STEPTOE & JOHNSON LLP
ATTORNEYS AT LAW

Gary A. Morgans
202.429.6234
gmorgans@steptoe.com

1330 Connecticut Avenue, NW
Washington, DC 20036-1795
Tel 202.429.3000
Fax 202.429.3902
steptoe.com

October 14, 2011

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: *PJM Interconnection, L.L.C.*, *Duke Energy Ohio, Inc.*, and *Duke Energy Kentucky, Inc.*, Docket No. ER12-91-000 (Intra-PJM Tariff/OATT, OA, RAA) and Docket No. ER12-92-000 (Rate Schedule Tariff/TOA)

Dear Ms. Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d (2006) and Part 35 of the regulations of the Federal Energy Regulatory Commission ("Commission" or "FERC"), 18 C.F.R. Part 35 (2011), Duke Energy Ohio, Inc. ("Duke Energy Ohio") and Duke Energy Kentucky, Inc. ("Duke Energy Kentucky") (jointly, "DEOK" or "the Companies") hereby file revisions to PJM Interconnection, L.L.C.'s ("PJM") Open Access Transmission Tariff ("PJM OATT").[1] The Companies are filing these tariff revisions in order to accomplish the Companies' move from the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") Regional

[1] Pursuant to Order No. 714, this filing is submitted by PJM on behalf of the Companies as part of an XML filing package that conforms with the Commission's regulations. PJM has agreed to make all filings on behalf of the PJM Transmission Owners in order to retain administrative control over the PJM Tariff. Thus, the Companies have requested PJM to submit this filing in the eTariff system as part of PJM's electronic Intra PJM Tariff.

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Transmission Organization ("RTO") to the PJM RTO.[2] As demonstrated herein, the move is expected to result in quantified net benefits to wholesale customers taking service on the Companies' transmission system of approximately $301 million, over a twenty-five year period as measured on a net present value basis, as well as substantial unquantified net benefits.

Subject to specified conditions, the Commission authorized the Companies to join PJM by order issued October 21, 2010.[3] The Companies are submitting modifications to the PJM OATT related to Duke Energy Ohio's and Duke Energy Kentucky's transmission revenue requirements, including formula rate protocols.[4] These modifications are discussed in Sections II.B. and III.

In addition, Pursuant to Section 205 of the FPA and Part 35 of the Commission's regulations, PJM is submitting modifications to the PJM OATT, as well as to the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("PJM OA"), the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region ("PJM RAA") and the PJM TOA, in order to accomplish the Companies' integration with PJM.[5] These modifications are discussed in Section II.A. PJM also

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[2] Duke Energy Indiana, Inc. ("Duke Energy Indiana") would remain in the Midwest ISO.

[3] *Duke Energy Ohio, Inc.*, 133 FERC ¶ 61,058 (2010) ("October 21 Order").

[4] The division of filing responsibilities between PJM and the Companies is consistent with the Section 205 filing rights allocated to PJM and the PJM transmission owners pursuant to Section 9 of the PJM OATT and Article 7 of the Consolidated Transmission Owners Agreement ("PJM TOA").

[5] The PJM TOA modifications are filed by PJM on behalf of the PJM Transmission Owners Administrative Committee, which endorsed the modifications on August 15, 2011.

requests a waiver of: (1) the PJM application fee for any Market Buyers applying for PJM membership before January 1, 2012, as a direct result of the Companies joining PJM; and (2) Schedule 9-FERC as it would apply to Companies, for a limited period, so as to avoid over collection of FERC-related fees from the Companies. The waiver request is discussed in Section V.

PJM and the Companies (jointly, "Applicants") also describe in this transmittal letter additional filings and the processes under which PJM will move pending generator interconnection requests in the Midwest ISO queue into the PJM queue. Finally, PJM addresses in this filing how existing transmission service agreements, including interconnection service agreements, for customers in the Companies' service territories will be transferred to PJM OATT service in a separate filing or filings. These matters are discussed in Section IV.

The Applicants request that the Commission accept the revised tariff records included with this filing and make them effective January 1, 2012, which is more than sixty days after the date of this filing. The Applicants also request waiver by the Commission of any requirements of the Commission's rules and regulations that may be necessary in order to permit the revisions to be accepted by the Commission and made effective in the manner proposed herein.

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I. BACKGROUND AND PURPOSE OF FILING

Duke Energy Ohio and Duke Energy Kentucky are wholly owned subsidiaries of Duke Energy Corporation and are principally engaged in providing integrated retail and wholesale electric utility service in Ohio and Kentucky, respectively.[6] The Companies, along with Duke Energy Indiana, another Duke Energy Corporation subsidiary, are transmission-owning members of the Midwest ISO, and make their transmission facilities available under the Midwest ISO Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Midwest ISO ASM Tariff"). The Midwest ISO is a Commission-approved RTO. Customers that desire transmission service over Duke Energy Ohio's, Duke Energy Kentucky's, or Duke Energy Indiana's transmission facilities currently submit their requests to the Midwest ISO.

Both of the Companies maintain transmission, distribution, and generation facilities. The Duke Energy Ohio transmission system consists of approximately 400 circuit miles of 345 kV transmission lines and more than 700 circuit miles of 138 kV facilities, and interconnects with the transmission systems of American Electric Power ("AEP"), Dayton Power & Light Company ("Dayton Power"), East Kentucky Power Cooperative, Ohio Valley Electric Corp., Louisville Gas and Electric Company,

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[6] On January 10, 2011, Duke Energy Corporation and Progress Energy, Inc., announced that the companies had executed an agreement to engage in a merger with the surviving company to be named Duke Energy Corporation. The companies filed with the Commission an application for approval of the merger under Section 203 of the Federal Power Act in Docket No. EC11-60 on April 4, 2011, along with associated tariff filings. On September 30, 2011, the Commission conditionally authorized the merger, subject to Commission approval of market power mitigation measures. *Duke Energy Corp.*, 136 FERC ¶ 61,245 (2011). The proposed merger is a separate matter and should not be a factor in the Commission's review of this filing.

Duke Energy Kentucky, and Duke Energy Indiana. Of these companies, only Duke Energy Kentucky and Duke Energy Indiana are members of the Midwest ISO. Duke Energy Kentucky owns a transmission system as well, consisting of 69 kV transmission and distribution facilities and eighteen high-side 138 kV connections. Duke Energy Kentucky is only interconnected with Duke Energy Ohio.

PJM is a Commission-approved Independent System Operator ("ISO") and RTO.[7] PJM is a transmission provider under, and the administrator of, the PJM OATT, operates energy and capacity markets, plans regional transmission expansion improvements to maintain grid reliability, relieve congestion, and provide for the integration of new generation resources, including renewable resources, and conducts the day-to-day operations of the transmission system in the PJM Region.

Duke Energy Ohio and Duke Energy Kentucky, or their corporate predecessors, have been members of the Midwest ISO as transmission owners since 1997, and have determined that it would be in their and their customers' best interest to move from the Midwest ISO to PJM (the "RTO Realignment"). To that end, the Companies submitted a Section 205 filing with the Commission on June 25, 2010, requesting, among other things, that the Commission find that, subject to the submission of future filings identified in this filing, the proposed RTO Realignment meets the standard for withdrawal from an RTO. Duke Energy Indiana would remain in the Midwest ISO.

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[7] *Pennsylvania-New Jersey-Maryland Interconnection*, 81 FERC ¶ 61,257 (1997), *reh'g denied*, 92 FERC ¶ 61,282 (2000); *PJM Interconnection, L.L.C.*, 101 FERC ¶ 61,345 (2002).

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The Companies proposed to move to PJM on January 1, 2012, in order to coincide with the date that Duke Energy Ohio's current Ohio rate plan expires.

On October 21, 2010, the Commission ruled upon the Companies' request. The Commission stated that an applicant proposing to withdraw from an RTO is required to satisfy three requirements:

(1) The withdrawal proposal must satisfy the terms of the applicant's contractual obligations as they relate to RTO withdrawal;

(2) The proposed replacement arrangements must comply with Order Nos. 888 and 890 and the standard of review applicable to proposed tariff provisions that differ from the *pro forma* OATT; and

(3) The replacement arrangements must be just, reasonable, and not unduly discriminatory.[8]

With respect to the first requirement, the Commission ruled that there were five contractual obligations that the Companies had to meet in order to withdraw from the Midwest ISO:

(a) Provide written notice to the Midwest ISO;

(b) Ensure the availability of continued transmission service for existing customers;[9]

(c) Pay their financial obligations to the Midwest ISO;[10]

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[8] October 21 Order at P 14.

[9] "[E]xisting" arrangements means those transmission contracts entered into prior to the date that the Companies notified the Midwest ISO of their intent to withdraw, (*i.e.*, May 20, 2010). *Louisville Gas & Elec. Co.*, 114 FERC ¶ 61,282 at P 44 ("*LG&E Withdrawal Order*"); *see also Louisville Gas & Elec. Co.*, *order on reh'g*, 116 FERC ¶ 61,020 at P 24 (2006) ("*LG&E Rehearing Order*"). "[C]ontracts" include "grandfathered agreements, executed transmission service agreements under the [Midwest ISO ASM Tariff] that cover specific transactions, and [any] confirmed reservation on the Midwest ISO open access same-time information system (OASIS) in existence as of the notice date." *LG&E Withdrawal Order*, 114 FERC ¶ 61,282 at P 46; *see also LG&E Rehearing Order*, 116 FERC ¶ 61,020 at P 24.

(d) Achieve a negotiated resolution, as between the Companies and the Midwest ISO, of the Companies' obligations to construct new facilities; and

(e) Receive all applicable federal and state regulatory approvals.[11]

The Commission determined that the Companies satisfied item (a) on this list, the written notice requirement.[12] With respect to item (b), the Commission ruled that the Companies had committed to make the filings that were necessary to comply with this requirement as well.[13] Below, the Companies demonstrate that this filing meets that requirement. The Commission found that the Companies had committed to meet their financial obligations to the Midwest ISO – item (c) – and that issues related to the exit fee (including recovery of the fee) should be addressed in a future filing.[14] Below, the Companies demonstrate that their inclusion of the exit fee in wholesale transmission rates is just and reasonable and consistent with Commission policy.[15] In addition, the

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[10] The Companies are contesting their obligation to pay for certain legacy transmission costs, so the extent of such obligations remains an open question at this time. *See* Section II.B.4, note 43 below.

[11] October 21 Order at P 70.

[12] *Id.* at P 71.

[13] *Id.* at P 72.

[14] *Id.* at P 73.

[15] The Companies will themselves take service under these wholesale transmission rates. However, we note that the Companies have each entered into a settlement at the retail level that will affect pass-through to retail customers of certain types of costs. The Companies do not seek to preempt those settlement agreements, which were accepted in Ohio PUC Case Nos. 11-2641-EL-RDR and 11-2642-EL-RDR (May 25, 2011) and KPSC Case No. 2010-00203 (Jan. 25, 2011). Flow-through of costs at the retail level will be tailored to comply with the settlement agreements.

Companies are in negotiations with the Midwest ISO regarding financial obligations and construction of facilities, so those issues are not addressed here.

With respect to the Companies' obligations under item (d), the Companies are currently negotiating this matter with the Midwest ISO, and anticipate that this matter will be addressed in a new Schedule 38 of the Midwest ISO ASM Tariff to be filed by the Midwest ISO. Finally, with respect to item (e), the Commission ruled that the Companies had received the applicable federal and state regulatory approvals required under Article Five, Section II of the Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO TO Agreement"), subject to the Companies meeting the conditions in the October 21 Order, the outcome of the Companies' future filings with the Commission, and the outcome of Duke Energy Kentucky's then-pending filing with the Kentucky Public Service Commission ("KPSC").[16]

The Commission ruled that it could not make any final determinations with respect to the second and third requirements that had to be met to withdraw from an RTO, and required the Companies to address these requirements in their subsequent filings. This filing demonstrates that the Companies meet these two requirements.

The purpose of this filing is to submit the amendments to the PJM OATT, PJM OA, PJM RAA, and PJM TOA that are necessary to meet the conditions that the Commission imposed in its October 21 Order. It includes revisions to the PJM OATT to

[16] October 21 Order at P 77.

include the Companies' transmission revenue requirements, which is accomplished by adding the Companies' formula rate as a new Attachment H-22A to the PJM OATT. That formula rate is largely identical to the formula rate that the Companies operate under in the Midwest ISO, modified to reflect differences between the two regions' rate design as well as to address financial obligations to PJM and to the RTO from which they are exiting. Included as a part of that formula is a set of formula rate protocols that gives customers the opportunity to review the data that the Companies use in calculating their transmission revenue requirements, as well as to challenge those calculations if they believe they are incorrect. These formula rate protocols largely mirror Commonwealth Edison Company's ("ComEd") protocols, which are included as part of Attachment H-13 in the PJM OATT, and which were approved as part of a settlement in Docket No. ER07-583.[17] In addition to adding a formula rate and accompanying protocols, the amendments to the PJM OATT also include a number of modifications to existing OATT provisions that are necessary to accomplish the integration of the Companies into PJM. Most of these changes are ministerial in nature, and all of them are described in Section II below.[18]

Together, these replacement arrangements satisfy the requirements of Order Nos. 888 and 890 (and the standard of review applicable to proposed tariff revisions that differ from the *pro forma* OATT), and are just and reasonable and not unduly

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[17] *Commonwealth Edison Co.*, 122 FERC ¶ 61,030 (2008).

[18] At a later date, the Midwest ISO will submit ministerial amendments to its OATT to reflect the departure of Duke Energy Ohio and Duke Energy Kentucky.

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discriminatory – the other two requirements that the Commission directed the Companies to meet in order to transfer from the Midwest ISO to PJM.

This filing in many ways mirrors the February 1, 2011, application of PJM and American Transmission Systems, Inc. ("ATSI") in Docket Nos. ER11-2814 and ER11-2815, in which PJM and ATSI requested the necessary changes to the PJM OATT, PJM OA, PJM RAA, and PJM TOA to accomplish ATSI's integration into PJM. The Commission approved the changes to these agreements that PJM requested, and granted in part the changes to the PJM OATT that ATSI requested.[19] The Commission, however, rejected without prejudice ATSI's request to include in its PJM rates any legacy Midwest ISO Transmission Expansion Plan ("MTEP") costs for which ATSI was responsible ("Legacy MTEP Costs"), the exit fee that the Midwest ISO charged ATSI in connection with ATSI's exit from the Midwest ISO ("Midwest ISO Exit Fee"), the charges that PJM assessed ATSI for the costs that PJM incurred in connection with ATSI's move into PJM ("PJM Integration Costs"), and the internal integration costs that ATSI incurred in connection with its move into PJM, the recovery of which ATSI deferred. The Commission stated that ATSI could submit a new Section 205 filing seeking to recover such costs. The Commission stated that, in order to recover such costs, ATSI would have to demonstrate that the benefits to wholesale transmission customers from its move into PJM outweighed these costs.[20]

[19] *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,198 (2011) ("*ATSI*").
[20] *ATSI* at PP 59-60.

In this filing, the Companies are seeking the recovery of their Legacy MTEP Costs, and, to the extent necessary, their Midwest ISO Exit Fee and PJM Integration Costs, as well as an additional Midwest ISO exit charge related to Long-Term Firm Transmission Rights ("LTTR Exit Charge").[21] For ease of reference, the Companies will refer to the Midwest ISO Exit Fee, LTTR Exit Charge, and PJM Integration Costs as the "Transition Costs." While the Companies do not agree that the Federal Power Act requires a cost-benefit analysis such as was set forth in *ATSI* in order to include their Legacy MTEP Costs and Transition Costs in the Companies' rates, the Companies have nonetheless included a cost-benefit analysis demonstrating that the benefits to wholesale transmission customers from RTO Realignment outweigh the Legacy MTEP Costs and Transition Costs that the Companies have included in their formula rate.

That analysis was prepared by Robert B. Stoddard of Charles River Associates, and is included as Attachment D to this filing. The analysis shows that the quantifiable benefits from RTO Realignment to the Companies' wholesale customers are far greater than the Legacy MTEP Costs and Transition Costs – approximately $301 million in savings over 25 years, on a net present value basis. Moreover, Mr. Stoddard shows that there are substantial unquantified benefits to the move, in addition to these quantified benefits. Thus, even under the *ATSI* standard, it is just and reasonable for the Companies to include these costs in their PJM rates.

[21] Unlike ATSI, the Companies have not deferred their internal integration costs, and are not seeking any changes to their treatment under the formula rate.

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II. DESCRIPTION OF FILING

A. PJM's Revisions to the PJM OATT, PJM OA, PJM RAA, and PJM TOA

PJM's revisions to the PJM OATT, PJM OA, PJM RAA, and PJM TOA are needed to implement the integration of the Companies' service areas into PJM on January 1, 2012, in accordance with the Commission's October 21 Order. To accomplish this integration, PJM is establishing the Companies' service areas as a zone within PJM, to be known as the DEOK Zone. These changes are ministerial in that they add, where needed, the DEOK Zone and/or the Companies as Transmission Owners to the PJM OATT, PJM OA, PJM RAA, and PJM TOA. PJM submitted comparable changes to these documents in connection with ATSI's move from the Midwest ISO to PJM, and PJM's explanation below of the need for these changes largely mirrors that provided in the *ATSI* case. The Commission approved the changes in the *ATSI* case, and should approve them here as well.

1. PJM OATT and PJM OA Revisions[22]

a. PJM OATT Section 1.32G

The PJM OATT Section 1.32G provides a definition for the PJM West Region describing which transmission zones are included in that defined term. PJM seeks to revise this definition to include Duke Energy Ohio and Duke Energy Kentucky, to reflect

[22] PJM's revisions to the PJM OATT, PJM OA, and PJM RAA were approved by the PJM Members Committee on August 25, 2011.

that the DEOK Zone is more electrically contiguous with the zones in the Western Region of PJM than with any other zones or collection of zones in the PJM Region.[23]

b. PJM OATT Attachment C-2, Conversion of Service in the DEOK Zone

PJM proposes to add Attachment C-2 of the PJM OATT, which is entitled "Conversion of Service in the DEOK Zone." But for the names of the parties, Attachment C-2 is substantially identical to Attachment C-1,[24] which was originally incorporated into the PJM OATT when PJM became the Transmission Provider for the Dominion and Duquesne Zones under the PJM OATT on December 1, 2004,[25] and January 1, 2005,[26] respectively. Attachment C-1 was revised earlier this year when PJM became the transmission provider for the ATSI Zone on June 1, 2011. As Attachment C-1 needs to remain in place at this time to complete the conversion of service in the ATSI Zone, PJM is adding Attachment C-2 in this filing to provide information on the conversion of transmission service and interconnection service in the DEOK Zone from the existing service under the Midwest ISO ASM Tariff to service under the PJM OATT

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[23] PJM also seeks to modify the definition of PJM West Region to include ATSI, which PJM inadvertently failed to do in the ATSI filing in Docket Nos. ER11-2814 and -2815.

[24] There are also minor wording differences between Attachments C-1 and C-2 to better describe the conversion process.

[25] *PJM Interconnection, L.L.C.*, 109 FERC ¶ 61,012 (2004), *order on reh'g*, 110 FERC ¶ 61,234, *order accepting compliance filings*, 111 FERC ¶ 61,257 (2005).

[26] *Duquesne Light Co.*, 122 FERC ¶ 61,039, *order on reh'g and compliance*, 124 FERC ¶ 61,219 (2008).

with respect to the Companies' integration into PJM. Attachment C-2 sets forth the principles that shall govern such conversions.

More specifically, Attachment C-2 sets forth the principles under which transmission service reservations under the Midwest ISO ASM Tariff for the DEOK Zone will be converted to the most closely analogous service under the PJM OATT. Attachment C-2 will address the conversion process for transmission service with an export from the DEOK Zone and an import to the remainder of the PJM Region (or vice versa). Not all transmission service provided under the Midwest ISO ASM Tariff exactly matches a service under the PJM OATT. Variances in transmission service requests will be converted into defined product types under the PJM OATT as more fully explained in Attachment C-2.

Regarding conversion of the existing transmission service agreements under the Midwest ISO ASM Tariff for the DEOK Zone, PJM is working with the Companies and the individual transmission service customers with the goal of entering into and filing, no later than November 1, 2011, replacement transmission service agreements under the PJM OATT. Again, the goal is to convert such service to the most closely analogous service under the PJM OATT. For instance, Network Integration Transmission Service ("NITS") customers will maintain their existing status and receive the same capacity (in megawatts) and rollover rights as exists under the Midwest ISO ASM Tariff service. Transmission service customers who currently take firm point-to-point ("PTP") service under the Midwest ISO ASM Tariff for reservations out of the DEOK Zone in the

Midwest ISO into the PJM Region will become internal PTP service customers in PJM as of January 1, 2012. Those customers will have the option, when appropriate, to convert their firm PTP service under the Midwest ISO ASM Tariff to PJM NITS. Transmission service customers taking firm PTP service under the Midwest ISO ASM Tariff into the DEOK Zone also will have the option to terminate their PTP service and take NITS in PJM.[27]

Attachment C-2 also addresses interconnection service migration – both for pending interconnection requests under the Midwest ISO interconnection queue as well as for existing interconnection customers with interconnection agreements. For instance, generator interconnection requests that are pending in the Midwest ISO's interconnection queue in the DEOK Zone as of January 1, 2012, will be migrated into PJM's interconnection queue with queue priority that is based on the date the interconnection customer entered Midwest ISO's queue. PJM will pick up the study process where it was left off in the Midwest ISO study process.

With respect to existing generation interconnection customers, PJM is working with each customer to ensure interconnection service is maintained and that interconnection customers who were under generation interconnection agreements prior to May 20, 2010, will retain deliverability of their generating units at no additional interconnection cost to interconnection customers to the extent they are not modifying

[27] Indeed, the only customer currently using internal PTP service has already opted to switch to NITS service in PJM and has already executed a PJM NITSA. Such NITSA is anticipated to be filed by November 1, 2011.

their facilities.[28] Some interconnection customers have indicated that they will choose to convert to a three-party Interconnection Service Agreement under PJM's OATT. In other instances, the customers have chosen to retain their existing interconnection agreements, and such agreements will be assigned a PJM service agreement number. With respect to those customers, PJM is negotiating minor amendments to such agreements, as needed. The new interconnection service agreements or revised interconnection agreements will be filed with the Commission. It is currently anticipated that such agreements will be filed prior to January 1, 2012.

As to load or transmission owner interconnection agreements and other similar agreements (collectively "transmission-related" agreements) between the Companies and third parties, they will generally be refiled as PJM service agreements.[29] In some cases, such agreements are today already both Midwest ISO and PJM service agreements. Modifications may be required to replace the Midwest ISO with references to PJM. The Midwest ISO or the Companies concurrently will cancel the agreements being superseded.

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[28] May 20, 2010, is the date that the Companies notified the Midwest ISO that they would be withdrawing from the Midwest ISO. For those interconnections customers who have or will enter into interconnection agreements after May 20, 2010, PJM is working to ensure that the customers are aware of any upgrades that may be needed to be deliverable in PJM so that such customers can make informed business decisions.

[29] The agreements that will be refiled are either service agreements under the Midwest ISO ASM Tariff or bilateral rate schedules.

c. PJM OATT Attachment J, PJM Transmission Zones

The PJM OATT Attachment J lists the Transmission Zones in the PJM Region. Attachment J also includes a map of the PJM Region depicting the PJM Transmission Zones. PJM proposes to amend Attachment J to include the DEOK Zone in the PJM Region.

Schedule 4 of the PJM OA, which is the standard form of agreement to become a member of PJM, requires a copy of Attachment J from the PJM OATT marked to show changes to the PJM Region boundaries if membership requires expansion of the PJM Region to integrate the new members. In this case, the integration of the Companies into PJM requires expansion of the PJM Region. The change in PJM Region boundaries is shown on the marked copy of Attachment J. The proposed revisions to Attachment J are consistent with the maps that were attached by the Companies when each of them signed Schedule 4 of the PJM OA.

d. PJM OATT Attachment K-Appendix and PJM OA Schedule 1, Section 3.2.3(q)

PJM proposes to revise Section 3.2.3(q) in PJM OATT Attachment K-Appendix and in PJM OA Schedule 1 by adding the DEOK Zone to the transmission zones for the Western Region of the PJM. Section 3.2.3 contains the Operating Reserve rules applicable to Market Sellers' generator units that participate in the PJM markets. Sub-paragraph (q) sets forth how PJM determines the regional balancing Operating Reserve rates for the Western and Eastern Regions. The DEOK Zone is a Western Region transmission zone for purposes of balancing Operating Reserve rates because the DEOK Zone is more electrically contiguous with the zones in the Western Region of PJM than with any other zones or collection of zones in the PJM Region.

e. PJM OATT Attachment K-Appendix and PJM OA Schedule 1, Section 7.4.2(b)

Section 7.4.2 (b) in PJM OATT Attachment K-Appendix and in PJM OA Schedule 1 provides for the Auction Revenue Rights ("ARRs") allocation process to be performed by PJM. Under Section 7.4.2(b), in stage 1A of the ARR allocation process, each Network Service User may request ARRs for a term covering ten consecutive PJM Planning Periods beginning with the immediately ensuing PJM Planning Period from a subset of the historical generation resources that were designated to be delivered to load based on the historical reference year for the zone. Also under Section 7.4.2(b) in stage 1A of the ARR allocation process, each Qualifying Transmission Customer (as defined in subsection (f) of Section 7.4.2) may request ARRs based on the MWs of firm service provided between the receipt and delivery points as to which the Transmission Customer had PTP service during the historical reference year.

While the historical reference year for all zones in PJM is 1998 for all zones in existence at that time, Section 7.4.2(b) sets forth the historic reference years for all zones that integrated into PJM after 1998. Under Section 7.4.2 (b), PJM "shall specify a historical reference year for a new PJM zone corresponding to the year that the zone is integrated into the PJM Interchange Energy Markets." Because the DEOK Zone will integrate into PJM during 2012, PJM proposes to revise Section 7.4.2(b) in PJM OATT Attachment K-Appendix and in PJM OA Schedule 1 by adding "2012 for the DEOK Zone historic reference year."

f. PJM OATT, Attachment L, List of Transmission Owners

Transmission owners in PJM are listed in Attachment L to the PJM OATT. The PJM OATT defines "Transmission Owner" as: "[e]ach entity that owns, leases or otherwise has a possessory interest in facilities used for the transmission of electric energy in interstate commerce under the Tariff."[30] The Companies meet this definition. Thus, PJM submits for filing a revised Attachment L to the PJM OATT adding Duke Energy Ohio and Duke Energy Kentucky to the list of PJM Transmission Owners.

g. PJM OATT Attachment DD, Section 5.10, Cost of New Entry

PJM proposes to revise PJM OATT, Attachment DD Section 5.10, by adding the DEOK Zone to the chart of "Geographic Location Within the PJM Region Encompassing These Zones." Attachment DD Section 5.10 contains the requirements under which PJM must clear each Reliability Pricing Model's Base Residual Auction and Incremental Auction for a Delivery Year. These requirements include the use of a Cost of New Entry ("CONE") for the Transmission Zones that comprise each Locational Deliverability Area ("LDA") in the PJM Region, as set forth in the table in Section 5.10. The DEOK Zone is

[30] PJM OATT, Section 1.45F.

included in "CONE Area 3" on the chart which currently includes AEP, Dayton, ComEd, APS, Duquesne, and ATSI.

2. PJM RAA Revisions

a. PJM RAA Schedule 10.1, Locational Deliverability Areas and Requirements

PJM RAA Schedule 10.1 lists the zones, combination of zones and portions of such zones in the PJM Region that make up the LDAs for purposes of determining locational capacity obligations under the RAA. Thus, PJM proposes to revise Schedule 10.1 by adding the DEOK Zone. Also, PJM adds the Companies to the larger LDA that is currently defined as ComEd, AEP, Dayton, APS, Duquesne and ATSI. As stated above, the DEOK Zone is more electrically contiguous with the zones in the Western Region of PJM than with any other zones or collection of zones in the PJM Region.

b. PJM RAA Schedule 15, Zones Within the PJM Region

Schedule 15 to the PJM RAA lists the Transmission Zones in the PJM Region in the same manner as PJM OATT Attachment J discussed above. Like PJM OATT Attachment J, PJM RAA Schedule 15 also includes a map of the PJM Region depicting the PJM Transmission Zones. Thus, PJM proposes to amend Schedule 15 to include the DEOK Zone in the PJM Region.

c. PJM RAA Schedule 17, Parties to the RAA

Because the Companies are also Load Serving Entities, they are required to sign the PJM RAA.[31] Duke Energy Kentucky signed the PJM RAA on November 29, 2010, in accordance with Section 11.6(b) of the PJM OA and was already listed in Schedule 17. Duke Energy Ohio signed the RAA on September 27, 2011 and PJM now revises the PJM RAA Schedule 17 to include Duke Energy Ohio.

3. <u>PJM TOA Revisions</u>

a. Addition of the Companies to the List of PJM Transmission Owners

Attachment A to the PJM TOA lists the transmission owners in the PJM Region.[32] In preparation for the DEOK Zone integration on January 1, 2012, the Companies signed the PJM TOA on September 27, 2011. The transmission owners under the PJM TOA are listed in Attachment A of the TOA. The PJM OATT defines "Transmission Owner" as: "[e]ach entity that owns, leases or otherwise has a possessory interest in facilities used for the transmission of electric energy in interstate commerce under the Tariff." The transmission owners are listed in Attachment L to the PJM OATT.[33] The PJM TOA contains a similar definition which states that Transmission Owner "shall mean those entities that own or lease (with rights equivalent to ownership) Transmission Facilities."[34]

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[31] *See* PJM OA, Section 11.6 (b); PJM RAA, Article 4.

[32] *See* PJM TOA, Section 1.28.

[33] PJM OATT, Section 1.45F.

[34] PJM TOA, Section 1.28.

The Companies will be PJM transmission owners on January 1, 2012, because, on that date, the Companies' transmission facilities will: (i) be within the PJM Region; (ii) meet the definition of transmission facilities in Section 1.27 of the PJM TOA; and (iii) have been demonstrated to the satisfaction of PJM to be integrated with the Transmission System of the PJM Region and integrated into the planning and operation of such.[35]

Therefore, PJM hereby submits for filing, as part of the PJM TOA, a signature page to the TOA executed by the Companies. PJM also submits for filing a revised Attachment A to the PJM TOA adding the Companies to the list of PJM Transmission Owners.[36]

B. Substantive Revisions to the PJM OATT

The Companies are making a number of substantive revisions to the PJM OATT in order to transfer to PJM in a manner that complies with the Commission's requirements as set forth in the October 21 Order. To that end, we will first describe the substantive changes to the PJM OATT that the Companies are proposing, and in Section III demonstrate that these changes should be approved.

1. Transmission Rates

The Companies are proposing to incorporate revenue requirements and rates for four transmission and ancillary services under the PJM OATT:

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[35] PJM TOA, Section 1.27.

[36] On August 15, 2011, PJM reviewed this change with the PJM Transmission Owners Agreement Administrative Committee and received its endorsement to the change.

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(1) Network Integration Transmission Service (PJM OATT, Attachment H-22);

(2) Transmission Owner Scheduling, System Control, and Dispatch Service ("Scheduling Service") (PJM OATT, Schedule 1A);

(3) Long-Term Firm and Short-Term Firm Point-to-Point Transmission Service (PJM OATT, Schedule 7); and

(4) Non-Firm PTP Transmission Service (PJM OATT, Schedule 8).

This filing includes the Companies' formula rate for these services. The rates are based on the Companies' existing rates in the Midwest ISO, with modifications necessary to implement the move to PJM. These modifications are discussed in Sections II.B.2-II.B.6 below. The Companies' rates for all of these services are based on their zonal revenue requirement. This is consistent with the manner in which other PJM Transmission Owners calculate such rates, and has been accepted by the Commission.

Network Integration Transmission Service: Turning first to the rate for Network Integration Transmission Service, the Companies' revenue requirements for such service in the Midwest ISO are calculated pursuant to a formula rate included as Attachment O to the Midwest ISO ASM Tariff. The Companies are including this same formula rate as Attachment H-22A to the PJM OATT, modified as discussed below. The rates disaggregate the current combined calculation for Duke Energy Ohio, Duke Energy Kentucky and their sister company, Duke Energy Indiana, so that the new rates only reflect the revenue requirements for the Duke Energy companies moving from the Midwest ISO to PJM, namely Duke Energy Ohio and Duke Energy Kentucky.[37] The

[37] PJM will make payments to and receive revenues from Duke Energy Ohio on behalf of both Companies.

formula rate is recalculated annually each June 1 based on the prior year's costs, and continues in effect until the following May 31. The preamble to Attachment H-22 states that the rate for NITS shall be as calculated under Attachment H-22.

Point-to-Point Transmission Service: The formula rate set forth in Attachment H-22A will also be used to calculate the Companies' PTP service rates under Schedules 7 and 8. The Companies are modifying Schedules 7 and 8 of the PJM OATT to state that the rates for such service shall be calculated pursuant to Attachment H-22.

Scheduling Service: To calculate the rate for Scheduling Service under the PJM OATT, the Companies will use the same expenses used to calculate the rate for such service under the Midwest ISO ASM Tariff. The rate format is somewhat different, because the charges for Scheduling Service under the Midwest ISO ASM Tariff are contained in two Schedules (Schedules 1 and 24), whereas the PJM OATT includes only one Schedule. The Companies are therefore combining the expenses included in Midwest ISO ASM Tariff Schedules 1 and 24 into a single formula rate for use in the PJM OATT Schedule 1A. As with the formula rate for transmission service, the rate will be recalculated annually each June 1 based on prior year's costs, and will continue in effect until the following May 31. The Companies are modifying Part A of Schedule 1A of the PJM OATT to state the rates for such service shall be calculated pursuant to Attachment H-22, Appendix A.[38]

[38] During the period in which the rate will be based on the Companies' 2010 and 2011 calendar year costs and loads (January 1, 2012 – May 31, 2013), the MWh used in the rate divisor will be based on the calendar year settlement records provided to the Midwest ISO. For rates based on

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The Companies are also modifying Part B of Schedule 1A. Part B allocates the revenues from Scheduling Service provided to Non-Zone Load among the PJM Transmission Owners. In order for the Companies to receive a share of this credit, it will be necessary for the Companies and the other PJM Transmission Owners to review this distribution through a stakeholder process, to determine what share of the credit the Companies will receive. The Companies will pursue this matter subsequent to this filing, and make the necessary changes to Part B. For now, Part B is being modified to add the Companies to the list of Transmission Owners, and to indicate that the Companies' share of the credit is currently 0.00%.

2. Changes to Formula Rate Divisor and Revenue Credits and Elimination of FERC Annual Charges and Contract Demand Adjustment

The Companies are proposing several changes to their existing formula rate divisor and revenue credits and to eliminate certain unnecessary provisions. First, for the NITS rate, the Companies are changing the rate divisor from 12 coincident peak ("CP") to 1 CP consistent with Section 34.1 of the PJM OATT, which requires use of a 1 CP rate divisor. Second, for the PTP service rate, the Companies are eliminating the adjustment between PTP service contract demands and loads served using PTP service, consistent with the practice in PJM. Third, the Companies are eliminating the lines in the formula rate that relate to FERC Annual Charges assessed under the Midwest ISO ASM Tariff.

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subsequent years' costs and loads, the MWh used in the rate divisor will be based on PJM settlement records.

Inasmuch as PJM charges fees directly to customers, the lines are unnecessary. Fourth, the Companies are combining several lines for the Account 456.1 revenue credit calculation into a single entry, and have revised the accompanying note (Note U) to reflect this change. This change is necessary to remove calculations that are unique to the Midwest ISO ASM Tariff. Fifth, because operation and maintenance ("O&M") expenses that are recovered under the Schedule 1A rate are also included in the O&M accounts in the transmission service formula rate, an adjustment is being made to remove these costs from the transmission service formula rate (Note L). Sixth, the Companies are eliminating the revenue credit for non-firm PTP service, since PJM directly credits such revenues to transmission customers.[39] ATSI proposed similar changes in its formula rate when it integrated with PJM, and the Commission accepted these changes as just and reasonable.[40] The Commission also accepted similar changes in other proceedings.[41]

Next, the Companies are proposing a transitional adjustment to the firm PTP revenues used as a credit in the calculation of the net zonal revenue requirement for the rate years beginning June 1, 2013, and June 1, 2014. Under the Companies' formula rate, the Companies' share of firm PTP service revenues for loads sinking outside the DEOK Zone for the prior calendar year is used to reduce zonal revenue requirements for the current rate year beginning June 1. For example, the Companies' zonal rates in PJM for

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[39] The Companies have also added language to Note P of the formula rate to the capitalization does not include amounts related to purchase accounting, consistent with the Companies' calculations under the Midwest ISO ASM Tariff and Commission precedent.

[40] *ATSI* at PP 10-17, 59-68, Ordering Paragraph B.

[41] *See, e.g., PJM Interconnection, L.L.C.*, 109 FERC ¶ 61,302 at P 20 (2004).

the rate year beginning June 1, 2012 reflect PTP revenues received in 2011. The Companies, however, were still members of the Midwest ISO in 2011. Thus, absent a change in the formula rate, there will be a mismatch between the revenues that the Companies receive and the revenues they credit under their formula rate. To correct this mismatch, the Companies are including the same adjustment that ATSI included in its formula rate (modified to reflect the different time period at issue here), to achieve better consistency between the revenues received by the Companies and the level of the revenue credit. As in *ATSI*, the adjustment modifies the firm PTP service revenue credits until the revenue credit is based on revenues received in PJM. The Commission accepted this change in the *ATSI* proceeding. Mr. William Don Wathen Jr., Vice President of Rates – Ohio and Kentucky, discusses this adjustment in more detail in Section III.F of his testimony.[42]

3. <u>PJM RTEP Projects</u>

The Companies will be responsible for the construction of new PJM Regional Transmission Expansion Plan ("RTEP") projects in the DEOK Zone consistent with Schedule 12 of the PJM OATT once they join PJM. Since these facilities will be the Companies' transmission assets, their cost will be included in the Companies' formula rate. Additionally, the costs for such projects will be included as Transmission Enhancement Charges, to be allocated to transmission customers as provided for under Schedule 12 of the PJM OATT. Accordingly, there needs to be a mechanism for

[42] Direct Testimony of William Don Wathen Jr. ("Wathen Testimony") (Exhibit DUK-100).

calculating the annual revenue requirement for these projects (for inclusion in PJM OATT Schedule 12) as well as for crediting the Companies' revenue requirements for the cost of these facilities (which is recovered under PJM OATT Schedule 12).

To accomplish this, Appendix C to the Companies' formula rate includes a formula for deriving the annual revenue requirement for any RTEP projects assigned to the Companies. The revenue requirements calculated under Appendix C will be provided to PJM for developing zonal rates under PJM OATT Schedule 12. That same revenue requirement derived in Appendix C and provided to PJM for inclusion in PJM OATT Schedule 12 rates will be used to offset the zonal revenue requirements in the Companies' formula rate. These revenue credits are included on page 1, line 5b, of the formula rate as the Transmission Enhancement Credit. This is similar to the manner in which ATSI treated this cost.

4. Legacy MTEP Projects

After the Companies are integrated into PJM, the Companies will continue to be obligated to pay for a portion of the costs of certain legacy MTEP projects identified in the MTEP and approved by the Midwest ISO Board of Directors prior to the Companies' integration into PJM ("Legacy MTEP Charges").[43] In addition, after the integration,

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[43] The Companies are contesting their obligation to pay for the cost of certain Legacy MTEP projects known as Multi-Value Projects ("MVP"). *See* Request for Rehearing of Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc., *Midwest Indep. Transmission Sys. Operator, Inc.*, Docket No. ER10-1791 (Jan. 18, 2011) and Motion to Intervene and Comments of Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc., *FirstEnergy Serv. Co. v. Midwest Indep. Transmission Sys. Operator, Inc.*, Docket No. EL11-56 (Sept. 2, 2011). These matters are pending before the Commission. In the instant filing, the Companies are seeking appropriate

transmission owners serving load in zones other than the DEOK Zone will continue to be obligated to pay for the cost of the one Legacy MTEP project that the Companies have built in their zone, thereby paying a portion of the cost of facilities included in the Companies' formula rate.

The Companies propose to amend the PJM OATT to address both of these issues. First, the Midwest ISO will bill PJM for the cost of Legacy MTEP projects in zones other than the DEOK Zone for which the Companies remain responsible, and PJM will bill customers in the DEOK Zone for these costs. This is the same manner in which these costs are handled in the Midwest ISO (the Midwest ISO bills these charges to customers in the DEOK Zone pursuant to Midwest ISO ASM Tariff Schedule 26). Mr. Wathen provides the details behind these calculations in Section III.C of his testimony. Second, the revenues from transmission owners serving load in zones other than the DEOK Zone for the cost of the one Legacy MTEP project whose cost is included in the Companies' PJM transmission revenue requirements will continue to be credited against the Companies' costs ("Legacy MTEP Credits").[44] This credit, currently included on page 3, line 30, of Attachment O to the Midwest ISO ASM Tariff, is included on page 1, line 5a, of the formula rate. Mr. Wathen provides the details behind these calculations as well.

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treatment of Legacy MTEP Charges, including MVP costs to the extent that the Companies ultimately are adjudicated to be obligated to pay them.

[44] The Companies refer to Legacy MTEP Charges and Legacy MTEP Credits together as the "Legacy MTEP Costs."

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The justification for transmission customers continuing to be responsible for these charges and credits is discussed in Section III below.[45]

Because of this charge and this credit, there needs to be a process in the PJM OATT for charging costs and distributing revenues related to Legacy MTEP facilities. New Attachment JJ to the PJM OATT accomplishes this. New Attachment JJ of the PJM OATT sets forth the method by which transmission customers taking transmission service for deliveries into the DEOK Zone will be charged for the cost of Legacy MTEP projects constructed by other Midwest ISO Transmission Owners for which the Companies remain responsible, the method by which PJM will transmit to the Midwest ISO the revenues received from transmission customers taking service for deliveries into the DEOK Zone for such Legacy MTEP projects, and the manner in which PJM will distribute revenues received from the Midwest ISO for the Legacy MTEP projects constructed by the Companies.[46] These methods are described in Section III.C. of Mr. Wathen's testimony.

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[45] The Companies anticipate that the Midwest ISO will be filing an amendment to the Midwest ISO ASM Tariff under which (1) the Companies would remain responsible for the cost of certain Legacy MTEP facilities constructed in zones other than the DEOK Zone, and (2) transmission owners serving load in zones other than the DEOK Zone would remain responsible for the cost of the Legacy MTEP facility constructed in the DEOK Zone. These items are included on page 3, line 2a, and page 1, line 5a, respectively, of the Companies formula rate. While the Companies are negotiating in good faith with the Midwest ISO regarding the Midwest ISO's filing of such tariff provisions, the Companies reserve the right to protest any such filing, and inclusion of these items in the Companies formula rate is not a concession that the Midwest ISO will appropriately determine or allocate these costs.

[46] PJM's role is to administer the charges and credits; accordingly, however, PJM shall not be liable to the Midwest ISO for any amounts billed but uncollected for any reason. In addition, to

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5. Additional Formula Rate Matters: Protocols, Depreciation Rates, and Post-Employment Benefits Other Than Pensions ("PBOP") Expenses

The Companies have included Formula Rate Implementation Protocols as a part of their formula rate (Attachment H-22B). These protocols provide for the Companies to recalculate their rates on an annual basis, and give customers and other interested parties the opportunity to monitor the operation of the formula rate. Among other things, these protocols provide for the Companies to submit their formula rate calculations to the Commission for informational purposes, give interested parties the opportunity to conduct discovery with respect to the Companies' charges, and establish a procedure for interested parties to challenge the Companies' calculations if they believe the calculations are incorrect. The protocols are substantially the same as Commonwealth Edison's formula rate protocols (PJM Tariff Attachment H-13), with definitions added from AEP Transmission Companies' formula rate protocols (PJM Tariff Attachment H-14).[47] They are described in more detail in Section IV of Mr. Wathen's testimony.

Like Commonwealth Edison's protocols, the protocols included in Attachment H-22B state that depreciation rates and PBOP expense shall be stated values until changed pursuant to an FPA Section 205 or 206 filing made effective by the

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protect the interests of both the Midwest ISO and PJM, Attachment JJ provides that in the event PJM experiences a payment shortfall, it will make up for the shortfall in its payments to the Midwest ISO, and charge the shortfall to DEOK's account. It will then be up to DEOK to recover the shortfall directly from the customer, as provided in Attachment JJ.

[47] Commonwealth Edison's protocols were approved as part of a settlement in Docket No. ER07-583. *Commonwealth Edison Co*, 122 FERC ¶ 61,030 (2008). AEP Transmission Companies' protocols were approved as part of a settlement in Docket No. ER10-355. *AEP Appalachian Transmission Co., Inc.*, 135 FERC ¶ 61,066 (2011).

Commission. To comply with this requirement, the Companies are amending the formula rate to state the transmission, general plant, and intangible plant depreciation rates and PBOP values that will be used in the formula rate. The depreciation rates and PBOP values are the same as the Companies are currently using in the Midwest ISO, and thus do not constitute a change from the existing rate. As provided in the protocols, future changes to these values will require a filing with the Commission. This requirement is consistent with Commission precedent.

6. Midwest ISO Exit Fee, LTTR Exit Charge, and PJM Integration Costs ("Transition Costs")

Under Article Five, Section II.B of the Midwest ISO Transmission Owners' Agreement ("Midwest ISO TOA"), the Companies are required to pay certain amounts to the Midwest ISO as an "exit fee" (Midwest ISO Exit Fee). The Midwest ISO Exit Fee compensates the Midwest ISO for certain long-term costs that the Midwest ISO incurs in connection with the services that it provides. In particular, a portion of the charges under Midwest ISO ASM Tariff Schedules 10, 16, and 17 is assessed to transmission customers such as the Companies, including transmission customers in the DEOK Zone.[48] This

[48] Schedule 10 (ISO Cost Recovery Adder) provides for the recovery of the costs associated with operating the Midwest ISO, exclusive of those costs recovered under Schedules 1, 16 and 17. Schedule 16 (Financial Transmission Rights ("FTR") Administrative Service Cost Recovery Adder) provides for the recovery of the costs associated with administering the Midwest ISO's FTR market. Schedule 17 (Energy Market Support Administrative Service Cost Recovery Adder) provides for the recovery of the costs associated with administering the Midwest ISO's energy markets.

amount is subject to negotiation between the Midwest ISO and the departing member.[49] The Companies propose to include the Midwest ISO Exit Fee in their transmission rates.

Also, on July 29, 2011, the Midwest ISO filed, on behalf of itself and the Companies, an executed Settlement Agreement in Docket Nos. ER11-2059 *et al*. Under the Settlement Agreement, the Companies will pay to the Midwest ISO $1.8 million to resolve the dispute between the Companies and the Midwest ISO over tariff revisions proposed to address alleged adverse effects on the feasibility of Long-Term Firm Transmission Rights resulting from the withdrawal of the Companies from the Midwest ISO. ATSI did not seek recovery of this category of costs (the LTTR Exit Charge), and so it was not discussed in the *ATSI* order. The Companies seek recovery of these costs in wholesale rates and, because these costs are costs being imposed as a result of withdrawing from the Midwest ISO, the Companies' witness Robert Stoddard has included these costs in the cost-benefit analysis, which is discussed below.

The Companies also anticipate that PJM will charge the Companies up to approximately $1 million for PJM's costs in connection with the transition to PJM (PJM Integration Costs). As O&M expenses, the PJM Integration Costs will flow through the

[49] The Companies and the Midwest ISO recently executed an Exit Fee Agreement, which sets forth how the Midwest ISO Exit Fee will be calculated. The Agreement was filed with the Commission on October 5, 2011 in Docket No. ER12-33. The Companies anticipate that the Midwest ISO Exit Fee will be approximately $14.4 million.

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Companies' existing formula rate. These costs, together with the Midwest ISO Exit Fee and the LTTR Exit Charge, comprise the Companies' Transition Costs.[50]

The Companies are including the Transition Costs in the formula rate. In order to provide additional transparency as well as ensure the proper cost allocation, the Companies have added lines to the formula rate to accommodate these costs. The two Midwest ISO fees (Midwest ISO Exit Fee and LTTR Exit Charge) are included on page 3, line 1c ("Midwest ISO Fees"), and the PJM Integration Costs are included on page 3, line 3d. These costs are allocated 100% to transmission service customers, since the costs were incurred on their behalf. Because the O&M and Administrative and General ("A&G") accounts to which the Companies expect to record these costs (Account 930.2 for the PJM Integration Costs and Account 566 for the Midwest ISO Exit Fee and LTTR Exit Charge) are already included in the formula rate, an allocated portion of these costs would flow through the formula rate even absent this amendment (and thus to that extent do not require Commission authorization). To prevent a double-recovery of these costs, lines have been added to the formula rate to subtract the costs from the O&M and A&G expense of which they are a part. Mr. Wathen discusses this in Section III.D of his testimony.

[50] The Companies would incur the administrative costs that the Midwest ISO Exit Fee covers if they remained in the Midwest ISO, although not as an upfront charge. To avoid dispute, the Companies include this cost as an RTO Transition Cost.

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III. THE PROPOSED AMENDMENTS SHOULD BE APPROVED

The enclosed amendments to the PJM OATT, PJM OA, PJM RAA, and PJM TOA constitute the changes that are needed to these documents to comply with the October 21 Order. These replacement arrangements comply with Order Nos. 888 and 890, and are just and reasonable and not unduly discriminatory. The amendments should be approved.

A. The Companies' Proposed Tariff Amendments Are Just and Reasonable and Not Unduly Discriminatory

1. Introduction

The Companies' proposed amendments to the PJM Tariff result in existing transmission customers receiving service on terms and conditions that are comparable to the terms and conditions under which they currently receive transmission service. In addition, these customers will be subject to the same formula rate, modified as necessary to reflect the transition to PJM. The Companies have also included formula rate protocols, patterned after those already in use in PJM, that will give customers the ability to monitor the operation of the Companies' formula rate. The inclusion of Legacy MTEP Costs and Transition Costs in the Companies' rates is consistent with Commission precedent.[51]

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[51] *See, e.g.*, *Virginia Elec. & Power Co.*, 125 FERC ¶ 61,391 (2008), *reh'g denied*, 128 FERC ¶ 61,026 (2009); *New York Indep. Sys. Operator, Inc.*, 92 FERC ¶ 61,180 (2000); *PJM Interconnection, L.L.C. and Allegheny Power*, 96 FERC ¶ 61,060, at 61,222-23 (2001), *order approving uncontested settlement*, 100 FERC ¶ 61,088 (2002); *Am. Elec. Power Serv. Corp.*, 113 FERC ¶ 63,031, *order approving uncontested settlement*, 113 FERC ¶ 61,294 (2005), *as corrected*, 115 FERC ¶ 61,114 (2006).

In *ATSI*, the Commission found that similar arrangements were just and reasonable and not unduly discriminatory, with two exceptions. First, the Commission ruled that the protocols that ATSI filed may be unjust and unreasonable, and set that matter for hearing. The Companies have addressed that concern here by using largely the same formula rate protocols already in use by Commonwealth Edison under the PJM OATT. Second, the Commission ruled that ATSI had failed to demonstrate that the inclusion of ATSI's Legacy MTEP Costs and RTO transition costs in the rates to customers was just and reasonable. The Companies have addressed this as well, as explained below. Because these were the only two faults found with ATSI's approach, and because, other than the measures the Companies have taken to address these issues, the Companies' approach is materially the same as ATSI's, the PJM rates proposed by the Companies to replace their Midwest ISO rates are just, reasonable, and not unduly discriminatory.[52]

2. <u>Inclusion of Transition Costs and Legacy MTEP Charges in the Companies' Wholesale Rates Should Not Depend on a Numeric Cost-Benefit Analysis</u>

In *ATSI*, the Commission stated that ATSI had made general assertions regarding the benefits of the transition, but had not demonstrated that those benefits outweighed ATSI's Legacy MTEP Costs and RTO transition costs. Accordingly, the Commission directed ATSI to remove these costs from its rates. The Commission added, however, that ATSI could make a Section 205 filing to include these costs in rates if it demonstrated that the benefits to wholesale customers from RTO Realignment

[52] *ATSI* at P 69.

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outweighed ATSI's Legacy MTEP Costs and Transition Costs that ATSI sought to recover from its customers.[53]

The Companies should not be required to demonstrate that the benefits of moving to PJM outweigh the prudently incurred costs of the RTO Realignment in order for the transmission owner to include such costs in its rates. Under the FPA, a utility is entitled to recover its prudently incurred costs of providing service.[54] The Companies' formula rate recovers their actual costs, so the only question here is whether the costs incurred were prudent. The costs at issue were incurred in order to continue to provide Commission-approved service in the DEOK Zone, and were prudently incurred on behalf of the Companies' customers. The Commission approved the incurrence of Legacy MTEP Costs in the various cases approving establishment of the MTEP mechanism.[55] The Commission approved the incurrence of costs for Schedules 10, 16, and 17 in the cases in which it approved those schedules, their application to customers in the Midwest ISO, and the use of borrowing by the Midwest ISO to fund the associated costs, subject to

[53] On June 30, 2011, ATSI sought rehearing of the Commission's rejection of its inclusion of Legacy MTEP Costs and RTO transition costs. Action on ATSI's request is pending.

[54] *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944); *Miss. Power Co.*, 50 F.P.C. 885, 912 (1973); *New England Power Co.*, 49 FERC ¶ 63,007 at 65,038 (1989), *aff'd in relevant part,* 52 FERC ¶ 61,090 (1990); *Pub. Serv. Comm'n of N.Y. v. FPC*, 467 F.2d 361, 370 (D.C. Cir. 1972).

[55] *See, e.g., Midwest Indep. Transmission Sys. Operator, Inc.*, 114 FERC ¶ 61,106 (conditionally accepting tariff revisions to implement transmission expansion cost allocation policy of RECB Task Force – "RECB I"), *order on technical conference, reh'g, clarification, and compliance*, 117 FERC ¶ 61,241 (2006), *order on reh'g and clarification*, 118 FERC ¶ 61,208 (2007); *Midwest Indep. Transmission Sys. Operator, Inc.*, 118 FERC ¶ 61,209 (conditionally accepting tariff revisions to incorporate transmission expansion cost allocation methodology for Regionally Beneficial Projects – "RECB II"), *order on reh'g and compliance filing*, 120 FERC ¶ 61,080 (2007), *order on reh'g and compliance filing*, 122 FERC ¶ 61,127 (2008).

future payback.[56] There is no basis in the record of this case for overturning those findings, or for departing from the precedent cited above providing for the inclusion of such costs in the Companies' formula rate. Customers in the DEOK Zone would be responsible for paying for Legacy MTEP Costs (and receive the benefit of non-DEOK Zone load paying a share of the cost of the Companies' Legacy MTEP project) regardless of whether the Companies departed from the Midwest ISO.

Because incurrence of these costs has already been deemed prudent, it would be a form of regulatory "double jeopardy" to require the Companies to again justify recovery of the same costs. Nor does withdrawal from the Midwest ISO mean that it is appropriate to second guess the prudence of incurring those costs. The Commission has authorized companies to recover prudently incurred RTO start up costs even if incurrence of the costs does not lead to membership in an RTO.[57] In some such cases, such recovery has been through the rates of a different RTO that the company subsequently joins.[58]

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[56] *See, e.g., Midwest Indep. Transmission Sys. Operator, Inc.*, 102 FERC ¶ 61,192 (order on voluntary remand summarizing history of review of Schedule 10), *order denying reh'g and clarifying prior order*, 104 FERC ¶ 61,012 (2003), *aff'd sum nom. Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361 (D.C. Cir. 2004); *Midwest Indep. Transmission Sys. Operator, Inc.*, 102 FERC ¶ 61,193 (2002) (approving contested partial settlement addressing issues regarding Schedule 10), *order on compliance and reh'g*, 103 FERC ¶ 61,205 (2003); *Midwest Indep. Transmission Sys. Operator, Inc.*, 101 FERC ¶ 61,221 at P 35 (2002) (allowing MISO to recover its prudently incurred costs associated with FTRs and energy markets under Schedules 16 and 17, subject to subsequent informational reports of such projected and actual costs); *order on reh'g and clarification*, 103 FERC ¶ 61,035 (2003).

[57] *See, e.g., Idaho Power Co.*, 123 FERC ¶ 61,104 at P 10 (2008) (allowing recovery of $4.6 million in costs incurred in utility's unsuccessful attempt to develop an RTO).

[58] *See, e.g., Illinois Power Co.*, 108 FERC ¶ 61,258 at PP 3, 6 (2004) (authorizing recovery under the Midwest ISO tariff for $8.7 million in start up costs associated with Illinois Power's efforts to form the Alliance RTO).

Likewise, the Companies should be entitled to recover prudently incurred Midwest ISO costs.[59] No cost-benefit analysis should be required to support recovery of such costs.

However, as set forth below, the Companies have demonstrated that the benefits of the move do substantially outweigh the costs, meaning that the *ATSI* standard is satisfied. Accordingly, the Companies do not believe that the Commission needs to rule on whether it is appropriate to apply the *ATSI* standard to the Companies if the Commission approves inclusion in wholesale rates of RTO Transition Costs and Legacy MTEP Costs on the basis of the analysis below.[60]

3. Benefits of the RTO Realignment Far Outweigh Costs

In *ATSI*, the Commission denied ATSI's request to recover RTO transition costs and Legacy MTEP Costs because ATSI had made assertions of benefits that it had not supported with evidence:

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[59] Of the costs identified in the ATSI Order as requiring justification, only one category, costs of integrating into the new RTO, relates to expenditures not previously deemed prudent. In this case, that cost is estimated to be approximately one million dollars.

[60] *Cf. Ocean State Power*, 47 FERC ¶ 61,321 at 61,130 (1989) (beginning long line of cases under which the Commission has found transactions to meet the requirements of the test under FPA Section 203 without addressing underlying issue of whether the transaction was subject to the Commission's Section 203 jurisdiction).

> ATSI makes general assertions of the benefits without a demonstration of why it would be just and reasonable for ATSI's wholesale transmission customers to bear the RTO transition costs, particularly in light of claims that the realignment produces higher rates without offsetting benefits. We therefore find that ATSI fails to provide sufficient information or support that would enable the Commission to find that it is just and reasonable for ATSI's transmission customers to bear the costs arising from the decision to switch RTOs.*
>
> ________________
>
> **See* 5 U.S.C. § 556(d) (2006) ("Except as otherwise provided by statute, the proponent of a rule or order has the burden of proof."). *Cf.* 16 U.S.C. § 824d (2006) ("At any hearing involving a rate or charge sought to be increased, the burden of proof to show that the increased rate or charge is just and reasonable shall be upon the public utility"); 18 C.F.R. § 35.13(e)(3) (2011) ("Any utility that files a rate increase shall be prepared to go forward at a hearing on reasonable notice on the data submitted under this section, to sustain the burden of proof under the Federal Power Act of establishing that the rate increase is just and reasonable and not unduly discriminatory or preferential or otherwise unlawful within the meaning of the Act.").[61]

As the quoted footnote from the *ATSI* order shows, the rate proponent is not required to show that there will be no new costs, or that rates will go down, but rather only that the rate in question is just, reasonable, and not unduly discriminatory. A rate can be just and reasonable for a variety of reasons, including a showing of benefits that are not easily reducible to numbers. For example, it may be appropriate to increase rates

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[61] *ATSI* at P 59 & n.60.

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to attain public policy goals,[62] notwithstanding that public policy benefits cannot be readily quantified. Thus, determination of whether a rate is just and reasonable can require evaluation of both quantified and unquantified inputs.

In this case, both quantified factors and unquantified factors weigh strongly in favor of the RTO Realignment and support recovery of Transition Costs and Legacy MTEP Costs. In his attached testimony, the Companies' witness Robert Stoddard[63] discusses both quantified and unquantified factors and explains why the move will result in net benefits in each category. His conclusion: "Put simply, customers in the PJM DEOK Zone will pay less *and* get more."[64]

In fact, what the study shows is that the move will not result in a rate increase at all, but rather in a substantial overall decrease in rates, even after payment of Transition Costs and Legacy MTEP Costs.[65] Thus, while such a decrease is not a necessity in light of the substantial net unquantified benefits that also result from the move, it does mean that the Commission need not decide this case on the basis of the evidence presented by

[62] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000 at PP 203-24, FERC Stats. & Regs. ¶ 31,323 (2011) (recognizing that transmission construction (and costs) may be driven by public policies rather than by actual need for additional transmission to reliably serve load).

[63] Mr. Stoddard is an expert on market design who has participated heavily in the design of RTO markets, including both the PJM and the Midwest ISO markets, and in the evaluation of costs and benefits of RTO membership. Direct Testimony of Robert B. Stoddard at 1-2 ("Stoddard Testimony") (Exhibit DUK-200). As such, he is eminently qualified to conduct this analysis.

[64] *Id.* at 28.

[65] This further supports the Companies' view that application of the *ATSI* standard is unwarranted here, since the legal justification provided for the standard were statutory and regulatory provisions relating to the burden of proof where a rate *increase* is proposed. *ATSI* at P 59 & n.60.

Mr. Stoddard showing that, on a market design basis, PJM is better suited for the Companies and their customers.

Even if the savings in the quantified portion of Mr. Stoddard's analysis were overstated by more than the $301 million in net benefits that Mr. Stoddard calculates, which he does not believe to be the case,[66] the unquantified benefits provide a substantial buffer, such that overall net benefits would still exist, and still justify recovery of Transition Costs and Legacy MTEP Costs.[67] Thus, even under the *ATSI* standard, the Commission should authorize inclusion of Transition Costs and Legacy MTEP Costs in the Companies' zonal transmission rates.

i. Description of Study

Mr. Stoddard analyzed costs and benefits in two categories: quantified costs and benefits and unquantified costs and benefits. Unquantified costs and benefits consist of (a) those categories of costs and benefits (principally market design elements,[68] but also including uplift costs[69]) that would be hard to measure, and (b) those categories of costs and benefits that he did not expect to vary significantly between the RTOs, namely local

[66] In several places in his testimony Mr. Stoddard describes conservative assumptions that he believes tend to understate the quantified net benefit. Stoddard Testimony at 15 (marginal losses), 28 (limitation of analysis to 25 years), 33-34 (capacity costs), and 35 (credit to customers toward Midwest ISO administrative costs).

[67] *See, e.g.*, *id.* at 5 ("Adding the large and real (but unquantified) benefits I discuss here to the quantified benefits, which themselves markedly exceed the Transition Costs and Legacy MTEP Costs, makes the case for recovering such costs in rates quite compelling.").

[68] *Id.* at 10-14.

[69] *Id.* at 15.

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costs in zonal transmission rates,[70] and energy, capacity, and ancillary services costs.[71] The remaining buckets of costs – high voltage transmission upgrade costs in both RTOs, RTO administrative costs, and Transition Costs – were the subject of his quantitative analysis.

ii. Quantified Net Benefits

In his quantification of costs and benefits, Mr. Stoddard compared two cases to determine the gross cost or benefit of the move. In the first case, which is a hypothetical comparison case, he calculated costs for DEOK Zone customers if the Companies remain in the Midwest ISO in 2012 and beyond.[72] In the second case, he calculated costs for DEOK Zone customers if the Companies are in PJM beginning January 1, 2012.[73] This resulted in a substantial gross benefit (i.e., the amount by which the cost of staying in the Midwest ISO exceeds the cost of being in PJM) of $819.4 million.[74]

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[70] *Id*.

[71] *Id*. at 32. ("MISO and PJM form a Joint and Common Market ("JCM"), under a framework established under the PJM-Midwest ISO Joint Operating Agreement ("JOA") . . . For this reason, I would not expect any persistent meaningful difference in the market prices for energy, capacity, and ancillary services in the DEOK Zone resulting from shifting the MISO/ PJM boundary from one side of the Companies service territories to the other. While the market convergence anticipated under the JCM has not yet been fully realized, there is no reason to expect that it will not be.") Mr. Stoddard explained that analysis of movement between RTOs is unlike when a stand-alone utility joins an RTO, because in the latter case one would expect production cost savings, while in the former case such savings were already realized when the utility first joined an RTO, and no change would be expected as a result of the move between RTOs. *Id.*

[72] *Id*. at 7-8.

[73] *Id*. at 8.

[74] *Id*. at 9.

Once he had determined the gross benefit, Mr. Stoddard summed the Midwest ISO-related costs that the Commission said, in the *ATSI* order, must be justified to be included in rates (*i.e.*, the Transition Costs and Legacy MTEP Costs.)[75] The total of such costs is $518.4 million.[76] He then subtracted the total of all such costs from the gross benefit to determine whether there is a net benefit to the move, and obtained a substantial net benefit of $301 million.[77] His calculation is summarized on Table 1 of his testimony, which is reproduced here:

[75] *Id*.

[76] *Id*.

[77] *Id*.

Table 1. Net Present Value of Projected Quantified Costs/Benefits, 2012-2036 ($M)[78]

Costs of staying in MISO as of 1/1/12:	
Committed MTEP Costs ("Legacy MTEP")	$501.2
Future MTEP Costs	948.4
Administrative Costs	155.2
TOTAL MISO	**$1,604.9**
Costs of being in PJM as of 1/1/12:	
RTEP Costs	657.0
Administrative Costs	128.5
TOTAL PJM	**$785.5**
Gross Savings Before Adjustments for Transition and Legacy MTEP Costs	**$819.4**
Transition and Legacy MTEP Costs:	
Legacy MTEP Costs	$501.2
MISO Exit Costs and Fees	16.2
Reimbursable PJM Integration Costs	1.0
Total Transition/Legacy MTEP Costs	**$518.4**
Net Savings After Transition/Legacy MTEP Costs	**$301.0**

[78] Components may not sum to totals due to rounding.

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iii. Unquantified Net Benefits

Mr. Stoddard states that "[t]he realignment of the Companies from MISO to PJM will create several direct and indirect benefits that, although not readily quantifiable, are important."[79] "Foremost among these . . . is the superior support in PJM for competitive retail markets,"[80] a direct result of the fact that "[b]ecause many of the PJM states adopted retail competition more than a decade ago, the PJM market was designed from the ground up to facilitate retail competition and to ensure that costs of maintaining system resource adequacy are allocated equitably as retail customers switch suppliers."[81] Although the Companies will begin their time in PJM under Fixed Resource Requirements ("FRR") plans, the Companies and their zonal customers will "benefit from the stability of the well-established RPM design" because "RPM allocates the costs of maintaining resource adequacy equitably, meaning there is value in having the competitively determined BRA price available to use as backstop price for capacity sales to competitive retail suppliers in the absence of any explicit state cost allocation mechanism."[82] Mr. Stoddard explains in more detail the benefits of PJM's resource adequacy design to the Companies,[83] and contrasts that with the Midwest ISO's resource adequacy construct, which does not presently provide the same benefits.[84] While the

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[79] Stoddard Testimony at 10.

[80] *Id*.

[81] *Id*.

[82] *Id.* at 12 (footnote omitted).

[83] *Id*.

[84] *Id*. at 13.

Midwest ISO has filed a new resource adequacy proposal, it has not yet been sufficiently "vetted, refined and road-tested" to consider it to provide benefits equal to the benefits provided by PJM's market when it comes to retail choice states.[85]

More generally, Mr. Stoddard has reviewed the Companies' prior RTO Realignment filings, and notes that the Companies have "supported the [RTO Realignment] decision as providing a wide range of benefits, based on a variety of factors, to customers taking service in their transmission zone. I have reviewed these factors and, as an economist and market designer, believe them to be real and sufficient, even when the direct value of the benefit is difficult to quantify."[86]

iv. Conclusion: Benefits Far Outweigh Costs

Mr. Stoddard concludes that the Companies have satisfied the *ATSI* standard both on the basis of quantified net benefits and unquantified net benefits:

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[85] *Id*. at 14.

[86] *Id*. at 10.

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Q. WILL THE MOVE OF THE COMAPNIES TO PJM RESULT IN NET BENEFITS THAT SATISFY THE ATSI TEST?

A. Yes – the accrued net benefit will be substantial. Subtracting the estimated NPV for the categories of costs that Duke is seeking to recover under the standard set forth in the *ATSI Order* ($518.4 million) from the estimated NPV of the gross benefits of the realignment ($819.4 million) results in a net benefit of $301.0 million. Therefore, customers in the DEOK Zone, even after paying for Transition Costs and Legacy MTEP Costs will be at least $301 million better off as a result of the move of the Companies to PJM.

Q. WHAT DO YOU MEAN BY *"AT LEAST* $301 MILLION BETTER OFF"?

A. The $301 million represents the net quantified benefit through 2036 – conservatively ignoring additional anticipated savings beyond this 25-year window. In addition, as I have explained above, there are also factors that I do not quantify. As an expert in market design, I expect factors associated with the design of PJM's market, even though unquantified, to materially enhance, directly and indirectly, the overall net benefit of the move for wholesale customers.[87]

Taken together, the quantified and unquantified benefits of the RTO Realignment significantly outweigh the Transition Costs and Legacy MTEP Costs that the Companies seek to recover. Indeed, the quantified benefits alone more than satisfy the *ATSI* standard. Accordingly, the Companies should be allowed to recover such costs in wholesale rates.[88]

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[87] *Id*. at 27-28.

[88] *ATSI* at P 60.

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4. The Companies' Proposed Tariff Amendments Provide for the Continuation of Existing Transmission Service at Existing Rates, Terms, and Conditions

The Companies' proposed PJM OATT amendments give their existing transmission customers continued access to transmission service under rates, terms, and conditions that are comparable to those available under the Midwest ISO ASM Tariff. In addition, the PJM OATT is a Commission-approved tariff. In comparable circumstances in *ATSI*, the Commission ruled that this proposal satisfied the requirement that transmission customers would have continued access to transmission service, as required by the Midwest ISO TOA. The Commission should make that same ruling here.

5. The Companies' Proposed Tariff Amendments Comply with Order Nos. 888 and 890

The Companies, upon their integration with PJM, will be subject to the terms and conditions of the PJM OATT, a Commission-authorized RTO tariff. In comparable circumstances in *ATSI*, the Commission ruled that this integration plan, as conditioned by the Commission's order in *ATSI*, satisfies the requirement that the proposed replacement arrangements must comply with Order Nos. 888 and 890 and/or the standard of review applicable to proposed tariff revisions that differ from the *pro forma* tariff. The conditions that the Commission imposed in *ATSI* required ATSI to remove certain costs from its formula rate – conditions that, as shown above, are not necessary here. The Companies submit that under the circumstances the Companies have complied with this requirement.

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IV. OTHER RELATED FUTURE FILINGS AND MILESTONES

The Companies and/or PJM will be making additional future filings with the Commission in relation to the Companies' integration into PJM. These additional filings will address the migration of existing transmission, transmission-related, and generator interconnection agreements into PJM.[89] They will also address reactive power rates in both PJM and the Midwest ISO, as well as the initial allocation of Financial Transmission Rights. Such filings will be accompanied by cancellations of the existing agreements that are either Midwest ISO service agreements or the Companies' rate schedules, as necessary. As noted *supra*, the Midwest ISO also will have to submit housekeeping changes to its tariff.

In addition, other filings may be submitted by other parties concerning generator deactivations, the status of NERC certifications, the termination of tariffs that will no longer be needed after the Companies' integration into PJM, and as noted above, a new schedule to the Midwest ISO ASM Tariff addressing continuing MTEP obligations. Also, generator owners may submit filings to address reactive power rates in both PJM and the Midwest ISO. These filings will be submitted as required to effect the orderly transition into PJM on January 1, 2012.

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[89] PJM has established a page on its website dedicated to the integration of the Companies into PJM. *See* http://www.pjm.com/markets-and-operations/markets-integration/duke-energy.aspx.

V. WAIVER OF MARKET BUYER APPLICATION FEES AND SCHEDULE 9-FERC

PJM requests a waiver of the $1,500 PJM application fees for Market Buyers applying for PJM membership as a direct result of the Companies' integration into PJM.[90] This limited waiver will apply only to those Market Buyers who were required to apply for PJM membership as a direct result of the Companies' integration into PJM. The waiver will not apply to Market Buyers joining PJM after January 1, 2012, and will not apply to Market Buyer or other PJM membership applicants seeking PJM membership for reasons unrelated to the Companies' integration into PJM.

This waiver is appropriate because the costs that the $1,500 application fee is intended to cover have already been paid by the Companies as part of the Companies' integration costs. Thus, there is no need to charge the Market Buyers that are required to apply to PJM for membership as a result of the integration of the DEOK Zone into PJM.

PJM also requests a temporary waiver of Schedule 9-FERC, which concerns PJM's billing of the annual FERC charge attributable to the Transmission Owners in the PJM region. As the Commission will utilize transmission volumes from 2011 for the 2012 FERC Annual Charge, the Midwest ISO's 2012 annual charge will include the Companies' transmission volumes and PJM's 2012 annual charge will not. The Midwest ISO will bill the Companies directly for the 2012 FERC Annual Charge assessed to the Midwest ISO for the Companies' 2011 transmission volumes. If PJM started assessing this fee to the Companies as soon as they joined PJM, the Companies would have to pay

[90] PJM OA, Schedule 1, Section 1.4.3.

a disproportionate share of the annual assessment. To ensure that the Companies are not over- or under-assessed their share of the annual FERC fees, PJM is requesting a temporary waiver of Schedule 9-FERC of the PJM OATT charges to the DEOK Zone. This waiver would cover the period beginning with the planned integration date of January 1, 2012 and expire on September 30, 2012.

VI. ADDITIONAL INFORMATION

A. Proposed Effective Date

PJM and the Companies request an effective date of January 1, 2012, for the rates, terms, and conditions for transmission service that are described in the tariff records that are filed herewith.

B. Communications

Communications should be directed to the following:

For PJM:

Steven R. Pincus
Assistant General Counsel
PJM Interconnection, L.L.C.
955 Jefferson Avenue
Norristown, PA 19403
(610) 666-4370

Jennifer H. Tribulski
Senior Counsel
PJM Interconnection, L.L.C.
955 Jefferson Avenue
Norristown, PA 19403
(610) 666-4363

Craig Glazer
Vice President – Federal Government Policy
PJM Interconnection, L.L.C.
1200 G Street, NW, Suite 600
Washington, DC 20005
(202) 423-4743

STEPTOE & JOHNSON LLP

For Duke Energy Ohio and Duke Energy Kentucky:

Paul R. Kinny
Associate General Counsel
Duke Energy Corporation
550 South Tryon
Charlotte, NC 28202
(980) 373-6609

James B. Gainer
Vice President – Federal
Regulatory Policy
Duke Energy Corporation
550 South Tryon
Charlotte, NC 28202
(704) 382-5618

Gary A. Morgans
Steptoe & Johnson LLP
1330 Connecticut Avenue, NW
Washington, DC 20036
(202) 429-6234

Noel Symons
McGuireWoods LLP
2001 K Street, NW
Suite 400
Washington, DC 20006
(202) 857-2929

C. List of Documents Submitted With Filing

Together with this filing letter PJM and the Companies submit the following:[91]

1. Clean and marked revised PJM OATT Section 1.32G;
2. Clean and marked revised PJM OATT Attachment J;[92]
3. New Attachment C-2 to the PJM OATT;
4. Clean and marked revised PJM OATT Attachment DD, Section 5.10;
5. Clean and marked revised PJM OATT Attachment K-Appendix, Section 3.2.2(q);
6. Clean and marked revised PJM OA Schedule 1, Section 3.2.2(q);

[91] Attachment A is the marked sections of the PJM OATT, Attachment B is the clean sections of the PJM OATT, and Attachment E is the signature pages for the TOA. Attachment A also includes the clean versions of PJM OATT Schedule C-2 and Attachments H-22, H-22A, H-22B, and JJ.

[92] Revisions adding the DEOK Zone to the map are not marked due to technical limitations. PJM requests a waiver of the Commission's regulations that would require the submission of marked tariff revisions for the revised map in this tariff section.

7. Clean and marked revised PJM OATT Attachment K-Appendix, Section 7.4.2 (b);
8. Clean and marked revised PJM OA Schedule 1, Section 7.4.2(b);
9. Clean and marked revised PJM OATT Attachment L;
10. Clean and marked revised PJM RAA Schedule 10.1;
11. Clean and marked revised PJM RAA Schedule 15;[93]
12. Clean and marked revised PJM RAA Schedule 17;
13. Clean and marked revised PJM TOA Attachment A;
14. A new signature page to the PJM TOA;
15. Clean and marked revised PJM OATT Schedule 1A (Transmission Owner Scheduling, System Control, and Dispatch Service);
16. Clean and marked revised PJM OATT Schedule 7 (Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service);
17. Clean and marked revised PJM OATT Schedule 8 (Non-Firm Point-To-Point Transmission Service);
18. New PJM OATT Attachment JJ (MTEP Project Cost Recovery For DEOK Zone);
19. New PJM OATT Attachment H-22 (Annual Transmission Rates – DEOK for Network Integration Transmission Service and Point-to-Point Transmission Service);[94]
20. New PJM OATT Attachment H-22A (Rate Formula Template – Utilizing FERC Form 1 Data);
21. New PJM OATT Attachment H-22B (DEOK Formula Rate Implementation Protocols);
22. Testimony and Exhibits of William Don Wathen Jr. on behalf of Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc. (Attachment C); and
23. Testimony and Exhibits of Robert B. Stoddard on behalf of Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc. (Attachment D).

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[93] Revisions adding the DEOK Zone to the map are not marked due to technical limitations. PJM requests a waiver of the Commission's regulations that would require the submission of marked tariff revisions for the revised map in this tariff section.

[94] For new tariff language in items 3, 14, 18, and 19, PJM and the Companies request waiver of the Commission's regulations that would require the submission of marked tariff revisions.

D. Miscellaneous

There are no costs included in this filing that have been alleged or judged in any administrative judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

E. Cost Support, Revenue Comparison, and Request for Waiver

Except as noted above in Section II, the formula rate that will be used to calculate the Companies' transmission rates as transmission owners in PJM is unchanged from that used to calculate their transmission rates in the Midwest ISO. In order to illustrate the operation of the formula rate in both RTOs, the Companies have enclosed as Exhibit Nos. DUK-101 and DUK-102 a calculation of their transmission revenue requirements for 2010 as calculated under their formula rate in both RTOs.

To the extent that waivers of the Commission's cost support regulations in 18 C.F.R. § 35.13 (2011) are necessary, the Companies respectfully request such waivers, including waiver of the full Period I-Period II data requirements, waiver of the attestation concerning Period II submissions required by Section 35.13(c)(6), and waiver of the requirements in Section 35.13(a)(2)(iv) to determine if and the extent to which a proposed change constitutes a rate increase based on Period I-Period II rates and billing determinants. Good cause exists for such waiver. The testimony and exhibits accompanying this filing, together with the Companies' publicly available FERC Form 1 information, provide ample support for the reasonableness of the proposed formula rate.

Detailed statements of the applicant's cost of service are not needed where the proposed rates are formulary and will be based on actual costs as reflected in the applicant's audited books and records. Further, such waiver would be consistent with Commission precedent for a formula rate of this nature.[95]

In addition, although the Companies believe that this filing includes sufficient information to meet the Commission's filing requirements, they request waiver of any applicable regulations to allow the filing to take effect in the manner described. Good cause exists for waiver because this filing will incorporate the Companies' existing transmission formula rate under the Midwest ISO Tariff into the PJM OATT with only the necessary changes described above.

F. Service

PJM has served a copy of this filing on all PJM Members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. PJM also has served the parties listed on the Commission's official service list for Docket No. ER09-1589.

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[95] *Southern California Edison Co.*, 136 FERC ¶ 61,074 at P 29 (2011) (granting waiver of Period I and II data); *Pub. Serv. Elec. & Gas Co.*, 124 FERC ¶ 61,303 at PP 23-24 (2008) (granting waiver of Sections 35.13(d)(1)-(2), 35.13(d)(5), and 35.13(h)); *Oklahoma Gas & Elec. Co.*, 122 FERC ¶ 61,071 at P 41 (2008) (same); *Am. Elec. Power Serv. Corp.*, 120 FERC ¶ 61,205 at P 41 (2007) (granting waiver of Period I and II data); *Commonwealth Edison Co.*, 119 FERC ¶ 61,238 at PP 92-94 (2007) (granting waiver of Period I and II data and cost-of-service statements); *Trans-Allegheny Interstate Line Co.*, 119 FERC ¶ 61,219 at P 57 (2007) (same); *Duquesne Light Co.*, 118 FERC ¶ 61,087 at P 79 (2007) (granting waiver of Sections 35.13(d)(1)-(2) and 35.13(h)); *Idaho Power Co.*, 115 FERC ¶ 61,281 at P 20 (2006) (granting waiver of Period II data); *Allegheny Power Sys. Operating Cos.*, 111 FERC ¶ 61,308 at PP 55-56 (2005) (granting waiver of Period I and II data).

In accordance with the Commission's regulations, PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: http://www.pjm.com/documents/ferc-manuals/ferc-filings.aspx with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region alerting them that this filing has been made by PJM and is available by following such link.[96] If the document is not immediately available by using the referenced link, the document will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the FERC's eLibrary website located at the following link: http://www.ferc.gov/docs-filing/elibrary.asp in accordance with the Commission's regulations and Order No. 714.

VII. CONCLUSION

Thank you for your consideration of this request. Please contact the undersigned if you have any questions.

[96] Attached to Mr. Stoddard's Testimony identified as Attachment D are three Exhibits. Two of these, Exhibits DUK-202 and DUK-203, are spreadsheets. The filing with the Commission includes the spreadsheets in both PDF format and an active Excel format. However, due to PJM's service requirements regarding tariff related matters, only the PDF format will be available via the link for service on the PJM website. Parties desiring access to the active Excel spreadsheets (which have more functionality and may be easier to read) are invited to retrieve them from FERC's eLibrary or to contact the undersigned counsel to Duke Energy to request a copy.

STEPTOE & JOHNSON LLP

Respectfully submitted,

Gary A. Morgans

Gary A. Morgans
Steptoe & Johnson LLP
1330 Connecticut Avenue, NW
Washington, DC 20036

Noel Symons
McGuireWoods LLP
2001 K Street, NW
Suite 400
Washington, DC 20006

Paul R. Kinny
Associate General Counsel
Duke Energy Corporation
550 South Tryon Street
Mail Code DEC45A
Charlotte, NC 28202

Attorneys for Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc.

On behalf of PJM Interconnection, L.L.C., Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc.

Attachment A
Marked Format
(Redline)

Sections of the
PJM Open Access Transmission Tariff,
PJM Operating Agreement,
PJM Reliability Assurance Agreement
and
PJM Consolidated Transmission Owners Agreement

(Agreements separated by cover pages)

PJM Open Access Transmission Tariff
Marked Format

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Atlantic City Electric Company Formula Rate Appendix A

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Delmarva Power & Light Company Load Power Factor Charge Applicable to Service the Interconnection Points

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ATTACHMENT GG - APPENDIX III – GENERAL TERMS AND CONDITIONS

Definitions – O – P - Q

1.27C Office of the Interconnection:

Office of the Interconnection shall have the meaning set forth in the Operating Agreement.

1.28 Open Access Same-Time Information System (OASIS):

The information system and standards of conduct contained in Part 37 and Part 38 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

1.28A Operating Agreement of the PJM Interconnection, L.L.C. or Operating Agreement:

That agreement dated as of April 1, 1997 and as amended and restated as of June 2, 1997 and as amended from time to time thereafter, among the members of the PJM Interconnection, L.L.C.

1.28A.01 Option to Build:

The option of the New Service Customer to build certain Customer-Funded Upgrades, as set forth in, and subject to the terms of, the Construction Service Agreement.

1.28B Optional Interconnection Study:

A sensitivity analysis of an Interconnection Request based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

1.28C Optional Interconnection Study Agreement:

The form of agreement for preparation of an Optional Interconnection Study, as set forth in Attachment N-3 of the Tariff.

1.29 Part I:

Tariff Definitions and Common Service Provisions contained in Sections 2 through 12.

1.30 Part II:

Tariff Sections 13 through 27 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.31 Part III:

Tariff Sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.31A Part IV:

Tariff Sections 36 through 112 pertaining to generation or merchant transmission interconnection to the Transmission System in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.31B Part V:

Tariff Sections 113 through 122 pertaining to the deactivation of generating units in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.31C Part VI:

Tariff Sections 200 through 237 pertaining to the queuing, study, and agreements relating to New Service Requests, and the rights associated with Customer-Funded Upgrades in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.32 Parties:

The Transmission Provider, as administrator of the Tariff, and the Transmission Customer receiving service under the Tariff. PJMSettlement shall be the Counterparty to Transmission Customers.

1.32.01 PJM:

PJM Interconnection, L.L.C.

1.32A PJM Administrative Service:

The services provided by PJM pursuant to Schedule 9 of this Tariff.

1.32B PJM Control Area:

The Control Area that is recognized by NERC as the PJM Control Area.

1.32C PJM Interchange Energy Market:

The regional competitive market administered by the Transmission Provider for the purchase and sale of spot electric energy at wholesale interstate commerce and related services, as more fully set forth in Attachment K – Appendix to the Tariff and Schedule 1 to the Operating Agreement.

1.32D PJM Manuals:

The instructions, rules, procedures and guidelines established by the Transmission Provider for the operation, planning, and accounting requirements of the PJM Region and the PJM Interchange Energy Market.

1.32E PJM Region:

Shall mean the aggregate of the PJM West Region, the VACAR Control Zone, and the MAAC Control Zone.

1.32F PJM South Region:

The VACAR Control Zone.

