLE

12 Months Ending 12/31/2### (actuals)

1. Monthly Energy Rate

		Actual Annual Energy Related Costs ($) (1)	Net MWh Gen. and MWh Purchased, less MWh sold (MWh) (2)	Monthly Energy Rate ($/MWh) (1) / (2) (3)
2.	JANUARY, 2###	$	#	$
	FEBRUARY, 2###	$	#	$
	MARCH, 2###	$	#	$
	APRIL, 2###	$	#	$
	MAY, 2###	$	#	$
	JUNE, 2###	$	#	$
	JULY, 2###	$	#	$
	AUGUST, 2###	$	#	$
	SEPTEMBER, 2###	$	#	$
	OCTOBER, 2###	$	#	$
	NOVEMBER, 2###	$	#	$
	DECEMBER, 2###	$	#	$

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.

B-22
DETERMINATION OF ACTUAL
MONTHLY ENERGY RELATED COSTS
MONTH OF ________________, 2###

	FOSSIL FUEL EXPENSE	Account	Reference	Amount
1.	Coal-conventional	501	Note A	$
2.	Coal-combined cycle	501	Note A	
3.	Coal-inventory adjustment	501	Note A	
4.	Gas-conventional	501	Note A	$
5.	Gas-combined cycle	501	Note A	
6.	Oil-conventional	501	Note A	$
7.	Oil-combined cycle	501	Note A	
8.	Lignite	501	Note A	$
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			$
	PURCHASED POWER			
13.	Energy Related	555	Note A & B	$
	OTHER PRODUCTION EXPENSE			
14.	Energy Related		P.23, L.8	$
	TOTAL PRODUCTION COST			
15.	Energy Related		L.12, 13 & 14	$
16.	Off-system sales for resale revenues net of margins		Note C	$
17.	SUBTOTAL ENERGY RELATED COSTS		L.15 - L.16	$
18.	12th of Energy related A & G Expense		P.10	$
19.	12th of Energy related return		P.5	$
20.	12th of Energy related dep. exp.		P.16	$
21.	12th of Energy related income tax		P.18	$
22.	Total Energy Related Costs		L.17 thru 21	$

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

B-23

DETERMINATION OF MONTHLY ENERGY RELATED OTHER PRODUCTION EXPENSE

MONTH OF ________________, 2###

		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	$
2.	Fuel Handling	501	Note A	$
3.	Lignite Handling	501	Note A	$
4.	Other Steam Expense		Note B	$
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		$

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

Note B: Workpapers -- tab WP-14

EXHIBIT KDP-3

B-1

CAPACITY (FIXED) CHARGE CALCULATION

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.

B-2

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

1. Capacity Daily Rates

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

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

Where: Annual Production Fixed Cost, P.4

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

B-3
Generator Step Up Transformer Workpaper
12 Months Ending 12/31/2010 (actuals)

Exhibit KDP-3

		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

B-4

ANNUAL PRODUCTION FIXED COST

12 Months Ending 12/31/2010 (actuals)

Exhibit KDP-3

		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

B-5

RETURN ON PRODUCTION-RELATED INVESTMENT

12 Months Ending 12/31/2010 (actuals)

		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.

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	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	16,872,922
						99%	
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-3, P	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.

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)	(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

41	Summary Production Related AD	Total	Demand	Energy
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.

B-7

Exhibit KDP-3

PRODUCTION-RELATED GENERAL PLANT ALLOCATION

12 Months Ending 12/31/2010 (actuals)

General Plant Accounts 101 and 106

1. GENERAL PLANT	Total System (Note A) (1)	Allocation Factor (2)	Related to Production (1) x (2) (3)	Demand (4)	Energy (5)
2					
3. Land	3,247,961	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 INTANGI!	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)

B-8

Exhibit KDP-3

PRODUCTION-RELATED CASH REQUIREMENT

12 Months Ending 12/31/2010 (actuals)

			PRODUCTION	
	Reference	Amount (1)	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

B-9
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		
		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*	*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 EXPENS	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.

B-11

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.

B-12
LONG TERM DEBT
12 Months Ending 12/31/2010 (actuals)

Exhibit KDP-3
Page 12

		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%

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

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

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

5.	Hedge (Gain) / Loss prior to Application of Recovery Limit Enter a hedge Gain as a negative value and a hedge Loss as a positive value			0
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) To be subtracted or added to actual Interest Expenses on Exhibit KDP-3, Page 12, Line 14			0

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

B-13a
PREFERRED STOCK
12 Months Ending 12/31/2010 (actuals)

			(1) Reference	(2) Amount
1.	Preferred Stock Dividends		FF1, P.118, L.29	0
2.	Preferred Stock Outstanding	Note A & B	FF1, P.251, L. 12 (f)	0
3.	Plus: Premium on Preferred Stock	Note A	FF1, P.112, L.6	0
4.	Less: Discount on Pfd Stock	Note A	FF1, P. 112. 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)

Exhibit KDP-3
Page 13b

		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

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Exhibit KDP-3

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

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CLASSIFICATION OF FIXED AND VARIABLE PRODUCTION EXPENSES

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

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

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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

B-17
PRODUCTION RELATED
TAXES OTHER THAN INCOME TAXES
12 Months Ending 12/31/2010 (actuals)

		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

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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.

B-19

COMPUTATION OF EFFECTIVE INCOME TAX RATE

12 Months Ending 12/31/2010 (actuals)

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-3-11 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.	<u>Gross Plant Allocator</u>		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%

B-20
ENERGY CHARGE CALCULATION BY MONTH
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	$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 CHARGES **$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.