1.32.F.01 PJMSettlement:

PJM Settlement, Inc. (or its successor).

1.32G PJM West Region:

The PJM West Region shall include the Zones of Allegheny Power; Commonwealth Edison Company (including Commonwealth Edison Co. of Indiana); AEP East Operating Companies; The Dayton Power and Light Company; ~~and~~ the Duquesne Light Company, American Transmission Systems, Incorporated, and Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.

1.33 Point(s) of Delivery:

Point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Part II of the Tariff. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.33A Point of Interconnection:

The point or points, shown in the appropriate appendix to the Interconnection Service Agreement and the Interconnection Construction Service Agreement, where the Customer Interconnection Facilities interconnect with the Transmission Owner Interconnection Facilities or the Transmission System.

1.34 Point(s) of Receipt:

Point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under

Part II of the Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.35 Point-To-Point Transmission Service:

The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff.

1.36 Power Purchaser:

The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

1.36.01 PRD Curve

PRD Curve shall have the meaning provided in the Reliability Assurance Agreement.

1.36.02 PRD Provider

PRD Provider shall have the meaning provided in the Reliability Assurance Agreement.

1.36.03 PRD Reservation Price

PRD Reservation Price shall have the meaning provided in the Reliability Assurance Agreement.

1.36.04 PRD Substation:

PRD Substation shall have the meaning provided in the Reliability Assurance Agreement.

1.36.*05* Pre-Confirmed Application:

An Application that commits the Eligible Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

1.36A Pre-Expansion PJM Zones:

Zones included in this Tariff, along with applicable Schedules and Attachments, for certain Transmission Owners – Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power and Light Company, Jersey Central Power and Light Company, Metropolitan Edison Company, PECO Energy Company, Pennsylvania Electric Company, Pennsylvania Power & Light Group, Potomac Electric Power Company, Public Service Electric and Gas Company, Allegheny Power, and Rockland Electric Company.

1.36A.01 Price Responsive Demand

Price Responsive Demand shall have the meaning provided in the Reliability Assurance Agreement.

1.36A.*02* Project Financing:

Shall mean: (a) one or more loans, leases, equity and/or debt financings, together with all modifications, renewals, supplements, substitutions and replacements thereof, the proceeds of which are used to finance or refinance the costs of the Customer Facility, any alteration, expansion or improvement to the Customer Facility, the purchase and sale of the Customer Facility or the operation of the Customer Facility; (b) a power purchase agreement pursuant to which Interconnection Customer's obligations are secured by a mortgage or other lien on the Customer Facility; or (c) loans and/or debt issues secured by the Customer Facility.

1.36A.*03* Project Finance Entity:

Shall mean: (a) a holder, trustee or agent for holders, of any component of Project Financing; or (b) any purchaser of capacity and/or energy produced by the Customer Facility to which Interconnection Customer has granted a mortgage or other lien as security for some or all of Interconnection Customer's obligations under the corresponding power purchase agreement.

1.36B Queue Position:

The priority assigned to an Interconnection Request, a Completed Application, or an Upgrade Request pursuant to applicable provisions of Part VI.

SCHEDULE 1A
Transmission Owner Scheduling, System Control and Dispatch Service

Scheduling, System Control and Dispatch Service is provided directly by the Transmission Provider under Schedule 1. The Transmission Customer must purchase this service from the Transmission Provider. Certain control center facilities of the Transmission Owners also are required to provide this service. This Schedule 1A sets forth the charges for Scheduling, System Control and Dispatch Service based on the cost of operating the control centers of the Transmission Owners. The Transmission Provider shall administer the provision of Transmission Owner Scheduling, System Control and Dispatch Service. PJMSettlement shall be the Counterparty to the purchases of Transmission Owner Scheduling, System Control and Dispatch Service.

The charges for operation of the control centers of the Transmission Owners shall be determined by multiplying the applicable rate as follows times the Transmission Customer's use of the Transmission System (including losses) on a megawatt hour basis:

(A) For a Transmission Customer serving Zone Load in:

Zone	**Rate ($/MWh)**
Atlantic City Electric Company	0.0781
Baltimore Gas and Electric Company	0.0430
Delmarva Power & Light Company	0.0743
PECO Energy Company	0.1189
PP&L, Inc. Group	0.0618
Potomac Electric Power Company	0.0186
Public Service Electric and Gas Company	0.1030
Jersey Central Power & Light Company	0.0796
Metropolitan Edison Company	0.0796
Pennsylvania Electric Company	0.0796
Rockland Electric Company	0.2475
Commonwealth Edison Company	0.2223
AEP East Operating Companies	Rate updated annually Per Attachment H-14
The Dayton Power and Light Company	0.0797
Duquesne Light Company[1]	0.0520
American Transmission Systems, Incorporated ("ATSI")	Rate updated annually Per Attachment H-21
Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc. ("DEOK")	Rate updated annually Per Attachment H-22

[1] Charges for service under this schedule to customers of The Dayton Power and Light Company that are subject to the provisions of the October 14, 2003 Stipulation and Agreement of Settlement approved in FERC Docket No. EL03-56-000 shall be governed by such settlement.

(B) For a Transmission Customer serving Non-Zone Load (a Network Customer serving Non-Zone Network Load or a Transmission Customer taking Point-to-Point service where the Point of Delivery is at the boundary of the PJM Region):

$0.1019/MWh

Each month, PJMSettlement shall pay to each Transmission Owner an amount equal to the charges billed for that Transmission Owner's zone pursuant to (A) above, plus that Transmission Owner's share as stated below of the charges billed to Transmission Customers serving Non-Zone Network Load pursuant to (B) above:

Transmission Owner	**Share (%)**
Atlantic City Electric Company	0.50
Baltimore Gas and Electric Company	0.80
Delmarva Power & Light Company	0.77
PECO Energy Company	2.68
PP&L, Inc. Group	1.36
Potomac Electric Power Company	0.33
Public Service Electric and Gas Company	2.64
Jersey Central Power & Light Company	1.30
Metropolitan Edison Company	0.43
Pennsylvania Electric Company	0.66
Rockland Electric Company	0.20
Commonwealth Edison Company	37.62
AEP East Operating Companies	47.90
The Dayton Power and Light Company	2.36
Duquesne Light Company	0.45
American Transmission Systems, Incorporated ("ATSI")	0.00
Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc. ("DEOK")	0.00

SCHEDULE 7
Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service

1) The Transmission Customer shall pay each month for Reserved Capacity at the sum of the applicable charges set forth below for the Point of Delivery:

Summary of Charges
(in $/kW)

Point of Delivery	Yearly Charge	Monthly Charge	Weekly Charge	Daily On-Peak[1] Charge	Daily Off-Peak[2/] Charge
Border of PJM	18.888	1.574	0.3632	0.0726	0.0519
AE Zone	23.809	1.984	0.4580	0.0920	0.0650
BG&E Zone	15.675	1.306	0.3010	0.0600	0.0430
Delmarva Zone	19.378	1.615	0.3730	0.0750	0.0530
JCPL Zone	15.112	1.259	0.2906	0.0581	0.0414
MetEd Zone	15.112	1.259	0.2906	0.0581	0.0414
Penelec Zone	15.112	1.259	0.2906	0.0581	0.0414
PECO Zone	26.264	2.189	0.5051	0.1010	0.0722
PPL Zone: Total charge is the sum of the components	PPL: * AEC: 0.463 UGI: *	PPL: * AEC: 0.039 UGI: *	PPL: * AEC: 0.0089 UGI: *	PPL: * AEC: 0.0018 UGI: *	PPL: * AEC: 0.0013 UGI: *
Pepco Zone	20.999	1.750	0.4040	0.0810	0.0580
PSE&G Zone	23.696	1.975	0.4557	0.0911	0.0651
AP Zone	20.847	1.737	0.4009	0.0802	0.0573
Rockland Zone	32.114	2.676	0.6176	0.1235	0.0882
ComEd Zone[3/]	[4/]				

* PPL Electric Utilities Corporation's and UGI Utilities' respective component of the total charge is posted on the PJM Internet website.

Point of Delivery	Yearly Charge	Monthly Charge	Weekly Charge	Daily On-Peak[1] Charge	Daily Off-Peak[2/] Charge
AEP East Zone 5/	Monthly Charge X 12	Rate Pursuant to Attachment H-14	Yearly Charge / 52	Weekly Charge / 5	Weekly Charge / 7
Dayton Zone	15.674	1.306	0.3014	0.0603	0.0431
Duquesne Zone	14.17	1.18	0.27	0.0540	0.0386
Dominion Zone					
ATSI Zone	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21
DEOK Zone	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22

Effective December 1, 2004, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 7 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc. obtained pursuant to requests submitted on or after November 17, 2003, for service commencing on or after April 1, 2004. Effective April 1, 2006, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 7 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc.

1/ Monday – Friday except the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

2/ Saturday and Sunday and the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

3/ Each month, revenue credits will be applied to the gross charge in accordance with section 8 below to determine the actual charge to the Transmission Customer.

4/ The charges for the ComEd zone are posted on PJM's website. In addition to other rates set forth in this schedule, customers within the ComEd zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - $/kW/year = $1,523,039, divided by the 1 CP demand for the ComEd zone for the prior calendar year;

Monthly Rate - $/kW/month. = Annual Rate divided by 12;

Weekly Rate - $/kW/week = Annual Rate divided by 52;

Daily Rate - $/kW/day = Weekly Rate divided by 5.

In order to ensure that the charge does not result in either an over-recovery or under-recovery of ComEd's start-up costs, PJM will institute an annual true-up mechanism in the month of May of each of the years 2008-2014. In May of each of those years, PJM will compare the amount collected under this charge for the previous 12 months with the target annual amount of $1,523,039 and calculate any credits or surcharges that would be needed to ensure that $1,523,039 is collected for each year. Any credit or surcharge will be assessed in the June bills for years 2008-2014, consistent with the above methodology.

5/ The rates for firm point-to-point transmission service in the AEP Zone will be charged at the yearly, monthly, weekly or daily rate equivalent to the rate effective in such period under Attachment H-14. In addition to other rates set forth in this schedule, customers within the AEP East Zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - $/kW/year = $2,362,185, plus any applicable true-up adjustment, divided by the 1 CP demand for the AEP East Zone for the prior calendar year;

Monthly Rate - $/kW/month. = Annual Rate divided by 12;

Weekly Rate - $/kW/week = Annual Rate divided by 52;

Daily Rate - $/kW/day = Weekly Rate divided by 5.

For the period November 1, 2005 through March 31, 2006, the rate shall be $8.94/MW-month; for the period April 1 through December 31, 2006, the rate shall be $8.60/MW-month, thereafter, the rate will be subject to the following true-up:

In order to ensure that the charge does not result in either over-recovery or under-recovery of AEP's start-up costs, PJM will institute an annual true-up mechanism and implement revised charges as of January 1st of each of the years 2007-2019. In January of each of those years, PJM will compare the amount collected under this charge for the previous year or part thereof with the target annual amount of $2,362,185 and calculate the rates that would be needed, given the expected billing demands, to collect $2,362,185, adjusted for any prior year over-collection or under-collection. In the final year that the rate is collected, PJM will calculate the rate to collect five-twelfths of the annual amount ($984,244), plus or minus any prior year true up amount, by May 31 of that year, and shall charge such rate until that amount is collected, whether that date be before or after May 31, 2020.

6/ The service period charges rounded to four decimal places for the Dominion Zone are as follows:

Yearly Charge - $/kW/year = the formula rate for Network Integration Transmission Service as described in Attachment H-16 and Attachment H-16A divided by 1000 kW/MW

Monthly Charge - $/kW/month. = Yearly Charge divided by 12;

Weekly Charge - $/kW/week = Yearly Charge divided by 52;

Daily On-Peak Charge - $/kW/day = Weekly Charge divided by 5;

Daily Off-Peak Charge - $/kW/day = Weekly Charge divided by 7.

On a monthly basis, revenue credits shall be calculated based on the sum of VEPCO's share of revenues collected during the month from Schedule 7 and Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A. The sum of these revenue credits will appear as an adjustment to the to the gross monthly service period charges produced by the above formula.

2) The total demand charge in any week, pursuant to a reservation for Daily On-Peak Delivery, or Daily Off-Peak Delivery shall not exceed the Weekly Delivery rate specified in section (1) above for weekly service times the highest amount in kilowatts of Reserved Capacity and any additional transmission service, if any, in any day during such week.

3) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

4) **Congestion, Losses and Capacity Export:** In addition to any payment under this Schedule, the Transmission Customer shall pay Redispatch Costs as specified in Section 27 of the Tariff. The Transmission Customer shall be responsible for losses as specified in the Tariff. Any Transmission Customer that is a Capacity Export Transmission Customer, as defined in Attachment DD to this Tariff, shall pay any applicable charges, and receive any applicable credits, for such a customer pursuant to Attachment DD.

5) **Other Supporting Facilities and Taxes:** In addition to the rates set forth in section (1) of this schedule, the Transmission Customer shall pay charges determined on a case-by-case basis for facilities necessary to provide Transmission Service at voltages lower than those shown in Attachment H for the applicable Zone(s) and any amounts necessary to reimburse PJMSettlement for any amounts payable as sales, excise, "Btu," carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

6) **Transitional Revenue Neutrality Charge:** In addition to the rates set forth in section (1) of this schedule and any other applicable charges, the Transmission Customer shall also pay for Reserved Capacity for delivery at the border of the PJM Region a non-discountable charge of $3.60/kw/year, $0.30/kw/mo., $0.0692/kw/week, $0.0099/kw/day-off-peak, or $0.0138/kw/day-on-peak. PJM shall distribute all revenues from the Transitional Revenue Neutrality Charge to Allegheny Power. The charge provided for under this section (6) shall terminate effective as of the day on which the sum total of the revenues collected by this charge, the Transitional Revenue Neutrality Charge under Schedule 8, and the Transitional Market Expansion Charge under Schedule 11 equal $84,993,360.

7) **Transmission Enhancement Charges.** In addition to the rates set forth in Section (1) of this Schedule and any other applicable charges, the Transmission Customer shall also pay any Transmission Enhancement Charges for which it is designated as a Responsible Customer under Schedule 12 appended to the Tariff.

8) **Determination of monthly charges for ComEd Zone:** On a monthly basis, revenue credits shall be calculated based on the sum of ComEd's share of revenues collected during the month from: (i) the PJM Border Rate under Schedule 7; (ii) Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A; (iii) Seams Elimination Charge/Cost Adjustment/Assignment ("SECA") revenues allocable to ComEd under the Tariff; and (iv) any Point-To-Point Transmission Service where the Point of Receipt and the Point of Delivery are both internal to the ComEd Zone. On this basis, the sum of these revenues will appear as a reduction to the gross monthly rate stated above on a Transmission Customer's bill in that month for service under this schedule.

9) **Determination of monthly charges for AEP Zone:** On a monthly basis, revenue credits shall be calculated based on the sum of AEP's share of revenues collected during the month from: (i) the PJM Border Rate under Schedule 7; (ii) Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A; and (iii) Firm Point-To-Point Transmission Service where the Point of Delivery is internal to the AEP Zone. The sum of these revenue credits will appear as an adjustment (reduction) to the gross monthly rate stated above on a Transmission Customer's bill in that month for service under this schedule.

10) **Resales:** The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.

SCHEDULE 8
Non-Firm Point-To-Point Transmission Service

1) The Transmission Customer shall pay for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below for the Point of Delivery:

Summary of Charges

Point of Delivery	Monthly Charge ($/kW)	Weekly Charge ($/kW)	Daily On-Peak[1/] Charge ($/kW)	Daily Off-Peak[2/] Charge ($/kW)	Hourly On-Peak[3/] Charge ($/MWh)	Hourly Off-Peak[4/] Charge ($/MWh)
Border of PJM	1.574	0.3632	0.0726	0.0519	4.54	2.16
AE Zone	1.984	0.4580	0.0920	0.0650	5.7	2.72
BG&E Zone	1.306	0.3010	0.0600	0.0430	3.8	1.80
Delmarva Zone	1.615	0.3730	0.0750	0.0530	4.6	2.21
JCPL Zone	1.259	0.2906	0.0581	0.0414	3.6	1.73
MetEd Zone	1.259	0.2906	0.0581	0.0414	3.6	1.73
Penelec Zone	1.259	0.2906	0.0581	0.0414	3.6	1.73
PECO Zone	2.189	0.5051	0.1010	0.0722	6.3	3.01
PPL Zone: Total charge is the sum of the components	PPL: * AEC: 0.039 UGI: *	PPL: * AEC: 0.0089 UGI: *	PPL: * AEC: 0.0018 UGI: *	PPL: * AEC: 0.0013 UGI: *	PPL: * AEC: 0.11 UGI: *	PPL: * AEC: 0.05 UGI: *
Pepco Zone	1.750	0.4040	0.0810	0.0580	5.0	2.40
PSE&G Zone	1.975	0.4557	0.0911	0.0651	5.7	2.71
AP Zone	1.737	0.4009	0.0802	0.0573	5.0	2.39
Rockland Zone	2.676	0.6176	0.1235	0.0882	7.7	3.67
ComEd Zone[5/]	[6/]					

* PPL Electric Utilities Corporation's and UGI Utilities' respective component of the total charge is posted on the PJM Internet website.

AEP East Zone[7/] Nov. 1, 2005 SECA Ended W-JF Line In	AEP East Zone[7/]	Rate Pursuant to Attachment H-14	Monthly Charge X 12 / 52 ~~0.24948~~	Weekly Charge / 5	Weekly Charge / 7	Daily On-Peak Charge / 16
Dayton Zone	Dayton Zone	1.306	0.3014	0.0603	0.0431	3.77
Duquesne Zone	Duquesne Zone	1.18	0.27	0.0540	0.0386	3.38
Dominion Zone[8/]	Dominion Zone[8/]					
ATSI Zone	ATSI Zone	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21
DEOK Zone	DEOK Zone	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22

1/ Monday - Friday except the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

2/ Saturday and Sunday and the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

3/ 7:00 a.m. up to the hour ending 11:00 p.m.

4/ 11:00 p.m. up to the hour ending 7:00 a.m.

5/ Each month, revenue credits will be applied to the gross charge in accordance with Paragraph 9 below to determine the actual charge to the Transmission Customer.

6/ The charges for the ComEd zone are posted on PJM's website. In addition to the other rates set forth in this schedule, customers within the ComEd zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - $/kW/year = $1,523,039, divided by the 1 CP demand for the ComEd zone for the prior calendar year;

Monthly Rate - $/kW/month. = Annual Rate divided by 12;

Weekly Rate - $/kW/week = Annual Rate divided by 52;

Daily rate - $/kW/day = Weekly Rate divided by 5.

In order to ensure that the charge does not result in either an over-recovery or under-recovery of ComEd's start-up costs, PJM will institute an annual true-up mechanism in the month of May of each of the years 2008-2014. In May of each of those years, PJM will compare the amount collected under this charge for the previous 12 months with the target annual amount of $1,523,039 and calculate any credits or surcharges that would be needed to ensure that $1,523,039 is collected for each year. Any credit or surcharge will be assessed in the June bills for years 2008-2014, consistent with the above methodology.

7/ The rates for non-firm point-to-point transmission service in the AEP Zone will be charged at the monthly, weekly, daily or hourly rate equivalent to the rate effective in such period under Attachment H-14. In addition to other rates set forth in this schedule, customers within the AEP East Zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - $/kW/year = $2,362,185, plus any applicable true-up adjustment, divided by the 1 CP demand for the AEP East Zone for the prior calendar year;

Monthly Rate - $/kW/month. = Annual Rate divided by 12;

Weekly Rate - $/kW/week = Annual Rate divided by 52;

Daily Rate - $/kW/day = Weekly Rate divided by 5.

For the period November 1, 2005 through March 31, 2006, the rate shall be $8.94/MW-month; for the period April 1 through December 31, 2006, the rate shall be $8.60/MW-month, thereafter, the rate will be subject to the following true-up:

In order to ensure that the charge does not result in either over-recovery or under-recovery of AEP's start-up costs, PJM will institute an annual true-up mechanism and implement revised charges as of January 1st of each of the years 2007-2019. In January of each of those years, PJM will compare the amount collected under this charge for the previous year or part thereof with the target annual amount of $2,362,185 and calculate the rates that would be needed, given the expected billing demands, to collect $2,362,185, adjusted for any prior year over-collection or under-collection. In the final year that the rate is collected, PJM will calculate the rate to collect five-twelfths of the annual amount, ($984,244), plus or minus any prior year true up amount, by May 31 of that year, and shall charge such rate until that amount is collected, whether that date be before or after May 31, 2020.

Effective December 1, 2004, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 8 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc. obtained pursuant to requests submitted on or after November 17, 2003, for service commencing on or after April 1, 2004. Effective April 1, 2006, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 7 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc.

8/ The service period charges rounded to four decimal places for the Dominion Zone are as follows:

Monthly Charge - $/kW/month = the formula rate for Network Integration Transmission Service as described in Attachment H-16 and Attachment H-16A divided by 12 divided by 1000 kW/MW;

Weekly Charge - $/kW/week = 12 times Monthly Charge divided by 52;

Daily On-Peak Charge - $/kW/day = Weekly Charge divided by 5;

Daily Off-Peak Charge - $/kW/day = Weekly Charge divided by 7;

Hourly On-Peak Charge - $/MWh = Daily On-Peak Charge / 16 hours *1000 kW/ MW;

Hourly Off-Peak Charge - $/ MWh = Daily Off-Peak Charge / 24 hours *1000 kW/ MW.

2) The total demand charge in any week, pursuant to a reservation for Daily On-Peak Delivery or Daily Off-Peak Delivery, shall not exceed the Weekly Delivery rate specified in section (1) above for weekly service times the highest amount in kilowatts of Reserved Capacity and any additional transmission service, if any, in any day during such week.

3) **Hourly delivery:** The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed the amounts set forth above for a Point of Delivery.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (1) above for daily service times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (1) above for weekly service times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

4) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

5) **Congestion, Losses and Capacity Export:** A Transmission Customer desiring Non-Firm Point-to-Point Transmission Service may elect to pay transmission congestion charges. If the Transmission Customer so elects, it shall either (a) if the applicable Transmission Congestion Charge as calculated pursuant to Attachment K is positive, pay the higher of the applicable Transmission Congestion Charge or the applicable rate under section (1) above, or (b) if the applicable Transmission Congestion Charge as calculated pursuant to Attachment K is negative, pay or be credited the sum of the applicable Transmission Congestion Charge and the rate under section (1) above. The Transmission Customer shall be responsible for losses as specified in the

Tariff. Any Transmission Customer that is a Capacity Export Transmission Customer, as defined in Attachment DD to this Tariff, shall pay for any applicable charges, and receive any applicable credits, for such a customer pursuant to Attachment DD.

6) **Other Supporting Facilities and Taxes:** In addition to the charges set forth in section (1) of this schedule, the Transmission Customer shall pay charges determined on a case-by-case basis for facilities necessary to provide Transmission Service at voltages lower than those shown in Attachment H for the applicable Zone(s) and any amounts necessary to reimburse the Transmission Provider for any amounts payable as sales, excise, "Btu," carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

7) **Transitional Revenue Neutrality Charge:** In addition to the rates set forth in Section (1) of this Schedule and any other applicable charges, the Transmission Customer shall also pay for Reserved Capacity for delivery at the border of the area comprised of the PJM Control Area and PJM West region a non-discountable charge of $0.241/kw/mo., $0.0556/kw/week, $0.0079/kw/day (both on-peak and off-peak), or $0.33/Mw/hour (both on-peak and off-peak). PJM shall distribute all revenues from the Transitional Revenue Neutrality Charge to Allegheny Power. The charge provided for under this section (7) shall terminate effective as of the day on which the sum total of the revenues collected by this charge, the Transitional Revenue Neutrality Charge under Schedule 7, and the Transitional Market Expansion Charge under Schedule 11 equal $84,993,360.

8) **Transmission Enhancement Charges:** In addition to the rates set forth in Section (1) of this Schedule and any other applicable charges, the Transmission Customer shall also pay any Transmission Enhancement Charges for which it is designated as a Responsible Customer under Schedule 12 appended to the Tariff.

9) **Determination of monthly charges for ComEd Zone:** On a monthly basis, revenue credits shall be calculated based on the sum of ComEd's share of revenues collected during the month from: (i) the PJM Border Rate under Schedule 7; (ii) Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A; (iii) Seams Elimination Charge/Cost Adjustment/Assignment ("SECA") revenues allocable to ComEd under the Tariff; and (iv) any Point-To-Point Transmission Service where the Point of Receipt and the Point of Delivery are both internal to the ComEd Zone. On this basis, the sum of these revenues will appear as a reduction to the gross monthly rate stated above on a Transmission Customer's bill in that month for service under this schedule.

10) **Resales:** The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.

ATTACHMENT C-2

Conversion of Service in the Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc. (“DEOK”) Zone

The Office of the Interconnection is scheduled to become the Transmission Provider for the Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc. (“DEOK”) Zone under the terms of this Tariff on January 1, 2012 and the open access transmission tariff of the Midwest Independent Transmission System Operator, Inc. (“Midwest ISO”) shall be superseded with respect to the DEOK Zone. Reservations purchased on the Midwest ISO nodes prior to the integration of the DEOK Zone into PJM shall be converted to the appropriate service under this Tariff and subject to the rates, terms and conditions of this Tariff. In addition, interconnection requests under the Midwest ISO tariff pending prior to the integration of the DEOK Zone into PJM shall be converted to requests for interconnection under this Tariff. This Attachment sets forth the principles that shall govern such conversions of service.

For service with an export from the DEOK Zone and an import to the remainder of the PJM Region (or vice-versa), the transmission service will be converted into a single reservation under this Tariff. For service with an export from the DEOK Zone and an import to the Midwest ISO Region (or vice-versa), the transmission service cannot be converted into a single reservation Customers who have reservations that need to be converted will be contacted directly by the Office of the Interconnection. Not all transmission service provided under the Midwest ISO tariff exactly matches a service under this Tariff. Differences include variations in product definitions and PJM Region LMP pricing points. These variances in transmission requests will be converted into the defined product types explained below. The guidelines for the conversion of service are as follows:

1. All existing reservations will retain the same capacity (in megawatts) and will be converted to a comparable PJM product and duration with the applicable point of receipt, point of delivery, and path. Firm Point-to-Point Transmission Service redirected on a non-firm basis to Secondary Receipt or Delivery Points under the Midwest ISO tariff prior to the DEOK integration date will be converted to service under this tariff on the basis of the original firm points of receipt and delivery. Firm Point-to-Point Transmission Service redirected on a firm basis under section 22.2 (Modification on a Firm Basis) (or equivalent) of the Midwest ISO tariff prior to the DEOK integration date will be converted to service under this tariff on the basis of the modified firm points of receipt and delivery.

2. All DEOK Zone Midwest ISO reservations extending past the integration date must select Source and Sink LMP pricing points, where applicable, and willing to pay congestion (or not), if applicable. Willing to pay congestion (or not) must be determined no later than 12:00 noon EPT, 30 days prior to the DEOK integration start date. In the event the customer does not choose within the allotted deadline above, PJM will convert the service to the most closely analogous service under the PJM Tariff, in PJM’s judgment. Willing to pay congestion is optional for non-firm and non-designated transmission service; Firm service, by definition, is willing to pay congestion. All

converted service (as they exist) will be placed on the PJM OASIS no later than 30 days prior to the DEOK integration start date.

3. All Midwest ISO DEOK Zone import reservations will be converted to one of the following service types as defined by this Tariff or on the PJM OASIS: Spot market, Non-Firm Point-to-Point, Firm Point-to-Point, Network Designated or Network Non-Designated. This choice will be made on an individual reservation basis, based on the scheduling intent of the reservation.

   All service with an export from the DEOK Zone into the Midwest ISO will be represented with new PJM reservations with one of the following service types as defined by this Tariff or on the PJM OASIS: Non-Firm Point-to-Point, or Firm Point-to-Point. This choice will be made on an individual reservation basis, based on the scheduling intent of the reservation.

4. All existing DEOK Zone Midwest ISO extended transmission requests (i.e. monthly, weekly, daily) that span multiple months will be converted to their largest individual components as defined on the PJM OASIS. For example, a monthly request from October 1 to December 1 will be converted to two individual monthly requests, October 1 to November 1, and November 1 to December 1; and a daily request from January 1 of one year to January 1 of the next year will be converted to yearly service.

5. Sliding monthly service (i.e. monthly service that does not run from the first day of the given month to the last day of the given month) will be converted to weekly and daily service.

6. Sliding weekly service (i.e. weekly service that does not run from Monday at 00:00 to Sunday at 23:59) will be converted to daily service.

7. Transmission service that is not currently confirmed on the Midwest ISO DEOK Zone OASIS nodes and is in an active state such as “Received”, “Queued” or “Study” will be transferred to the integrated PJM OASIS node and will maintain its initial queued date.

8. All “Grandfathered” requests that exist on the DEOK Zone Midwest ISO OASIS nodes will require a reservation on the PJM OASIS node.

9. To facilitate the OASIS transition, from one month prior to the integration start date until such integration start date, requests for service that are active on or after such date one month prior to the integration start date should be made on both the pre-integration transmission owner or OASIS nodes and the PJM OASIS nodes.

10. Reservations will be converted based on the priority of the product.

11. Although the Office of the Interconnection will attempt to convert existing transmission reservations into comparable reservations on the PJM OASIS, there will be unique instances where this will not be possible (e.g., reliability issues, etc.). In this case,

reservations will be reviewed on a case-by-case basis. Transmission service that is not currently accepted on the DEOK Zone Midwest ISO OASIS nodes and is in an active state such as “Received”, “Queued” or “Study” will be assigned the same status and queue position on the PJM OASIS as it had on the Midwest ISO OASIS prior to conversion.

12. Converted Point-to-Point and Network transmission service reservations that intersect with or begin after the integration commencement date will be posted to the PJM OASIS web page on a weekly basis. The web page will identify the original DEOK Zone Midwest ISO reservation and the new PJM OASIS reservation.

13. An Interconnection Request pending under the Midwest ISO OATT at the time of the integration of the DEOK Zone shall be assigned the same priority date under this Tariff as such request had under the Midwest ISO’s OATT immediately prior to such integration. The Interconnection Request will be assigned a PJM queue identifier such that the Interconnection Customer’s priority date relative to existing PJM queued Interconnection Requests can be easily determined. All such Interconnection Requests will be integrated into PJM’s existing Interconnection Queue(s), effective on the DEOK integration start date, and will be subject to the generation interconnection procedures under Part IV and Part VI of this Tariff. On the DEOK integration date, PJM will assume the technical studies that have been started by the Midwest ISO. After the studies are complete, the Interconnection Customer will be required to pay for any Network Upgrades and/or Local Upgrades that are needed for the unit to qualify for Capacity Interconnection Rights under the this Tariff.

ATTACHMENT H-22
Annual Transmission Rates – DEOK
for Network Integration Transmission Service
and Point-to-Point Transmission Service

1. The Annual Transmission Revenue Requirements ("ATRR") and the rates for Network Integration Transmission Service and Point-to-Point Transmission Service are equal to the results of the formula shown in Attachment H-22A, and will be posted on the PJM website. The ATRR and the rates reflect the cost of providing transmission service over the 69 kV and higher transmission facilities of Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc. (jointly, "DEOK"). Service utilizing other DEOK facilities will be provided at rates determined on a case-by-case basis and stated in service agreements with affected customers.

2. The formula rate in this attachment shall be effective until amended by DEOK or modified by the Commission.

3. In addition to the rate set forth in paragraph 1, a Network Customer purchasing Network Integration Transmission Service shall pay for transmission congestion charges, in accordance with the provisions of the Tariff, and any amounts necessary to reimburse DEOK for any amounts payable by it as sales, excise, "Btu," carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

Formula Rate - Non-Levelized — For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

Line No.			Total		Allocator	Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)					$ -
	REVENUE CREDITS (Note T)					
2	Account No. 454	(page 4, line 34)	$ -	TP	0.00000	$ -
3	Account No. 456.1	(page 4, line 35)	0	TP	0.00000	0
4a	Revenues from Grandfathered Interzonal Transactions		0	TP	0.00000	0
4b	Revenues from service provided by ISO at a discount		0	TP	0.00000	0
5a	Legacy MTEP Credit (Appendix C, page 2, line 3, col. 12)		0		1.00000	0
5b	RTEP Transmission Enhancement Credit (Appendix B, page 2, line 3, col. 12)		0		1.00000	0
5c	Firm PTP Revenue Credit Adjustment (Appendix E, line 10, col. 3)		0		1.00000	0
6	TOTAL REVENUE CREDITS (sum lines 2-5c)					$ -
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ -
	DIVISOR					
8	1 CP (Note A)					0
9	12 CP (Note B)					0
10	Reserved					
11	Reserved					
12	Reserved					
13	Reserved					
14	Reserved					
15	Annual Cost ($/kW/Yr) - 1 CP	(line 7 / line 8)	$0.000			
16	Annual Cost ($/kW/Yr) - 12 CP	(line 7 / line 9)	$0.000			
17	Network Rate ($/kW/Mo)	(line 15 / 12)	$0.000			
17a	Point-To-Point Rate ($/kW/Mo)	(line 16 / 12)	$0.000			
			Peak Rate			Off-Peak Rate
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	$0.000			
19	Point-To-Point Rate ($/kW/Day)	(line 16 / 260; line 16 / 365)	$0.000	Capped at weekly rate		$0.000
20	Point-To-Point Rate ($/MWh)	(line 16 / 4,160; line 16 / 8,760 * 1000)	$0.000	Capped at weekly and daily rate		$0.000

Formula Rate - Non-Levelized | For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

Line No.	(1) RATE BASE:	(2) Form No. 1 Page, Line, Col.	(3) Company Total		(4) Allocator	(5) Transmission (Col. 3 times Col. 4)
	GROSS PLANT IN SERVICE					
1	Production	205.46.g	$ -	NA		
2	Transmission	207.58.g	0	TP	0.00000	$ -
3	Distribution	207.75.g	0	NA		
4	General & Intangible	205.5.g & 207.99.g	0	W/S	0.00000	0
5	Common	356.1	0	CE	0.00000	0
6	TOTAL GROSS PLANT (sum lines 1-5)		$ -	GP=	0.000%	$ -
	ACCUMULATED DEPRECIATION					
7	Production	219.20-24.c	$ -	NA		
8	Transmission	219.25.c	0	TP	0.00000	$ -
9	Distribution	219.26.c	0	NA		
10	General & Intangible	219.28.c	0	W/S	0.00000	0
11	Common	356.1	0	CE	0.00000	0
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		$ -			$ -
	NET PLANT IN SERVICE					
13	Production	(line 1 - line 7)	$ -			
14	Transmission	(line 2 - line 8)	0			$ -
15	Distribution	(line 3 - line 9)	0			
16	General & Intangible	(line 4 - line 10)	0			0
17	Common	(line 5 - line 11)	0			0
18	TOTAL NET PLANT (sum lines 13-17)		$ -	NP=	0.000%	$ -
	ADJUSTMENTS TO RATE BASE (Note F)					
19	Account No. 281 (enter negative)	273.8.k	$ -	NA	zero	$ -
20	Account No. 282 (enter negative)	275.2.k	0	NP	0.00000	0
21	Account No. 283 (enter negative)	277.9.k	0	NP	0.00000	0
22	Account No. 190	234.8.c	0	NP	0.00000	0
23	Account No. 255 (enter negative)	267.8.h	0	NP	0.00000	0
24	TOTAL ADJUSTMENTS (sum lines 19- 23)		$ -			$ -
25	LAND HELD FOR FUTURE USE (Note G)	214.x.d	$ -	TP	0.00000	$ -
	WORKING CAPITAL (Note H)					
26	CWC	calculated	$ -			0
27	Materials & Supplies (Note G)	227.8.c & .16.c	0	TE	0.00000	0
28	Prepayments (Account 165)	111.57.c	0	GP	0.00000	0
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		$ -			$ -
30	RATE BASE (sum lines 18, 24, 25, & 29)		$ -			$ -

Formula Rate - Non-Levelized | For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

Line No.	(1) RATE BASE	(2) Form No. 1 Page, Line, Col.	(3) Company Total		(4) Allocator	(5) Transmission (Col. 3 times Col. 4)
	O&M					
1	Transmission	321.112.b	$ -	TE	0.00000	$ -
1a	Less LSE Expenses included in Transmission O&M Accounts (Note V)	321.88.b, 92.b; 322.121.b	0		1.00000	0
1b	Less Midwest ISO Fees included in Transmission O&M	(Note X)	0	TE	0.00000	0
1c	Plus Midwest ISO Fees	(Note X)	0		1.00000	0
2	Less Account 565	321.96.b	0	TE	0.00000	0
3	A&G	323.197.b	0	W/S	0.00000	0
3a	Less Actual PBOP Expense	(Note E)	0	W/S	0.00000	0
3b	Plus Fixed PBOP Expense	(Note E)	0	W/S	0.00000	0
3c	Less PJM integration Costs included in A&G	(Note Y)	0	W/S	0.00000	0
3d	Plus PJM Integration Costs	(Note Y)	0		1.00000	0
4	Less FERC Annual Fees	350.14.b	0	W/S	0.00000	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Advertising (Note I)		0	W/S	0.00000	0
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.00000	0
6	Common	356.1	0	CE	0.00000	0
7	Transmission Lease Payments		0		1.00000	0
8	TOTAL O&M (Sum lines 1, 2a, 3, 5a, 6, 7 less lines 1a, 2, 4, 5)		$ -			$ -
	DEPRECIATION EXPENSE					
9	Transmission	336.7.b	$ -	TP	0.00000	$ -
10	General	336.10.b	0	W/S	0.00000	0
11	Common	336.11.b	0	CE	0.00000	0
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		$ -			$ -
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
13	Payroll	263.i	$ -	W/S	0.00000	$ -
14	Highway and vehicle	263.i	0	W/S	0.00000	0
15	PLANT RELATED					
16	Property	263.i	0	GP	0.00000	0
17	Gross Receipts	263.i	0	NA	zero	0
18	Other	263.i	0	GP	0.00000	0
19	Payments in lieu of taxes		0	GP	0.00000	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		$ -			$ -
	INCOME TAXES (Note K)					
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.000000%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		0.000000%			
	where WCLTD=(page 4, line 27) and R= (page 4, line 30)					
	and FIT, SIT & p are as given in footnote K.					
23	1 / (1 - T) = (from line 21)		0.0000			
24	Amortized Investment Tax Credit	266.8.f (enter negative)	0			
25	Income Tax Calculation (line 22 * line 28)		$ -	NA		$ -
26	ITC adjustment (line 23 * line 24)		0	NP	0.00000	0
27	Total Income Taxes	(line 25 plus line 26)	$ -			$ -

28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]	$ -	NA	$ -
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)	$ -		$ -

Formula Rate - Non-Levelized — For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)
SUPPORTING CALCULATIONS AND NOTES

Line No.	**TRANSMISSION PLANT INCLUDED IN ISO RATES**		
1	Total transmission plant (page 2, line 2, column 3)		$ -
2	Less transmission plant excluded from ISO rates (Note M)		0
3	Less transmission plant included in OATT Ancillary Services (Note N)		0
4	Transmission plant included in ISO Rates (line 1 less lines 2 & 3)		$ -
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)	TP=	0.00000
	TRANSMISSION EXPENSES		
6	Total transmission expenses (page 3, line 1, column 3)		$ -
7	Less transmission expenses included in OATT Ancillary Services (Note L)		0
8	Included transmission expenses (line 6 less line 7)		$ -
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)		0.00000
10	Percentage of transmission plant included in ISO Rates (line 5)	TP	0.00000
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)	TE=	0.00000

WAGES & SALARY ALLOCATOR (W&S)

		Form 1 Reference	$	TP	Allocation		W&S Allocator ($ / Allocation)		
12	Production	354.20.b	0	0.00	0				
13	Transmission	354.21.b	0	0.00	0				
14	Distribution	354.23.b	0	0.00	0				
15	Other	354.24,25,26.b	0	0.00	0				
16	Total (sum lines 12-15)		0		0	=	0.00000	=	WS

COMMON PLANT ALLOCATOR (CE) (Note O)

			$	% Electric (line 17 / line 20)		W&S Allocator (line 16)		CE
17	Electric	200.3.c	0					
18	Gas	201.3.d	0	0.00000	*	0.00000	=	0.00000
19	Water	201.3.e	0					
20	Total (sum lines 17 - 19)		0					

RETURN (R)

			$
21		Long Term Interest (117, sum of 62.c through 67.c)	0
22		Preferred Dividends (118.29c) (positive number)	0
	Development of Common Stock:		
23		Proprietary Capital (112.16.c)	0
24		Less Preferred Stock (line 28)	0
25		Less Account 216.1 (112.12.c) (enter negative)	0
26		Common Stock (sum lines 23-25)	0

		(Note P)	$	%	Cost	Weighted		
27	Long Term Debt (112, sum of 18.c through 21.c)		0	0%	0.0000	0.0000	=	WCLTD
28	Preferred Stock (112.3.c)		0	0%	0.0000	0.0000		
29	Common Stock (line 26)		0	0%	0.1238	0.0000		
30	Total (sum lines 27-29)		0			0.0000	=	R

REVENUE CREDITS

			Load
	ACCOUNT 447 (SALES FOR RESALE) (Note Q)	(310-311)	
31	a. Bundled Non-RQ Sales for Resale (311.x.h)		0
32	b. Bundled Sales for Resale included in Divisor on page 1		-
33	Total of (a)-(b)		0
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)		$ -
35	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) (Note U)	(330.x.n)	$ -

Formula Rate - Non-Levelized　　　　For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Notes:

A　DEOK 1 CP is Duke Energy Ohio ("DEO") Monthly Firm Transmission System Peak Load as reported on page 400, column b of Form 1 at the time of DEO's annual peak, plus load served by Duke Energy Kentucky at Longbranch. For years ending 12/31/2010 and 12/31/2011, this sum will be reduced by the amount of distribution load served by East Kentucky Power Cooperative via Duke Kentucky's Hebron substation. Excludes demands from grandfathered interzonal transactions and demands from service provided by ISO at a discount.

B　DEOK 12 CP is DEO Monthly Firm Transmission System Peak Load as reported on page 400, column b of Form 1 at the time of DEO's monthly peaks, plus load served by Duke Kentucky at Longbranch. For years ending 12/31/2010 and 12/31/2011, this sum will be reduced by the amount of distribution load served by East Kentucky Power Cooperative via Duke Kentucky's Hebron substation. Excludes demands from grandfathered interzonal transactions and demands from service provided by ISO at a discount.

C　Reserved

D　Reserved

E　This deduction is to remove expenses recorded by DEOK for Postretirement Benefits Other than Pensions (PBOP). PBOP expense is set forth in line 3b and is fixed until changed as the result of a filing at FERC. The fixed amount of PBOP for DEO is $2,342,494 and for Duke Energy Kentucky ("DEK") is $575,908.

F　The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.

G　Identified in Form 1 as being only transmission related.

H　Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5.
Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111 line 57 in the Form 1.

I　Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.

J　Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.

K　The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26).

Inputs Required:	FIT =	0.00%	
	SIT=	0.00%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

L　Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.

M　Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).

N　Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to be included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

O　Enter dollar amounts.

P　Debt cost rate = long-term interest (line 21) / long term debt (line 27). Preferred cost rate = preferred dividends (line 22) / preferred outstanding (line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC. Capitalization adjusted to exclude impacts of purchase accounting.

Q　Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.

R　Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

S　Reserved

T　The revenues credited on page 1 lines 2-5c shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, or facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

Formula Rate - Non-Levelized — For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Notes:

U — On Line 35, enter revenues from RTO settlements that are associated with NITS and firm Point-to-Point Service for which the load is not included in the divisor to derive Duke Energy Ohio's and Duke Energy Kentucky's zonal rates. Exclude non-firm Point-to-Point revenues, revenues related to MTEP and RTEP projects, revenues from grandfathered interzonal transactions and revenues from service provided by ISO at a discount.

V — Account Nos. 561.4, 561.8 and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.

W — Reserved

X — Midwest ISO Fees include (1) the charges that DEOK paid to the Midwest ISO pursuant to the Settlement Agreement filed on July 29, 2011 in Docket No. ER11-2059 and (2) the exit fees that DEOK paid to the Midwest ISO pursuant to the Exit Fee Agreement filed on October 5, 2011 in Docket No. ER12-33.

Y — PJM Integration Costs are the fees that PJM assessed DEOK for the costs that PJM incurred in connection with DEOK's move into PJM.

For the 12 months ended 12/31/_____

Duke Energy Ohio and Duke Energy Kentucky
Transmission Formula Rate Revenue Requirement
Utilizing FERC Form 1 Data
For Rates Effective January 1, 2012

Schedule 1A Rate Calculation

Line No.		Source	Revenue Requirement	
A.	Schedule 1A Annual Revenue Requirements			
1	Total Load Dispatch & Scheduling (Account 561)	Attachment H-22A, Page 4, Line 7	$ -	
2	Revenue Credits for Schedule 1A - Note A		$ -	
3	Net Schedule 1A Revenue Requirement for Zone		$ -	
B.	Schedule 1A Rate Calculations			
4	2010 Annual MWh - Note B	(401a.22b & 24b)	-	MWh
5	Schedule 1A rate $/MWh (Line 3 / Line 4)	(Line 3 / Line 4)	$0.0000	$/MWh

Notes:

A Revenue received pursuant to PJM Schedule 1A revenue allocation procedures for transmission service outside of DEOK's zone during the year used to calculate rates under Attachment H-22A.

B Load expressed in MWh consistent with load used for billing under Schedule 1A for the DEOK zone. Data from RTO settlement systems for the calendar year prior to the rate year.

For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio and Duke Energy Kentucky
RTEP – Transmission Enhancement Charges

To be completed in conjunction with Attachment H-22A

Line No.	(1)	(2) Attachment H-22A Page, Line, Col.	(3) Transmission	(4) Allocator
	TRANSMISSION PLANT			
1	Gross Transmission Plant - Total	Sch. H-22A, p 2, line 2 col 5 (Note A)	-	
2	Net Transmission Plant - Total	Sch. H-22A, p 2, line 14 col 5 (Note B)	-	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Sch. H-22A, p 3, line 8 col 5	-	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	0.00%	0.00%
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G&C Depreciation Expense	Sch. H-22A, p 3, lines 10 & 11, col 5 (Note H)	-	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	0.00%	0.00%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Sch. H-22A, p 3, line 20 col 5	-	
8	Annual Allocation Factor for Other Taxes	(line 5 divided by line 1 col 3)	0.00%	0.00%
9	**Annual Allocation Factor for Expense**	**Sum of lines 4, 6 and 8**		**0.00%**
	INCOME TAXES			
10	Total Income Taxes	Sch. H-22A, p 3, line 27 col 5	-	
11	Annual Allocation Factor for Income Taxes	(line 8 divided by line 2 col 3)	0.00%	0.00%
	RETURN			
12	Return on Rate Base	Sch. H-22A, p 3, line 28 col 5	-	
13	Annual Allocation Factor for Return on Rate Base	(line 10 divided by line 2 col 3)	0.00%	0.00%
14	**Annual Allocation Factor for Return**	**Sum of lines 11 and 13**		**0.00%**

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio and Duke Energy Kentucky
RTEP – Transmission Enhancement Charges

Network Upgrade Charge Calculation By Project

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line No.	Project Name	RTEP Project Number	Project Gross Plant	Annual Allocation Factor for Expense	Annual Expense Charge	Project Net Plant	Annual Allocation Factor for Return	Annual Return Charge	Project Depreciation Expense	Annual Revenue Requirement	True-Up Adjustment	Network Upgrade Charge
			(Note C)	(Page 1 line 7)	(Col. 3 * Col. 4)	(Note D)	(Page 1 line 12)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)	Sum Col. 10 & 11 (Note G)
1b			$ -	0.00%	$0.00	$ -	0.00%	$0.00	$0	$0.00	$ -	$0.00
1c			$ -	0.00%	$0.00	$ -	0.00%	$0.00	$0	$0.00	$ -	$0.00
2	Annual Totals									$0	$0	$0
3	RTEP Transmission Enhancement Charges for Attachment H-22A, Page 1, Line 5c											$0

Notes:

A. Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-22A and includes any sub lines 2a or 2b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.

B. Net Transmission Plant is that identified on page 2 line 14 of Attachment H-22A and includes any sub lines 14a or 14b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.

C. Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes CWIP in rate base if applicable. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.

D. Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.

E. Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-22A page 3 line 12.

F. True-Up Adjustment is included pursuant to a FERC approved methodology if applicable.

G. The Network Upgrade Charge is the value to be used in Schedule 26.

H. The Total General and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 9.

For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio and Duke Energy Kentucky
Legacy MTEP Credit

To be completed in conjunction with Attachment H-22A

	(1)	(2)	(3)	(4)
Line No.		Attachment H-22A Page, Line, Col.	Transmission	Allocator
	TRANSMISSION PLANT			
1	Gross Transmission Plant - Total	Sch. H-22A, p 2, line 2 col 5 (Note A)	-	
2	Net Transmission Plant - Total	Sch. H-22A, p 2, line 14 col 5 (Note B)	-	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Sch. H-22A, p 3, line 8 col 5	-	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	0.00%	0.00%
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G&C Depreciation Expense	Sch. H-22A, p 3, lines 10 & 11, col 5 (Note H)	-	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	0.00%	0.00%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Sch. H-22A, p 3, line 20 col 5	-	
8	Annual Allocation Factor for Other Taxes	(line 5 divided by line 1 col 3)	0.00%	0.00%
9	**Annual Allocation Factor for Expense**	**Sum of lines 4, 6 and 8**		**0.00%**
	INCOME TAXES			
10	Total Income Taxes	Sch. H-22A, p 3, line 27 col 5	-	
11	Annual Allocation Factor for Income Taxes	(line 8 divided by line 2 col 3)	0.00%	0.00%
	RETURN			
12	Return on Rate Base	Sch. H-22A, p 3, line 28 col 5	-	
13	Annual Allocation Factor for Return on Rate Base	(line 10 divided by line 2 col 3)	0.00%	0.00%
14	**Annual Allocation Factor for Return**	**Sum of lines 11 and 13**		**0.00%**

For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio and Duke Energy Kentucky
Legacy MTEP Credit

Network Upgrade Charge Calculation By Project

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line No.	Project Name	MTEP Project Number	Project Gross Plant	Annual Allocation Factor for Expense	Annual Expense Charge	Project Net Plant	Annual Allocation Factor for Return	Annual Return Charge	Project Depreciation Expense	Annual Revenue Requirement	True-Up Adjustment	Network Upgrade Charge
			(Note C)	(Page 1 line 7)	(Col. 3 * Col. 4)	(Note D)	(Page 1 line 12)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)	Sum Col. 10 & 11 (Note G)
1b			$ -	0.00%	$0.00	$ -	0.00%	$0.00	$0	$0.00	$ -	$0.00
1c			$ -	0.00%	$0.00	$ -	0.00%	$0.00	$0	$0.00	$ -	$0.00
2	Annual Totals									$0	$0	$0
3	Legacy MTEP Credit for Attachment H-22A, Page 1, Line 5a											$0

Notes:

A. Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-22A and includes any sub lines 2a or 2b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.

B. Net Transmission Plant is that identified on page 2 line 14 of Attachment H-22A and includes any sub lines 14a or 14b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.

C. Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes CWIP in rate base if applicable. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.

D. Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.

E. Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-22A page 3 line 12.

F. True-Up Adjustment is included pursuant to a FERC approved methodology if applicable.

G. The Network Upgrade Charge is the value to be used in Schedule 26.

H. The Total General and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 9.

DUKE ENERGY OHIO, INC.
DEPRECIATION RATES

FERC Account Number (A)	Company Account Number (B)	Description (C)	Actual Accrual Rates (D) %
		Wholly Owned Transmission Plant	
350	3403	Rights of Way	1.54
352	3420	Structures & Improvements	1.90
352	3424	Structures & Improvements - Duke Ohio - Loc. in Ky.	1.90
353	3430	Station Equipment	1.44
353	3434	Station Equipment - Duke Ohio - Loc. in Ky.	1.44
354	3440	Towers & Fixtures	1.85
354	3444	Towers & Fixtures - Duke Ohio - Loc. in Ky.	1.85
355	3450	Poles & Fixtures	2.31
355	3454	Poles & Fixtures - Duke Ohio - Loc. in Ky.	2.31
356	3460	Overhead Conductors & Devices	1.91
356	3464	Overhead Conductors & Devices - Duke Ohio - Loc. in Ky.	1.91
357	3470	Underground Conduit	1.43
358	3480	Underground Conductors & Devices	2.37
		Commonly Owned Transmission Plant - CCD Projects	
352	3421	Structures & Improvements - CCD Projects	2.50
352	3425	Structures & Improvements - CCD Projects	2.50
353	3431	Station Equipment - CCD Projects	1.44
353	3432	Station Equipment - CCD Projects	1.44
353	3435	Station Equipment - CCD Projects	1.44
353	3437	Station Equipment - CCD Projects	1.44
354	3441	Towers & Fixtures - CCD Projects	3.00
354	3442	Towers & Fixtures - CCD Projects	3.00
354	3445	Towers & Fixtures - CCD Projects	3.00
354	3446	Towers & Fixtures - CCD Projects - Loc. In Ky.	3.00
354	3448	Towers & Fixtures - CCD Projects	3.00
355	3451	Poles & Fixtures - CCD Projects	3.00
355	3455	Poles & Fixtures - CCD Projects	3.00
356	3461	Overhead Conductors & Devices - CCD Projects	2.50
356	3462	Overhead Conductors & Devices - CCD Projects	2.50
356	3465	Overhead Conductors & Devices - CCD Projects	2.50
356	3466	Overhead Conductors & Devices - CCD Projects - Loc. In Ky.	2.50
		Commonly Owned Transmission Plant - CD Projects	
352	3423	Structures & Improvements - CD Projects	2.50
353	3433	Station Equipment - CD Projects	1.44
353	3438	Station Equipment - CD Projects	1.44
354	3447	Towers & Fixtures - CD Projects	3.00
356	3467	Overhead Conductors & Devices - CD Projects	2.50
		General and Intagible Plant	
303	3030	Miscellaneous Intangible Plant	20.00
389	3890	Land and Land Rights	N/A
390	3900	Structures and Improvements	2.50
391	3910	Office Furniture and Equipment	2.00
391	3911	Electronic Data Processing Equipment	20.00
391	3920	Transportation Equipment	8.33
391	3921	Trailers	4.25
392	3940	Tools, Shop & Garage Equipment	4.00
392	3950	Laboratory Equipment	6.67
393	3960	Power Operated Equipment	5.88
393	3970	Communication Equipment	6.67
394	3980	Miscellaneous Equipment	5.00

DUKE ENERGY KENTUCKY, INC.
DEPRECIATION RATES

FERC Account Number (A)	Company Account Number (B)	Description (C)	Actual Accrual Rates (D)
			%
		Transmission Plant	
350	3501	Rights of Way	1.48
352	3520	Structures & Improvements	0.41
353	3530	Station Equipment	2.25
353	3532	Station Equipment - Major	2.77
353	3535	Station Equipment – Electronic	9.55
355	3550	Poles & Fixtures	2.28
356	3560	Overhead Conductors & Devices	2.31
		General and Intangible Plant	20.00
303	3030	Miscellaneous Intangible Plant	1.77
390	3900	Land and Land Rights	18.56
391	39110	Structures and Improvements	6.53
392	3921	Electronic Data Processing Equipment	4.14
394	3940	Transportation Equipment	6.93
397	3970	Stores Equipment	

For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio and Duke Energy Kentucky
Firm PTP Service Revenue Credit Adjustment Calculation

To be completed in conjunction with Attachment H-22A

	(1)	(2)	(3)
No.		**Reference**	**Company Total**
	REVENUE CREDIT TRUE-UP		
1	Difference Between Revenue Received In PJM vs. Midwest ISO	(Note A)	$0
	ACCUMULATED BALANCE OF REVENUE CREDIT TRUE-UP		
2	Accumulated Balance of Deferral	(Note B)	$0
3	Income Tax Rate for Deferral Calculation	(Note C)	0.00%
4	Deferred Income Taxes on Accumulated Deferral (line 2 * line 3)		$0
5	Accumulated Deferral for Carrying Cost Calculation (Line 2 - Line 4)		$0
	INCOME TAXES		
6	CIT = (T/(1-T)) * (1 - (WCLTD/R))	Attachment H-22, page 3, line 22	0.00%
7	Income Taxes (Line 6 * Line 9)		$0
	CARRYING COST ON DEFERRAL		
8	FERC Refund Rate		0.00%
9	Carrying Cost (Line 5 * Line 8)	(Note C)	$0
10	Revenue Credit Adjustment (Line 1 + Line 7 + Line 9)		$0

Notes
A. From Appendix E, Workpaper, Column (4).
B. Accumulated balance of deferral as of December 31st of the year prior to effective date of new rate.
C. Effective deferred tax rate during applicable test year.
D. FERC Refund Rate is the approved rate as of December 31 of calendar prior to the rate year (see 18 C.F.R. Section 35.19a).

Duke Energy Ohio and Duke Energy Kentucky

Worksheet for Firm PTP Service Revenue Credit Adjustment Calculation

(1) Period	(2) Actual Firm PTP Service Revenue Included in Test Year Rate Calculation (Note A)	(3) Actual Firm PTP Service Revenue Received from PJM (Note B)	(4) = (2) - (3) Difference Between Revenue Received and Amount in Rates Excluding True Up	(5) Monthly True-Up Adjustment Included In H-22A Net Revenue Requirement (Note C)	(6) = (4) - (5) Amount Deferred for Future Recovery	(7) = Prior month's Balance + (6) Accumulated Balance of Deferred Firm PTP Service Revenue Credit Adjustment
Jan-12	$ -	$ -	$ -		$ -	$ -
Feb-12	-	-	-		-	-
Mar-12	-	-	-		-	-
Apr-12	-	-	-		-	-
May-12	-	-	-		-	-
Jun-12	-	-	-		-	-
Jul-12	-	-	-		-	-
Aug-12	-	-	-		-	-
Sep-12	-	-	-		-	-
Oct-12	-	-	-		-	-
Nov-12	-	-	-		-	-
Dec-12	-	-	-		-	-
Total				$	$ -	-
						-
Jan-13	-	-	-		$ -	-
Feb-13	-	-	-		-	-
Mar-13	-	-	-		-	-
Apr-13	-	-	-		-	-
May-13	-	-	-		-	-
Jun-13			-	-	-	-
Jul-13				-	-	-
Aug-13				-	-	-
Sep-13				-	-	-
Oct-13				-	-	-
Nov-13				-	-	-
Dec-13				-	-	$ -
Total				$ -	$ -	
Jan-14				$ -	$ -	$ -
Feb-14				-	-	-
Mar-14				-	-	-
Apr-14				-	-	-
May-14				-	-	-
Jun-14				-	-	-
Jul-14				-	-	-
Aug-14				-	-	-
Sep-14				-	-	-
Oct-14				-	-	-
Nov-14				-	-	-
Dec-14				-	-	$ -
Total				$ -	$ -	
Jan-15				$ -	$ -	$ -
Feb-15				-	-	-
Mar-15				-	-	-
Apr-15				-	-	-
May-15				-	-	$ -
Total				$ -	$ -	

Notes:

A. Monthly Firm PTP service revenue from Midwest ISO during test year applicable to currently effectives NITS and PTP service rates.
B. Actual monthly Firm PTP service revenue received from PJM during current period.
C. Recovery of deferral begins with the first period for billing rates approved using a test year for Attachment H-22A that includes actual operations in PJM.

ATTACHMENT H-22B
DEOK FORMULA RATE IMPLEMENTATION PROTOCOLS

<u>Definitions</u>

"Annual Transmission Revenue Requirements" means the result produced by populating the Formula Rate Template with data as provided by the Formula Rate.

"Annual Update" means the posting and informational filing submitted by DEOK on or before May 15 of each year that sets forth the DEOK Cost of Service ("COS") for the subsequent Rate Year.

"Discovery Period" means the period after each annual Publication Date to serve information requests on DEOK as provided in Section 2.b below.

"DEOK" means Duke Energy Kentucky, Inc., and Duke Energy Ohio, Inc.

"First Rate Year" means the period that begins on January 1, 2012, and ends on May 31, 2012.

"Formal Challenge" means a challenge to an Annual Update submitted to the Federal Energy Regulatory Commission ("FERC") as provided in Section 3.a below.

"Formula Rate" means these Formula Rate Implementation Protocols (to be included as Attachment H-22B of the PJM Interconnection, L.L.C. ("PJM"), FERC Electric Tariff ("PJM Tariff")) and the Formula Rate Template.

"Formula Rate Template" means the collection of formulae, and worksheets, unpopulated with any data, to be included as Attachment H-22A of the PJM Tariff.

"Interested Party" means any person or entity having standing under Section 206 of the Federal Power Act ("FPA") with respect to the Annual Update.

"Material Changes" means (i) material changes in DEOK's accounting policies and practices, (ii) changes in FERC's Uniform System of Accounts ("USofA"), (iii) changes in FERC Form No. 1 reporting requirements as applicable, or (iv) changes in the FERC's accounting policies and practices, which change causes a result under the Formula Rate different from the result under the Formula Rate as calculated without such change.

"Preliminary Challenge" means a written challenge to the Annual Update submitted to DEOK as provided in Section 2.a below.

"Protocols" means these Formula Rate Implementation Protocols (to be included as Attachment H-22B of the PJM Tariff).

"Publication Date" means the date on which the Annual Update is posted under the provisions of Section 1.b below.

"Rate Year" means the twelve consecutive month period that begins on June 1 and continues through May 31 of the subsequent calendar year except for the First Rate Year.

"Review Period" means the period during which Interested Parties may review the calculations in the Annual Update as provided in Section 2.a below.

Section 1 <u>Annual Updates</u>

a. Beginning with the Rate Year that commences on June 1, 2012, and during each Rate Year thereafter, the Annual Transmission Revenue Requirement calculated in accordance with Attachment H-22A and the Network Integration Transmission Service and Point-to-Point rates derived therefrom shall be applicable to transmission services provided by PJM for the DEOK zone during the Rate Year.

b. On or before May 15, 2012, and on or before May 15 of each succeeding Rate Year, DEOK shall recalculate its Annual Transmission Revenue Requirement, producing the "Annual Update" for the upcoming Rate Year, and:
   (i) post such Annual Update on PJM's Internet website (via a link to the Transmission Services page or a similar successor page) as both a .pdf (Portable Document Format) document and a fully-functioning Excel file;
   (ii) submit such Annual Update as an informational filing with the FERC;
   (iii) provide contact information for inquiries concerning the Annual Update.

c. If the date for making the Annual Update posting/filing should fall on a weekend or a holiday recognized by the FERC, then the posting/filing shall be due on the next business day.

d. The date on which the last of the events listed in Section 1.b or 1.c occurs shall be that year's "Publication Date."

e. Within two business days of the Publication Date, DEOK shall also provide notice on PJM's Internet website (via a link to the Transmission Services page or a similar successor page) of the time, date and location of an open meeting among interested parties ("Annual Meeting"). This Annual Meeting shall (i) permit DEOK to explain and clarify its Annual Update and (ii) provide interested parties an opportunity to seek information and clarifications from DEOK about the Annual Update. The Annual Meeting shall take place no sooner than ten (10) days after posting of the notice and no later than thirty (30) days after the Publication Date.

f. Inputs to the Formula Rate are based on DEOK's books, which reflect:
   (i) the FERC's Uniform System of Accounts, and

(ii) applicable FERC Form No. 1[1] as each exists as of the later of the date of DEOK's initial filing of the Formula Rate or the last day of the calendar year immediately preceding the effective date of the most recent revision to the Formula Rate.

g. The Annual Update for the Rate Year:

(i) shall, to the extent specified in the Formula Rate, be based upon DEOK's FERC Form No. 1 data for the most recent calendar year, and to the extent specified in the Formula Rate, be based upon the books and records of DEOK consistent with Section 1.f above;

(ii) shall, as and to the extent specified in the Formula Rate, provide the formula rate calculations and all inputs thereto, as well as supporting documentation for data not otherwise available in the FERC Form No. 1 that are used in the Formula Rate;[2]

(iii) shall provide sufficient information[3] to enable customers to replicate the calculation of the formula results from FERC Form No. 1 and other applicable accounting inputs and to compare that calculation to that of prior years, including all workpapers necessary to explain any changes made since the last update, and to include as applicable:

(1) a copy of the FERC Form No. 1 used for the update if it is not otherwise publicly available;

(2) identification of any changes in the formula references to the FERC Form No. 1;

(3) identification of all adjustments made to the FERC Form No. 1 data in determining formula inputs, including relevant footnotes to the FERC Form No. 1 and any adjustments not shown in a FERC Form No. 1 footnote;

1. If the referenced form is superseded, the successor form(s) shall be utilized and supplemented as necessary to provide equivalent information as that provided in the superseded form. If the referenced form(s) is (are) discontinued, equivalent information as that provided in the discontinued form(s) shall be utilized.

2. It is the intent of the Formula Rate, including the supporting explanations and allocations described therein, that each input to the Formula Rate will be either taken directly from the FERC Form No. 1 for the most recent calendar year or reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information provided by DEOK with the Annual Update. Where the reconciliation is provided through a worksheet included in the filed Formula Rate Template, the inputs to the worksheet must meet this transparency standard, and doing so will satisfy this transparency requirement for the amounts that are output from the worksheet and input to the main body of the Formula Rate.

3. As appropriate, competitively sensitive information may be provided only to those persons bound by the terms of a suitable confidentiality agreement or protective order.

(4) a reconciliation of monthly peak demands shown on the FERC Form 1 and monthly peak demands used in the formula in sufficient detail to enable transparent reconciliation of these two measures;

(5) a description of those factors influencing any change in the annual revenue requirement, including an identification of any respects in which charges under the formula rate materially differ from the preceding Annual Update (e.g., due to changes in accounting procedures, the purchase or sale of major assets, or other such significant changes) and identification of the major reason(s) for the differences, if any, between the Annual Update and the prior year's Annual Update; and

(6) any changes to the data inputs made as a result of a reconciliation made under Section 4 below.

(iv) shall describe material changes, if any, in DEOK's accounting policies, practices and procedures from those in effect for the calendar year upon which the immediately preceding Annual Update was based that could or did affect the charges under the Formula Rate ("Material Accounting Changes");[4]

(v) shall be subject to challenge and review only in accordance with the procedures set forth in this Attachment H-22B, as to the appropriateness of the input data, the prudence of the costs and expenditures included for recovery in the Annual Update, and the application of the Formula Rate according to its terms and the procedures in this Attachment H-22B (including terms and procedures related to challenges concerning Material Accounting Changes);

(vi) except as provided for in Section 1.j below, shall not seek to modify the Formula Rate and shall not be subject to challenge by anyone for the purpose of modifying the Formula Rate (i.e., all such modifications to the Formula Rate will require, as applicable, a Federal Power Act ("FPA") Section 205 or Section 206 filing).

h. Formula Rate inputs for rate of return on common equity, depreciation rates and Post-Employment Benefits Other Than Pensions ("PBOP") shall be stated values until changed pursuant to an FPA Section 205 or 206 filing made effective by the Commission. An application under Section 205 or Section 206 to modify stated values for depreciation rates or PBOP expense under the Formula Rate or Protocols shall not open review of other components of the Formula Rate or Protocols.

i. Extraordinary property losses recorded in FERC Account 182.1 shall be amortized for Formula Rate purposes pursuant to a Section 205 or 206 filing made effective by the Commission.

[4] Such notice may incorporate by reference applicable disclosure statements filed with the Securities and Exchange Commission ("SEC").

j. Any change to the underlying Uniform System of Accounts or FERC Form No. 1 as described in Section 1.f above shall be grounds for a presumption that the application of the Formula Rate shall be modified to restore the balance of the Formula Rate as accepted by the FERC (the intent being to prevent such changes in these underlying Uniform System of Accounts or FERC Form No. 1 from causing an automatic shift in the charges calculated under the Formula Rate without input from other interested parties). Any interested party seeking changes to the application of the Formula Rate due to a change in the Uniform System of Accounts or FERC Form No. 1 as described in Section 1.f, shall first raise the matter with DEOK in accordance with Section 2.a below before pursuing a Formal Challenge.

Section 2 **<u>Annual Review Procedures</u>**

Each Annual Update shall be subject to the following review procedures ("Annual Review Procedures"):

a. Interested parties shall have up to one hundred eighty (180) days after the Publication Date (unless such period is extended with the written consent of DEOK or by FERC Order) to review the inputs, supporting explanations, allocations and calculations ("Review Period") and to notify DEOK in writing, which may be made electronically, of any specific challenges, including challenges related to the rate treatment of Material Accounting Changes, to the application of the Formula Rate and to changes to the Uniform System of Accounts or FERC Form No. 1 as described in Section 1.f, above, ("Preliminary Challenge"). Failure to raise an issue with DEOK in accordance with Section 1.j above or to pursue an issue through a Preliminary Challenge or to lodge a Formal Challenge, regarding any issue as to a given Annual Update, shall bar pursuit of such issue with respect to that Annual Update, but shall not bar pursuit of such issue or the lodging of a Formal Challenge as to such issue as it relates to a subsequent Annual Update.

b. Interested Parties shall have up to one hundred fifty (150) days after each annual Publication Date (unless such period is extended with the written consent of DEOK or by FERC Order) to serve reasonable information requests on DEOK; provided, however, that the parties making such requests shall make a good faith effort to submit consolidated sets of information requests that limit the number and overlap of questions to the maximum extent practicable. Such information requests shall be limited to what is necessary to determine if DEOK has properly applied the Formula Rate, the requirements and procedures of this Attachment H-22B, and the prudence of the costs and expenditures included for recovery in the Annual Update, and shall not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable.

c. DEOK shall make a good faith effort to respond to information requests pertaining to the Annual Update within fifteen (15) business days of receipt of such requests.

d. To the extent DEOK and any interested party(ies) are unable to resolve disputes related to information requests submitted in accordance with these Annual Review Procedures, DEOK or any interested party may petition the FERC to appoint an Administrative Law Judge as a discovery master. The discovery master shall have the power to issue binding orders to resolve discovery disputes and compel the production of discovery, as appropriate, in accordance with the Annual Review Procedures and consistent with the FERC's discovery rules.

e. Preliminary Challenges shall be subject to the resolution procedures and limitations in Section 3. Formal Challenges shall be filed pursuant to these Protocols and shall include the information required under 18 C.F.R. § 385.206 (b) (1), (2), (3), (4), and (7).

Section 3 <u>Resolution of Challenges</u>

a. If DEOK and any interested party(ies) have not resolved any Preliminary Challenge to the Annual Update within twenty-one (21) days after the Review Period, an interested party shall have an additional twenty-one (21) days (unless such period is extended with the written consent of DEOK to continue efforts to resolve the Preliminary Challenge) to make a Formal Challenge with the FERC, which shall be served on DEOK by electronic service on the date of such filing. However, there shall be no need to make a Formal Challenge or to await conclusion of the time periods in Section 2 if the FERC already has initiated a proceeding to consider the Annual Update. A party's Formal Challenge may not raise any issue that was not the subject of that party's Preliminary Challenge during the applicable Review Period.

b. Any response by DEOK to a Formal Challenge must be submitted to the FERC within twenty (20) days of the date of the filing of the Formal Challenge, and shall be served on the filing party(ies) by electronic service on the date of such filing.

c. In any proceeding initiated by the FERC concerning the Annual Update or in response to a Formal Challenge, DEOK shall bear the burden, consistent with Section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the Formula Rate, consistent with Section 1.g(v), and that it followed the applicable requirements and procedures in this Attachment H-22B, in that year's Annual Update. Nothing herein is intended to alter the burdens applied by the Commission with respect to prudence challenges.

d. Subject to judicial review of FERC orders, each Annual Update shall become final as to the Annual Transmission Revenue Requirement calculated for the Rate Year for which the Annual Update was calculated and no longer subject to challenge pursuant to these Protocols or by any other means by the FERC or any other entity on the later to occur of (i) passage of the twenty-one (21) day period (or extended period, if applicable) for making a Formal Challenge if no such challenge has been made and the FERC has not initiated a proceeding to consider the Annual Update, or (ii) a final FERC order issued in response to a Formal Challenge or a proceeding initiated by the FERC to consider the Annual Update.

e. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of DEOK to file unilaterally, pursuant to FPA Section 205 and the regulations thereunder, to change the Formula Rate or any of its inputs (including, but not limited to, rate of return and transmission incentive rate treatment), or to replace the Formula Rate with a stated rate, or the right of any other party to request such changes pursuant to Section 206 of the Federal Power Act and the regulations thereunder.

f. Subject to Section 2.e above, it is recognized that resolution of Formal Challenges concerning Material Accounting Changes or related to the Uniform System of Accounts or FERC Form No. 1 as described above may necessitate adjustments to the Formula Rate input data for the applicable Annual Update or changes to the Formula Rate to achieve a just and reasonable end result consistent with the intent of the Formula Rate.

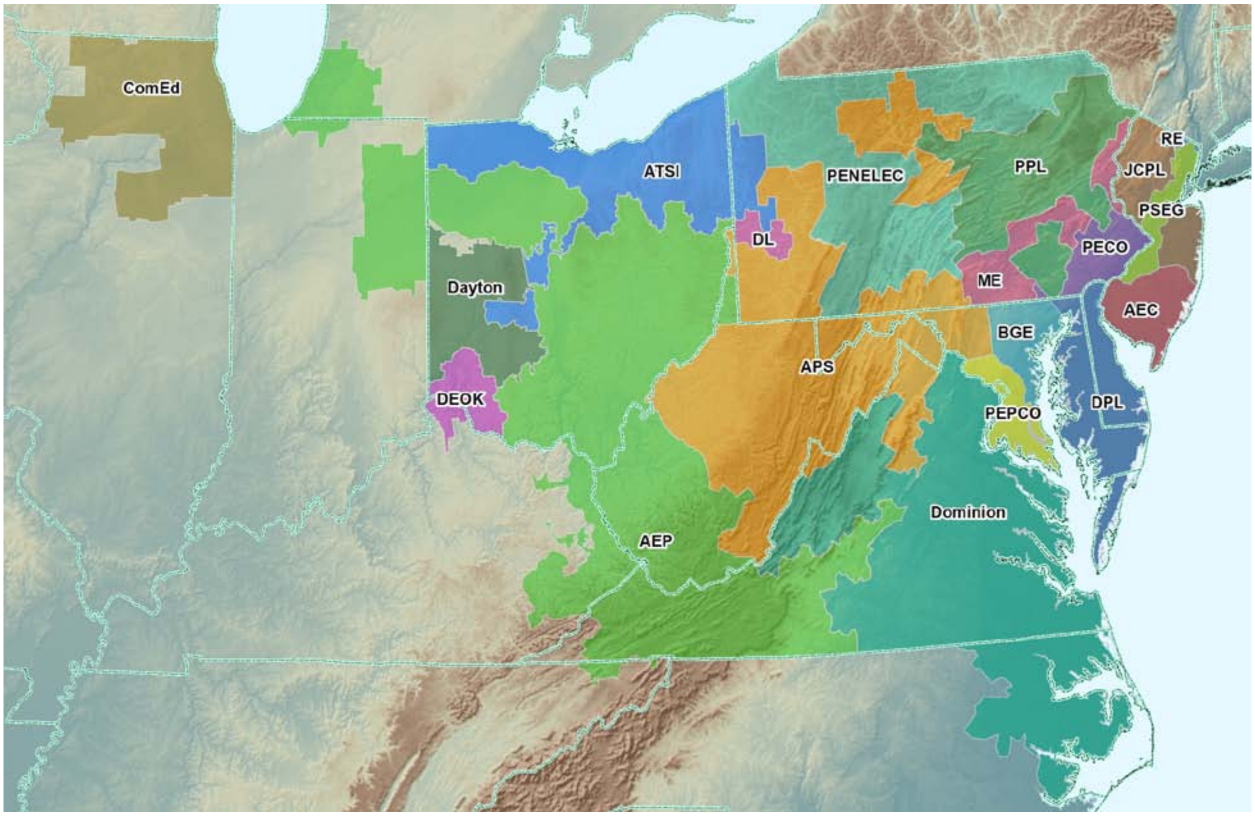
g. In making or resolving any Preliminary or Formal Challenge under this Section, a party may rely on all information provided by DEOK, including information provided under the terms of a confidentiality agreement or protective order; provided, however, that parties receiving such information pursuant to a confidentiality agreement or protective order shall be bound by the restrictions placed by such agreement or order on disclosure or use of confidential information.

Section 4 **<u>Changes to Annual Informational Filings</u>**

Any changes to the data inputs, including but not limited to revisions to DEOK's FERC Form No. 1, or as the result of any FERC proceeding to consider the Annual Update, or as a result of the procedures set forth herein, shall be incorporated into the Formula Rate and the charges produced by the Formula Rate (with interest determined in accordance with 18 C.F.R. § 35.19a) in the Annual Update for the next effective Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments and any refunds or surcharges. However, actual refunds or surcharges (with interest determined in accordance with 18 C.F.R. § 35.19a) for the then current rate year shall be made in the event that the Formula Rate is replaced by a stated rate for DEOK.

ATTACHMENT J

PJM Transmission Zones



FULL NAME	SHORT NAME
Pennsylvania Electric Company	PENELEC
Allegheny Power	APS
PPL Electric Utilities Corporation	PPL
Metropolitan Edison Company	ME
Jersey Central Power and Light Company	JCPL
Public Service Electric and Gas Company	PSEG
Atlantic City Electric Company	AEC
PECO Energy Company	PECO
Baltimore Gas and Electric Company	BGE
Delmarva Power and Light Company	DPL
Potomac Electric Power Company	PEPCO
Rockland Electric Company	RE
Commonwealth Edison Company	ComEd
AEP East Zone	AEP
The Dayton Power and Light Company	Dayton
Duquesne Light Company	DL
Virginia Electric and Power Company	Dominion
American Transmission Systems, Incorporated	ATSI
Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.	DEOK

3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Section 2 of this Schedule

(b) Market Buyers shall be charged for all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price .

(c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(d) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the total amount of net hourly PJM Interchange for each Market Buyer, including Generating Market Buyers, in accordance with the PJM Manuals. For Internal Market Buyers that are Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall include determination of the net energy flows from: (i) tie lines; (ii) any generation resource the output of which is controlled by the Market Buyer but delivered to it over another entity's Transmission Facilities; (iii) any generation resource the output of which is controlled by another entity but which is directly interconnected with the Market Buyer's transmission system; (iv) deliveries pursuant to bilateral energy sales; (v) receipts pursuant to bilateral energy purchases; and (vi) an adjustment to account for the day-ahead PJM Interchange, calculated as the difference between scheduled withdrawals and injections by that Market Buyer in the Day-ahead Energy Market. For External Market Buyers and Internal Market Buyers that are not Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall determine the energy scheduled hourly for delivery to the Market Buyer net of the amounts scheduled by the External Market Buyer in the Day-ahead Energy Market.

(e) An Internal Market Buyer shall be charged for Spot Market Energy purchases to the extent of its hourly net purchases from the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. An External Market Buyer shall be charged for its Spot Market Energy purchases based on the energy delivered to it, determined as specified in Section 3.2.1(d) above. The total charge shall be determined by the product of the hourly net amount of PJM Interchange Imports times the hourly Real-time System Energy Price for that Market Buyer.

(f) A Generating Market Buyer shall be paid as a Market Seller for sales of Spot Market Energy to the extent of its hourly net sales into the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. The total payment shall be determined by the product of the hourly net amount of PJM Interchange Exports times the hourly Real-time System Energy Price for that Market Seller.

3.2.2 Regulation.

(a) Each Internal Market Buyer that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). An Internal Market Buyer that does not meet its hourly Regulation obligation shall be charged for Regulation dispatched by the Office of the Interconnection to meet such obligation at the Regulation market-clearing price determined in accordance with subsection (c) of this section, plus the amounts, if any, described in subsection (f) of this section.

(b) A Generating Market Buyer supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection in excess of its hourly Regulation obligation shall be credited for each increment of such Regulation at the higher of (i) the Regulation market-clearing price in such Regulation Zone or (ii) the sum of the regulation offer and the unit-specific opportunity cost of the generation resource supplying the increment of Regulation, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day. The market-clearing price for each regulating hour shall be equal to the highest sum of a resource's Regulation offer plus its estimated unit-specific opportunity costs, determined as described in subsection (d) below from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.3.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation market-clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour shall be equal to the sum of the unit-specific opportunity costs (i) incurred during the hour in which the obligation is fulfilled, plus costs (ii) associated with uneconomic operation during the hour preceding the initial regulating hour ("preceding shoulder hour"), plus costs (iii) associated with uneconomic operation during the hour after the final regulating hour ("following shoulder hour").

The unit-specific opportunity costs incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (a) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the resource's expected output during the preceding shoulder hour, times (b) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource during the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (c) the percentage of the preceding shoulder hour during which the deviation was incurred.

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (a) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the resource's expected output in the following shoulder hour, times (b) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (c) the percentage of the following shoulder hour that the deviation was incurred.

Estimated opportunity costs for Demand Resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's Regulation signals from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Internal Market Buyer in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to section 1.10.1A(e) of this Schedule. A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region for which the cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Section 3.2.A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

(c) The sum of the foregoing credits calculated in accordance with Section 3.2.3(b) plus any unallocated charges from Section 3.2.3(h) and 5.1.7 and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection and that is not committed solely for the purpose of providing Synchronized Reserve: For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following segments: 1) the greater of their day-ahead schedules or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

Credits received pursuant to this section shall be equal to the positive difference between a resource's total offered price for start-up (shutdown costs for Demand Resources) and no-load fees and energy, determined on the basis of the resource's scheduled output, and the total value of the resource's energy as determined by the Real-time Energy Market and the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

Except as provided in Section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to Section 3.2.3(b) plus the resource's opportunity cost and less any amounts credited for Synchronized Reserve in excess of the Synchronized Reserve offer plus the resource's opportunity cost and less any amounts credited for Reactive Services as specified in Section 3.2.3.B, and less any amounts for Day-ahead Scheduling Reserve in excess of the Day-ahead Scheduling Reserve offer plus the resource's opportunity cost, shall be credited to the Market Seller.

Synchronized Reserve and Day-ahead Scheduling Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding hour(s) in which the Synchronized Reserve and Day-ahead Scheduling Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each period the unit operates in condensing and generation mode for one or more contiguous hours.

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

> LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;
>
> AG equals the actual hourly integrated output of the unit;
>
> URTLMP equals the real time LMP at the unit's bus;
>
> UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UB shall not be negative.

(f-1) A Market Seller's combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section

1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described above for a steam unit or combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG, or (ii) {(URTLMP – UB) x DAG where:

URTLMP equals the real time LMP at the unit's bus;

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit, determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(f-2) A Market Seller's hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2A(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d) such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (i) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day, except as noted below and in the PJM Manuals; (ii) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (iii) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day; and (iv) deviations of energy sales from the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12.

Deviations that occur within a single Zone shall be associated with the Eastern or Western Regions, as defined in Section 3.2.3(q) of this Schedule, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at interfaces and hubs shall be associated with the Eastern or Western Region if all the busses that define all interfaces or all hubs are located in the region. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by busses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed

Operating Reserve charges in the event of an Operating Reserve shortage in real-time or where PJM initiates the request for load reductions in real-time in order to avoid an Operating Reserve shortage as described in this Schedule, Section 6A, Scarcity Pricing.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in Section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for each Control Zone of the PJM Region based on the Control Zone to which the resource was synchronized to provide synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such Control Zone pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared ("Maximum Generation Emergency Alert"); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Operating Reserves credit otherwise provided by Section 3.2.3.(b) or Section 3.2.3(e) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as "MaxGen Conditions"). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Schedule 2 of the

Operating Agreement, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any hours required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described in the PJM Manuals. Ramp-limited desired MW values shall be used to determine generation resource real-time deviations from the resource's day-ahead schedules.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

(i) real-time economic minimum <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

$$\text{Ramp\_Request}_t = (\text{UDStarget}_{t-1} - \text{AOutput}_{t-1}) / (\text{UDSLAtime}_{t-1})$$

$$\text{RL\_Desired}_t = \text{AOutput}_{t-1} + \left(\text{Ramp\_Request}_t * \text{Case\_Eff\_time}_{t-1}\right)$$

where:

1. UDStarget = UDS basepoint for the previous UDS case
2. AOutput = Unit's output at case solution time
3. UDSLAtime = UDS look ahead time
4. Case_Eff_time = Time between base point changes
5. RL_Desired = Ramp-limited desired MW

To determine if a resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the UDS Basepoint or the actual output and ramp-limited desired MW value. The % off dispatch and MW off dispatch will be a time-weighted average over the course of an hour.

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and UDS Basepoint, or if its % off dispatch is <= 10, or it's hourly integrated Real-time MWh is within 5% or 5 MW (whichever is greater) of the hourly integrated ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – Day-Ahead MWh.

- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – UDS LMP Desired MW.

- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – hourly integrated Ramp-Limited Desired MW.

- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the hour is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time Mwh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

- If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch, and the resource has tripped, for the hour the resource tripped and the hours it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – Day-Ahead MWh.

- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time MWh and Day-Ahead MWh.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, DEOK transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(iii) Reliability and deviation regional balancing Operating Reserve rates shall be determined by summing the relevant RTO balancing Operating Reserve rates and regional adder rates.

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

3.2.3A Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Synchronized Reserve Zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Synchronized Reserve Zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). An Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts if any, described in subsections (g), (h) and (i) of this section.

(b) A Generating Market Buyer supplying Synchronized Reserve at the direction of the Office of the Interconnection, in excess of its hourly Synchronized Reserve Obligation, shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation units that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price.

ii) Credits for Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions ("Tier 2 Synchronized Reserve") shall be the higher of (i) the Synchronized Reserve Market Clearing Price or (ii) the sum of (A) the Synchronized Reserve offer, and (B) the specific opportunity cost of the generation resource supplying the increment of Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

iii) Credits for Synchronized Reserve provided by Demand Resources that are synchronized to the grid and accept the obligation to reduce load in response to a synchronized Reserve Event initiated by the Office of the Interconnection shall be the sum of (i) the higher of (A) the Synchronized Reserve offer or (B) the synchronized Reserve Market Clearing Price and (ii) if a Synchronized Reserve Event is actually initiated by the Office of the Interconnection and the Demand Resource reduced its load in response to the event, the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

(c) The Synchronized Reserve Energy Premium Price is the average of the five-minute Locational Marginal Prices calculated during the Synchronized Reserve Event plus an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Synchronized Reserve Zone by the Office of the Interconnection prior to the operating hour and such market-clearing price shall be equal to, from among the generation resources or Demand Resources selected to provide Synchronized Reserve for such Synchronized Reserve Zone, the highest sum of either (i) a generation resource's Synchronized Reserve offer and opportunity cost or (ii) a demand response resource's Synchronized Reserve offer.

(e) In determining the Synchronized Reserve Market Clearing Price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the expected Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market. The opportunity costs for a Demand Resource shall be zero.

(g) Charges for Tier 1 Synchronized Reserve will be allocated in proportion to the amount of Tier 1 Synchronized Reserve applied to each Synchronized Reserve Obligation. In the event Tier 1 Synchronized Reserve is provided by a Market Seller in excess of that Market Seller's Synchronized Reserve Obligation, the remainder of the Tier 1 Synchronized Reserve that is not utilized to fulfill the Seller's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

(h) Any amounts credited for Tier 2 Synchronized Reserve in an hour in excess of the Synchronized Reserve Market Clearing Price in that hour shall be allocated and charged to each

Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation in proportion to its purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) In the event the Office of the Interconnection needs to assign more Tier 2 Synchronized Reserve during an hour than was estimated as needed at the time the Synchronized Reserve Market Clearing Price was calculated for that hour due to a reduction in available Tier 1 Synchronized Reserve, the costs of the excess Tier 2 Synchronized Reserve shall be allocated and charged to those providers of Tier 1 Synchronized Reserve whose available Tier 1 Synchronized Reserve was reduced from the needed amount estimated during the Synchronized Reserve Market Clearing Price calculation, in proportion to the amount of the reduction in Tier 1 Synchronized Reserve availability.

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled by the owner to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Synchronized Reserve in response to an actual Synchronized Reserve Event, the owner of the resource shall incur an additional Synchronized Reserve Obligation in the amount of the shortfall for a period of three consecutive days with the same peak classification (on-peak or off-peak) as the day of the Synchronized Reserve Event at least three business days following the Synchronized Reserve Event. The overall Synchronized Reserve requirement for each Synchronized Reserve Zone of the PJM Region on which the Synchronized Reserve Obligations, except for the additional obligations set forth in this section, are based shall be reduced by the amount of this shortfall for the applicable three-day period.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l) is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Demand Resource's consumption at the end of the Synchronized Reserve Event and (ii) the

Batch Load Demand Resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJMSettlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

(b) A Day-ahead Scheduling Reserves Resource that receives a Day-ahead Scheduling Reserves schedule pursuant to subsection (a) of this section shall be paid the hourly Day-ahead Scheduling Reserves Market clearing price for the MW obligation in each hour of the schedule, subject to meeting the requirements of subsection (c) of this section.

(c) To be eligible for payment pursuant to subsection (b) of this section, Day-ahead Scheduling Reserves Resources shall comply with the following provisions:

(i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.

(ii) Generation resources and Demand Resources with start times or shut-down times, respectively, equal to or less than 30 minutes are required to respond to dispatch directives from the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule. To meet this requirement the resource shall be required to start or shut down within the specified notification time plus its start or shut down time, provided that such time shall be less than thirty minutes.

(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

Resources that do not comply with the provisions of this subsection (c) shall not be eligible to receive credits pursuant to subsection (b) of this section.

(d) The cost of credits allocated to Day-ahead Scheduling Reserves Resources pursuant to this section shall be charged to Load-Serving Entities in the PJM Region based on load ratio share (net of operating Behind The Meter Generation, but not to be less than zero), provided that a Load-Serving Entity may satisfy its Day-ahead Scheduling Reserves obligation, which is equal to the Day-ahead Scheduling Reserves Requirement multiplied by the Load-Serving Entity's load ratio share for the PJM Region, through one or any combination of the following: 1) the Day-ahead Scheduling Reserves Market; 2) and bilateral arrangements. The Day-ahead Scheduling Reserve charges allocated pursuant to this section shall reflect any portion of a Load-Serving Entity's Day-ahead Scheduling Reserves obligation that is met by bilateral arrangement(s).

(e) If the Day-ahead Scheduling Reserves Requirement is not satisfied through the operation of subsection (a) of this section, any additional Operating Reserves required to meet the requirement shall be scheduled by the Office of the Interconnection pursuant to Section 3.2.3 of Schedule 1 of this Agreement.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit hourly in an amount equal to {(LMPDMW - AG) x (URTLMP - UB)}

where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

AG equals the actual hourly integrated output of the unit;

URTLMP equals the real time LMP at the unit's bus;

UB equals the unit offer for that unit for which output is reduced or suspended determined according to the real time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UB shall not be negative.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG, or (ii) {(URTLMP – UB) x DAG where:

URTLMP equals the real time LMP at the unit's bus;

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to Section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual hourly integrated output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

UB equals the unit offer for that unit for which output is increased, determined according to the real time scheduled offer curve on which the unit was operating;

URTLMP equals the real time LMP at the unit's bus; and

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2A(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generating unit's bus, (C) the generating unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to paragraph (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to section (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

Each Market Buyer shall be assessed Transmission Congestion Charges as specified in Section 5 of this Schedule.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Section 5 of this Schedule.

3.2.6 Emergency Energy.

(a) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each hour of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(b) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each hour of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(c) The net costs or net revenues associated with sales or purchases of hourly energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each hour of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Buyer in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Buyer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Buyer's internal accounting.

(b) If deliveries to a Market Buyer that has PJM Interchange meters in accordance with Section 14 of the Operating Agreement include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Buyer, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market Buyer and the unmetered Market Participant specified by them to the Office of the Interconnection.

7.4 Allocation of Auction Revenues.

7.4.1 Eligibility.

(a) Annual auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated among holders of Auction Revenue Rights in proportion to, but not more than, the Target Allocation of Auction Revenue Rights Credits for the holder.

(b) Auction Revenue Rights Credits will be calculated based upon the clearing price results of the applicable Annual Financial Transmission Rights auction.

(c) Monthly and Balance of Planning Period FTR auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated according to the following priority schedule:

(i) To stage 1 and 2 Auction Revenue Rights holders in accordance with section 7.4.4 of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(ii) of this section;

(ii) To the Residual Auction Revenue Rights holders in proportion to, but not more than their Target Allocation as determined pursuant to section 7.4.3(b) of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(iii) of this section;

(iii) To FTR Holders in accordance with section 5.2.6 of Schedule 1 of this Agreement.

(d) Long-term FTR auction revenues associated with FTRs that cover individual Planning Periods shall be distributed in the Planning Period for which the FTR is effective. Long-term FTR auction revenues associated with FTRs that cover multiple Planning Years shall be distributed equally across each Planning Period in the effective term of the FTR. Long-term FTR auction revenue distributions within a Planning Period shall be in accordance with the following provisions:

(i) Long-term FTR Auction revenues shall be distributed to Auction Revenue Rights holders in the effective Planning Period for the FTR. The distribution shall be in proportion to the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately. The distribution shall not exceed, when added to the distribution of revenues from the prompt-year annual FTR auction itself, the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately.

(ii) Long-term FTR auction revenues remaining after distributions made pursuant to Section 7.4.1(d)(ii) of Schedule 1 of this Agreement shall be distributed pursuant to Section 5.2.6 of Schedule 1 of this Agreement.

7.4.2 Auction Revenue Rights.

(a) Prior to the end of each PJM Planning Period an annual allocation of Auction Revenue Rights for the next PJM Planning Period shall be performed using a two stage allocation process. Stage 1 shall consist of stages 1A and 1B, which shall allocate ten year and annual Auction Revenue Rights, respectively, and stage 2 shall allocate annual Auction Revenue Rights. The Auction Revenue Rights allocation process shall be performed in accordance with Sections 7.4 and 7.5 hereof and the PJM Manuals.

With respect to the allocation of Auction Revenue Rights, if the Office of the Interconnection discovers an error in the allocation, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the business day following the initial publication of allocation results. After this initial notification, if the Office of the Interconnection determines that it is necessary to post modified allocation results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the second business day following the publication of the initial allocation. Thereafter, the Office of the Interconnection must post any corrected allocation results by no later than 5:00 p.m. of the fourth calendar day following the initial publication. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced allocation is under publicly noticed review by the FERC.

(b) In stage 1A of the allocation process, each Network Service User may request Auction Revenue Rights for a term covering ten consecutive PJM Planning Periods beginning with the immediately ensuing PJM Planning Period from a subset of the historical generation resources that were designated to be delivered to load based on the historical reference year for the Zone, and each Qualifying Transmission Customer (as defined in subsection (f) of this section) may request Auction Revenue Rights based on the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. The historical reference year for all Zones shall be 1998, except that the historical reference year shall be: 2002 for the Allegheny Power and Rockland Electric Zones; 2004 for the AEP East, The Dayton Power & Light Company and Commonwealth Edison Company Zones; 2005 for the Virginia Electric and Power Company and Duquesne Light Company Zones; 2011 for the ATSI Zone; 2012 for the DEOK Zone; and the Office of the Interconnection shall specify a historical reference year for a new PJM zone corresponding to the year that the zone is integrated into the PJM Interchange Energy Market. For stage 1, the Office of the Interconnection shall determine a set of eligible historical generation resources for each Zone based on the historical reference year and assign a pro rata amount of megawatt capability from each historical generation resource to each Network Service User in the Zone based on its proportion of peak load in the Zone. Auction Revenue Rights shall be allocated to each Network Service User in a Zone from each historical generation resource in a number of megawatts equal to or less than the amount of the historical generation resource that has been assigned to the Network Service User. Each Auction Revenue Right allocated to a Network Service User shall be to the aggregate load buses of such Network Service User in a Zone or, with respect to Non-Zone Network Load, to the border of the PJM Region. In stage 1A of the allocation process, the sum of each Network Service User's allocated Auction Revenue Rights for a Zone must be equal to or less than the Network Service User's pro-rata share of the Zonal Base Load for that Zone.

Each Network Service User's pro-rata share of the Zonal Base Load shall be based on its proportion of peak load in the Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than fifty percent (50%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined under Section 34.1 of the Tariff. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than fifty percent (50%) of the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. If stage 1A Auction Revenue Rights are adversely affected by any new or revised statute, regulation or rule issued by an entity with jurisdiction over the Office of the Interconnection, the Office of the Interconnection shall, to the greatest extent practicable, and consistent with any such statute, regulation or rule change, preserve the priority of the stage 1A Auction Revenue Rights for a minimum period covering the ten (10) consecutive PJM Planning Periods ("Stage 1A Transition Period") immediately following the implementation of any such changes, provided that the terms of all stage 1A Auction Revenue Rights in effect at the time the Office of the Interconnection implements the Stage 1A Transition Period shall be reduced by one PJM Planning Period during each annual stage 1A Auction Revenue Rights allocation performed during the Stage 1A Transition Period so that all stage 1A Auction Revenue Rights that were effective at the start of the Stage 1A Transition Period expire at the end of that period.

(c) In stage 1B of the allocation process each Network Service User may request Auction Revenue Rights from the subset of the historical generation resources determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process, and each Qualifying Transmission Customer may request Auction Revenue Rights based on the megawatts of firm service determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process. In stage 1B of the allocation process, the sum of each Network Service User's allocated Auction Revenue Rights request for a Zone must be equal to or less than the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 34.1 of the Tariff and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than the difference between one hundred percent (100%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than the difference between one hundred percent (100%) of the megawatts of firm service as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone.

(d) In stage 2 of the allocation process, the Office of the Interconnection shall conduct an iterative allocation process that consists of three rounds with up to one third of the remaining system Auction Revenue Rights capability allocated in each round. Each round of this allocation process will be conducted sequentially with Network Service Users and Transmission Customers being given the opportunity to view results of each allocation round prior to submission of Auction Revenue Right requests into the subsequent round. In each round, each Network Service User shall designate a subset of buses from which Auction Revenue Rights will be sourced. Valid Auction Revenue Rights source buses include only Zones, generators, hubs and external Interface Pricing Points. The Network Service User shall specify the amount of Auction Revenue Rights requested from each source bus. Each Auction Revenue Right shall be sinked to the aggregate load buses of the Network Service User in a Zone or, with respect to Non-Zone Network Load, to the border of the PJM Region. The sum of each Network Service User's Auction Revenue Rights requests in each stage 2 allocation round for each Zone must be equal to or less than one third of the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Right Allocation from stages 1A and 1B of the allocation process for that Zone. The stage 2 allocation to Transmission Customers shall be as set forth in subsection (f)

(e) On a daily basis within the annual Financial Transmission Rights auction period, a proportionate share of Network Service User's Auction Revenue Rights for each Zone are reallocated as Network Load changes from one Network Service User to another within that Zone.

(f) A Qualifying Transmission Customer shall be any customer with an agreement for Long-Term Point-to-Point Transmission Service, as defined in the PJM Tariff, used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located either outside or within the PJM Region, and that was confirmed and in effect during the historical reference year for the Zone in which the resource is located. Such an agreement shall allow the Qualifying Transmission Customer to participate in the first stage of the allocation, but only if such agreement has remained in effect continuously following the historical reference year and is to continue in effect for the period addressed by the allocation, either by its term or by renewal or rollover. The megawatts of Auction Revenue Rights the Qualifying Transmission Customer may request in the first stage of the allocation may not exceed the lesser of: (i) the megawatts of firm service between the designated Network Resource and the load delivery point (or applicable point at the border of the PJM Region for load located outside such region) under contract during the historical reference year; and (ii) the megawatts of firm service presently under contract between such historical reference year receipt and delivery points.

A Qualifying Transmission Customer may request Auction Revenue Rights in either or both of the stage 1 or 2 of the allocation without regard to whether such customer is subject to a charge for Firm Point-to-Point Transmission Service under Section 1 of Schedule 7 of the PJM Tariff ("Base Transmission Charge"). A Transmission Customer that is not a Qualifying Transmission Customer may request Auction Revenue Rights in stage2 of the allocation process, but only if it is subject to a Base Transmission Charge. The Auction Revenue Rights that such a Transmission

Customer may request in each round of stage 2 of the allocation process must be equal to or less than one third of the number of megawatts equal to the megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has Firm Point-to-Point Transmission Service. The source point of the Auction Revenue Rights must be the designated source point that is specified in the Transmission Service Request and the sink point of the Auction Revenue Rights must be the designated sink point that is specified in the Transmission Service Request. A Qualifying Transmission Customer may request Auction Revenue Rights in each round of stage 2 of the allocation process in a number of megawatts equal to or less than one third of the difference between the number of megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has Firm Point-to-Point Transmission Service and its Auction Revenue Right Allocation from stage 1 of the allocation process.

(g) PJM Transmission Customers that serve load in the Midwest ISO may participate in stage 1 of the allocation to the extent permitted by, and in accordance with, this Section 7.4.2 and other applicable provisions of this Schedule 1. For service from non-historic sources, these customers may participate in stage 2, but in no event can they receive an allocation of ARRs/FTRs from PJM greater than their firm service to loads in MISO.

(h) Subject to subsection (i) of this section, all Auction Revenue Rights must be simultaneously feasible. If all Auction Revenue Right requests made during the annual allocation process are not feasible then Auction Revenue Rights are prorated and allocated in proportion to the megawatt level requested and in inverse proportion to the effect on the binding constraints.

(i) If any Auction Revenue Right requests made during stage 1A of the annual allocation process are not feasible, then PJM shall increase the capability limits of the binding constraints that would have rendered the Auction Revenue Rights infeasible to the extent necessary in order to allocate such Auction Revenue Rights without their being infeasible, and such increased limits shall be included in all modeling used for subsequent Auction Revenue Rights and Financial Transmission Rights allocations and auctions for the Planning Year; provided that, the foregoing notwithstanding, this subsection (i) shall not apply if the infeasibility is caused by extraordinary circumstances. For the purposes of this subsection, extraordinary circumstances shall mean an event of force majeure that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Auction Revenue Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates stage 1A Auction Revenue Rights as a result of this subsection (i) that would not otherwise have been feasible, then PJM shall notify Members and post on its web site (a) the aggregate megawatt quantities, by sources and sinks, of such Auction Revenue Rights and (b) any increases in capability limits used to allocate such Auction Revenue Rights.

(j) Long-Term Firm Point-to-Point Transmission Service customers that are not Qualifying Transmission Customers and Network Service Users serving Non-Zone Network

Load may participate in stage 1 of the annual allocation of Auction Revenue Rights pursuant to Section 7.4.2(a)-(c) of Schedule 1 of this Agreement, subject to the following conditions:

i. The relevant Transmission Service shall be used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located outside the PJM Region.

ii. To be eligible to participate in stage 1A of the annual Auction Revenue Rights allocation: 1) the relevant Transmission Service shall remain in effect for the stage 1A period addressed by the allocation; and 2) the control area in which the external load is located has similar rules for load external to the relevant control area.

iii. Source points for stage 1 requests authorized pursuant to this subsection 7.4.2(j) shall be limited to: 1) generation resources owned by the LSE serving the load located outside the PJM Region; or 2) generation resources subject to a bona fide firm energy and capacity supply contract executed by the LSE to meet its load obligations, provided that such contract remains in force and effect for a minimum term of ten (10) years from the first effective Planning Period that follows the initial stage 1 request.

iv. For Long-Term Firm Point-to-Point Transmission customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j), the generation resource(s) designated as source points may include any portion of the generating capacity of such resource(s) that is not, at the time of the request, already identified as a Capacity Resource.

v. For Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j), at the time of the request, the generation resource(s) designated as source points must either be committed into PJM's RPM market or be designated as part of the entity's FRR Capacity Plan for the purpose of serving the capacity requirement of the external load.

vi. All stage 1 source point requests made pursuant to this subsection 7.4.2(j) shall not increase the megawatt flow on facilities binding in the relevant annual Auction Revenue Rights allocation or in future stage 1A allocations and shall not cause megawatt flow to exceed applicable ratings on any other facilities in either set of conditions in the simultaneous feasibility test prescribed in subsection (vii) of this subsection 7.4.2(j).

vii. To ensure the conditions of subsection (vi) of this subsection 7.4.2(j) are met, a simultaneous feasibility test shall be conducted: 1) based on next allocation year with all existing stage 1 and stage 2 Auction Revenue Rights modeled as fixed injection-withdrawal pairs; and 2) based on 10 year allocation model with all eligible stage 1A Auction Revenue Rights for each year including base load growth for each year.

viii. Requests for stage 1 Auction Revenue Rights made pursuant to this subsection 7.4.2(j) that are received by PJM by November 1st of a Planning Period shall be processed for the next annual Auction Revenue Rights allocation. Requests received after November 1st shall not be considered for the upcoming annual Auction Revenue Rights allocation. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.

ix. Requests for new or alternate stage 1 resources made by Network Service Users and external LSEs that are received by November 1st shall be evaluated at the same time. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.

x. Stage 1 Auction Revenue Rights source points that qualify pursuant to this subsection 7.4.2(j) shall be eligible as stage 1 Auction Revenue Rights source points in subsequent annual Auction Revenue Rights allocations.

xi. Long-Term Firm Point-to-Point Transmission customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer's Long-Term Firm Point-to-Point Transmission service contract megawatt amount; or 2) the customer's Firm Transmission Withdrawal Rights.

xii. Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer's network service peak load; or 2) the customer's Firm Transmission Withdrawal Rights.

xiii. Stage 1A Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed 50% of the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j).

xiv. Stage 1B Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed the difference between the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatts granted in stage 1A.

xv. In each round of Stage 2 of an annual allocation of Auction Revenue Rights megawatt requests made pursuant to this subsection 7.4.2(j) shall be equal to or less than one third of the difference between the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatt amount allocated in stage 1.

xvi. Stage 1 Auction Revenue Rights sources established pursuant to this subsection 7.4.2(j) and the associated Auction Revenue Rights megawatt amount may be replaced with an alternate resource pursuant to the process established in Section 7.7 of Schedule 1 of this Agreement.

7.4.2a Bilateral Transfers of Auction Revenue Rights

(a) Market Participants may enter into bilateral agreements to transfer Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights to a third party.

Such bilateral transfers shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules related to its eFTR tools.

(b) For purposes of clarity, with respect to all bilateral transfers of Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights, the rights and obligations to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights that are the subject of such a bilateral transfer shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. In no event, shall the purchase and sale of an Auction Revenue Right or the right to receive an allocation of Auction Revenue Rights pursuant to a bilateral transfer constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

(c) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights. Such consent shall be based upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall not transfer to the third party and the holder of the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall continue to receive all rights attributable to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights and remain subject to all credit requirements and obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights.

(d) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the Auction Revenue Right and for which payment is not made to PJMSettlement by the buyer under such a bilateral transfer.

(e) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.

(f) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.

7.4.3 Target Allocation of Auction Revenue Right Credits.

(a) A Target Allocation of Auction Revenue Right Credits for each entity holding an Auction Revenue Right shall be determined for each Auction Revenue Right. After each round of the annual Financial Transmission Right auction, each Auction Revenue Right shall be divided by four and multiplied by the price differences for the receipt and delivery points associated with the Auction Revenue Right, calculated as the Locational Marginal Price at the delivery points(s) minus the Locational Marginal Price at the receipt point(s), where the price for the receipt and delivery point is determined by the clearing prices of each round of the annual Financial Transmission Right auction. The daily total Target Allocation for an entity holding the Auction Revenue Rights shall be the sum of the daily Target Allocations associated with all of the entity's Auction Revenue Rights.

(b) A Target Allocation of Residual Auction Revenue Rights Credits for each entity allocated Residual Auction Revenue Rights pursuant to section 7.9 of Schedule 1 of this Agreement shall be determined on a monthly basis for each month in a Planning Period beginning with the month the Residual Auction Revenue Right(s) becomes effective through the end of the relevant Planning Period. The Target Allocation for Residual Auction Revenue Rights Credits shall be equal to megawatt amount of the Residual Auction Revenue Rights multiplied by the LMP differential between the source and sink nodes of the corresponding FTR obligations in each prompt-month FTR auction that occurs from the effective date of the Residual Auction Revenue Rights through the end of the relevant Planning Period.

7.4.4 Calculation of Auction Revenue Right Credits.

(a) Each day, the total of all the daily Target Allocations determined as specified above in Section 7.4.3 plus any additional Auction Revenue Rights Target Allocations applicable for that day shall be compared to the total revenues of all applicable monthly Financial Transmission Rights auction(s) (divided by the number of days in the month) plus the total revenues of the annual Financial Transmission Rights auction (divided by the number of days in the Planning Period). If the total of the Target Allocations is less than the total auction revenues, the Auction Revenue Right Credit for each entity holding an Auction Revenue Right shall be equal to its Target Allocation. All remaining funds shall be distributed as Excess Congestion Charges pursuant to Section 5.2.5.

(b) If the total of the Target Allocations is greater than the total auction revenues, each holder of Auction Revenue Rights shall be assigned a share of the total auction revenues in proportion to its Auction Revenue Rights Target Allocations for Auction Revenue Rights which have a positive Target Allocation value. Auction Revenue Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Auction Revenue Right Credit.

(c) At the end of a Planning Period, if all Auction Revenue Right holders did not receive Auction Revenue Right Credits equal to their Target Allocations, PJMSettlement shall assess a charge equal to the difference between the Auction Revenue Right Credit Target Allocations for all revenue deficient Auction Revenue Rights and the actual Auction Revenue Right Credits allocated to those Auction Revenue Right holders. The aggregate charge for a Planning Period assessed pursuant to this section, if any, shall be added to the aggregate charge for a Planning Period assessed pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and collected pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and distributed to the Auction Revenue Right holders that did not receive Auction Revenue Right Credits equal to their Target Allocation.

ATTACHMENT L
List of Transmission Owners

Allegheny Electric Cooperative, Inc.
American Transmission Systems, Incorporated
Atlantic City Electric Company
Baltimore Gas and Electric Company
NAEA Rock Springs, LLC
Delmarva Power & Light Company
Duke Energy Ohio, Inc.
Duke Energy Kentucky, Inc.
Jersey Central Power & Light Company
Metropolitan Edison Company
Neptune Regional Transmission System, LLC
Old Dominion Electric Cooperative
Pennsylvania Electric Company
PECO Energy Company
Pennsylvania Power & Light Company
Potomac Electric Power Company
Public Service Electric and Gas Company
Rockland Electric Company
Trans-Allegheny Interstate Line Company
UGI Utilities, Inc.
Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power
Commonwealth Edison Company and Commonwealth Edison Company of Indiana, Inc.
The Dayton Power and Light Company
AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company)
Duquesne Light Company
Virginia Electric and Power Company
Linden VFT, LLC
City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power

5.10 Auction Clearing Requirements

The Office of the Interconnection shall clear each Base Residual Auction and Incremental Auction for a Delivery Year in accordance with the following:

a) Variable Resource Requirement Curve

The Office of the Interconnection shall determine Variable Resource Requirement Curves for the PJM Region and for such Locational Deliverability Areas as determined appropriate in accordance with subsection (a)(iii) for such Delivery Year to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. It is recognized that the variable resource requirement reflected in the Variable Resource Requirement Curve can result in an optimized auction clearing in which the level of Capacity Resources committed for a Delivery Year exceeds the PJM Region Reliability Requirement (less the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012, or less the Short-Term Resource Procurement Target for Delivery Years thereafter) or Locational Deliverability Area Reliability Requirement (less the Forecast Zonal ILR Obligation for Delivery Years through May 31, 2012, or less the Short-Term Resource Procurement Target for Delivery Years thereafter for the Zones associated with such LDA) for such Delivery Year. For any auction, the Updated Forecast Peak Load, and Short-Term Resource Procurement Target applicable to such auction, shall be used, *and Price Responsive Demand from any applicable approved PRD Plan, including any associated PRD Reservation Prices, shall be reflected in the derivation of the Variable Resource Requirement Curves, in accordance with the methodology specified in the PJM Manuals.*

i) Methodology to Establish the Variable Resource Requirement Curve

Prior to the Base Residual Auction, in accordance with the schedule in the PJM Manuals, the Office of the Interconnection shall establish the Variable Resource Requirement Curve for the PJM Region as follows:

- Each Variable Resource Requirement Curve shall be plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis;
- The Variable Resource Requirement Curve for the PJM Region shall be plotted by first combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), (iii) a straight line connecting points (2) and (3), and (iv) a vertical line from point (3) to the x-axis, where:
  - For point (1), price equals: [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin (“IRM”)% minus 3%) divided by (100%

plus IRM%)] minus the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter;

- For point (2), price equals: (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset) divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 1%) divided by (100% plus IRM%)] minus the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter; and

- For point (3), price equals [0.2 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 5%) divided by (100% plus IRM%)] minus the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter;

ii) For any Delivery Year, the Office of the Interconnection shall establish a separate Variable Resource Requirement Curve for each LDA for which:

A. the Capacity Emergency Transfer Limit is less than 1.15 times the Capacity Emergency Transfer Objective, as determined by the Office of the Interconnection in accordance with NERC and Applicable Regional Reliability Council guidelines; or

B. such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; or

C. such LDA is determined in a preliminary analysis by the Office of the Interconnection to be likely to have a Locational Price Adder, based on historic offer price levels; provided however that for the Base Residual Auction conducted for the Delivery Year commencing on June 1, 2012, the EMAAC, SWMAAC and MAAC LDAs shall employ separate Variable Resource Requirement Curves regardless of the outcome of the above three tests; and provided further that the Office of the Interconnection may establish a separate Variable Resource Requirement Curve for an LDA not otherwise qualifying under the above three tests if it finds that such is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards, in which case the Office of the Interconnection shall post such finding, such LDA, and such Variable Resource Requirement Curve on its internet site no later than the

March 31 last preceding the Base Residual Auction for such Delivery Year. The same process as set forth in subsection (a)(i) shall be used to establish the Variable Resource Requirement Curve for any such LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement and the LDA Short-Term Resource Procurement Target shall be substituted for the PJM Region Short-Term Resource Procurement Target. For purposes of calculating the Capacity Emergency Transfer Limit under this section, all generation resources located in the PJM Region that are, or that qualify to become, Capacity Resources, shall be modeled at their full capacity rating, regardless of the amount of capacity cleared from such resource for the immediately preceding Delivery Year.

iii) Procedure for ongoing review of Variable Resource Requirement Curve shape.

Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall perform a review of the shape of the Variable Resource Requirement Curve, as established by the requirements of the foregoing subsection. Such analysis shall be based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis. Based on the results of such review, PJM shall prepare a recommendation to either modify or retain the existing Variable Resource Requirement Curve shape. The Office of the Interconnection shall post the recommendation and shall review the recommendation through the stakeholder process to solicit stakeholder input. If a modification of the Variable Resource Requirement Curve shape is recommended, the following process shall be followed:

A) If the Office of the Interconnection determines that the Variable Resource Requirement Curve shape should be modified, Staff of the Office of the Interconnection shall propose a new Variable Resource Requirement Curve shape on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

B) The PJM Members shall review the proposed modification to the Variable Resource Requirement Curve shape.

C) The PJM Members shall either vote to endorse the proposed modification, to propose alternate modifications or to recommend no modification by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) The PJM Board of Managers shall consider a proposed modification to the Variable Resource Requirement Curve shape, and the Office of the Interconnection shall file any approved modified Variable Resource Requirement Curve shape with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

iv) Cost of New Entry

A) For the Delivery Year commencing on June 1, 2012, and continuing thereafter unless and until changed pursuant to subsection (B) below, the Cost of New Entry for the PJM Region shall be $112,868 per MW-year. The Cost of New Entry for each LDA shall be determined based upon the Transmission Owner zones that comprise such LDA, as provided in the table below. If an LDA combines transmission zones with differing Cost of New Entry values, the lowest such value shall be used.

Geographic Location Within the PJM Region Encompassing These Zones	Cost of New Entry in $/MW-Year
PS, JCP&L, AE, PECO, DPL, RECO (“CONE Area 1”)	122,040
BGE, PEPCO (“CONE Area 2”)	112,868
AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK (“CONE Area 3”)	115,479
PPL, MetEd, Penelec (“CONE Area 4”)	112,868
Dominion (“CONE Area 5”)	112,868

B) Beginning with the 2013-2014 Delivery Year, the CONE shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable H-W Index, in accordance with the following:

(1) The Applicable H-W Index for any Delivery Year shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in the Total Other Production Plant Index shown in the Handy-Whitman Index of Public Utility Construction Costs for the North Atlantic Region for purposes of CONE Areas 1, 2, and 4, for the North Central Region for purposes of CONE Area 3, and for the South Atlantic Region for purposes of CONE Area 5.

(2) The CONE in a CONE Area shall be adjusted prior to the Base Residual Auction for each Delivery Year by applying the Applicable H-W Index for such CONE Area to the Benchmark CONE for such CONE Area.

(3) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year.

(4) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vii)(C) or any filing to establish new or revised CONE Areas.

v) Net Energy and Ancillary Services Revenue Offset

A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (A) the annual average of the revenues that would have been received by the Reference Resource during a period of three consecutive calendar years preceding the time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) fuel prices reported during such period at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of $6.47 per MWh, and actual PJM hourly average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of $2,199 per MW-year.

B) The Office of the Interconnection also shall determine a Net Energy and Ancillary Market Revenue Offset each year for each sub-region of the PJM Region for which the Cost of New Entry is determined, as identified above, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the average hourly LMPs for the transmission zone in which such resource was assumed to be installed for purposes of the CONE estimate (as specified in the PJM Manuals) shall be used in place of the PJM Region average hourly LMPs; (2) if such sub-region was not integrated into the PJM Region for the entire applicable period, then the offset shall be calculated using only those whole calendar years during which the sub-region was integrated; and (3) a posted fuel pricing point in such sub-region, if available, and (if such pricing point is not available) a fuel transmission adder appropriate to each assumed Cost of New Entry location from an appropriate PJM Region pricing point shall be used for each such sub-region.

vi) Adjustment to Net Energy and Ancillary Services Revenue Offset

Beginning with the Base Residual Auction scheduled for May 2010, the Net Energy and Ancillary Services Revenue Offset for a CONE Area shall be adjusted following any Delivery Year during which Scarcity Pricing was effective in such CONE Area pursuant to the Scarcity Pricing provisions of section 6A of Schedule 1 to the PJM Operating Agreement. Following each Delivery Year, the Scarcity Pricing revenues the Reference Resource in each CONE Area would have received during such Delivery Year shall be calculated based on the assumed heat rate and other characteristics of the Reference Resource, assumed Peak-Hour Dispatch, and the actual locational marginal prices and actual fuel prices during the Delivery Year for the applicable location, which shall be the transmission zone in which such resource was assumed to be installed for purposes of the estimate of CONE applicable to such CONE Area. The Scarcity Pricing revenues so determined shall be subtracted from the Net CONE otherwise calculated for such CONE Area for use in the Base Residual Auction next occurring after the Delivery Year in which Scarcity Pricing was effective in such CONE Area.

vii) Process for Establishing Parameters of Variable Resource Requirement Curve

A) The parameters of the Variable Resource Requirement Curve will be established prior to the conduct of the Base Residual Auction for a Delivery Year and will be used for such Base Residual Auction.

B) The Office of the Interconnection shall determine the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement for each Locational Deliverability Area for which a Variable Resource Requirement Curve has been established for such Base Residual Auction on or before February 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values will be applied, in accordance with the Reliability Assurance Agreement.

C) Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall review the calculation of the Cost of New Entry for each CONE Area.

1) If the Office of the Interconnection determines that the Cost of New Entry values should be modified, the Staff of the Office of the Interconnection shall propose new Cost of New Entry values on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

2) The PJM Members shall review the proposed values.

3) The PJM Members shall either vote to endorse the proposed values or propose alternate values by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

4) The PJM Board of Managers shall consider Cost of New Entry values, and the Office of the Interconnection shall file any approved modified Cost of New Entry values with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall review the methodology set forth in this Attachment for determining the Net Energy and Ancillary Services Revenue Offset for the PJM Region and for each Zone.

1) If the Office of the Interconnection determines that the Net Energy and Ancillary Services Revenue Offset methodology should be modified, Staff of the Office of the Interconnection shall propose a new Net Energy and Ancillary Services Revenue Offset methodology on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

2) The PJM Members shall review the proposed methodology.

3) The PJM Members shall either vote to endorse the proposed methodology or propose an alternate methodology by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

4) The PJM Board of Managers shall consider the Net Revenue Offset methodology, and the Office of the Interconnection shall file any approved modified Net Energy and Ancillary Services Revenue Offset values with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

b) Locational Requirements

The Office of Interconnection shall establish locational requirements prior to the Base Residual Auction to quantify the amount of Unforced Capacity that must be committed in each Locational Deliverability Area, in accordance with the PJM Reliability Assurance Agreement.

c) Minimum Annual Resource Requirements

Prior to the Base Residual Auction and each Incremental Auction for each Delivery Year, beginning with the Delivery Year that starts on June 1, 2014, the Office of the Interconnection shall establish the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year.

d) Preliminary PJM Region Peak Load Forecast for the Delivery Year

The Office of the Interconnection shall establish the Preliminary PJM Region Load Forecast for the Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the Base Residual Auction for such Delivery Year.

e) Updated PJM Region Peak Load Forecasts for Incremental Auctions

The Office of the Interconnection shall establish the updated PJM Region Peak Load Forecast for a Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the First, Second, and Third Incremental Auction for such Delivery Year.

ATTACHMENT JJ
MTEP PROJECT COST RECOVERY FOR DEOK ZONE

I. Definitions

A. DEOK – Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc.

B. Midwest ISO or MISO – The Midwest Independent Transmission System Operator, Inc.

C. Midwest ISO Tariff – The Midwest ISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff.

D. Midwest ISO Transmission Owner – Any transmission owner in the Midwest ISO, including any independent transmission company, responsible for the construction of MTEP Projects under Attachment FF of the Midwest ISO Tariff.

E. MTEP – The Midwest ISO Transmission Expansion Plan established pursuant to Attachment FF of the Midwest ISO Tariff.

F. MTEP Project – A transmission project constructed by DEOK or by Midwest ISO Transmission Owners pursuant to Attachment FF of the Midwest ISO Tariff for which all or a portion of the revenue requirement is allocated to DEOK pursuant to the Midwest ISO Tariff.

G. Network Service Peak Load – A Network Service Transmission Customer's share of the previous year's DEOK zonal peak load (1 CP).

II. Introduction and Purpose

Transmission Customers taking transmission service for deliveries in the DEOK Zone shall pay a portion of the cost of MTEP Projects constructed by Midwest ISO Transmission Owners. This Attachment JJ sets forth the method by which Transmission Customers taking transmission service for deliveries into the DEOK Zone are charged for the cost of MTEP Projects constructed by Midwest ISO Transmission Owners. This Attachment also sets forth the method by which the PJM Office of the Interconnection will transmit to the Midwest ISO the revenues received from Transmission Customers taking transmission service for deliveries into the DEOK Zone for the cost of MTEP Projects to be constructed by Midwest ISO Transmission Owners. Finally, it addresses the manner in which the PJM Office of the Interconnection will distribute to Duke Energy Ohio, Inc. on behalf of DEOK the revenues received from the Midwest ISO for the cost of MTEP Projects constructed by DEOK.

III. MTEP Project Revenue Requirements Allocated to DEOK Zone

A. Recovery of Annual Revenue Requirements for Midwest ISO Transmission Owners' MTEP Projects

Each month, and pursuant to agreed-upon settlement procedures, PJM shall bill each Network Customer in the DEOK Zone its monthly share of the revenue requirements allocated to DEOK for MTEP Projects constructed by the Midwest ISO Transmission Owners, determined in accordance with the Midwest ISO Tariff and as billed by the Midwest ISO to PJM ("Network Customer's MTEP Project Charge"). A Network Customer's share of such revenue requirements shall be based on its Network Service Peak Load in the DEOK Zone.

B. Revenue Distribution from Payments Made by Transmission Customers in DEOK Zone; Shortfall in Payment

Each month, and pursuant to agreed-upon settlement procedures, the PJM Office of the Interconnection shall remit to the Midwest ISO the revenue requirements allocated to DEOK for MTEP Projects constructed by the Midwest ISO Transmission Owners, as set forth in Section III.A. In addition, in the event that the revenues received by PJM from a Network Customer pursuant to Section III.A. are less than the Network Customer's MTEP Project Share ("Shortfall"), and PJM makes up such Shortfall in its remittance to the Midwest ISO, (a) PJM shall apply such Shortfall to the financial settlement of Duke Energy Ohio, Inc.'s account (on behalf of DEOK), and (b) such Network Customer shall thereafter be obligated to remit such Shortfall directly to DEOK instead of to PJM, together with any Late Payment Charges that would otherwise be due to PJMSettlement under Section 7.1A of this Tariff. DEOK shall have all rights to seek recovery of such Shortfall directly from the Network Customer, and such rights shall be enforceable by DEOK at FERC and in any court of competent jurisdiction. DEOK shall be a third party beneficiary under the Network Customer's service agreement with PJM for the limited purpose of seeking recovery of such Shortfall.

IV. <u>DEOK MTEP Project Revenue Requirements Allocated to Midwest ISO Zones</u>

A. Derivation of Annual Revenue Requirements

Under the methodology provided under Attachment H–22 to this Tariff, DEOK will periodically update the Annual Revenue Requirements for MTEP Projects constructed by DEOK. No later than May 1 each year, DEOK shall provide these updated revenue requirements to the Midwest ISO for the upcoming June 1 – May 31 rate year.

B. Allocation of Annual Revenue Requirements to Midwest ISO Zones

The portion of the Annual Revenue Requirements derived under Section IV.A that will be recovered from transmission customers taking transmission service in the Midwest ISO shall be calculated by the Midwest ISO in accordance with the Midwest ISO Tariff.

C. Monthly Revenue Requirements Owed from the Midwest ISO Zones

Each month, and pursuant to agreed-upon settlement procedures, the Midwest ISO shall remit an amount to the PJM Office of the Interconnection from revenues collected by the

Midwest ISO in proportion to DEOK's annual pro-rata share of the total Network Upgrade Charge as described in the Midwest ISO Schedule 38.

D. Revenue Distribution from Payments Made by Transmission Customers in the Midwest ISO

Pursuant to agreed-upon settlement procedures, PJM shall credit to Duke Energy Ohio's account (on behalf of DEOK) in the subsequent month the amount of revenue requirements that the Midwest ISO remits to PJM pursuant to Section IV.C for the prior month.

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3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Section 2 of this Schedule.

(b) Market Buyers shall be charged for all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(d) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the total amount of net hourly PJM Interchange for each Market Buyer, including Generating Market Buyers, in accordance with the PJM Manuals. For Internal Market Buyers that are Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall include determination of the net energy flows from: (i) tie lines; (ii) any generation resource the output of which is controlled by the Market Buyer but delivered to it over another entity's Transmission Facilities; (iii) any generation resource the output of which is controlled by another entity but which is directly interconnected with the Market Buyer's transmission system; (iv) deliveries pursuant to bilateral energy sales; (v) receipts pursuant to bilateral energy purchases; and (vi) an adjustment to account for the day-ahead PJM Interchange, calculated as the difference between scheduled withdrawals and injections by that Market Buyer in the Day-ahead Energy Market. For External Market Buyers and Internal Market Buyers that are not Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall determine the energy scheduled hourly for delivery to the Market Buyer net of the amounts scheduled by the External Market Buyer in the Day-ahead Energy Market.

(e) An Internal Market Buyer shall be charged for Spot Market Energy purchases to the extent of its hourly net purchases from the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. An External Market Buyer shall be charged for its Spot Market Energy purchases based on the energy delivered to it, determined as specified in Section 3.2.1(d) above. The total charge shall be determined by the product of the hourly net amount of PJM Interchange Imports times the hourly Real-time System Energy Price for that Market Buyer.

(f) A Generating Market Buyer shall be paid as a Market Seller for sales of Spot Market Energy to the extent of its hourly net sales into the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. The total payment shall be determined by the product of the hourly net amount of PJM Interchange Exports times the hourly Real-time System Energy Price for that Market Seller.

3.2.2 Regulation.

(a) Each Internal Market Buyer that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). An Internal Market Buyer that does not meet its hourly Regulation obligation shall be charged for Regulation dispatched by the Office of the Interconnection to meet such obligation at the Regulation market-clearing price determined in accordance with subsection (c) of this Section, plus the amounts, if any, described in subsection (f) of this section.

(b) A Generating Market Buyer supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection in excess of its hourly Regulation obligation shall be credited for each increment of such Regulation at the higher of (i) the Regulation market-clearing price in such Regulation Zone or (ii) the sum of the regulation offer and the unit-specific opportunity cost of the generation resource supplying the increment of Regulation, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day. The market-clearing price for each regulating hour shall be equal to the highest sum of a resource's Regulation offer plus its estimated unit-specific opportunity costs, determined as described in subsection (d) below from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.3.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation market-clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour shall be equal to the sum of the unit-specific opportunity costs (i) incurred during the hour in which the obligation is fulfilled, plus costs (ii) associated with uneconomic operation during the hour preceding the initial regulating hour ("preceding shoulder hour"), plus costs (iii) associated with uneconomic operation during the hour after the final regulating hour ("following shoulder hour").

The unit-specific opportunity costs incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market.

Estimated opportunity costs for Demand Resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's Regulation signals from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Internal Market Buyer in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to section 1.10.1A(e) of this Schedule. A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region for which the cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Section 3.2.A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unfor*e*seen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

(c) The sum of the foregoing credits calculated in accordance with Section 3.2.3(b) plus any unallocated charges from Section 3.2.3(h) and 5.1.7, and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection and that is not committed solely for the purpose of providing Synchronized Reserve: For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following segments: 1) the greater of their day-ahead schedules or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

Credits received pursuant to this section shall be equal to the positive difference between a resource's total offered price for start-up (shutdown costs for Demand Resources) and no-load fees and energy, determined on the basis of the resource's scheduled output, and the total value of the resource's energy as determined by the Real-time Energy Market and the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

Except as provided in Section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to Section 3.2.3(b) plus the resource's opportunity cost and less any amounts credited for Synchronized Reserve in excess of the Synchronized Reserve offer plus the resource's opportunity cost and less any amounts credited for providing Reactive Services as specified in Section 3.2.3B, and less any amounts for Day-ahead Scheduling Reserve in excess of the Day-ahead Scheduling Reserve offer plus the resource's opportunity cost, shall be credited to the Market Seller.

Synchronized Reserve and Day-ahead Scheduling Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding hour(s) in which the Synchronized Reserve and Day-ahead Scheduling Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each period the unit operates in condensing and generation mode for one or more contiguous hours.

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

AG equals the actual hourly integrated output of the unit;

URTLMP equals the real time LMP at the unit's bus;

UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UB shall not be negative.

(f-1) A Market Seller's combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described above for a steam unit or combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG}, or (ii) {(URTLMP – UB) x DAG} where:

URTLMP equals the real time LMP at the unit's bus;

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit, determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(f-2) A Market Seller's hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2A(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (i) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day; (ii) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (iii) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day, except as noted below and in the PJM Manuals; and (iv) deviations of energy sales from the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such region pursuant to Section 1.12.

Deviations that occur within a single Zone shall be associated with the Eastern or Western Region, as defined in Section 3.2.3(q) of this Schedule, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at interfaces and hubs shall be associated with the Eastern or Western Region if all the busses that define all interfaces or all hubs are located in the region. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by busses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of an Operating Reserve shortage in real-time or where PJM initiates the request for load reductions in real-time in order to avoid an Operating Reserve shortage as described in this Schedule, Section 6A, Scarcity Pricing.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in Section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for each Control Zone of the PJM Region based on the Control Zone to which the resource was synchronized to provide synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such Control Zone pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared ("Maximum Generation Emergency Alert"); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Operating Reserves credit otherwise provided by Section 3.2.3.(b) or Section 3.2.3(e) in connection with marked-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as "MaxGen Conditions"). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Schedule 2 of the Operating Agreement, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any hours required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer

Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described in the PJM Manuals. Ramp-limited desired MW values shall be used to determine generation resource real-time deviations from the resource's day-ahead schedules.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

(i) real-time economic minimum <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

$$\mathbf{Ramp\_Request}_t = \frac{(\mathbf{UDStarget}_{t-1} - \mathbf{AOutput}_{t-1})}{(\mathbf{UDSLAtime}_{t-1})}$$

$$\mathbf{RL\_Desired}_t = \mathbf{AOutput}_{t-1} + \left(\mathbf{Ramp\_Request}_t * \mathbf{Case\_Eff\_time}_{t-1}\right)$$

where:

1. UDStarget = UDS basepoint for the previous UDS case

2. AOutput = Unit's output at case solution time
3. UDSLAtime = UDS look ahead time
4. Case_Eff_time = Time between base point changes
5. RL_Desired = Ramp-limited desired MW

To determine if a resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the UDS Basepoint or the actual output and ramp-limited desired MW value. The % off dispatch and MW off dispatch will be a time-weighted average over the course of an hour.

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and UDS Basepoint, or if its % off dispatch is <= 10, or it's hourly integrated Real-time MWh is within 5% or 5 MW (whichever is greater) of the hourly integrated ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – Day-Ahead MWh.

- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – UDS LMP Desired MW.

- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – hourly integrated Ramp-Limited Desired MW.

- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the hour is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time Mwh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

- If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch, and the resource has tripped, for the hour the resource tripped and the hours it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – Day-Ahead MWh.

- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time MWh and Day-Ahead MWh.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, DEOK transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(iii) Reliability and deviation regional balancing Operating Reserve rates shall be determined by summing the relevant RTO balancing Operating Reserve rates and regional adder rates.

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

3.2.3A Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Synchronized Reserve Zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Synchronized Reserve Zone, for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). An Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts if any, described in subsections (g), (h) and (i) of this section.

(b) A Generating Market Buyer supplying Synchronized Reserve at the direction of the Office of the Interconnection, in excess of its hourly Synchronized Reserve Obligation, shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation units that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price.

ii) Credits for Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions ("Tier 2 Synchronized Reserve") shall be the higher of (i) the Synchronized Reserve Market Clearing Price or (ii) the sum of (A) the Synchronized Reserve offer, and (B) the specific opportunity cost of the generation resource supplying the increment of Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

iii) Credits for Synchronized Reserve provided by Demand Resources that are synchronized to the grid and accept the obligation to reduce load in response to a Synchronized Reserve Event initiated by the Office of the Interconnection shall be the sum of (i) the higher of (A) the synchronized Reserve offer or (B) the Synchronized Reserve Market Clearing Price and (ii) if a Synchronized Reserve Event is actually initiated by the Office of the Interconnection and the Demand Resource reduced its load in response to the event, the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

(c) The Synchronized Reserve Energy Premium Price is the average of the five-minute Locational Marginal Prices calculated during the Synchronized Reserve Event plus an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Synchronized Reserve Zone by the Office of the Interconnection prior to the operating hour and such market-clearing price shall be equal to, from among the generation resources or Demand Resources selected to provide Synchronized Reserve for such Synchronized Reserve Zone, the highest sum of either (i) a generation resource's Synchronized Reserve offer and opportunity cost or (ii) a demand response resource's Synchronized Reserve offer.

(e) In determining the Synchronized Reserve Market Clearing Price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the expected Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market. The opportunity costs for a Demand Resource shall be zero.

(g) Charges for Tier 1 Synchronized Reserve will be allocated in proportion to the amount of Tier 1 Synchronized Reserve applied to each Synchronized Reserve Obligation. In the event Tier 1 Synchronized Reserve is provided by a Market Seller in excess of that Market Seller's Synchronized Reserve Obligation, the remainder of the Tier 1 Synchronized Reserve that is not utilized to fulfill the Seller's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

(h) Any amounts credited for Tier 2 Synchronized Reserve in an hour in excess of the Synchronized Reserve Market Clearing Price in that hour shall be allocated and charged to each Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation in proportion to its purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) In the event the Office of the Interconnection needs to assign more Tier 2 Synchronized Reserve during an hour than was estimated as needed at the time the Synchronized Reserve Market Clearing Price was calculated for that hour due to a reduction in available Tier 1 Synchronized Reserve, the costs of the excess Tier 2 Synchronized Reserve shall be allocated and charged to those providers of Tier 1 Synchronized Reserve whose available Tier 1 Synchronized Reserve was reduced from the needed amount estimated during the Synchronized Reserve Market Clearing Price calculation, in proportion to the amount of the reduction in Tier 1 Synchronized Reserve availability.

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled by the owner to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Synchronized Reserve in response to an actual Synchronized Reserve Event, the owner of the resource shall incur an additional Synchronized Reserve Obligation in the amount of the shortfall for a period of three consecutive days with the same peak classification (on-peak or off-peak) as the day of the Synchronized Reserve Event at least three business days following the Synchronized Reserve Event. The overall Synchronized Reserve requirement for each Synchronized Reserve Zone of the PJM Region on which the Synchronized Reserve Obligations, except for the additional obligations set forth in this section, are based shall be reduced by the amount of this shortfall for the applicable three-day period.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l), is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption ten minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or

Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Demand Resource’s consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Demand Resource’s consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Demand Resource’s consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJMSettlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

(b) A Day-ahead Scheduling Reserves Resource that receives a Day-ahead Scheduling Reserves schedule pursuant to subsection (a) of this section shall be paid the hourly Day-ahead Scheduling Reserves Market clearing price for the MW obligation in each hour of the schedule, subject to meeting the requirements of subsection (c) of this section.

(c) To be eligible for payment pursuant to subsection (b) of this section, Day-ahead Scheduling Reserves Resources shall comply with the following provisions:

(i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.

(ii) Generation resources and Demand Resources with start times or shut-down times, respectively, equal to or less than 30 minutes are required to respond to dispatch directives from the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule. To meet this requirement the resource shall be required to start or shut down within the specified notification time plus its start or shut down time, provided that such time shall be less than thirty minutes.

(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

Resources that do not comply with the provisions of this subsection (c) shall not be eligible to receive credits pursuant to subsection (b) of this section.

(d) The cost of credits allocated to Day-ahead Scheduling Reserves Resources pursuant to this section shall be charged to Load-Serving Entities in the PJM Region based on load ratio share (net of operating Behind The Meter Generation, but not to be less than zero), provided that a Load-Serving Entity may satisfy its Day-ahead Scheduling Reserves obligation, which is equal to the Day-ahead Scheduling Reserves Requirement multiplied by the Load-Serving Entity's load ratio share for the PJM Region, through one or any combination of the following: 1) the Day-ahead Scheduling Reserves Market; 2) and bilateral arrangements. The Day-ahead Scheduling Reserve charges allocated pursuant to this section shall reflect any portion of a Load-Serving Entity's Day-ahead Scheduling Reserves obligation that is met by bilateral arrangement(s).

(e) If the Day-ahead Scheduling Reserves Requirement is not satisfied through the operation of subsection (a) of this section, any additional Operating Reserves required to meet the requirement shall be scheduled by the Office of the Interconnection pursuant to Section 3.2.3 of Schedule 1 of this Agreement.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit hourly in an amount equal to {(LMPDMW - AG) x (URTLMP - UB)}

where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

AG equals the actual hourly integrated output of the unit;

URTLMP equals the real time LMP at the unit's bus;

UB equals the unit offer for that unit for which output is reduced or suspended determined according to the real time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UB shall not be negative.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG, or (ii) {(URTLMP – UB) x DAG where:

URTLMP equals the real time LMP at the unit's bus;

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to Section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual hourly integrated output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

UB equals the unit offer for that unit for which output is increased, determined according to the real time scheduled offer curve on which the unit was operating;

URTLMP equals the real time LMP at the unit's bus; and

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2A(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generation unit's bus, (C) the generation unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each

Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

Each Market Buyer shall be assessed Transmission Congestion Charges as specified in Section 5 of this Schedule.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Section 5 of this Schedule.

3.2.6 Emergency Energy.

(a) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each hour of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(b) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each hour of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(c) The net costs or net revenues associated with sales or purchases of hourly energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each hour of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Buyer in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Buyer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Buyer's internal accounting.

(b) If deliveries to a Market Buyer that has PJM Interchange meters in accordance with Section 14 of the Operating Agreement include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Buyer, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market Buyer and the unmetered Market Participant specified by them to the Office of the Interconnection.

7.4 Allocation of Auction Revenues.

7.4.1 Eligibility.

(a) Annual auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated among holders of Auction Revenue Rights in proportion to, but not more than, the Target Allocation of Auction Revenue Rights Credits for the holder.

(b) Auction Revenue Rights Credits will be calculated based upon the clearing price results of the applicable Annual Financial Transmission Rights auction.

(c) Monthly and Balance of Planning Period FTR auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated according to the following priority schedule:

> (i) To stage 1 and 2 Auction Revenue Rights holders in accordance with section 7.4.4 of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(ii) of this section;
>
> (ii) To the Residual Auction Revenue Rights holders in proportion to, but not more than their Target Allocation as determined pursuant to section 7.4.3(b) of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(iii) of this section;
>
> (iii) To FTR Holders in accordance with section 5.2.6 of Schedule 1 of this Agreement.

(d) Long-term FTR auction revenues associated with FTRs that cover individual Planning Periods shall be distributed in the Planning Period for which the FTR is effective. Long-term FTR auction revenues associated with FTRs that cover multiple Planning Years shall be distributed equally across each Planning Period in the effective term of the FTR. Long-term FTR auction revenue distributions within a Planning Period shall be in accordance with the following provisions:

> (i) Long-term FTR Auction revenues shall be distributed to Auction Revenue Rights holders in the effective Planning Period for the FTR. The distribution shall be in proportion to the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately. The distribution shall not exceed, when added to the distribution of revenues from the prompt-year annual FTR auction itself, the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately.

(ii) Long-term FTR auction revenues remaining after distributions made pursuant to Section 7.4.1(d)(ii) of Schedule 1 of this Agreement shall be distributed pursuant to Section 5.2.6 of Schedule 1 of this Agreement.

7.4.2 Auction Revenue Rights.

(a) Prior to the end of each PJM Planning Period an annual allocation of Auction Revenue Rights for the next PJM Planning Period shall be performed using a two stage allocation process. Stage 1 shall consist of stages 1A and 1B, which shall allocate ten year and annual Auction Revenue Rights, respectively, and stage 2 shall allocate annual Auction Revenue Rights. The Auction Revenue Rights allocation process shall be performed in accordance with Sections 7.4 and 7.5 hereof and the PJM Manuals.

With respect to the allocation of Auction Revenue Rights, if the Office of the Interconnection discovers an error in the allocation, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the business day following the initial publication of allocation results. After this initial notification, if the Office of the Interconnection determines that it is necessary to post modified allocation results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the second business day following the publication of the initial allocation. Thereafter, the Office of the Interconnection must post any corrected allocation results by no later than 5:00 p.m. of the fourth calendar day following the initial publication. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced allocation is under publicly noticed review by the FERC.

(b) In stage 1A of the allocation process, each Network Service User may request Auction Revenue Rights for a term covering ten consecutive PJM Planning Periods beginning with the immediately ensuing PJM Planning Period from a subset of the historical generation resources that were designated to be delivered to load based on the historical reference year for the Zone, and each Qualifying Transmission Customer (as defined in subsection (f) of this section) may request Auction Revenue Rights based on the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. The historical reference year for all Zones shall be 1998, except that the historical reference year shall be: 2002 for the Allegheny Power and Rockland Electric Zones; 2004 for the AEP East, The Dayton Power & Light Company and Commonwealth Edison Company Zones; 2005 for the Virginia Electric and Power Company and Duquesne Light Company Zones; 2011 for the ATSI Zone; 2012 for the DEOK Zone; and the Office of the Interconnection shall specify a historical reference year for a new PJM zone corresponding to the year that the zone is integrated into the PJM Interchange Energy Market. For stage 1, the Office of the Interconnection shall determine a set of eligible historical generation resources for each Zone based on the historical reference year and assign a pro rata amount of megawatt capability from each historical generation resource to each Network Service User in the Zone based on its proportion of peak load in the Zone. Auction Revenue Rights shall be allocated to each Network Service User in a Zone from each historical generation resource in a number of megawatts equal to or less than the amount of the historical generation resource that has been assigned to the Network Service User. Each Auction Revenue Right allocated to a Network Service User shall be to the aggregate load buses of such Network Service User in a Zone or, with respect to Non-Zone Network Load, to the border of the PJM Region. In stage 1A of the allocation process, the sum of each Network Service User's allocated Auction Revenue Rights for a Zone must be equal to or less than the Network Service User's pro-rata share of the Zonal Base Load for that Zone. Each Network Service User's pro-rata share of the Zonal Base Load shall be based on its proportion of peak load in the Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than fifty percent (50%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined under Section 34.1 of the Tariff. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than fifty percent (50%) of the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. If stage 1A Auction Revenue Rights are adversely affected by any new or revised statute, regulation or rule issued by an entity with jurisdiction over the Office of the Interconnection, the Office of the Interconnection shall, to the greatest extent practicable, and consistent with any such statute, regulation or rule change, preserve the priority of the stage 1A Auction Revenue Rights for a minimum period covering the ten (10) consecutive PJM Planning Periods ("Stage 1A Transition Period") immediately following the implementation of any such changes, provided that the terms of all stage 1A Auction Revenue Rights in effect at the time the Office of the Interconnection implements the Stage 1A Transition Period shall be reduced by one PJM Planning Period during each annual stage 1A Auction Revenue Rights allocation performed during the Stage 1A Transition Period so that all stage 1A Auction Revenue Rights that were effective at the start of the Stage 1A Transition Period expire at the end of that period.

(c) In stage 1B of the allocation process each Network Service User may request Auction Revenue Rights from the subset of the historical generation resources determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process, and each Qualifying Transmission Customer may request Auction Revenue Rights based on the megawatts of firm service determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process. In stage 1B of the allocation process, the sum of each Network Service User's allocation Auction Revenue Rights request for a Zone must be equal to or less than the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 34.1 of the Tariff and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than the difference between one hundred percent (100%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than the difference between one hundred percent (100%) of the megawatts of firm service as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone.

(d) In stage 2 of the allocation process, the Office of the Interconnection shall conduct an iterative allocation process that consists of three rounds with up to one third of the remaining system Auction Revenue Rights capability allocated in each round. Each round of this allocation process will be conducted sequentially with Network Service Users and Transmission Customers being given the opportunity to view results of each allocation round prior to submission of Auction Revenue Right requests into the subsequent round. In each round, each Network Service User shall designate a subset of buses from which Auction Revenue Rights will be sourced. Valid Auction Revenue Rights source buses include only Zones, generators, hubs and external Interface Pricing Points. The Network Service User shall specify the amount of Auction Revenue Rights requested from each source bus. Each Auction Revenue Right shall be sinked to the aggregate load buses of the Network Service User in a Zone or, with respect to Non-Zone Network Load, to the border of the PJM Region. The sum of each Network Service User's Auction Revenue Rights requests in each stage 2 allocation round for each Zone must be equal to or less than one third of the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Right Allocation from stages 1A and 1B of the allocation process for that Zone. The stage 2 allocation to Transmission Customers shall be as set forth in subsection (f).

(e) On a daily basis within the annual Financial Transmission Rights auction period, a proportionate share of Network Service User's Auction Revenue Rights for each Zone are reallocated as Network Load changes from one Network Service User to another within that Zone.

(f) A Qualifying Transmission Customer shall be any customer with an agreement for Long-Term Point-to-Point Transmission Service, as defined in the PJM Tariff, used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located either outside or within the PJM Region, and that was confirmed and in effect during the historical reference year for the Zone in which the resource is located. Such an agreement shall allow the Qualifying Transmission Customer to participate in the first stage of the allocation, but only if such agreement has remained in effect continuously following the historical reference year and is to continue in effect for the period addressed by the allocation, either by its term or by renewal or rollover. The megawatts of Auction Revenue Rights the Qualifying Transmission Customer may request in the first stage of the allocation may not exceed the lesser of: (i) the megawatts of firm service between the designated Network Resource and the load delivery point (or applicable point at the border of the PJM Region for load located outside such region) under contract during the historical reference year; and (ii) the megawatts of firm service presently under contract between such historical reference year receipt and delivery points. A Qualifying Transmission Customer may request Auction Revenue Rights in either or both of stage 1 or 2 of the allocation without regard to whether such customer is subject to a charge for Firm Point-to-Point Transmission Service under Section 1 of Schedule 7 of the PJM Tariff ("Base Transmission Charge"). A Transmission Customer that is not a Qualifying Transmission Customer may request Auction Revenue Rights in stage 2 of the allocation process, but only if it is subject to a Base Transmission Charge. The Auction Revenue Rights that such a Transmission Customer may request in each round of stage 2 of the allocation process must be equal to or less than one third of the number of megawatts equal to the megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has Firm Point-to-Point Transmission Service. The source point of the Auction Revenue Rights must be the designated source point that is specified in the Transmission Service request and the sink point of the Auction Revenue Rights must be the designated sink point that is specified in the Transmission Service request. A Qualifying Transmission Customer may request Auction

Revenue Rights in each round of stage 2 of the allocation process in a number of megawatts equal to or less than one third of the difference between the number of megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has Firm Point-to-Point Transmission Service and its Auction Revenue Right Allocation from stage 1 of the allocation process.

(g) PJM Transmission Customers that serve load in the Midwest ISO may participate in stage 1 of the allocation to the extent permitted by, and in accordance with, this Section 7.4.2 and other applicable provisions of this Schedule 1. For service from non-historic sources, these customers may participate in stage 2, but in no event can they receive an allocation of ARRs/FTRs from PJM greater than their firm service to loads in MISO.

(h) Subject to subsection (i) of this section, all Auction Revenue Rights must be simultaneously feasible. If all Auction Revenue Right requests made during the annual allocation process are not feasible then Auction Revenue Rights are prorated and allocated in proportion to the megawatt level requested and in inverse proportion to the effect on the binding constraints.

(i) If any Auction Revenue Right requests made during stage 1A of the annual allocation process are not feasible, then PJM shall increase the capability limits of the binding constraints that would have rendered the Auction Revenue Rights infeasible to the extent necessary in order to allocate such Auction Revenue Rights without their being infeasible, and such increased limits shall be included in all modeling used for subsequent Auction Revenue Rights and Financial Transmission Rights allocations and auctions for the Planning Year; provided that, the foregoing notwithstanding, this subsection (i) shall not apply if the infeasibility is caused by extraordinary circumstances. For the purposes of this subsection, extraordinary circumstances shall mean an event of force majeure that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Auction Revenue Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates stage 1A Auction Revenue Rights as a result of this subsection (i) that would not otherwise have been feasible, then PJM shall notify Members and post on its web site (a) the aggregate megawatt quantities, by sources and sinks, of such Auction Revenue Rights and (b) any increases in capability limits used to allocate such Auction Revenue Rights.

(j) Long-Term Firm Point-to-Point Transmission Service customers that are not Qualifying Transmission Customers and Network Service Users serving Non-Zone Network Load may participate in stage 1 of the annual allocation of Auction Revenue Rights pursuant to Section 7.4.2(a)-(c) of Schedule 1 of this Agreement, subject to the following conditions:

i. The relevant Transmission Service shall be used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located outside the PJM Region.

ii. To be eligible to participate in stage 1A of the annual Auction Revenue Rights allocation: 1) the relevant Transmission Service shall remain in effect for the stage 1A period addressed by the allocation; and 2) the control area in which the external load is located has similar rules for load external to the relevant control area.

iii. Source points for stage 1 requests authorized pursuant to this subsection 7.4.2(j) shall be limited to: 1) generation resources owned by the LSE serving the load located outside the PJM Region; or 2) generation resources subject to a bona fide firm energy and capacity supply contract executed by the LSE to meet its load obligations, provided that such contract remains in force and effect for a minimum term of ten (10) years from the first effective Planning Period that follows the initial stage 1 request.

iv. For Long-Term Firm Point-to-Point Transmission Customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) , the generation resource(s) designated as source points may include any portion of the generating capacity of such resource(s) that is not, at the time of the request, already identified as a Capacity Resource.

v. For Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j), at the time of the request, the generation resource(s) designated as source points must either be committed into PJM's RPM market or be designated as part of the entity's FRR Capacity Plan for the purpose of serving the capacity requirement of the external load.

vi. All stage 1 source point requests made pursuant to this subsection 7.4.2(j) shall not increase the megawatt flow on facilities binding in the relevant annual Auction Revenue Rights allocation or in future stage 1A allocations and shall not cause megawatt flow to exceed applicable ratings on any other facilities in either set of conditions in the simultaneous feasibility test prescribed in subsection (vii) of this subsection 7.4.2(j).

vii. To ensure the conditions of subsection (vi) of this subsection 7.4.2(j) are met, a simultaneous feasibility test shall be conducted: 1) based on next allocation year with all existing stage 1 and stage 2 Auction Revenue Rights modeled as fixed injection-withdrawal pairs; and 2) based on 10 year allocation model with all eligible stage 1A Auction Revenue Rights for each year including base load growth for each year.

viii. Requests for stage 1 Auction Revenue Rights made pursuant to this subsection 7.4.2(j) that are received by PJM by November 1st of a Planning Period shall be processed for the next annual Auction Revenue Rights allocation. Requests received after November 1st shall not be considered for the upcoming annual Auction Revenue Rights allocation. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.

ix. Requests for new or alternate stage 1 resources made by Network Service Users and external LSEs that are received by November 1st shall be evaluated at the same time. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.

x. Stage 1 Auction Revenue Rights source points that qualify pursuant to this subsection 7.4.2(j) shall be eligible as stage 1 Auction Revenue Rights source points in subsequent annual Auction Revenue Rights allocations.

xi. Long-Term Firm Point-to-Point Transmission Customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer's Long-Term Firm Point-to-Point Transmission service contract megawatt amount; or 2) the customer's Firm Transmission Withdrawal Rights.

xii. Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer's network service peak load; or 2) the customer's Firm Transmission Withdrawal Rights.

xiii. Stage 1A Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed 50% of the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j).

xiv. Stage 1B Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed the difference between the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatts granted in stage 1A.

xv. In each round of Stage 2 of an annual allocation of Auction Revenue Rights, megawatt requests made pursuant to this subsection 7.4.2(j) shall be equal to or less than one third of the difference between the maximum allowed megawatts authorized by paragraphs (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatt amount allocated in stage 1.

xvi. Stage 1 Auction Revenue Rights sources established pursuant to this subsection 7.4.2(j) and the associated Auction Revenue Rights megawatt amount may be replaced with an alternate resource pursuant to the process established in Section 7.7 of Schedule 1 of this Agreement.

7.4.2a Bilateral Transfers of Auction Revenue Rights

(a) Market Participants may enter into bilateral agreements to transfer Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights to a third party. Such bilateral transfers shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules related to its eFTR tools.

(b) For purposes of clarity, with respect to all bilateral transfers of Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights, the rights and obligations to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights that are the subject of such a bilateral transfer shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. In no event, shall the purchase and sale of an Auction Revenue Right or the right to receive an allocation of Auction Revenue Rights pursuant to a bilateral transfer constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

(c) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights. Such consent shall be based upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall not transfer to the third party and the holder of the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall continue to receive all rights attributable to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights and remain subject to all credit requirements and obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights.

(d) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the Auction Revenue Right and for which payment is not made to PJMSettlement by the buyer under such a bilateral transfer.

(e) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.

(f) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.

7.4.3 Target Allocation of Auction Revenue Right Credits.

(a) A Target Allocation of Auction Revenue Right Credits for each entity holding an Auction Revenue Right shall be determined for each Auction Revenue Right. After each round of the annual Financial Transmission Right auction, each Auction Revenue Right shall be divided by four and multiplied by the price differences for the receipt and delivery points associated with the Auction Revenue Right, calculated as the Locational Marginal Price at the delivery points(s) minus the Locational Marginal Price at the receipt point(s), where the price for the receipt and delivery point is determined by the clearing prices of each round of the annual Financial Transmission Right auction. The daily total Target Allocation for an entity holding the Auction Revenue Rights shall be the sum of the daily Target Allocations associated with all of the entity's Auction Revenue Rights.

(b) A Target Allocation of residual Auction Revenue Rights Credits for each entity allocated Residual Auction Revenue Rights pursuant to section 7.9 of Schedule 1 of this Agreement shall be determined on a monthly basis for each month in a Planning Period beginning with the month the Residual Auction Revenue Right(s) becomes effective through the end of the relevant Planning Period. The Target Allocation for Residual Auction Revenue Rights Credits shall be equal to megawatt amount of the Residual Auction Revenue Rights multiplied by the LMP differential between the source and sink nodes of the corresponding FTR obligation in each prompt-month FTR auction that occurs from the effective date of the Residual Auction Revenue Rights through the end of the relevant Planning Period.

7.4.4 Calculation of Auction Revenue Right Credits.

(a) Each day, the total of all the daily Target Allocations determined as specified above in Section 7.4.3 plus any additional Auction Revenue Rights Target Allocations applicable for that day shall be compared to the total revenues of all applicable monthly Financial Transmission Rights auction(s) (divided by the number of days in the month) plus the total revenues of the annual Financial Transmission Rights auction (divided by the number of days in the Planning Period). If the total of the Target Allocations is less than the total auction revenues, the Auction Revenue Right Credit for each entity holding an Auction Revenue Right shall be equal to its Target Allocation. All remaining funds shall be distributed as Excess Congestion Charges pursuant to Section 5.2.5.

(b) If the total of the Target Allocations is greater than the total auction revenues, each holder of Auction Revenue Rights shall be assigned a share of the total auction revenues in proportion to its Auction Revenue Rights Target Allocations for Auction Revenue Rights which have a positive Target Allocation value. Auction Revenue Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Auction Revenue Right Credit.

(c) At the end of a Planning Period, if all Auction Revenue Right holders did not receive Auction Revenue Right Credits equal to their Target Allocations, PJMSettlement shall assess a charge equal to the difference between the Auction Revenue Right Credit Target Allocations for all revenue deficient Auction Revenue Rights and the actual Auction Revenue Right Credits allocated to those Auction Revenue Right holders. The aggregate charge for a Planning Period assessed pursuant to this section, if any, shall be added to the aggregate charge for a Planning Period assessed pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and collected pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and distributed to the Auction Revenue Right holders that did not receive Auction Revenue Right Credits equal to their Target Allocation.

PJM Reliability Assurance Agreement
Marked Format

SCHEDULE 10.1

LOCATIONAL DELIVERABILITY AREAS AND REQUIREMENTS

The capacity obligations imposed under this Agreement recognize the locational value of Capacity Resources. To ensure that such locational value is properly recognized and quantified, the Office of the Interconnection shall follow the procedures in this Schedule.

A. Following the Transition Period, as such term is defined in Attachment DD to the Tariff, the Locational Deliverability Areas for the purposes of determining locational capacity obligations hereunder, but not necessarily for the purposes of the Regional Transmission Expansion Planning Protocol, shall consist of the following Zones (as defined in Schedule 15), combinations of such Zones, and portions of such Zones:

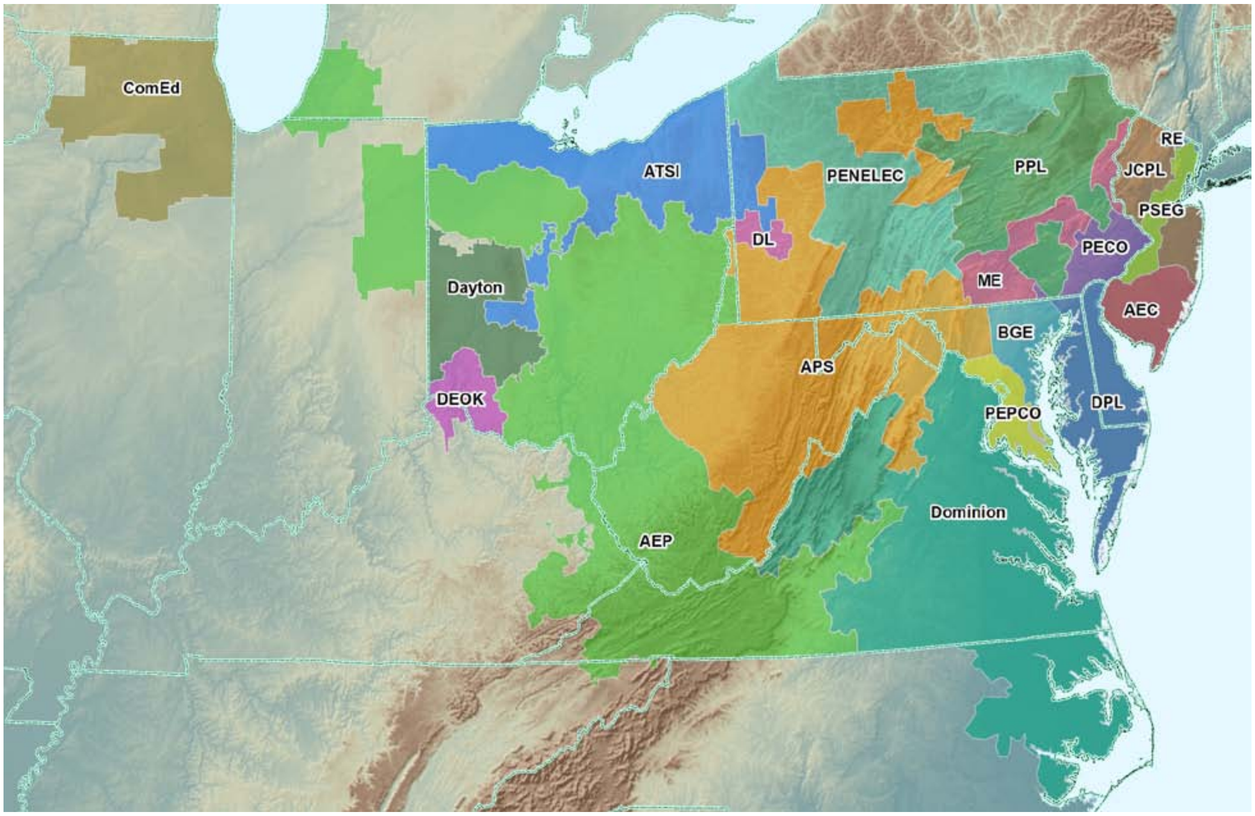
- ATSI
- DEOK
- Dominion
- Penelec
- ComEd
- AEP
- Dayton
- Duquesne
- APS
- AE
- BGE
- DPL
- PECO
- PEPCO
- PSEG
- JCPL
- MetEd
- PPL
- Mid-Atlantic Area Council (MAAC) Region (consisting of all the zones listed below for Eastern MAAC, Western MAAC, and Southwestern MAAC)
- ComEd, AEP, Dayton, APS, Duquesne, ~~and~~ ATSI, and DEOK
- Eastern MAAC (PSE&G, JCP&L, PECO, AE, DPL & RE)
- Southwestern MAAC (PEPCO & BG&E)
- Western MAAC (Penelec, MetEd, PPL)
- PSEG northern region (north of Linden substation); and
- DPL southern region (south of Chesapeake and Delaware Canal

B. For purposes of evaluating the need for any changes to the foregoing list, Locational Deliverability Areas shall be those areas, identified by the load deliverability analyses conducted pursuant to the Regional Transmission Expansion Planning Protocol and the PJM Manuals that have a limited ability to import capacity due to physical limitations of the transmission system, voltage limitations or stability limitations. Such limits on import capability shall not reflect the effect of Qualifying Transmission Upgrades offered in the Base Residual Auction. The Locational Deliverability Areas identified in Paragraph A above (as it may be amended from time to time) for a Delivery Year shall be modeled in the Base Residual Auction and any Incremental Auction conducted for such Delivery Year. If the Office of the Interconnection includes a new Locational Deliverability Area in the Regional Transmission Expansion Planning Protocol, it shall make a filing with FERC to amend this Schedule to add a new Locational Deliverability Area (including a new aggregate LDA), if such new Locational Deliverability Area is projected to have a capacity emergency transfer limit less than 1.15 times the capacity emergency transfer objective of such area, or if warranted by other reliability concerns consistent with the Reliability Principles and Standards. In addition, any Party may propose, and the Office of the Interconnection shall evaluate, consistent with the same CETO/CETO comparison or other reliability concerns, possible new Locational Deliverability Areas (including aggregate LDAs) for inclusion under the Regional Transmission Expansion Planning Protocol and for purposes of determining locational capacity obligations hereunder.

C. For each Locational Deliverability Area for which a separate VRR Curve was established for a Delivery Year, the Office of the Interconnection shall determine, pursuant to procedures set forth in the PJM Manuals, the Percentage of Internal Resources Required, that must be committed during such Delivery Year from Capacity Resources physically located in such Locational Deliverability Area.

SCHEDULE 15

ZONES WITHIN THE PJM REGION



FULL NAME	SHORT NAME
Pennsylvania Electric Company	Penelec
Allegheny Power	APS
PPL Group	PPL
Metropolitan Edison Company	MetEd
Jersey Central Power and Light Company	JCPL
Public Service Electric and Gas Company	PSEG
Atlantic City Electric Company	AEC
PECO Energy Company	PECO
Baltimore Gas and Electric Company	BGE
Delmarva Power and Light Company	DPL
Potomac Electric Power Company	PEPCO
Rockland Electric Company	RE
Commonwealth Edison Company	ComEd
AEP East Zone	AEP
The Dayton Power and Light Company	Dayton
Virginia Electric and Power Company	Dominion
Duquesne Light Company	DL
American Transmission Systems, Incorporated	ATSI
Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.	DEOK

SCHEDULE 17

PARTIES TO THE RELIABILITY ASSURANCE AGREEMENT

This Schedule sets forth the Parties to the Agreement:

AEP Retail Energy Partners LLC
AES Red Oak, LLC
Algonquin Energy Services Inc.
Allegheny Electric Cooperative, Inc.
Allegheny Energy Supply Company, L.L.C.
Ally Energy LLC.
Alpha Gas and Electric LLC
Ambit Northeast, LLC
Ameren Energy Marketing Company
American Electric Power Service Corporation on behalf of its affiliates:
    Appalachian Power Company
    Columbus Southern Power Company
    Indiana Michigan Power Company
    Kentucky Power Company
    Kingsport Power Company
    Ohio Power Company
    Wheeling Power Company.
American Municipal Power, Inc.
American Power Partners LLC
American PowerNet Management, L.P.
American Transmission Systems, Inc.
AP Gas and Electric (PA), LLC
APN Starfirst, LP
ArcelorMittal USA LLC
Asset and Energy Cost Saving Cooperative, LLC
Atlantic City Electric Company
Baltimore Gas and Electric Company
Bank of America, N.A.
Barclays Bank PLC
Bativa, IL (City of)
BBPC LLC d/b/a Great Eastern Energy
Blackstone Wind Farm, LLC
Blue Ridge Power Agency, Inc.
Blue Star Energy Services, Inc.
Border Energy Electric Services, Inc.
Borough of Butler, Butler Electric Division
Borough of Chambersburg
Borough of Lavallette, New Jersey
Borough of Mont Alto, PA
Borough of Park Ridge, New Jersey

Borough of Pitcairn, Pennsylvania
Borough of Seaside Heights, New Jersey
Borough of South River, New Jersey
BP Energy Company
Brighten Energy LLC
Cargill Power Markets LLC
Castlebridge Energy Group, LLC
CCES LLC
Central Virginia Electric Cooperative
Centre Lane Trading Limited
Champion Energy Marketing LLC
Champion Energy, LLC
Cincinnati Bell Energy, LLC
Citizens' Electric Company of Lewisburg, PA
City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power
City of Dover, Delaware
City of Naperville
City of New Martinsville - WV
City of Philippi - West VA
City of Rochelle
Clearview Electric, Inc.
Cleveland Electric Illuminating Company (The)
Commerce Energy, Inc.
Commonwealth Edison Company
Conectiv Energy Supply, Inc.
ConEdison Energy, Inc.
ConocoPhillips Company
Consolidated Edison Solutions, Inc.
Constellation Energy Commodities Group, Inc.
Constellation NewEnergy, Inc.
Constellation Power Source Generation, Inc.
Corporate Services Support Corp
Credit Suisse (USA), Inc.
Dayton Power & Light Company (The)
DC Energy LLC
Delaware Municipal Electric Corporation
Delmarva Power & Light Company
Denver Energy, LLC
Devonshire Energy LLC
Direct Energy Business, LLC
Direct Energy Services, LLC
Discount Energy Group, LLC
Discount Energy, LLC
Dominion Retail, Inc.
Downes Associates, Inc.
DPL Energy Resources, Inc.

Driftwood LLC
DTE Energy Supply, Inc.
DTE Energy Trading, Inc.
Duke Energy Commercial Asset Management, Inc.
Duke Energy Kentucky, Inc.
Duke Energy Ohio, Inc.
Duke Energy Retail Sales, LLC
Duquesne Light Company
Duquesne Light Energy, LLC
Dynegy Energy Services, Inc.
Dynegy Kendall Energy, LLC
E Minus LLC
Eagle Energy, LLC
Easton Utilities Commission
EDF Industrial Power Services (IL), LLC
EDF Trading North America, LLC
Edison Mission Marketing and Trading, Inc.
Employers' Energy Alliance of Pennsylvania, Inc.
Energetix, Inc.
Energy America, LLC
Energy Cooperative Association of Pennsylvania (The)
Energy Cooperative of America, Inc.
Energy International Power Marketing Corporation
Energy Plus Holdings LLC
Energy Services Providers, Inc.
EnerPenn USA, LLC
ERA MA, LLC
Evraz Claymont Steel
Exelon Energy Company
Exelon Generation Co., LLC
FirstEnergy Solutions Corp.
First Point Power, LLC
Front Royal (Town of)
Galt Power Inc.
Gateway Energy Services Corporation
GenOn Power Midwest, LP
Gerdau Ameristeel Energy, Inc.
GDF Suez Retail Energy Solutions, LLC
Glacial Energy of New Jersey, Inc.
Great American Power, LLC
Green Mountain Energy Company
Hagerstown Light Department
Harrison REA, Inc. - Clarksburg, WV
Hess Corporation
HIKO Energy, LLC
Hoosier Energy REC, Inc.