B-22
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

B-22
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

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

	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

B-22
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

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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

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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

B-22
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

B-22
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

B-22
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

B-23

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

B-23

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

B-23

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

B-23

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

B-23

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

B-23

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

B-23

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

B-23

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

B-23

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

B-23

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

B-23
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

EXHIBIT KDP-4

B-1
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.

B-2
DETERMINATION OF RATES APPLICABLE TO
OPC'S CAPACITY REQUIREMENTS
12 Months Ending 12/31/2010 (actuals)

Exhibit KDP-4
Page 2

1. Capacity Daily Rates

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

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

Where: Annual Production Fixed Cost, P.4

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

B-3
Generator Step Up Transformer Workpaper
12 Months Ending 12/31/2010 (actuals)

Exhibit KDP-4

		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

B-5
RETURN ON PRODUCTION-RELATED INVESTMENT
12 Months Ending 12/31/2010 (actuals)

		Reference	Amount	Demand	Energy
1.	ELECTRIC PLANT		(1)	(2)	(3)
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.	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.1	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	62,171,980
						99%	
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-4, P	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

41	Summary Production Related AD	Total	Demand	Energy
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.

B-7

Exhibit KDP-4

PRODUCTION-RELATED GENERAL PLANT ALLOCATION

12 Months Ending 12/31/2010 (actuals)

General Plant Accounts 101 and 106

1. GENERAL PLANT	Total System (Note A) (1)	Allocation Factor (2)	Related to Production (1) x (2) (3)	Demand (4)	Energy (5)
2					
3. Land	4,967,489	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 INTANGII	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%

B-7
PRODUCTION-RELATED GENERAL PLANT ALLOCATION
12 Months Ending 12/31/2010 (actuals)

Exhibit KDP-4
Page 7

2 of 2

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 (1)	Demand (2)	Energy (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

B-9
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	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		
					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	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 EXPENS	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.

B-11

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	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)
	<u>12 Months Ending 12/31/2010 (Actual)</u>			
1.	Bonds (Acc 221)	FF1, 112.18.c.	0	
2.	Less: Reacquired Bonds (Acc 222)	FF1, 112.19.c.	(303,000,000)	
3.	Advances from Assoc Companies (Acc 223)	FF1, 112.20.c.	200,000,000	
4.	Other Long Term Debt (Acc 224)	FF1, 112.21.c.	2,837,580,000	
5.	*Total Long Term Debt Balance*		*2,734,580,000*	
	<u>Costs and Expenses (actual)</u>			
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%

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

Exhibit KDP-4
Page 12a

		(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-4, 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..

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

Exhibit KDP-4
Page 13b

		Source	Balances
1.	Total Proprietary Capital	WP-12a, col. a	3,148,530,292
	Less:		
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

B-14

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

CLASSIFICATION OF FIXED AND VARIABLE PRODUCTION EXPENSES

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

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

B-16

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

B-17

PRODUCTION RELATED

TAXES OTHER THAN INCOME TAXES

12 Months Ending 12/31/2010 (actuals)

		SYSTEM			PRODUCTION
		REFERENCE	AMOUNT (1)	%	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

B-18

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.

B-19
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-4-11 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%

B-20

ENERGY CHARGE CALCULATION

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 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	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

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

Exhibit KDP-4

	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

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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

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DETERMINATION OF ACTUAL MONTHLY ENERGY RELATED COSTS

MONTH OF APRIL, 2010

	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

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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

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

Exhibit KDP-4

	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

B-22
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

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

	FOSSIL FUEL EXPENSE	Account	Reference	Amount
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

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

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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

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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

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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

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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

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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

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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

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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

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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

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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

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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

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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

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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

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

ENERGY RELATED PRODUCTION COSTS NOT INCLUDED ON PAGE 22, L. 1 THRU 13

		ACCOUNT	REFERENCE	AMOUNT
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

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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

EXHIBIT KDP-5

Exhibit KDP-5
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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 (1)	Σ Revenues (2)	LMP (3)=(2)/(1)	MLR (4)	CSP Revenue (5)=(2)x(4)	Σ MWh (6)	Σ Revenues (7)	LMP (8)=(7)/(6)	MLR (9)	OPCO Revenue (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 (1)	Σ Cost (2)=(1)x(3)	Cost Rate (3)	MLR (4)	CSP Cost (5)=(2)x(4)	Σ MWh (6)	Σ Cost (7)=(6)x(8)	Cost Rate (8)	MLR (9)	OPCo Cost (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 (1)	Σ Energy Value (2)	Margin (3)=(2)/(1)	MLR (4)	CSP Value (5)=(2)x(4)	Σ MWh (6)	Σ Energy Value (7)	Margin (8)=(7)/(6)	MLR (9)	OPCo Value (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**

Exhibit KDP-5
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Energy Credit For CSP and OPCo
2010 Energy Credit Applicable to PJM 2011/2010 Planning Year

IV. Jurisdictional 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

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

(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

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

(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>**

EXHIBIT KDP-6

Exhibit KDP-6
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Merged CSP and OPCo Capacity Charge
2010 Energy Credit Applicable to PJM 2011/2010 Planning Year

I. Merged CSP and OPCo Capacity Daily Rate

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

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

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

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

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

(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**

EXHIBIT KDP-7

Exhibit KDP-7

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