HOP Energy, LLC
HSBC Technology & Services (USA), Inc.
Hudson Energy Services, LLC
IDT Energy, Inc.
Illinois Municipal Electric Agency
J. Aron & Company
J.P. Morgan Ventures Energy Corporation
Jack Rich, Inc. d/b/a Anthracite Power & Light Company
Jersey Central Power & Light Company
Kuehne Chemical Company, Inc.
L & P Electric Inc., d/b/a Leggett & Platt Electric Inc.
Liberty Power Corp., L.L.C.
Liberty Power Delaware LLC
Liberty Power Holdings LLC
Linde Energy Services, Inc.
Lower Electric, LLC
Macquarie Cook Energy LLC
Major Energy Electric Services LLC
Manitou Energy Fund, LP
Marathon Power, LLC
MC Squared Energy Services, LLC
Meadow Lake Wind Farm II LLC
Meadow Lake Wind Farm III LLC
Meadow Lake Wind Farm IV LLC
Meadow Lake Wind Farm LLC
MeadWestvaco Corporation
Metropolitan Edison Company
MidAmerican Energy Company
Mint Energy, LLC
Morgan Stanley Capital Group, Inc.
MP2 Energy NE, LLC
MXenergy Electric, Inc.
Natgasco, Inc.
Nexgen Management and Consulting Inc
Nextera Energy Services New Jersey, LLC
Nextera Energy Services, Illinois, LLC
Noble Americas Energy Solutions LLC
Noble Americas Gas & Power Corp.
Nordic Energy Services LLC
North American Power and Gas LLC.
North Carolina Electric Membership Corporation
North Carolina Municipal Power Agency Number 1
Northern Virginia Electric Cooperative - NOVEC
NRG Power Marketing, L.L.C.
NYSEG Solutions, Inc.
Oasis Power, LLC dba Oasis Energy

Occidental Power Services, Inc.
Ohio Edison Company
Ohms Energy Company, LLC
Old Dominion Electric Cooperative
Palmco Power MD, LLC
Palmco Power NJ, LLC
Palmco Power OH, LLC
Palmco Power PA, LLC
Panda Power Corporation
Parma Energy, LLC
PBF Power Marketing LLC
PECO Energy Company
Pennsylvania Electric Company
Pennsylvania Power Company
People's Power & Gas, LLC
PEPCO Energy Services, Inc.
Planet Energy (Maryland) Corp.
Planet Energy (Pennsylvania) Corp.
Planet Energy (USA) Corp.
Plymouth Rock Energy, LLC
Potomac Electric Power Company
Powhatan Energy Fund LLC
PPL Electric Utilities Corporation d/b/a PPL Utilities
PPL Energy Plus, LLC
Prairieland Energy, Inc.
PSEG Energy Resources and Trade LLC
Public Power, LLC
Public Service Electric & Gas Company
Realgy, LLC
ResCom Energy, LLC
Respond Power LLC
RG Steel Sparrows Point, LLC
Riverside Generating, LLC
Rolling Hills Generating, LLC
S.J. Energy Partners, Inc.
Santanna Energy Services
SMART Papers Holdings, LLC
Solios Power Mid-Atlantic Trading LLC
South Jersey Energy Company
South Jersey Energy Solutions, L.L.C.
Southeastern Power Administration
Southern Indiana Gas & Electric
Southern Maryland Electric Cooperative, Inc.
Spark Energy, L.P.
Sperian Energy Corp
Starion Energy PA Inc.

Stream Energy Columbia, LLC
Stream Energy Maryland, LLC
Stream Energy Pennsylvania, LLC
Superior Plus Energy Services Inc.
TC Energy Trading, LLC
Tenaska Power Services Co.
Texas Retail Energy, LLC
The Trustees of the University of Pennsylvania
Thurmont Municipal Light Company
Toledo Edison Company (The)
Town of Berlin, Maryland
Town of Williamsport
TransAlta Energy Marketing (U.S.) Inc.
TransCanada Power Marketing Ltd.
Tri-County Rural Electric Cooperative, Inc.
TriEagle Energy, LP
Trinity Powerworks, Inc.
U.S. Energy Partners dba PAETEC Energy Marketing
UBS AG, acting through its London Branch
UGI Energy Services, Inc.
UGI Utilities, Inc. - Electric Division
Valero Power Marketing, LLC
VCharge, Inc.
Verde Energy USA, Inc.
Vineland Municipal Electric Utility (City of Vineland)
Virginia Electric & Power Company
Viridian Energy PA LLC
Wabash Valley Power Association, Inc.
Washington Gas Energy Services, Inc.
Wellsboro Electric Company
West Penn Power Company d/b/a Allegheny Power
York Generation Company, LLC

PJM Consolidated Transmission Owners Agreement
Marked Format

ATTACHMENT A

TO THE CONSOLIDATED

TRANSMISSION OWNERS AGREEMENT

Monongahela Power Company, The Potomac Edison Company and West Penn Power Company, all doing business as Allegheny Power

American Electric Power Service Corporation on behalf of its operating companies: Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company

Commonwealth Edison Company and Commonwealth Edison Company of Indiana, Inc.

Dayton Power and Light Company

Virginia Electric and Power Company (Dominion Virginia Power)

Public Service Electric and Gas Company

PECO Energy Company

PPL Electric Utilities Corporation

Baltimore Gas and Electric Company

Jersey Central Power & Light Company

Metropolitan Edison Company

Pennsylvania Electric Company

Potomac Electric Power Company

Atlantic City Electric Company

Delmarva Power & Light Company

UGI Utilities, Inc.

Allegheny Electric Cooperative, Inc.

CED Rock Springs, LLC

Old Dominion Electric Cooperative

Rockland Electric Company

Duquesne Light Company

Neptune Regional Transmission System, LLC

Trans-Allegheny Interstate Line Company

Linden VFT, LLC

American Transmission Systems, Incorporated

City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power

Duke Energy Ohio, Inc.

Duke Energy Kentucky, Inc.

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

PJM Interconnection, L.L.C.

By: ________________________________
Name: Phillip G. Harris
Title: President and CEO
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Monongahela Power Company, The Potomac Edison Company and West Penn Power Company, all doing business as Allegheny Power

By: ______________________________
Name: James R. Haney
Title: Vice President
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

American Electric Power Service Corporation

By:________________________________
Name:
Title:
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Exelon Corporation on behalf of its subsidiaries
Commonwealth Edison Company and Commonwealth Edison
Company of Indiana, Inc.

By:_________________________________
Name: Susan Ivey
Title: Vice President, Transmission Operations and Planning, Exelon Corporation
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

The Dayton Power and Light Company

By: ___________________________________
Name: Patricia K. Swanke
Title: Vice President - Operations
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Virginia Electric and Power Company (Dominion Virginia Power)

By:________________________________
Name: Gary L. Sypolt
Title: President – Dominion Transmission
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Public Service Electric and Gas Company

By: ________________________________
Name: Ralph LaRossa
Title: Vice President - Electric Delivery
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Exelon Corporation on behalf of its subsidiary
PECO Energy Company

By:________________________________
Name: Susan Ivey
Title: Vice President, Transmission Operations and Planning, Exelon Corporation
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

PPL Electric Utilities Corporation

By:__________________________________
Name: John F. Sipics
Title: President
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Baltimore Gas and Electric Company

By:_____________________________
Name: Mark P. Huston
Title: Vice President, Electric Transmission and Distribution
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Jersey Central Power & Light Company

By: ________________________________
Name: Stanley F. Szwed
Title: Vice President – Energy Delivery Policy
First Energy Service Company
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Metropolitan Edison Company

By:________________________________
Name: Stanley F. Szwed
Title: Vice President – Energy Delivery Policy
First Energy Service Company
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Pennsylvania Electric Company

By:______________________________
Name: Stanley F. Szwed
Title: Vice President – Energy Delivery Policy
First Energy Service Company
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Potomac Electric Power Company

By:_______________________________
Name: David M. Valazquez
Title: Vice President, Pepco Holdings, Inc.
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Atlantic City Electric Company

By: ________________________________
Name: David M. Valazquez
Title: Vice President, Pepco Holdings, Inc.
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Delmarva Power & Light Company

By:_________________________________

Name: David M. Valazquez

Title: Vice President, Pepco Holdings, Inc.

Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

UGI Utilities, Inc.

By: ___________________________
Name: Richard E. Gill
Title: Assistant Secretary - Electric Transmission
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

CED Rock Springs, LLC

By:________________________________
Name:
Title:
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Old Dominion Electric Cooperative

By:________________________________
Name:
Title:
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Rockland Electric Company

By:________________________________
Name:
Title:
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Duquesne Light Company

By:________________________________
Name:
Title:
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Allegheny Electric Cooperative, Inc.

By: ________________________________
Name: Richard W. Osborne
Title: Vice President Power Supply & Engineering
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Neptune Regional Transmission System, LLC

By: ________________________________
Name: Edward M. Stern
Title: CEO
Date: March 7, 2007

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Trans-Allegheny Interstate Line Company

By: ________________________________
Name: James R. Haney
Title: Vice President
Date: November 8, 2007

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Linden VFT, LLC

By: ________________________________
Name: Andrew J. Keleman
Title: Authorized Representative
Date: April 1, 2009

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

American Transmission Systems, Incorporated

By: ________________________________
Name: Richard R. Grigg
Title: President
Date: December 17, 2009

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

City of Cleveland, Department of Public Utilities
Division of Cleveland Public Power

By: _ ________________________________
Name: Barry A. Withers
Title: Director
Date: March 22, 2011

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Duke Energy Ohio, Inc.

By: _ ________________________________
Name: Julia S. Janson
Title: President
Date: September 27, 2011

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Duke Energy Kentucky, Inc.

By: __________________________________
Name: Julia S. Janson
Title: President
Date: September 27, 2011

Attachment B
Clean Format
(non-redline)

Sections of the
PJM Open Access Transmission Tariff,
PJM Operating Agreement,
PJM Reliability Assurance Agreement
and
PJM Consolidated Transmission Owners Agreement

(Agreements separated by cover pages)

PJM Open Access Transmission Tariff
Clean Format

TABLE OF CONTENTS

ATTACHMENT GG - APPENDIX III – GENERAL TERMS AND CONDITIONS

Definitions – O – P - Q

1.27C Office of the Interconnection:

Office of the Interconnection shall have the meaning set forth in the Operating Agreement.

1.28 Open Access Same-Time Information System (OASIS):

The information system and standards of conduct contained in Part 37 and Part 38 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

1.28A Operating Agreement of the PJM Interconnection, L.L.C. or Operating Agreement:

That agreement dated as of April 1, 1997 and as amended and restated as of June 2, 1997 and as amended from time to time thereafter, among the members of the PJM Interconnection, L.L.C.

1.28A.01 Option to Build:

The option of the New Service Customer to build certain Customer-Funded Upgrades, as set forth in, and subject to the terms of, the Construction Service Agreement.

1.28B Optional Interconnection Study:

A sensitivity analysis of an Interconnection Request based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

1.28C Optional Interconnection Study Agreement:

The form of agreement for preparation of an Optional Interconnection Study, as set forth in Attachment N-3 of the Tariff.

1.29 Part I:

Tariff Definitions and Common Service Provisions contained in Sections 2 through 12.

1.30 Part II:

Tariff Sections 13 through 27 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.31 Part III:

Tariff Sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.31A Part IV:

Tariff Sections 36 through 112 pertaining to generation or merchant transmission interconnection to the Transmission System in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.31B Part V:

Tariff Sections 113 through 122 pertaining to the deactivation of generating units in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.31C Part VI:

Tariff Sections 200 through 237 pertaining to the queuing, study, and agreements relating to New Service Requests, and the rights associated with Customer-Funded Upgrades in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.32 Parties:

The Transmission Provider, as administrator of the Tariff, and the Transmission Customer receiving service under the Tariff. PJMSettlement shall be the Counterparty to Transmission Customers.

1.32.01 PJM:

PJM Interconnection, L.L.C.

1.32A PJM Administrative Service:

The services provided by PJM pursuant to Schedule 9 of this Tariff.

1.32B PJM Control Area:

The Control Area that is recognized by NERC as the PJM Control Area.

1.32C PJM Interchange Energy Market:

The regional competitive market administered by the Transmission Provider for the purchase and sale of spot electric energy at wholesale interstate commerce and related services, as more fully set forth in Attachment K – Appendix to the Tariff and Schedule 1 to the Operating Agreement.

1.32D PJM Manuals:

The instructions, rules, procedures and guidelines established by the Transmission Provider for the operation, planning, and accounting requirements of the PJM Region and the PJM Interchange Energy Market.

1.32E PJM Region:

Shall mean the aggregate of the PJM West Region, the VACAR Control Zone, and the MAAC Control Zone.

1.32F PJM South Region:

The VACAR Control Zone.

1.32.F.01 PJMSettlement:

PJM Settlement, Inc. (or its successor).

1.32G PJM West Region:

The PJM West Region shall include the Zones of Allegheny Power; Commonwealth Edison Company (including Commonwealth Edison Co. of Indiana); AEP East Operating Companies; The Dayton Power and Light Company; the Duquesne Light Company, American Transmission Systems, Incorporated, and Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.

1.33 Point(s) of Delivery:

Point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Part II of the Tariff. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.33A Point of Interconnection:

The point or points, shown in the appropriate appendix to the Interconnection Service Agreement and the Interconnection Construction Service Agreement, where the Customer Interconnection Facilities interconnect with the Transmission Owner Interconnection Facilities or the Transmission System.

1.34 Point(s) of Receipt:

Point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Part II of the Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.35 Point-To-Point Transmission Service:

The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff.

1.36 Power Purchaser:

The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

1.36.01 PRD Curve

PRD Curve shall have the meaning provided in the Reliability Assurance Agreement.

1.36.02 PRD Provider

PRD Provider shall have the meaning provided in the Reliability Assurance Agreement.

1.36.03 PRD Reservation Price

PRD Reservation Price shall have the meaning provided in the Reliability Assurance Agreement.

1.36.04 PRD Substation:

PRD Substation shall have the meaning provided in the Reliability Assurance Agreement.

1.36.*05* Pre-Confirmed Application:

An Application that commits the Eligible Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

1.36A Pre-Expansion PJM Zones:

Zones included in this Tariff, along with applicable Schedules and Attachments, for certain Transmission Owners – Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power and Light Company, Jersey Central Power and Light Company, Metropolitan Edison Company, PECO Energy Company, Pennsylvania Electric Company, Pennsylvania Power & Light Group, Potomac Electric Power Company, Public Service Electric and Gas Company, Allegheny Power, and Rockland Electric Company.

1.36A.01 Price Responsive Demand

Price Responsive Demand shall have the meaning provided in the Reliability Assurance Agreement.

1.36A.*02* Project Financing:

Shall mean: (a) one or more loans, leases, equity and/or debt financings, together with all modifications, renewals, supplements, substitutions and replacements thereof, the proceeds of which are used to finance or refinance the costs of the Customer Facility, any alteration, expansion or improvement to the Customer Facility, the purchase and sale of the Customer Facility or the operation of the Customer Facility; (b) a power purchase agreement pursuant to which Interconnection Customer's obligations are secured by a mortgage or other lien on the Customer Facility; or (c) loans and/or debt issues secured by the Customer Facility.

1.36A.*03* Project Finance Entity:

Shall mean: (a) a holder, trustee or agent for holders, of any component of Project Financing; or (b) any purchaser of capacity and/or energy produced by the Customer Facility to which Interconnection Customer has granted a mortgage or other lien as security for some or all of Interconnection Customer's obligations under the corresponding power purchase agreement.

1.36B Queue Position:

The priority assigned to an Interconnection Request, a Completed Application, or an Upgrade Request pursuant to applicable provisions of Part VI.

SCHEDULE 1A
Transmission Owner Scheduling, System Control and Dispatch Service

Scheduling, System Control and Dispatch Service is provided directly by the Transmission Provider under Schedule 1. The Transmission Customer must purchase this service from the Transmission Provider. Certain control center facilities of the Transmission Owners also are required to provide this service. This Schedule 1A sets forth the charges for Scheduling, System Control and Dispatch Service based on the cost of operating the control centers of the Transmission Owners. The Transmission Provider shall administer the provision of Transmission Owner Scheduling, System Control and Dispatch Service. PJMSettlement shall be the Counterparty to the purchases of Transmission Owner Scheduling, System Control and Dispatch Service.

The charges for operation of the control centers of the Transmission Owners shall be determined by multiplying the applicable rate as follows times the Transmission Customer's use of the Transmission System (including losses) on a megawatt hour basis:

(A) For a Transmission Customer serving Zone Load in:

Zone	Rate ($/MWh)
Atlantic City Electric Company	0.0781
Baltimore Gas and Electric Company	0.0430
Delmarva Power & Light Company	0.0743
PECO Energy Company	0.1189
PP&L, Inc. Group	0.0618
Potomac Electric Power Company	0.0186
Public Service Electric and Gas Company	0.1030
Jersey Central Power & Light Company	0.0796
Metropolitan Edison Company	0.0796
Pennsylvania Electric Company	0.0796
Rockland Electric Company	0.2475
Commonwealth Edison Company	0.2223
AEP East Operating Companies	Rate updated annually Per Attachment H-14
The Dayton Power and Light Company	0.0797
Duquesne Light Company[1]	0.0520
American Transmission Systems, Incorporated ("ATSI")	Rate updated annually Per Attachment H-21
Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc. ("DEOK")	Rate updated annually Per Attachment H-22

[1] Charges for service under this schedule to customers of The Dayton Power and Light Company that are subject to the provisions of the October 14, 2003 Stipulation and Agreement of Settlement approved in FERC Docket No. EL03-56-000 shall be governed by such settlement.

(B) For a Transmission Customer serving Non-Zone Load (a Network Customer serving Non-Zone Network Load or a Transmission Customer taking Point-to-Point service where the Point of Delivery is at the boundary of the PJM Region):

$0.1019/MWh

Each month, PJMSettlement shall pay to each Transmission Owner an amount equal to the charges billed for that Transmission Owner's zone pursuant to (A) above, plus that Transmission Owner's share as stated below of the charges billed to Transmission Customers serving Non-Zone Network Load pursuant to (B) above:

Transmission Owner	**Share (%)**
Atlantic City Electric Company	0.50
Baltimore Gas and Electric Company	0.80
Delmarva Power & Light Company	0.77
PECO Energy Company	2.68
PP&L, Inc. Group	1.36
Potomac Electric Power Company	0.33
Public Service Electric and Gas Company	2.64
Jersey Central Power & Light Company	1.30
Metropolitan Edison Company	0.43
Pennsylvania Electric Company	0.66
Rockland Electric Company	0.20
Commonwealth Edison Company	37.62
AEP East Operating Companies	47.90
The Dayton Power and Light Company	2.36
Duquesne Light Company	0.45
American Transmission Systems, Incorporated ("ATSI")	0.00
Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc. ("DEOK")	0.00

SCHEDULE 7
Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service

1) The Transmission Customer shall pay each month for Reserved Capacity at the sum of the applicable charges set forth below for the Point of Delivery:

Summary of Charges
(in $/kW)

Point of Delivery	Yearly Charge	Monthly Charge	Weekly Charge	Daily On-Peak[1] Charge	Daily Off-Peak[2/] Charge
Border of PJM	18.888	1.574	0.3632	0.0726	0.0519
AE Zone	23.809	1.984	0.4580	0.0920	0.0650
BG&E Zone	15.675	1.306	0.3010	0.0600	0.0430
Delmarva Zone	19.378	1.615	0.3730	0.0750	0.0530
JCPL Zone	15.112	1.259	0.2906	0.0581	0.0414
MetEd Zone	15.112	1.259	0.2906	0.0581	0.0414
Penelec Zone	15.112	1.259	0.2906	0.0581	0.0414
PECO Zone	26.264	2.189	0.5051	0.1010	0.0722
PPL Zone: Total charge is the sum of the components	PPL: * AEC: 0.463 UGI: *	PPL: * AEC: 0.039 UGI: *	PPL: * AEC: 0.0089 UGI: *	PPL: * AEC: 0.0018 UGI: *	PPL: * AEC: 0.0013 UGI: *
Pepco Zone	20.999	1.750	0.4040	0.0810	0.0580
PSE&G Zone	23.696	1.975	0.4557	0.0911	0.0651
AP Zone	20.847	1.737	0.4009	0.0802	0.0573
Rockland Zone	32.114	2.676	0.6176	0.1235	0.0882
ComEd Zone[3/]	[4/]				

* PPL Electric Utilities Corporation's and UGI Utilities' respective component of the total charge is posted on the PJM Internet website.

Point of Delivery	Yearly Charge	Monthly Charge	Weekly Charge	Daily On-Peak[1] Charge	Daily Off-Peak[2/] Charge
AEP East Zone 5/	Monthly Charge X 12	Rate Pursuant to Attachment H-14	Yearly Charge / 52	Weekly Charge / 5	Weekly Charge / 7
Dayton Zone	15.674	1.306	0.3014	0.0603	0.0431
Duquesne Zone	14.17	1.18	0.27	0.0540	0.0386
Dominion Zone					
ATSI Zone	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21
DEOK Zone	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22

Effective December 1, 2004, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 7 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc. obtained pursuant to requests submitted on or after November 17, 2003, for service commencing on or after April 1, 2004. Effective April 1, 2006, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 7 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc.

1/ Monday – Friday except the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

2/ Saturday and Sunday and the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

3/ Each month, revenue credits will be applied to the gross charge in accordance with section 8 below to determine the actual charge to the Transmission Customer.

4/ The charges for the ComEd zone are posted on PJM's website. In addition to other rates set forth in this schedule, customers within the ComEd zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - $/kW/year = $1,523,039, divided by the 1 CP demand for the ComEd zone for the prior calendar year;

Monthly Rate - $/kW/month. = Annual Rate divided by 12;

Weekly Rate - $/kW/week = Annual Rate divided by 52;

Daily Rate - $/kW/day = Weekly Rate divided by 5.

In order to ensure that the charge does not result in either an over-recovery or under-recovery of ComEd's start-up costs, PJM will institute an annual true-up mechanism in the month of May of each of the years 2008-2014. In May of each of those years, PJM will compare the amount collected under this charge for the previous 12 months with the target annual amount of $1,523,039 and calculate any credits or surcharges that would be needed to ensure that $1,523,039 is collected for each year. Any credit or surcharge will be assessed in the June bills for years 2008-2014, consistent with the above methodology.

5/ The rates for firm point-to-point transmission service in the AEP Zone will be charged at the yearly, monthly, weekly or daily rate equivalent to the rate effective in such period under Attachment H-14. In addition to other rates set forth in this schedule, customers within the AEP East Zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - $/kW/year = $2,362,185, plus any applicable true-up adjustment, divided by the 1 CP demand for the AEP East Zone for the prior calendar year;

Monthly Rate - $/kW/month. = Annual Rate divided by 12;

Weekly Rate - $/kW/week = Annual Rate divided by 52;

Daily Rate - $/kW/day = Weekly Rate divided by 5.

For the period November 1, 2005 through March 31, 2006, the rate shall be $8.94/MW-month; for the period April 1 through December 31, 2006, the rate shall be $8.60/MW-month, thereafter, the rate will be subject to the following true-up:

In order to ensure that the charge does not result in either over-recovery or under-recovery of AEP's start-up costs, PJM will institute an annual true-up mechanism and implement revised charges as of January 1st of each of the years 2007-2019. In January of each of those years, PJM will compare the amount collected under this charge for the previous year or part thereof with the target annual amount of $2,362,185 and calculate the rates that would be needed, given the expected billing demands, to collect $2,362,185, adjusted for any prior year over-collection or under-collection. In the final year that the rate is collected, PJM will calculate the rate to collect five-twelfths of the annual amount ($984,244), plus or minus any prior year true up amount, by May 31 of that year, and shall charge such rate until that amount is collected, whether that date be before or after May 31, 2020.

6/ The service period charges rounded to four decimal places for the Dominion Zone are as follows:

Yearly Charge - $/kW/year = the formula rate for Network Integration Transmission Service as described in Attachment H-16 and Attachment H-16A divided by 1000 kW/MW

Monthly Charge - $/kW/month. = Yearly Charge divided by 12;

Weekly Charge - $/kW/week = Yearly Charge divided by 52;

Daily On-Peak Charge - $/kW/day = Weekly Charge divided by 5;

Daily Off-Peak Charge - $/kW/day = Weekly Charge divided by 7.

On a monthly basis, revenue credits shall be calculated based on the sum of VEPCO's share of revenues collected during the month from Schedule 7 and Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A. The sum of these revenue credits will appear as an adjustment to the to the gross monthly service period charges produced by the above formula.

2) The total demand charge in any week, pursuant to a reservation for Daily On-Peak Delivery, or Daily Off-Peak Delivery shall not exceed the Weekly Delivery rate specified in section (1) above for weekly service times the highest amount in kilowatts of Reserved Capacity and any additional transmission service, if any, in any day during such week.

3) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

4) **Congestion, Losses and Capacity Export:** In addition to any payment under this Schedule, the Transmission Customer shall pay Redispatch Costs as specified in Section 27 of the Tariff. The Transmission Customer shall be responsible for losses as specified in the Tariff. Any Transmission Customer that is a Capacity Export Transmission Customer, as defined in Attachment DD to this Tariff, shall pay any applicable charges, and receive any applicable credits, for such a customer pursuant to Attachment DD.

5) **Other Supporting Facilities and Taxes:** In addition to the rates set forth in section (1) of this schedule, the Transmission Customer shall pay charges determined on a case-by-case basis for facilities necessary to provide Transmission Service at voltages lower than those shown in Attachment H for the applicable Zone(s) and any amounts necessary to reimburse PJMSettlement for any amounts payable as sales, excise, "Btu," carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

6) **Transitional Revenue Neutrality Charge:** In addition to the rates set forth in section (1) of this schedule and any other applicable charges, the Transmission Customer shall also pay for Reserved Capacity for delivery at the border of the PJM Region a non-discountable charge of $3.60/kw/year, $0.30/kw/mo., $0.0692/kw/week, $0.0099/kw/day-off-peak, or $0.0138/kw/day-on-peak. PJM shall distribute all revenues from the Transitional Revenue Neutrality Charge to Allegheny Power. The charge provided for under this section (6) shall terminate effective as of the day on which the sum total of the revenues collected by this charge, the Transitional Revenue Neutrality Charge under Schedule 8, and the Transitional Market Expansion Charge under Schedule 11 equal $84,993,360.

7) **Transmission Enhancement Charges.** In addition to the rates set forth in Section (1) of this Schedule and any other applicable charges, the Transmission Customer shall also pay any Transmission Enhancement Charges for which it is designated as a Responsible Customer under Schedule 12 appended to the Tariff.

8) **Determination of monthly charges for ComEd Zone:** On a monthly basis, revenue credits shall be calculated based on the sum of ComEd's share of revenues collected during the month from: (i) the PJM Border Rate under Schedule 7; (ii) Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A; (iii) Seams Elimination Charge/Cost Adjustment/Assignment ("SECA") revenues allocable to ComEd under the Tariff; and (iv) any Point-To-Point Transmission Service where the Point of Receipt and the Point of Delivery are both internal to the ComEd Zone. On this basis, the sum of these revenues will appear as a reduction to the gross monthly rate stated above on a Transmission Customer's bill in that month for service under this schedule.

9) **Determination of monthly charges for AEP Zone:** On a monthly basis, revenue credits shall be calculated based on the sum of AEP's share of revenues collected during the month from: (i) the PJM Border Rate under Schedule 7; (ii) Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A; and (iii) Firm Point-To-Point Transmission Service where the Point of Delivery is internal to the AEP Zone. The sum of these revenue credits will appear as an adjustment (reduction) to the gross monthly rate stated above on a Transmission Customer's bill in that month for service under this schedule.

10) **Resales:** The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.

SCHEDULE 8
Non-Firm Point-To-Point Transmission Service

1) The Transmission Customer shall pay for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below for the Point of Delivery:

Summary of Charges

Point of Delivery	Monthly Charge ($/kW)	Weekly Charge ($/kW)	Daily On-Peak[1/] Charge ($/kW)	Daily Off-Peak[2/] Charge ($/kW)	Hourly On-Peak[3/] Charge ($/MWh)	Hourly Off-Peak[4/] Charge ($/MWh)
Border of PJM	1.574	0.3632	0.0726	0.0519	4.54	2.16
AE Zone	1.984	0.4580	0.0920	0.0650	5.7	2.72
BG&E Zone	1.306	0.3010	0.0600	0.0430	3.8	1.80
Delmarva Zone	1.615	0.3730	0.0750	0.0530	4.6	2.21
JCPL Zone	1.259	0.2906	0.0581	0.0414	3.6	1.73
MetEd Zone	1.259	0.2906	0.0581	0.0414	3.6	1.73
Penelec Zone	1.259	0.2906	0.0581	0.0414	3.6	1.73
PECO Zone	2.189	0.5051	0.1010	0.0722	6.3	3.01
PPL Zone: Total charge is the sum of the components	PPL: * AEC: 0.039 UGI: *	PPL: * AEC: 0.0089 UGI: *	PPL: * AEC: 0.0018 UGI: *	PPL: * AEC: 0.0013 UGI: *	PPL: * AEC: 0.11 UGI: *	PPL: * AEC: 0.05 UGI: *
Pepco Zone	1.750	0.4040	0.0810	0.0580	5.0	2.40
PSE&G Zone	1.975	0.4557	0.0911	0.0651	5.7	2.71
AP Zone	1.737	0.4009	0.0802	0.0573	5.0	2.39
Rockland Zone	2.676	0.6176	0.1235	0.0882	7.7	3.67
ComEd Zone[5/]	[6/]					

* PPL Electric Utilities Corporation's and UGI Utilities' respective component of the total charge is posted on the PJM Internet website.

AEP East Zone[7/] Nov. 1, 2005 SECA Ended W-JF Line In	AEP East Zone[7/]	Rate Pursuant to Attachment H-14	Monthly Charge X 12 / 52 ~~0.249 48~~	Weekly Charge / 5	Weekly Charge / 7	Daily On-Peak Charge / 16
Dayton Zone	Dayton Zone	1.306	0.3014	0.0603	0.0431	3.77
Duquesne Zone	Duquesne Zone	1.18	0.27	0.0540	0.0386	3.38
Dominion Zone[8/]	Dominion Zone[8/]					
ATSI Zone	ATSI Zone	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21
DEOK Zone	DEOK Zone	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22

1/ Monday - Friday except the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

2/ Saturday and Sunday and the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

3/ 7:00 a.m. up to the hour ending 11:00 p.m.

4/ 11:00 p.m. up to the hour ending 7:00 a.m.

5/ Each month, revenue credits will be applied to the gross charge in accordance with Paragraph 9 below to determine the actual charge to the Transmission Customer.

6/ The charges for the ComEd zone are posted on PJM's website. In addition to the other rates set forth in this schedule, customers within the ComEd zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:
Annual Rate - $/kW/year = $1,523,039, divided by the 1 CP demand for the ComEd zone for the prior calendar year;
Monthly Rate - $/kW/month. = Annual Rate divided by 12;
Weekly Rate - $/kW/week = Annual Rate divided by 52;
Daily rate - $/kW/day = Weekly Rate divided by 5.
In order to ensure that the charge does not result in either an over-recovery or under-recovery of ComEd's start-up costs, PJM will institute an annual true-up mechanism in the month of May of each of the years 2008-2014. In May of each of those years, PJM will compare the amount collected under this charge for the previous 12 months with the target annual amount of $1,523,039 and calculate any credits or surcharges that would be needed to ensure that $1,523,039 is collected for each year. Any credit or surcharge will be assessed in the June bills for years 2008-2014, consistent with the above methodology.

7/ The rates for non-firm point-to-point transmission service in the AEP Zone will be charged at the monthly, weekly, daily or hourly rate equivalent to the rate effective in such period under Attachment H-14. In addition to other rates set forth in this schedule, customers within the AEP East Zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - $/kW/year = $2,362,185, plus any applicable true-up adjustment, divided by the 1 CP demand for the AEP East Zone for the prior calendar year;

Monthly Rate - $/kW/month. = Annual Rate divided by 12;

Weekly Rate - $/kW/week = Annual Rate divided by 52;

Daily Rate - $/kW/day = Weekly Rate divided by 5.

For the period November 1, 2005 through March 31, 2006, the rate shall be $8.94/MW-month; for the period April 1 through December 31, 2006, the rate shall be $8.60/MW-month, thereafter, the rate will be subject to the following true-up:

In order to ensure that the charge does not result in either over-recovery or under-recovery of AEP's start-up costs, PJM will institute an annual true-up mechanism and implement revised charges as of January 1st of each of the years 2007-2019. In January of each of those years, PJM will compare the amount collected under this charge for the previous year or part thereof with the target annual amount of $2,362,185 and calculate the rates that would be needed, given the expected billing demands, to collect $2,362,185, adjusted for any prior year over-collection or under-collection. In the final year that the rate is collected, PJM will calculate the rate to collect five-twelfths of the annual amount, ($984,244), plus or minus any prior year true up amount, by May 31 of that year, and shall charge such rate until that amount is collected, whether that date be before or after May 31, 2020.

Effective December 1, 2004, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 8 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc. obtained pursuant to requests submitted on or after November 17, 2003, for service commencing on or after April 1, 2004. Effective April 1, 2006, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 7 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc.

8/ The service period charges rounded to four decimal places for the Dominion Zone are as follows:

Monthly Charge - $/kW/month = the formula rate for Network Integration Transmission Service as described in Attachment H-16 and Attachment H-16A divided by 12 divided by 1000 kW/MW;

Weekly Charge - $/kW/week = 12 times Monthly Charge divided by 52;

Daily On-Peak Charge - $/kW/day = Weekly Charge divided by 5;

Daily Off-Peak Charge - $/kW/day = Weekly Charge divided by 7;

Hourly On-Peak Charge - $/MWh = Daily On-Peak Charge / 16 hours *1000 kW/ MW;

Hourly Off-Peak Charge - $/ MWh = Daily Off-Peak Charge / 24 hours *1000 kW/ MW.

2) The total demand charge in any week, pursuant to a reservation for Daily On-Peak Delivery or Daily Off-Peak Delivery, shall not exceed the Weekly Delivery rate specified in section (1) above for weekly service times the highest amount in kilowatts of Reserved Capacity and any additional transmission service, if any, in any day during such week.

3) **Hourly delivery:** The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed the amounts set forth above for a Point of Delivery.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (1) above for daily service times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (1) above for weekly service times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

4) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

5) **Congestion, Losses and Capacity Export:** A Transmission Customer desiring Non-Firm Point-to-Point Transmission Service may elect to pay transmission congestion charges. If the Transmission Customer so elects, it shall either (a) if the applicable Transmission Congestion Charge as calculated pursuant to Attachment K is positive, pay the higher of the applicable Transmission Congestion Charge or the applicable rate under section (1) above, or (b) if the applicable Transmission Congestion Charge as calculated pursuant to Attachment K is negative, pay or be credited the sum of the applicable Transmission Congestion Charge and the rate under section (1) above. The Transmission Customer shall be responsible for losses as specified in the

Tariff. Any Transmission Customer that is a Capacity Export Transmission Customer, as defined in Attachment DD to this Tariff, shall pay for any applicable charges, and receive any applicable credits, for such a customer pursuant to Attachment DD.

6) **Other Supporting Facilities and Taxes:** In addition to the charges set forth in section (1) of this schedule, the Transmission Customer shall pay charges determined on a case-by-case basis for facilities necessary to provide Transmission Service at voltages lower than those shown in Attachment H for the applicable Zone(s) and any amounts necessary to reimburse the Transmission Provider for any amounts payable as sales, excise, "Btu," carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

7) **Transitional Revenue Neutrality Charge:** In addition to the rates set forth in Section (1) of this Schedule and any other applicable charges, the Transmission Customer shall also pay for Reserved Capacity for delivery at the border of the area comprised of the PJM Control Area and PJM West region a non-discountable charge of $0.241/kw/mo., $0.0556/kw/week, $0.0079/kw/day (both on-peak and off-peak), or $0.33/Mw/hour (both on-peak and off-peak). PJM shall distribute all revenues from the Transitional Revenue Neutrality Charge to Allegheny Power. The charge provided for under this section (7) shall terminate effective as of the day on which the sum total of the revenues collected by this charge, the Transitional Revenue Neutrality Charge under Schedule 7, and the Transitional Market Expansion Charge under Schedule 11 equal $84,993,360.

8) **Transmission Enhancement Charges:** In addition to the rates set forth in Section (1) of this Schedule and any other applicable charges, the Transmission Customer shall also pay any Transmission Enhancement Charges for which it is designated as a Responsible Customer under Schedule 12 appended to the Tariff.

9) **Determination of monthly charges for ComEd Zone:** On a monthly basis, revenue credits shall be calculated based on the sum of ComEd's share of revenues collected during the month from: (i) the PJM Border Rate under Schedule 7; (ii) Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A; (iii) Seams Elimination Charge/Cost Adjustment/Assignment ("SECA") revenues allocable to ComEd under the Tariff; and (iv) any Point-To-Point Transmission Service where the Point of Receipt and the Point of Delivery are both internal to the ComEd Zone. On this basis, the sum of these revenues will appear as a reduction to the gross monthly rate stated above on a Transmission Customer's bill in that month for service under this schedule.

10) **Resales:** The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.

ATTACHMENT C-2

Conversion of Service in the Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc. ("DEOK") Zone

The Office of the Interconnection is scheduled to become the Transmission Provider for the Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc. ("DEOK") Zone under the terms of this Tariff on January 1, 2012 and the open access transmission tariff of the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") shall be superseded with respect to the DEOK Zone. Reservations purchased on the Midwest ISO nodes prior to the integration of the DEOK Zone into PJM shall be converted to the appropriate service under this Tariff and subject to the rates, terms and conditions of this Tariff. In addition, interconnection requests under the Midwest ISO tariff pending prior to the integration of the DEOK Zone into PJM shall be converted to requests for interconnection under this Tariff. This Attachment sets forth the principles that shall govern such conversions of service.

For service with an export from the DEOK Zone and an import to the remainder of the PJM Region (or vice-versa), the transmission service will be converted into a single reservation under this Tariff. For service with an export from the DEOK Zone and an import to the Midwest ISO Region (or vice-versa), the transmission service cannot be converted into a single reservation Customers who have reservations that need to be converted will be contacted directly by the Office of the Interconnection. Not all transmission service provided under the Midwest ISO tariff exactly matches a service under this Tariff. Differences include variations in product definitions and PJM Region LMP pricing points. These variances in transmission requests will be converted into the defined product types explained below. The guidelines for the conversion of service are as follows:

1. All existing reservations will retain the same capacity (in megawatts) and will be converted to a comparable PJM product and duration with the applicable point of receipt, point of delivery, and path. Firm Point-to-Point Transmission Service redirected on a non-firm basis to Secondary Receipt or Delivery Points under the Midwest ISO tariff prior to the DEOK integration date will be converted to service under this tariff on the basis of the original firm points of receipt and delivery. Firm Point-to-Point Transmission Service redirected on a firm basis under section 22.2 (Modification on a Firm Basis) (or equivalent) of the Midwest ISO tariff prior to the DEOK integration date will be converted to service under this tariff on the basis of the modified firm points of receipt and delivery.

2. All DEOK Zone Midwest ISO reservations extending past the integration date must select Source and Sink LMP pricing points, where applicable, and willing to pay congestion (or not), if applicable. Willing to pay congestion (or not) must be determined no later than 12:00 noon EPT, 30 days prior to the DEOK integration start date. In the event the customer does not choose within the allotted deadline above, PJM will convert the service to the most closely analogous service under the PJM Tariff, in PJM's judgment. Willing to pay congestion is optional for non-firm and non-designated transmission service; Firm service, by definition, is willing to pay congestion. All

converted service (as they exist) will be placed on the PJM OASIS no later than 30 days prior to the DEOK integration start date.

3. All Midwest ISO DEOK Zone import reservations will be converted to one of the following service types as defined by this Tariff or on the PJM OASIS: Spot market, Non-Firm Point-to-Point, Firm Point-to-Point, Network Designated or Network Non-Designated. This choice will be made on an individual reservation basis, based on the scheduling intent of the reservation.

   All service with an export from the DEOK Zone into the Midwest ISO will be represented with new PJM reservations with one of the following service types as defined by this Tariff or on the PJM OASIS: Non-Firm Point-to-Point, or Firm Point-to-Point. This choice will be made on an individual reservation basis, based on the scheduling intent of the reservation.

4. All existing DEOK Zone Midwest ISO extended transmission requests (i.e. monthly, weekly, daily) that span multiple months will be converted to their largest individual components as defined on the PJM OASIS. For example, a monthly request from October 1 to December 1 will be converted to two individual monthly requests, October 1 to November 1, and November 1 to December 1; and a daily request from January 1 of one year to January 1 of the next year will be converted to yearly service.

5. Sliding monthly service (i.e. monthly service that does not run from the first day of the given month to the last day of the given month) will be converted to weekly and daily service.

6. Sliding weekly service (i.e. weekly service that does not run from Monday at 00:00 to Sunday at 23:59) will be converted to daily service.

7. Transmission service that is not currently confirmed on the Midwest ISO DEOK Zone OASIS nodes and is in an active state such as “Received”, “Queued” or “Study” will be transferred to the integrated PJM OASIS node and will maintain its initial queued date.

8. All “Grandfathered” requests that exist on the DEOK Zone Midwest ISO OASIS nodes will require a reservation on the PJM OASIS node.

9. To facilitate the OASIS transition, from one month prior to the integration start date until such integration start date, requests for service that are active on or after such date one month prior to the integration start date should be made on both the pre-integration transmission owner or OASIS nodes and the PJM OASIS nodes.

10. Reservations will be converted based on the priority of the product.

11. Although the Office of the Interconnection will attempt to convert existing transmission reservations into comparable reservations on the PJM OASIS, there will be unique instances where this will not be possible (e.g., reliability issues, etc.). In this case,

reservations will be reviewed on a case-by-case basis. Transmission service that is not currently accepted on the DEOK Zone Midwest ISO OASIS nodes and is in an active state such as “Received”, “Queued” or “Study” will be assigned the same status and queue position on the PJM OASIS as it had on the Midwest ISO OASIS prior to conversion.

12. Converted Point-to-Point and Network transmission service reservations that intersect with or begin after the integration commencement date will be posted to the PJM OASIS web page on a weekly basis. The web page will identify the original DEOK Zone Midwest ISO reservation and the new PJM OASIS reservation.

13. An Interconnection Request pending under the Midwest ISO OATT at the time of the integration of the DEOK Zone shall be assigned the same priority date under this Tariff as such request had under the Midwest ISO’s OATT immediately prior to such integration. The Interconnection Request will be assigned a PJM queue identifier such that the Interconnection Customer’s priority date relative to existing PJM queued Interconnection Requests can be easily determined. All such Interconnection Requests will be integrated into PJM’s existing Interconnection Queue(s), effective on the DEOK integration start date, and will be subject to the generation interconnection procedures under Part IV and Part VI of this Tariff. On the DEOK integration date, PJM will assume the technical studies that have been started by the Midwest ISO. After the studies are complete, the Interconnection Customer will be required to pay for any Network Upgrades and/or Local Upgrades that are needed for the unit to qualify for Capacity Interconnection Rights under the this Tariff.

ATTACHMENT H-22
Annual Transmission Rates – DEOK
for Network Integration Transmission Service
and Point-to-Point Transmission Service

1. The Annual Transmission Revenue Requirements ("ATRR") and the rates for Network Integration Transmission Service and Point-to-Point Transmission Service are equal to the results of the formula shown in Attachment H-22A, and will be posted on the PJM website. The ATRR and the rates reflect the cost of providing transmission service over the 69 kV and higher transmission facilities of Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc. (jointly, "DEOK"). Service utilizing other DEOK facilities will be provided at rates determined on a case-by-case basis and stated in service agreements with affected customers.

2. The formula rate in this attachment shall be effective until amended by DEOK or modified by the Commission.

3. In addition to the rate set forth in paragraph 1, a Network Customer purchasing Network Integration Transmission Service shall pay for transmission congestion charges, in accordance with the provisions of the Tariff, and any amounts necessary to reimburse DEOK for any amounts payable by it as sales, excise, "Btu," carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

Formula Rate - Non-Levelized | For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

Line No.			Total		Allocator	Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)					$ -
	REVENUE CREDITS (Note T)		Total		Allocator	
2	Account No. 454	(page 4, line 34)	$ -	TP	0.00000	$ -
3	Account No. 456.1	(page 4, line 35)	0	TP	0.00000	0
4a	Revenues from Grandfathered Interzonal Transactions		0	TP	0.00000	0
4b	Revenues from service provided by ISO at a discount		0	TP	0.00000	0
5a	Legacy MTEP Credit (Appendix C, page 2, line 3, col. 12)		0		1.00000	0
5b	RTEP Transmission Enhancement Credit (Appendix B, page 2, line 3, col. 12)		0		1.00000	0
5c	Firm PTP Revenue Credit Adjustment (Appendix E, line 10, col. 3)		0		1.00000	0
6	TOTAL REVENUE CREDITS (sum lines 2-5c)					$ -
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ -
	DIVISOR					
8	1 CP (Note A)					0
9	12 CP (Note B)					0
10	Reserved					
11	Reserved					
12	Reserved					
13	Reserved					
14	Reserved					
15	Annual Cost ($/kW/Yr) - 1 CP	(line 7 / line 8)	$0.000			
16	Annual Cost ($/kW/Yr) - 12 CP	(line 7 / line 9)	$0.000			
17	Network Rate ($/kW/Mo)	(line 15 / 12)	$0.000			
17a	Point-To-Point Rate ($/kW/Mo)	(line 16 / 12)	$0.000			
			Peak Rate			Off-Peak Rate
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	$0.000			
19	Point-To-Point Rate ($/kW/Day)	(line 16 / 260; line 16 / 365)	$0.000	Capped at weekly rate		$0.000
20	Point-To-Point Rate ($/MWh)	(line 16 / 4,160; line 16 / 8,760 * 1000)	$0.000	Capped at weekly and daily rate		$0.000

Formula Rate - Non-Levelized

For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

Line No.	(1) RATE BASE:	(2) Form No. 1 Page, Line, Col.	(3) Company Total		(4) Allocator	(5) Transmission (Col. 3 times Col. 4)
	GROSS PLANT IN SERVICE					
1	Production	205.46.g	$ -	NA		
2	Transmission	207.58.g	0	TP	0.00000	$ -
3	Distribution	207.75.g	0	NA		
4	General & Intangible	205.5.g & 207.99.g	0	W/S	0.00000	0
5	Common	356.1	0	CE	0.00000	0
6	TOTAL GROSS PLANT (sum lines 1-5)		$ -	GP=	0.000%	$ -
	ACCUMULATED DEPRECIATION					
7	Production	219.20-24.c	$ -	NA		
8	Transmission	219.25.c	0	TP	0.00000	$ -
9	Distribution	219.26.c	0	NA		
10	General & Intangible	219.28.c	0	W/S	0.00000	0
11	Common	356.1	0	CE	0.00000	0
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		$ -			$ -
	NET PLANT IN SERVICE					
13	Production	(line 1 - line 7)	$ -			
14	Transmission	(line 2 - line 8)	0			$ -
15	Distribution	(line 3 - line 9)	0			
16	General & Intangible	(line 4 - line 10)	0			0
17	Common	(line 5 - line 11)	0			0
18	TOTAL NET PLANT (sum lines 13-17)		$ -	NP=	0.000%	$ -
	ADJUSTMENTS TO RATE BASE (Note F)					
19	Account No. 281 (enter negative)	273.8.k	$ -	NA	zero	$ -
20	Account No. 282 (enter negative)	275.2.k	0	NP	0.00000	0
21	Account No. 283 (enter negative)	277.9.k	0	NP	0.00000	0
22	Account No. 190	234.8.c	0	NP	0.00000	0
23	Account No. 255 (enter negative)	267.8.h	0	NP	0.00000	0
24	TOTAL ADJUSTMENTS (sum lines 19- 23)		$ -			$ -
25	LAND HELD FOR FUTURE USE (Note G)	214.x.d	$ -	TP	0.00000	$ -
	WORKING CAPITAL (Note H)					
26	CWC	calculated	$ -			0
27	Materials & Supplies (Note G)	227.8.c & .16.c	0	TE	0.00000	0
28	Prepayments (Account 165)	111.57.c	0	GP	0.00000	0
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		$ -			$ -
30	RATE BASE (sum lines 18, 24, 25, & 29)		$ -			$ -

Formula Rate - Non-Levelized

For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

Line No.	(1) RATE BASE	(2) Form No. 1 Page, Line, Col.	(3) Company Total		(4) Allocator	(5) Transmission (Col. 3 times Col. 4)
	O&M					
1	Transmission	321.112.b	$ -	TE	0.00000	$ -
1a	Less LSE Expenses included in Transmission O&M Accounts (Note V)	321.88.b, 92.b; 322.121.b	0		1.00000	0
1b	Less Midwest ISO Fees included in Transmission O&M	(Note X)	0	TE	0.00000	0
1c	Plus Midwest ISO Fees	(Note X)	0		1.00000	0
2	Less Account 565	321.96.b	0	TE	0.00000	0
3	A&G	323.197.b	0	W/S	0.00000	0
3a	Less Actual PBOP Expense	(Note E)	0	W/S	0.00000	0
3b	Plus Fixed PBOP Expense	(Note E)	0	W/S	0.00000	0
3c	Less PJM integration Costs included in A&G	(Note Y)	0	W/S	0.00000	0
3d	Plus PJM Integration Costs	(Note Y)	0		1.00000	0
4	Less FERC Annual Fees	350.14.b	0	W/S	0.00000	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Advertising (Note I)		0	W/S	0.00000	0
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.00000	0
6	Common	356.1	0	CE	0.00000	0
7	Transmission Lease Payments		0		1.00000	0
8	TOTAL O&M (Sum lines 1, 2a, 3, 5a, 6, 7 less lines 1a, 2, 4, 5)		$ -			$ -
	DEPRECIATION EXPENSE					
9	Transmission	336.7.b	$ -	TP	0.00000	$ -
10	General	336.10.b	0	W/S	0.00000	0
11	Common	336.11.b	0	CE	0.00000	0
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		$ -			$ -
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
13	Payroll	263.i	$ -	W/S	0.00000	$ -
14	Highway and vehicle	263.i	0	W/S	0.00000	0
15	PLANT RELATED					
16	Property	263.i	0	GP	0.00000	0
17	Gross Receipts	263.i	0	NA	zero	0
18	Other	263.i	0	GP	0.00000	0
19	Payments in lieu of taxes		0	GP	0.00000	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		$ -			$ -
	INCOME TAXES (Note K)					
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.000000%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		0.000000%			
	where WCLTD=(page 4, line 27) and R= (page 4, line 30)					
	and FIT, SIT & p are as given in footnote K.					
23	1 / (1 - T) = (from line 21)		0.0000			
24	Amortized Investment Tax Credit	266.8.f (enter negative)	0			
25	Income Tax Calculation (line 22 * line 28)		$ -	NA		$ -
26	ITC adjustment (line 23 * line 24)		0	NP	0.00000	0
27	Total Income Taxes	(line 25 plus line 26)	$ -			$ -

28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]	$ -	NA	$ -
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)	$ -		$ -

Formula Rate - Non-Levelized — For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)
SUPPORTING CALCULATIONS AND NOTES

Line No.	TRANSMISSION PLANT INCLUDED IN ISO RATES									
1	Total transmission plant (page 2, line 2, column 3)							$ -		
2	Less transmission plant excluded from ISO rates (Note M)							0		
3	Less transmission plant included in OATT Ancillary Services (Note N)							0		
4	Transmission plant included in ISO Rates (line 1 less lines 2 & 3)							$ -		
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)						TP=	0.00000		
	TRANSMISSION EXPENSES									
6	Total transmission expenses (page 3, line 1, column 3)							$ -		
7	Less transmission expenses included in OATT Ancillary Services (Note L)							0		
8	Included transmission expenses (line 6 less line 7)							$ -		
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)							0.00000		
10	Percentage of transmission plant included in ISO Rates (line 5)						TP	0.00000		
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)						TE=	0.00000		
	WAGES & SALARY ALLOCATOR (W&S)									
		Form 1 Reference	$	TP	Allocation					
12	Production	354.20.b	0	0.00	0					
13	Transmission	354.21.b	0	0.00	0					
14	Distribution	354.23.b	0	0.00	0			W&S Allocator		
15	Other	354.24,25,26.b	0	0.00	0			($ / Allocation)		
16	Total (sum lines 12-15)		0		0	=		0.00000	=	WS
	COMMON PLANT ALLOCATOR (CE) (Note O)									
			$		% Electric			W&S Allocator		
17	Electric	200.3.c	0		(line 17 / line 20)			(line 16)		CE
18	Gas	201.3.d	0		0.00000	*		0.00000	=	0.00000
19	Water	201.3.e	0							
20	Total (sum lines 17 - 19)		0							
	RETURN (R)							$		
21		Long Term Interest (117, sum of 62.c through 67.c)						0		
22		Preferred Dividends (118.29c) (positive number)						0		
	Development of Common Stock:									
23		Proprietary Capital (112.16.c)						0		
24		Less Preferred Stock (line 28)						0		
25		Less Account 216.1 (112.12.c) (enter negative)						0		
26		Common Stock (sum lines 23-25)						0		
		(Note P)	$	%	Cost			Weighted		
27	Long Term Debt (112, sum of 18.c through 21.c)		0	0%	0.0000			0.0000	=	WCLTD
28	Preferred Stock (112.3.c)		0	0%	0.0000			0.0000		
29	Common Stock (line 26)		0	0%	0.1238			0.0000		
30	Total (sum lines 27-29)		0					0.0000	=	R

REVENUE CREDITS

			Load
	ACCOUNT 447 (SALES FOR RESALE) (Note Q)	(310-311)	
31	a. Bundled Non-RQ Sales for Resale (311.x.h)		0
32	b. Bundled Sales for Resale included in Divisor on page 1		-
33	Total of (a)-(b)		0
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)		$ -
35	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) (Note U)	(330.x.n)	$ -

Formula Rate - Non-Levelized | For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Notes:

A DEOK 1 CP is Duke Energy Ohio ("DEO") Monthly Firm Transmission System Peak Load as reported on page 400, column b of Form 1 at the time of DEO's annual peak, plus load served by Duke Energy Kentucky at Longbranch. For years ending 12/31/2010 and 12/31/2011, this sum will be reduced by the amount of distribution load served by East Kentucky Power Cooperative via Duke Kentucky's Hebron substation. Excludes demands from grandfathered interzonal transactions and demands from service provided by ISO at a discount.

B DEOK 12 CP is DEO Monthly Firm Transmission System Peak Load as reported on page 400, column b of Form 1 at the time of DEO's monthly peaks, plus load served by Duke Kentucky at Longbranch. For years ending 12/31/2010 and 12/31/2011, this sum will be reduced by the amount of distribution load served by East Kentucky Power Cooperative via Duke Kentucky's Hebron substation. Excludes demands from grandfathered interzonal transactions and demands from service provided by ISO at a discount.

C Reserved

D Reserved

E This deduction is to remove expenses recorded by DEOK for Postretirement Benefits Other than Pensions (PBOP). PBOP expense is set forth in line 3b and is fixed until changed as the result of a filing at FERC. The fixed amount of PBOP for DEO is $2,342,494 and for Duke Energy Kentucky ("DEK") is $575,908.

F The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.

G Identified in Form 1 as being only transmission related.

H Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5.
Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111 line 57 in the Form 1.

I Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.

J Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.

K The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26).

Inputs Required:	FIT =	0.00%	
	SIT=	0.00%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

L Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.

M Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).

N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to be included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

O Enter dollar amounts.

P Debt cost rate = long-term interest (line 21) / long term debt (line 27). Preferred cost rate = preferred dividends (line 22) / preferred outstanding (line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC. Capitalization adjusted to exclude impacts of purchase accounting.

Q Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.

R Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

S Reserved

T The revenues credited on page 1 lines 2-5c shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, or facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

Formula Rate - Non-Levelized | For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Notes:

U On Line 35, enter revenues from RTO settlements that are associated with NITS and firm Point-to-Point Service for which the load is not included in the divisor to derive Duke Energy Ohio's and Duke Energy Kentucky's zonal rates. Exclude non-firm Point-to-Point revenues, revenues related to MTEP and RTEP projects, revenues from grandfathered interzonal transactions and revenues from service provided by ISO at a discount.

V Account Nos. 561.4, 561.8 and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.

W Reserved

X Midwest ISO Fees include (1) the charges that DEOK paid to the Midwest ISO pursuant to the Settlement Agreement filed on July 29, 2011 in Docket No. ER11-2059 and (2) the exit fees that DEOK paid to the Midwest ISO pursuant to the Exit Fee Agreement filed on October 5, 2011 in Docket No. ER12-33.

Y PJM Integration Costs are the fees that PJM assessed DEOK for the costs that PJM incurred in connection with DEOK's move into PJM.

Attachment H-22A

For the 12 months ended 12/31/_____

Duke Energy Ohio and Duke Energy Kentucky
Transmission Formula Rate Revenue Requirement
Utilizing FERC Form 1 Data
For Rates Effective January 1, 2012

Schedule 1A Rate Calculation

Line No.		Source	Revenue Requirement	
A.	Schedule 1A Annual Revenue Requirements			
1	Total Load Dispatch & Scheduling (Account 561)	Attachment H-22A, Page 4, Line 7	$ -	
2	Revenue Credits for Schedule 1A - Note A		$ -	
3	Net Schedule 1A Revenue Requirement for Zone		$ -	
B.	Schedule 1A Rate Calculations			
4	2010 Annual MWh - Note B	(401a.22b & 24b)	-	MWh
5	Schedule 1A rate $/MWh (Line 3 / Line 4)	(Line 3 / Line 4)	$0.0000	$/MWh

Notes:

A Revenue received pursuant to PJM Schedule 1A revenue allocation procedures for transmission service outside of DEOK's zone during the year used to calculate rates under Attachment H-22A.

B Load expressed in MWh consistent with load used for billing under Schedule 1A for the DEOK zone. Data from RTO settlement systems for the calendar year prior to the rate year.

For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio and Duke Energy Kentucky
RTEP – Transmission Enhancement Charges

To be completed in conjunction with Attachment H-22A

Line No.	(1)	(2) Attachment H-22A Page, Line, Col.	(3) Transmission	(4) Allocator
	TRANSMISSION PLANT			
1	Gross Transmission Plant - Total	Sch. H-22A, p 2, line 2 col 5 (Note A)	-	
2	Net Transmission Plant - Total	Sch. H-22A, p 2, line 14 col 5 (Note B)	-	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Sch. H-22A, p 3, line 8 col 5	-	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	0.00%	0.00%
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G&C Depreciation Expense	Sch. H-22A, p 3, lines 10 & 11, col 5 (Note H)	-	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	0.00%	0.00%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Sch. H-22A, p 3, line 20 col 5	-	
8	Annual Allocation Factor for Other Taxes	(line 5 divided by line 1 col 3)	0.00%	0.00%
9	**Annual Allocation Factor for Expense**	**Sum of lines 4, 6 and 8**		**0.00%**
	INCOME TAXES			
10	Total Income Taxes	Sch. H-22A, p 3, line 27 col 5	-	
11	Annual Allocation Factor for Income Taxes	(line 8 divided by line 2 col 3)	0.00%	0.00%
	RETURN			
12	Return on Rate Base	Sch. H-22A, p 3, line 28 col 5	-	
13	Annual Allocation Factor for Return on Rate Base	(line 10 divided by line 2 col 3)	0.00%	0.00%
14	**Annual Allocation Factor for Return**	**Sum of lines 11 and 13**		**0.00%**

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio and Duke Energy Kentucky
RTEP – Transmission Enhancement Charges

Network Upgrade Charge Calculation By Project

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line No.	Project Name	RTEP Project Number	Project Gross Plant	Annual Allocation Factor for Expense	Annual Expense Charge	Project Net Plant	Annual Allocation Factor for Return	Annual Return Charge	Project Depreciation Expense	Annual Revenue Requirement	True-Up Adjustment	Network Upgrade Charge
			(Note C)	(Page 1 line 7)	(Col. 3 * Col. 4)	(Note D)	(Page 1 line 12)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)	Sum Col. 10 & 11 (Note G)
1b			$ -	0.00%	$0.00	$ -	0.00%	$0.00	$0	$0.00	$ -	$0.00
1c			$ -	0.00%	$0.00	$ -	0.00%	$0.00	$0	$0.00	$ -	$0.00
2	Annual Totals									$0	$0	$0
3	RTEP Transmission Enhancement Charges for Attachment H-22A, Page 1, Line 5c											$0

Notes:

A. Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-22A and includes any sub lines 2a or 2b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.

B. Net Transmission Plant is that identified on page 2 line 14 of Attachment H-22A and includes any sub lines 14a or 14b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.

C. Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes CWIP in rate base if applicable. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.

D. Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.

E. Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-22A page 3 line 12.

F. True-Up Adjustment is included pursuant to a FERC approved methodology if applicable.

G. The Network Upgrade Charge is the value to be used in Schedule 26.

H. The Total General and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 9.

For the 12 months ended 12/31/_____

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio and Duke Energy Kentucky
Legacy MTEP Credit

To be completed in conjunction with Attachment H-22A

Line No.	(1)	(2) Attachment H-22A Page, Line, Col.	(3) Transmission	(4) Allocator
	TRANSMISSION PLANT			
1	Gross Transmission Plant - Total	Sch. H-22A, p 2, line 2 col 5 (Note A)	-	
2	Net Transmission Plant - Total	Sch. H-22A, p 2, line 14 col 5 (Note B)	-	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Sch. H-22A, p 3, line 8 col 5	-	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	0.00%	0.00%
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G&C Depreciation Expense	Sch. H-22A, p 3, lines 10 & 11, col 5 (Note H)	-	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	0.00%	0.00%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Sch. H-22A, p 3, line 20 col 5	-	
8	Annual Allocation Factor for Other Taxes	(line 5 divided by line 1 col 3)	0.00%	0.00%
9	**Annual Allocation Factor for Expense**	**Sum of lines 4, 6 and 8**		**0.00%**
	INCOME TAXES			
10	Total Income Taxes	Sch. H-22A, p 3, line 27 col 5	-	
11	Annual Allocation Factor for Income Taxes	(line 8 divided by line 2 col 3)	0.00%	0.00%
	RETURN			
12	Return on Rate Base	Sch. H-22A, p 3, line 28 col 5	-	
13	Annual Allocation Factor for Return on Rate Base	(line 10 divided by line 2 col 3)	0.00%	0.00%
14	**Annual Allocation Factor for Return**	**Sum of lines 11 and 13**		**0.00%**

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio and Duke Energy Kentucky
Legacy MTEP Credit

Network Upgrade Charge Calculation By Project

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line No.	Project Name	MTEP Project Number	Project Gross Plant	Annual Allocation Factor for Expense	Annual Expense Charge	Project Net Plant	Annual Allocation Factor for Return	Annual Return Charge	Project Depreciation Expense	Annual Revenue Requirement	True-Up Adjustment	Network Upgrade Charge
			(Note C)	(Page 1 line 7)	(Col. 3 * Col. 4)	(Note D)	(Page 1 line 12)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)	Sum Col. 10 & 11 (Note G)
1b			$ -	0.00%	$0.00	$ -	0.00%	$0.00	$0	$0.00	$ -	$0.00
1c			$ -	0.00%	$0.00	$ -	0.00%	$0.00	$0	$0.00	$ -	$0.00
2	Annual Totals									$0	$0	$0
3	Legacy MTEP Credit for Attachment H-22A, Page 1, Line 5a											$0

Notes:

A. Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-22A and includes any sub lines 2a or 2b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.

B. Net Transmission Plant is that identified on page 2 line 14 of Attachment H-22A and includes any sub lines 14a or 14b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.

C. Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes CWIP in rate base if applicable. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.

D. Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.

E. Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-22A page 3 line 12.

F. True-Up Adjustment is included pursuant to a FERC approved methodology if applicable.

G. The Network Upgrade Charge is the value to be used in Schedule 26.

H. The Total General and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 9.

DUKE ENERGY OHIO, INC.
DEPRECIATION RATES

FERC Account Number (A)	Company Account Number (B)	Description (C)	Actual Accrual Rates (D) %
		Wholly Owned Transmission Plant	
350	3403	Rights of Way	1.54
352	3420	Structures & Improvements	1.90
352	3424	Structures & Improvements - Duke Ohio - Loc. in Ky.	1.90
353	3430	Station Equipment	1.44
353	3434	Station Equipment - Duke Ohio - Loc. in Ky.	1.44
354	3440	Towers & Fixtures	1.85
354	3444	Towers & Fixtures - Duke Ohio - Loc. in Ky.	1.85
355	3450	Poles & Fixtures	2.31
355	3454	Poles & Fixtures - Duke Ohio - Loc. in Ky.	2.31
356	3460	Overhead Conductors & Devices	1.91
356	3464	Overhead Conductors & Devices - Duke Ohio - Loc. in Ky.	1.91
357	3470	Underground Conduit	1.43
358	3480	Underground Conductors & Devices	2.37
		Commonly Owned Transmission Plant - CCD Projects	
352	3421	Structures & Improvements - CCD Projects	2.50
352	3425	Structures & Improvements - CCD Projects	2.50
353	3431	Station Equipment - CCD Projects	1.44
353	3432	Station Equipment - CCD Projects	1.44
353	3435	Station Equipment - CCD Projects	1.44
353	3437	Station Equipment - CCD Projects	1.44
354	3441	Towers & Fixtures - CCD Projects	3.00
354	3442	Towers & Fixtures - CCD Projects	3.00
354	3445	Towers & Fixtures - CCD Projects	3.00
354	3446	Towers & Fixtures - CCD Projects - Loc. In Ky.	3.00
354	3448	Towers & Fixtures - CCD Projects	3.00
355	3451	Poles & Fixtures - CCD Projects	3.00
355	3455	Poles & Fixtures - CCD Projects	3.00
356	3461	Overhead Conductors & Devices - CCD Projects	2.50
356	3462	Overhead Conductors & Devices - CCD Projects	2.50
356	3465	Overhead Conductors & Devices - CCD Projects	2.50
356	3466	Overhead Conductors & Devices - CCD Projects - Loc. In Ky.	2.50
		Commonly Owned Transmission Plant - CD Projects	
352	3423	Structures & Improvements - CD Projects	2.50
353	3433	Station Equipment - CD Projects	1.44
353	3438	Station Equipment - CD Projects	1.44
354	3447	Towers & Fixtures - CD Projects	3.00
356	3467	Overhead Conductors & Devices - CD Projects	2.50
		General and Intagible Plant	
303	3030	Miscellaneous Intangible Plant	20.00
389	3890	Land and Land Rights	N/A
390	3900	Structures and Improvements	2.50
391	3910	Office Furniture and Equipment	2.00
391	3911	Electronic Data Processing Equipment	20.00
391	3920	Transportation Equipment	8.33
391	3921	Trailers	4.25
392	3940	Tools, Shop & Garage Equipment	4.00
392	3950	Laboratory Equipment	6.67
393	3960	Power Operated Equipment	5.88
393	3970	Communication Equipment	6.67
394	3980	Miscellaneous Equipment	5.00

DUKE ENERGY KENTUCKY, INC.
DEPRECIATION RATES

FERC Account Number (A)	Company Account Number (B)	Description (C)	Actual Accrual Rates (D)
			%
		Transmission Plant	
350	3501	Rights of Way	1.48
352	3520	Structures & Improvements	0.41
353	3530	Station Equipment	2.25
353	3532	Station Equipment - Major	2.77
353	3535	Station Equipment – Electronic	9.55
355	3550	Poles & Fixtures	2.28
356	3560	Overhead Conductors & Devices	2.31
		General and Intangible Plant	20.00
303	3030	Miscellaneous Intangible Plant	1.77
390	3900	Land and Land Rights	18.56
391	39110	Structures and Improvements	6.53
392	3921	Electronic Data Processing Equipment	4.14
394	3940	Transportation Equipment	6.93
397	3970	Stores Equipment	

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio and Duke Energy Kentucky
Firm PTP Service Revenue Credit Adjustment Calculation

To be completed in conjunction with Attachment H-22A

No.	(1)	(2) Reference	(3) Company Total
	REVENUE CREDIT TRUE-UP		
1	Difference Between Revenue Received In PJM vs. Midwest ISO	(Note A)	$0
	ACCUMULATED BALANCE OF REVENUE CREDIT TRUE-UP		
2	Accumulated Balance of Deferral	(Note B)	$0
3	Income Tax Rate for Deferral Calculation	(Note C)	0.00%
4	Deferred Income Taxes on Accumulated Deferral (line 2 * line 3)		$0
5	Accumulated Deferral for Carrying Cost Calculation (Line 2 - Line 4)		$0
	INCOME TAXES		
6	CIT = (T/(1-T)) * (1 - (WCLTD/R))	Attachment H-22, page 3, line 22	0.00%
7	Income Taxes (Line 6 * Line 9)		$0
	CARRYING COST ON DEFERRAL		
8	FERC Refund Rate		0.00%
9	Carrying Cost (Line 5 * Line 8)	(Note C)	$0
10	Revenue Credit Adjustment (Line 1 + Line 7 + Line 9)		$0

Notes
A. From Appendix E, Workpaper, Column (4).
B. Accumulated balance of deferral as of December 31st of the year prior to effective date of new rate.
C. Effective deferred tax rate during applicable test year.
D. FERC Refund Rate is the approved rate as of December 31 of calendar prior to the rate year (see 18 C.F.R. Section 35.19a).

Duke Energy Ohio and Duke Energy Kentucky

Worksheet for Firm PTP Service Revenue Credit Adjustment Calculation

(1) Period	(2) Actual Firm PTP Service Revenue Included in Test Year Rate Calculation (Note A)	(3) Actual Firm PTP Service Revenue Received from PJM (Note B)	(4) = (2) - (3) Difference Between Revenue Received and Amount in Rates Excluding True Up	(5) Monthly True-Up Adjustment Included In H-22A Net Revenue Requirement (Note C)	(6) = (4) - (5) Amount Deferred for Future Recovery	(7) = Prior month's Balance + (6) Accumulated Balance of Deferred Firm PTP Service Revenue Credit Adjustment
Jan-12	$ -	$ -	$ -		$ -	$ -
Feb-12	-	-	-		-	-
Mar-12	-	-	-		-	-
Apr-12	-	-	-		-	-
May-12	-	-	-		-	-
Jun-12	-	-	-		-	-
Jul-12	-	-	-		-	-
Aug-12	-	-	-		-	-
Sep-12	-	-	-		-	-
Oct-12	-	-	-		-	-
Nov-12	-	-	-		-	-
Dec-12	-	-	-		-	-
Total				$	$ -	-
						-
Jan-13	-	-	-		$ -	-
Feb-13	-	-	-		-	-
Mar-13	-	-	-		-	-
Apr-13	-	-	-		-	-
May-13	-	-	-		-	-
Jun-13			-	-	-	-
Jul-13				-	-	-
Aug-13				-	-	-
Sep-13				-	-	-
Oct-13				-	-	-
Nov-13				-	-	-
Dec-13				-	-	$ -
Total				$ -	$ -	
Jan-14				$ -	$ -	$ -
Feb-14				-	-	-
Mar-14				-	-	-
Apr-14				-	-	-
May-14				-	-	-
Jun-14				-	-	-
Jul-14				-	-	-
Aug-14				-	-	-
Sep-14				-	-	-
Oct-14				-	-	-
Nov-14				-	-	-
Dec-14				-	-	$ -
Total				$ -	$ -	
Jan-15				$ -	$ -	$ -
Feb-15				-	-	-
Mar-15				-	-	-
Apr-15				-	-	-
May-15				-	-	$ -
Total				$ -	$ -	

Notes:

A. Monthly Firm PTP service revenue from Midwest ISO during test year applicable to currently effectives NITS and PTP service rates.
B. Actual monthly Firm PTP service revenue received from PJM during current period.
C. Recovery of deferral begins with the first period for billing rates approved using a test year for Attachment H-22A that includes actual operations in PJM.

ATTACHMENT H-22B
DEOK FORMULA RATE IMPLEMENTATION PROTOCOLS

Definitions

"Annual Transmission Revenue Requirements" means the result produced by populating the Formula Rate Template with data as provided by the Formula Rate.

"Annual Update" means the posting and informational filing submitted by DEOK on or before May 15 of each year that sets forth the DEOK Cost of Service ("COS") for the subsequent Rate Year.

"Discovery Period" means the period after each annual Publication Date to serve information requests on DEOK as provided in Section 2.b below.

"DEOK" means Duke Energy Kentucky, Inc., and Duke Energy Ohio, Inc.

"First Rate Year" means the period that begins on January 1, 2012, and ends on May 31, 2012.

"Formal Challenge" means a challenge to an Annual Update submitted to the Federal Energy Regulatory Commission ("FERC") as provided in Section 3.a below.

"Formula Rate" means these Formula Rate Implementation Protocols (to be included as Attachment H-22B of the PJM Interconnection, L.L.C. ("PJM"), FERC Electric Tariff ("PJM Tariff")) and the Formula Rate Template.

"Formula Rate Template" means the collection of formulae, and worksheets, unpopulated with any data, to be included as Attachment H-22A of the PJM Tariff.

"Interested Party" means any person or entity having standing under Section 206 of the Federal Power Act ("FPA") with respect to the Annual Update.

"Material Changes" means (i) material changes in DEOK's accounting policies and practices, (ii) changes in FERC's Uniform System of Accounts ("USofA"), (iii) changes in FERC Form No. 1 reporting requirements as applicable, or (iv) changes in the FERC's accounting policies and practices, which change causes a result under the Formula Rate different from the result under the Formula Rate as calculated without such change.

"Preliminary Challenge" means a written challenge to the Annual Update submitted to DEOK as provided in Section 2.a below.

"Protocols" means these Formula Rate Implementation Protocols (to be included as Attachment H-22B of the PJM Tariff).

"Publication Date" means the date on which the Annual Update is posted under the provisions of Section 1.b below.

"Rate Year" means the twelve consecutive month period that begins on June 1 and continues through May 31 of the subsequent calendar year except for the First Rate Year.

"Review Period" means the period during which Interested Parties may review the calculations in the Annual Update as provided in Section 2.a below.

Section 1 Annual Updates

a. Beginning with the Rate Year that commences on June 1, 2012, and during each Rate Year thereafter, the Annual Transmission Revenue Requirement calculated in accordance with Attachment H-22A and the Network Integration Transmission Service and Point-to-Point rates derived therefrom shall be applicable to transmission services provided by PJM for the DEOK zone during the Rate Year.

b. On or before May 15, 2012, and on or before May 15 of each succeeding Rate Year, DEOK shall recalculate its Annual Transmission Revenue Requirement, producing the "Annual Update" for the upcoming Rate Year, and:
   (i) post such Annual Update on PJM's Internet website (via a link to the Transmission Services page or a similar successor page) as both a .pdf (Portable Document Format) document and a fully-functioning Excel file;
   (ii) submit such Annual Update as an informational filing with the FERC;
   (iii) provide contact information for inquiries concerning the Annual Update.

c. If the date for making the Annual Update posting/filing should fall on a weekend or a holiday recognized by the FERC, then the posting/filing shall be due on the next business day.

d. The date on which the last of the events listed in Section 1.b or 1.c occurs shall be that year's "Publication Date."

e. Within two business days of the Publication Date, DEOK shall also provide notice on PJM's Internet website (via a link to the Transmission Services page or a similar successor page) of the time, date and location of an open meeting among interested parties ("Annual Meeting"). This Annual Meeting shall (i) permit DEOK to explain and clarify its Annual Update and (ii) provide interested parties an opportunity to seek information and clarifications from DEOK about the Annual Update. The Annual Meeting shall take place no sooner than ten (10) days after posting of the notice and no later than thirty (30) days after the Publication Date.

f. Inputs to the Formula Rate are based on DEOK's books, which reflect:
   (i) the FERC's Uniform System of Accounts, and

(ii) applicable FERC Form No. 1[1] as each exists as of the later of the date of DEOK's initial filing of the Formula Rate or the last day of the calendar year immediately preceding the effective date of the most recent revision to the Formula Rate.

g. The Annual Update for the Rate Year:

(i) shall, to the extent specified in the Formula Rate, be based upon DEOK's FERC Form No. 1 data for the most recent calendar year, and to the extent specified in the Formula Rate, be based upon the books and records of DEOK consistent with Section 1.f above;

(ii) shall, as and to the extent specified in the Formula Rate, provide the formula rate calculations and all inputs thereto, as well as supporting documentation for data not otherwise available in the FERC Form No. 1 that are used in the Formula Rate;[2]

(iii) shall provide sufficient information[3] to enable customers to replicate the calculation of the formula results from FERC Form No. 1 and other applicable accounting inputs and to compare that calculation to that of prior years, including all workpapers necessary to explain any changes made since the last update, and to include as applicable:

(1) a copy of the FERC Form No. 1 used for the update if it is not otherwise publicly available;

(2) identification of any changes in the formula references to the FERC Form No. 1;

(3) identification of all adjustments made to the FERC Form No. 1 data in determining formula inputs, including relevant footnotes to the FERC Form No. 1 and any adjustments not shown in a FERC Form No. 1 footnote;

1. If the referenced form is superseded, the successor form(s) shall be utilized and supplemented as necessary to provide equivalent information as that provided in the superseded form. If the referenced form(s) is (are) discontinued, equivalent information as that provided in the discontinued form(s) shall be utilized.

2. It is the intent of the Formula Rate, including the supporting explanations and allocations described therein, that each input to the Formula Rate will be either taken directly from the FERC Form No. 1 for the most recent calendar year or reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information provided by DEOK with the Annual Update. Where the reconciliation is provided through a worksheet included in the filed Formula Rate Template, the inputs to the worksheet must meet this transparency standard, and doing so will satisfy this transparency requirement for the amounts that are output from the worksheet and input to the main body of the Formula Rate.

3. As appropriate, competitively sensitive information may be provided only to those persons bound by the terms of a suitable confidentiality agreement or protective order.

(4) a reconciliation of monthly peak demands shown on the FERC Form 1 and monthly peak demands used in the formula in sufficient detail to enable transparent reconciliation of these two measures;

(5) a description of those factors influencing any change in the annual revenue requirement, including an identification of any respects in which charges under the formula rate materially differ from the preceding Annual Update (e.g., due to changes in accounting procedures, the purchase or sale of major assets, or other such significant changes) and identification of the major reason(s) for the differences, if any, between the Annual Update and the prior year's Annual Update; and

(6) any changes to the data inputs made as a result of a reconciliation made under Section 4 below.

(iv) shall describe material changes, if any, in DEOK's accounting policies, practices and procedures from those in effect for the calendar year upon which the immediately preceding Annual Update was based that could or did affect the charges under the Formula Rate ("Material Accounting Changes");[4]

(v) shall be subject to challenge and review only in accordance with the procedures set forth in this Attachment H-22B, as to the appropriateness of the input data, the prudence of the costs and expenditures included for recovery in the Annual Update, and the application of the Formula Rate according to its terms and the procedures in this Attachment H-22B (including terms and procedures related to challenges concerning Material Accounting Changes);

(vi) except as provided for in Section 1.j below, shall not seek to modify the Formula Rate and shall not be subject to challenge by anyone for the purpose of modifying the Formula Rate (i.e., all such modifications to the Formula Rate will require, as applicable, a Federal Power Act ("FPA") Section 205 or Section 206 filing).

h. Formula Rate inputs for rate of return on common equity, depreciation rates and Post-Employment Benefits Other Than Pensions ("PBOP") shall be stated values until changed pursuant to an FPA Section 205 or 206 filing made effective by the Commission. An application under Section 205 or Section 206 to modify stated values for depreciation rates or PBOP expense under the Formula Rate or Protocols shall not open review of other components of the Formula Rate or Protocols.

i. Extraordinary property losses recorded in FERC Account 182.1 shall be amortized for Formula Rate purposes pursuant to a Section 205 or 206 filing made effective by the Commission.

[4] Such notice may incorporate by reference applicable disclosure statements filed with the Securities and Exchange Commission ("SEC").

j. Any change to the underlying Uniform System of Accounts or FERC Form No. 1 as described in Section 1.f above shall be grounds for a presumption that the application of the Formula Rate shall be modified to restore the balance of the Formula Rate as accepted by the FERC (the intent being to prevent such changes in these underlying Uniform System of Accounts or FERC Form No. 1 from causing an automatic shift in the charges calculated under the Formula Rate without input from other interested parties). Any interested party seeking changes to the application of the Formula Rate due to a change in the Uniform System of Accounts or FERC Form No. 1 as described in Section 1.f, shall first raise the matter with DEOK in accordance with Section 2.a below before pursuing a Formal Challenge.

Section 2 **<u>Annual Review Procedures</u>**

Each Annual Update shall be subject to the following review procedures ("Annual Review Procedures"):

a. Interested parties shall have up to one hundred eighty (180) days after the Publication Date (unless such period is extended with the written consent of DEOK or by FERC Order) to review the inputs, supporting explanations, allocations and calculations ("Review Period") and to notify DEOK in writing, which may be made electronically, of any specific challenges, including challenges related to the rate treatment of Material Accounting Changes, to the application of the Formula Rate and to changes to the Uniform System of Accounts or FERC Form No. 1 as described in Section 1.f, above, ("Preliminary Challenge"). Failure to raise an issue with DEOK in accordance with Section 1.j above or to pursue an issue through a Preliminary Challenge or to lodge a Formal Challenge, regarding any issue as to a given Annual Update, shall bar pursuit of such issue with respect to that Annual Update, but shall not bar pursuit of such issue or the lodging of a Formal Challenge as to such issue as it relates to a subsequent Annual Update.

b. Interested Parties shall have up to one hundred fifty (150) days after each annual Publication Date (unless such period is extended with the written consent of DEOK or by FERC Order) to serve reasonable information requests on DEOK; provided, however, that the parties making such requests shall make a good faith effort to submit consolidated sets of information requests that limit the number and overlap of questions to the maximum extent practicable. Such information requests shall be limited to what is necessary to determine if DEOK has properly applied the Formula Rate, the requirements and procedures of this Attachment H-22B, and the prudence of the costs and expenditures included for recovery in the Annual Update, and shall not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable.

c. DEOK shall make a good faith effort to respond to information requests pertaining to the Annual Update within fifteen (15) business days of receipt of such requests.

d. To the extent DEOK and any interested party(ies) are unable to resolve disputes related to information requests submitted in accordance with these Annual Review Procedures, DEOK or any interested party may petition the FERC to appoint an Administrative Law Judge as a discovery master. The discovery master shall have the power to issue binding orders to resolve discovery disputes and compel the production of discovery, as appropriate, in accordance with the Annual Review Procedures and consistent with the FERC's discovery rules.

e. Preliminary Challenges shall be subject to the resolution procedures and limitations in Section 3. Formal Challenges shall be filed pursuant to these Protocols and shall include the information required under 18 C.F.R. § 385.206 (b) (1), (2), (3), (4), and (7).

Section 3 Resolution of Challenges

a. If DEOK and any interested party(ies) have not resolved any Preliminary Challenge to the Annual Update within twenty-one (21) days after the Review Period, an interested party shall have an additional twenty-one (21) days (unless such period is extended with the written consent of DEOK to continue efforts to resolve the Preliminary Challenge) to make a Formal Challenge with the FERC, which shall be served on DEOK by electronic service on the date of such filing. However, there shall be no need to make a Formal Challenge or to await conclusion of the time periods in Section 2 if the FERC already has initiated a proceeding to consider the Annual Update. A party's Formal Challenge may not raise any issue that was not the subject of that party's Preliminary Challenge during the applicable Review Period.

b. Any response by DEOK to a Formal Challenge must be submitted to the FERC within twenty (20) days of the date of the filing of the Formal Challenge, and shall be served on the filing party(ies) by electronic service on the date of such filing.

c. In any proceeding initiated by the FERC concerning the Annual Update or in response to a Formal Challenge, DEOK shall bear the burden, consistent with Section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the Formula Rate, consistent with Section 1.g(v), and that it followed the applicable requirements and procedures in this Attachment H-22B, in that year's Annual Update. Nothing herein is intended to alter the burdens applied by the Commission with respect to prudence challenges.

d. Subject to judicial review of FERC orders, each Annual Update shall become final as to the Annual Transmission Revenue Requirement calculated for the Rate Year for which the Annual Update was calculated and no longer subject to challenge pursuant to these Protocols or by any other means by the FERC or any other entity on the later to occur of (i) passage of the twenty-one (21) day period (or extended period, if applicable) for making a Formal Challenge if no such challenge has been made and the FERC has not initiated a proceeding to consider the Annual Update, or (ii) a final FERC order issued in response to a Formal Challenge or a proceeding initiated by the FERC to consider the Annual Update.

e. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of DEOK to file unilaterally, pursuant to FPA Section 205 and the regulations thereunder, to change the Formula Rate or any of its inputs (including, but not limited to, rate of return and transmission incentive rate treatment), or to replace the Formula Rate with a stated rate, or the right of any other party to request such changes pursuant to Section 206 of the Federal Power Act and the regulations thereunder.

f. Subject to Section 2.e above, it is recognized that resolution of Formal Challenges concerning Material Accounting Changes or related to the Uniform System of Accounts or FERC Form No. 1 as described above may necessitate adjustments to the Formula Rate input data for the applicable Annual Update or changes to the Formula Rate to achieve a just and reasonable end result consistent with the intent of the Formula Rate.

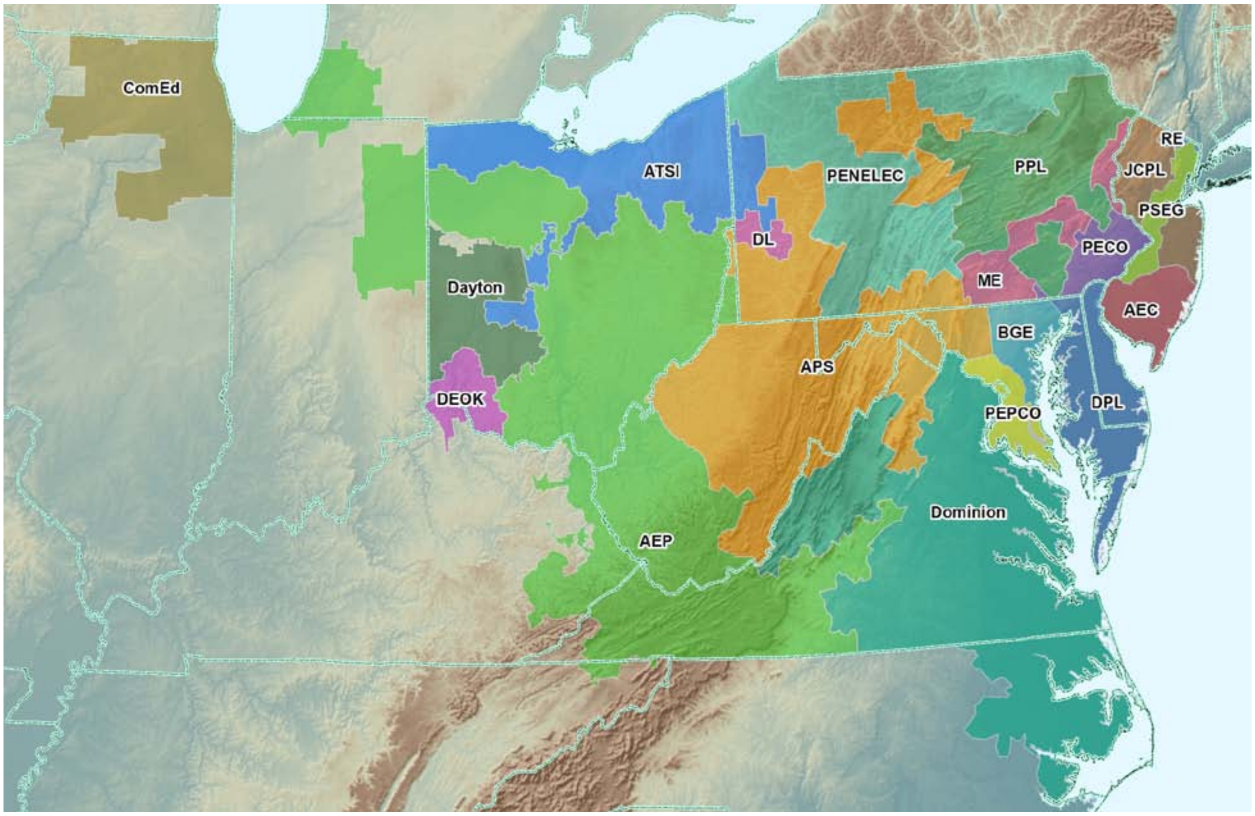
g. In making or resolving any Preliminary or Formal Challenge under this Section, a party may rely on all information provided by DEOK, including information provided under the terms of a confidentiality agreement or protective order; provided, however, that parties receiving such information pursuant to a confidentiality agreement or protective order shall be bound by the restrictions placed by such agreement or order on disclosure or use of confidential information.

Section 4 **Changes to Annual Informational Filings**

Any changes to the data inputs, including but not limited to revisions to DEOK's FERC Form No. 1, or as the result of any FERC proceeding to consider the Annual Update, or as a result of the procedures set forth herein, shall be incorporated into the Formula Rate and the charges produced by the Formula Rate (with interest determined in accordance with 18 C.F.R. § 35.19a) in the Annual Update for the next effective Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments and any refunds or surcharges. However, actual refunds or surcharges (with interest determined in accordance with 18 C.F.R. § 35.19a) for the then current rate year shall be made in the event that the Formula Rate is replaced by a stated rate for DEOK.

ATTACHMENT J

<u>PJM Transmission Zones</u>



FULL NAME	**SHORT NAME**
Pennsylvania Electric Company	PENELEC
Allegheny Power	APS
PPL Electric Utilities Corporation	PPL
Metropolitan Edison Company	ME
Jersey Central Power and Light Company	JCPL
Public Service Electric and Gas Company	PSEG
Atlantic City Electric Company	AEC
PECO Energy Company	PECO
Baltimore Gas and Electric Company	BGE
Delmarva Power and Light Company	DPL
Potomac Electric Power Company	PEPCO
Rockland Electric Company	RE
Commonwealth Edison Company	ComEd
AEP East Zone	AEP
The Dayton Power and Light Company	Dayton
Duquesne Light Company	DL
Virginia Electric and Power Company	Dominion
American Transmission Systems, Incorporated	ATSI
Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.	DEOK

3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Section 2 of this Schedule

(b) Market Buyers shall be charged for all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price .

(c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(d) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the total amount of net hourly PJM Interchange for each Market Buyer, including Generating Market Buyers, in accordance with the PJM Manuals. For Internal Market Buyers that are Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall include determination of the net energy flows from: (i) tie lines; (ii) any generation resource the output of which is controlled by the Market Buyer but delivered to it over another entity's Transmission Facilities; (iii) any generation resource the output of which is controlled by another entity but which is directly interconnected with the Market Buyer's transmission system; (iv) deliveries pursuant to bilateral energy sales; (v) receipts pursuant to bilateral energy purchases; and (vi) an adjustment to account for the day-ahead PJM Interchange, calculated as the difference between scheduled withdrawals and injections by that Market Buyer in the Day-ahead Energy Market. For External Market Buyers and Internal Market Buyers that are not Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall determine the energy scheduled hourly for delivery to the Market Buyer net of the amounts scheduled by the External Market Buyer in the Day-ahead Energy Market.

(e) An Internal Market Buyer shall be charged for Spot Market Energy purchases to the extent of its hourly net purchases from the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. An External Market Buyer shall be charged for its Spot Market Energy purchases based on the energy delivered to it, determined as specified in Section 3.2.1(d) above. The total charge shall be determined by the product of the hourly net amount of PJM Interchange Imports times the hourly Real-time System Energy Price for that Market Buyer.

(f) A Generating Market Buyer shall be paid as a Market Seller for sales of Spot Market Energy to the extent of its hourly net sales into the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. The total payment shall be determined by the product of the hourly net amount of PJM Interchange Exports times the hourly Real-time System Energy Price for that Market Seller.

3.2.2 Regulation.

(a) Each Internal Market Buyer that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). An Internal Market Buyer that does not meet its hourly Regulation obligation shall be charged for Regulation dispatched by the Office of the Interconnection to meet such obligation at the Regulation market-clearing price determined in accordance with subsection (c) of this section, plus the amounts, if any, described in subsection (f) of this section.

(b) A Generating Market Buyer supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection in excess of its hourly Regulation obligation shall be credited for each increment of such Regulation at the higher of (i) the Regulation market-clearing price in such Regulation Zone or (ii) the sum of the regulation offer and the unit-specific opportunity cost of the generation resource supplying the increment of Regulation, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day. The market-clearing price for each regulating hour shall be equal to the highest sum of a resource's Regulation offer plus its estimated unit-specific opportunity costs, determined as described in subsection (d) below from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.3.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation market-clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour shall be equal to the sum of the unit-specific opportunity costs (i) incurred during the hour in which the obligation is fulfilled, plus costs (ii) associated with uneconomic operation during the hour preceding the initial regulating hour ("preceding shoulder hour"), plus costs (iii) associated with uneconomic operation during the hour after the final regulating hour ("following shoulder hour").

The unit-specific opportunity costs incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (a) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the resource's expected output during the preceding shoulder hour, times (b) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource during the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (c) the percentage of the preceding shoulder hour during which the deviation was incurred.

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (a) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the resource's expected output in the following shoulder hour, times (b) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (c) the percentage of the following shoulder hour that the deviation was incurred.

Estimated opportunity costs for Demand Resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's Regulation signals from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Internal Market Buyer in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to section 1.10.1A(e) of this Schedule. A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region for which the cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Section 3.2.A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

(c) The sum of the foregoing credits calculated in accordance with Section 3.2.3(b) plus any unallocated charges from Section 3.2.3(h) and 5.1.7 and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection and that is not committed solely for the purpose of providing Synchronized Reserve: For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following segments: 1) the greater of their day-ahead schedules or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

Credits received pursuant to this section shall be equal to the positive difference between a resource's total offered price for start-up (shutdown costs for Demand Resources) and no-load fees and energy, determined on the basis of the resource's scheduled output, and the total value of the resource's energy as determined by the Real-time Energy Market and the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

Except as provided in Section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to Section 3.2.3(b) plus the resource's opportunity cost and less any amounts credited for Synchronized Reserve in excess of the Synchronized Reserve offer plus the resource's opportunity cost and less any amounts credited for Reactive Services as specified in Section 3.2.3.B, and less any amounts for Day-ahead Scheduling Reserve in excess of the Day-ahead Scheduling Reserve offer plus the resource's opportunity cost, shall be credited to the Market Seller.

Synchronized Reserve and Day-ahead Scheduling Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding hour(s) in which the Synchronized Reserve and Day-ahead Scheduling Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each period the unit operates in condensing and generation mode for one or more contiguous hours.

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

AG equals the actual hourly integrated output of the unit;

URTLMP equals the real time LMP at the unit's bus;

UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UB shall not be negative.

(f-1) A Market Seller's combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section

1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described above for a steam unit or combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG, or (ii) {(URTLMP – UB) x DAG where:

URTLMP equals the real time LMP at the unit's bus;

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit, determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(f-2) A Market Seller's hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2A(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d) such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (i) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day, except as noted below and in the PJM Manuals; (ii) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (iii) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day; and (iv) deviations of energy sales from the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12.

Deviations that occur within a single Zone shall be associated with the Eastern or Western Regions, as defined in Section 3.2.3(q) of this Schedule, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at interfaces and hubs shall be associated with the Eastern or Western Region if all the busses that define all interfaces or all hubs are located in the region. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by busses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed

Operating Reserve charges in the event of an Operating Reserve shortage in real-time or where PJM initiates the request for load reductions in real-time in order to avoid an Operating Reserve shortage as described in this Schedule, Section 6A, Scarcity Pricing.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in Section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for each Control Zone of the PJM Region based on the Control Zone to which the resource was synchronized to provide synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such Control Zone pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared ("Maximum Generation Emergency Alert"); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Operating Reserves credit otherwise provided by Section 3.2.3.(b) or Section 3.2.3(e) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as "MaxGen Conditions"). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Schedule 2 of the

Operating Agreement, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any hours required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described in the PJM Manuals. Ramp-limited desired MW values shall be used to determine generation resource real-time deviations from the resource's day-ahead schedules.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

(i) real-time economic minimum <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

$$\text{Ramp\_Request}_t = (\text{UDStarget}_{t-1} - \text{AOutput}_{t-1}) / (\text{UDSLAtime}_{t-1})$$

$$\text{RL\_Desired}_t = \text{AOutput}_{t-1} + \left(\text{Ramp\_Request}_t * \text{Case\_Eff\_time}_{t-1}\right)$$

where:

1. UDStarget = UDS basepoint for the previous UDS case
2. AOutput = Unit's output at case solution time
3. UDSLAtime = UDS look ahead time
4. Case_Eff_time = Time between base point changes
5. RL_Desired = Ramp-limited desired MW

To determine if a resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the UDS Basepoint or the actual output and ramp-limited desired MW value. The % off dispatch and MW off dispatch will be a time-weighted average over the course of an hour.

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and UDS Basepoint, or if its % off dispatch is <= 10, or it's hourly integrated Real-time MWh is within 5% or 5 MW (whichever is greater) of the hourly integrated ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – Day-Ahead MWh.

- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – UDS LMP Desired MW.

- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – hourly integrated Ramp-Limited Desired MW.

- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the hour is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time Mwh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

- If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch, and the resource has tripped, for the hour the resource tripped and the hours it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – Day-Ahead MWh.

- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time MWh and Day-Ahead MWh.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, DEOK transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(iii) Reliability and deviation regional balancing Operating Reserve rates shall be determined by summing the relevant RTO balancing Operating Reserve rates and regional adder rates.

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

3.2.3A Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Synchronized Reserve Zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Synchronized Reserve Zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). An Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts if any, described in subsections (g), (h) and (i) of this section.

(b) A Generating Market Buyer supplying Synchronized Reserve at the direction of the Office of the Interconnection, in excess of its hourly Synchronized Reserve Obligation, shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation units that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price.

ii) Credits for Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions ("Tier 2 Synchronized Reserve") shall be the higher of (i) the Synchronized Reserve Market Clearing Price or (ii) the sum of (A) the Synchronized Reserve offer, and (B) the specific opportunity cost of the generation resource supplying the increment of Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

iii) Credits for Synchronized Reserve provided by Demand Resources that are synchronized to the grid and accept the obligation to reduce load in response to a synchronized Reserve Event initiated by the Office of the Interconnection shall be the sum of (i) the higher of (A) the Synchronized Reserve offer or (B) the synchronized Reserve Market Clearing Price and (ii) if a Synchronized Reserve Event is actually initiated by the Office of the Interconnection and the Demand Resource reduced its load in response to the event, the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

(c) The Synchronized Reserve Energy Premium Price is the average of the five-minute Locational Marginal Prices calculated during the Synchronized Reserve Event plus an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Synchronized Reserve Zone by the Office of the Interconnection prior to the operating hour and such market-clearing price shall be equal to, from among the generation resources or Demand Resources selected to provide Synchronized Reserve for such Synchronized Reserve Zone, the highest sum of either (i) a generation resource's Synchronized Reserve offer and opportunity cost or (ii) a demand response resource's Synchronized Reserve offer.

(e) In determining the Synchronized Reserve Market Clearing Price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the expected Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market. The opportunity costs for a Demand Resource shall be zero.

(g) Charges for Tier 1 Synchronized Reserve will be allocated in proportion to the amount of Tier 1 Synchronized Reserve applied to each Synchronized Reserve Obligation. In the event Tier 1 Synchronized Reserve is provided by a Market Seller in excess of that Market Seller's Synchronized Reserve Obligation, the remainder of the Tier 1 Synchronized Reserve that is not utilized to fulfill the Seller's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

(h) Any amounts credited for Tier 2 Synchronized Reserve in an hour in excess of the Synchronized Reserve Market Clearing Price in that hour shall be allocated and charged to each

Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation in proportion to its purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) In the event the Office of the Interconnection needs to assign more Tier 2 Synchronized Reserve during an hour than was estimated as needed at the time the Synchronized Reserve Market Clearing Price was calculated for that hour due to a reduction in available Tier 1 Synchronized Reserve, the costs of the excess Tier 2 Synchronized Reserve shall be allocated and charged to those providers of Tier 1 Synchronized Reserve whose available Tier 1 Synchronized Reserve was reduced from the needed amount estimated during the Synchronized Reserve Market Clearing Price calculation, in proportion to the amount of the reduction in Tier 1 Synchronized Reserve availability.

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled by the owner to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Synchronized Reserve in response to an actual Synchronized Reserve Event, the owner of the resource shall incur an additional Synchronized Reserve Obligation in the amount of the shortfall for a period of three consecutive days with the same peak classification (on-peak or off-peak) as the day of the Synchronized Reserve Event at least three business days following the Synchronized Reserve Event. The overall Synchronized Reserve requirement for each Synchronized Reserve Zone of the PJM Region on which the Synchronized Reserve Obligations, except for the additional obligations set forth in this section, are based shall be reduced by the amount of this shortfall for the applicable three-day period.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l) is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Demand Resource's consumption at the end of the Synchronized Reserve Event and (ii) the

Batch Load Demand Resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJMSettlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

(b) A Day-ahead Scheduling Reserves Resource that receives a Day-ahead Scheduling Reserves schedule pursuant to subsection (a) of this section shall be paid the hourly Day-ahead Scheduling Reserves Market clearing price for the MW obligation in each hour of the schedule, subject to meeting the requirements of subsection (c) of this section.

(c) To be eligible for payment pursuant to subsection (b) of this section, Day-ahead Scheduling Reserves Resources shall comply with the following provisions:

(i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.

(ii) Generation resources and Demand Resources with start times or shut-down times, respectively, equal to or less than 30 minutes are required to respond to dispatch directives from the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule. To meet this requirement the resource shall be required to start or shut down within the specified notification time plus its start or shut down time, provided that such time shall be less than thirty minutes.

(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

Resources that do not comply with the provisions of this subsection (c) shall not be eligible to receive credits pursuant to subsection (b) of this section.

(d) The cost of credits allocated to Day-ahead Scheduling Reserves Resources pursuant to this section shall be charged to Load-Serving Entities in the PJM Region based on load ratio share (net of operating Behind The Meter Generation, but not to be less than zero), provided that a Load-Serving Entity may satisfy its Day-ahead Scheduling Reserves obligation, which is equal to the Day-ahead Scheduling Reserves Requirement multiplied by the Load-Serving Entity's load ratio share for the PJM Region, through one or any combination of the following: 1) the Day-ahead Scheduling Reserves Market; 2) and bilateral arrangements. The Day-ahead Scheduling Reserve charges allocated pursuant to this section shall reflect any portion of a Load-Serving Entity's Day-ahead Scheduling Reserves obligation that is met by bilateral arrangement(s).

(e) If the Day-ahead Scheduling Reserves Requirement is not satisfied through the operation of subsection (a) of this section, any additional Operating Reserves required to meet the requirement shall be scheduled by the Office of the Interconnection pursuant to Section 3.2.3 of Schedule 1 of this Agreement.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit hourly in an amount equal to {(LMPDMW - AG) x (URTLMP - UB)}

where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

AG equals the actual hourly integrated output of the unit;

URTLMP equals the real time LMP at the unit's bus;

UB equals the unit offer for that unit for which output is reduced or suspended determined according to the real time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UB shall not be negative.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG, or (ii) {(URTLMP – UB) x DAG where:

URTLMP equals the real time LMP at the unit's bus;

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to Section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual hourly integrated output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

UB equals the unit offer for that unit for which output is increased, determined according to the real time scheduled offer curve on which the unit was operating;

URTLMP equals the real time LMP at the unit's bus; and

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2A(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generating unit's bus, (C) the generating unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to paragraph (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to section (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

Each Market Buyer shall be assessed Transmission Congestion Charges as specified in Section 5 of this Schedule.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Section 5 of this Schedule.

3.2.6 Emergency Energy.

(a) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each hour of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(b) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each hour of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(c) The net costs or net revenues associated with sales or purchases of hourly energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each hour of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Buyer in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Buyer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Buyer's internal accounting.

(b) If deliveries to a Market Buyer that has PJM Interchange meters in accordance with Section 14 of the Operating Agreement include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Buyer, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market Buyer and the unmetered Market Participant specified by them to the Office of the Interconnection.

7.4 Allocation of Auction Revenues.

7.4.1 Eligibility.

(a) Annual auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated among holders of Auction Revenue Rights in proportion to, but not more than, the Target Allocation of Auction Revenue Rights Credits for the holder.

(b) Auction Revenue Rights Credits will be calculated based upon the clearing price results of the applicable Annual Financial Transmission Rights auction.

(c) Monthly and Balance of Planning Period FTR auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated according to the following priority schedule:

(i) To stage 1 and 2 Auction Revenue Rights holders in accordance with section 7.4.4 of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(ii) of this section;

(ii) To the Residual Auction Revenue Rights holders in proportion to, but not more than their Target Allocation as determined pursuant to section 7.4.3(b) of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(iii) of this section;

(iii) To FTR Holders in accordance with section 5.2.6 of Schedule 1 of this Agreement.

(d) Long-term FTR auction revenues associated with FTRs that cover individual Planning Periods shall be distributed in the Planning Period for which the FTR is effective. Long-term FTR auction revenues associated with FTRs that cover multiple Planning Years shall be distributed equally across each Planning Period in the effective term of the FTR. Long-term FTR auction revenue distributions within a Planning Period shall be in accordance with the following provisions:

(i) Long-term FTR Auction revenues shall be distributed to Auction Revenue Rights holders in the effective Planning Period for the FTR. The distribution shall be in proportion to the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately. The distribution shall not exceed, when added to the distribution of revenues from the prompt-year annual FTR auction itself, the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately.

(ii) Long-term FTR auction revenues remaining after distributions made pursuant to Section 7.4.1(d)(ii) of Schedule 1 of this Agreement shall be distributed pursuant to Section 5.2.6 of Schedule 1 of this Agreement.

7.4.2 Auction Revenue Rights.

(a) Prior to the end of each PJM Planning Period an annual allocation of Auction Revenue Rights for the next PJM Planning Period shall be performed using a two stage allocation process. Stage 1 shall consist of stages 1A and 1B, which shall allocate ten year and annual Auction Revenue Rights, respectively, and stage 2 shall allocate annual Auction Revenue Rights. The Auction Revenue Rights allocation process shall be performed in accordance with Sections 7.4 and 7.5 hereof and the PJM Manuals.

With respect to the allocation of Auction Revenue Rights, if the Office of the Interconnection discovers an error in the allocation, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the business day following the initial publication of allocation results. After this initial notification, if the Office of the Interconnection determines that it is necessary to post modified allocation results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the second business day following the publication of the initial allocation. Thereafter, the Office of the Interconnection must post any corrected allocation results by no later than 5:00 p.m. of the fourth calendar day following the initial publication. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced allocation is under publicly noticed review by the FERC.

(b) In stage 1A of the allocation process, each Network Service User may request Auction Revenue Rights for a term covering ten consecutive PJM Planning Periods beginning with the immediately ensuing PJM Planning Period from a subset of the historical generation resources that were designated to be delivered to load based on the historical reference year for the Zone, and each Qualifying Transmission Customer (as defined in subsection (f) of this section) may request Auction Revenue Rights based on the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. The historical reference year for all Zones shall be 1998, except that the historical reference year shall be: 2002 for the Allegheny Power and Rockland Electric Zones; 2004 for the AEP East, The Dayton Power & Light Company and Commonwealth Edison Company Zones; 2005 for the Virginia Electric and Power Company and Duquesne Light Company Zones; 2011 for the ATSI Zone; 2012 for the DEOK Zone; and the Office of the Interconnection shall specify a historical reference year for a new PJM zone corresponding to the year that the zone is integrated into the PJM Interchange Energy Market. For stage 1, the Office of the Interconnection shall determine a set of eligible historical generation resources for each Zone based on the historical reference year and assign a pro rata amount of megawatt capability from each historical generation resource to each Network Service User in the Zone based on its proportion of peak load in the Zone. Auction Revenue Rights shall be allocated to each Network Service User in a Zone from each historical generation resource in a number of megawatts equal to or less than the amount of the historical generation resource that has been assigned to the Network Service User. Each Auction Revenue Right allocated to a Network Service User shall be to the aggregate load buses of such Network Service User in a Zone or, with respect to Non-Zone Network Load, to the border of the PJM Region. In stage 1A of the allocation process, the sum of each Network Service User's allocated Auction Revenue Rights for a Zone must be equal to or less than the Network Service User's pro-rata share of the Zonal Base Load for that Zone.

Each Network Service User's pro-rata share of the Zonal Base Load shall be based on its proportion of peak load in the Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than fifty percent (50%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined under Section 34.1 of the Tariff. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than fifty percent (50%) of the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. If stage 1A Auction Revenue Rights are adversely affected by any new or revised statute, regulation or rule issued by an entity with jurisdiction over the Office of the Interconnection, the Office of the Interconnection shall, to the greatest extent practicable, and consistent with any such statute, regulation or rule change, preserve the priority of the stage 1A Auction Revenue Rights for a minimum period covering the ten (10) consecutive PJM Planning Periods ("Stage 1A Transition Period") immediately following the implementation of any such changes, provided that the terms of all stage 1A Auction Revenue Rights in effect at the time the Office of the Interconnection implements the Stage 1A Transition Period shall be reduced by one PJM Planning Period during each annual stage 1A Auction Revenue Rights allocation performed during the Stage 1A Transition Period so that all stage 1A Auction Revenue Rights that were effective at the start of the Stage 1A Transition Period expire at the end of that period.

(c) In stage 1B of the allocation process each Network Service User may request Auction Revenue Rights from the subset of the historical generation resources determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process, and each Qualifying Transmission Customer may request Auction Revenue Rights based on the megawatts of firm service determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process. In stage 1B of the allocation process, the sum of each Network Service User's allocated Auction Revenue Rights request for a Zone must be equal to or less than the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 34.1 of the Tariff and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than the difference between one hundred percent (100%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than the difference between one hundred percent (100%) of the megawatts of firm service as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone.

(d) In stage 2 of the allocation process, the Office of the Interconnection shall conduct an iterative allocation process that consists of three rounds with up to one third of the remaining system Auction Revenue Rights capability allocated in each round. Each round of this allocation process will be conducted sequentially with Network Service Users and Transmission Customers being given the opportunity to view results of each allocation round prior to submission of Auction Revenue Right requests into the subsequent round. In each round, each Network Service User shall designate a subset of buses from which Auction Revenue Rights will be sourced. Valid Auction Revenue Rights source buses include only Zones, generators, hubs and external Interface Pricing Points. The Network Service User shall specify the amount of Auction Revenue Rights requested from each source bus. Each Auction Revenue Right shall be sinked to the aggregate load buses of the Network Service User in a Zone or, with respect to Non-Zone Network Load, to the border of the PJM Region. The sum of each Network Service User's Auction Revenue Rights requests in each stage 2 allocation round for each Zone must be equal to or less than one third of the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Right Allocation from stages 1A and 1B of the allocation process for that Zone. The stage 2 allocation to Transmission Customers shall be as set forth in subsection (f)

(e) On a daily basis within the annual Financial Transmission Rights auction period, a proportionate share of Network Service User's Auction Revenue Rights for each Zone are reallocated as Network Load changes from one Network Service User to another within that Zone.

(f) A Qualifying Transmission Customer shall be any customer with an agreement for Long-Term Point-to-Point Transmission Service, as defined in the PJM Tariff, used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located either outside or within the PJM Region, and that was confirmed and in effect during the historical reference year for the Zone in which the resource is located. Such an agreement shall allow the Qualifying Transmission Customer to participate in the first stage of the allocation, but only if such agreement has remained in effect continuously following the historical reference year and is to continue in effect for the period addressed by the allocation, either by its term or by renewal or rollover. The megawatts of Auction Revenue Rights the Qualifying Transmission Customer may request in the first stage of the allocation may not exceed the lesser of: (i) the megawatts of firm service between the designated Network Resource and the load delivery point (or applicable point at the border of the PJM Region for load located outside such region) under contract during the historical reference year; and (ii) the megawatts of firm service presently under contract between such historical reference year receipt and delivery points.

A Qualifying Transmission Customer may request Auction Revenue Rights in either or both of the stage 1 or 2 of the allocation without regard to whether such customer is subject to a charge for Firm Point-to-Point Transmission Service under Section 1 of Schedule 7 of the PJM Tariff ("Base Transmission Charge"). A Transmission Customer that is not a Qualifying Transmission Customer may request Auction Revenue Rights in stage2 of the allocation process, but only if it is subject to a Base Transmission Charge. The Auction Revenue Rights that such a Transmission

Customer may request in each round of stage 2 of the allocation process must be equal to or less than one third of the number of megawatts equal to the megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has Firm Point-to-Point Transmission Service. The source point of the Auction Revenue Rights must be the designated source point that is specified in the Transmission Service Request and the sink point of the Auction Revenue Rights must be the designated sink point that is specified in the Transmission Service Request. A Qualifying Transmission Customer may request Auction Revenue Rights in each round of stage 2 of the allocation process in a number of megawatts equal to or less than one third of the difference between the number of megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has Firm Point-to-Point Transmission Service and its Auction Revenue Right Allocation from stage 1 of the allocation process.

(g) PJM Transmission Customers that serve load in the Midwest ISO may participate in stage 1 of the allocation to the extent permitted by, and in accordance with, this Section 7.4.2 and other applicable provisions of this Schedule 1. For service from non-historic sources, these customers may participate in stage 2, but in no event can they receive an allocation of ARRs/FTRs from PJM greater than their firm service to loads in MISO.

(h) Subject to subsection (i) of this section, all Auction Revenue Rights must be simultaneously feasible. If all Auction Revenue Right requests made during the annual allocation process are not feasible then Auction Revenue Rights are prorated and allocated in proportion to the megawatt level requested and in inverse proportion to the effect on the binding constraints.

(i) If any Auction Revenue Right requests made during stage 1A of the annual allocation process are not feasible, then PJM shall increase the capability limits of the binding constraints that would have rendered the Auction Revenue Rights infeasible to the extent necessary in order to allocate such Auction Revenue Rights without their being infeasible, and such increased limits shall be included in all modeling used for subsequent Auction Revenue Rights and Financial Transmission Rights allocations and auctions for the Planning Year; provided that, the foregoing notwithstanding, this subsection (i) shall not apply if the infeasibility is caused by extraordinary circumstances. For the purposes of this subsection, extraordinary circumstances shall mean an event of force majeure that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Auction Revenue Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates stage 1A Auction Revenue Rights as a result of this subsection (i) that would not otherwise have been feasible, then PJM shall notify Members and post on its web site (a) the aggregate megawatt quantities, by sources and sinks, of such Auction Revenue Rights and (b) any increases in capability limits used to allocate such Auction Revenue Rights.

(j) Long-Term Firm Point-to-Point Transmission Service customers that are not Qualifying Transmission Customers and Network Service Users serving Non-Zone Network

Load may participate in stage 1 of the annual allocation of Auction Revenue Rights pursuant to Section 7.4.2(a)-(c) of Schedule 1 of this Agreement, subject to the following conditions:

i. The relevant Transmission Service shall be used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located outside the PJM Region.

ii. To be eligible to participate in stage 1A of the annual Auction Revenue Rights allocation: 1) the relevant Transmission Service shall remain in effect for the stage 1A period addressed by the allocation; and 2) the control area in which the external load is located has similar rules for load external to the relevant control area.

iii. Source points for stage 1 requests authorized pursuant to this subsection 7.4.2(j) shall be limited to: 1) generation resources owned by the LSE serving the load located outside the PJM Region; or 2) generation resources subject to a bona fide firm energy and capacity supply contract executed by the LSE to meet its load obligations, provided that such contract remains in force and effect for a minimum term of ten (10) years from the first effective Planning Period that follows the initial stage 1 request.

iv. For Long-Term Firm Point-to-Point Transmission customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j), the generation resource(s) designated as source points may include any portion of the generating capacity of such resource(s) that is not, at the time of the request, already identified as a Capacity Resource.

v. For Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j), at the time of the request, the generation resource(s) designated as source points must either be committed into PJM's RPM market or be designated as part of the entity's FRR Capacity Plan for the purpose of serving the capacity requirement of the external load.

vi. All stage 1 source point requests made pursuant to this subsection 7.4.2(j) shall not increase the megawatt flow on facilities binding in the relevant annual Auction Revenue Rights allocation or in future stage 1A allocations and shall not cause megawatt flow to exceed applicable ratings on any other facilities in either set of conditions in the simultaneous feasibility test prescribed in subsection (vii) of this subsection 7.4.2(j).

vii. To ensure the conditions of subsection (vi) of this subsection 7.4.2(j) are met, a simultaneous feasibility test shall be conducted: 1) based on next allocation year with all existing stage 1 and stage 2 Auction Revenue Rights modeled as fixed injection-withdrawal pairs; and 2) based on 10 year allocation model with all eligible stage 1A Auction Revenue Rights for each year including base load growth for each year.

viii. Requests for stage 1 Auction Revenue Rights made pursuant to this subsection 7.4.2(j) that are received by PJM by November 1st of a Planning Period shall be processed for the next annual Auction Revenue Rights allocation. Requests received after November 1st shall not be considered for the upcoming annual Auction Revenue Rights allocation. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.

ix. Requests for new or alternate stage 1 resources made by Network Service Users and external LSEs that are received by November 1st shall be evaluated at the same time. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.

x. Stage 1 Auction Revenue Rights source points that qualify pursuant to this subsection 7.4.2(j) shall be eligible as stage 1 Auction Revenue Rights source points in subsequent annual Auction Revenue Rights allocations.

xi. Long-Term Firm Point-to-Point Transmission customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer's Long-Term Firm Point-to-Point Transmission service contract megawatt amount; or 2) the customer's Firm Transmission Withdrawal Rights.

xii. Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer's network service peak load; or 2) the customer's Firm Transmission Withdrawal Rights.

xiii. Stage 1A Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed 50% of the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j).

xiv. Stage 1B Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed the difference between the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatts granted in stage 1A.

xv. In each round of Stage 2 of an annual allocation of Auction Revenue Rights megawatt requests made pursuant to this subsection 7.4.2(j) shall be equal to or less than one third of the difference between the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatt amount allocated in stage 1.

xvi. Stage 1 Auction Revenue Rights sources established pursuant to this subsection 7.4.2(j) and the associated Auction Revenue Rights megawatt amount may be replaced with an alternate resource pursuant to the process established in Section 7.7 of Schedule 1 of this Agreement.

7.4.2a Bilateral Transfers of Auction Revenue Rights

(a) Market Participants may enter into bilateral agreements to transfer Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights to a third party.

Such bilateral transfers shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules related to its eFTR tools.

(b) For purposes of clarity, with respect to all bilateral transfers of Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights, the rights and obligations to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights that are the subject of such a bilateral transfer shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. In no event, shall the purchase and sale of an Auction Revenue Right or the right to receive an allocation of Auction Revenue Rights pursuant to a bilateral transfer constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

(c) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights. Such consent shall be based upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall not transfer to the third party and the holder of the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall continue to receive all rights attributable to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights and remain subject to all credit requirements and obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights.

(d) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the Auction Revenue Right and for which payment is not made to PJMSettlement by the buyer under such a bilateral transfer.

(e) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.

(f) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.

7.4.3 Target Allocation of Auction Revenue Right Credits.

(a) A Target Allocation of Auction Revenue Right Credits for each entity holding an Auction Revenue Right shall be determined for each Auction Revenue Right. After each round of the annual Financial Transmission Right auction, each Auction Revenue Right shall be divided by four and multiplied by the price differences for the receipt and delivery points associated with the Auction Revenue Right, calculated as the Locational Marginal Price at the delivery points(s) minus the Locational Marginal Price at the receipt point(s), where the price for the receipt and delivery point is determined by the clearing prices of each round of the annual Financial Transmission Right auction. The daily total Target Allocation for an entity holding the Auction Revenue Rights shall be the sum of the daily Target Allocations associated with all of the entity's Auction Revenue Rights.

(b) A Target Allocation of Residual Auction Revenue Rights Credits for each entity allocated Residual Auction Revenue Rights pursuant to section 7.9 of Schedule 1 of this Agreement shall be determined on a monthly basis for each month in a Planning Period beginning with the month the Residual Auction Revenue Right(s) becomes effective through the end of the relevant Planning Period. The Target Allocation for Residual Auction Revenue Rights Credits shall be equal to megawatt amount of the Residual Auction Revenue Rights multiplied by the LMP differential between the source and sink nodes of the corresponding FTR obligations in each prompt-month FTR auction that occurs from the effective date of the Residual Auction Revenue Rights through the end of the relevant Planning Period.

7.4.4 Calculation of Auction Revenue Right Credits.

(a) Each day, the total of all the daily Target Allocations determined as specified above in Section 7.4.3 plus any additional Auction Revenue Rights Target Allocations applicable for that day shall be compared to the total revenues of all applicable monthly Financial Transmission Rights auction(s) (divided by the number of days in the month) plus the total revenues of the annual Financial Transmission Rights auction (divided by the number of days in the Planning Period). If the total of the Target Allocations is less than the total auction revenues, the Auction Revenue Right Credit for each entity holding an Auction Revenue Right shall be equal to its Target Allocation. All remaining funds shall be distributed as Excess Congestion Charges pursuant to Section 5.2.5.

(b) If the total of the Target Allocations is greater than the total auction revenues, each holder of Auction Revenue Rights shall be assigned a share of the total auction revenues in proportion to its Auction Revenue Rights Target Allocations for Auction Revenue Rights which have a positive Target Allocation value. Auction Revenue Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Auction Revenue Right Credit.

(c) At the end of a Planning Period, if all Auction Revenue Right holders did not receive Auction Revenue Right Credits equal to their Target Allocations, PJMSettlement shall assess a charge equal to the difference between the Auction Revenue Right Credit Target Allocations for all revenue deficient Auction Revenue Rights and the actual Auction Revenue Right Credits allocated to those Auction Revenue Right holders. The aggregate charge for a Planning Period assessed pursuant to this section, if any, shall be added to the aggregate charge for a Planning Period assessed pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and collected pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and distributed to the Auction Revenue Right holders that did not receive Auction Revenue Right Credits equal to their Target Allocation.

ATTACHMENT L
<u>List of Transmission Owners</u>

Allegheny Electric Cooperative, Inc.
American Transmission Systems, Incorporated
Atlantic City Electric Company
Baltimore Gas and Electric Company
NAEA Rock Springs, LLC
Delmarva Power & Light Company
Duke Energy Ohio, Inc.
Duke Energy Kentucky, Inc.
Jersey Central Power & Light Company
Metropolitan Edison Company
Neptune Regional Transmission System, LLC
Old Dominion Electric Cooperative
Pennsylvania Electric Company
PECO Energy Company
Pennsylvania Power & Light Company
Potomac Electric Power Company
Public Service Electric and Gas Company
Rockland Electric Company
Trans-Allegheny Interstate Line Company
UGI Utilities, Inc.
Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power
Commonwealth Edison Company and Commonwealth Edison Company of Indiana, Inc.
The Dayton Power and Light Company
AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company)
Duquesne Light Company
Virginia Electric and Power Company
Linden VFT, LLC
City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power

5.10 Auction Clearing Requirements

The Office of the Interconnection shall clear each Base Residual Auction and Incremental Auction for a Delivery Year in accordance with the following:

a) Variable Resource Requirement Curve

The Office of the Interconnection shall determine Variable Resource Requirement Curves for the PJM Region and for such Locational Deliverability Areas as determined appropriate in accordance with subsection (a)(iii) for such Delivery Year to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. It is recognized that the variable resource requirement reflected in the Variable Resource Requirement Curve can result in an optimized auction clearing in which the level of Capacity Resources committed for a Delivery Year exceeds the PJM Region Reliability Requirement (less the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012, or less the Short-Term Resource Procurement Target for Delivery Years thereafter) or Locational Deliverability Area Reliability Requirement (less the Forecast Zonal ILR Obligation for Delivery Years through May 31, 2012, or less the Short-Term Resource Procurement Target for Delivery Years thereafter for the Zones associated with such LDA) for such Delivery Year. For any auction, the Updated Forecast Peak Load, and Short-Term Resource Procurement Target applicable to such auction, shall be used, *and Price Responsive Demand from any applicable approved PRD Plan, including any associated PRD Reservation Prices, shall be reflected in the derivation of the Variable Resource Requirement Curves, in accordance with the methodology specified in the PJM Manuals.*

i) Methodology to Establish the Variable Resource Requirement Curve

Prior to the Base Residual Auction, in accordance with the schedule in the PJM Manuals, the Office of the Interconnection shall establish the Variable Resource Requirement Curve for the PJM Region as follows:

- Each Variable Resource Requirement Curve shall be plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis;

- The Variable Resource Requirement Curve for the PJM Region shall be plotted by first combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), (iii) a straight line connecting points (2) and (3), and (iv) a vertical line from point (3) to the x-axis, where:

    - For point (1), price equals: [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin (“IRM”)% minus 3%) divided by (100%

plus IRM%)] minus the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter;

- For point (2), price equals: (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset) divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 1%) divided by (100% plus IRM%)] minus the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter; and

- For point (3), price equals [0.2 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 5%) divided by (100% plus IRM%)] minus the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter;

ii) For any Delivery Year, the Office of the Interconnection shall establish a separate Variable Resource Requirement Curve for each LDA for which:

A. the Capacity Emergency Transfer Limit is less than 1.15 times the Capacity Emergency Transfer Objective, as determined by the Office of the Interconnection in accordance with NERC and Applicable Regional Reliability Council guidelines; or

B. such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; or

C. such LDA is determined in a preliminary analysis by the Office of the Interconnection to be likely to have a Locational Price Adder, based on historic offer price levels; provided however that for the Base Residual Auction conducted for the Delivery Year commencing on June 1, 2012, the EMAAC, SWMAAC and MAAC LDAs shall employ separate Variable Resource Requirement Curves regardless of the outcome of the above three tests; and provided further that the Office of the Interconnection may establish a separate Variable Resource Requirement Curve for an LDA not otherwise qualifying under the above three tests if it finds that such is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards, in which case the Office of the Interconnection shall post such finding, such LDA, and such Variable Resource Requirement Curve on its internet site no later than the

March 31 last preceding the Base Residual Auction for such Delivery Year. The same process as set forth in subsection (a)(i) shall be used to establish the Variable Resource Requirement Curve for any such LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement and the LDA Short-Term Resource Procurement Target shall be substituted for the PJM Region Short-Term Resource Procurement Target. For purposes of calculating the Capacity Emergency Transfer Limit under this section, all generation resources located in the PJM Region that are, or that qualify to become, Capacity Resources, shall be modeled at their full capacity rating, regardless of the amount of capacity cleared from such resource for the immediately preceding Delivery Year.

iii) Procedure for ongoing review of Variable Resource Requirement Curve shape.

Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall perform a review of the shape of the Variable Resource Requirement Curve, as established by the requirements of the foregoing subsection. Such analysis shall be based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis. Based on the results of such review, PJM shall prepare a recommendation to either modify or retain the existing Variable Resource Requirement Curve shape. The Office of the Interconnection shall post the recommendation and shall review the recommendation through the stakeholder process to solicit stakeholder input. If a modification of the Variable Resource Requirement Curve shape is recommended, the following process shall be followed:

A) If the Office of the Interconnection determines that the Variable Resource Requirement Curve shape should be modified, Staff of the Office of the Interconnection shall propose a new Variable Resource Requirement Curve shape on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

B) The PJM Members shall review the proposed modification to the Variable Resource Requirement Curve shape.

C) The PJM Members shall either vote to endorse the proposed modification, to propose alternate modifications or to recommend no modification by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) The PJM Board of Managers shall consider a proposed modification to the Variable Resource Requirement Curve shape, and the Office of the Interconnection shall file any approved modified Variable Resource Requirement Curve shape with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

iv) Cost of New Entry

A) For the Delivery Year commencing on June 1, 2012, and continuing thereafter unless and until changed pursuant to subsection (B) below, the Cost of New Entry for the PJM Region shall be $112,868 per MW-year. The Cost of New Entry for each LDA shall be determined based upon the Transmission Owner zones that comprise such LDA, as provided in the table below. If an LDA combines transmission zones with differing Cost of New Entry values, the lowest such value shall be used.

Geographic Location Within the PJM Region Encompassing These Zones	**Cost of New Entry in $/MW-Year**
PS, JCP&L, AE, PECO, DPL, RECO (“CONE Area 1”)	122,040
BGE, PEPCO (“CONE Area 2”)	112,868
AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK (“CONE Area 3”)	115,479
PPL, MetEd, Penelec (“CONE Area 4”)	112,868
Dominion (“CONE Area 5”)	112,868

B) Beginning with the 2013-2014 Delivery Year, the CONE shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable H-W Index, in accordance with the following:

(1) The Applicable H-W Index for any Delivery Year shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in the Total Other Production Plant Index shown in the Handy-Whitman Index of Public Utility Construction Costs for the North Atlantic Region for purposes of CONE Areas 1, 2, and 4, for the North Central Region for purposes of CONE Area 3, and for the South Atlantic Region for purposes of CONE Area 5.

(2) The CONE in a CONE Area shall be adjusted prior to the Base Residual Auction for each Delivery Year by applying the Applicable H-W Index for such CONE Area to the Benchmark CONE for such CONE Area.

(3) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year.

(4) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vii)(C) or any filing to establish new or revised CONE Areas.

v) Net Energy and Ancillary Services Revenue Offset

A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (A) the annual average of the revenues that would have been received by the Reference Resource during a period of three consecutive calendar years preceding the time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) fuel prices reported during such period at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of $6.47 per MWh, and actual PJM hourly average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of $2,199 per MW-year.

B) The Office of the Interconnection also shall determine a Net Energy and Ancillary Market Revenue Offset each year for each sub-region of the PJM Region for which the Cost of New Entry is determined, as identified above, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the average hourly LMPs for the transmission zone in which such resource was assumed to be installed for purposes of the CONE estimate (as specified in the PJM Manuals) shall be used in place of the PJM Region average hourly LMPs; (2) if such sub-region was not integrated into the PJM Region for the entire applicable period, then the offset shall be calculated using only those whole calendar years during which the sub-region was integrated; and (3) a posted fuel pricing point in such sub-region, if available, and (if such pricing point is not available) a fuel transmission adder appropriate to each assumed Cost of New Entry location from an appropriate PJM Region pricing point shall be used for each such sub-region.

vi) Adjustment to Net Energy and Ancillary Services Revenue Offset

Beginning with the Base Residual Auction scheduled for May 2010, the Net Energy and Ancillary Services Revenue Offset for a CONE Area shall be adjusted following any Delivery Year during which Scarcity Pricing was effective in such CONE Area pursuant to the Scarcity Pricing provisions of section 6A of Schedule 1 to the PJM Operating Agreement. Following each Delivery Year, the Scarcity Pricing revenues the Reference Resource in each CONE Area would have received during such Delivery Year shall be calculated based on the assumed heat rate and other characteristics of the Reference Resource, assumed Peak-Hour Dispatch, and the actual locational marginal prices and actual fuel prices during the Delivery Year for the applicable location, which shall be the transmission zone in which such resource was assumed to be installed for purposes of the estimate of CONE applicable to such CONE Area. The Scarcity Pricing revenues so determined shall be subtracted from the Net CONE otherwise calculated for such CONE Area for use in the Base Residual Auction next occurring after the Delivery Year in which Scarcity Pricing was effective in such CONE Area.

vii) Process for Establishing Parameters of Variable Resource Requirement Curve

A) The parameters of the Variable Resource Requirement Curve will be established prior to the conduct of the Base Residual Auction for a Delivery Year and will be used for such Base Residual Auction.

B) The Office of the Interconnection shall determine the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement for each Locational Deliverability Area for which a Variable Resource Requirement Curve has been established for such Base Residual Auction on or before February 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values will be applied, in accordance with the Reliability Assurance Agreement.

C) Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall review the calculation of the Cost of New Entry for each CONE Area.

1) If the Office of the Interconnection determines that the Cost of New Entry values should be modified, the Staff of the Office of the Interconnection shall propose new Cost of New Entry values on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

2) The PJM Members shall review the proposed values.

3) The PJM Members shall either vote to endorse the proposed values or propose alternate values by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

4) The PJM Board of Managers shall consider Cost of New Entry values, and the Office of the Interconnection shall file any approved modified Cost of New Entry values with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall review the methodology set forth in this Attachment for determining the Net Energy and Ancillary Services Revenue Offset for the PJM Region and for each Zone.

1) If the Office of the Interconnection determines that the Net Energy and Ancillary Services Revenue Offset methodology should be modified, Staff of the Office of the Interconnection shall propose a new Net Energy and Ancillary Services Revenue Offset methodology on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

2) The PJM Members shall review the proposed methodology.

3) The PJM Members shall either vote to endorse the proposed methodology or propose an alternate methodology by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

4) The PJM Board of Managers shall consider the Net Revenue Offset methodology, and the Office of the Interconnection shall file any approved modified Net Energy and Ancillary Services Revenue Offset values with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

b) Locational Requirements

The Office of Interconnection shall establish locational requirements prior to the Base Residual Auction to quantify the amount of Unforced Capacity that must be committed in each Locational Deliverability Area, in accordance with the PJM Reliability Assurance Agreement.

c) Minimum Annual Resource Requirements

Prior to the Base Residual Auction and each Incremental Auction for each Delivery Year, beginning with the Delivery Year that starts on June 1, 2014, the Office of the Interconnection shall establish the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year.

d) Preliminary PJM Region Peak Load Forecast for the Delivery Year

The Office of the Interconnection shall establish the Preliminary PJM Region Load Forecast for the Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the Base Residual Auction for such Delivery Year.

e) Updated PJM Region Peak Load Forecasts for Incremental Auctions

The Office of the Interconnection shall establish the updated PJM Region Peak Load Forecast for a Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the First, Second, and Third Incremental Auction for such Delivery Year.

ATTACHMENT JJ
MTEP PROJECT COST RECOVERY FOR DEOK ZONE

I. Definitions

A. DEOK – Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc.

B. Midwest ISO or MISO – The Midwest Independent Transmission System Operator, Inc.

C. Midwest ISO Tariff – The Midwest ISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff.

D. Midwest ISO Transmission Owner – Any transmission owner in the Midwest ISO, including any independent transmission company, responsible for the construction of MTEP Projects under Attachment FF of the Midwest ISO Tariff.

E. MTEP – The Midwest ISO Transmission Expansion Plan established pursuant to Attachment FF of the Midwest ISO Tariff.

F. MTEP Project – A transmission project constructed by DEOK or by Midwest ISO Transmission Owners pursuant to Attachment FF of the Midwest ISO Tariff for which all or a portion of the revenue requirement is allocated to DEOK pursuant to the Midwest ISO Tariff.

G. Network Service Peak Load – A Network Service Transmission Customer's share of the previous year's DEOK zonal peak load (1 CP).

II. Introduction and Purpose

Transmission Customers taking transmission service for deliveries in the DEOK Zone shall pay a portion of the cost of MTEP Projects constructed by Midwest ISO Transmission Owners. This Attachment JJ sets forth the method by which Transmission Customers taking transmission service for deliveries into the DEOK Zone are charged for the cost of MTEP Projects constructed by Midwest ISO Transmission Owners. This Attachment also sets forth the method by which the PJM Office of the Interconnection will transmit to the Midwest ISO the revenues received from Transmission Customers taking transmission service for deliveries into the DEOK Zone for the cost of MTEP Projects to be constructed by Midwest ISO Transmission Owners. Finally, it addresses the manner in which the PJM Office of the Interconnection will distribute to Duke Energy Ohio, Inc. on behalf of DEOK the revenues received from the Midwest ISO for the cost of MTEP Projects constructed by DEOK.

III. MTEP Project Revenue Requirements Allocated to DEOK Zone

A. Recovery of Annual Revenue Requirements for Midwest ISO Transmission Owners' MTEP Projects

Each month, and pursuant to agreed-upon settlement procedures, PJM shall bill each Network Customer in the DEOK Zone its monthly share of the revenue requirements allocated to DEOK for MTEP Projects constructed by the Midwest ISO Transmission Owners, determined in accordance with the Midwest ISO Tariff and as billed by the Midwest ISO to PJM ("Network Customer's MTEP Project Charge"). A Network Customer's share of such revenue requirements shall be based on its Network Service Peak Load in the DEOK Zone.

B. Revenue Distribution from Payments Made by Transmission Customers in DEOK Zone; Shortfall in Payment

Each month, and pursuant to agreed-upon settlement procedures, the PJM Office of the Interconnection shall remit to the Midwest ISO the revenue requirements allocated to DEOK for MTEP Projects constructed by the Midwest ISO Transmission Owners, as set forth in Section III.A. In addition, in the event that the revenues received by PJM from a Network Customer pursuant to Section III.A. are less than the Network Customer's MTEP Project Share ("Shortfall"), and PJM makes up such Shortfall in its remittance to the Midwest ISO, (a) PJM shall apply such Shortfall to the financial settlement of Duke Energy Ohio, Inc.'s account (on behalf of DEOK), and (b) such Network Customer shall thereafter be obligated to remit such Shortfall directly to DEOK instead of to PJM, together with any Late Payment Charges that would otherwise be due to PJMSettlement under Section 7.1A of this Tariff. DEOK shall have all rights to seek recovery of such Shortfall directly from the Network Customer, and such rights shall be enforceable by DEOK at FERC and in any court of competent jurisdiction. DEOK shall be a third party beneficiary under the Network Customer's service agreement with PJM for the limited purpose of seeking recovery of such Shortfall.

IV. DEOK MTEP Project Revenue Requirements Allocated to Midwest ISO Zones

A. Derivation of Annual Revenue Requirements

Under the methodology provided under Attachment H–22 to this Tariff, DEOK will periodically update the Annual Revenue Requirements for MTEP Projects constructed by DEOK. No later than May 1 each year, DEOK shall provide these updated revenue requirements to the Midwest ISO for the upcoming June 1 – May 31 rate year.

B. Allocation of Annual Revenue Requirements to Midwest ISO Zones

The portion of the Annual Revenue Requirements derived under Section IV.A that will be recovered from transmission customers taking transmission service in the Midwest ISO shall be calculated by the Midwest ISO in accordance with the Midwest ISO Tariff.

C. Monthly Revenue Requirements Owed from the Midwest ISO Zones

Each month, and pursuant to agreed-upon settlement procedures, the Midwest ISO shall remit an amount to the PJM Office of the Interconnection from revenues collected by the

Midwest ISO in proportion to DEOK's annual pro-rata share of the total Network Upgrade Charge as described in the Midwest ISO Schedule 38.

D. Revenue Distribution from Payments Made by Transmission Customers in the Midwest ISO

Pursuant to agreed-upon settlement procedures, PJM shall credit to Duke Energy Ohio's account (on behalf of DEOK) in the subsequent month the amount of revenue requirements that the Midwest ISO remits to PJM pursuant to Section IV.C for the prior month.

PJM Operating Agreement
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3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Section 2 of this Schedule.

(b) Market Buyers shall be charged for all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(d) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the total amount of net hourly PJM Interchange for each Market Buyer, including Generating Market Buyers, in accordance with the PJM Manuals. For Internal Market Buyers that are Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall include determination of the net energy flows from: (i) tie lines; (ii) any generation resource the output of which is controlled by the Market Buyer but delivered to it over another entity's Transmission Facilities; (iii) any generation resource the output of which is controlled by another entity but which is directly interconnected with the Market Buyer's transmission system; (iv) deliveries pursuant to bilateral energy sales; (v) receipts pursuant to bilateral energy purchases; and (vi) an adjustment to account for the day-ahead PJM Interchange, calculated as the difference between scheduled withdrawals and injections by that Market Buyer in the Day-ahead Energy Market. For External Market Buyers and Internal Market Buyers that are not Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall determine the energy scheduled hourly for delivery to the Market Buyer net of the amounts scheduled by the External Market Buyer in the Day-ahead Energy Market.

(e) An Internal Market Buyer shall be charged for Spot Market Energy purchases to the extent of its hourly net purchases from the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. An External Market Buyer shall be charged for its Spot Market Energy purchases based on the energy delivered to it, determined as specified in Section 3.2.1(d) above. The total charge shall be determined by the product of the hourly net amount of PJM Interchange Imports times the hourly Real-time System Energy Price for that Market Buyer.

(f) A Generating Market Buyer shall be paid as a Market Seller for sales of Spot Market Energy to the extent of its hourly net sales into the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. The total payment shall be determined by the product of the hourly net amount of PJM Interchange Exports times the hourly Real-time System Energy Price for that Market Seller.

3.2.2 Regulation.

(a) Each Internal Market Buyer that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). An Internal Market Buyer that does not meet its hourly Regulation obligation shall be charged for Regulation dispatched by the Office of the Interconnection to meet such obligation at the Regulation market-clearing price determined in accordance with subsection (c) of this Section, plus the amounts, if any, described in subsection (f) of this section.

(b) A Generating Market Buyer supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection in excess of its hourly Regulation obligation shall be credited for each increment of such Regulation at the higher of (i) the Regulation market-clearing price in such Regulation Zone or (ii) the sum of the regulation offer and the unit-specific opportunity cost of the generation resource supplying the increment of Regulation, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day. The market-clearing price for each regulating hour shall be equal to the highest sum of a resource's Regulation offer plus its estimated unit-specific opportunity costs, determined as described in subsection (d) below from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.3.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation market-clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour shall be equal to the sum of the unit-specific opportunity costs (i) incurred during the hour in which the obligation is fulfilled, plus costs (ii) associated with uneconomic operation during the hour preceding the initial regulating hour ("preceding shoulder hour"), plus costs (iii) associated with uneconomic operation during the hour after the final regulating hour ("following shoulder hour").

The unit-specific opportunity costs incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market.

Estimated opportunity costs for Demand Resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's Regulation signals from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Internal Market Buyer in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to section 1.10.1A(e) of this Schedule. A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region for which the cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Section 3.2.A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unfor*e*seen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

(c) The sum of the foregoing credits calculated in accordance with Section 3.2.3(b) plus any unallocated charges from Section 3.2.3(h) and 5.1.7, and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection and that is not committed solely for the purpose of providing Synchronized Reserve: For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following segments: 1) the greater of their day-ahead schedules or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

Credits received pursuant to this section shall be equal to the positive difference between a resource's total offered price for start-up (shutdown costs for Demand Resources) and no-load fees and energy, determined on the basis of the resource's scheduled output, and the total value of the resource's energy as determined by the Real-time Energy Market and the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

Except as provided in Section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to Section 3.2.3(b) plus the resource's opportunity cost and less any amounts credited for Synchronized Reserve in excess of the Synchronized Reserve offer plus the resource's opportunity cost and less any amounts credited for providing Reactive Services as specified in Section 3.2.3B, and less any amounts for Day-ahead Scheduling Reserve in excess of the Day-ahead Scheduling Reserve offer plus the resource's opportunity cost, shall be credited to the Market Seller.

Synchronized Reserve and Day-ahead Scheduling Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding hour(s) in which the Synchronized Reserve and Day-ahead Scheduling Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each period the unit operates in condensing and generation mode for one or more contiguous hours.

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

AG equals the actual hourly integrated output of the unit;

URTLMP equals the real time LMP at the unit's bus;

UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UB shall not be negative.

(f-1) A Market Seller's combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described above for a steam unit or combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG}, or (ii) {(URTLMP – UB) x DAG} where:

URTLMP equals the real time LMP at the unit's bus;

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit, determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(f-2) A Market Seller's hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2A(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (i) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day; (ii) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (iii) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day, except as noted below and in the PJM Manuals; and (iv) deviations of energy sales from the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such region pursuant to Section 1.12.

Deviations that occur within a single Zone shall be associated with the Eastern or Western Region, as defined in Section 3.2.3(q) of this Schedule, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at interfaces and hubs shall be associated with the Eastern or Western Region if all the busses that define all interfaces or all hubs are located in the region. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by busses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of an Operating Reserve shortage in real-time or where PJM initiates the request for load reductions in real-time in order to avoid an Operating Reserve shortage as described in this Schedule, Section 6A, Scarcity Pricing.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in Section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for each Control Zone of the PJM Region based on the Control Zone to which the resource was synchronized to provide synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such Control Zone pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared ("Maximum Generation Emergency Alert"); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Operating Reserves credit otherwise provided by Section 3.2.3.(b) or Section 3.2.3(e) in connection with marked-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as "MaxGen Conditions"). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Schedule 2 of the Operating Agreement, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any hours required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer

Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described in the PJM Manuals. Ramp-limited desired MW values shall be used to determine generation resource real-time deviations from the resource's day-ahead schedules.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

(i) real-time economic minimum <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

$$\mathbf{Ramp\_Request}_t = \left(\mathbf{UDStarget}_{t-1} - \mathbf{AOutput}_{t-1}\right) \Big/ \left(\mathbf{UDSLAtime}_{t-1}\right)$$

$$\mathbf{RL\_Desired}_t = \mathbf{AOutput}_{t-1} + \left(\mathbf{Ramp\_Request}_t * \mathbf{Case\_Eff\_time}_{t-1}\right)$$

where:

1. UDStarget = UDS basepoint for the previous UDS case

2. AOutput = Unit's output at case solution time
3. UDSLAtime = UDS look ahead time
4. Case_Eff_time = Time between base point changes
5. RL_Desired = Ramp-limited desired MW

To determine if a resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the UDS Basepoint or the actual output and ramp-limited desired MW value. The % off dispatch and MW off dispatch will be a time-weighted average over the course of an hour.

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and UDS Basepoint, or if its % off dispatch is <= 10, or it's hourly integrated Real-time MWh is within 5% or 5 MW (whichever is greater) of the hourly integrated ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – Day-Ahead MWh.

- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – UDS LMP Desired MW.

- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – hourly integrated Ramp-Limited Desired MW.

- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the hour is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time Mwh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

- If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch, and the resource has tripped, for the hour the resource tripped and the hours it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – Day-Ahead MWh.

- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time MWh and Day-Ahead MWh.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, DEOK transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(iii) Reliability and deviation regional balancing Operating Reserve rates shall be determined by summing the relevant RTO balancing Operating Reserve rates and regional adder rates.

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

3.2.3A Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Synchronized Reserve Zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Synchronized Reserve Zone, for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). An Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts if any, described in subsections (g), (h) and (i) of this section.

(b) A Generating Market Buyer supplying Synchronized Reserve at the direction of the Office of the Interconnection, in excess of its hourly Synchronized Reserve Obligation, shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation units that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price.

ii) Credits for Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions ("Tier 2 Synchronized Reserve") shall be the higher of (i) the Synchronized Reserve Market Clearing Price or (ii) the sum of (A) the Synchronized Reserve offer, and (B) the specific opportunity cost of the generation resource supplying the increment of Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

iii) Credits for Synchronized Reserve provided by Demand Resources that are synchronized to the grid and accept the obligation to reduce load in response to a Synchronized Reserve Event initiated by the Office of the Interconnection shall be the sum of (i) the higher of (A) the synchronized Reserve offer or (B) the Synchronized Reserve Market Clearing Price and (ii) if a Synchronized Reserve Event is actually initiated by the Office of the Interconnection and the Demand Resource reduced its load in response to the event, the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

(c) The Synchronized Reserve Energy Premium Price is the average of the five-minute Locational Marginal Prices calculated during the Synchronized Reserve Event plus an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Synchronized Reserve Zone by the Office of the Interconnection prior to the operating hour and such market-clearing price shall be equal to, from among the generation resources or Demand Resources selected to provide Synchronized Reserve for such Synchronized Reserve Zone, the highest sum of either (i) a generation resource's Synchronized Reserve offer and opportunity cost or (ii) a demand response resource's Synchronized Reserve offer.

(e) In determining the Synchronized Reserve Market Clearing Price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the expected Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market. The opportunity costs for a Demand Resource shall be zero.

(g) Charges for Tier 1 Synchronized Reserve will be allocated in proportion to the amount of Tier 1 Synchronized Reserve applied to each Synchronized Reserve Obligation. In the event Tier 1 Synchronized Reserve is provided by a Market Seller in excess of that Market Seller's Synchronized Reserve Obligation, the remainder of the Tier 1 Synchronized Reserve that is not utilized to fulfill the Seller's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

(h) Any amounts credited for Tier 2 Synchronized Reserve in an hour in excess of the Synchronized Reserve Market Clearing Price in that hour shall be allocated and charged to each Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation in proportion to its purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) In the event the Office of the Interconnection needs to assign more Tier 2 Synchronized Reserve during an hour than was estimated as needed at the time the Synchronized Reserve Market Clearing Price was calculated for that hour due to a reduction in available Tier 1 Synchronized Reserve, the costs of the excess Tier 2 Synchronized Reserve shall be allocated and charged to those providers of Tier 1 Synchronized Reserve whose available Tier 1 Synchronized Reserve was reduced from the needed amount estimated during the Synchronized Reserve Market Clearing Price calculation, in proportion to the amount of the reduction in Tier 1 Synchronized Reserve availability.

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled by the owner to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Synchronized Reserve in response to an actual Synchronized Reserve Event, the owner of the resource shall incur an additional Synchronized Reserve Obligation in the amount of the shortfall for a period of three consecutive days with the same peak classification (on-peak or off-peak) as the day of the Synchronized Reserve Event at least three business days following the Synchronized Reserve Event. The overall Synchronized Reserve requirement for each Synchronized Reserve Zone of the PJM Region on which the Synchronized Reserve Obligations, except for the additional obligations set forth in this section, are based shall be reduced by the amount of this shortfall for the applicable three-day period.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l), is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption ten minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or

Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Demand Resource’s consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Demand Resource’s consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Demand Resource’s consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJMSettlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

(b) A Day-ahead Scheduling Reserves Resource that receives a Day-ahead Scheduling Reserves schedule pursuant to subsection (a) of this section shall be paid the hourly Day-ahead Scheduling Reserves Market clearing price for the MW obligation in each hour of the schedule, subject to meeting the requirements of subsection (c) of this section.

(c) To be eligible for payment pursuant to subsection (b) of this section, Day-ahead Scheduling Reserves Resources shall comply with the following provisions:

(i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.

(ii) Generation resources and Demand Resources with start times or shut-down times, respectively, equal to or less than 30 minutes are required to respond to dispatch directives from the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule. To meet this requirement the resource shall be required to start or shut down within the specified notification time plus its start or shut down time, provided that such time shall be less than thirty minutes.

(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

Resources that do not comply with the provisions of this subsection (c) shall not be eligible to receive credits pursuant to subsection (b) of this section.

(d) The cost of credits allocated to Day-ahead Scheduling Reserves Resources pursuant to this section shall be charged to Load-Serving Entities in the PJM Region based on load ratio share (net of operating Behind The Meter Generation, but not to be less than zero), provided that a Load-Serving Entity may satisfy its Day-ahead Scheduling Reserves obligation, which is equal to the Day-ahead Scheduling Reserves Requirement multiplied by the Load-Serving Entity's load ratio share for the PJM Region, through one or any combination of the following: 1) the Day-ahead Scheduling Reserves Market; 2) and bilateral arrangements. The Day-ahead Scheduling Reserve charges allocated pursuant to this section shall reflect any portion of a Load-Serving Entity's Day-ahead Scheduling Reserves obligation that is met by bilateral arrangement(s).

(e) If the Day-ahead Scheduling Reserves Requirement is not satisfied through the operation of subsection (a) of this section, any additional Operating Reserves required to meet the requirement shall be scheduled by the Office of the Interconnection pursuant to Section 3.2.3 of Schedule 1 of this Agreement.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit hourly in an amount equal to {(LMPDMW - AG) x (URTLMP - UB)}

where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

AG equals the actual hourly integrated output of the unit;

URTLMP equals the real time LMP at the unit's bus;

UB equals the unit offer for that unit for which output is reduced or suspended determined according to the real time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UB shall not be negative.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG, or (ii) {(URTLMP – UB) x DAG where:

URTLMP equals the real time LMP at the unit's bus;

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to Section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual hourly integrated output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

UB equals the unit offer for that unit for which output is increased, determined according to the real time scheduled offer curve on which the unit was operating;

URTLMP equals the real time LMP at the unit's bus; and

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2A(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generation unit's bus, (C) the generation unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each

Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

Each Market Buyer shall be assessed Transmission Congestion Charges as specified in Section 5 of this Schedule.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Section 5 of this Schedule.

3.2.6 Emergency Energy.

(a) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each hour of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(b) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each hour of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(c) The net costs or net revenues associated with sales or purchases of hourly energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each hour of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Buyer in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Buyer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Buyer's internal accounting.

(b) If deliveries to a Market Buyer that has PJM Interchange meters in accordance with Section 14 of the Operating Agreement include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Buyer, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market Buyer and the unmetered Market Participant specified by them to the Office of the Interconnection.

7.4 Allocation of Auction Revenues.

7.4.1 Eligibility.

(a) Annual auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated among holders of Auction Revenue Rights in proportion to, but not more than, the Target Allocation of Auction Revenue Rights Credits for the holder.

(b) Auction Revenue Rights Credits will be calculated based upon the clearing price results of the applicable Annual Financial Transmission Rights auction.

(c) Monthly and Balance of Planning Period FTR auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated according to the following priority schedule:

> (i) To stage 1 and 2 Auction Revenue Rights holders in accordance with section 7.4.4 of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(ii) of this section;
>
> (ii) To the Residual Auction Revenue Rights holders in proportion to, but not more than their Target Allocation as determined pursuant to section 7.4.3(b) of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(iii) of this section;
>
> (iii) To FTR Holders in accordance with section 5.2.6 of Schedule 1 of this Agreement.

(d) Long-term FTR auction revenues associated with FTRs that cover individual Planning Periods shall be distributed in the Planning Period for which the FTR is effective. Long-term FTR auction revenues associated with FTRs that cover multiple Planning Years shall be distributed equally across each Planning Period in the effective term of the FTR. Long-term FTR auction revenue distributions within a Planning Period shall be in accordance with the following provisions:

> (i) Long-term FTR Auction revenues shall be distributed to Auction Revenue Rights holders in the effective Planning Period for the FTR. The distribution shall be in proportion to the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately. The distribution shall not exceed, when added to the distribution of revenues from the prompt-year annual FTR auction itself, the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately.

(ii) Long-term FTR auction revenues remaining after distributions made pursuant to Section 7.4.1(d)(ii) of Schedule 1 of this Agreement shall be distributed pursuant to Section 5.2.6 of Schedule 1 of this Agreement.

7.4.2 Auction Revenue Rights.

(a) Prior to the end of each PJM Planning Period an annual allocation of Auction Revenue Rights for the next PJM Planning Period shall be performed using a two stage allocation process. Stage 1 shall consist of stages 1A and 1B, which shall allocate ten year and annual Auction Revenue Rights, respectively, and stage 2 shall allocate annual Auction Revenue Rights. The Auction Revenue Rights allocation process shall be performed in accordance with Sections 7.4 and 7.5 hereof and the PJM Manuals.

With respect to the allocation of Auction Revenue Rights, if the Office of the Interconnection discovers an error in the allocation, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the business day following the initial publication of allocation results. After this initial notification, if the Office of the Interconnection determines that it is necessary to post modified allocation results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the second business day following the publication of the initial allocation. Thereafter, the Office of the Interconnection must post any corrected allocation results by no later than 5:00 p.m. of the fourth calendar day following the initial publication. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced allocation is under publicly noticed review by the FERC.

(b) In stage 1A of the allocation process, each Network Service User may request Auction Revenue Rights for a term covering ten consecutive PJM Planning Periods beginning with the immediately ensuing PJM Planning Period from a subset of the historical generation resources that were designated to be delivered to load based on the historical reference year for the Zone, and each Qualifying Transmission Customer (as defined in subsection (f) of this section) may request Auction Revenue Rights based on the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. The historical reference year for all Zones shall be 1998, except that the historical reference year shall be: 2002 for the Allegheny Power and Rockland Electric Zones; 2004 for the AEP East, The Dayton Power & Light Company and Commonwealth Edison Company Zones; 2005 for the Virginia Electric and Power Company and Duquesne Light Company Zones; 2011 for the ATSI Zone; 2012 for the DEOK Zone; and the Office of the Interconnection shall specify a historical reference year for a new PJM zone corresponding to the year that the zone is integrated into the PJM Interchange Energy Market. For stage 1, the Office of the Interconnection shall determine a set of eligible historical generation resources for each Zone based on the historical reference year and assign a pro rata amount of megawatt capability from each historical generation resource to each Network Service User in the Zone based on its proportion of peak load in the Zone. Auction Revenue Rights shall be allocated to each Network Service User in a Zone from each historical generation resource in a number of megawatts equal to or less than the amount of the historical generation resource that has been assigned to the Network Service User. Each Auction Revenue Right allocated to a Network Service User shall be to the aggregate load buses of such Network Service User in a Zone or, with respect to Non-Zone Network Load, to the border of the PJM Region. In stage 1A of the allocation process, the sum of each Network Service User's allocated Auction Revenue Rights for a Zone must be equal to or less than the Network Service User's pro-rata share of the Zonal Base Load for that Zone. Each Network Service User's pro-rata share of the Zonal Base Load shall be based on its proportion of peak load in the Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than fifty percent (50%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined under Section 34.1 of the Tariff. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than fifty percent (50%) of the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. If stage 1A Auction Revenue Rights are adversely affected by any new or revised statute, regulation or rule issued by an entity with jurisdiction over the Office of the Interconnection, the Office of the Interconnection shall, to the greatest extent practicable, and consistent with any such statute, regulation or rule change, preserve the priority of the stage 1A Auction Revenue Rights for a minimum period covering the ten (10) consecutive PJM Planning Periods ("Stage 1A Transition Period") immediately following the implementation of any such changes, provided that the terms of all stage 1A Auction Revenue Rights in effect at the time the Office of the Interconnection implements the Stage 1A Transition Period shall be reduced by one PJM Planning Period during each annual stage 1A Auction Revenue Rights allocation performed during the Stage 1A Transition Period so that all stage 1A Auction Revenue Rights that were effective at the start of the Stage 1A Transition Period expire at the end of that period.

(c) In stage 1B of the allocation process each Network Service User may request Auction Revenue Rights from the subset of the historical generation resources determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process, and each Qualifying Transmission Customer may request Auction Revenue Rights based on the megawatts of firm service determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process. In stage 1B of the allocation process, the sum of each Network Service User's allocation Auction Revenue Rights request for a Zone must be equal to or less than the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 34.1 of the Tariff and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than the difference between one hundred percent (100%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than the difference between one hundred percent (100%) of the megawatts of firm service as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone.

(d) In stage 2 of the allocation process, the Office of the Interconnection shall conduct an iterative allocation process that consists of three rounds with up to one third of the remaining system Auction Revenue Rights capability allocated in each round. Each round of this allocation process will be conducted sequentially with Network Service Users and Transmission Customers being given the opportunity to view results of each allocation round prior to submission of Auction Revenue Right requests into the subsequent round. In each round, each Network Service User shall designate a subset of buses from which Auction Revenue Rights will be sourced. Valid Auction Revenue Rights source buses include only Zones, generators, hubs and external Interface Pricing Points. The Network Service User shall specify the amount of Auction Revenue Rights requested from each source bus. Each Auction Revenue Right shall be sinked to the aggregate load buses of the Network Service User in a Zone or, with respect to Non-Zone Network Load, to the border of the PJM Region. The sum of each Network Service User's Auction Revenue Rights requests in each stage 2 allocation round for each Zone must be equal to or less than one third of the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Right Allocation from stages 1A and 1B of the allocation process for that Zone. The stage 2 allocation to Transmission Customers shall be as set forth in subsection (f).

(e) On a daily basis within the annual Financial Transmission Rights auction period, a proportionate share of Network Service User's Auction Revenue Rights for each Zone are reallocated as Network Load changes from one Network Service User to another within that Zone.

(f) A Qualifying Transmission Customer shall be any customer with an agreement for Long-Term Point-to-Point Transmission Service, as defined in the PJM Tariff, used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located either outside or within the PJM Region, and that was confirmed and in effect during the historical reference year for the Zone in which the resource is located. Such an agreement shall allow the Qualifying Transmission Customer to participate in the first stage of the allocation, but only if such agreement has remained in effect continuously following the historical reference year and is to continue in effect for the period addressed by the allocation, either by its term or by renewal or rollover. The megawatts of Auction Revenue Rights the Qualifying Transmission Customer may request in the first stage of the allocation may not exceed the lesser of: (i) the megawatts of firm service between the designated Network Resource and the load delivery point (or applicable point at the border of the PJM Region for load located outside such region) under contract during the historical reference year; and (ii) the megawatts of firm service presently under contract between such historical reference year receipt and delivery points. A Qualifying Transmission Customer may request Auction Revenue Rights in either or both of stage 1 or 2 of the allocation without regard to whether such customer is subject to a charge for Firm Point-to-Point Transmission Service under Section 1 of Schedule 7 of the PJM Tariff ("Base Transmission Charge"). A Transmission Customer that is not a Qualifying Transmission Customer may request Auction Revenue Rights in stage 2 of the allocation process, but only if it is subject to a Base Transmission Charge. The Auction Revenue Rights that such a Transmission Customer may request in each round of stage 2 of the allocation process must be equal to or less than one third of the number of megawatts equal to the megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has Firm Point-to-Point Transmission Service. The source point of the Auction Revenue Rights must be the designated source point that is specified in the Transmission Service request and the sink point of the Auction Revenue Rights must be the designated sink point that is specified in the Transmission Service request. A Qualifying Transmission Customer may request Auction

Revenue Rights in each round of stage 2 of the allocation process in a number of megawatts equal to or less than one third of the difference between the number of megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has Firm Point-to-Point Transmission Service and its Auction Revenue Right Allocation from stage 1 of the allocation process.

(g) PJM Transmission Customers that serve load in the Midwest ISO may participate in stage 1 of the allocation to the extent permitted by, and in accordance with, this Section 7.4.2 and other applicable provisions of this Schedule 1. For service from non-historic sources, these customers may participate in stage 2, but in no event can they receive an allocation of ARRs/FTRs from PJM greater than their firm service to loads in MISO.

(h) Subject to subsection (i) of this section, all Auction Revenue Rights must be simultaneously feasible. If all Auction Revenue Right requests made during the annual allocation process are not feasible then Auction Revenue Rights are prorated and allocated in proportion to the megawatt level requested and in inverse proportion to the effect on the binding constraints.

(i) If any Auction Revenue Right requests made during stage 1A of the annual allocation process are not feasible, then PJM shall increase the capability limits of the binding constraints that would have rendered the Auction Revenue Rights infeasible to the extent necessary in order to allocate such Auction Revenue Rights without their being infeasible, and such increased limits shall be included in all modeling used for subsequent Auction Revenue Rights and Financial Transmission Rights allocations and auctions for the Planning Year; provided that, the foregoing notwithstanding, this subsection (i) shall not apply if the infeasibility is caused by extraordinary circumstances. For the purposes of this subsection, extraordinary circumstances shall mean an event of force majeure that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Auction Revenue Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates stage 1A Auction Revenue Rights as a result of this subsection (i) that would not otherwise have been feasible, then PJM shall notify Members and post on its web site (a) the aggregate megawatt quantities, by sources and sinks, of such Auction Revenue Rights and (b) any increases in capability limits used to allocate such Auction Revenue Rights.

(j) Long-Term Firm Point-to-Point Transmission Service customers that are not Qualifying Transmission Customers and Network Service Users serving Non-Zone Network Load may participate in stage 1 of the annual allocation of Auction Revenue Rights pursuant to Section 7.4.2(a)-(c) of Schedule 1 of this Agreement, subject to the following conditions:

i. The relevant Transmission Service shall be used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located outside the PJM Region.

ii. To be eligible to participate in stage 1A of the annual Auction Revenue Rights allocation: 1) the relevant Transmission Service shall remain in effect for the stage 1A period addressed by the allocation; and 2) the control area in which the external load is located has similar rules for load external to the relevant control area.

iii. Source points for stage 1 requests authorized pursuant to this subsection 7.4.2(j) shall be limited to: 1) generation resources owned by the LSE serving the load located outside the PJM Region; or 2) generation resources subject to a bona fide firm energy and capacity supply contract executed by the LSE to meet its load obligations, provided that such contract remains in force and effect for a minimum term of ten (10) years from the first effective Planning Period that follows the initial stage 1 request.

iv. For Long-Term Firm Point-to-Point Transmission Customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) , the generation resource(s) designated as source points may include any portion of the generating capacity of such resource(s) that is not, at the time of the request, already identified as a Capacity Resource.

v. For Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j), at the time of the request, the generation resource(s) designated as source points must either be committed into PJM's RPM market or be designated as part of the entity's FRR Capacity Plan for the purpose of serving the capacity requirement of the external load.

vi. All stage 1 source point requests made pursuant to this subsection 7.4.2(j) shall not increase the megawatt flow on facilities binding in the relevant annual Auction Revenue Rights allocation or in future stage 1A allocations and shall not cause megawatt flow to exceed applicable ratings on any other facilities in either set of conditions in the simultaneous feasibility test prescribed in subsection (vii) of this subsection 7.4.2(j).

vii. To ensure the conditions of subsection (vi) of this subsection 7.4.2(j) are met, a simultaneous feasibility test shall be conducted: 1) based on next allocation year with all existing stage 1 and stage 2 Auction Revenue Rights modeled as fixed injection-withdrawal pairs; and 2) based on 10 year allocation model with all eligible stage 1A Auction Revenue Rights for each year including base load growth for each year.

viii. Requests for stage 1 Auction Revenue Rights made pursuant to this subsection 7.4.2(j) that are received by PJM by November 1st of a Planning Period shall be processed for the next annual Auction Revenue Rights allocation. Requests received after November 1st shall not be considered for the upcoming annual Auction Revenue Rights allocation. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.

ix. Requests for new or alternate stage 1 resources made by Network Service Users and external LSEs that are received by November 1st shall be evaluated at the same time. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.

x. Stage 1 Auction Revenue Rights source points that qualify pursuant to this subsection 7.4.2(j) shall be eligible as stage 1 Auction Revenue Rights source points in subsequent annual Auction Revenue Rights allocations.

xi. Long-Term Firm Point-to-Point Transmission Customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer's Long-Term Firm Point-to-Point Transmission service contract megawatt amount; or 2) the customer's Firm Transmission Withdrawal Rights.

xii. Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer's network service peak load; or 2) the customer's Firm Transmission Withdrawal Rights.

xiii. Stage 1A Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed 50% of the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j).

xiv. Stage 1B Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed the difference between the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatts granted in stage 1A.

xv. In each round of Stage 2 of an annual allocation of Auction Revenue Rights, megawatt requests made pursuant to this subsection 7.4.2(j) shall be equal to or less than one third of the difference between the maximum allowed megawatts authorized by paragraphs (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatt amount allocated in stage 1.

xvi. Stage 1 Auction Revenue Rights sources established pursuant to this subsection 7.4.2(j) and the associated Auction Revenue Rights megawatt amount may be replaced with an alternate resource pursuant to the process established in Section 7.7 of Schedule 1 of this Agreement.

7.4.2a Bilateral Transfers of Auction Revenue Rights

(a) Market Participants may enter into bilateral agreements to transfer Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights to a third party. Such bilateral transfers shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules related to its eFTR tools.

(b) For purposes of clarity, with respect to all bilateral transfers of Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights, the rights and obligations to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights that are the subject of such a bilateral transfer shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. In no event, shall the purchase and sale of an Auction Revenue Right or the right to receive an allocation of Auction Revenue Rights pursuant to a bilateral transfer constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

(c) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights. Such consent shall be based upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall not transfer to the third party and the holder of the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall continue to receive all rights attributable to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights and remain subject to all credit requirements and obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights.

(d) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the Auction Revenue Right and for which payment is not made to PJMSettlement by the buyer under such a bilateral transfer.

(e) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.

(f) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.

7.4.3 Target Allocation of Auction Revenue Right Credits.

(a) A Target Allocation of Auction Revenue Right Credits for each entity holding an Auction Revenue Right shall be determined for each Auction Revenue Right. After each round of the annual Financial Transmission Right auction, each Auction Revenue Right shall be divided by four and multiplied by the price differences for the receipt and delivery points associated with the Auction Revenue Right, calculated as the Locational Marginal Price at the delivery points(s) minus the Locational Marginal Price at the receipt point(s), where the price for the receipt and delivery point is determined by the clearing prices of each round of the annual Financial Transmission Right auction. The daily total Target Allocation for an entity holding the Auction Revenue Rights shall be the sum of the daily Target Allocations associated with all of the entity's Auction Revenue Rights.

(b) A Target Allocation of residual Auction Revenue Rights Credits for each entity allocated Residual Auction Revenue Rights pursuant to section 7.9 of Schedule 1 of this Agreement shall be determined on a monthly basis for each month in a Planning Period beginning with the month the Residual Auction Revenue Right(s) becomes effective through the end of the relevant Planning Period. The Target Allocation for Residual Auction Revenue Rights Credits shall be equal to megawatt amount of the Residual Auction Revenue Rights multiplied by the LMP differential between the source and sink nodes of the corresponding FTR obligation in each prompt-month FTR auction that occurs from the effective date of the Residual Auction Revenue Rights through the end of the relevant Planning Period.

7.4.4 Calculation of Auction Revenue Right Credits.

(a) Each day, the total of all the daily Target Allocations determined as specified above in Section 7.4.3 plus any additional Auction Revenue Rights Target Allocations applicable for that day shall be compared to the total revenues of all applicable monthly Financial Transmission Rights auction(s) (divided by the number of days in the month) plus the total revenues of the annual Financial Transmission Rights auction (divided by the number of days in the Planning Period). If the total of the Target Allocations is less than the total auction revenues, the Auction Revenue Right Credit for each entity holding an Auction Revenue Right shall be equal to its Target Allocation. All remaining funds shall be distributed as Excess Congestion Charges pursuant to Section 5.2.5.

(b) If the total of the Target Allocations is greater than the total auction revenues, each holder of Auction Revenue Rights shall be assigned a share of the total auction revenues in proportion to its Auction Revenue Rights Target Allocations for Auction Revenue Rights which have a positive Target Allocation value. Auction Revenue Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Auction Revenue Right Credit.

(c) At the end of a Planning Period, if all Auction Revenue Right holders did not receive Auction Revenue Right Credits equal to their Target Allocations, PJMSettlement shall assess a charge equal to the difference between the Auction Revenue Right Credit Target Allocations for all revenue deficient Auction Revenue Rights and the actual Auction Revenue Right Credits allocated to those Auction Revenue Right holders. The aggregate charge for a Planning Period assessed pursuant to this section, if any, shall be added to the aggregate charge for a Planning Period assessed pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and collected pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and distributed to the Auction Revenue Right holders that did not receive Auction Revenue Right Credits equal to their Target Allocation.

PJM Reliability Assurance Agreement
Clean Format

SCHEDULE 10.1

LOCATIONAL DELIVERABILITY AREAS AND REQUIREMENTS

The capacity obligations imposed under this Agreement recognize the locational value of Capacity Resources. To ensure that such locational value is properly recognized and quantified, the Office of the Interconnection shall follow the procedures in this Schedule.

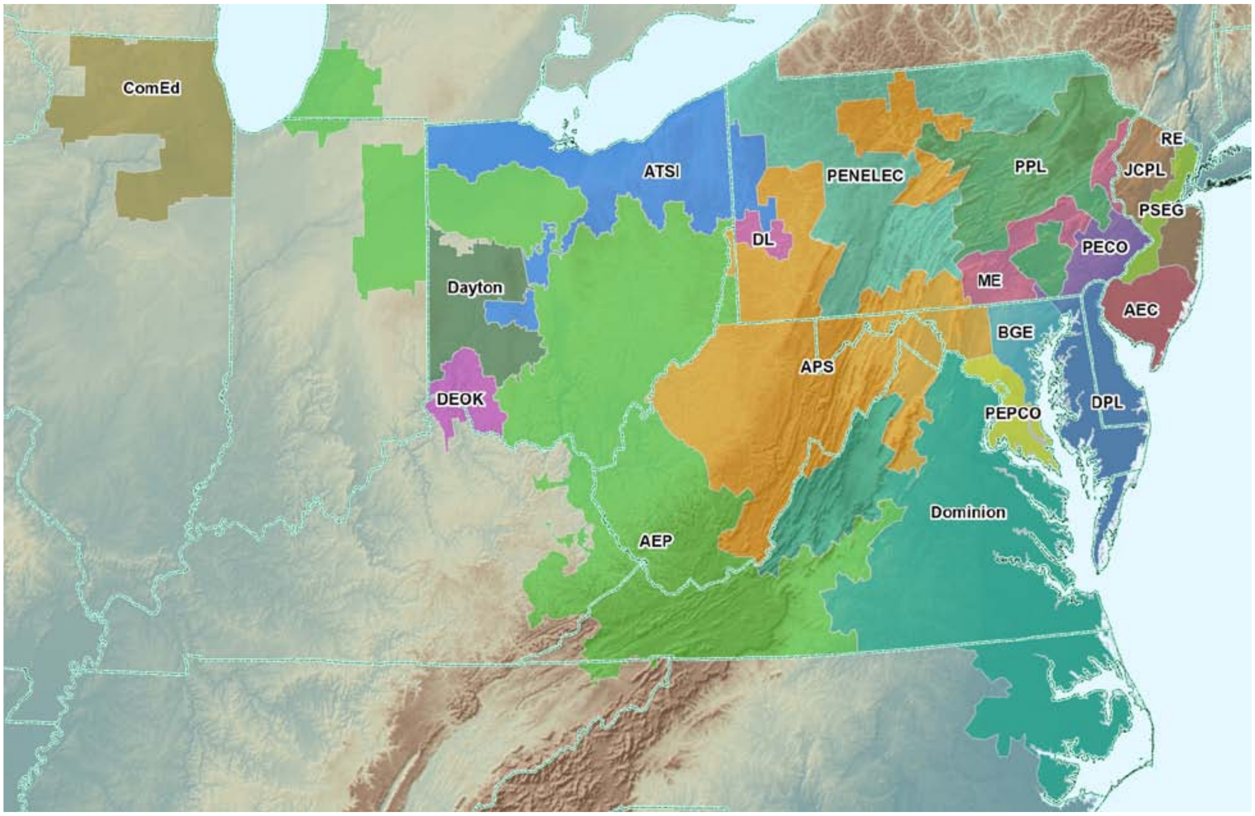
A. Following the Transition Period, as such term is defined in Attachment DD to the Tariff, the Locational Deliverability Areas for the purposes of determining locational capacity obligations hereunder, but not necessarily for the purposes of the Regional Transmission Expansion Planning Protocol, shall consist of the following Zones (as defined in Schedule 15), combinations of such Zones, and portions of such Zones:

- ATSI
- DEOK
- Dominion
- Penelec
- ComEd
- AEP
- Dayton
- Duquesne
- APS
- AE
- BGE
- DPL
- PECO
- PEPCO
- PSEG
- JCPL
- MetEd
- PPL
- Mid-Atlantic Area Council (MAAC) Region (consisting of all the zones listed below for Eastern MAAC, Western MAAC, and Southwestern MAAC)
- ComEd, AEP, Dayton, APS, Duquesne, ATSI, and DEOK
- Eastern MAAC (PSE&G, JCP&L, PECO, AE, DPL & RE)
- Southwestern MAAC (PEPCO & BG&E)
- Western MAAC (Penelec, MetEd, PPL)
- PSEG northern region (north of Linden substation); and
- DPL southern region (south of Chesapeake and Delaware Canal

B. For purposes of evaluating the need for any changes to the foregoing list, Locational Deliverability Areas shall be those areas, identified by the load deliverability analyses conducted pursuant to the Regional Transmission Expansion Planning Protocol and the PJM Manuals that have a limited ability to import capacity due to physical limitations of the transmission system, voltage limitations or stability limitations. Such limits on import capability shall not reflect the effect of Qualifying Transmission Upgrades offered in the Base Residual Auction. The Locational Deliverability Areas identified in Paragraph A above (as it may be amended from time to time) for a Delivery Year shall be modeled in the Base Residual Auction and any Incremental Auction conducted for such Delivery Year. If the Office of the Interconnection includes a new Locational Deliverability Area in the Regional Transmission Expansion Planning Protocol, it shall make a filing with FERC to amend this Schedule to add a new Locational Deliverability Area (including a new aggregate LDA), if such new Locational Deliverability Area is projected to have a capacity emergency transfer limit less than 1.15 times the capacity emergency transfer objective of such area, or if warranted by other reliability concerns consistent with the Reliability Principles and Standards. In addition, any Party may propose, and the Office of the Interconnection shall evaluate, consistent with the same CETO/CETO comparison or other reliability concerns, possible new Locational Deliverability Areas (including aggregate LDAs) for inclusion under the Regional Transmission Expansion Planning Protocol and for purposes of determining locational capacity obligations hereunder.

C. For each Locational Deliverability Area for which a separate VRR Curve was established for a Delivery Year, the Office of the Interconnection shall determine, pursuant to procedures set forth in the PJM Manuals, the Percentage of Internal Resources Required, that must be committed during such Delivery Year from Capacity Resources physically located in such Locational Deliverability Area.

SCHEDULE 15
ZONES WITHIN THE PJM REGION



FULL NAME	SHORT NAME
Pennsylvania Electric Company	Penelec
Allegheny Power	APS
PPL Group	PPL
Metropolitan Edison Company	MetEd
Jersey Central Power and Light Company	JCPL
Public Service Electric and Gas Company	PSEG
Atlantic City Electric Company	AEC
PECO Energy Company	PECO
Baltimore Gas and Electric Company	BGE
Delmarva Power and Light Company	DPL
Potomac Electric Power Company	PEPCO
Rockland Electric Company	RE
Commonwealth Edison Company	ComEd
AEP East Zone	AEP
The Dayton Power and Light Company	Dayton
Virginia Electric and Power Company	Dominion
Duquesne Light Company	DL
American Transmission Systems, Incorporated	ATSI
Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.	DEOK

SCHEDULE 17

PARTIES TO THE RELIABILITY ASSURANCE AGREEMENT

This Schedule sets forth the Parties to the Agreement:

AEP Retail Energy Partners LLC
AES Red Oak, LLC
Algonquin Energy Services Inc.
Allegheny Electric Cooperative, Inc.
Allegheny Energy Supply Company, L.L.C.
Ally Energy LLC.
Alpha Gas and Electric LLC
Ambit Northeast, LLC
Ameren Energy Marketing Company
American Electric Power Service Corporation on behalf of its affiliates:
    Appalachian Power Company
    Columbus Southern Power Company
    Indiana Michigan Power Company
    Kentucky Power Company
    Kingsport Power Company
    Ohio Power Company
    Wheeling Power Company.
American Municipal Power, Inc.
American Power Partners LLC
American PowerNet Management, L.P.
American Transmission Systems, Inc.
AP Gas and Electric (PA), LLC
APN Starfirst, LP
ArcelorMittal USA LLC
Asset and Energy Cost Saving Cooperative, LLC
Atlantic City Electric Company
Baltimore Gas and Electric Company
Bank of America, N.A.
Barclays Bank PLC
Bativa, IL (City of)
BBPC LLC d/b/a Great Eastern Energy
Blackstone Wind Farm, LLC
Blue Ridge Power Agency, Inc.
Blue Star Energy Services, Inc.
Border Energy Electric Services, Inc.
Borough of Butler, Butler Electric Division
Borough of Chambersburg
Borough of Lavallette, New Jersey
Borough of Mont Alto, PA
Borough of Park Ridge, New Jersey

Borough of Pitcairn, Pennsylvania
Borough of Seaside Heights, New Jersey
Borough of South River, New Jersey
BP Energy Company
Brighten Energy LLC
Cargill Power Markets LLC
Castlebridge Energy Group, LLC
CCES LLC
Central Virginia Electric Cooperative
Centre Lane Trading Limited
Champion Energy Marketing LLC
Champion Energy, LLC
Cincinnati Bell Energy, LLC
Citizens' Electric Company of Lewisburg, PA
City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power
City of Dover, Delaware
City of Naperville
City of New Martinsville - WV
City of Philippi - West VA
City of Rochelle
Clearview Electric, Inc.
Cleveland Electric Illuminating Company (The)
Commerce Energy, Inc.
Commonwealth Edison Company
Conectiv Energy Supply, Inc.
ConEdison Energy, Inc.
ConocoPhillips Company
Consolidated Edison Solutions, Inc.
Constellation Energy Commodities Group, Inc.
Constellation NewEnergy, Inc.
Constellation Power Source Generation, Inc.
Corporate Services Support Corp
Credit Suisse (USA), Inc.
Dayton Power & Light Company (The)
DC Energy LLC
Delaware Municipal Electric Corporation
Delmarva Power & Light Company
Denver Energy, LLC
Devonshire Energy LLC
Direct Energy Business, LLC
Direct Energy Services, LLC
Discount Energy Group, LLC
Discount Energy, LLC
Dominion Retail, Inc.
Downes Associates, Inc.
DPL Energy Resources, Inc.

Driftwood LLC
DTE Energy Supply, Inc.
DTE Energy Trading, Inc.
Duke Energy Commercial Asset Management, Inc.
Duke Energy Kentucky, Inc.
Duke Energy Ohio, Inc.
Duke Energy Retail Sales, LLC
Duquesne Light Company
Duquesne Light Energy, LLC
Dynegy Energy Services, Inc.
Dynegy Kendall Energy, LLC
E Minus LLC
Eagle Energy, LLC
Easton Utilities Commission
EDF Industrial Power Services (IL), LLC
EDF Trading North America, LLC
Edison Mission Marketing and Trading, Inc.
Employers' Energy Alliance of Pennsylvania, Inc.
Energetix, Inc.
Energy America, LLC
Energy Cooperative Association of Pennsylvania (The)
Energy Cooperative of America, Inc.
Energy International Power Marketing Corporation
Energy Plus Holdings LLC
Energy Services Providers, Inc.
EnerPenn USA, LLC
ERA MA, LLC
Evraz Claymont Steel
Exelon Energy Company
Exelon Generation Co., LLC
FirstEnergy Solutions Corp.
First Point Power, LLC
Front Royal (Town of)
Galt Power Inc.
Gateway Energy Services Corporation
GenOn Power Midwest, LP
Gerdau Ameristeel Energy, Inc.
GDF Suez Retail Energy Solutions, LLC
Glacial Energy of New Jersey, Inc.
Great American Power, LLC
Green Mountain Energy Company
Hagerstown Light Department
Harrison REA, Inc. - Clarksburg, WV
Hess Corporation
HIKO Energy, LLC
Hoosier Energy REC, Inc.

HOP Energy, LLC
HSBC Technology & Services (USA), Inc.
Hudson Energy Services, LLC
IDT Energy, Inc.
Illinois Municipal Electric Agency
J. Aron & Company
J.P. Morgan Ventures Energy Corporation
Jack Rich, Inc. d/b/a Anthracite Power & Light Company
Jersey Central Power & Light Company
Kuehne Chemical Company, Inc.
L & P Electric Inc., d/b/a Leggett & Platt Electric Inc.
Liberty Power Corp., L.L.C.
Liberty Power Delaware LLC
Liberty Power Holdings LLC
Linde Energy Services, Inc.
Lower Electric, LLC
Macquarie Cook Energy LLC
Major Energy Electric Services LLC
Manitou Energy Fund, LP
Marathon Power, LLC
MC Squared Energy Services, LLC
Meadow Lake Wind Farm II LLC
Meadow Lake Wind Farm III LLC
Meadow Lake Wind Farm IV LLC
Meadow Lake Wind Farm LLC
MeadWestvaco Corporation
Metropolitan Edison Company
MidAmerican Energy Company
Mint Energy, LLC
Morgan Stanley Capital Group, Inc.
MP2 Energy NE, LLC
MXenergy Electric, Inc.
Natgasco, Inc.
Nexgen Management and Consulting Inc
Nextera Energy Services New Jersey, LLC
Nextera Energy Services, Illinois, LLC
Noble Americas Energy Solutions LLC
Noble Americas Gas & Power Corp.
Nordic Energy Services LLC
North American Power and Gas LLC.
North Carolina Electric Membership Corporation
North Carolina Municipal Power Agency Number 1
Northern Virginia Electric Cooperative - NOVEC
NRG Power Marketing, L.L.C.
NYSEG Solutions, Inc.
Oasis Power, LLC dba Oasis Energy

Occidental Power Services, Inc.
Ohio Edison Company
Ohms Energy Company, LLC
Old Dominion Electric Cooperative
Palmco Power MD, LLC
Palmco Power NJ, LLC
Palmco Power OH, LLC
Palmco Power PA, LLC
Panda Power Corporation
Parma Energy, LLC
PBF Power Marketing LLC
PECO Energy Company
Pennsylvania Electric Company
Pennsylvania Power Company
People's Power & Gas, LLC
PEPCO Energy Services, Inc.
Planet Energy (Maryland) Corp.
Planet Energy (Pennsylvania) Corp.
Planet Energy (USA) Corp.
Plymouth Rock Energy, LLC
Potomac Electric Power Company
Powhatan Energy Fund LLC
PPL Electric Utilities Corporation d/b/a PPL Utilities
PPL Energy Plus, LLC
Prairieland Energy, Inc.
PSEG Energy Resources and Trade LLC
Public Power, LLC
Public Service Electric & Gas Company
Realgy, LLC
ResCom Energy, LLC
Respond Power LLC
RG Steel Sparrows Point, LLC
Riverside Generating, LLC
Rolling Hills Generating, LLC
S.J. Energy Partners, Inc.
Santanna Energy Services
SMART Papers Holdings, LLC
Solios Power Mid-Atlantic Trading LLC
South Jersey Energy Company
South Jersey Energy Solutions, L.L.C.
Southeastern Power Administration
Southern Indiana Gas & Electric
Southern Maryland Electric Cooperative, Inc.
Spark Energy, L.P.
Sperian Energy Corp
Starion Energy PA Inc.

Stream Energy Columbia, LLC
Stream Energy Maryland, LLC
Stream Energy Pennsylvania, LLC
Superior Plus Energy Services Inc.
TC Energy Trading, LLC
Tenaska Power Services Co.
Texas Retail Energy, LLC
The Trustees of the University of Pennsylvania
Thurmont Municipal Light Company
Toledo Edison Company (The)
Town of Berlin, Maryland
Town of Williamsport
TransAlta Energy Marketing (U.S.) Inc.
TransCanada Power Marketing Ltd.
Tri-County Rural Electric Cooperative, Inc.
TriEagle Energy, LP
Trinity Powerworks, Inc.
U.S. Energy Partners dba PAETEC Energy Marketing
UBS AG, acting through its London Branch
UGI Energy Services, Inc.
UGI Utilities, Inc. - Electric Division
Valero Power Marketing, LLC
VCharge, Inc.
Verde Energy USA, Inc.
Vineland Municipal Electric Utility (City of Vineland)
Virginia Electric & Power Company
Viridian Energy PA LLC
Wabash Valley Power Association, Inc.
Washington Gas Energy Services, Inc.
Wellsboro Electric Company
West Penn Power Company d/b/a Allegheny Power
York Generation Company, LLC

PJM Consolidated Transmission Owners Agreement
Clean Format

ATTACHMENT A

TO THE CONSOLIDATED

TRANSMISSION OWNERS AGREEMENT

Monongahela Power Company, The Potomac Edison Company and West Penn Power Company, all doing business as Allegheny Power

American Electric Power Service Corporation on behalf of its operating companies: Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company

Commonwealth Edison Company and Commonwealth Edison Company of Indiana, Inc.

Dayton Power and Light Company

Virginia Electric and Power Company (Dominion Virginia Power)

Public Service Electric and Gas Company

PECO Energy Company

PPL Electric Utilities Corporation

Baltimore Gas and Electric Company

Jersey Central Power & Light Company

Metropolitan Edison Company

Pennsylvania Electric Company

Potomac Electric Power Company

Atlantic City Electric Company

Delmarva Power & Light Company

UGI Utilities, Inc.

Allegheny Electric Cooperative, Inc.

CED Rock Springs, LLC

Old Dominion Electric Cooperative

Rockland Electric Company

Duquesne Light Company

Neptune Regional Transmission System, LLC

Trans-Allegheny Interstate Line Company

Linden VFT, LLC

American Transmission Systems, Incorporated

City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power

Duke Energy Ohio, Inc.

Duke Energy Kentucky, Inc.

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

PJM Interconnection, L.L.C.

By: ________________________________
Name: Phillip G. Harris
Title: President and CEO
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Monongahela Power Company, The Potomac Edison Company and West Penn Power Company, all doing business as Allegheny Power

By: ______________________________
Name: James R. Haney
Title: Vice President
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

American Electric Power Service Corporation

By:________________________________
Name:
Title:
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Exelon Corporation on behalf of its subsidiaries
Commonwealth Edison Company and Commonwealth Edison
Company of Indiana, Inc.

By:_________________________________
Name: Susan Ivey
Title: Vice President, Transmission Operations and Planning, Exelon Corporation
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

The Dayton Power and Light Company

By: ___________________________________
Name: Patricia K. Swanke
Title: Vice President - Operations
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Virginia Electric and Power Company (Dominion Virginia Power)

By:__________________________________
Name: Gary L. Sypolt
Title: President – Dominion Transmission
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Public Service Electric and Gas Company

By: ______________________________

Name: Ralph LaRossa
Title: Vice President - Electric Delivery
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Exelon Corporation on behalf of its subsidiary
PECO Energy Company

By:_________________________________
Name: Susan Ivey
Title: Vice President, Transmission Operations and Planning, Exelon Corporation
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

PPL Electric Utilities Corporation

By:___________________________________
Name: John F. Sipics
Title: President
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Baltimore Gas and Electric Company

By:_____________________________

Name: Mark P. Huston

Title: Vice President, Electric Transmission and Distribution

Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Jersey Central Power & Light Company

By: ______________________________

Name: Stanley F. Szwed

Title: Vice President – Energy Delivery Policy

First Energy Service Company

Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Metropolitan Edison Company

By:______________________________
Name: Stanley F. Szwed
Title: Vice President – Energy Delivery Policy
First Energy Service Company
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Pennsylvania Electric Company

By:_____________________________
Name: Stanley F. Szwed
Title: Vice President – Energy Delivery Policy
First Energy Service Company
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Potomac Electric Power Company

By:______________________________
Name: David M. Valazquez
Title: Vice President, Pepco Holdings, Inc.
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Atlantic City Electric Company

By: ________________________________
Name: David M. Valazquez
Title: Vice President, Pepco Holdings, Inc.
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Delmarva Power & Light Company

By:________________________________

Name: David M. Valazquez

Title: Vice President, Pepco Holdings, Inc.

Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

UGI Utilities, Inc.

By: ___________________________
Name: Richard E. Gill
Title: Assistant Secretary - Electric Transmission
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

CED Rock Springs, LLC

By:_________________________________
Name:
Title:
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Old Dominion Electric Cooperative

By:_________________________________
Name:
Title:
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Rockland Electric Company

By:__________________________________
Name:
Title:
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Duquesne Light Company

By:________________________________
Name:
Title:
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Allegheny Electric Cooperative, Inc.

By: ________________________________
Name: Richard W. Osborne
Title: Vice President Power Supply & Engineering
Date: December 15, 2005

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Neptune Regional Transmission System, LLC

By: ________________________________
Name: Edward M. Stern
Title: CEO
Date: March 7, 2007

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Trans-Allegheny Interstate Line Company

By: ________________________________

Name: James R. Haney

Title: Vice President

Date: November 8, 2007

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Linden VFT, LLC

By: ________________________________

Name: Andrew J. Keleman

Title: Authorized Representative

Date: April 1, 2009

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

American Transmission Systems, Incorporated

By: ________________________________
Name: Richard R. Grigg
Title: President
Date: December 17, 2009

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

City of Cleveland, Department of Public Utilities
Division of Cleveland Public Power

By: _ ________________________________
Name: Barry A. Withers
Title: Director
Date: March 22, 2011

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Duke Energy Ohio, Inc.

By: _ ________________________________
Name: Julia S. Janson
Title: President
Date: September 27, 2011

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Duke Energy Kentucky, Inc.

By: _ ________________________________
Name: Julia S. Janson
Title: President
Date: September 27, 2011

Attachment C

Direct Testimony and Exhibits of
William Don Wathen Jr. on behalf of Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.,	)	
Duke Energy Ohio, Inc., and	)	Docket No. ER12-_____
Duke Energy Kentucky, Inc.	)	

DIRECT TESTIMONY OF

WILLIAM DON WATHEN JR.

ON BEHALF OF

DUKE ENERGY OHIO, INC., AND

DUKE ENERGY KENTUCKY, INC.

October 13, 2011

TABLE OF CONTENTS

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.,	)	
Duke Energy Ohio, Inc., and	)	Docket No. ER12-_____
Duke Energy Kentucky, Inc.	)	

DIRECT TESTIMONY OF

WILLIAM DON WATHEN JR.

ON BEHALF OF

DUKE ENERGY OHIO, INC., AND

DUKE ENERGY KENTUCKY, INC.

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William Don Wathen Jr., and my business address is 139 East Fourth Street, Cincinnati, Ohio 45202.

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

A. I am employed by Duke Energy Business Services, LLC ("DEBS") as General Manager and Vice President of Rates, Ohio and Kentucky. DEBS provides various administrative and other services to Duke Energy Ohio, Inc., ("Duke Energy Ohio") and Duke Energy Kentucky, Inc., ("Duke Energy Kentucky") (collectively, the "Companies" or "DEOK") and to other affiliated companies of Duke Energy Corporation ("Duke Energy").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received Bachelor Degrees in Business and Chemical Engineering, and a Master of Business Administration Degree, all from the University of Kentucky. After completing graduate studies, I was employed by Kentucky Utilities Company as a planning analyst. In 1989, I began employment with the Indiana Utility Regulatory Commission as a senior engineer. From 1992 until mid-1998, I was employed by SVBK Consulting Group, where I held several positions as a consultant focusing principally on utility rate matters. I was hired by Cinergy Services, Inc., in 1998 as an Economic and Financial Specialist in the Budgets and Forecasts Department. In 1999, I was promoted to the position of Manager, Financial Forecasts. In August 2003, I was named to the position of Director - Rates. On December 1, 2009, I took the position of General Manager and Vice President of Rates, Ohio and Kentucky.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION ("COMMISSION" or "FERC")?

A. Yes. I presented testimony in Docket No. EL95-31 supporting a cost of capital recommendation. In addition, I have presented testimony on numerous occasions in state and local regulatory agencies in Indiana, Kentucky, Ohio, and Louisiana.

Q. PLEASE SUMMARIZE YOUR DUTIES AS GENERAL MANAGER AND VICE PRESIDENT OF RATES, OHIO AND KENTUCKY.

A. As General Manager and Vice President of Rates, Ohio and Kentucky, I am responsible for all state and federal rate matters involving Duke Energy Ohio and Duke Energy Kentucky.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe the formula rate that will be used to calculate the Companies' revenue requirements after they transfer their generation and transmission assets from operating in the Midwest Independent System Operator, Inc. ("Midwest ISO") to the PJM Interconnection, L.L.C. ("PJM"). This formula rate will be included as part of the PJM Open Access Transmission Tariff ("OATT"). I will also describe the other changes to the PJM OATT related to the Companies' revenue requirements that the Companies are proposing in connection with this transfer.

II. BACKGROUND

Q. PLEASE DESCRIBE THE COMPANIES AND THE SERVICES THEY PROVIDE.

A. Duke Energy Ohio and Duke Energy Kentucky are wholly owned subsidiaries of Duke Energy, and offer retail and wholesale electric service in service territories located in southwestern Ohio and northern Kentucky, respectively. The Companies, along with Duke Energy Indiana, Inc., ("Duke Energy Indiana") previously placed their transmission facilities under the operational control of the Midwest ISO, and wholesale customers that take transmission service utilizing such facilities obtain transmission service under the Midwest ISO Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Midwest ISO ASM Tariff").

Q. WHY ARE THE COMPANIES MAKING THIS FILING?

A. On June 25, 2010, the Companies submitted a filing in Docket No. ER10-1562-000 initiating the process of transferring their generation and transmission assets from operating in the Midwest ISO to PJM. On October 21, 2010, the Commission conditionally approved the Companies' proposed transfer. In order to accomplish this transfer, it is necessary for the Companies to modify the PJM OATT to include the Companies' transmission revenue requirements. It is the Companies' intention to effectuate this transfer on January 1, 2012; consequently, the Companies are filing this application to establish a formula rate to determine their revenue requirements under the PJM OATT so that appropriate rates for Network Integration Transmission Service ("NITS"), Point-to-Point ("PTP') Service, and Transmission Owner Scheduling, System Control, and Dispatch can be reflected in the PJM OATT and charged by PJM.

Q. HOW ARE THE COMPANIES' WHOLESALE TRANSMISSION CUSTOMERS CURRENTLY CHARGED FOR THE TRANSMISSION SERVICES THEY RECEIVE?

A. Today, wholesale customers using the Companies' facilities typically are assessed transmission charges based on the transmission rates developed by the Midwest ISO for the Duke pricing zone ("MISO Duke Zone").[1] There are also PTP rates under the Midwest ISO ASM Tariff that reflect a blending of the rates in the various pricing zones. Any customer using the transmission facilities owned and operated by Duke Energy Ohio and/or Duke Energy Kentucky will be billed under the new rates under PJM's OATT, once approved.

[1] Through December 31, 2011, the MISO Duke Zone includes Duke Energy Ohio, Duke Energy Kentucky, and Duke Energy Indiana.

Q. WHICH EXISTING TRANSMISSION CUSTOMERS WILL BE IMPACTED BY THE TRANSITION FROM THE MIDWEST ISO TO PJM?

A. Wholesale transmission customers with load in the service area footprints of Duke Energy Kentucky and Duke Energy Ohio will be the primary set of impacted customers. These customers typically purchase NITS from the Midwest ISO today and will purchase such service from PJM after the transition. Also, there will be impacts for customers remaining in the MISO Duke Zone, because even though their formula rates will not change, the inputs to the formula will change – the formula inputs will no longer include the costs (or load) of the Companies. This proceeding is limited to service under the PJM OATT.

Q. WHAT ABOUT RETAIL TRANSMISSION CUSTOMERS; WILL THEY TAKE SERVICE UNDER THE PJM OATT?

A. Duke Energy's retail customers in Kentucky and Ohio do not take transmission service under the Midwest ISO ASM Tariff and they similarly will not become PJM OATT customers. As required by the Midwest ISO, and as will be required by PJM, the Companies each enter into a NITS Agreement with the ISO to obtain transmission service for their retail load, except for any Ohio retail load that obtains generation service from a competitive retail electric service[2] ("CRES") provider. CRES providers, or their agents, obtain transmission service for such retail customers. In approving a settlement, the Public Utilities Commission of Ohio ("PUCO") authorized Duke Energy Ohio, as of January 1, 2012, to begin billing all retail customers for NITS and certain other transmission costs on a non-bypassable basis.[3] Under this settlement, CRES providers will still be billed all relevant PJM charges like any other NITS customer but financial responsibility for the payment of the NITS charges will be borne by Duke Energy Ohio.

Q. HAVE THE COMPANIES' RETAIL REGULATORS WEIGHED IN ON THE PROPOSED TRANSFER TO PJM AND THE POTENTIAL IMPACTS ON THE COMPANIES' RETAIL RATES?

A. Yes. The Kentucky Public Service Commission ("KPSC") conditionally approved the transfer on December 22, 2010,[4] and, as referenced above, the PUCO approved the riders for cost recovery related to the transfer on May

[2] "Competitive retail electric service" is defined in Chapter 4928.01 of Ohio's Revised Code.

[3] Case Nos. 11-2641-EL-RDR and 11-2642-EL-RDR (May 25, 2011).

[4] The KPSC approval in Case No. 2010-00203 was conditioned upon the agreement of PJM and Duke Energy Kentucky to specific terms of the realignment. The terms were eventually accepted by Duke Energy Kentucky and PJM and the KPSC issued its Final Order January 25, 2011.

25, 2011.[5] Both regulators have agreed to the transition and have approved settlements that include conditions that impact whether some of the transmission rates submitted to FERC in this docket will be collected from retail customers. Such settlements are not at issue in this case – the Companies do not seek to preempt the settlement agreements.

III. PROPOSED RATES

Q. DOES THE MIDWEST ISO CURRENTLY HAVE APPROVED RATES FOR THE TRANSMISSION SERVICES DESCRIBED IN YOUR TESTIMONY?

A. Yes. Currently, as a member of the Midwest ISO, Duke Energy Ohio, Duke Energy Kentucky, and Duke Energy Indiana establish revenue requirements that are included in the rates for NITS and PTP service via a formula rate found in Attachment O of the Midwest ISO ASM Tariff. The formula rate in Attachment O uses actual historical, audited financial data, and peak load data available in public documents, *i.e.*, the FERC Form No. 1 ("Form 1") to establish an annual revenue requirement for transmission facilities for the combined Midwest operations of Duke Energy. The calculations are supplied to the Midwest ISO each year for review and comment, and ordinarily go into effect on June 1st, following the year being

[5] Case Nos. 11-2641-EL-RDR and 11-2642-EL-RDR.

used as the source of the revenue requirement calculation. For example, the current rates are based on actual data for 2010 and went into effect on June 1, 2011.

Q. WHAT RATES ARE THE COMPANIES PROPOSING TO MODIFY IN THIS FILING?

A. Although the Companies already have wholesale revenue requirement calculations and rates in place for the use of their transmission facilities, they were established under the Midwest ISO ASM Tariff. Because the Companies will be operating under a new tariff and because of the differences between the Midwest ISO ASM Tariff and PJM's OATT, the Companies submit this filing to obtain Commission approval of new transmission revenue requirements and the resulting rates. Toward that end, my testimony will support the Companies' proposed charges for:

(1) Network Integrated Transmission Service – PJM OATT Schedule H-22;

(2) Transmission Owner Scheduling, System Control and Dispatch Service – PJM OATT Schedule 1A;

(3) Short-term and long-term PTP transmission service – PJM OATT Schedule 7; and

(4) Non-firm point-to-point transmission service – PJM OATT Schedule 8.

Most of the changes being proposed in this filing are due to the differences between the Midwest ISO and PJM in the methodologies they use for calculating these various rates.

As is the case today, actual data from the Form 1 and the Companies' books and records will be used to set the rates. The Companies propose to maintain the same rate formula, modified to accommodate the methodological differences between the two regional transmission organization ("RTO") tariffs and to reflect certain transitional charges. The formula will be applied to the Companies' costs, and initially will continue to be based on actual data from the 2010 Form 1 until subsequent Form 1 data are available. The Companies propose to maintain the existing timeline for updating the revenue requirement and rate calculations for updated data such that June 1st will continue to be the effective date for new rates for all subsequent years after the transition.

A. Network Integration and Point-to-Point Transmission Service

Q. HOW WILL THE CALCULATION OF THE COMPANIES' REVENUE REQUIREMENT FOR NITS AND PTP SERVICE BE AFFECTED BY THE TRANSFER TO PJM?

A. As I discussed above, the formula rate used for the calculations of each individual Company's revenue requirement is similar to the Attachment O formula rate. The proposed rates disaggregate the current combined calculation for the Companies and Duke Energy Indiana, so that the new rates only reflect the Companies' costs. The changes in the calculation of the Companies' revenue requirement are discussed in more detail below.

Q. PLEASE IDENTIFY THESE CHANGES.

A. The formula rate that the Companies are filing differs from the Attachment O formula rate in the following respects:

- *Transition Costs*: As a result of the transition to PJM, the Companies will be charged an exit fee by the Midwest ISO ("Midwest ISO Exit Fee"), and have entered into a Settlement Agreement under which, if approved by the Commission, they would make a payment to the Midwest ISO to address alleged adverse effects on the feasibility of Long-Term Firm Transmission Rights resulting from the Companies' withdrawal from the Midwest ISO ("LTTR Exit Charge"). The Companies will also be subject to integration fees assessed by PJM ("PJM Integration Costs"). For purposes of this filing, the Midwest ISO Exit Fee, LTTR Exit Charge, and PJM Integration Costs will be referred to as "Transition Costs." These costs are included in the formula rate. As defined herein, Transition Costs exclude any transmission enhancement project cost from either ISO. I discuss this change in more detail in Section III.D of my testimony.

- *Regional Transmission Expansion Planning ("RTEP")*: Under Schedule 12 of PJM's OATT, transmission customers are billed for projects approved under PJM's Regional Transmission Planning process, including projects constructed in the DEOK Zone. Because transmission customers are billed directly by PJM for such costs, the charge is not included in the NITS and PTP service revenue requirement calculation. A line has been added to the formula rate to identify transmission enhancement revenue credited to the Companies by PJM under Schedule 12 of its OATT. Line 5b, on page 1 of Attachment H-22A, will reflect any credits to the Companies under Schedule 12. The methodology and formula for this adjustment are included as Appendix B to Attachment H-22A. I discuss this change in more detail in Section III.E of my testimony.
- *Firm PTP Service Revenue Credit Adjustment*: The Companies are likely to receive different credits for firm PTP service in PJM than they received in the Midwest ISO. Because the Companies' rates are based on historical data, the rates they will charge in PJM for the first seventeen months (*i.e.*, January 1, 2012, through May 31, 2013) will be based on experience in the Midwest ISO. The methodology and formula for this adjustment are provided as a separate schedule

in the application. I discuss this in more detail in Section III.F of my testimony.

- *Non-Firm PTP Service Revenue Credit:* In the Midwest ISO, revenues from non-firm PTP service are used to reduce the overall transmission revenue requirement, whereas in PJM such revenues are directly credited to customers. Accordingly, this offset is being removed from the formula rate. I discuss this change in more detail in Section III.F. of my testimony.
- *1 CP vs. 12 CP*: PJM uses a different basis from that used in the Midwest ISO for billing NITS. Instead of using the average of the 12 peaks coincident with the RTO's peak demand (*i.e.*, "12 CP"), PJM uses the Companies' demand at the time of the transmission zone's annual peak (*i.e.*, "1 CP"). For PTP service, both use 12 CP. To accommodate the difference in billing data, additional load data were added to the Attachment H-22A formula. Adjustments to the FERC Form 1 data are being made for load served at both the Longbranch and Hebron substations, consistent with PJM's practices and to conform the rate divisor to the total load billed.
- *Adjustment Between PTP Contract Demand and Load*: Under the Midwest ISO's ASM Tariff, Transmission Owners are required to adjust for differences between contract demand and actual load when

calculating demand on the system. The PJM OATT does not provide for this adjustment; therefore, it is being eliminated from the formula rate.

- *FERC Annual Charges*: Lines 21 and 22, on page 1 of the Companies' Attachment O formula rate, relate to FERC Annual Charges assessed to the Transmission Owner under the Midwest ISO's ASM Tariff. This charge has been calculated and administered by the Midwest ISO under Schedule 10-FERC of the Midwest ISO's ASM Tariff; therefore, it is not part of the overall revenue requirement calculation for NITS and PTP service. PJM has a similar charge billed in the same manner. Inasmuch as this charge is independent of the NITS and PTP revenue requirement calculation, references to it are being removed from the proposed Attachment H-22A.
- *Other Electric Revenue (Account 456.1):* Several of the existing lines on the Companies' Attachment O are being replaced with a single line (page 4, line 35) for the amount of certain revenues that will be credited against the revenue requirement. Additional revenue credits specifically identified on page 1, lines 4a through 5c, are excluded from page 4, line 35.

- *Depreciation Rates and PBOP Expense:* The formula rate protocols (discussed below) specify that depreciation rates and Post-Employment Benefits Other Than Pensions ("PBOP") shall be stated values until changed pursuant to a filing with the Commission. To comply with this requirement, the Companies are amending the formula rate to state the transmission, general plant, and intangible plant depreciation rates and PBOP values that are used in the formula rate. These are the same depreciation rates and PBOP expenses that the Companies currently are using under Attachment O. The depreciation rates are set forth in Appendix D to Attachment H-22A.

Q. HAVE YOU INCLUDED A CALCULATION OF THE NEW REVENUE REQUIREMENT AND PROPOSED RATES FOR NITS AND PTP SERVICE IN THIS FILING?

A. Yes. The filing herein includes a series of schedules that represent the Companies' calculation of the NITS and PTP service revenue requirement and rate calculation, which will be identified as Attachment H-22A in PJM's OATT. There are three sets of schedules: one each for Duke Energy Ohio and Duke Energy Kentucky, and one for the combined companies which, for purposes of presentation, is identified as DEOK. The DEOK revenue requirement and rate calculation is ultimately what will be the basis for billing customers, but it is necessary to do the calculation for both Companies as part of that overall calculation. These calculations are included in Exhibit No. DUK-101. Additional work papers supporting the calculation of the revenue requirement are included in Exhibit No. DUK-102.

For comparison, I have also included a calculation of the same rates for the two companies under the Midwest ISO's Attachment O. For this comparison, I am including the schedules for Duke Energy Ohio and Duke Energy Kentucky that were filed with the most recent Attachment O update with the Midwest ISO in May 2011. These calculations are included in Exhibit No. DUK-103.

Q. ARE THE COMPANIES PROPOSING ANY CHANGES TO SCHEDULES 7 AND 8 OF PJM'S OATT?

A. Yes. The Companies are amending Schedules 7 and 8 to indicate that the PTP service rate for the DEOK Zone will be as calculated under Attachment H-22A.

B. Transmission Owner Scheduling, System Control, and Dispatch Service

Q. HOW WILL THE CALCULATION OF THE COMPANIES' REVENUE REQUIREMENTS FOR TRANSMISSION OWNER SCHEDULING, SYSTEM CONTROL, AND DISPATCH SERVICE BE AFFECTED BY THE TRANSFER TO PJM?

A. The Companies currently recover the costs for Transmission Owner Scheduling, System Control, and Dispatch Service under two schedules in Midwest ISO's ASM Tariff, namely Schedule 1 and Schedule 24. In the Midwest ISO, these costs are aggregated with other providers and regionalized for recovery.

In PJM, in contrast, the charges for Transmission Owner Scheduling, System Control, and Dispatch Service are included in a single schedule – Schedule 1A – and are based on the revenue requirement for each zone. Transmission customers must purchase this Schedule 1A service from the Transmission Owner, and the costs to be recovered are equal to the Companies' costs of providing this service.

Appendix A of Attachment H-22A sets forth the formula rate for calculating the charges for Transmission Owner Scheduling, System Control, and Dispatch Service based on the cost of operating the control centers of Duke Energy Ohio and Duke Energy Kentucky. The eligible costs for recovery for this service are recorded in specific accounts under the Commission's Uniform System of Accounts ("USofA"). Generally, the revenue requirement for Schedule 1A is equal to the sum of selected FERC operating and maintenance ("O&M") accounts as represented in the Form 1. Dividing these O&M accounts by energy usage (*i.e.*, MWhs) in the new "DEOK Zone" determines the rate.

Following the same proposal with the calculation of the Companies' NITS and PTP service rates, the Companies propose to make minimal changes to the formula for calculating this charge beyond what is needed to reflect the move to PJM and to reflect any credits that may be due to the Companies.

Q. ARE THE COMPANIES PROPOSING ANY CHANGES TO SCHEDULE 1A?

A. Yes. The Companies are amending Schedule 1A to indicate that for a Transmission customer serving DEOK Zone load, the rate for Transmission Owner Scheduling, System Control, and Dispatch Service will be as calculated under Attachment H-22A, Appendix A.

Q. DOES THE CHANGE FOR SCHEDULE 1A HAVE ANY EFFECT ON THE CHANGES BEING PROPOSED FOR THE NITS AND PTP SERVICE REVENUE REQUIREMENT CALCULATION?

A. No. The costs being recovered under PJM's Schedule 1A and the costs recovered under the Midwest ISO's Schedules 1 and 24 are all excluded from the NITS and PTP revenue requirement calculation and, therefore, have no bearing on the changes being proposed for Attachment H-22A.

Q. HOW ARE REVENUES UNDER SCHEDULE 1A FROM NON-ZONAL CUSTOMERS TREATED?

A. PJM distributes non-zonal revenue to transmission owners based on allocations developed in stakeholder processes. Revenue recovered for Transmission Owner Scheduling, System Control, and Dispatch Service from non-zonal customers is distributed according to the established allocations and any such revenue received by the Companies will offset amounts to be recovered from zonal customers. This revenue credit is reflected in Attachment H-22A, Appendix A, line 2. Until such time as PJM establishes the percentage of non-zonal Schedule 1A revenue allocable to the Companies, this credit is set at $0; however, it is expected that PJM will revise its schedule of allocations for Schedule 1A non-zonal revenue to reflect the Companies' PJM membership.

C. Legacy MTEP Charges and Legacy MTEP Credits

Q. DOES THE MIDWEST ISO HAVE A PROCESS FOR TRANSMISSION EXPANSION?

A. Both the Midwest ISO and PJM have processes for approving and implementing certain capital additions to the footprints of their respective RTOs. In both RTOs, the costs for such facilities are generally socialized among all RTO members in whole or in part. The Midwest ISO's process for this is known as the Midwest ISO Transmission Expansion Plan ("MTEP").

Q. PLEASE DISCUSS THE RATE TREATMENT FOR THESE PROJECTS.

A. Currently, customers within the Duke MISO Zone pay for their share of the revenue requirement associated with MTEP projects across the entire footprint of the Midwest ISO. I have been advised by counsel that the Midwest ISO has asserted that the Companies should continue to be responsible for some portion of the revenue requirement for Legacy MTEP projects outside of the DEOK Zone that have been constructed, or are approved by the Midwest ISO Board of Directors before the date of the Companies' departure from the Midwest ISO ("Legacy MTEP" projects). The charges ("Legacy MTEP Charges") are based on the revenue requirements associated with the projects. I understand that the Companies disagree with the Midwest ISO's position with respect to certain Legacy MTEP projects called MVP projects, but I have been asked to design mechanisms that would recover any such cost assignments whatever they are adjudicated to be.

The Companies also receive payments from Midwest ISO transmission customers in other transmission zones, via the Midwest ISO, for their share of the revenue requirement associated with any projects the Companies have constructed under the MTEP process, or are approved by the Midwest ISO Board of Directors prior to the Companies' integration into PJM. These credits ("Legacy MTEP Credits") are based on the revenue requirements associated with the projects.

Q. IS THERE A PROCESS IN THE PJM OATT FOR CHARGING COSTS AND DISTRIBUTING REVENUES RELATED TO LEGACY MTEP FACILITIES?

A. The Companies are proposing to add Attachment JJ to the PJM OATT for this purpose. Attachment JJ will establish the process for charging transmission customers within the DEOK Zone for a proportionate share of costs associated with Legacy MTEP projects constructed by transmission owners in the Midwest ISO. Generally, the procedure is that the Midwest ISO will bill PJM for Legacy MTEP costs, and PJM will collect these charges from customers, just as the Midwest ISO did under Schedule 26 of the Midwest ISO ASM Tariff.

Attachment JJ will also establish the mechanism by which the Companies will receive revenue for projects they have constructed or will construct pursuant to the MTEP approval process. Under Attachment JJ, the Midwest ISO will remit to PJM revenues for MTEP projects the Companies have constructed pursuant to the Midwest ISO ASM Tariff, and PJM will remit these revenues to the Companies.

Q. HOW ARE THE COMPANIES PROPOSING TO REFLECT THE MTEP CREDITS IN THE REVENUE REQUIREMENT CALCULATION?

A. Under Attachment JJ, the Companies will continue to receive credits for projects they have constructed as members of the Midwest ISO; therefore, the formula rate in Attachment H-22A will continue to include the adjustment for the reduction in revenue requirement attributable to the revenue being received for these Legacy MTEP projects. For clarity, this credit will now appear with the other revenue credits in the formula rate (page 1, line 5a), rather than on page 3, line 30 of Attachment O. The credit is included on page 1, line 5a, and is calculated in Appendix C, which is equivalent to Attachment GG under the Midwest ISO's ASM Tariff. Specifically, Appendix C provides calculations to reflect the revenue requirements associated with these MTEP projects. Because the formula rate for NITS and PTP revenue requirements within the DEOK Zone is based on the overall cost of providing these services, including the projects deemed related to MTEP obligations, it is appropriate to credit the revenue collected for these MTEP projects against the overall revenue requirement.

Q. HOW ARE THE COMPANIES PROPOSING THAT THE MTEP CHARGES BE RECOVERED?

A. These charges are not included in the Companies' existing formula rate; instead, the Midwest ISO bills customers directly for these costs. The Companies are proposing to keep this same process in place, except that PJM, rather than the Midwest ISO, will do the billing. NITS customers will be billed based on their load ratio share, while PTP service customers will be billed based on their reservations. It is appropriate that customers bear responsibility for the charges for these MTEP projects since they are part of the Companies' cost of providing NITS and PTP service.

D. Transition Costs

Q. EARLIER IN YOUR TESTIMONY YOU DISCUSSED TRANSITION COSTS. WILL YOU EXPLAIN THESE COSTS IN MORE DETAIL?

A. Yes. As I briefly addressed above, as a result of the transition from the Midwest ISO to PJM, the Companies expect that there will be three broad categories of costs for the transition:

- *PJM Integration Costs*: These are costs to integrate the Companies' operations and systems with PJM. These costs will be directly billed to the Companies by PJM.
- *Midwest ISO Exit Fee*: The Midwest ISO will be charging the Companies an amount equal to their financial obligations incurred related to the Midwest ISO's long-term liabilities associated with its administration costs for Schedule 10 (Transmission), Schedule 16 (FTR Service), and Schedule 17 (Energy Market Service) under the Midwest ISO's ASM Tariff.
- *LTTR Exit Charge:* The Companies have agreed (in a settlement subject to Commission approval) to pay the Midwest ISO $1.8 million to resolve the dispute between the Companies and the Midwest ISO regarding alleged adverse effects on the feasibility of Long-Term Firm Transmission Rights resulting from the Companies' departure from the Midwest ISO.

Q. ARE THESE COSTS INCLUDED IN THE FORMULA RATE?

A. Yes. In order to provide additional transparency as well as ensure the proper cost allocation, the Companies have added lines to the formula rate to accommodate these costs. The two Midwest ISO fees (Midwest ISO Exit Fee and LTTR Exit Charge) are included on page 3, line 1c ("Midwest ISO Fees"), and the PJM Integration Costs will be included on page 3, line 3d. These costs are allocated to transmission service customers, since the costs were incurred on their behalf. In order to ensure that there is no double recovery of these costs, lines have been added to the formula rate to subtract these costs from the O&M and A&G expenses of which they are a part. These subtractions appear on page 3, lines 1b and 3c.

Q. DO THE COMPANIES HAVE AN ESTIMATE OF THE TOTAL AMOUNT OF TRANSITION COSTS?

A. The Companies recently reached an agreement with the Midwest ISO as to how the exit fee will be calculated. The PJM Integration costs are expected to be up to $1 million, while the LTTR Exit Charge is $1.8 million. The Companies have developed an estimate of the total Transition Costs. Using the best information known to the Companies at this time, it is expected that the sum of the Transition Costs to be incurred by the Companies will be approximately $17.2 million. Again, this is an estimate and, in addition to the uncertainty around the magnitude of the number, it is also uncertain over what period(s) these costs will be incurred.

Q. WHY ARE THE COMPANIES PROPOSING THAT THEY BE ALLOWED TO RECOVER THE TRANSITION COSTS?

A. It is the Companies' position that the transition from the Midwest ISO to PJM will be in the best interests of all stakeholders, including their wholesale customers. A general proposition in ratemaking is that a regulated company is permitted to recover its prudently incurred costs of constructing, operating, and maintaining facilities that are used and useful for the provision of utility service, and I believe that to be the case with respect to Legacy MTEP Costs and the Transition Costs. In addition, I have been informed that Companies' Witness Robert B. Stoddard has determined that the benefits of the move clearly outweigh the Transition Costs and Legacy MTEP Costs. While it is the Companies' position that such a showing should not be required, a showing that benefits outweigh costs further supports my view that it is appropriate and fair to allow the Companies to recover from wholesale transmission customers the costs associated with the transition.

Q. DO THE COMPANIES PROPOSE TO RECOVER THESE COSTS AS THEY ARE BILLED TO THE COMPANIES?

A. It is the Companies' intention to include the Transition Costs in the formula rate calculation as they are incurred. In this instant proceeding, the Companies are submitting a formula rate for establishing the NITS and PTP revenue requirement based on 2010 actual results. By May 15, 2012, the Companies will update the formula rate using 2011 actual results, with the revised rates going into effect June 1, 2012. Each year thereafter, the formula rate will be updated on the same timeline for the then most current actual data for the prior calendar year.

E. Transmission Enhancement Credits

Q. DOES THE COMPANIES' FORMULA RATE ADDRESS HOW THE COMPANIES WILL BE COMPENSATED FOR TRANSMISSION ENHANCEMENT PROJECTS FOR WHICH THEY ARE RESPONSIBLE?

A. Yes. To the extent that the Companies are assigned responsibility for constructing transmission enhancement projects by PJM, they will be entitled to recover the costs of such projects from customers outside the DEOK Zone under Schedule 12 of PJM's OATT. The revenue requirement for such projects will be developed pursuant to a formula included as Appendix B to Attachment H-22. The revenue requirement calculated in

Appendix B is provided to PJM for billing and PJM will, in turn, credit the Companies for their transmission enhancement projects.

Inasmuch as the rate base and operating expense associated with such projects are included in the overall NITS and PTP revenue requirement calculation, the revenue collected for such projects will be credited against the overall NITS and PTP revenue requirement calculation.

Q. PLEASE PROVIDE A SUMMARY OF THE PROCESS OUTLINED IN APPENDIX B.

A. The formula shown in Appendix B is a standard revenue requirement calculation and essentially mirrors the current formula used by the Companies to calculate the revenue requirement for MTEP projects under Attachment GG of Midwest ISO's ASM Tariff. The formula uses input data associated with the RTEP projects including gross plant, O&M expense, taxes other than income taxes, a return component, and income taxes.

Q. ARE THE COMPANIES INCLUDING ANY PJM TRANSMISSION ENHANCEMENT CREDITS IN THIS INITIAL FILING?

A. No. This credit will only be for projects constructed by the Companies and approved by PJM under its RTEP process. Inasmuch as the Companies are not yet members of PJM, there are no projects to include in this calculation for purposes of this filing. Consequently, for the initial rates, the value of this adjustment is $0. However, to the extent that the Companies are eligible for such credits in the future, they will be reflected on line 5b of page 1 of the Attachment H-22A formula rate.

F. PTP Revenue Credits

Q. HOW DOES REVENUE RECEIVED FOR NON-FIRM PTP SERVICE IMPACT THE OVERALL REVENUE REQUIREMENT CALCULATION?

A. Under the Midwest ISO's ASM Tariff, revenue from non-firm PTP is credited against the overall revenue requirement to reduce the overall rate. In PJM, revenue it receives for non-firm PTP is credited directly to transmission customers. Because PJM provides the credit directly to customers rather than treating these non-firm PTP revenues as an offset to overall transmission revenue requirement, an adjustment is required to the formula rate to remove the offset included in Attachment O that will now be handled directly by PJM. In the proposed Attachment H-22A, the impact of this adjustment is reflected on page 4, line 35, "ACCOUNT 456.1 (OTHER ELECTRIC REVENUES)." The change increases the transmission revenue requirement by $688,948 and the rate impact to transmission customers should be mitigated by the credits PJM will deliver directly to customers for non-firm PTP revenue.

Q. WHAT IS THE NATURE OF THE FIRM PTP REVENUE CREDIT ADJUSTMENT YOU ARE PROPOSING IN THIS CASE?

A. This adjustment is simply to recognize another transitional item associated with the Companies' move to PJM. The Companies' NITS and PTP service rates are being established using actual results from a historical test year, 2010 in this initial case. It is expected that the Companies will experience different levels of revenue associated with firm PTP service as a member of PJM than they did in 2010 as a member of the Midwest ISO. Because the actual firm PTP revenue is an offset to the overall revenue requirement calculation, the Companies are proposing to essentially reconcile the difference for as long as the applicable rates are based on a test year based on experience in the Midwest ISO rather than PJM. The proposed calculation of the PTP Revenue Credit is provided in Appendix E of Attachment H-22.

Q. HOW WILL THIS ADJUSTMENT WORK?

A. During the first five months of calendar year 2012, the firm PTP service revenue credit included in the Companies' rates will reflect firm PTP service revenues received in the Midwest ISO during 2010, rather than their firm PTP service revenues received in PJM during the first five months of 2012. Accordingly, the Companies will compare the amount of their firm PTP service revenues received in the Midwest ISO during the first five months of 2010 to the actual firm PTP service revenues they will receive in PJM during the first five months of 2012, and create a deferral for the accumulated difference. Similarly, the NITS and PTP service rates to be effective beginning June 1, 2012, will be based on actual data for 2011. Consequently, the same issue persists for the period June 1, 2012, through May 31, 2012, when the NITS and PTP service rates will be based, in part, on the firm PTP service revenues being received in the Midwest ISO (*i.e.*, during 2011) even though there is likely to be a significant difference in the firm PTP revenues expected to actually be received during the period when the new rates would be effective.

As reflected in Appendix E and the associated workpaper, the Companies will track the difference between the firm PTP service revenue actually received in PJM and the firm PTP service revenue flowing through NITS and PTP service rates during the same period. Appendix E will be used to reflect the monthly difference in firm PTP service revenue and will be used to calculate the carrying costs on the deferral net of deferred taxes. Of course, it is possible that firm PTP service revenue in PJM could be higher than in the Midwest ISO, which would reduce the deferral and its impact on future rates.

Q. WHEN WILL THE COMPANIES BEGIN RECOVERING THE BALANCE OF THE DEFERRAL?

A. The first opportunity for recovering the balance of the true-up adjustment for firm PTP service revenue will be the rate year beginning June 1, 2013. The rates to be implemented on June 1, 2013, will be based on actual historical data for 2012, which is the first year of the Companies' transition to PJM. The NITS and PTP service rates for first five months of 2013 will be based on actual data for 2011; consequently, there will continue to be deferrals through May 31, 2013, the last month that NITS and PTP service rates will be based on the Companies' experience in the Midwest ISO. The implication of this is that the firm PTP service revenue true-up adjustment will be addressed one final time when the Companies calculate new rates under Attachment H-22 for the twelve months beginning June 1, 2014.

Q. ARE THERE ANY ACCOUNTING IMPLICATIONS OF THIS PROPOSED ADJUSTMENT?

A. Yes. Because this is a deferral for which the Companies expect to recover in rates, the Companies will record the deferral and any associated carrying costs in a regulatory asset account (*i.e.*, Account 182.3 of the Uniform System of Accounts). The regulatory asset will be amortized when recovery of the deferral begins.

IV. FORMULA RATE PROTOCOLS

Q. HAVE THE COMPANIES PREPARED A SET OF PROTOCOLS TO ACCOMPANY THE PROPOSED CALCULATION OF REVENUE REQUIREMENTS?

A. Yes. The Companies' filing includes proposed Attachment H-22B, which includes a detailed set of protocols describing the process to be used by the Companies for developing the formula rates for NITS, PTP, and Transmission Owner Scheduling, System Control, and Dispatch Service under Schedule 1A. The protocols being proposed here are similar to protocols approved by the Commission for Commonwealth Edison,[6] and generally describe the methodology for the annual updates that will be made to the formula rates. Additionally, the protocols describe how the annual update will be posted and made available to customers, how customers can review the filings, how information requests will be handled, and how informal dispute resolutions regarding the annual update will be addressed.

Q. WILL YOU GIVE A BRIEF OVERVIEW OF THE PROTOCOLS?

A. The protocols generally provide a discussion of the process the Companies will use to annually update its rates under Attachment H-22. Similar to the

[6] Attachment H-13 of PJM's OATT.

process currently followed for updating their rates as members of the Midwest ISO, the Companies will file by May 15th of each year all of the schedules, calculations, and assumptions used to support the revenue requirement calculation in Attachment H-22A. All of the information will be posted on PJM's website and the Companies will also file the information with the Commission. Any interested party will have up to one hundred eighty (180) days to review the material and to notify the Companies of any specific issues it seeks to challenge in the annual update filing. The protocols provide parties with an opportunity to submit reasonable data requests to the Companies and include a dispute resolution process that includes the opportunity to pursue disputes at the Commission.

V. SUMMARY OF PROPOSED TARIFF CHANGES

Q. WILL YOU SUMMARIZE THE TARIFF CHANGES YOU ARE SPONSORING?

A. I am sponsoring the Companies' changes to Schedules 1A, 7, and 8, which add references to the Companies' formula rates. In addition, I am sponsoring the Company's proposed Attachment H-22, which is comprised of the following:

Introduction: Includes an outline and summary of the NITS and PTP rate calculation and any relevant information regarding the rate calculation.

Attachment H-22A: Provides the detailed calculations and supporting data to calculate the NITS and PTP rates. References to source data are included. In addition to the formula rate, Attachment H-22A includes five appendices, as follows:

Appendix A: Provides the detailed calculations and supporting data to calculate the Companies' Schedule 1A rate.

Appendix B: Provides the detailed calculations and supporting data to calculate the net RTEP transmission enhancement credit included in Attachment H-22A.

Appendix C: Provides the detailed calculations and supporting data to calculate the MTEP credit included in Attachment H-22A.

Appendix D: Provides the Companies' depreciation rates.

Appendix E: Provides the detailed calculations and supporting data to reconcile changes in actual PTP revenues in PJM versus amount in rates.

Attachment H-22B: Formula Rate Implementation Protocols.

Q. WHEN ARE THE COMPANIES PROPOSING TO IMPLEMENT THE NEW RATES BEING PROPOSED IN THIS FILING?

A. The Companies request implementation of the new rates on January 1, 2012, contemporaneous with the first day of their move to PJM.

VI. CONTINUITY OF SERVICE

Q. WHAT IMPACT WILL THE COMPANIES' TRANSITION TO PJM HAVE ON THOSE AGREEMENTS LISTED AS GRANDFATHERED AGREEMENTS IN ATTACHMENT P TO THE MIDWEST ISO ASM TARIFF?

A. Those agreements, which do not involve the provision of transmission service, will generally retain the same rates, terms, and conditions but will become PJM OATT service agreements. Minor modifications likely will be proposed, if necessary, in a separate filing to reflect the transition.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.,	)	
Duke Energy Ohio, Inc., and	)	**Docket No. ER12-______**
Duke Energy Kentucky, Inc.	)	

AFFIDAVIT OF WILLIAM DON WATHEN JR.

William Don Wathen Jr., being first duly sworn, deposes and says that he is the William Don Wathen Jr., referred to in the foregoing testimony, that he has read such testimony and is familiar with the contents thereof, and that the answers therein are true and correct to the best of his knowledge, information, and belief.

Don Wathen Jr.

William Don Wathen Jr.

Subscribed and sworn to me before this 14th day of October 2011, by William Don Wathen Jr., proved to me on the basis of satisfactory evidence to be the person who appeared before me.

Elizabeth H Watts

Notary Public

Commission Expires on: Does Not Expire

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2010

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)					$ 76,114,260
	REVENUE CREDITS (Note T)		Total	Allocator		
2	Account No. 454	(page 4, line 34)	$ 2,138,192	TP	0.88109	$ 1,883,941
3	Account No. 456.1	(page 4, line 35)	10,713,648	TP	0.88109	9,439,696
4a	Revenues from Grandfathered Interzonal Transactions		0	TP	0.88109	0
4b	Revenues from service provided by ISO at a discount		0	TP	0.88109	0
5a	Legacy MTEP Credit (Appendix C, page 2, line 3, col. 12)		2,745,291		1.00000	2,745,291
5b	RTEP Transmission Enhancement Credit (Appendix B, page 2, line 3, col. 12)		0		1.00000	0
5c	Firm PTP Revenue Credit Adjustment (Appendix E, line 10, col. 3)		0		1.00000	0
6	TOTAL REVENUE CREDITS (sum lines 2-5c)					$ 14,068,929
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ 62,045,331
	DIVISOR					
8	1 CP (Note A)					5,571,000
9	12 CP (Note B)					4,407,000
10	Reserved					
11	Reserved					
12	Reserved					
13	Reserved					
14	Reserved					
15	Annual Cost ($/kW/Yr) - 1 CP	(line 7 / line 8)	$11.137			
16	Annual Cost ($/kW/Yr) - 12 CP	(line 7 / line 9)	$14.079			
17	Network Rate ($/kW/Mo)	(line 15 / 12)	$0.928			
17a	Point-To-Point Rate ($/kW/Mo)	(line 16 / 12)	$1.173			
			Peak Rate			Off-Peak Rate
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	$0.271			
19	Point-To-Point Rate ($/kW/Day)	(line 16 / 260; line 16 / 365)	$0.054	Capped at weekly rate		$0.039
20	Point-To-Point Rate ($/MWh)	(line 16 / 4,160; line 16 / 8,760 * 1000)	$0.003	Capped at weekly and daily rate		$1.607

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2010

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

Line No.	(1) RATE BASE:	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col. 3 times Col. 4)
	GROSS PLANT IN SERVICE					
1	Production	205.46.g	$ 5,824,679,801	NA		
2	Transmission	207.58.g	700,368,802	TP	0.88109	$ 617,088,486
3	Distribution	207.75.g	2,187,696,932	NA		
4	General & Intangible	205.5.g & 207.99.g	187,573,057	W/S	0.02847	5,340,899
5	Common	356.1	272,290,958	CE	0.02435	6,628,971
6	TOTAL GROSS PLANT (sum lines 1-5)		$ 9,172,609,550	GP=	6.858%	$ 629,058,356
	ACCUMULATED DEPRECIATION					
7	Production	219.20-24.c	$ 2,082,873,195	NA		
8	Transmission	219.25.c	245,324,444	TP	0.88109	$ 216,153,103
9	Distribution	219.26.c	756,639,434	NA		
10	General & Intangible	219.28.c	11,610,690	W/S	0.02847	330,599
11	Common	356.1	128,664,096	CE	0.02435	3,132,350
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		$ 3,225,111,859			$ 219,616,052
	NET PLANT IN SERVICE					
13	Production	(line 1 - line 7)	$ 3,741,806,606			
14	Transmission	(line 2 - line 8)	455,044,358			$ 400,935,383
15	Distribution	(line 3 - line 9)	1,431,057,498			
16	General & Intangible	(line 4 - line 10)	175,962,367			5,010,300
17	Common	(line 5 - line 11)	143,626,862			3,496,621
18	TOTAL NET PLANT (sum lines 13-17)		$ 5,947,497,691	NP=	6.884%	$ 409,442,304
	ADJUSTMENTS TO RATE BASE (Note F)					
19	Account No. 281 (enter negative)	273.8.k	$ (15,859,572)	NA	zero	$ -
20	Account No. 282 (enter negative)	275.2.k	(1,263,992,853)	NP	0.06884	(87,016,788)
21	Account No. 283 (enter negative)	277.9.k	(218,268,409)	NP	0.06884	(15,026,205)
22	Account No. 190	234.8.c	33,166,739	NP	0.06884	2,283,291
23	Account No. 255 (enter negative)	267.8.h	(3,965,127)	NP	0.06884	(272,970)
24	TOTAL ADJUSTMENTS (sum lines 19- 23)		$ (1,468,919,222)			$ (100,032,673)
25	LAND HELD FOR FUTURE USE (Note G)	214.x.d	$ 125,772	TP	0.88109	$ 110,817
	WORKING CAPITAL (Note H)					
26	CWC	calculated	$ 29,364,327			2,041,131
27	Materials & Supplies (Note G)	227.8.c & .16.c	7,727,868	TE	0.83622	6,462,220
28	Prepayments (Account 165)	111.57.c	47,181,052	GP	0.06858	3,235,681
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		$ 84,273,247			$ 11,739,031
30	RATE BASE (sum lines 18, 24, 25, & 29)		$ 4,562,977,488			$ 321,259,479

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2010

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col. 3 times Col. 4)
	O&M					
1	Transmission	321.112.b	$ 39,439,018	TE	0.83622	$ 32,979,809
1a	Less LSE Expenses included in Transmission O&M Accounts (Note V)	321.88.b, 92.b; 322.121.b	3,224,016		1.00000	3,224,016
1b	Less Midwest ISO Exit Fees included in Transmission O&M	(Note X)	0	TE	0.83622	0
1c	Plus Midwest ISO Exit Fees	(Note X)	0		1.00000	0
2	Less Account 565	321.96.b	23,747,074	TE	0.83622	19,857,846
3	A&G	323.197.b	230,631,902	W/S	0.02847	6,566,944
3a	Less Actual PBOP Expense	(Note E)	2,918,402	W/S	0.02847	83,098
3b	Plus Fixed PBOP Expense	(Note E)	2,918,402	W/S	0.02847	83,098
3c	Less PJM Integration Costs included in A&G	(Note Y)	100,069	W/S	0.02847	2,849
3d	Plus PJM Integration Costs	(Note Y)	100,069		1.00000	100,069
4	Less FERC Annual Fees	350.14.b	949,771	W/S	0.02847	27,043
5	Less EPRI & Reg. Comm. Exp. & Non-safety Advertising (Note I)		7,235,444	W/S	0.02847	206,020
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.83622	0
6	Common	356.1	0	CE	0.02435	0
7	Transmission Lease Payments		0		1.00000	0
8	TOTAL O&M (sum lines 1, 2a, 3, 5a, 6, 7 less lines 1a, 2, 4, 5)		$ 234,914,615			$ 16,329,047
	DEPRECIATION EXPENSE					
9	Transmission	336.7.b	$ 11,730,584	TP	0.88109	$ 10,335,709
10	General	336.10.b	2,449,704	W/S	0.02847	69,752
11	Common	336.11.b	4,949,571	CE	0.02435	120,498
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		$ 19,129,859			$ 10,525,960
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
13	Payroll	263.i	$ 14,725,694	W/S	0.02847	$ 419,295
14	Highway and vehicle	263.i	39,763	W/S	0.02847	1,132
15	PLANT RELATED					
16	Property	263.i	102,743,065	GP	0.06858	7,046,128
17	Gross Receipts	263.i	4,568,022	NA	zero	0
18	Other	263.i	0	GP	0.06858	0
19	Payments in lieu of taxes		0	GP	0.06858	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		$ 122,076,544			$ 7,466,555
	INCOME TAXES (Note K)					
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		35.357500%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		43.569937%			
	where WCLTD=(page 4, line 27) and R= (page 4, line 30)					
	and FIT, SIT & p are as given in footnote K.					
23	1 / (1 - T) = (from line 21)		1.5470			
24	Amortized Investment Tax Credit	266.8.f (enter negative)	0			
25	Income Tax Calculation (line 22 * line 28)		$ 180,142,509	NA		$ 12,683,054
26	ITC adjustment (line 23 * line 24)		0	NP	0.06884	0
27	Total Income Taxes	(line 25 plus line 26)	$ 180,142,509			$ 12,683,054
28	RETURN		$ 413,455,974	NA		$ 29,109,644
	[Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]					
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		$ 969,719,501			$ 76,114,260

Formula Rate - Non-Levelized | For the 12 months ended 12/31/2010

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)
SUPPORTING CALCULATIONS AND NOTES

Line No.	TRANSMISSION PLANT INCLUDED IN ISO RATES		
1	Total transmission plant (page 2, line 2, column 3)		$ 700,368,802
2	Less transmission plant excluded from ISO rates (Note M)		0
3	Less transmission plant included in OATT Ancillary Services (Note N)		83,280,316
4	Transmission plant included in ISO Rates (line 1 less lines 2 & 3)		$ 617,088,486
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)	TP=	0.88109
	TRANSMISSION EXPENSES		
6	Total transmission expenses (page 3, line 1, column 3)		$ 39,439,018
7	Less transmission expenses included in OATT Ancillary Services (Note L)		2,008,358
8	Included transmission expenses (line 6 less line 7)		$ 37,430,660
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)		0.94908
10	Percentage of transmission plant included in ISO Rates (line 5)	TP	0.88109
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)	TE=	0.83622

WAGES & SALARY ALLOCATOR (W&S)

Line		Form 1 Reference	$	TP	Allocation		W&S Allocator ($ / Allocation)	
12	Production	354.20.b	68,848,052	0.00	0			
13	Transmission	354.21.b	3,983,058	0.88	3,509,436			
14	Distribution	354.23.b	27,424,899	0.00	0			
15	Other	354.24,25,26.b	22,995,816	0.00	0			
16	Total (sum lines 12-15)		123,251,825		3,509,436	=	0.02847	= WS

COMMON PLANT ALLOCATOR (CE) (Note O)

Line			$	% Electric (line 17 / line 20)		W&S Allocator (line 16)		CE
17	Electric	200.3.c	7,822,343,580					
18	Gas	201.3.d	1,326,536,176	0.85501	*	0.02847	=	0.02435
19	Water	201.3.e	0					
20	Total (sum lines 17 - 19)		9,148,879,756					

RETURN (R)

Line			$
21		Long Term Interest (117, sum of 62.c through 67.c)	112,585,499
22		Preferred Dividends (118.29c) (positive number)	0
	Development of Common Stock:		
23		Proprietary Capital (112.16.c)	3,669,022,997
24		Less Preferred Stock (line 28)	0
25		Less Account 216.1 (112.12.c) (enter negative)	(108,049,782)
26		Common Stock (sum lines 23-25)	3,560,973,215

Line		(Note P)	$	%	Cost	Weighted	
27	Long Term Debt (112, sum of 18.c through 21.c)		2,546,827,765	42%	0.0442	0.0184	=WCLTD
28	Preferred Stock (112.3.c)		0	0%	0.0000	0.0000	
29	Common Stock (line 26)		3,560,973,215	58%	0.1238	0.0722	
30	Total (sum lines 27-29)		6,107,800,980			0.0906	=R

REVENUE CREDITS

Line			Load
	ACCOUNT 447 (SALES FOR RESALE) (Note Q)	(310-311)	
31	a. Bundled Non-RQ Sales for Resale (311.x.h)		0
32	b. Bundled Sales for Resale included in Divisor on page 1		-
33	Total of (a)-(b)		0
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)		$ 2,138,192
35	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) (Note U)	(330.x.n)	$ 10,713,648

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2010

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)

References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter

A DEOK 1 CP is Duke Energy Ohio ("DEO") Monthly Firm Transmission System Peak Load as reported on page 400, column b of Form 1 at the time of DEO's annual peak, plus load served by Duke Energy Kentucky at Longbranch. For years ending 12/31/2010 and 12/31/2011, this sum will be reduced by the amount of distribution load served by East Kentucky Power Cooperative via Duke Kentucky's Hebron substation. Excludes demands from grandfathered interzonal transactions and demands from service provided by ISO at a discount.

B DEOK 12 CP is DEO Monthly Firm Transmission System Peak Load as reported on page 400, column b of Form 1 at the time of DEO's monthly peaks, plus load served by Duke Kentucky at Longbranch. For years ending 12/31/2010 and 12/31/2011, this sum will be reduced by the amount of distribution load served by East Kentucky Power Cooperative via Duke Kentucky's Hebron substation. Excludes demands from grandfathered interzonal transactions and demands from service provided by ISO at a discount.

C Reserved

D Reserved

E This deduction is to remove expenses recorded by DEOK for Postretirement Benefits Other than Pensions (PBOP). PBOP expense is set forth in line 3b and is fixed until changed as the result of a filing at FERC. The fixed amount of PBOP for DEO is $2,342,494 and for Duke Energy Kentucky ("DEK") is $575,908.

F The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.

G Identified in Form 1 as being only transmission related.

H Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111 line 57 in the Form 1.

I Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.

J Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.

K The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26).

Inputs Required:	FIT =	35.00%	
	SIT=	0.55%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

L Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.

M Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).

N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to be included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

O Enter dollar amounts.

P Debt cost rate = long-term interest (line 21) / long term debt (line 27). Preferred cost rate = preferred dividends (line 22) / preferred outstanding (line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC. Capitalization adjusted to exclude impacts of purchase accounting.

Q Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.

R Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

S Reserved

T The revenues credited on page 1 lines 2-5c shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, or facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2010

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO AND DUKE ENERGY KENTUCKY (DEOK)

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)

References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
U	On Line 35, enter revenues from RTO settlements that are associated with NITS and firm Point-to-Point Service for which the load is not included in the divisor to derive Duke Energy Ohio's and Duke Energy Kentucky's zonal rates. Exclude non-firm Point-to-Point revenues, revenues related to MTEP and RTEP projects, revenues from grandfathered interzonal transactions and revenues from service provided by ISO at a discount.
V	Account Nos. 561.4, 561.8 and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.
W	Reserved
X	Midwest ISO Exit Fees include (1) the charge that DEOK paid to the Midwest ISO pursuant to the Settlement Agreement filed on July 29, 2011 in Docket No. ER11-2059 and (2) the exit fees that DEOK paid to the Midwest ISO pursuant to the Exit Fee Agreement filed on October 5, 2011 in Docket No. ER12-33.
Y	PJM Integration Costs are the fees that PJM assessed DEOK for the costs that PJM incurred in connection with DEOK's move into PJM.

For the 12 months ended 12/31/2010

Duke Energy Ohio and Duke Energy Kentucky
Transmission Formula Rate Revenue Requirement
Utilizing FERC Form 1 Data
For Rates Effective January 1, 2012

Schedule 1A Rate Calculation

Line No.		Source	Revenue Requirement
A.	Schedule 1A Annual Revenue Requirements		
1	Total Load Dispatch & Scheduling (Account 561)	Attachment H-22A, Page 4, Line 7	$ 2,008,358
2	Revenue Credits for Schedule 1A - Note A		$ -
3	Net Schedule 1A Revenue Requirement for Zone		$ 2,008,358
B.	Schedule 1A Rate Calculations		
4	2010 Annual MWh - Note B	(401a.22b & 24b)	49,405,221 MWh
5	Schedule 1A rate $/MWh (Line 3 / Line 4)	(Line 3 / Line 4)	$0.0407 $/MWh

Note:

A Revenue received pursuant to PJM Schedule 1A revenue allocation procedures for transmission service outside of DEOK's zone during the year used to calculate rates under Attachment H-22A.

B Load expressed in MWh consisitent with load used for billing under Schedule 1A for the DEOK zone. Data from RTO settlement systems for the calendar year prior to the rate year

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio and Duke Energy Kentucky
RTEP - Transmission Enhancement Charges

To be completed in conjunction with Attachment H-22A.

	(1)	(2)	(3)	(4)
Line No.		Attachment H-22A Page, Line, Col.	Transmission	Allocator
	TRANSMISSION PLANT			
1	Gross Transmission Plant - Total	Sch. H-22A, p 2, line 2 col 5 (Note A)	617,088,486	
2	Net Transmission Plant - Total	Sch. H-22A, p 2, line 14 col 5 (Note B)	400,935,383	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Sch. H-22A, p 3, line 8 col 5	16,329,047	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	2.65%	2.65%
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G&C Depreciation Expense	Sch. H-22A, p 3, lines 10 & 11, col 5 (Note H)	190,250	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	0.03%	0.03%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Sch. H-22A, p 3, line 20 col 5	7,466,555	
8	Annual Allocation Factor for Other Taxes	(line 5 divided by line 1 col 3)	1.21%	1.21%
9	**Annual Allocation Factor for Expense**	**Sum of lines 4, 6 and 8**		**3.89%**
	INCOME TAXES			
10	Total Income Taxes	Sch. H-22A, p 3, line 27 col 5	12,683,054	
11	Annual Allocation Factor for Income Taxes	(line 8 divided by line 2 col 3)	3.16%	3.16%
	RETURN			
12	Return on Rate Base	Sch. H-22A, p 3, line 28 col 5	29,109,644	
13	Annual Allocation Factor for Return on Rate Base	(line 10 divided by line 2 col 3)	7.26%	7.26%
14	**Annual Allocation Factor for Return**	**Sum of lines 11 and 13**		**10.42%**

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio and Duke Energy Kentucky
RTEP - Transmission Enhancement Charges

Network Upgrade Charge Calculation By Project

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line No.	Project Name	RTEP Project Number	Project Gross Plant	Annual Allocation Factor for Expense	Annual Expense Charge	Project Net Plant	Annual Allocation Factor for Return	Annual Return Charge	Project Depreciation Expense	Annual Revenue Requirement	True-Up Adjustment	Network Upgrade Charge
			(Note C)	(Page 1 line 7)	(Col. 3 * Col. 4)	(Note D)	(Page 1 line 12)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)	Sum Col. 10 & 11 (Note G)
1a	[illegible]	[illegible]	$ -	3.89%	$0.00	$ -	10.42%	$0.00	$0	$0.00	$ -	$0.00
1b	[illegible]	[illegible]	$ -	3.89%	$0.00	$ -	10.42%	$0.00	$0	$0.00	$ -	$0.00
2	Annual Totals									$0	$0	$0
3	RTEP Transmission Enhancement Charges for Attatchment H-22A, Page 1, Line 5c											$0

Note Letter	
A	Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-22A and includes any sub lines 2a or 2b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.
B	Net Transmission Plant is that identified on page 2 line 14 of Attachment H-22A and includes any sub lines 14a or 14b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.
C	Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes CWIP in rate base if applicable. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.
D	Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.
E	Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-22A page 3 line 12.
F	True-Up Adjustment is included pursuant to a FERC approved methodology if applicable.
G	The Network Upgrade Charge is the value to be used in Schedule 26.
H	The Total General and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 9.

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio and Duke Energy Kentucky
Legacy MTEP Credit

To be completed in conjunction with Attatchment H-22A.

	(1)	(2)	(3)	(4)
Line No.		Attachment H-22A Page, Line, Col.	Transmission	Allocator
	TRANSMISSION PLANT			
1	Gross Transmission Plant - Total	Sch. H-22A, p 2, line 2 col 5 (Note A)	617,088,486	
2	Net Transmission Plant - Total	Sch. H-22A, p 2, line 14 col 5 (Note B)	400,935,383	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Sch. H-22A, p 3, line 8 col 5	16,329,047	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	2.65%	2.65%
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G&C Depreciation Expense	Sch. H-22A, p 3, lines 10 & 11, col 5 (Note H)	190,250	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	0.03%	0.03%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Sch. H-22A, p 3, line 20 col 5	7,466,555	
8	Annual Allocation Factor for Other Taxes	(line 5 divided by line 1 col 3)	1.21%	1.21%
9	**Annual Allocation Factor for Expense**	**Sum of lines 4, 6 and 8**		**3.89%**
	INCOME TAXES			
10	Total Income Taxes	Sch. H-22A, p 3, line 27 col 5	12,683,054	
11	Annual Allocation Factor for Income Taxes	(line 8 divided by line 2 col 3)	3.16%	3.16%
	RETURN			
12	Return on Rate Base	Sch. H-22A, p 3, line 28 col 5	29,109,644	
13	Annual Allocation Factor for Return on Rate Base	(line 10 divided by line 2 col 3)	7.26%	7.26%
14	**Annual Allocation Factor for Return**	**Sum of lines 11 and 13**		**10.42%**

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio and Duke Energy Kentucky
Legacy MTEP Credit

Network Upgrade Charge Calculation By Project

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line No.	Project Name	MTEP Project Number	Project Gross Plant	Annual Allocation Factor for Expense	Annual Expense Charge	Project Net Plant	Annual Allocation Factor for Return	Annual Return Charge	Project Depreciation Expense	Annual Revenue Requirement	True-Up Adjustment	Network Upgrade Charge
			(Note C)	(Page 1 line 7)	(Col. 3 * Col. 4)	(Note D)	(Page 1 line 12)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)	Sum Col. 10 & 11 (Note G)
1a	Hillcrest 345 kV	91	$ 17,643,404	3.89%	$685,788.34	$ 16,872,581	10.42%	$1,758,763.91	$300,739	$2,745,291.24	$ -	$2,745,291.24
1b	Project 2	P3	$ -	3.89%	$0.00	$ -	10.42%	$0.00	$0	$0.00	$ -	$0.00
1c	Project 3	P3	$ -	3.89%	$0.00	$ -	10.42%	$0.00	$0	$0.00	$ -	$0.00
2	Annual Totals									$2,745,291	$0	$2,745,291
3	Legacy MTEP Credit for Attatchment H-22A, Page 1, Line 5a											$2,745,291

Note Letter

A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-22A and includes any sub lines 2a or 2b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.
B Net Transmission Plant is that identified on page 2 line 14 of Attachment H-22A and includes any sub lines 14a or 14b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.
C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes CWIP in rate base if applicable. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.
D Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.
E Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-22A page 3 line 12.
F True-Up Adjustment is included pursuant to a FERC approved methodology if applicable.
G The Network Upgrade Charge is the value to be used in Schedule 26.
H The Total General and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 9.

DUKE ENERGY OHIO, INC.
DEPRECIATION RATES

FERC Account Number (A)	Company Account Number (B)	Description (C)	Actual Accrual Rates (D) %
		Wholly Owned Transmission Plant	
350	3403	Rights of Way	1.54
352	3420	Structures & Improvements	1.90
352	3424	Structures & Improvements - Duke Ohio - Loc. in Ky.	1.90
353	3430	Station Equipment	1.44
353	3434	Station Equipment - Duke Ohio - Loc. in Ky.	1.44
354	3440	Towers & Fixtures	1.85
354	3444	Towers & Fixtures - Duke Ohio - Loc. in Ky.	1.85
355	3450	Poles & Fixtures	2.31
355	3454	Poles & Fixtures - Duke Ohio - Loc. in Ky.	2.31
356	3460	Overhead Conductors & Devices	1.91
356	3464	Overhead Conductors & Devices - Duke Ohio - Loc. in Ky.	1.91
357	3470	Underground Conduit	1.43
358	3480	Underground Conductors & Devices	2.37
		Commonly Owned Transmission Plant - CCD Projects	
352	3421	Structures & Improvements - CCD Projects	2.50
352	3425	Structures & Improvements - CCD Projects	2.50
353	3431	Station Equipment - CCD Projects	1.44
353	3432	Station Equipment - CCD Projects	1.44
353	3435	Station Equipment - CCD Projects	1.44
353	3437	Station Equipment - CCD Projects	1.44
354	3441	Towers & Fixtures - CCD Projects	3.00
354	3442	Towers & Fixtures - CCD Projects	3.00
354	3445	Towers & Fixtures - CCD Projects	3.00
354	3446	Towers & Fixtures - CCD Projects - Loc. In Ky.	3.00
354	3448	Towers & Fixtures - CCD Projects	3.00
355	3451	Poles & Fixtures - CCD Projects	3.00
355	3455	Poles & Fixtures - CCD Projects	3.00
356	3461	Overhead Conductors & Devices - CCD Projects	2.50
356	3462	Overhead Conductors & Devices - CCD Projects	2.50
356	3465	Overhead Conductors & Devices - CCD Projects	2.50
356	3466	Overhead Conductors & Devices - CCD Projects - Loc. In Ky.	2.50
		Commonly Owned Transmission Plant - CD Projects	
352	3423	Structures & Improvements - CD Projects	2.50
353	3433	Station Equipment - CD Projects	1.44
353	3438	Station Equipment - CD Projects	1.44
354	3447	Towers & Fixtures - CD Projects	3.00
356	3467	Overhead Conductors & Devices - CD Projects	2.50
		General and Intagible Plant	
303	3030	Miscellaneous Intangible Plant	20.00
389	3890	Land and Land Rights	N/A
390	3900	Structures and Improvements	2.50
391	3910	Office Furniture and Equipment	5.00
391	3911	Electronic Data Processing Equipment	20.00
391	3920	Transportation Equipment	8.33
391	3921	Trailers	4.25
392	3940	Tools, Shop & Garage Equipment	4.00
392	3950	Laboratory Equipment	6.67
393	3960	Power Operated Equipment	5.88
393	3970	Communication Equipment	6.67
394	3980	Miscellaneous Equipment	5.00

DUKE ENERGY KENTUCKY, INC.
DEPRECIATION RATES

FERC Account Number (A)	Company Account Number (B)	Description (C)	Actual Accrual Rates (D) %
		Transmission Plant	
350	3501	Rights of Way	1.48
352	3520	Structures & Improvements	0.41
353	3530	Station Equipment	2.25
353	3532	Station Equipment - Major	2.77
353	3535	Station Equipment - Electronic	9.55
355	3550	Poles & Fixtures	2.28
356	3560	Overhead Conductors & Devices	2.31
		General and Intagible Plant	
303	3030	Miscellaneous Intangible Plant	20.00
390	3900	Land and Land Rights	1.77
391	3910	Structures and Improvements	18.56
392	3921	Electronic Data Processing Equipment	6.53
394	3940	Transportation Equipment	4.14
397	3970	Stores Equipment	6.93

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio and Duke Energy Kentucky
Firm PTP Service Revenue Credit Adjustment Calculation

To be completed in conjunction with Attatchment H-22A.

No.	(1)	(2) Reference	(3) Company Total
	REVENUE CREDIT TRUE-UP		
1	Difference Between Revenue Received In PJM vs. Midwest ISO	(Note A)	$0
	ACCUMULATED BALANCE OF REVENUE CREDIT TRUE-UP		
2	Accumulated Balance of Deferral	(Note B)	$0
3	Income Tax Rate for Deferral Calculation	(Note C)	0.00%
4	Deferred Income Taxes on Accumulated Deferral (Line 2 * Line 3)		$0
5	Accumulated Deferral for Carrying Cost Calculation (Line 2 - Line 4)		$0
	INCOME TAXES		
6	CIT = (T/(1-T)) * (1 - (WCLTD/R))	Attachment H-22, page 3, line 22	0.00%
7	Income Taxes (Line 6 * Line 9)		$0
	CARRYING COST ON DEFERRAL		
8	FERC Refund Rate		0.00%
9	Carrying Cost (Line 5 * Line 8)	(Note C)	$0
10	Revenue Credit Adjustment (Line 1 + Line 7 + Line 9)		$0

Note

A From Appendix E, Workpaper, Column (4).

B Accumulated balance of deferral as of December 31st of the year prior to effective date of new rates.

C Effective deferred tax rate during applicable test year.

D FERC Refund Rate is the approved rate as of December 31 of calendar prior to the rate year (see 18 CFR Section 35.19a).

Attachment H-22A
Appendix E
Workpaper

Duke Energy Ohio and Duke Energy Kentucky

Worksheet for Firm PTP Service Revenue Credit Adjustment Calculation

(1) Period	(2) Actual Firm PTP Service Revenue Included in Test Year Rate Calculation (Note A)	(3) Actual Firm PTP Service Revenue Received from PJM (Note B)	(4) = (2) - (3) Difference Between Revenue Received and Amount in Rates Excluding True Up	(5) Monthly True-Up Adjustment Included In H-22A Net Revenue Requirement (Note C)	(6) = (4) - (5) Amount Deferred for Future Future Recovery	(7) = Prior month's Balance + (6) Accumulated Balance of Deferred Firm PTP Service Revenue Credit Adjustment
Jan-12	$ -	$ -	$ -		$ -	$ -
Feb-12	-	-	-		-	-
Mar-12	-	-	-		-	-
Apr-12	-	-	-		-	-
May-12	-	-	-		-	-
Jun-12	-	-	-		-	-
Jul-12	-	-	-		-	-
Aug-12	-	-	-		-	-
Sep-12	-	-	-		-	-
Oct-12	-	-	-		-	-
Nov-12	-	-	-		-	-
Dec-12	-	-	-		-	-
Total					$ -	-
Jan-13	-	-	-		$ -	-
Feb-13	-	-	-		-	-
Mar-13	-	-	-		-	-
Apr-13	-	-	-		-	-
May-13	-	-	-		-	-
Jun-13				-	-	-
Jul-13				-	-	-
Aug-13				-	-	-
Sep-13				-	-	-
Oct-13				-	-	-
Nov-13				-	-	-
Dec-13				-	-	-
Total				$ -	$ -	$ -
Jan-14				$ -	$ -	$ -
Feb-14				-	-	-
Mar-14				-	-	-
Apr-14				-	-	-
May-14				-	-	-
Jun-14				-	-	-
Jul-14				-	-	-
Aug-14				-	-	-
Sep-14				-	-	-
Oct-14				-	-	-
Nov-14				-	-	-
Dec-14				-	-	-
Total				$ -	$ -	$ -
Jan-15				$ -	$ -	$ -
Feb-15				-	-	-
Mar-15				-	-	-
Apr-15				-	-	-
May-15				-	-	-
Total				$ -	$ -	$ -

Notes:

(A) Monthly Firm PTP service revenue from Midwest ISO during test year applicable to currently effectives NITS and PTP service rates.
(B) Actual monthly Firm PTP service revenue received from PJM during current period.
(C) Recovery of deferral begins with the first period for billing rates approved using a test year for Attachment H-22A that includes actual operations in PJM.

Ex. No. DUK-101

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2010

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO

Line No.						Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)					$ 69,727,961
	REVENUE CREDITS (Note T)		Total	Allocator		
2	Account No. 454	(page 4, line 34)	$ 2,128,793	TP	0.87591	$ 1,864,624
3	Account No. 456.1	(page 4, line 35)	10,713,648	TP	0.87591	9,384,157
4a	Revenues from Grandfathered Interzonal Transactions		0	TP	0.87591	0
4b	Revenues from service provided by ISO at a discount		0	TP	0.87591	0
5a	Legacy MTEP Credit (Appendix C, page 2, line 3, col. 12)		2,662,150		1.00000	2,662,150
5b	RTEP Transmission Enhancement Credit (Appendix B, page 2, line 3, col. 12)		0		1.00000	0
5c	Firm PTP Revenue Credit Adjustment (Appendix E, line 10, col. 3)		0		1.00000	0
6	TOTAL REVENUE CREDITS (sum lines 2-5c)					$ 13,910,931
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ 55,817,030
	DIVISOR					
8	1 CP (Note A)					4,679,000
9	12 CP (Note B)					3,711,833
10	Reserved					
11	Reserved					
12	Reserved					
13	Reserved					
14	Reserved					
15	Annual Cost ($/kW/Yr) - 1 CP	(line 7 / line 8)	$11.929			
16	Annual Cost ($/kW/Yr) - 12 CP	(line 7 / line 9)	$15.038			
17	Network Rate ($/kW/Mo)	(line 15 / 12)	$0.994			
17a	Point-To-Point Rate ($/kW/Mo)	(line 16 / 12)	$1.253			
			Peak Rate			Off-Peak Rate
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	$0.289			
19	Point-To-Point Rate ($/kW/Day)	(line 16 / 260; line 16 / 365)	$0.058	Capped at weekly rate		$0.041
20	Point-To-Point Rate ($/MWh)	(line 16 / 4,160; line 16 / 8,760 * 1000)	$0.004	Capped at weekly and daily rate		$1.717

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2010

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO

Line No.	(1) RATE BASE:	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col. 3 times Col. 4)
	GROSS PLANT IN SERVICE					
1	Production	205.46.g	$ 5,047,479,619	NA		
2	Transmission	207.58.g	671,111,058	TP	0.87591	$ 587,830,742
3	Distribution	207.75.g	1,844,361,344	NA		
4	General & Intangible	205.5.g & 207.99.g	180,438,606	W/S	0.02762	4,983,548
5	Common	356.1	242,989,309	CE	0.02393	5,813,914
6	TOTAL GROSS PLANT (sum lines 1-5)		$ 7,986,379,936	GP=	7.496%	$ 598,628,204
	ACCUMULATED DEPRECIATION					
7	Production	219.20-24.c	$ 1,655,125,088	NA		
8	Transmission	219.25.c	233,399,352	TP	0.87591	$ 204,436,080
9	Distribution	219.26.c	625,814,226	NA		
10	General & Intangible	219.28.c	10,627,310	W/S	0.02762	293,517
11	Common	356.1	111,410,252	CE	0.02393	2,665,671
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		$ 2,636,376,228			$ 207,395,268
	NET PLANT IN SERVICE					
13	Production	(line 1 - line 7)	$ 3,392,354,531			
14	Transmission	(line 2 - line 8)	437,711,706			$ 383,394,662
15	Distribution	(line 3 - line 9)	1,218,547,118			
16	General & Intangible	(line 4 - line 10)	169,811,296			4,690,031
17	Common	(line 5 - line 11)	131,579,057			3,148,243
18	TOTAL NET PLANT (sum lines 13-17)		$ 5,350,003,708	NP=	7.313%	$ 391,232,936
	ADJUSTMENTS TO RATE BASE (Note F)					
19	Account No. 281 (enter negative)	273.8.k	$ (15,661,825)	NA	zero	$ -
20	Account No. 282 (enter negative)	275.2.k	(1,097,529,071)	NP	0.07313	(80,259,668)
21	Account No. 283 (enter negative)	277.9.k	(214,513,307)	NP	0.07313	(15,686,844)
22	Account No. 190	234.8.c	43,330,440	NP	0.07313	3,168,651
23	Account No. 255 (enter negative)	267.8.h	(3,695,922)	NP	0.07313	(270,274)
24	TOTAL ADJUSTMENTS (sum lines 19- 23)		$ (1,288,069,685)			$ (93,048,135)
25	LAND HELD FOR FUTURE USE (Note G)	214.x.d	$ 125,772	TP	0.87591	$ 110,165
	WORKING CAPITAL (Note H)					
26	CWC	calculated	$ 25,573,431			1,512,677
27	Materials & Supplies (Note G)	227.8.c & .16.c	7,718,927	TE	0.79215	6,114,553
28	Prepayments (Account 165)	111.57.c	45,697,343	GP	0.07496	3,425,296
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		$ 78,989,701			$ 11,052,526
30	RATE BASE (sum lines 18, 24, 25, & 29)		$ 4,141,049,496			$ 309,347,492

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2010

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col. 3 times Col. 4)
	O&M					
1	Transmission	321.112.b	$ 17,959,496	TE	0.79215	$ 14,226,625
1a	Less LSE Expenses included in Transmission O&M Accounts (Note V)	321.88.b, 92.b; 322.121.b	2,454,329		1.00000	2,454,329
1b	Less Midwest ISO Exit Fees included in Transmission O&M	(Note X)	0	TE	0.79215	0
1c	Plus Midwest ISO Exit Fees	(Note X)	0		1.00000	0
2	Less Account 565	321.96.b	6,505,839	TE	0.79215	5,153,604
3	A&G	323.197.b	201,656,909	W/S	0.02762	5,569,578
3a	Less Actual PBOP Expense	(Note E)	2,342,494	W/S	0.02762	64,698
3b	Plus Fixed PBOP Expense	(Note E)	2,342,494	W/S	0.02762	64,698
3c	Less PJM Integration Costs included in A&G	(Note Y)	83,058	W/S	0.02762	2,294
3d	Plus PJM Integration Costs	(Note Y)	83,058		1.00000	83,058
4	Less FERC Annual Fees	350.14.b	670,788	W/S	0.02762	18,527
5	Less EPRI & Reg. Comm. Exp. & Non-safety Advertising (Note I)		5,398,000	W/S	0.02762	149,088
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.79215	0
6	Common	356.1	0	CE	0.02393	0
7	Transmission Lease Payments		0		1.00000	0
8	TOTAL O&M (sum lines 1, 2a, 3, 5a, 6, 7 less lines 1a, 2, 4, 5)		$ 204,587,449			$ 12,101,420
	DEPRECIATION EXPENSE					
9	Transmission	336.7.b	$ 11,107,812	TP	0.87591	$ 9,729,408
10	General	336.10.b	2,344,984	W/S	0.02762	64,766
11	Common	336.11.b	4,334,407	CE	0.02393	103,708
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		$ 17,787,203			$ 9,897,882
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
13	Payroll	263.i. 4, 5, 12	$ 12,810,088	W/S	0.02762	$ 353,803
14	Highway and vehicle	263.i. 6	34,961	W/S	0.02762	966
15	PLANT RELATED					
16	Property	263.i. 14, 20	97,584,795	GP	0.07496	7,314,579
17	Gross Receipts	263.i. 22	4,568,022	NA	zero	0
18	Other	263.i	0	GP	0.07496	0
19	Payments in lieu of taxes		0	GP	0.07496	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		$ 114,997,866			$ 7,669,348
	INCOME TAXES (Note K)					
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		35.000000%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) = where WCLTD=(page 4, line 27) and R= (page 4, line 30) and FIT, SIT & p are as given in footnote K.		42.879763%			
23	1 / (1 - T) = (from line 21)		1.5385			
24	Amortized Investment Tax Credit	266.8.f (enter negative)	0			
25	Income Tax Calculation (line 22 * line 28)		$ 160,934,423	NA		$ 12,022,233
26	ITC adjustment (line 23 * line 24)		0	NP	0.07313	0
27	Total Income Taxes	(line 25 plus line 26)	$ 160,934,423			$ 12,022,233
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]		$ 375,315,564	NA		$ 28,037,078
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		$ 873,622,505			$ 69,727,961

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2010

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO
SUPPORTING CALCULATIONS AND NOTES

Line No.								
	TRANSMISSION PLANT INCLUDED IN ISO RATES							
1	Total transmission plant (page 2, line 2, column 3)						671,111,058	
2	Less transmission plant excluded from ISO rates (Note M)						0	
3	Less transmission plant included in OATT Ancillary Services (Note N)						83,280,316	
4	Transmission plant included in ISO Rates (line 1 less lines 2 & 3)						587,830,742	
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)					TP=	0.87591	
	TRANSMISSION EXPENSES							
6	Total transmission expenses (page 3, line 1, column 3)						17,959,496	
7	Less transmission expenses included in OATT Ancillary Services (Note L)						1,717,328	
8	Included transmission expenses (line 6 less line 7)						16,242,168	
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)						0.90438	
10	Percentage of transmission plant included in ISO Rates (line 5)					TP	0.87591	
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)					TE=	0.79215	
	WAGES & SALARY ALLOCATOR (W&S)							
		Form 1 Reference	$	TP	Allocation			
12	Production	354.20.b	57,676,930	0.00	0			
13	Transmission	354.21.b	3,321,634	0.88	2,909,442			
14	Distribution	354.23.b	23,830,724	0.00	0		W&S Allocator	
15	Other	354.24,25,26.b	20,512,455	0.00	0		($ / Allocation)	
16	Total (sum lines 12-15)		105,341,743		2,909,442	=	0.02762	= WS
	COMMON PLANT ALLOCATOR (CE) **(Note O)**							
			$		% Electric (line 17 / line 20)		W&S Allocator (line 16)	CE
17	Electric	200.3.c	6,734,823,068					
18	Gas	201.3.d	1,039,345,339		0.86631	*	0.02762	= 0.02393
19	Water	201.3.e	0					
20	Total (sum lines 17 - 19)		7,774,168,407					
	RETURN (R)						$	
21		Long Term Interest (117, sum of 62.c through 67.c)					98,012,064	
22		Preferred Dividends (118.29.c) (positive number)					0	
	Development of Common Stock:							
23		Proprietary Capital (112.16.c)					3,203,668,932	
24		Less Preferred Stock (112.3.c)					0	
25		Less Account 216.1 (112.12.c) (enter negative)					(108,049,782)	
26		Common Stock (sum lines 23-25)					3,095,619,150	
		(Note P)	$	%	Cost		Weighted	
27	Long Term Debt (112, sum of 18.c through 21.c)		2,214,256,271	42%	0.0443		0.0185	=WCLTD
28	Preferred Stock (112.3.c)		0	0%	0.0000		0.0000	
29	Common Stock (line 26)		3,095,619,150	58%	**0.1238**		0.0722	
30	Total (sum lines 27-29)		5,309,875,421				0.0906	=R
	REVENUE CREDITS						Load	
	ACCOUNT 447 (SALES FOR RESALE) (Note Q)		(310-311)					
31	a. Bundled Non-RQ Sales for Resale (311.x.h)						0	
32	b. Bundled Sales for Resale included in Divisor on page 1						0	
33	Total of (a)-(b)						0	
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)						$ 2,128,793	
35	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) (Note U)		(330.x.n)				$ 10,713,648	

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2010

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter

A DEOK 1 CP is Duke Energy Ohio ("DEO") Monthly Firm Transmission System Peak Load as reported on page 400, column b of Form 1 at the time of DEO's annual peak, plus load served by Duke Energy Kentucky at Longbranch. For years ending 12/31/2010 and 12/31/2011, this sum will be reduced by the amount of distribution load served by East Kentucky Power Cooperative via Duke Kentucky's Hebron substation. (1) Excludes demands from grandfathered interzonal transactions and demands from service provided by ISO at a discount.

B DEOK 12 CP is DEO Monthly Firm Transmission System Peak Load as reported on page 400, column b of Form 1 at the time of DEO's monthly peaks, plus load served by Duke Kentucky at Longbranch. For years ending 12/31/2010 and 12/31/2011, this sum will be reduced by the amount of distribution load served by East Kentucky Power Cooperative via Duke Kentucky's Hebron substation. (2) Excludes demands from grandfathered interzonal transactions and demands from service provided by ISO at a discount.

C Reserved

D Reserved

E This deduction is to remove expenses recorded by DEOK for Postretirement Benefits Other than Pensions (PBOP). PBOP expense is set forth in line 3b and is fixed until changed as the result of a filing at FERC. The fixed amount of PBOP for DEO is $2,342,494 and for Duke Energy Kentucky ("DEK") is $575,908.

F The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.

G Identified in Form 1 as being only transmission related.

H Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5.
Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111 line 57 in the Form 1.

I Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.

J Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.

K The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26).

Inputs Required:	FIT =	35.00%	
	SIT=	0.55%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

L Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.

M Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).

N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to be included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

O Enter dollar amounts.

P Debt cost rate = long-term interest (line 21) / long term debt (line 27). Preferred cost rate = preferred dividends (line 22) / preferred outstanding (line 28).
ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC. Capitalization adjusted to exclude impacts of purchase accounting.

Q Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.

R Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

S Reserved

T The revenues credited on page 1 lines 2-5c shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, or facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2010

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY OHIO

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)

References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
U	On Line 35, enter revenues from RTO settlements that are associated with NITS and firm Point-to-Point Service for which the load is not included in the divisor to derive Duke Energy Ohio's and Duke Energy Kentucky's zonal rates. Exclude non-firm Point-to-Point revenues, revenues related to MTEP and RTEP projects, revenues from grandfathered interzonal transactions and revenues from service provided by ISO at a discount.
V	Account Nos. 561.4, 561.8 and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.
W	Reserved
X	Midwest ISO Exit Fees include (1) the charge that DEOK paid to the Midwest ISO pursuant to the Settlement Agreement filed on July 29, 2011 in Docket No. ER11-2059 and (2) the exit fees that DEOK paid to the Midwest ISO pursuant to the Exit Fee Agreement filed on October 5, 2011 in Docket No. ER12-33.
Y	PJM Integration Costs are the fees that PJM assessed DEOK for the costs that PJM incurred in connection with DEOK's move into PJM.

(1) For the purpose of calculating the DEO annual peak, the DEK annual peak as reported on page 401, column d of Form 1, was subtracted from the DEO annual peak as reported on page 400.

(2) For the purpose of calculating the DEO monthly peak, the DEK monthly peak as reported on page 401, column d of Form 1, was subtracted from the DEO monthly peak as reported on page 400.

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio
RTEP - Transmission Enhancement Charges

To be completed in conjunction with Attatchment H-22A.

	(1)	(2)	(3)	(4)
Line No.		Attachment H-22A Page, Line, Col.	Transmission	**Allocator** Allocator
	TRANSMISSION PLANT			
1	Gross Transmission Plant - Total	Sch. H-22A, p 2, line 2 col 5 (Note A)	587,830,742	
2	Net Transmission Plant - Total	Sch. H-22A, p 2, line 14 col 5 (Note B)	383,394,662	
	O&M EXPENSE			2.06%
3	Total O&M Allocated to Transmission	Sch. H-22A, p 3, line 8 col 5	12,101,420	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	2.06%	
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			0.03%
5	Total G&C Depreciation Expense	Sch. H-22A, p 3, lines 10 & 11, col 5 (Note H)	168,474	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	0.03%	
	TAXES OTHER THAN INCOME TAXES			1.30%
7	Total Other Taxes	Sch. H-22A, p 3, line 20 col 5	7,669,348	
8	Annual Allocation Factor for Other Taxes	(line 5 divided by line 1 col 3)	1.30%	**3.39%**
9	**Annual Allocation Factor for Expense**	**Sum of lines 4, 6 and 8**		
	INCOME TAXES			3.14%
10	Total Income Taxes	Sch. H-22A, p 3, line 27 col 5	12,022,233	
11	Annual Allocation Factor for Income Taxes	(line 8 divided by line 2 col 3)	3.14%	
	RETURN			7.31%
12	Return on Rate Base	Sch. H-22A, p 3, line 28 col 5	28,037,078	
13	Annual Allocation Factor for Return on Rate Base	(line 10 divided by line 2 col 3)	7.31%	**10.45%**
14	**Annual Allocation Factor for Return**	**Sum of lines 11 and 13**		

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio
RTEP - Transmission Enhancement Charges

Network Upgrade Charge Calculation By Project

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line No.	Project Name	RTEP Project Number	Project Gross Plant	Annual Allocation Factor for Expense	Annual Expense Charge	Project Net Plant	Annual Allocation Factor for Return	Annual Return Charge	Project Depreciation Expense	Annual Revenue Requirement	True-Up Adjustment	Network Upgrade Charge
			(Note C)	(Page 1 line 7)	(Col. 3 * Col. 4)	(Note D)	(Page 1 line 12)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)	Sum Col. 10 & 11 (Note G)
1a			$ -	3.39%	$0.00	$ -	10.45%	$0.00	$0	$0.00	$ -	$0.00
1b			$ -	3.39%	$0.00	$ -	10.45%	$0.00	$0	$0.00	$ -	$0.00
1c			$ -	3.39%	$0.00	$ -	10.45%	$0.00	$0	$0.00	$ -	$0.00
2	Annual Totals									$0	$0	$0
3	RTEP Transmission Enhancement Charges for Attatchment H-22A, Page 1, Line 5c											$0

Note Letter

A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-22A and includes any sub lines 2a or 2b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.
B Net Transmission Plant is that identified on page 2 line 14 of Attachment H-22A and includes any sub lines 14a or 14b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order
C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes CWIP in rate base if applicable. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.
D Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.
E Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-22A page 3 line 12.
F True-Up Adjustment is included pursuant to a FERC approved methodology if applicable.
G The Network Upgrade Charge is the value to be used in Schedule 26.
H The Total General and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 9.

Ex. No. DUK-101

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio
Legacy MTEP Credit

To be completed in conjunction with Attatchment H-22A.

Line No.	(1)	(2) Attachment H-22A Page, Line, Col.	(3) Transmission	(4) Allocator
	TRANSMISSION PLANT			
1	Gross Transmission Plant - Total	Sch. H-22A, p 2, line 2 col 5 (Note A)	587,830,742	
2	Net Transmission Plant - Total	Sch. H-22A, p 2, line 14 col 5 (Note B)	383,394,662	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Sch. H-22A, p 3, line 8 col 5	12,101,420	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	2.06%	2.06%
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G&C Depreciation Expense	Sch. H-22A, p 3, lines 10 & 11, col 5 (Note H)	168,474	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	0.03%	0.03%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Sch. H-22A, p 3, line 20 col 5	7,669,348	
8	Annual Allocation Factor for Other Taxes	(line 5 divided by line 1 col 3)	1.30%	1.30%
9	**Annual Allocation Factor for Expense**	**Sum of lines 4, 6 and 8**		**3.39%**
	INCOME TAXES			
10	Total Income Taxes	Sch. H-22A, p 3, line 27 col 5	12,022,233	
11	Annual Allocation Factor for Income Taxes	(line 8 divided by line 2 col 3)	3.14%	3.14%
	RETURN			
12	Return on Rate Base	Sch. H-22A, p 3, line 28 col 5	28,037,078	
13	Annual Allocation Factor for Return on Rate Base	(line 10 divided by line 2 col 3)	7.31%	7.31%
14	**Annual Allocation Factor for Return**	**Sum of lines 11 and 13**		**10.45%**

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Ohio
Legacy MTEP Credit

Network Upgrade Charge Calculation By Project

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line No.	Project Name	MTEP Project Number	Project Gross Plant	Annual Allocation Factor for Expense	Annual Expense Charge	Project Net Plant	Annual Allocation Factor for Return	Annual Return Charge	Project Depreciation Expense	Annual Revenue Requirement	True-Up Adjustment	Network Upgrade Charge
			(Note C)	(Page 1 line 7)	(Col. 3 * Col. 4)	(Note D)	(Page 1 line 12)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)	Sum Col. 10 & 11 (Note G)
1a	Hillcrest 345 kV	91	$ 17,643,404	3.39%	$598,464.95	$ 16,872,581	10.45%	$1,762,945.69	$300,739	$2,662,149.64	$ -	$2,662,149.64
1b	Project 2	P2	$ -	3.39%	$0.00	$ -	10.45%	$0.00	$0	$0.00	$ -	$0.00
1c	Project 3	P3	$ -	3.39%	$0.00	$ -	10.45%	$0.00	$0	$0.00	$ -	$0.00
2	Annual Totals									$2,662,150	$0	$2,662,150
3	Legacy MTEP Credit for Attatchment H-22A, Page 1, Line 5a											$2,662,150

Note Letter	
A	Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-22A and includes any sub lines 2a or 2b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.
B	Net Transmission Plant is that identified on page 2 line 14 of Attachment H-22A and includes any sub lines 14a or 14b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.
C	Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes CWIP in rate base if applicable. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.
D	Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.
E	Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-22A page 3 line 12.
F	True-Up Adjustment is included pursuant to a FERC approved methodology if applicable.
G	The Network Upgrade Charge is the value to be used in Schedule 26.
H	The Total General and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 9.

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2010

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY KENTUCKY

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)					$ 7,053,717
	REVENUE CREDITS (Note T)					
2	Account No. 454	(page 4, line 34)	$ 9,399	TP	1.00000	$ 9,399
3	Account No. 456.1	(page 4, line 35)	0	TP	1.00000	0
4a	Revenues from Grandfathered Interzonal Transactions		0	TP	1.00000	0
4b	Revenues from service provided by ISO at a discount		0	TP	1.00000	0
5a	Legacy MTEP Credit (Appendix C, page 2, line 3, col. 12)		0		1.00000	0
5b	RTEP Transmission Enhancement Credit (Appendix B, page 2, line 3, col. 12)		0		1.00000	0
5c	Firm PTP Revenue Credit Adjustment (Appendix E, line 10, col. 3)		0		1.00000	0
6	TOTAL REVENUE CREDITS (sum lines 2-5c)					$ 9,399
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ 7,044,318
	DIVISOR					
8	1 CP (Note A)					892,000
9	12 CP (Note B)					695,167
10	Reserved					
11	Reserved					
12	Reserved					
13	Reserved					
14	Reserved					
15	Annual Cost ($/kW/Yr) - 1 CP	(line 7 / line 8)	$7.897			
16	Annual Cost ($/kW/Yr) - 12 CP	(line 7 / line 9)	$10.133			
17	Network Rate ($/kW/Mo)	(line 15 / 12)	$0.658			
17a	Point-To-Point Rate ($/kW/Mo)	(line 16 / 12)	$0.844			
			Peak Rate			Off-Peak Rate
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	$0.195			
19	Point-To-Point Rate ($/kW/Day)	(line 16 / 260; line 16 / 365	$0.039	Capped at weekly rate		$0.028
20	Point-To-Point Rate ($/MWh)	(line 16 / 4,160; line 16 / 8,760 * 1000)	$0.002	Capped at weekly and daily rate		$1.157

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2010

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY KENTUCKY

Line No.	(1) RATE BASE	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col. 3 times Col. 4)
	GROSS PLANT IN SERVICE					
1	Production	205.46.g	$ 777,200,182	NA		
2	Transmission	207.58.g	29,257,744	TP	1.00000	$ 29,257,744
3	Distribution	207.75.g	343,335,588	NA		
4	General & Intangible	205.5.g & 207.99.g	7,134,451	W/S	0.03693	263,477
5	Common	356.1	29,301,649	CE	0.02922	856,052
6	TOTAL GROSS PLANT (sum lines 1-5)		$ 1,186,229,614	GP=	2.561%	$ 30,377,273
	ACCUMULATED DEPRECIATION					
7	Production	219.20-24.c	$ 427,748,107	NA		
8	Transmission	219.25.c	11,925,092	TP	1.00000	$ 11,925,092
9	Distribution	219.26.c	130,825,208	NA		
10	General & Intangible	219.28.c	983,380	W/S	0.03693	36,316
11	Common	356.1	17,253,844	CE	0.02922	504,074
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		$ 588,735,631			$ 12,465,482
	NET PLANT IN SERVICE					
13	Production	(line 1 - line 7)	$ 349,452,075			
14	Transmission	(line 2 - line 8)	17,332,652			$ 17,332,652
15	Distribution	(line 3 - line 9)	212,510,380			
16	General & Intangible	(line 4 - line 10)	6,151,071			227,161
17	Common	(line 5 - line 11)	12,047,805			351,978
18	TOTAL NET PLANT (sum lines 13-17)		$ 597,493,983	NP=	2.998%	$ 17,911,791
	ADJUSTMENTS TO RATE BASE (Note F)					
19	Account No. 281 (enter negative)	273.8.k	$ (197,747)	NA	zero	$ -
20	Account No. 282 (enter negative)	275.2.k	(166,463,782)	NP	0.02998	(4,990,284)
21	Account No. 283 (enter negative)	277.9.k	(3,755,102)	NP	0.02998	(112,571)
22	Account No. 190	234.8.c	(10,163,701)	NP	0.02998	(304,689)
23	Account No. 255 (enter negative)	267.8.h	(269,205)	NP	0.02998	(8,070)
24	TOTAL ADJUSTMENTS (sum lines 19-23)		$ (180,849,537)			$ (5,415,614)
25	LAND HELD FOR FUTURE USE (Note G)	214.x.d	$ -	TP	1.00000	$ -
	WORKING CAPITAL (Note H)					
26	CWC	calculated	$ 3,790,896			552,431
27	Materials & Supplies (Note G)	227.8.c & .16.c	8,941	TE	0.98645	8,820
28	Prepayments (Account 165)	111.57.c	1,483,709	GP	0.02561	37,995
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		$ 5,283,546			$ 599,246
30	RATE BASE (sum lines 18, 24, 25, & 29)		$ 421,927,992			$ 13,095,423

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2010

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY KENTUCKY

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col. 3 times Col. 4)
	O&M					
1	Transmission	321.112.b	$ 21,479,522	TE	0.98645	$ 21,188,492
1a	Less LSE Expenses included in Transmission O&M Accounts (Note V)	321.88.b, 92.b; 322.121.b	769,687		1.00000	769,687
1b	Less Midwest ISO Exit Fees included in Transmission O&M	(Note X)	0	TE	0.98645	0
1c	Plus Midwest ISO Exit Fees	(Note X)	0		1.00000	0
2	Less Account 565	321.96.b	17,241,235	TE	0.98645	17,007,630
3	A&G	323.197.b	28,974,993	W/S	0.03693	1,070,054
3a	Less Actual PBOP Expense	(Note E)	575,908	W/S	0.03693	21,268
3b	Plus Fixed PBOP Expense	(Note E)	575,908	W/S	0.03693	21,268
3c	Less PJM Integration Costs included in A&G	(Note Y)	17,011	W/S	0.03693	628
3d	Plus PJM Integration Costs	(Note Y)	17,011		1.00000	17,011
4	Less FERC Annual Fees	350.14.b	278,983	W/S	0.03693	10,303
5	Less EPRI & Reg. Comm. Exp. & Non-safety Advertising (Note I)		1,837,444	W/S	0.03693	67,857
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.98645	0
6	Common	356.1	0	CE	0.02922	0
7	Transmission Lease Payments		0		1.00000	0
8	TOTAL O&M (sum lines 1, 2a, 3, 5a, 6, 7 less lines 1a, 2, 4, 5)		$ 30,327,166			$ 4,419,451
	DEPRECIATION EXPENSE					
9	Transmission	336.7.b	$ 622,772	TP	1.00000	$ 622,772
10	General	336.10.b	104,720	W/S	0.03693	3,867
11	Common	336.11.b	615,164	CE	0.02922	17,972
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		$ 1,342,656			$ 644,611
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
13	Payroll	263.i. 6, 7, 13	$ 1,915,606	W/S	0.03693	$ 70,744
14	Highway and vehicle	263.i. 5	4,802	W/S	0.03693	177
15	PLANT RELATED					
16	Property	263.i. 14, 22	5,158,270	GP	0.02561	132,094
17	Gross Receipts	263.i	0	NA	zero	0
18	Other	263.i	0	GP	0.02561	0
19	Payments in lieu of taxes		0	GP	0.02561	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		$ 7,078,678			$ 203,015
	INCOME TAXES (Note K)					
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		38.900000%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		50.812433%			
	where WCLTD=(page 4, line 27) and R= (page 4, line 30)					
	and FIT, SIT & p are as given in footnote K.					
23	1 / (1 - T) = (from line 21)		1.6367			
24	Amortized Investment Tax Credit	266.8.f (enter negative)	0			
25	Income Tax Calculation (line 22 * line 28)		$ 19,394,943	NA		$ 601,963
26	ITC adjustment (line 23 * line 24)		0	NP	0.02998	0
27	Total Income Taxes	(line 25 plus line 26)	$ 19,394,943			$ 601,963
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]		$ 38,169,680	NA		$ 1,184,676
29	REVENUE REQUIREMENT (sum lines 8, 12, 20, 27, 28)		$ 96,313,123			$ 7,053,717

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2010

Rate Formula Template
Utilizing FERC Form 1 Data

DUKE ENERGY KENTUCKY
SUPPORTING CALCULATIONS AND NOTES

Line No.	**TRANSMISSION PLANT INCLUDED IN ISO RATES**		
1	Total transmission plant (page 2, line 2, column 3)		29,257,744
2	Less transmission plant excluded from ISO rates (Note M)		0
3	Less transmission plant included in OATT Ancillary Services (Note N)		0
4	Transmission plant included in ISO Rates (line 1 less lines 2 & 3)		29,257,744
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)	TP=	1.00000
	TRANSMISSION EXPENSES		
6	Total transmission expenses (page 3, line 1, column 3)		21,479,522
7	Less transmission expenses included in OATT Ancillary Services (Note L)		291,030
8	Included transmission expenses (line 6 less line 7)		21,188,492
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)		0.98645
10	Percentage of transmission plant included in ISO Rates (line 5)	TP	1.00000
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)	TE=	0.98645

WAGES & SALARY ALLOCATOR (W&S)

Line No.		Form 1 Reference	$	TP	Allocation				
12	Production	354.20.b	11,171,122	0.00	0				
13	Transmission	354.21.b	661,424	1.00	661,424				
14	Distribution	354.23.b	3,594,175	0.00	0		W&S Allocator		
15	Other	354.24,25,26.b	2,483,361	0.00	0		($ / Allocation)		
16	Total (sum lines 12-15)		17,910,082		661,424	=	0.03693	=	WS

COMMON PLANT ALLOCATOR (CE)

Line No.			$	% Electric (line 17 / line 20)		W&S Allocator (line 16)		CE
17	Electric	200.3.c	1,087,520,512					
18	Gas	201.3.d	287,190,837	0.79109	*	0.03693	=	0.02922
19	Water	201.3.e	0					
20	Total (sum lines 17 - 19)		1,374,711,349					

RETURN (R)

Line No.			$
21		Long Term Interest (117, sum of 62.c through 67.c)	14,573,435
22		Preferred Dividends (118.29c) (positive number)	0
	Development of Common Stock:		
23		Proprietary Capital (112.16.c)	465,354,065
24		Less Preferred Stock (line 28)	0
25		Less Account 216.1 (112.12.c) (enter negative)	0
26		Common Stock (sum lines 23-25)	465,354,065

Line No.		(Note P)	$	%	Cost	Weighted	
27	Long Term Debt (112, sum of 18.c through 21.c)		332,571,494	42%	0.0438	0.0183	=WCLTD
28	Preferred Stock (112.3.c)		0	0%	0.0000	0.0000	
29	Common Stock (line 26)		465,354,065	58%	0.1238	0.0722	
30	Total (sum lines 27-29)		797,925,559			0.0905	=R

REVENUE CREDITS

Line No.				Load
	ACCOUNT 447 (SALES FOR RESALE) (Note Q)	(310-311)		
31	a. Bundled Non-RQ Sales for Resale (311.x.h)			0
32	b. Bundled Sales for Resale included in Divisor on page 1			0
33	Total of (a)-(b)			0
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)		$	9,399
35	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) (Note U)	(330.x.n)	$	-

Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 12/31/2010

Utilizing FERC Form 1 Data

DUKE ENERGY KENTUCKY

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)

References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
A	DEOK 1 CP is Duke Energy Ohio ("DEO") Monthly Firm Transmission System Peak Load as reported on page 400, column b of Form 1 at the time of DEO's annual peak, plus load served by Duke Energy Kentucky at Longbranch. For years ending 12/31/2010 and 12/31/2011, this sum will be reduced by the amount of distribution load served by East Kentucky Power Cooperative via Duke Kentucky's Hebron substation. (1) Excludes demands from grandfathered interzonal transactions and demands from service provided by ISO at a discount.
B	DEOK 12 CP is DEO Monthly Firm Transmission System Peak Load as reported on page 400, column b of Form 1 at the time of DEO's monthly peaks, plus load served by Duke Kentucky at Longbranch. For years ending 12/31/2010 and 12/31/2011, this sum will be reduced by the amount of distribution load served by East Kentucky Power Cooperative via Duke Kentucky's Hebron substation. (2) Excludes demands from grandfathered interzonal transactions and demands from service provided by ISO at a discount.
C	Reserved
D	Reserved
E	This deduction is to remove expenses recorded by DEOK for Postretirement Benefits Other than Pensions (PBOP). PBOP expense is set forth in line 3b and is fixed until changed as the result of a filing at FERC. The fixed amount of PBOP for DEO is $2,342,494 and for Duke Energy Kentucky ("DEK") is $575,908.
F	The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
G	Identified in Form 1 as being only transmission related.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111 line 57 in the Form 1.
I	Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26).

Inputs Required:	FIT =	35.00%	
	SIT=	0.55%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.
M	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to be included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts.
P	Debt cost rate = long-term interest (line 21) / long term debt (line 27). Preferred cost rate = preferred dividends (line 22) / preferred outstanding (line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC. Capitalization adjusted to exclude impacts of purchase accounting.
Q	Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Reserved
T	The revenues credited on page 1 lines 2-5c shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, or facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2010

Rate Formula Template

Utilizing FERC Form 1 Data

DUKE ENERGY KENTUCKY

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)

References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
U	On Line 35, enter revenues from RTO settlements that are associated with NITS and firm Point-to-Point Service for which the load is not included in the divisor to derive Duke Energy Ohio's and Duke Energy Kentucky's zonal rates. Exclude non-firm Point-to-Point revenues, revenues related to MTEP and RTEP projects, revenues from grandfathered interzonal transactions and revenues from service provided by ISO at a discount.
V	Account Nos. 561.4, 561.8 and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.
W	Reserved
X	Midwest ISO Exit Fees include (1) the charge that DEOK paid to the Midwest ISO pursuant to the Settlement Agreement filed on July 29, 2011 in Docket No. ER11-2059 and (2) the exit fees that DEOK paid to the Midwest ISO pursuant to the Exit Fee Agreement filed on October 5, 2011 in Docket No. ER12-33.
Y	PJM Integration Costs are the fees that PJM assessed DEOK for the costs that PJM incurred in connection with DEOK's move into PJM.

(1) For the purpose of calculating the DEK annual peak, the DEK annual peak is as reported on page 401, column d of Form 1, at the time of the DEK annual peak.

(2) For the purpose of calculating the DEK monthly peak, the DEK monthly peak is as reported on page 401, column d of Form 1, at the time of the DEK monthly peak.

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Kentucky
RTEP - Transmission Enhancement Charges

To be completed in conjunction with Attachment H-22A.

	(1)	(2)	(3)	(4)
Line No.		Attachment H-22A Page, Line, Col.	Transmission	Allocator
	TRANSMISSION PLANT			
1	Gross Transmission Plant - Total	Sch. H-22A, p 2, line 2 col 5 (Note A)	29,257,744	
2	Net Transmission Plant - Total	Sch. H-22A, p 2, line 14 col 5 (Note B)	17,332,652	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Sch. H-22A, p 3, line 8 col 5	4,419,451	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	15.11%	15.11%
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G&C Depreciation Expense	Sch. H-22A, p 3, lines 10 & 11, col 5 (Note H)	21,839	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	0.07%	0.07%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Sch. H-22A, p 3, line 20 col 5	203,015	
8	Annual Allocation Factor for Other Taxes	(line 5 divided by line 1 col 3)	0.69%	0.69%
9	**Annual Allocation Factor for Expense**	**Sum of lines 4, 6 and 8**		**15.87%**
	INCOME TAXES			
10	Total Income Taxes	Sch. H-22A, p 3, line 27 col 5	601,963	
11	Annual Allocation Factor for Income Taxes	(line 8 divided by line 2 col 3)	3.47%	3.47%
	RETURN			
12	Return on Rate Base	Sch. H-22A, p 3, line 28 col 5	1,184,676	
13	Annual Allocation Factor for Return on Rate Base	(line 10 divided by line 2 col 3)	6.83%	6.83%
14	**Annual Allocation Factor for Return**	**Sum of lines 11 and 13**		**10.31%**

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Kentucky
RTEP - Transmission Enhancement Charges

Network Upgrade Charge Calculation By Project

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line No.	Project Name	RTEP Project Number	Project Gross Plant	Annual Allocation Factor for Expense	Annual Expense Charge	Project Net Plant	Annual Allocation Factor for Return	Annual Return Charge	Project Depreciation Expense	Annual Revenue Requirement	True-Up Adjustment	Network Upgrade Charge
			(Note C)	(Page 1 line 7)	(Col. 3 * Col. 4)	(Note D)	(Page 1 line 12)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)	Sum Col. 10 & 11 (Note G)
1a			$ -	15.87%	$0.00	$ -	10.31%	$0.00	$0	$0.00	$ -	$0.00
1b			$ -	15.87%	$0.00	$ -	10.31%	$0.00	$0	$0.00	$ -	$0.00
1c			$ -	15.87%	$0.00	$ -	10.31%	$0.00	$0	$0.00	$ -	$0.00
2	Annual Totals									$0	$0	$0
3	RTEP Transmission Enhancement Charges for Attatchment H-22A, Page 1, Line 5c											$0

Note Letter
A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-22A and includes any sub lines 2a or 2b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.
B Net Transmission Plant is that identified on page 2 line 14 of Attachment H-22A and includes any sub lines 14a or 14b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.
C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes CWIP in rate base if applicable. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.
D Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.
E Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-22A page 3 line 12.
F True-Up Adjustment is included pursuant to a FERC approved methodology if applicable.
G The Network Upgrade Charge is the value to be used in Schedule 26.
H The Total General and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 9.

Ex. No. DUK-101

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Kentucky
Legacy MTEP Credit

To be completed in conjunction with Attatchment H-22A.

	(1)	(2)	(3)	(4)
Line No.		Attachment H-22A Page, Line, Col.	Transmission	Allocator
	TRANSMISSION PLANT			
1	Gross Transmission Plant - Total	Sch. H-22A, p 2, line 2 col 5 (Note A)	29,257,744	
2	Net Transmission Plant - Total	Sch. H-22A, p 2, line 14 col 5 (Note B)	17,332,652	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Sch. H-22A, p 3, line 8 col 5	4,419,451	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	15.11%	15.11%
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G&C Depreciation Expense	Sch. H-22A, p 3, lines 10 & 11, col 5 (Note H)	21,839	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	0.07%	0.07%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Sch. H-22A, p 3, line 20 col 5	203,015	
8	Annual Allocation Factor for Other Taxes	(line 5 divided by line 1 col 3)	0.69%	0.69%
9	**Annual Allocation Factor for Expense**	**Sum of lines 4, 6 and 8**		**15.87%**
	INCOME TAXES			
10	Total Income Taxes	Sch. H-22A, p 3, line 27 col 5	601,963	
11	Annual Allocation Factor for Income Taxes	(line 8 divided by line 2 col 3)	3.47%	3.47%
	RETURN			
12	Return on Rate Base	Sch. H-22A, p 3, line 28 col 5	1,184,676	
13	Annual Allocation Factor for Return on Rate Base	(line 10 divided by line 2 col 3)	6.83%	6.83%
14	**Annual Allocation Factor for Return**	**Sum of lines 11 and 13**		**10.31%**

Rate Formula Template
Utilizing Attachment H-22A Data

Duke Energy Kentucky
Legacy MTEP Credit

Network Upgrade Charge Calculation By Project

Line No.	(1) Project Name	(2) MTEP Project Number	(3) Project Gross Plant	(4) Annual Allocation Factor for Expense	(5) Annual Expense Charge	(6) Project Net Plant	(7) Annual Allocation Factor for Return	(8) Annual Return Charge	(9) Project Depreciation Expense	(10) Annual Revenue Requirement	(11) True-Up Adjustment	(12) Network Upgrade Charge
			(Note C)	(Page 1 line 7)	(Col. 3 * Col. 4)	(Note D)	(Page 1 line 12)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)	Sum Col. 10 & 11 (Note G)
1a	Project 1	P1	$ -	15.87%	$0.00	$ -	10.31%	$0.00	$0	$0.00	$ -	$0.00
1b	Project 2	P2	$ -	15.87%	$0.00	$ -	10.31%	$0.00	$0	$0.00	$ -	$0.00
1c	Project 3	P3	$ -	15.87%	$0.00	$ -	10.31%	$0.00	$0	$0.00	$ -	$0.00
2	Annual Totals									$0	$0	$0
3	Legacy MTEP Credit for Attatchment H-22A, Page 1, Line 5a											$0

Note Letter
A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-22A and includes any sub lines 2a or 2b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.
B Net Transmission Plant is that identified on page 2 line 14 of Attachment H-22A and includes any sub lines 14a or 14b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.
C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes CWIP in rate base if applicable. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.
D Project Net Plant is the Project Gross Plant identified in Column 3 less the associated Accumulated Depreciation.
E Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-22A page 3 line 12.
F True-Up Adjustment is included pursuant to a FERC approved methodology if applicable.
G The Network Upgrade Charge is the value to be used in Schedule 26.
H The Total General and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 9.

Ex. No. DUK-101

Duke Energy Ohio and Duke Energy Kentucky

FASB 106 and FAS 109 Regulatory Assets & Liabilities

Account 190	DEO	DEK	DEOK
Per Books Total, Page 234, line 18	$ 57,096,235	$ (9,994,664)	$ 47,101,571
Less: FAS 106 and FAS 109 Related items **Note:1**	13,765,795	169,037	$ 13,934,832
Adjusted Balances - To Page 2 of 5, Line 22	$ 43,330,440	$ (10,163,701)	$ 33,166,739

Account 282	DEO	DEK	DEOK
Per Books Total, Page 275, line 2, column k	$ 1,168,225,104	$ 167,140,589	$ 1,335,365,693
Less: FAS 106 and FAS 109 Related items **Note 1**	70,696,033	676,807	$ 71,372,840
Adjusted Balances - To Page 2 of 5, Line 20	$ 1,097,529,071	$ 166,463,782	$ 1,263,992,853

Note 1: There are currently only FAS106 related regulatory assets on DEO. For DEK there are no reg assets or liabilities and therefore no need to adjust the Accumulated Deferred Income Taxes for FAS 106.

Duke Energy Ohio and Duke Energy Kentucky

For the 12 months ended 12/31/2010

Materials and Supplies
Allocation of Account 163

Year to Date 2010

Duke Energy Ohio

	M&S	Percentage	163	Total M&S (1)
Production	48,099,268	60.40%	125,470	
Transmission	7,698,844	9.67%	20,083	7,718,927
Distribution	23,830,152	29.93%	62,163	
Total M&S	79,628,264	100.00%	207,716	

Duke Energy Kentucky

	M&S	Percentage	163	
Production	15,739,453	98.86%	1,252,008	
Transmission	8,282	0.05%	659	8,941
Distribution	173,207	1.09%	13,778	
Total M&S	15,920,942	100.00%	1,266,445	

Duke Energy Ohio and Kentucky

	M&S	163	
Production	63,838,721	1,377,479	
Transmission	7,707,126	20,742	7,727,868
Distribution	24,003,359	75,941	
Total M&S	95,549,206	207,716	

(1) To Page 2 of 5, Line 27.

Duke Energy Ohio and Duke Energy Kentucky

For the 12 months ended 12/31/2010

Detail of Land Held for Future Use

	Transmission Related	Non-Transmission Related Portion	Reported on FERC Form 1
Duke Energy Ohio			
East Bend Station		$ 1,959,275	$ 1,959,275
J.M. Stuart Station		272,173	272,173
Woodsdale Station		2,012,790	2,012,790
Other Projects	125,772	42,004	167,776
J.M. Stuart Station - Production		91,232	91,232
East Bend Station - Production	-	251,236	251,236
Total	$ 125,772	$ 4,628,710	$ 4,754,482
Duke Energy Kentucky			
	-	-	-
Duke Energy Ohio and Kentucky			
Balances - To Page 2 of 5, Line 25	$ 125,772	$ 4,628,710	$ 4,754,482

Source: FERC Form 1 Page 214

Duke Energy Ohio and Duke Energy Kentucky

For the 12 months ended 12/31/2010

Safety and Non-Safety Related Advertising

	Source		DEO		DEK		DEOK
General Advertising - 930.1	Form 1, P. 323, L.191	$	87,626	$	14,377	$	102,003
Regulatory Commission Expense	Form 1, P.351, col. d, L.9		2,485,456		588,672		3,074,128
Regulatory Commission Expense	Form 1, P.351, col. d, L.10		663,597		951,889		1,615,486
Regulatory Commission Expense	Form 1, P.351, col. d, L.11		124,669				124,669
Regulatory Commission Expense	Form 1, P.351, col. d, L.22		139,714				139,714
Electric Power Research Institute	Form 1, P.353, col. d, L.10		1,896,938		282,506		2,179,444
Subtotal		$	5,398,000	$	1,837,444	$	7,235,444
Amount of Safety Related Advertising			-		-		-
Amount of Non-Safety Related Advertising		$	5,398,000	$	1,837,444	$	7,235,444

Duke Energy Ohio and Duke Energy Kentucky

For the 12 months ended 12/31/2010

Balancing Authority Costs

	DEO	DEK	DEOK
A&G Expense			
A&G Expense, Page 323, line 197, column b	$ 201,656,909	$ 28,974,993	$ 230,631,902
Less: Balancing Authority costs that should have been recorded in account 561, instead were recorded in Account 920 after accounting system change	-	-	-
Adjusted A&G Expense - To Page 3, Line 3	$ 201,656,909	$ 28,974,993	$ 230,631,902
Transmission Expense			
Transmission Expense, Page 321, line 112, column b	$ 17,959,496	$ 21,479,522	$ 39,439,018
Add: Balancing Authority costs that should have been recorded in account 561, instead were recorded in Account 920 after accounting system change	-	-	-
Adjusted Transmission Expense - To Page3, Line1	$ 17,959,496	$ 21,479,522	$ 39,439,018
Balancing Authority Costs in 561 through 561.3			
B.A. Costs in Transmission Expense on Page 321 of FF1	$ 1,717,328	$ 291,030	$ 2,008,358
Add: Balancing Authority costs that should have been recorded in account 561, instead were recorded in Account 920 after accounting system change	-	-	-
Adjusted B.A. Costs - To Page 4, Line 7	$ 1,717,328	$ 291,030	$ 2,008,358

Duke Energy Ohio and Duke Energy Kentucky

For the 12 months ended 12/31/2010

State Tax Composite Rate

State	Ohio	Kentucky	
	Duke Energy Ohio	Duke Energy Kentucky	TOTAL
Revenue Requirement	$ 69,727,960.54	$ 7,053,717.43	$ 76,781,677.96
Tax Rate	0.00%	6.00%	
State Taxes	$ -	$ 423,223.05	$ 423,223.05
Composite Tax Rate			0.55%

Duke Energy Ohio and Duke Energy Kentucky

For the 12 months ended 12/31/2010

Determination of Transmission Plant Included in OATT Ancillary Services

	DEO	DEK	DEOK
Generation Step-up Transformers	$ 23,208,297	$ -	$ 23,208,297
Assets removed through 2011 by FERC Agreement	60,072,019		60,072,019
Sole use Property			-
Distribution Use	-	-	-
Transmission plant included in OATT Ancillary Services - To Page 4, Line 3	$ 83,280,316	$ -	$ 83,280,316

Duke Energy Ohio and Duke Energy Kentucky

Revenue Credits, Accounts 454 and 456

	Account 454		
	DEO	DEK	DEOK
Per Books Total, Page 300	$ 16,984,843	$ 672,339	$ 17,657,182
Tower Lease Revenues in per Books Total above	100,479	2,469	102,948
Rent from Electric Property in per Books Total above	1,890,770	138,601	2,029,371
Portion attributable to Transmission	5.0%	5.0%	5.0%
Revenue Credit Applicable to Attatchment H-22A	$ 195,017	$ 9,399	$ 204,417
Step-ups leased to Duke Energy Kentucky	1,933,776		1,933,776
Total Account 454 - To Page 4 of 5, Line 34	$ 2,128,793	$ 9,399	$ 2,138,193

	Account 456		
	DEO	DEK	DEOK
Per Books Total, Page 300	$ 29,681,332	$ 12,632,601	$ 42,313,933
Remove Non-Transmission and Non-ISO Related Revenues:			
Production	37,998,012	12,614,601	50,612,613
Common Transmission **(Note 1)**	37,196,664	-	37,196,664
Distribution	710,048	-	710,048
Customer Account	-	-	-
Administrative and General	(58,910,990)	18,000	(58,892,990)
Revenue Associated with MISO Schedules 7,8,9 and 26	$ 12,687,598	$ -	$ 12,687,598
Schedule 26 - Legacy MTEP	1,285,002		1,285,002
Schedule 8 - Non-Firm Point-to-Point	688,948		688,948
Total Account 456 - To Page 4 of 5, Line 35	$ 10,713,648	$ -	$ 10,713,648

Note 1: Revenues associated with Common lines that are 69KV, below the ISO 100KV limit.

Duke Energy Ohio and Duke Energy Kentucky

Duke Energy Ohio Consolidated
Capital Structure
December 31, 2010
(In Dollars)

	Actual 12/31/10		Purchase Accounting	Goodwill Impairments Sep09 and Jun10	Other Asset Impairment Charges	Adjusted 12/31/10	Midwest DENA Equity	Capital Structure without Purchase accounting and Midwest DENA	
Liabilities and Shareholders' Equity									
Non-Current Liabilities									
Long-Term Debt (3)	$ 2,556,677,916		$ 6,371,809			$ 2,563,049,725		$ 2,563,049,725	
Deferred Debt Expense	$ (22,724,517)		$ (4,041,641)			$ (26,766,158)		$ (26,766,158)	
Less: Current portion of deferred debt expense	$ -					$ -		$ -	
0257010 Unamortized Gain-Debt	$ 528,921					$ 528,921		$ 528,921	
Total Long-term debt	**$ 2,534,482,320**	**32%**	**$ 2,330,168**	**$ -**	**$ -**	**$ 2,536,812,488**	**$ -**	**$ 2,536,812,488**	**44%**
Common Stock Equity									
0201000 Common Stock Issued	$ 762,136,231		$ -			$ 762,136,231	$ -	$ 762,136,231	
207000 Premium on capital stock	$ -		$ 362,457,437			$ 362,457,437		$ 362,457,437	
0208000 Donations From Stockholder	$ 28,950,000		$ 197,206,819			$ 226,156,819		$ 226,156,819	
0208001 Donations From Stockholder-DENA	$ 1,462,336,840		$ -			$ 1,462,336,840	$ (1,462,336,840)	$ -	
0208010 Donat Recvd From Stkhld Tax	$ 15,641,578		$ 68,538,328			$ 84,179,906		$ 84,179,906	
210020 Gain on Redemption of Capital	$ -		$ 147,685			$ 147,685		$ 147,685	
0211004 Misc Paid in Capital Purch Acctg	$ 2,879,949,148		$ (2,879,949,148)			$ -		$ -	
0211005 Misc Paid in Capital Premerger Equity	$ 557,581,098		$ (603,514,486)			$ (45,933,388)		$ (45,933,388)	
0211007 Misc PIC Premerg RE for Div	$ 625,474,493		$ (625,474,493)			$ -		$ -	
211110 PIC - Sharesaver (BDMS account)	$ -		$ (3,350,836)			$ (3,350,836)		$ (3,350,836)	
214010 Common stock equity inter-company	$ -		$ (21,750,868)			$ (21,750,868)		$ (21,750,868)	
0216000/0216100 Unappropriated RE/Undistr Subsid Earnings	$ (405,899,213)		$ 870,373,203	726,711,261	40,629,393	$ 1,231,814,644	$ (20,510,155)	$ 1,211,304,489	
0216100 Unappropriated RE/Undistr Subsid Earnings - Equitization	$ -		$ -			$ -	$ 503,497,905	$ 503,497,905	
0438000 Dividends Declared on Common Stock	$ -					$ -		$ -	
	$ (440,568,022)		$ 27,505,832	676,741,585	26,074,048	$ 289,753,443	$ (97,811,152)	$ 191,942,291	
Accum other comprehensive income (loss)	$ (21,663,377)		$ (45,455,363)			$ (67,118,740)	$ -	$ (67,118,740)	
Total Common Stock Equity	**$ 5,463,938,776**	**68%**	**$ (2,653,265,890)**	**$ 1,403,452,846**	**$ 66,703,441**	**$ 4,280,829,173**	**$ (1,077,160,242)**	**$ 3,203,668,931**	**56%**
TOTAL CAPITALIZATION	**$ 7,998,421,096**		**$ (2,650,935,722)**	**$ 1,403,452,846**	**$ 66,703,441**	**$ 6,817,641,661**	**$ (1,077,160,242)**	**$ 5,740,481,419**	

Adjustment to Proprietary Capital for Duke Ohio Attatchment H-22A $ (2,260,269,845)

Duke Energy Ohio and Duke Energy Kentucky

2010 MONTHLY PEAKS IN MEGAWATTS

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Average
DEO - Monthly Transmission System Peak Load (1)	4,204,000	4,148,000	3,856,000	3,428,000	4,434,000	5,305,000	5,285,000	5,571,000	5,163,000	3,589,000	3,557,000	4,344,000	52,884,000	4,407,000
Less:														
DEK Monthly Peak Demand (2)	671,000	655,000	608,000	530,000	694,000	822,000	821,000	892,000	816,000	575,000	555,000	703,000	8,342,000	695,167
DEO - Monthly Transmission System Peak Load	3,533,000	3,493,000	3,248,000	2,898,000	3,740,000	4,483,000	4,464,000	4,679,000	4,347,000	3,014,000	3,002,000	3,641,000	44,542,000	3,711,833

Notes:

(1) DEOK 1 CP is Duke Energy Ohio ("DEO") Monthly Firm Transmission System Peak Load as reported on page 400, column b of Form 1 at the time of DEO's annual peak, plus load served by Duke Energy Kentucky at Longbranch. For years ending 12/31/2010 and 12/31/2011, this sum will be reduced by the amount of distribution load served by

(2) Source: DEK peak as reported on FERC Form 1 Page 401b

Ex. No. DUK-103

Midwest ISO
FERC Electric Tariff, Fourth Revised Volume No. 1

First Revised Sheet No. 2624
Superseding Original Sheet No. 2624

Attachment O
page 1 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2010

DUKE ENERGY OHIO

Line No.			Total	Allocator		Allocated Amount	
1	GROSS REVENUE REQUIREMENT (page 3, line 31)					$ 66,986,221	
	REVENUE CREDITS	(Note T)					
2	Account No. 454	(page 4, line 34)	2,128,793	TP	0.87591	1,864,624	
3	Account No. 456	(page 4, line 37)	11,402,596	TP	0.87591	9,987,611	
4	Revenues from Grandfathered Interzonal Transactions		0	TP	0.87591	0	Line 4 supported by schedules.
5	Revenues from service provided by the ISO at a discount		0	TP	0.87591	0	Line 5 supported by schedules.
6	TOTAL REVENUE CREDITS (sum lines 2-5)					11,852,235	
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ 55,133,986	
	DIVISOR						
8	Average of 12 coincident system peaks for requirements (RQ) service				(Note A)	1,715,917	Line 8 supported with monthly CP and associated net energy.
9	Plus 12 CP of firm bundled sales over one year not in line 8				(Note B)	1,705,083	
10	Plus 12 CP of Network Load not in line 8				(Note C)	0	
11	Less 12 CP of firm P-T-P over one year (enter negative)				(Note D)	0	
12	Plus Contract Demand of firm P-T-P over one year					0	
13	Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)					0	
14	Less Contract Demands from service over one year provided by ISO at a discount (enter negative)					0	
15	Divisor (sum lines 8-14)					3,421,000	
16	Annual Cost ($/kW/Yr)	(line 7 / line 15)	16.116				
17	Network & P-to-P Rate ($/kW/Mo)	(line 16 / 12)	1.343				

Line No.			Peak Rate		Off-Peak Rate	
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	0.310		$0.310	
19	Point-To-Point Rate ($/kW/Day)	(line 16 / 260; line 16 / 365)	0.062	Capped at weekly rate	$0.044	
20	Point-To-Point Rate ($/MWh)	(line 16 / 4,160; line 16 / 8,76 times 1,000)	0.004	Capped at weekly and daily rates	$1.845	
21	FERC Annual Charge($/MWh)	(Note E)	**$0.000**	Short Term	$0.000	Short Term
22			$0.000	Long Term	$0.000	Long Term

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2010

DUKE ENERGY OHIO

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE					
1	Production	205.46.g	5,047,479,619	NA		
2	Transmission	207.58.g	671,111,058	TP	0.87591	587,830,742
3	Distribution	207.75.g	1,844,361,344	NA		
4	General & Intangible	205.5.g & 207.99.g	180,438,606	W/S	0.02762	4,983,548
5	Common	356.1	242,989,309	CE	0.02393	5,813,914
6	TOTAL GROSS PLANT (sum lines 1-5)		7,986,379,936	GP=	7.496%	598,628,204
	ACCUMULATED DEPRECIATION					
7	Production	219.20-24.c	1,655,125,088	NA		
8	Transmission	219.25.c	233,399,352	TP	0.87591	204,436,081
9	Distribution	219.26.c	625,814,226	NA		
10	General & Intangible	219.28.c	10,627,310	W/S	0.02762	293,517
11	Common	356.1	111,410,252	CE	0.02393	2,665,671
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		2,636,376,228			207,395,268
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	3,392,354,531			
14	Transmission	(line 2- line 8)	437,711,706			383,394,662
15	Distribution	(line 3 - line 9)	1,218,547,118			
16	General & Intangible	(line 4 - line 10)	169,811,296			4,690,031
17	Common	(line 5 - line 11)	131,579,057			3,148,243
18	TOTAL NET PLANT (sum lines 13-17)		5,350,003,708	NP=	7.313%	391,232,936
	ADJUSTMENTS TO RATE BASE (Note F)					
19	Account No. 281 (enter negative)	273.8.k	(15,661,825)	NA	zero	0
20	Account No. 282 (enter negative)	275.2.k	(1,097,529,071)	NP	0.07313	(80,259,668)
21	Account No. 283 (enter negative)	277.9.k	(214,513,307)	NP	0.07313	(15,686,843)
22	Account No. 190	234.8.c	43,330,440	NP	0.07313	3,168,651
23	Account No. 255 (enter negative)	267.8.h	(3,695,922)	NP	0.07313	(270,274)
24	TOTAL ADJUSTMENTS (sum lines 19- 23)		(1,288,069,685)			(93,048,134)
25	LAND HELD FOR FUTURE USE	214.x.d (Note G)	125,772	TP	0.87591	110,165
	WORKING CAPITAL (Note H)					
26	CWC	calculated	25,573,431			1,502,582
27	Materials & Supplies (Note G)	227.8.c & .16.c	7,718,927	TE	0.79215	6,114,553
28	Prepayments (Account 165)	111.57.c	45,697,343	GP	0.07496	3,425,296
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		78,989,701			11,042,431
30	RATE BASE (sum lines 18, 24, 25, & 29)		4,141,049,497			309,337,398

Ex. No. DUK-103

Midwest ISO
FERC Electric Tariff, Fourth Revised Volume No. 1

Third Revised Sheet No.2626
Superseding Second Revised Sheet No. 2626

Attachment O
page 3 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2010

DUKE ENERGY OHIO

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)	
	O&M						
1	Transmission	321.112.b	17,959,496	TE	0.79215	14,226,625	
1a	Less LSE Expenses included in Transmission O&M Accounts (Note V)	321.88.b, 92.b; 322.121.b	2,454,329		1.00000	2,454,329	
2	Less Account 565	321.96.b	6,505,839	TE	0.79215	5,153,604	
3	A&G	323.197.b	201,656,909	W/S	0.02762	5,569,576	
4	Less FERC Annual Fees		670,788	W/S	0.02762	18,527	
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		5,398,000	W/S	0.02762	149,088	
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.79215	0	
6	Common	356.1	0	CE	0.02393	0	
7	Transmission Lease Payments		0		1.00000	0	
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 2, 4, 5)		204,587,449			12,020,656	
	DEPRECIATION EXPENSE						
9	Transmission	336.7.b	11,107,812	TP	0.87591	9,729,408	
10	General	336.10.b	2,344,984	W/S	0.02762	64,766	
11	Common	336.11.b	4,334,407	CE	0.02393	103,708	
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		17,787,203			9,897,882	
	TAXES OTHER THAN INCOME TAXES (Note J)						
	LABOR RELATED						
13	Payroll	263.i. 4, 5, 12	12,810,088	W/S	0.02762	353,803	
14	Highway and vehicle	263.i. 6, 7, 15, 16	34,961	W/S	0.02762	966	
15	PLANT RELATED						
16	Property	263.i. 17, 27	97,584,795	GP	0.07496	7,314,579	
17	Gross Receipts	263.i. 24, 29	4,568,022	NA	zero	0	
18	Other	263.i	0	GP	0.07496	0	
19	Payments in lieu of taxes		0	GP	0.07496	0	
20	TOTAL OTHER TAXES (sum lines 13 - 19)		114,997,866			7,669,348	
	INCOME TAXES	(Note K)					
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		35.00%				
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		42.88%				
	where WCLTD=(page 4, line 27) and R= (page 4, line30)						
	and FIT, SIT & p are as given in footnote K.						
23	1 / (1 - T) = (from line 21)		1.5385				
24	Amortized Investment Tax Credit (266.8f) (enter negative)		0				exclude this amount included in Account 255 on row 97
25	Income Tax Calculation = line 22 * line 28		160,934,423	NA		12,021,840	
26	ITC adjustment (line 23 * line 24)		0	NP	0.07313	0	
27	Total Income Taxes	(line 25 plus line 26)	160,934,423			12,021,840	
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]		375,315,564	NA		28,036,163	
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		873,622,505			69,645,889	
30	LESS ATTACHMENT GG ADJUSTMENT [Attachment GG, page 2, line 3, column 10] (Note W) [Revenue Requirement for facilities included on page 2, line 2, and also included in Attachment GG]		2,659,668			2,659,668	
31	REV. REQUIREMENT TO BE COLLECTED UNDER ATTACHMENT O (line 29 - line 30)		870,962,837			66,986,221	

Ex. No. DUK-103

Midwest ISO
FERC Electric Tariff, Fourth Revised Volume No. 1

First Revised Sheet No. 2627
Superseding Original Revised Sheet No. 2627

Attachment O
page 4 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2010

DUKE ENERGY OHIO
SUPPORTING CALCULATIONS AND NOTES

Line No.	TRANSMISSION PLANT INCLUDED IN ISO RATES		
1	Total transmission plant (page 2, line 2, column 3)		671,111,058
2	Less transmission plant excluded from ISO rates (Note M)		0
3	Less transmission plant included in OATT Ancillary Services (Note N)		83,280,316
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)		587,830,742
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)	TP=	0.87591

Year End Bulk/Common Split

Line No.	TRANSMISSION EXPENSES		
6	Total transmission expenses (page 3, line 1, column 3)		17,959,496
7	Less transmission expenses included in OATT Ancillary Services (Note L) (page 321, line 84, column (b))		1,717,328
8	Included transmission expenses (line 6 less line 7)		16,242,168
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)		0.90438
10	Percentage of transmission plant included in ISO Rates (line 5)	TP	0.87591
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)	TE=	0.79215

Schedule 1 Recoverable Expenses

$ 1,717,328	Acct 561.1 - 561.3, 561.BA included in Line 7?
420,072	Acct 561.BA for Schedule 24
1,297,256	Acct 561.1 - 561.3 available for Schedule 1
	Revenue Credits for Sched 1 Acct 561.1 - 561.3
530,338	transactions <1 yr
-	non-firm
-	transactions w/ load not in divisor
530,338	total Revenue Credits
$ 766,918	Net Schedule 1 Expenses (Acct 561.1 - 561.3 minus Credits)

WAGES & SALARY ALLOCATOR (W&S)

Line No.		Form 1 Reference	$	TP	Allocation		
12	Production	354.20.b	57,676,930	0.00	0		
13	Transmission	354.21.b	3,321,634	0.88	2,909,442		
14	Distribution	354.23.b	23,830,724	0.00	0		W&S Allocator
15	Other	354.24,25,26.b	20,512,455	0.00	0		($ / Allocation)
16	Total (sum lines 12-15)		105,341,743		2,909,442	=	0.02762 = WS

COMMON PLANT ALLOCATOR (CE) (Note O)

Line No.			$	% Electric (line 17 / line 20)		W&S Allocator (line 16)		CE
17	Electric	200.3.c	6,734,823,068	0.86631	*	0.02762	=	0.02393
18	Gas	201.3.d	1,039,345,339					
19	Water	201.3.e	0					
20	Total (sum lines 17 - 19)		7,774,168,407					

RETURN (R)

Line No.			$
21		Long Term Interest (117, sum of 62.c through 67.c)	98,012,064
22		Preferred Dividends (118.29.c) (positive number)	0
	Development of Common Stock:		
23		Proprietary Capital (112.16.c)	3,203,668,932
24		Less Preferred Stock (112.3.c)	0
25		Less Account 216.1 (112.12.c) (enter negative)	(108,049,782)
26		Common Stock (sum lines 23-25)	3,095,619,150

Line No.		$	%	Cost (Note P)	Weighted	
27	Long Term Debt (112, sum of 18.c through 21.c)	2,214,256,271	42%	0.0443	0.0185	=WCLTD
28	Preferred Stock (112.3.c)	0	0%	0.0000	0.0000	
29	Common Stock (line 26)	3,095,619,150	58%	0.1238	0.0722	
30	Total (sum lines 27-29)	5,309,875,421			0.0906	=R

REVENUE CREDITS

Line No.				Load
	ACCOUNT 447 (SALES FOR RESALE)	(310-311)	(Note Q)	
31	a. Bundled Non-RQ Sales for Resale (311.x.h)			0
32	b. Bundled Sales for Resale included in Divisor on page 1			0
33	Total of (a)-(b)			0
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)			$ 2,128,793
	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) (Note U)	(330.x.n)		
35	a. Transmission charges for all transmission transactions			$ 29,681,332
36	b. Transmission charges for all transmission transactions included in Divisor on Page 1			16,993,734
36a	c. Transmission charges associated with Schedule 26 (Note X)			1,285,002
37	Total of (a)-(b)-(c)			$ 11,402,596

Line 34 supported by notes in Form 1 or detailed Schedule
Line 35 supported by notes in Form 1 or detailed Schedule
Line 36 supported by notes in Form 1 or detailed Schedule

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2010

DUKE ENERGY OHIO

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
A	Peak as would be reported on page 401, column d of Form 1 at the time of the ISO coincident monthly peaks.
B	Labeled LF, LU, IF, IU on pages 310-311 of Form 1 at the time of the ISO coincident monthly peaks.
C	Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
D	Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
E	The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.
F	The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
G	Identified in Form 1 as being only transmission related.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111 line 57 in the Form 1.
I	Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26).

Inputs Required:				
	FIT =	35.00%		
	SIT=	0.57%	(State Income Tax Rate or Composite SIT)	SIT work papers if required
	p =	0.00%	(percent of federal income tax deductible for state purposes)	

L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.
M	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to be included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts
P	Debt cost rate = long-term interest (line 21) / long term debt (line 27). Preferred cost rate = preferred dividends (line 22) / preferred outstanding (line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.
Q	Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4 page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have <u>not</u> been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.
T	The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.
U	Account 456.1 entry shall be the annual total of the quarterly values reported at Form 1, 330.x.n.
V	Account Nos. 561.4, 561.8 and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.
W	Pursuant to Attachment GG of the Midwest ISO Tariff, removes dollar amount of revenue requirements calculated pursuant to Attachment GG

Ex. No. DUK-103

Midwest ISO
FERC Electric Tariff, Fourth Revised Volume No. 1

First Revised Sheet No. 2624
Superseding Original Sheet No. 2624

Attachment O
page 1 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2010

DUKE ENERGY KENTUCKY

Line No.			Total	Allocator		Allocated Amount	
1	GROSS REVENUE REQUIREMENT (page 3, line 31)					$ 7,037,055	
	REVENUE CREDITS	(Note T)					
2	Account No. 454	(page 4, line 34)	9,399	TP	1.00000	9,399	
3	Account No. 456	(page 4, line 37)	0	TP	1.00000	0	
4	Revenues from Grandfathered Interzonal Transactions		0	TP	1.00000	0	Line 4 supported by schedules.
5	Revenues from service provided by the ISO at a discount		0	TP	1.00000	0	Line 5 supported by schedules.
6	TOTAL REVENUE CREDITS (sum lines 2-5)					9,399	
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ 7,027,656	
	DIVISOR						
8	Average of 12 coincident system peaks for requirements (RQ) service				(Note A)	692,417	Line 8 supported with monthly CP and associated net energy.
9	Plus 12 CP of firm bundled sales over one year not in line 8				(Note B)	0	
10	Plus 12 CP of Network Load not in line 8				(Note C)	0	
11	Less 12 CP of firm P-T-P over one year (enter negative)				(Note D)	0	
12	Plus Contract Demand of firm P-T-P over one year					0	
13	Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)					0	
14	Less Contract Demands from service over one year provided by ISO at a discount (enter negative)					0	
15	Divisor (sum lines 8-14)					692,417	
16	Annual Cost ($/kW/Yr)	(line 7 / line 15)	10.149				
17	Network & P-to-P Rate ($/kW/Mo)	(line 16 / 12)	0.846				
			Peak Rate			Off-Peak Rate	
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	0.195			$0.195	
19	Point-To-Point Rate ($/kW/Day)	(line 16 / 260; line 16 / 365)	0.039	Capped at weekly rate		$0.028	
20	Point-To-Point Rate ($/MWh)	(line 16 / 4,160; line 16 / 8,7(times 1,000)	0.002	Capped at weekly and daily rates		$1.162	
21	FERC Annual Charge($/MWh)	(Note E)	$0.000	Short Term		$0.000 Short Term	
22			$0.000	Long Term		$0.000 Long Term	

Midwest ISO
FERC Electric Tariff, Fourth Revised Volume No. 1

First Revised Sheet No. 2625
Superseding Original Revised Sheet No. 2625

Attachment O
page 2 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2010

DUKE ENERGY KENTUCKY

Line No.	(1) RATE BASE:	(2) Form No. 1 Page, Line, Col.	(3) Company Total		(4) Allocator	(5) Transmission (Col 3 times Col 4)
	GROSS PLANT IN SERVICE					
1	Production	205.46.g	777,200,182	NA		
2	Transmission	207.58.g	29,257,744	TP	1.00000	29,257,744
3	Distribution	207.75.g	343,335,588	NA		
4	General & Intangible	205.5.g & 207.99.g	7,134,451	W/S	0.03693	263,477
5	Common	356.1	29,301,649	CE	0.02922	856,052
6	TOTAL GROSS PLANT (sum lines 1-5)		1,186,229,614	GP=	2.561%	30,377,274
	ACCUMULATED DEPRECIATION					
7	Production	219.20-24.c	427,748,107	NA		
8	Transmission	219.25.c	11,925,092	TP	1.00000	11,925,092
9	Distribution	219.26.c	130,825,208	NA		
10	General & Intangible	219.28.c	983,380	W/S	0.03693	36,316
11	Common	356.1	17,253,844	CE	0.02922	504,074
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		588,735,631			12,465,482
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	349,452,075			
14	Transmission	(line 2- line 8)	17,332,652			17,332,652
15	Distribution	(line 3 - line 9)	212,510,380			
16	General & Intangible	(line 4 - line 10)	6,151,071			227,161
17	Common	(line 5 - line 11)	12,047,805			351,979
18	TOTAL NET PLANT (sum lines 13-17)		597,493,983	NP=	2.998%	17,911,791
	ADJUSTMENTS TO RATE BASE (Note F)					
19	Account No. 281 (enter negative)	273.8.k	(197,747)	NA	zero	0
20	Account No. 282 (enter negative)	275.2.k	(166,463,782)	NP	0.02998	(4,990,284)
21	Account No. 283 (enter negative)	277.9.k	(3,755,102)	NP	0.02998	(112,571)
22	Account No. 190	234.8.c	(10,163,701)	NP	0.02998	(304,689)
23	Account No. 255 (enter negative)	267.8.h	(269,205)	NP	0.02998	(8,070)
24	TOTAL ADJUSTMENTS (sum lines 19- 23)		(180,849,537)			(5,415,615)
25	LAND HELD FOR FUTURE USE	214.x.d (Note G)	0	TP	1.00000	0
	WORKING CAPITAL (Note H)					
26	CWC	calculated	3,790,896			550,384
27	Materials & Supplies (Note G)	227.8.c & .16.c	8,941	TE	0.98645	8,820
28	Prepayments (Account 165)	111.57.c	1,483,709	GP	0.02561	37,995
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		5,283,546			597,198
30	RATE BASE (sum lines 18, 24, 25, & 29)		421,927,992			13,093,375

Ex. No. DUK-103

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2010

DUKE ENERGY KENTUCKY

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	321.112.b	21,479,522	TE	0.98645	21,188,492
1a	Less LSE Expenses included in Transmission O&M Accounts (Note V)	321.88.b, 92.b; 322.121.b	769,687		1.00000	769,687
2	Less Account 565	321.96.b	17,241,235	TE	0.98645	17,007,630
3	A&G	323.197.b	28,974,993	W/S	0.03693	1,070,054
4	Less FERC Annual Fees		278,983	W/S	0.03693	10,303
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		1,837,444	W/S	0.03693	67,857
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.98645	0
6	Common	356.1	0	CE	0.02922	0
7	Transmission Lease Payments		0		1.00000	0
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 2, 4, 5)		30,327,166			4,403,069
	DEPRECIATION EXPENSE					
9	Transmission	336.7.b	622,772	TP	1.00000	622,772
10	General	336.10.b	104,720	W/S	0.03693	3,867
11	Common	336.11.b	615,164	CE	0.02922	17,972
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		1,342,656			644,611
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
13	Payroll	263.i. 6, 7, 14	1,915,606	W/S	0.03693	70,744
14	Highway and vehicle	263.i. 5, 13	4,802	W/S	0.03693	177
15	PLANT RELATED					
16	Property	263.i. 15, 26	5,158,270	GP	0.02561	132,094
17	Gross Receipts	263.i	0	NA	zero	0
18	Other	263.i	0	GP	0.02561	0
19	Payments in lieu of taxes		0	GP	0.02561	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		7,078,678			203,015
	INCOME TAXES	(Note K)				
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		38.90%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		50.81%			
	where WCLTD=(page 4, line 27) and R= (page 4, line30)					
	and FIT, SIT & p are as given in footnote K.					
23	1 / (1 - T) = (from line 21)		1.6367			
24	Amortized Investment Tax Credit (266.8f) (enter negative)		0			
25	Income Tax Calculation = line 22 * line 28		19,394,943	NA		601,869
26	ITC adjustment (line 23 * line 24)		0	NP	0.02998	0
27	Total Income Taxes	(line 25 plus line 26)	19,394,943			601,869
28	RETURN		38,169,680	NA		1,184,491
	[Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]					
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		96,313,123			7,037,055
30	LESS ATTACHMENT GG ADJUSTMENT [Attachment GG, page 2, line 3, column 10] (Note W)					
	[Revenue Requirement for facilities included on page 2, line 2, and also included in Attachment GG]		0			0
31	REV. REQUIREMENT TO BE COLLECTED UNDER ATTACHMENT O (line 29 - line 30)		96,313,123			7,037,055

exclude this amount included in Account 255 on row 97

Ex. No. DUK-103

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2010

DUKE ENERGY KENTUCKY
SUPPORTING CALCULATIONS AND NOTES

Line No.								
	TRANSMISSION PLANT INCLUDED IN ISO RATES							
1	Total transmission plant (page 2, line 2, column 3)						29,257,744	
2	Less transmission plant excluded from ISO rates (Note M)						0	
3	Less transmission plant included in OATT Ancillary Services (Note N)						0	
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)						29,257,744	
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)					TP=	1.00000	
	TRANSMISSION EXPENSES							
6	Total transmission expenses (page 3, line 1, column 3)						21,479,522	
7	Less transmission expenses included in OATT Ancillary Services (Note L) (page 321, line 84, column (b))						291,030	
8	Included transmission expenses (line 6 less line 7)						21,188,492	
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)						0.98645	
10	Percentage of transmission plant included in ISO Rates (line 5)					TP	1.00000	
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)					TE=	0.98645	
	WAGES & SALARY ALLOCATOR (W&S)							
		Form 1 Reference	$	TP	Allocation			
12	Production	354.20.b	11,171,122	0.00	0			
13	Transmission	354.21.b	661,424	1.00	661,424			
14	Distribution	354.23.b	3,594,175	0.00	0		W&S Allocator	
15	Other	354.24,25,26.b	2,483,361	0.00	0		($ / Allocation)	
16	Total (sum lines 12-15)		17,910,082		661,424	=	0.03693	= WS
	COMMON PLANT ALLOCATOR (CE) (Note O)							
			$		% Electric (line 17 / line 20)		W&S Allocator (line 16)	CE
17	Electric	200.3.c	1,087,520,512					
18	Gas	201.3.d	287,190,837		0.79109	*	0.03693 =	0.02922
19	Water	201.3.e	0					
20	Total (sum lines 17 - 19)		1,374,711,349					
	RETURN (R)						$	
21		Long Term Interest (117, sum of 62.c through 67.c)					14,573,435	
22		Preferred Dividends (118.29c) (positive number)					0	
	Development of Common Stock:							
23		Proprietary Capital (112.16.c)					465,354,065	
24		Less Preferred Stock (line 28)					0	
25		Less Account 216.1 (112.12.c) (enter negative)					0	
26		Common Stock (sum lines 23-25)					465,354,065	
			$	%	Cost (Note P)		Weighted	
27	Long Term Debt (112, sum of 18.c through 21.c)		332,571,494	42%	0.0438		0.0183	=WCLTD
28	Preferred Stock (112.3.c)		0	0%	0.0000		0.0000	
29	Common Stock (line 26)		465,354,065	58%	0.1238		0.0722	
30	Total (sum lines 27-29)		797,925,559				0.0905	=R
	REVENUE CREDITS						Load	
	ACCOUNT 447 (SALES FOR RESALE)		(310-311)	(Note Q)				
31	a. Bundled Non-RQ Sales for Resale (311.x.h)						0	
32	b. Bundled Sales for Resale included in Divisor on page 1						0	
33	Total of (a)-(b)						0	
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)						$ 9,399	
	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) (Note U)		(330.x.n)					
35	a. Transmission charges for all transmission transactions						$ 12,632,601	
36	b. Transmission charges for all transmission transactions included in Divisor on Page 1						12,632,601	
36a	c. Transmission charges associated with Schedule 26 (Note X)							
37	Total of (a)-(b)-(c)						$ -	

Schedule 1 Recoverable Expenses

$ 291,030	Acct 561.1 - 561.3, 561.BA included in Line 7?
59,753	Acct 561.BA for Schedule 24
231,277	Acct 561.1 - 561.3 available for Schedule 1
	Revenue Credits for Sched 1 Acct 561.1 - 561.3
-	transactions <1 yr
-	non-firm
-	transactions w/ load not in divisor
-	total Revenue Credits
$ 231,277	Net Schedule 1 Expenses (Acct 561.1 - 561.3 minus Credits)

Line 34 supported by notes in Form 1 or detailed Schedule

Line 35 supported by notes in Form 1 or detailed Schedule
Line 36 supported by notes in Form 1 or detailed Schedule

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2010

DUKE ENERGY KENTUCKY

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
A	Peak as would be reported on page 401, column d of Form 1 at the time of the ISO coincident monthly peaks.
B	Labeled LF, LU, IF, IU on pages 310-311 of Form 1 at the time of the ISO coincident monthly peaks.
C	Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
D	Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
E	The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.
F	The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
G	Identified in Form 1 as being only transmission related.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111 line 57 in the Form 1.
I	Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26).

Inputs Required:	FIT =	35.00%		
	SIT=	0.57%	(State Income Tax Rate or Composite SIT)	SIT work papers if required
	p =	0.00%	(percent of federal income tax deductible for state purposes)	

L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.
M	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to be included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts
P	Debt cost rate = long-term interest (line 21) / long term debt (line 27). Preferred cost rate = preferred dividends (line 22) / preferred outstanding (line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.
Q	Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4 page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have <u>not</u> been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.
T	The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.
U	Account 456.1 entry shall be the annual total of the quarterly values reported at Form 1, 330.x.n.
V	Account Nos. 561.4, 561.8 and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.
W	Pursuant to Attachment GG of the Midwest ISO Tariff, removes dollar amount of revenue requirements calculated pursuant to Attachment GG

Attachment D

Direct Testimony and Exhibits of
Robert B. Stoddard on behalf of Duke Energy
Ohio, Inc., and Duke Energy Kentucky, Inc.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM INTERCONNECTION, L.L.C.,	)	
DUKE ENERGY OHIO, INC., AND	)	**DOCKET NO. ER12-_____**
DUKE ENERGY KENTUCKY, INC.	)	

DIRECT TESTIMONY OF

ROBERT B. STODDARD

ON BEHALF OF

DUKE ENERGY OHIO, INC., AND

DUKE ENERGY KENTUCKY, INC.

OCTOBER 14, 2011

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.,	)	
Duke Energy Ohio, Inc., and	)	Docket No. ER12-_____
Duke Energy Kentucky, Inc.	)	

DIRECT TESTIMONY OF

ROBERT B. STODDARD

ON BEHALF OF

DUKE ENERGY OHIO, INC., AND

DUKE ENERGY KENTUCKY, INC.

I. INTRODUCTION AND QUALIFICATIONS

Q. WHAT IS YOUR NAME AND PROFESSIONAL AFFILIATION?

A. My name is Robert B. Stoddard. I am a Vice President and the leader of the Energy & Environment Practice of Charles River Associates ("CRA") in its offices at 200 Clarendon Street, T-33, Boston, Massachusetts 02116.

Q. WHAT ARE YOUR PROFESSIONAL QUALIFICATIONS?

A. I am an economist with extensive experience with and knowledge of electricity market design and operation. My work over the past decade has focused on electricity industry restructuring and on providing strategic analyses and testimony for utilities, generation owners, and governments regarding the financial implications of market design and structure, particularly regarding Regional Transmission Organizations ("RTOs") market design. I have testified frequently before the Federal Energy Regulatory Commission ("FERC" or "Commission") and various states' legislatures and utility commissions on competitive market design and market power issues. I hold degrees in economics from Amherst College and Yale University. My resume is attached as Exhibit No. DUK-201.

Q. DO YOU HAVE ANY PARTICULAR EXPERIENCE WITH COST-BENEFIT STUDIES OF A UTILITY JOINING AN RTO OR CHANGING ITS RTO MEMBERSHIP?

A. Yes. My colleagues and I at CRA have substantial expertise on the economic analysis of the costs and benefits of membership in RTOs. Our public work includes a study for the Southeast Association of Regulatory Utility Commissioners, a study supporting Dominion's entry into the PJM Interconnection ("PJM"), testimony supporting continued participation in ISO New England of the Maine utilities, studies for Ameren regarding its membership decision between either the Midwest Independent Transmission System Operator ("MISO") or the Southwest Power Pool ("SPP"), and a study conducted at the behest of the Commission regarding a similar choice for Entergy. The collective experience we gained in these assignments, along with additional experience from similar, non-public evaluations of the costs and benefits of membership in a particular RTO or the potential effect of RTO reconfiguration, has informed my analysis and conclusions in this matter, as has my substantial experience on market design matters.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY TODAY?

A. I have been asked by counsel for Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc. ("DEO" and "DEK", respectively; collectively "DEOK" or "the Companies") to review potential effects of the proposed realignment of their RTO membership from MISO to PJM and, in particular, to evaluate whether the reasonably anticipated benefits from this transfer to wholesale transmission customers in the Companies' transmission zone exceed the reasonably anticipated Transition Costs and Legacy MISO Transmission Expansion Plan ("MTEP") Costs that the Companies seek in this docket to include in wholesale rates.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE THE FINDINGS OF YOUR ANALYSIS OF THE COSTS AND BENEFITS FOR WHOLESALE CUSTOMERS IN THE DEOK TRANSMISSION ZONE.

A. My review of the proposed transfer supports the conclusion that the RTO realignment will benefit wholesale customers in the DEOK transmission zone. Many of these benefits are not readily quantifiable but are nonetheless, in my judgment, real. The PJM market design and settlements systems are better suited than MISO's for retail-choice states like Ohio. Further, placing the last remaining Ohio utility into the same RTO as the rest of the state will assist Ohio regulators by providing a single long-term transmission and resource planning framework and consistent market rules across the state. Although Kentucky is not a retail-choice state, PJM's market design and settlement systems also serve vertically integrated utilities well, and DEK's customers will benefit from the proven resource adequacy design in PJM (as well as participate financially in the benefits described below). These reasons alone are, in my view, sufficient to support the Companies' proposed RTO realignment.

The focus of this testimony, however, is on a quantifiable and clear benefit that customers in the Companies' transmission zone can reasonably anticipate from the proposed realignment: the reduction in allocated RTO charges over the next several decades. As I describe in detail below, the reasonably expected reductions in these RTO costs are far greater than the Transition Costs and "Legacy MTEP" Costs that the Companies seek to recover, consequently supporting the reasonableness of allowing the Companies to include these Transition Costs and Legacy MTEP Costs in their wholesale rates under Commission precedent expressed in its recent order on the transition of the American Transmission System, Inc. ("ATSI"), a wholly-owned subsidiary of FirstEnergy Corp., from MISO to PJM. In that order, the Commission states that a utility must "specifically identify the benefits of the RTO realignment decision with respect to its wholesale transmission customers and include a cost-benefit analysis showing that the benefits to wholesale transmission customers exceed the costs of the realignment….”[1] My testimony today provides the Commission such a cost-benefit analysis. Adding the large and real (but unquantified) benefits I discuss here to the quantified benefits, which themselves markedly exceed the Transition Costs and Legacy MTEP Costs, makes the case for recovering such costs in rates quite compelling.

Q. IS THE COMPANIES' PROPOSAL CONSISTENT WITH TRADITIONAL RATEMAKING PRINCIPLES?

A. Yes. The Companies have filed to realign their RTO memberships from MISO to PJM; in this instant docket, the Companies propose to include in the transmission rates charged to wholesale customers within the DEOK PJM Zone certain costs associated with that realignment. This proposal is consistent with traditional ratemaking principles, which allow recovery in rates of investment costs that are prudently incurred. For example, vertically integrated utilities have historically built power plants and been allowed to recover those costs over time in rates, including costs of Construction Work in Progress ("CWIP"). The Commission has followed this ratemaking principle with respect to the costs associated with membership in RTOs, even in instances when those costs ultimately did not lead

[1] *PJM Interconnection, LLC,* 135 FERC ¶ 61,198 at 60 (May 31, 2011) ("ATSI Order").

to the formation of an operational RTO, analogous to CWIP.[2] In this docket, the Companies propose to recover certain costs associated with their move to PJM. As I discuss below, this investment will be dwarfed by the benefits to wholesale customers taking transmission service within the DEOK Zone of PJM and, consequently, it would be consistent with ratemaking principles and Commission precedent to allow the Companies to recover RTO Transition Costs and Legacy MTEP Costs from wholesale customers.

The Companies have reached settlements with their respective state regulators regarding pass-through of certain costs. I am told that any pass-through of costs to retail customers will be consistent with such state settlements. My testimony is limited to an analysis of effects relative to FERC-jurisdictional wholesale transmission rates.

Q. HOW DID YOU ASSESS WHETHER THERE WERE NET SAVINGS FOR WHOLESALE CUSTOMERS IN THE DEOK TRANSMISSION ZONE SUFFICIENT TO COVER THE TRANSITION COSTS AND LEGACY MTEP COSTS THAT THE COMPANIES ARE SEEKING TO RECOVER IN RATES?

A. To compare the costs and benefits of the Companies' proposed move from MISO to PJM, I evaluated the Net Present Value ("NPV") of estimated annual

[2] *See Idaho Power Co.*, 123 FERC ¶ 61,104 at P 10 (2008) (allowing recovery of $4.6 million in costs incurred in utility's unsuccessful attempt to develop an RTO).

transmission expansion costs to the Companies over the 25-year period from 2012 through 2036 under two scenarios: (1) staying within MISO and (2) leaving MISO and joining PJM. Because of the unique circumstances of this case, in which the Companies are not only moving *between* two established RTOs, but also *within* the Joint and Common Market operated by PJM and MISO, this cost-benefit analysis considers only a subset of the elements that my colleagues and I at CRA have included in earlier cost-benefit analyses, e.g. Dominion joining PJM and Entergy's choice between MISO and the Southwest Power Pool,[3] as I explain more fully below.

The analysis set forth in this testimony can be summarized as follows. In the first instance, I set aside the categories of costs that the Commission said, in the ATSI Order, should be justified on a cost-benefit basis if inclusion in rates is sought.[4] These are Transition Costs (exit fees and other charges payable to MISO and integration costs reimbursed to PJM) and Legacy MTEP Costs (which I do not consider to be Transition Costs because they are costs that ratepayers in the DEOK Zone are already obligated to pay, and would pay even if the RTO Realignment did not occur). In order to provide a basis of comparison for purposes of

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[3] *Application of Virginia Electric and Power Company to Join PJM as PJM South*, State Corporation Commission of Virginia Case No. PUE-2000-00551 (2003); "Cost-Benefit Analysis of Entergy and Cleco Power Joining the SPP RTO," (Sept. 30, 2010), *available at* http://www.spp.org/publications/FERC%20SPP%20Entergy%20CBA%20Report%20Final.pdf (hereinafter "Entergy Application").

[4] *See* ATSI Order.

quantifying the net result of the move, I calculated the costs, from January 1, 2012 forward, for the hypothetical comparison case that included staying in MISO. I then quantified the costs of being in PJM from January 1, 2012 forward. There is a substantial gross benefit because the costs of staying in MISO would be significantly higher than those of moving to PJM, as shown in Table 1 below.[5] The ATSI test then requires that Transition Costs and Legacy MTEP Costs be subtracted from the gross benefit. Calculating the difference, a substantial net benefit results, also as shown in Table 1.

[5] This calculation only considers the NPV of costs and savings for the 25-year period ending in 2036. Savings are projected to continue beyond 2036, but conservatively I have not included an additional terminal value component herein.

Table 1. Net Present Value of Projected Quantified Costs/Benefits, 2012-2036 ($M)[6]

Costs of staying in MISO as of 1/1/12:	
Committed MTEP Costs ("Legacy MTEP")	$501.2
Future MTEP Costs	948.4
Administrative Costs	155.2
TOTAL MISO	**$1,604.9**
Costs of being in PJM as of 1/1/12:	
RTEP Costs	657.0
Administrative Costs	128.5
TOTAL PJM	**$785.5**
Gross Savings Before Adjustments for Transition and Legacy MTEP Costs	**$819.4**
Transition and Legacy MTEP Costs:	
Legacy MTEP Costs	$501.2
MISO Exit Costs and Fees	16.2
Reimbursable PJM Integration Costs	1.0
Total Transition/Legacy MTEP Costs	**$518.4**
Net Savings After Transition/Legacy MTEP Costs	**$301.0**

[6] Components may not sum to totals due to rounding.

III. BACKGROUND

Q. PLEASE EXPLAIN YOUR UNDERSTANDING OF THE COMPANIES' RATIONALE FOR JOINING PJM AND THE ATTENDANT COSTS, BENEFITS, AND UNCERTAINTIES.

A. In their prior filings with the Commission supporting its proposed RTO realignment, the Companies have supported the decision as providing a wide range of benefits, based on a variety of factors, to customers taking service in their transmission zone. I have reviewed these factors and, as an economist and market designer, believe them to be real and sufficient, even when the direct value of the benefit is difficult to quantify. I discuss some of these benefits below.

A. Qualitative Factors

Q. HAVE YOU BEEN ABLE TO QUANTIFY ALL OF THE BENEFITS TO CUSTOMERS IN THE DEOK ZONE?

A. No. The realignment of the Companies from MISO to PJM will create several direct and indirect benefits that, although not readily quantifiable, are important. Foremost among these, in my view, is the superior support in PJM for competitive retail markets. Because many of the PJM states adopted retail competition more than a decade ago, the PJM market was designed from the ground up to facilitate retail competition and to ensure that costs of maintaining system resource adequacy are allocated equitably as retail customers switch suppliers. MISO, by contrast, serves a region that is almost exclusively served by vertically integrated utilities, with very limited competitive retail access. The difference in state regulatory requirements permeates and informs the two RTOs' markets, and systems designs, in numerous ways.

Most notably from my view as an expert in capacity market design are the fundamental differences in the approach to pricing resource adequacy between MISO and PJM. PJM's Reliability Pricing Model ("RPM") has proven itself to be successful in securing sufficient resources (committed more than three years in advance through RPM's Base Residual Auctions ("BRA")) to meet resource adequacy requirements both regionally and within constrained areas.[7] The long lead-time before the commitment year creates and embraces price elasticity of supply, as demonstrated by the sloping supply stacks published by the PJM Independent Market Monitor.[8] This slope, coupled with the sloping Variable Resource Requirement demand curve, enhances price stability, which in turn provides greater investor confidence in the market and in market prices – which leads to greater stability to wholesale and retail rates. A further important design aspect of the RPM is its transparent allocation of costs to load-serving entities, based on the actual load served.

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[7] The Brattle Group, *Second Performance Assessment of PJM's Reliability Pricing Model*, (August 2011), *available at* http://www.pjm.com/documents/~/media/committees-groups/committees/mrc/20110818/20110826-brattle-report-second-performance-assessment-of-pjm-reliability-pricing-model.ashx.

[8] *See, e.g.*, *2012/2013 RPM Base Residual Auction Results*, *available at* http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2012-13-base-residual-auction-report-document-pdf.ashx .

Q. HOW WILL PJM'S CAPACITY MARKET DESIGN BENEFIT CUSTOMERS TAKING SERVICE IN THE DEOK ZONE?

A. The Companies have elected to participate in the RPM using the Fixed Resource Requirement ("FRR") option. That election notwithstanding, the Companies and customers taking service in the DEOK Zone benefit from the stability of the well-established RPM design.[9] RPM allocates the costs of maintaining resource adequacy equitably, meaning there is value in having the competitively determined BRA price available to use as backstop price for capacity sales to competitive retail suppliers in the absence of any explicit state cost allocation mechanism.

More generally, these features of the RPM, while particularly important in the context of competitive retail access, which Ohio has embraced, provide a proven platform for maintaining systems in states without retail choice, such as Kentucky. Unless there is a capacity market design that investors can trust to provide compensatory prices, the only likely entities that will be able to raise capital to build required new generation are those utilities that can include the generation in rate base. When loads are served by vertically-integrated utilities,

[9] The stability of this market implies less volatility in PJM capacity prices compared to newly forming capacity markets. This means less risk, and therefore a lower discount rate is appropriate for the valuation of expected future capacity payments. Because capacity prices over time must be sufficiently high to support new entry, risk-averse investors will require higher average capacity prices in a volatile market than in a stable market. Even if expected future capacity payments were the same, they would have a higher net present value in PJM (lower discount rate yields a higher NPV for the same cash flow).

which typically build and contract for generation through an integrated resource planning process overseen by state regulators, a weak capacity market is relatively unimportant. But for DEO, which does not have a mechanism guaranteed to survive the next retail rate case to pass along capacity costs to all the transmission customers it serves, the strength of PJM's RPM design provides both a means to assure that its transmission customers will have adequate resources, even if DEO does not directly build or contract for new generation, and a means to equitably allocate costs for such resources if it does choose to build or buy additional resources. Because, as noted above, the Companies have chosen the FRR option, other entities in the DEOK Zone also needed to elect whether to be part of the Companies' FRR plan (and be charged their pro rata cost of capacity), develop their own FRR plan, or participate in the RPM market-based mechanisms to obtain their supply; in any case, however, the RPM framework assures that every customer in the DEOK Zone, regardless of their supply source, is carrying its cost responsibility for resource adequacy. By contrast, MISO does not currently offer a credible resource adequacy mechanism to serve competitive retail loads. As MISO itself has recognized, the lack of a mechanism to allocate costs to shifting retail loads is a deficiency in the current market design.[10] Further, because MISO's current resource market operates month-to-month, it provides neither the

[10] *See* Duke Energy Answer and Motion for Leave to Answer, *Duke Energy Ohio and Duke Energy Kentucky*, Docket No. ER10-1562-000, Attachment A (filed Aug. 10, 2010).

price stability nor the forward signal that would be needed to support market-based new entry. Additionally, the current MISO design fails to address locational deliverability requirements adequately.

Q. DO THE RECENTLY FILED CHANGES TO THE MISO RESOURCE ADEQUACY MARKET ADDRESS YOUR CONCERNS, IN THE CONTEXT OF CUSTOMERS IN THE COMPANIES' TRANSMISSION ZONE?

A. No, not fully. To address the deficiencies cited by the Commission in its current market design MISO has filed a revised resource adequacy market called Module E-1.[11] Although Module E-1 addresses deficiencies in the allocation of charges for retail switching, at least in part, and would put in place a locational dimension to resource adequacy, intervenors have raised serious concerns about many aspects of the proposed Module E-1. Consequently, it is not clear what Module E-1 will look like following the current FERC process. Until this new MISO design has been vetted, refined and road-tested, it is my opinion that customers in the DEOK Zone will be better served (whether as a direct RPM participant or an FRR Entity) by the proven ability of the RPM market to attract new entry both from regulated and non-regulated entities, allocate costs equitably among all loads in a transmission zone, and price locational capacity appropriately.

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[11] Midwest ISO Filing to Enhance RAR by Incorporating Locational Capacity Market Mechanisms, *Midwest Indep. Transmission Sys. Operator,* Docket No. ER11-4081 *et al*. (filed July 20, 2011).

B. Quantitative Factors

Q. WHAT QUANTIFIABLE BENEFITS FROM THE REALIGNMENT OF THE COMPANIES INTO PJM HAVE YOU IDENTIFIED?

A. In addition to these important qualitative factors, there are a number of quantitative factors that could be considered in the proposed RTO realignment. These factors include (at least in principle) differences in the costs of energy, capacity, ancillary services, and uplift costs, and RTO administration. Although these factors are theoretically quantifiable, I have only done so where I believe the difference between the RTOs is likely to be material and readily quantified. With respect to the first three factors, these costs are largely determined by market forces. Given that MISO and PJM form a Joint and Common Market ("JCM"), I would not expect any persistent meaningful difference in the market prices for energy, capacity, and ancillary services—while the market convergence anticipated under the JCM has not yet been fully realized, there is no reason to expect that it will not be.

Likewise, I have no basis to forecast a persistent difference in uplift costs because these costs are difficult to predict going forward. Also, I have not credited the Companies with any benefit from allocation of excess revenues collected from marginal losses, which I believe will be more favorable to customers in the DEOK Zone under PJM. Moreover, I have assumed no increase in zonal transmission rates, other than with respect to allocation of costs for high-voltage upgrades as discussed below (inasmuch as these rates primarily reflect the allowed rate of return on transmission facilities in the DEOK Zone, which are not affected by realignment).

I have, however, used forecasts of RTO administrative costs provided by the RTOs as a basis for determining that customers in the DEOK Zone will see a substantial savings in such costs as result of the move. I have also estimated the costs connected to socialized high voltage transmission upgrades, which also will be lower in PJM. Legacy costs already assigned to the Companies under MTEP will be charged to the Companies regardless of whether they are in MISO or in PJM, while other future MTEP costs will only be allocated to the Companies in the hypothetical comparison case where they remain in MISO. Certain transmission projects already committed under PJM's Regional Transmission Expansion Plan ("RTEP") process will not be charged to the Companies upon joining PJM, whereas an allocation of the cost of certain other RTEP projects already committed will be assigned to the Companies upon their integration into PJM.[12]

[12] As I explain below, upon joining PJM, the Companies will be allocated a share of "Regional" transmission projects operating at or above 500 kV and Necessary Lower Voltage Facilities already committed. The Companies will not be allocated a share of the cost of "Non-Regional" Lower Voltage Facilities committed prior to its integration into PJM.

Q. PLEASE EXPLAIN THE TRANSMISSION PLANNING AND COST ALLOCATION PROCESS IN MISO.

A. MISO has developed forward-looking plans for transmission expansion to address evolving transmission needs. These plans are refined and reported annually as the MTEP. Cost allocation among MISO zones for these projects is divided among local beneficiaries and pool-wide, with recent Baseline Reliability and Market Efficiency projects at 345 kV and above having 20% of their costs allocated across MISO on a postage stamp basis using a peak load ratio based on the average of twelve monthly coincident peak loads in each zone in the most recent year (the 12CP measure). Conversely, for Generator Interconnection projects at 345 kV and above, the postage-stamp share is 10%. Zonal responsibility for these project categories, in terms of a percentage of costs to be allocated, is fixed at the time of MISO Board approval of a project.

Moreover, a newly created category of transmission projects, the Multi-Value Projects ("MVP"s), are largely associated with emerging state-specific Renewable Portfolio Standards ("RPS") for increasing the region's reliance on renewable power, which for MISO is dominated by wind energy centers being proposed or developed primarily in the western states of MISO where the geography of mountains and plains is most favorable for wind farms. New transmission lines are planned to connect these wind sites to load centers throughout MISO, and for other purposes deemed consistent with the Multi-Value

Project criteria. Because the renewable energy generators are often in remote regions of MISO, these MVP transmission lines connecting them to load centers are often quite costly. The MVP projects are deemed by MISO to create a pool-wide benefit, and therefore the costs for these projects are 100% allocated to all MISO members according to their actual energy usage (monthly GWh consumed), whether a particular line serves their territory or not.[13]

Q. WHAT IS YOUR UNDERSTANDING OF HOW MTEP PROJECT COSTS FOR PROJECTS THAT HAVE BEEN APPROVED WOULD BE ASSIGNED TO THE COMPANIES FOLLOWING THEIR REALIGNMENT?

A. A key feature in MISO's tariff-based cost allocation for non-MVP projects is the persistence of the obligation of a particular member to continue paying for any project approved while that member was part of MISO, even if that member should withdraw from MISO.

With respect to MVP projects, my understanding of how the costs are assigned is that FERC may have approved allocation to withdrawing transmission owners of MVP project costs for projects approved before the withdrawal of the transmission owner, though I am told that (a) the Companies believe that any such allocation is unlawful for a variety of reasons, and (b) the Companies have

[13] *See* MISO Tariff Attachment MM § 4; MISO Tariff Attachment FF §§ 2(c), 3.

committed to the Public Utilities Commission of Ohio to contest such an allocation, both at FERC and before the Court of Appeals if necessary.

For purposes of this cost-benefit analysis, and without any concession of the propriety or legality of assigning such costs to the Companies, I have assumed that the Companies will be required to pay costs, after withdrawing, for MVP and non-MVP projects approved by the MISO Board prior to their withdrawal.

Q. HOW ARE MTEP PROJECT COSTS COMPUTED IN YOUR ANALYSIS?

A. Annual charges approved by the MISO Board for each new or improved transmission project (both MVP and non-MVP) are based on annual revenue requirements for the project, including operations, maintenance, and financing costs for the life of the line.[14] My estimates for Legacy MTEP Costs through MTEP11[15] are based on those from MISO's documents for MTEP10 (for non-MVP projects approved through the MTEP10 cycle) and current draft documents for MTEP11 (for non-MVP projects pending approval in the MTEP11 cycle and all MVP projects in the "Priority 1" portfolio). These documents include MTEP Report Appendices A-1, A-2 and A-3, including Schedules 26 (non-MVP) and 26A (MVP) Indicative Annual Charges by zone for the next 10 to 40 years. The Annual Charge Rates are based on annual revenue requirements for each MTEP

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[14] *See* MISO Tariff Attachment MM § 3(a)(i); MISO Tariff Attachment GG § 3(a)(i).

[15] MTEP11 or MTEP-11 is the abbreviation for the current 2011 MISO Transmission Expansion Plan cycle including projects that will are expected to be approved in December 2011. MTEP10 means the 2010 cycle of the planning process that ended last December.

project (including depreciation cost schedules for up to 40 years), which are then allocated by MISO to each zone and Transmission Owner based on their current MISO Attachments MM and O data. Although the annual cost declines slowly after the first year, the costs remain substantial many years after a project is completed.

For the foregoing reasons, I have assumed that the Companies will be considered to be liable in future years for any MISO transmission project already built, already approved by MISO, or expected to be approved prior to their proposed Jan. 1, 2012 withdrawal date, including the $4 billion identified below of remaining "Candidate MVP Portfolio 1" project costs that MISO is expected to approve just weeks before the Companies withdraw. Estimated annual cost shares for proposed projects expected to be approved after that date, however, are only allocated to the Companies under the hypothetical comparison case where they remain in MISO and do not join PJM.

Q. HOW DID YOU DETERMINE WHAT THE MAGNITUDE OF THESE COSTS WOULD LIKELY BE?

A. I relied on material from MISO. In addition to regular MTEP reports and meetings, in late 2010 MISO prepared a Regional Generation Outlook Study (RGOS)[16] which considered several scenarios of growth in renewable generation

[16] *Midwest ISO Regional Generation Outlet Study* (Nov. 19, 2010), *available at* https://www.midwestiso.org/Library/Repository/Study/RGOS/Regional%20Generation%20Outlet%20Study.pdf (hereinafter "*RGOS Study*").

and associated transmission line projects needed to deliver that energy to load. Those candidate projects deemed by MISO to be clearly necessary were designated Portfolio 1 MVP projects and slated for early approval.

MISO has posted a draft version of the MTEP11 Report,[17] which provides information as to the proposed MVP Portfolio 1 as well as other projects submitted for approval as part of MTEP11 at the December 2011 Board meeting. The MVP Portfolio 1 includes the Michigan Thumb Loop expansion, which was approved as part of MTEP10, the Brookings to Twin Cities development, which was conditionally approved earlier this year, and 15 additional MVP projects. These projects are shown below as Table 2.[18] I have assumed that these recommendations will be accepted (MISO makes the same assumption in the current MTEP 11 Appendix A tables). The total costs for the initial MVP Portfolio is approximately $5.20 billion, with in-service dates from 2013 to 2020.

Table 2 – Candidate MVP Portfolio 1 Projects, Approved and Pending Approval in December 2011[19]

	Project	State(s)	In-Service Year	Cost (2011 $M)
1	Big Stone-Brookings	SD	2017	191
2	**Brookings, SD -SE Twin Cities ***	**MN, SD**	**2015**	**695**

[17] Tables and Reports *available at* https://www.midwestiso.org/Planning/TransmissionExpansionPlanning/Pages/TransmissionExpansionPlan.aspx.

[18] This list of MVP projects is from MTEP11 Appendix A-3.1, Exh. DUK-203, as posted on the web link above on Sept. 23, 2011.

[19] Components may not sum to totals due to rounding.

3	Lakefield Jct.-Winnebago–Winco–Burt area & Sheldon–Burt area–Webster	MN,IA	2015	506
4	Winco–Lime Creek–Emery-Blackhawk–Hazleton	IA	2015	480
5	N. LaCrosse-N. Madison-Cardinal & Dubuque Co.- Spring Green-Cardinal	WI	2020	714
6	Ellendale-Big Stone	ND, SD	2019	261
7	Adair-Ottumwa	IA, MO	2017	152
8	West Adair to Palmyra Tap	MO, IL	2018	98
9	Palmyra-Quincy-Merdosia-Ipava & Meredosia-Pawnee	IL	2018	392
10	New Pawnee-Pana	IL	2018	88
11	Pana-Mt. Zion-Kansas-Sugar Creek	IN	2020	284
12	New Reynolds-Burr Oak-Hiple	MI	2013	271
13	**Michigan Thumb Loop Expansion ****	**IN**	**2015**	**510**
14	New Reynolds-Greentown	WI, IL	2018	245
15	Pleasant Prairie-Zion Energy Center	IL	2014	26
16	Fargo-Oak Grove	IL	2018	193
17	Sidney-Rising	IL	2017	90
Total				$5,197

* Conditionally approved June 2011.

** Approved in MTEP10.

Q. DID YOU INCLUDE ANY COSTS FOR OTHER TRANSMISSION PROJECTS IN YOUR ANALYSIS?

A. Yes. As identified below, prospective costs beyond MTEP11 are estimated using the same approach as the Legacy cost estimates, with future MVP project costs based on the RGOS report and non-MVP project costs projected from the 2011 spending rate, adjusted downward to account for the impact of the MVP portfolio, as described below. The RGOS report includes three scenarios for additional

MVP projects totaling on average $10.59 billion,[20] to be considered for approval in 2012 or later. I have taken the average cost value of these scenarios, as they are deemed equally likely at this stage, and I assume that they will eventually be approved with in-service dates (and project costs) spread equally over years 2014 through 2024.[21] These long-range projects are divided into three groups in the RGOS study: (1) transmission lines entirely in MISO, (2) lines entirely in PJM zones adjacent to MISO, and (3) lines that span both ISOs, including DC links. I have assumed that on average the costs of this last group will be shared 50/50 by the two ISOs. Thus, I allocate all of the MISO-only project costs and 50% of the shared project costs to MISO members, while I allocate all of the PJM-only project costs plus the remaining 50% of shared project costs to PJM members (including the Companies if they move to PJM).

While the MTEP plans include non-MVP projects, there is little specific guidance beyond the already-approved 2011 projects. Assuming that the MVP portfolio will reduce the need for certain baseline reliability projects, I have estimated future non-MVP pool-shared costs at half of their 2011 level. For this

[20] As shown later in Table 9, the total average cost for the three scenarios for MISO projects plus half of the joint PJM-MISO project costs (I assume for purposes here these are split equally between the ISOs for this calculation) is $15.24 billion in 2010$. Converting to 2011$ and subtracting the $4.95 billion assumed at that time for the Portfolio 1 MVP projects leaves $10.59 for future projects. See Tab "RGOS MVP" at Exhibit DUK-203.

[21] RGOS has a twenty-year outlook horizon, but the anticipated development of renewables is concentrated in the initial portion of that window. I have assumed an even spread of project costs over the years 2014-2024 for those projects not already listed in Table 2 (MVP Portfolio 1).

smaller component of MISO transmission expansion costs, I use the 12CP peak load allocation ratio for the Companies' shares if they stay in MISO beyond 2011.

Q. PLEASE EXPLAIN THE TRANSMISSION PLANNING AND COST ALLOCATION PROCESS IN PJM

A. As new members of PJM, the Companies would be assigned costs for certain transmission projects approved in the PJM RTEP process. To estimate the economic impact of the Companies' proposed RTO realignment, I estimated the PJM transmission expansion cost that would be allocated to the Companies between 2012 and 2036. Broadly speaking, transmission costs are socialized according to two allocation methods described in Schedule 12 of the PJM Open Access Transmission Tariff ("OATT"). Costs associated with Transmission Facilities operating at or above 500 kV and Necessary Lower Voltage Facilities are allocated based on an annual load ratio share using each transmission zone's annual peak load over a twelve month period ending October 31 of the preceding year.[22] Costs associated with Lower Voltage Facilities costing more than $5 million are allocated using the Distribution Factor ("DFAX") analysis.[23] Both of these allocation formulas, along with my methodology for estimating the Companies' share of the total costs, are described in greater detail below.

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22 *See* PJM Tariff, Schedule 12 § (b)(i)(A).

23 *See* PJM Tariff, Schedule 12 § (b)(iii)(C).

IV. THE ATSI COST/BENEFIT TEST

Q. WHAT DO YOU UNDERSTAND TO BE THE CURRENT ECONOMIC STANDARD FOR EVALUATING THE RECOVERY OF TRANSITION AND LEGACY MTEP COSTS?

A. In a recent FERC Order on Proposed Tariff Revisions related to ATSI's move from MISO to PJM, the Commission required the use of a cost-benefit analysis if ATSI seeks recovery of certain costs associated with the change in RTOs:

> *"Accordingly, we will accept and suspend ATSI's proposed revisions to the PJM OATT to add its formula rate for the ATSI zone, ... subject to refund and ATSI making a compliance filing within 30 days of the date of this order removing from its formula rates the following costs: (1) PJM Integration Costs; (2) ATSI's deferred internal integration costs; and (3) MISO exit fees, including Legacy MTEP costs. Our finding is without prejudice to ATSI submitting a new section 205 filing seeking recovery of these costs. If ATSI makes such a filing,* ***it should specifically identify the benefits of the RTO realignment decision with respect to its wholesale transmission customers and include a cost-benefit analysis showing that the benefits to wholesale transmission customers exceed the costs of the realignment****, i.e., the PJM Integration Costs, deferred integration costs, and MISO exit fees, including Legacy MTEP costs."*[24]

ATSI has sought rehearing of this requirement on multiple grounds, and I express no opinion on the legal merits of the ATSI Order or ATSI's subsequent rehearing challenge. Rather, I apply the *ATSI Order* analysis at the Companies' request, in support of their request to recover their Transition and Legacy MTEP Costs, without regard to whether the test is legally appropriate. Upon analysis, I

[24] ATSI Order at 60 (emphasis added).

believe that the move will result in an overall net quantified savings driven by net savings in transmission and administrative costs, and that the move will also result in a net positive benefit in terms of unquantified costs and benefits, and thus the *ATSI Order* standard indicates that the Companies should be entitled to include their Transition and Legacy MTEP Costs in wholesale rates.

Q. WHAT "COSTS" HAVE YOU CONSIDERED UNDER THE *ATSI* STANDARD?

A. I have considered three categories of costs, which I calculate below. My findings can be summarized as follows:

First, for the hypothetical comparison case, I calculated the costs of being a MISO member if the Companies were to stay in MISO after the end of this year. These consisted of Legacy MTEP Costs (unpaid costs of MTEP projects approved prior to January 1, 2012), Future MTEP Costs (costs for MTEP projects that may be approved on or after January 1, 2012), and MISO Administrative Costs. The NPV of such costs is $1,605 million.[25]

Second, I calculated the costs of the Companies being a PJM member starting on January 1, 2012. These costs consist of RTEP charges and PJM Administrative Charges. The NPV of such costs is $785 million.[26]

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[25] See Tables 1 and 15 for summary results. This NPV value and those following are calculated in my workpapers, included as Exhibit DUK-203, based on costs from 2012 to 2036. *See* Tab "NPV Summary". These calculations are described in detail in subsequent sections.

[26] *Id*.

Third, I calculated the value of the categories of costs that, under the *ATSI* test, are required to be justified via cost-benefit analysis for purposes of inclusion in rates. These are the Transition Costs and the Legacy MTEP Costs. The NPV of such costs is $518.4 million.[27]

Q. HOW DID YOU USE THESE THREE CATEGORIES OF COSTS TO DETERMINE BENEFITS?

A. As shown in Table 1 above, I first compute the "gross benefit" to be the net present value of (a) the costs of staying in MISO, minus (b) the costs of belonging to PJM starting next year. The NPV of such gross benefit totals $819.4 million.

Q. DOES THIS CALCULATION OF GROSS BENEFIT ALONE SATISFY THE ATSI TEST?

A. No. In order for the ATSI test to be satisfied, the gross benefit must exceed the third category of costs – the Transition Costs plus Legacy MTEP Costs.

Q. WILL THE MOVE OF THE COMPANIES TO PJM RESULT IN NET BENEFITS THAT SATISFY THE ATSI TEST?

A. Yes – the accrued net benefit will be substantial. Subtracting the estimated NPV for the categories of costs that Duke is seeking to recover under the standard set forth in the *ATSI Order* ($518.4 million) from the estimated NPV of the gross benefits of the realignment ($819.4 million) results in a net benefit of $301.0 million. Therefore, customers in the DEOK Zone, even after paying for Transition

[27] *Id*.

and Legacy MTEP Costs will be at least $301 million better off as a result of the move of the Companies to PJM.

Q. WHAT DO YOU MEAN BY "*AT LEAST* $301 MILLION BETTER OFF"?

A. The $301 million represents the net quantified benefit through 2036 – conservatively ignoring additional anticipated savings beyond this 25-year window. In addition, as I have explained above, there are also factors that I do not quantify. As an expert in market design, I expect factors associated with the design of PJM's market, even though unquantified, to materially enhance, directly and indirectly, the overall net benefit of the move for wholesale customers. Put simply, customers in the PJM DEOK Zone will pay less *and* get more.

Q. HOW DID YOU COMPUTE PJM RTEP COSTS?

A. Upon joining PJM, the Companies will be assigned an allocation of the cost of "Regional" projects already approved, and can expect to be assigned a share of similarly classified projects anticipated to be approved in the future. Regional transmission projects, also referred to as "backbone" projects, are those operating at or above 500 kV and Necessary Lower Voltage Facilities, and their cost is allocated according to each PJM member's share of the system-wide non-coincident peak during a previous twelve months period.

Costs associated with "Non-Regional" projects, i.e., Lower Voltage Facilities costing more than $5 million, are allocated according to the DFAX methodology, as described in detail below. Under the PJM Tariff, the Companies would not incur any cost responsibility for DFAX allocated projects approved prior to the date of their transition into PJM, but would incur cost responsibility for DFAX projects approved after that date.[28]

Q. HOW DID YOU COMPUTE PJM ADMINISTRATIVE CHARGES?

A. I have done a review of administrative charges the Companies would be subject to in MISO and PJM, under their respective tariffs. As I explain in more detail below, these differences result in a net benefit in future administration charges in PJM compared to MISO. That assumption is supported, as detailed below, by a recent report indicating that as of 2010, administrative rates in MISO were approximately 1.5 times those of PJM.[29] Although this price gap is expected to diminish, future rates projected by MISO from 2014 forward are still 6.4 cents higher per MWh of load served than those projected by PJM.

Q. HOW DID YOU COMPUTE FUTURE MISO TRANSMISSION EXPANSION COSTS?

A. As detailed below, future MISO transmission charges used for the hypothetical comparison case of staying in MISO (i.e., the Future MTEP Costs from Table 1) are those payments designed to cover the annual carrying charges of transmission projects approved after the anticipated January 1, 2012 transition date. Assuming that the Companies are integrated into PJM on that date, they will not be

[28] *See* PJM Tariff, Schedule 12 § (b)(iii)(C).

responsible for any of the carrying costs of those projects. This includes the remaining portfolio of suggested MVP-scale projects in MISO and a share of joint MISO-PJM projects, with total expected project costs of $10.6 billion allocated to MISO members over the next decade or so.[30] In addition, I anticipate that spending on smaller non-MVP projects will continue, although at a significantly lower pace.

Q. HOW DID YOU COMPUTE FUTURE MISO ADMINISTRATIVE CHARGES (SCHEDULES 10, 16, 17)?

A. By leaving MISO in 2012, the Companies will not incur future administrative charges assessed annually by MISO to member entities. These costs are specified in Schedules 10, 16 and 17 of the MISO Tariff, and they are described in detail below.

Q. HOW DO YOU COMPUTE THE "LEGACY" MISO TRANSMISSION EXPANSION COSTS?

A. The majority of these costs arise from MTEP projects approved prior to the Companies' departure from MISO. The cost recovery allocation responsibility over the economic life of these projects is assessed to all MISO members at the

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[29] PJM Interconnection et al. 2011 ISO/RTO Metrics Report, *RTO/ISO Performance Metrics*, Docket No. AD10-5-000 (filed Aug. 31, 2011) ("2011 Performance Metrics Report").

[30] None of the MVP projects fall within the Companies' territories. The 10.6 B$ includes 9.2 B$ of remaining MISO internal projects plus half of 2.8 B$ worth of joint MISO-PJM projects (after scaling to 2011$ - see Table 9 and tab "RGOS MVPs" in Exhibit DUK-203).

time of project approvals, even if they later withdraw from the RTO (as I note above, the Companies dispute whether this is appropriate for MVP, but I assume solely for purposes of making this analysis that MISO's interpretation will prevail). Within these projects there are four groups:

1. MVP Projects already approved as of this writing;
2. MVP Projects recommended for (and expected to win) approval before the end of 2011;
3. Non-MVP projects already approved. A portion of these project costs is allocated to all members of MISO as of the time of approval; and
4. Three non-MVP projects recommended for (and expected to win) approval before the end of 2011. The Companies' estimated shares of these project costs range from 0.62% to 1.05%.[31]

Q. HOW DO YOU TREAT THE COSTS OF PROJECTS FOR WHICH THE COMPANIES ARE THE SOLE BENEFICIARIES?

A. Because the Companies have proposed only ministerial changes in their zonal transmission rate formula following the realignment, and costs for local projects will be allocated under that rate regardless of which RTO the Companies are in, I have not included these costs in this analysis.

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[31] These non-MVP projects are listed in MTEP11 Appendix A-1 (included in Exhibit DUK-203) with a cost allocation to all zones, including the DUK Zone ("DEM" in the table"). I assign the new DEOK zone 42.1% of these DUK costs based on the 12CP peak load values for the five transmission owners in the DUK zone. See Tab "12CP" in the same Exhibit DUK-203.

Q. DID YOU INCLUDE ESTIMATES OF POTENTIAL NET SAVINGS IN ENERGY, CAPACITY, AND ANCILLARY SERVICE COSTS?

A. No. MISO and PJM form a Joint and Common Market ("JCM"), under a framework established under the PJM-Midwest ISO Joint Operating Agreement ("JOA") executed by the Midwest ISO and PJM, in accordance with the Commission's March 18, 2004, August 5, 2004, and March 3, 2005 orders in Docket No. ER04-375[32] and July 31, 2002 order in Docket Nos. EL02-65, *et al.*[33] Under this framework, the costs of energy, capacity, and ancillary services across the footprint of the JCM are largely determined by market forces, including the ability and practice of market participants to buy power in one RTO and sell it in the other, causing prices to converge. For this reason, I would not expect any persistent meaningful difference in the market prices for energy, capacity, and ancillary services in the DEOK Zone resulting from shifting the MISO/ PJM boundary from one side of the Companies service territories to the other. While the market convergence anticipated under the JCM has not yet been fully realized, there is no reason to expect that it will not be.

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[32] *See Midwest Indep. Transmission Sys. Operator and PJM Interconnection, LLC,* 106 FERC ¶ 61,251 (2004), *order on reh'g, clarification, and compliance*, 108 FERC ¶ 61,143 at PP 58, 59 (2004), *order modifying and accepting tariff filing*, 110 FERC ¶ 61,226 at P 75 (2005).

[33] *See Alliance Companies,* 100 FERC ¶ 61,137 (2002).

Q. BUT HASN'T CRA INCLUDED THESE BENEFITS IN PRIOR STUDIES OF RTO ENTRY?

A. Yes, previous cost-benefit studies of RTO membership have often included an analysis of the energy savings, but this savings has been driven by improvements in system commitment and dispatch and by improved use of interties. Colleagues of mine at CRA recently performed a study analyzing the benefits of Entergy joining an RTO.[34] The study found significant production cost savings associated with integrating Entergy into an RTO, achieved by eliminating inefficiencies resulting from committing and dispatching resources in Entergy separately from those in adjoining RTOs. I would not expect any such savings to be achieved through the integration of the Companies into PJM, because the operation of generation and transmission in the Companies has already been integrated into an RTO, and any associated gains in efficiency already realized.

Although the posted capacity prices in MISO and PJM appear to diverge significantly at this time, these capacity *spot prices* do not fully reflect the capacity *costs* borne by most MISO customers. Most customers in MISO support the cost of new generation entry (capacity costs) through a ratemaking framework, in which investments in new generation are made predominantly by regulated utilities. In PJM, investments in new entry and the associated costs are predominantly determined through a competitive market, with investment risks

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[34] *See* Entergy Application, *supra* note 3.

borne by merchant investors. In my analysis, I have conservatively not accounted for any associated quantitative benefit of joining PJM.

Q. WHAT TRANSITION COSTS DID YOU INCLUDE IN YOUR ASSESSMENT?

A. The Transition Costs associated with the Companies withdrawing from MISO and joining PJM consist of two components: (i) exit fees and charges associated with the Companies' withdrawal from MISO and (ii) PJM costs to integrate the Companies. Each of these components is described below. As I have noted previously, I do not consider Legacy MTEP Costs to be Transition Costs because these costs would have to be borne by wholesale customers taking service in the DEOK Zone regardless of which RTO the Companies are in. Thus, in performing the *ATSI Order* analysis, I account for Legacy MTEP Costs separately from Transition Costs (mathematically, the result is the same as it would be if I had included the Legacy MTEP Costs in the category of Transition Costs).

Q. WHAT EXIT FEES AND CHARGES ASSOCIATED WITH WITHDRAWAL FROM MISO DID YOU INCLUDE?

A. Exit fees and charges associated with withdrawal from MISO, equal to approximately $16.2 million, consist of two components: administrative exit fees, and payments to be made pursuant to a Settlement Agreement between the Companies and MISO under Docket Nos. ER11-2059-000 *et al*. Both of these costs appear on Table 1 above under the description "MISO Exit Charges and Fees."

Q. PLEASE DESCRIBE THE EXIT FEE.

A. My understanding is that the Companies will prepay (as an exit fee) administrative costs shortly after the Withdrawal Date of December 31, 2011. These administrative costs are associated with Schedules 10, 16 and 17 of the MISO Tariff. It is my understanding that the Companies expect this amount to be approximately $14.4 million. Because any wholesale transmission customer who shares in the payment of such costs will receive a credit against future administrative costs (i.e., a prepayment credit toward Schedule 10, 16 and 17 costs for future uses of the MISO transmission system), my accounting for the full $14.4 million here as Transition Costs is a conservative assumption.

Q. DESCRIBE THE EXIT CHARGE FROM DOCKET NO. ER11-2059-000.

A. On July 29, 2011, MISO filed, on behalf of itself and the Companies, an executed Settlement Agreement in Docket Nos. ER11-2059-000 *et al.* Under the Settlement Agreement, if approved by FERC, the Companies will collectively pay to MISO the sum of $1.8 million to resolve the dispute between the Companies and MISO over tariff revisions proposed to address alleged adverse effects on the feasibility of Long-Term Firm Transmission Rights resulting from the withdrawal of the Companies from MISO.

Q. WHAT COSTS TO INTEGRATE THE COMPANIES WILL NEED TO BE REIMBURSED TO PJM?

A. The Companies have informed me that they expect to have to reimburse PJM for integration costs of approximately $1 million.

V. ANALYSIS OF MISO TRANSMISSION EXPANSION COSTS

Q. PLEASE EXPLAIN HOW YOU ESTIMATE FUTURE MISO TRANSMISSION EXPANSION COSTS.

A. As noted above, MISO allocates regional transmission costs to member Transmission Owners ("TOs") who are part of MISO at the time each project is approved, and these costs (expressed as annual revenue requirements), including depreciation schedules that can last up to 40 years, are then recovered over the economic lifetime of each project. Thus, the Companies are faced with two categories of MISO costs: those that are already approved (or will be approved before their Jan. 1, 2012 anticipated withdrawal date), and those that will likely be approved after that date. For those already approved under the MTEP process going back to 2006, and expected to be approved during the remaining months of 2011, I have assumed that the Companies will pay their allocated share of carrying costs into the future, whether they leave MISO or not. I refer to these as the "Legacy MTEP" Costs.

For both Legacy and Future MTEP Costs, the projects divide into the larger Multi Value Projects and traditional non-MVP projects. I address all these categories in more detail below. For all projects, I have assumed a long-term carrying cost structure derived from MISO's published "Schedule 26-A Indicative Annual Charges," which allocates total carrying costs of approximately 20% of MVP project costs to member TOs in the first full year of service for each project. This percentage slowly declines by approximately 1/3 of 1% each year, reaching 12% in the 25th year of service. In years prior to the first full in-service year, a portion of the full 20% is often allocated to cover Construction Work In Progress (CWIP) costs, which I have modeled as 5%, 10% and 15% for MVP-scale projects in the three years leading up to the first full year (at 20%). For smaller non-MVP scale projects I have compressed this CWIP allocation to 10% in just one year prior to in-service. I have used the same revenue recovery schedules for both MISO and PJM transmission expansion investments.

Q. HOW DID YOU CALCULATE THE ALLOCATIONS OF THESE COSTS TO THE COMPANIES?

A. The Companies are part of a larger MISO transmission zone, called the Cinergy Zone (CIN) or sometimes the Duke Zone (DUK).[35] The DUK (or CIN) Zone is allocated a share of MTEP costs, which is then sub-divided among five TOs: DEO, DEK, Duke Energy Indiana (DEI), Wabash Valley Power Association (WVPA), and the Indiana Municipal Power Association (IMPA). MVP projects and non-MVP projects are allocated on different bases, as discussed below. For

[35] Both abbreviations are used in current MISO tables.

each group I have estimated the DEO plus DEK cost share both as a fraction of the DUK/CIN Zone allocation, and as a fraction of the total MISO costs.

Q. ON WHAT BASIS DID YOU ALLOCATE THE COST OF MVP PROJECTS?

A. MISO allocates shares of MVP costs to the MISO zones according to an annual energy consumption ratio. The most recent Indicative Schedule 26-A Allocation table shows that the DUK/CIN Zone would be assessed 13.0% of the total MISO costs for MVP projects already approved or pending 2011 approval.[36]

Based on total 2010 MWh sales to customers reported in FERC Form 1 filings, shown below as Table 3, DEO plus DEK account for 36.24% of the total sales in the DUK/CIN Zone. Multiplied times the 13.0% share above, this yields a 4.72% share of MISO total MVP costs for the Companies in the current allocation period.

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[36] *See* MVP Charges by zone for years 2012 through 2021 at MTEP11 Appendix A-3.3 (included in Exhibit DUK-203).

Table 3. MWH Sales to Customer in MISO's DUK (CIN) Transmission Zone[37]

Supplier	Sales to Customers (MWh)	
DEO	20,830,286	30.26%
DEK	4,116,600	5.98%
DEI	28,258,839	41.05%
WVPA	9,529,250	13.84%
IMPA	6,112,550	8.88%
2010 total sales to Customers	68,847,525	100.00%

Q. ON WHAT BASIS DID YOU ALLOCATE THE COST OF NON-MVP PROJECTS?

A. The costs of traditional (Non-MVP) projects including baseline reliability enhancements in MISO are currently split among TOs, with 80% charged to locally affected TOs and 20% to the ISO as a whole for projects at and above 345 kV. The 20% component is divided among MISO's transmission zones according to the "12CP" measure of average coincident transmission system peak loads for each of the 12 months in the preceding year. Costs for baseline reliability projects below the 345 kV threshold are allocated, utilizing a Line Outage Distribution Factor methodology, to local beneficiaries. Market efficiency projects are similarly cost shared, with those projects at or above the 345 kV threshold being 20% cost shared across the MISO footprint. The remaining 80% of the cost of market efficiency projects is allocated to the beneficiaries within the affected planning region(s). Generator Interconnection projects associated with the

[37] Source: 2010 FERC Form 1's (filed April 2011), p. 400a (Electric Energy Account).

transmission system at or above the 345 kV threshold are cost shared as well, with 10% allocated across the MISO footprint. Using the June 2011 MISO Tariff Attachment O, the CIN pricing zone has a 12CP measure of 9,772 MW, which is 12.30 % of the MISO total. Of this, the three Duke Energy companies account for 8,840 MW (90.47% of the CIN Zone). Using the most recent 12CP values for each company (as filed in their 2010 FERC Form 1, although the metric is from 2009), DEO plus DEK's share of this is 42.12% of the CIN Zone, or 5.18% of the total MISO costs (*see* Table 4 below).

Table 4. DEO/DEK Allocations of non-MVP shared costs in MISO[38]

	Peak Load (kW, 12CP)[a]	Percent of Duke Energy	Percent of DUK Zone[b]	Percent of non-MVP Shared Costs[c]
Duke IN	4,573,333	53.44%	48.35%	5.95%
Duke OH **Duke KY**	3,313,500 +670,583	46.56%	42.12%	5.18%
Duke total	8,557,416	100.00%	90.47%	11.13%

[a] FERC Form 1, 2010 (submitted April 2011; 12CP values following page 401b reflect 2009 loads)
[b] Denominator includes Wabash Valley Power Association and Indiana Municipal Power Agency.

[c] DEOK share of 12.3%, which is full DUK Zone percentage of total of MISO 12CP peak load measures.

[38] 12CP peak load values and share for DUK zone from MISO Tariff Schedule O (June 2011). Values come from most recent (2010) FERC Form 1 for DEO, DEK and other members of DUK Zone. *See* Exhibit DUK-203 at Tab "12CP."

Q. HOW DID YOU COMPUTE THE COST OF LEGACY MTEP PROJECTS?

A. Projects approved by MISO as of June 2011 are included in MISO's Indicative Schedules of Charges 26 (non-MVP) and 26-a (MVP only). The more recent version in MTEP11 Appendix A extends this to include costs for MVP and non-MVP projects pending approval in December 2011.[39] In my analysis, I have assumed annual charge rates and costs consistent with MISO's estimates over a 40-year span. As noted in the workbook for Schedule 26-A, "Annual Revenue Requirement (are) calculated using an estimated Annual Charge Rate for each Transmission Owner based on the methodology described in (MISO Tariff) Attachment MM. Annual Charge Rate estimated using Transmission Owner's Attachment O (annual energy) data as of January 2011 and assumes 40-year straight-line depreciation." Indicative charge rates are shown for a 40-year span, with total revenues peaking at 20% of initial project costs in the first full year of service. This percentage declines slowly over time at approximately 0.33% per year, to 19% in Year 4, 18% in Year 7, and so on. Pre-service years can be allocated CWIP costs on a project-by-project approval basis, in the one to four

[39] Excel spreadsheets entitled "Schedule 26 Indicative Annual Charges," "Schedule 26-A Indicative Annual Charges" and "MTEP 11_Appendix A-1.xlsx" *available online from MISO via links at* https://www.midwestiso.org/Planning/TransmissionExpansionPlanning/Pages/TransmissionExpansionPlan.aspx.

years leading up to full service. The deduced percentages from the earlier Schedule 26-A workbook[40] are shown below in Table 5:

Table 5: Annual Revenue Requirement charged to MISO Participants as a Percentage of Transmission Project Initial Costs

Project Service Year	Annual Charge Rate	Project Service Year	Annual Charge Rate	Project Service Year	Annual Charge Rate
1	20.00%	13	16.02%	25	12.05%
2	19.66%	14	15.69%	26	11.72%
3	19.33%	15	15.36%	27	11.39%
4	19.00%	16	15.03%	28	11.05%
5	18.67%	17	14.70%	29	10.72%
6	18.34%	18	14.37%	30	10.39%
7	18.01%	19	14.03%	31	10.06%
8	17.68%	20	13.70%	32	9.73%
9	17.35%	21	13.37%	33	9.40%
10	17.02%	22	13.04%	34	9.07%
11	16.68%	23	12.71%	35	8.74%
12	16.35%	24	12.38%	36	8.41%

The Schedule 26 (non-MVP) table shows the DUK (CIN) pricing zone's allocation of costs for already approved non-MVP projects (beginning with the MTEP 2006 plan) for years 2012-2021. Assuming the average in-service date for these projects is 2009, I have extended the payments through 2036 using the annual charge rate schedule in Table 5. The fractions of the DUK (CIN) zonal

[40] The earlier Schedule 26-A workbook is included as Exhibit DUK-202. This version only included two MVP projects that are already approved, with the same in-service year (2015). This single year aspect allows the annual revenue requirements to be inferred directly as a function of project age. The later version of the Schedule 26-A workbook, with all 17 Priority 1 MVP Projects included across a range of in-service years, is included and contained in Exhibit DUK-203.

costs allocated to the Companies are calculated using the 42.12% share shown in Table 4. These costs are shown below as Table 6.

Table 6. MISO Costs from non-MVP projects approved through June 2011 and pending in Dec. 2011. Highlighted entries are from MISO estimates[41], later years are estimated extensions.

Calendar Year	CIN zone charges for Non-MVP Projects Through MTEP10	CIN zone charges for Non-MVP Projects Pending in MTEP11	DEO-DEK share of CIN total (42.1% based on 12CP ratios)
2012	$13,885,664	$25,104	$5,859,002
2013	$16,312,953	$24,702	$6,881,170
2014	$18,657,090	$38,228	$7,874,182
2015	$19,557,803	$65,681	$8,265,110
2016	$19,277,607	$134,915	$8,176,256
2017	$19,316,181	$283,297	$8,255,000
2018	$19,030,314	$351,320	$8,163,247
2019	$18,744,448	$420,969	$8,072,180
2020	$18,458,581	$414,242	$7,948,944
2021	$18,172,714	$407,515	$7,825,708
2022	$17,797,108	$400,413	$7,664,517
2023	$17,421,502	$393,312	$7,503,326
2024	$17,045,896	$386,210	$7,342,136
2025	$16,670,290	$379,108	$7,180,945
2026	$16,294,684	$372,006	$7,019,755
2027	$15,919,078	$364,905	$6,858,564
2028	$15,543,472	$357,803	$6,697,373
2029	$15,167,866	$350,701	$6,536,183
2030	$14,792,260	$343,599	$6,374,992
2031	$14,416,655	$336,498	$6,213,802
2032	$14,041,049	$329,396	$6,052,611
2033	$13,665,443	$322,294	$5,891,420
2034	$13,289,837	$315,192	$5,730,230
2035	$12,914,231	$308,091	$5,569,039
2036	$12,538,625	$300,989	$5,407,848

[41] Schedule 26 Indicative Charges Workbook, *supra* note 39; s*ee also* Exhibit DUK-203 at Table 6 Tab.

Similarly, draft MTEP 11 Appendix A-3.2 shows indicative MVP (Schedule 26-A) charges allocated to the DUK (CIN) pricing zone. These are associated with the two initial MVP projects already approved (the Michigan Thumb Loop Expansion and Brookings County Twin Cities 345 kV Projects, with total project costs estimated at $1.24 billion[42]), plus fifteen additional MVP projects with various in-service dates as late as 2020, expected to be approved in December 2011 at additional costs of approximately $4.0 billion.[43] These costs are also projected by MISO through 2021, but I have extended the expected cost allocation through 2036, based on the load growth assumptions and estimated rates per MWh provided by MISO through 2051. The Companies' share of the DUK (CIN) Zone for these projects, shown in Table 7 below, uses the annual energy ratio discussed above.

[42] Estimated project cost taken from MISO estimate in "Schedule 26-A Indicative Annual Charges.xls" spreadsheet, *supra* note 39.

[43] See Table 2. The total cost without the two highlighted projects is $3.992 billion.

Table 7. MISO Costs for CIN zone and DEOK share from MVP projects already approved (2) and pending approval (15) in 2011. Highlighted entries are from MISO estimates; later years from CRA analysis.[44]

Calendar Year	MVP charges ($M) for CIN zone for MVP Projects Approved or pending approval in 2011	DEO-DEK share ($) (36.2% based on GWh ratios)
2012	$1.15	$414,897
2013	$9.09	$3,380,428
2014	$23.74	$8,770,352
2015	$34.99	$12,929,810
2016	$62.64	$22,864,414
2017	$67.83	$24,742,163
2018	$83.78	$30,263,140
2019	$97.61	$35,273,887
2020	$107.69	$38,925,792
2021	$111.81	$40,418,698
2022	$110.32	$39,974,579
2023	$109.03	$39,506,641
2024	$107.68	$39,017,854
2025	$106.28	$38,510,625
2026	$104.83	$37,986,927
2027	$103.35	$37,448,394
2028	$101.83	$36,896,390
2029	$100.27	$36,332,064
2030	$98.68	$35,756,388
2031	$97.06	$35,170,194
2032	$95.42	$34,574,191
2033	$93.75	$33,968,993
2034	$92.05	$33,355,131
2035	$90.34	$32,733,065
2036	$88.60	$32,103,200

[44] These charges through 2021 are taken from MTEP11 Appendix A-3.3. Subsequent years are extended using hourly charge rates from Appendix A-3.2 multiplied times DEOK annual energy estimates (calculated using MISO's assumed 1.42% annual growth rate.) See Tabs "Table 7" and "MTEP11 Appendix A-3.1,2,3" in Exhibit DUK-203.

Q. HOW DID YOU TREAT PENDING MVP AND NON-MVP PROJECTS WITH EXPECTED APPROVAL IN 2011?

A. In addition to those projects already approved as of June 2011, the MTEP 2011 plan lists additional projects recommended for approval at the December MTEP meetings. These include three non-MVP projects, with varied allocation percentages to the DUK Zone, and 15 additional MVP projects discussed above with in-service dates ranging from 2014 to 2020. I have assumed for purposes of this testimony that the MTEP committee will approve all of these recommended projects in December 2011. Indicative annual charges for Schedule 26 (non-MVP) and Schedule 26-A (MVP) projects, including those pending imminent approval, are already included in the MTEP 11 Appendices through 2021, and I have extended these projections to 2036 based on projected load growth and rates per MWh (for MVP projects) and analysis of in-service years and the revenue requirements (for non-MVP projects).

Q. HOW DID YOU ASSESS FUTURE TRANSMISSION COSTS IN MISO THAT WOULD NOT BE CHARGED AS A LEGACY MTEP COST?

A. The MISO costs that the Companies will not incur (assuming they withdraw from MISO on Jan. 1, 2012) relate to both MVP and non-MVP projects that are anticipated for approval in 2012 or later. MISO's Regional Generation Outlook Study (RGOS)[45] includes a discussion of future MVP projects in MISO, as well as

[45] *RGOS Study*, *supra* note 16.

projects in PJM zones adjacent to MISO and joint projects (especially DC lines) whose footprints and costs are likely to be shared between the two RTOs. I anticipate continued growth in non-MVP projects for baseline reliability, market efficiency, and generator interconnection projects with allocation to the Companies beyond 2011, albeit at a slower pace than before due to the secondary benefits from the MVP projects in reducing congestion and improving reliability (in addition to connecting renewables to MISO's grid).

I anticipate that all projects listed as recommended for approval in "MTEP11 Appendix A1" will be approved at the December meeting shortly before the withdrawal of the Companies, including those with allocation to the Companies. To represent the costs of non-MVP projects in the earlier stages of planning, I haven't projected specific projects, but rather extrapolate an annual spend rate for projects based on the trend in recent years, with a downward adjustment to reflect the large number of MVP projects and their beneficial impact on system reliability.

The RGOS study considered a 20-year horizon, and suggests three portfolios of proposed projects to meet the RPS mandates in MISO over that period. Each portfolio consists of a combination of MISO projects, PJM projects (in PJM zones adjacent to MISO) and shared (joint) MISO-PJM projects. I took the average investment totals for the three scenarios (as they are deemed equally desirable pending further study), and subtracted from the MISO-only totals the approximately $5 billion already approved or anticipated to be approved in December 2011.[46] I allocated all of the remaining MISO projects plus 50% of the shared MISO-PJM costs (a total of $10.6 billion in 2011$) to future MVP-type projects in MISO, with the annual cost allocations based on spreading project in-service dates evenly over the 2014 – 2024 period.[47] The resulting annual cost contributions to the Companies (should the Companies remain in MISO) are shown below in Table 8. The costs for all three scenarios are shown below in the PJM discussion as Table 9 (in 2010 $M).

Also shown in Table 8 are the estimated future costs associated with non-RGOS, non-MVP projects in MISO approved in 2012 or after.[48] The annual level of total costs for these baseline reliability and generator interconnect projects in MTEP10 is approximately $100 million, of which approximately half is shared across MISO. I have assumed this annual non-MVP spend level of approximately $50 million will continue in 2012 and beyond. I have also assumed that the total cost of these projects will increase from this initial level by 0.81% per year (the

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[46] Earlier MISO estimates for MVP circa June 2011 indicated $4.95 billion costs for Candidate MVP Portfolio 1 projects. I subtracted this more contemporary estimate of $4.95 billion from the RGOS total for MISO (which was $15.24 billion in 2010$, escalated to $15.54 billion in 2011$) yielding $10.59 billion in remaining project RGOS project costs.

[47] Current projects from MTEP10 and MTEP11 cycles have in-service years from 2013 to 2020, with costs by in-service year ranging from $0.3 billion to $2.2 billion. My assumed project schedule adds the $10.6 billion in estimated future project costs at an intermediate rate of approximately $0.96 billion per year over eleven years (2014 to 2024), i.e. as though one project with that cost begins full service at the beginning of each of those years.

[48] Costs shown for 2012 reflect only estimated CWIP costs for projects with in-service dates beginning in 2014 or 2015 (MVP) and 2013 (non-MVP).

MISO system-wide forecast for peak load growth rated used in MTEP11). Using the 12CP peak load share ratio for the Companies, I have added this smaller component to the annual estimated costs shown below.

Table 8. Future MISO Costs from RGOS-MVP and non-RGOS projects approved after 2011[49]

Calendar Year	RGOS MVP Estimate ($)	Non-RGOS Estimate ($)
2012	6,813,913	261,058
2013	13,627,826	789,518
2014	22,713,043	1,317,734
2015	31,647,798	1,845,596
2016	40,432,093	2,372,993
2017	49,065,926	2,899,811
2018	57,549,297	3,425,931
2019	65,882,207	3,951,235
2020	74,064,656	4,475,601
2021	82,096,644	4,998,904
2022	87,706,866	5,521,018
2023	90,895,322	6,041,813
2024	91,662,012	6,561,157
2025	90,006,937	7,078,915
2026	88,351,862	7,594,949
2027	86,696,787	8,109,120
2028	85,041,712	8,621,283
2029	83,386,637	9,131,294
2030	81,731,562	9,639,003
2031	80,076,487	10,144,259
2032	78,421,412	10,646,907
2033	76,766,337	11,146,789
2034	75,111,262	11,643,744
2035	73,456,187	12,137,609
2036	71,801,112	12,628,216

[49] See Tabs “Table 8”, “RGOS MVPs” and “Non-RGOS” in my work papers at Exhibit DUK-203 for calculations. The values represent shares allocated to DEO and DEK.

VI. ANALYSIS OF PJM TRANSMISSION EXPANSION COSTS

Q. HOW DID YOU ASSESS THE LIKELY COST OF FUTURE "REGIONAL" PROJECTS IN PJM?

A. Upon joining PJM, the Companies will be assigned an allocation of the cost of "Regional" projects already approved, and can expect to be assigned a share of similarly classified projects anticipated to be approved in the future. Regional transmission projects are those operating at or above 500 kV and Necessary Lower Voltage Facilities, and their cost is allocated according to each PJM member's share of the system-wide coincident peak during the previous twelve months.

Based on my review of certain RTEP data provided on the PJM website, I identified approximately $6.4 billion of transmission projects allocated on a load share basis as of June 2011.[50]

Q. ARE THERE REGIONAL PJM PROJECTS THAT ARE REASONABLY ANTICIPATED BUT NOT YET APPROVED?

A. Yes. These fall into two categories:

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[50] Total project costs were based on my analysis of data posted on the PJM ISO Website current as of June 2011, *available at* http://pjm.com/~/media/committees-groups/committees/teac/20110707/20110707-schedule-12-summary-of-cost-allocations-june-2011.ashx (hereinafter "RTEP Cost Allocations").

1. RTEP projects

In addition to the RTEP projects that have already been approved, I have included both the Mid-Atlantic Power Pathway ("MAPP") and Potomac-Appalachian Transmission Highline ("PATH") in my analysis. The MAPP project is a 500 kV, 150-mile transmission line intended to connect the Delmarva Peninsula with Southern Maryland. PATH is a 765 kV, 275-mile transmission project that will run from Putnam County, W.Va., to Frederick County, Md. For the purposes of my analysis, I have assumed that MAPP first enters service in 2018 and that PATH enters service in 2025.

2. RGOS projects in PJM

In estimating the cost of future backbone transmission projects in PJM, I further relied on the November 2010 Regional Generation Outlet Study ("RGOS") conducted by MISO. This was consistent with the approach I used to estimate the cost of future transmission projects for MISO (as described above). The RGOS report estimates future transmission costs for MISO and PJM under three different scenarios.

1) Native Voltage overlay that does not introduce new voltages such as 765 kV in areas where they do not currently exist;

(2) A 765 kV overlay allowing the introduction of 765 kV transmission throughout the study footprint; and

(3) Native Voltage with DC transmission that allows for the expansion of DC technology within the study footprint.[51]

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[51] *RGOS Study*, *supra* note 16.

Costs for these three scenarios, and the average values I used, are shown in Table 9 below. For my estimate of future PJM transmission capital requirements, I have used the average of the estimates provided under the three RGOS scenarios. In the case of joint projects and DC ties connecting PJM and MISO, I have assumed that PJM TOs would incur 50% of the total project costs, meaning that I included 50% of the cost of such projects in future PJM rates, and 50% of the cost in future MISO rates. I also assume that these costs will be incurred over an 11-year period beginning in 2014.

As shown in Table 9 below, I estimate that PJM will incur roughly $4.13 billion (in 2010$) in future RGOS costs (treated as backbone transmission costs) between 2014 and 2024 (escalated to $4.21 billion in 2011$ and spread evenly as $383 million per year). Of these costs, approximately $2.76 billion will be associated with projects exclusively within the PJM footprint and approximately $1.36 billion will be associated with joint PJM/MISO projects.

Table 9: RGOS Estimate of the Cost of Future MISO, PJM and Joint PJM/MISO Transmission Projects (2010 $M)[52]

(2010 $M)	Scenario 1: Native Voltage	Scenario 2: 765 kV	Scenario 3: Native DC	Estimated Capital Cost
MISO	13,868	15,099	12,662	**13,876**
MISO 50% Share of Joint/DC	242	478	3,372	**1,364**
Total MISO Costs	14,110	15,577	16,034	**15,240**
PJM	1,952	4,196	2,138	**2,762**
PJM 50% Share of Joint/DC	242	478	3,372	**1,364**
Total PJM Costs	2,194	4,674	5,510	**4,126**
Total RGOS Costs	16,304	20,250	21,544	**19,366**

Q. HOW DID YOU ASSESS THE COST OF "NON-REGIONAL" PROJECTS IN PJM?

A. As identified above, costs associated with Lower Voltage Facilities costing more than $5 million are allocated according to the DFAX methodology. For each such facility, "distribution factors" are calculated for every constrained transmission facility that requires the Lower Voltage Facility to avoid violating a reliability criterion or to relieve congestion. The costs of such Lower Voltage Facilities are socialized among the owners of impacted transmission facilities in proportion to the distribution factors for those facilities. The distribution factors are calculated as follows:

Distribution Factor = (After-shift power flow – pre-shift power flow) / Total amount of power shifted

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[52] *Id*. at 4 (Table 1.2-2). These values come from the RGOS study, plus my assumptions noted in the text. RGOS study estimated costs shown are in 2010 $M. These are escalated to 2011 $M for my analysis.

Based on my review of PJM RTEP project planning and cost allocation data,[53] there are approximately $8.9 billion of RTEP projects that have been allocated according to the DFAX method. Of these projects, $4.7 billion were allocated to a single entity[54] and $4.2 billion were allocated to multiple entities.[55] The costs of projects that will be allocated solely to the Companies are likely to be the same in PJM as they would be in MISO. As a result, I have focused my analysis on those Lower Voltage Facilities that are allocated to multiple entities.

If the Companies join PJM on January 1, 2012 as expected, they would not incur any cost responsibility for DFAX allocated projects that are approved prior to 2012.[56] They would, however, incur cost responsibility for DFAX projects approved after January 1, 2012. Of the already approved DFAX projects that are allocated to multiple entities, $3.7 billion are scheduled to be in service between 2011 and 2016 (an average of $616 million per year).[57] I have assumed that the total cost of new DFAX projects (those not approved by January 1, 2012) in-service between 2017 and 2036 will increase from the 2011-2016 average of $616 million at a rate of 1.74% per year (the PJM system-wide forecast annual increase

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[53] RTEP Cost Allocations, *supra* note 50 (I did not rely on power flow calculations, only cost allocations in my analysis).

[54] As a simplifying assumption, I have treated transmission projects allocated 98% or more to a single entity as though they were fully allocated to that single entity.

[55] *See* calculations at Tabs "Allocation % Summary w calcs" and "Allocation $ Summary" in Exhibit DUK-203.

[56] *See* PJM Tariff, Schedule 12 § (b)(iii)(C).

in peak load). Table 10 below shows my forecast of new DFAX projects from 2017 to 2036.

Table 10: Forecast Cost of Anticipated DFAX Projects (2010 $M)

Year	Cost of Anticipated DFAX Projects ($)
2017	627
2018	638
2019	649
2020	660
2021	672
2022	683
2023	695
2024	707
2025	720
2026	732
2027	745
2028	758
2029	771
2030	785
2031	798
2032	812
2033	826
2034	841
2035	855
2036	870

Q. HOW DID YOU CALCULATE THE ALLOCATION OF THESE PJM TRANSMISSION COSTS TO THE DEO/DEK ZONE?

A. The allocation differs depending on whether the transmission project is a regional or non-regional project.

To attribute a portion of the cost of PJM's backbone transmission projects to the DEOK Zone, I estimated what the Companies' share of PJM's 2010 total non-

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[57] *See* calculations at Tab "Tables 10, 12-14" in Exhibit DUK-203.

coincident peak load would have been. Including DEO, DEK and ATSI, I estimated that PJM's 2010 total non-coincident peak load would have been approximately 159.43 GW. The Companies' peak load was 5.56 GW, or 3.49% of the total. Table 11 below shows my estimate of PJM 2010 non-coincident peak annual loads by zone, with DEOK and ATSI added.

Table 11: 2010 PJM Annual Peak Load by Transmission Zone including ATSI and DEOK Zones[58]

Transmission Zone	2010 Peak Load (MW)	Allocation (%)
Atlantic City Elec. Co. (AEC)	2,936	1.84%
American Elec. Power (AEP)	23,492	14.74%
Allegheny Energy (APS)	8,480	5.32%
Baltimore Gas & Elec. (BGE)	6,924	4.34%
Commonwealth Edison (ComEd)	21,915	13.75%
Dayton Power & Light	3,398	2.13%
Duquesne Light Co. (DL)	2,889	1.81%
DelMarVa Power & Light (DPL)	4,055	2.54%
Dominion Virginia Power	19,140	12.01%
Jersey City Power & Light (JCPL)	6,420	4.03%
Metropolitan Edison (ME)	2,940	1.84%
NEPTUNE Regional Trans. System*	683	0.43%
PECO Energy Co.	8,865	5.56%
Penn. Elec. Co (PENELEC)	2,970	1.86%
Potomac Elec. Power Co. (PEPCO)	6,654	4.17%
PPL Electric Utilities Corp. (PPL)	7,411	4.65%
Public Svc. Elec. & Gas Co. (PSEG)	10,761	6.75%
Rockland Elec. Co. (RECO)	430	0.27%
East Cost Power (ECP)*	306	0.19%
American Trans. System Inc. (ATSI)	13,195	8.28%

[58] Sources: (excluding DEOK and ATSI): PJM Tariff, Amendments to Schedule 12-Appendix, filed with FERC January 4, 2011, *available at* www.pjm.com/~/media/documents/ferc/2011-filings/20110104-er11-2622-000.ashx. DEOK and ATSI Peak loads taken from DEO and ATSI 2010 FERC filings (Form 1, p. 400).

Duke Energy OH-KY (DEOK)	**5,561**	**3.49%**
PJM Total	**159,426**	**100%**

* Merchant transmission facilities assessed based on annual peak load.

Table 12 below shows the Companies' allocation of existing and anticipated backbone transmission projects based on their 3.49% load ratio share.

Table 12: DEOK Zone Share of PJM Backbone Transmission Costs Approved or Anticipated to be In-Service by 2026

In-Service Year	Total Project Costs ($M)	DEOK Share of Project Costs ($M)
2007	3	0
2008	51	2
2009	57	2
2010	68	2
2011	93	3
2012	1,250	44
2013	23	1
2014	402	14
2015	388	14
2016	2,019	70
2017	383	13
2018	1,511	53
2019	383	13
2020	383	13
2021	383	13
2022	383	13
2023	383	13
2024	383	13
2025	0	0
2026	2,100	73

To calculate the DEOK Zone's share of non-regional projects (i.e., the projects whose costs are allocated using DFAX), I used Dayton's share of such projects as a proxy for the costs the Companies would incur, given that Dayton is similarly situated electrically on the transmission grid with respect to the non-regional projects. Because Dayton's share of PJM's 2010 coincident peak load (as adjusted on Table 11 to include DEOK and ATSI within PJM) was only 2.13%

compared with 3.49% for the Companies, I estimated that the Companies' share of new DFAX projects would be 1.7 times that of Dayton's. I have assumed new allocations of DFAX projects to the Companies between 2012 and 2017 will increase at a constant rate. For all DFAX projects approved by June 2011 and allocated to multiple entities, Dayton was allocated $7.7 million of the total PJM costs of $4,232 million, or 0.182%. Table 13 below shows my estimate of total DFAX project allocations to the Companies.

Table 13: The Companies' Share ($M) of Future DFAX Transmission Projects Allocated to Multiple Entities

In-Service Year	DEOK Share of DFAX Project Costs ($M)
2012	0.31
2013	0.63
2014	0.94
2015	1.26
2016	1.57
2017	1.89
2018	1.92
2019	1.95
2020	1.99
2021	2.02
2022	2.06
2023	2.09
2024	2.13
2025	2.17
2026	2.20
2027	2.24
2028	2.28
2029	2.32
2030	2.36
2031	2.40
2032	2.44
2033	2.49
2034	2.53
2035	2.57
2036	2.62

Q. HOW DID YOU CALCULATE THE DEOK ZONE ANNUAL PJM TRANSMISSION CHARGES?

A. To calculate the annual charges resulting from the DEOK Zone's allocation of backbone and DFAX transmission projects, I assumed the same annual charge rate schedule as a percentage of initial project costs, as I did for MISO (shown in Table 5). For Regional, or backbone, projects, I assumed that recovery begins 3 years before the first full year in service. For DFAX projects, I assumed that revenue recovery begins the year prior to the first full year in service. My estimate of the Companies' transmission charges for both backbone and DFAX transmission projects is presented in Table 14 below.

Table 14: DEOK Zone Share of PJM Socialized Transmission Charges from 2012 to 2036 (2011$)

Calendar Year	Backbone Charges ($)	DFAX Charges ($)
2012	$9,176,599	$31,444
2013	$12,741,961	$125,761
2014	$17,505,085	$281,910
2015	$22,892,537	$498,849
2016	$30,166,027	$775,538
2017	$37,385,659	$1,110,936
2018	$41,518,092	$1,475,839
2019	$45,606,335	$1,841,116
2020	$47,553,049	$2,206,772
2021	$49,455,572	$2,572,816
2022	$51,313,905	$2,939,253
2023	$52,460,959	$3,306,090
2024	$56,558,437	$3,673,334
2025	$59,944,637	$4,040,993
2026	$62,619,558	$4,409,073
2027	$65,294,479	$4,777,582
2028	$64,065,129	$5,146,528
2029	$62,835,779	$5,515,917
2030	$61,606,429	$5,885,758
2031	$60,377,079	$6,256,058
2032	$59,147,729	$6,626,826
2033	$57,918,379	$6,998,070
2034	$56,689,028	$7,369,797
2035	$55,459,678	$7,742,017
2036	$54,230,328	$8,114,738

VII. ANALYSIS OF ADMINISTRATIVE CHARGES

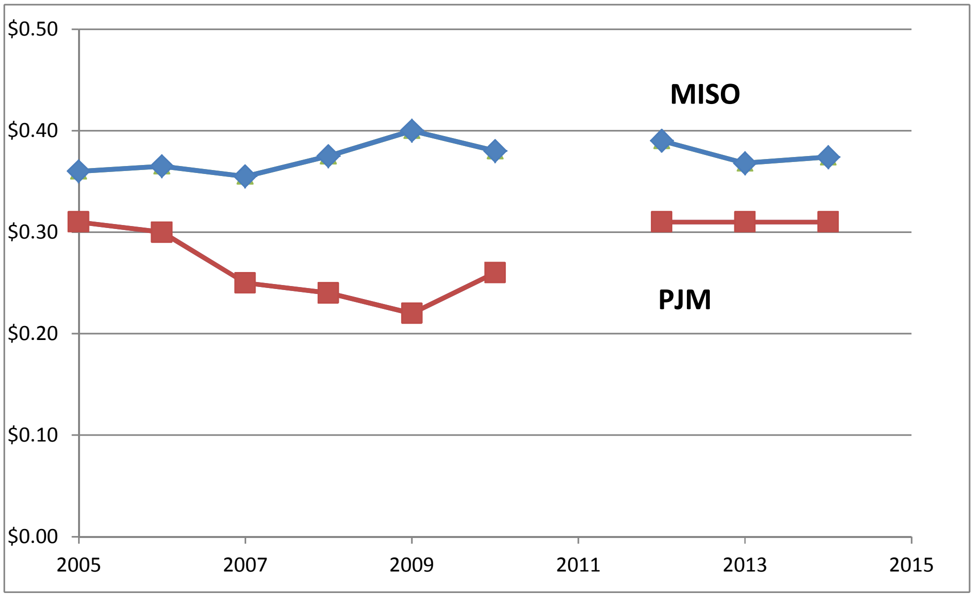
Q. DID YOU CONSIDER DIFFERENCES IN THE LIKELY LEVEL OF FUTURE PJM AND MISO ADMINISTRATION CHARGES?

Yes. As stated above, I have reviewed the administrative charges the Companies would be subject to under both MISO and PJM. The 2011 ISO/RTO Performance Metrics Report[59] indicates that administrative costs in MISO have been generally rising and as of 2010, were approximately 50% higher than those of PJM, whose comparable costs have been generally flat or falling.[60] In that year, these charges were $0.38/MWh in MISO, but only $0.26/MWh in PJM, representing a potential savings of $0.12/MWh. For the Companies' combined annual sales to customers of 24.9 TWh (2010 value), this translates into potential annual savings of approximately $3.0 million if the Companies move to PJM. However, these projected savings are somewhat reduced going forward, as MISO projects its rates to drop to $0.390/MWh in 2012, $0.368/MWh in 2013 and $0.374 in 2014, while PJM projects that its rates will rise to approximately $0.31/MWh beginning in 2011. However, even with this narrowing of the gap, projected savings from administrative charges alone total $26.7 million (NPV) over the 25-year span analyzed.

[59] 2011 Performance Metrics Report at 195 (MISO costs); 313 (PJM costs).

[60] *See* Figure 1.

Figure 1. Administrative costs for MISO and PJM ($/MWh of load served). ***Source: 2011 Performance Metrics Report.***



VIII. <u>OVERALL ASSESSMENT OF COSTS AND BENEFITS</u>

Q. HOW DID YOU COMPARE THE BENEFITS TO THE COSTS OF THE PROPOSED RTO REALIGNMENT?

A. To compare the costs and benefits of the Companies' proposed RTO realignment, I evaluated the NPV of estimated annual costs associated with transmission grid expansion over the 25-year period from 2012 through 2036 under two scenarios: (1) staying within MISO and (2) leaving MISO and joining PJM. These costs are estimated in real 2011 USD, and then discounted back to January 1, 2012 using a 5% discount rate[61] and treating each year's total costs as occurring at mid-year.

[61] Note that inflation is not included in this discount rate because the cash flows are expressed in real dollars. If the costs were expressed in nominal dollars including inflation, the discount rate would then be higher by the assumed inflation rate.

This approach allows comparisons on both a year-by-year basis and on an overall 25-year window basis, as shown in Table 15.

Table 15. Net Present Value of Future Costs ($M), 2012-2036

	(a)	(b)	(c)	(d) = (a) + (b) + (c)	(e)	(f)	(g) = (e) + (f)	(h) = (d) - (g)	(i)	(j) = (h) - (a) - (i)
Year	Legacy MTEP Costs	Future MTEP Costs	MISO Admin Costs	Total MISO Costs	PJM RTEP Costs	PJM Admin Costs	Total PJM Costs	Gross Benefit to Move to PJM	Tran-sition Costs	Net Benefit after Trans & Legacy Costs
2012	6.3	7.1	9.9	23.2	9.2	7.8	17.0	6.2	17.2	(17.3)
2013	10.3	14.4	9.4	34.1	12.9	7.9	20.8	13.3		3.0
2014	16.6	24.0	9.7	50.4	17.8	8.0	25.8	24.5		7.9
2015	21.2	33.5	9.8	64.5	23.4	8.1	31.5	33.0		11.8
2016	31.0	42.8	10.0	83.8	30.9	8.2	39.2	44.6		13.6
2017	33.0	52.0	10.1	95.0	38.5	8.4	46.9	48.2		15.2
2018	38.4	61.0	10.2	109.6	43.0	8.5	51.5	58.2		19.7
2019	43.3	69.8	10.3	123.5	47.4	8.6	56.0	67.5		24.2
2020	46.9	78.5	10.5	135.9	49.8	8.7	58.4	77.4		30.6
2021	48.2	87.1	10.6	146.0	52.0	8.8	60.8	85.1		36.9
2022	47.6	93.2	10.8	151.6	54.3	8.9	63.2	88.5		40.8
2023	47.0	96.9	10.9	154.8	55.8	9.0	64.8	90.0		43.0
2024	46.4	98.2	11.0	155.6	60.2	9.1	69.4	86.2		39.9
2025	45.7	97.1	11.2	154.0	64.0	9.3	73.3	80.7		35.0
2026	45.0	95.9	11.3	152.3	67.0	9.4	76.4	75.9		30.9
2027	44.3	94.8	11.5	150.6	70.1	9.5	79.6	71.0		26.7
2028	43.6	93.7	11.6	148.9	69.2	9.6	78.8	70.0		26.4
2029	42.9	92.5	11.8	147.2	68.4	9.8	78.1	69.0		26.2
2030	42.1	91.4	11.9	145.4	67.5	9.9	77.4	68.1		25.9
2031	41.4	90.2	12.1	143.7	66.6	10.0	76.6	67.0		25.7
2032	40.6	89.1	12.2	141.9	65.8	10.1	75.9	66.0		25.4
2033	39.9	87.9	12.4	140.2	64.9	10.3	75.2	65.0		25.1
2034	39.1	86.8	12.6	138.4	64.1	10.4	74.5	63.9		24.8
2035	38.3	85.6	12.7	136.6	63.2	10.5	73.7	62.9		24.6
2036	37.5	84.4	12.9	134.8	62.3	10.7	73.0	61.8		24.3
SUM	936.7	1,848.0	277.3	3,062.0	1,288.2	229.7	1,517.9	1,544.1	17.2	590.2
NPV*	**501.2**	**948.4**	**155.2**	**1,604.9**	**657.0**	**128.5**	**785.5**	**819.4**	**17.2**	**301.0**

*NPV discounts annual costs to 2011 at a discount rate of 5 percent per year. This does not include inflation, as costs are already in real 2011$.

Q. HOW DOES THE NET PRESENT VALUE OF FUTURE COSTS, AS DEFINED IN THE ATSI STANDARD, COMPARE TO THE NPV OF FUTURE BENEFITS?

A. The quantified future benefits of moving to PJM are the lower costs associated with paying PJM's transmission expansion and administrative fees, rather than MISO's. The NPV of these quantified benefits is $819.4 million. The quantified costs, as defined per the ATSI Order standard, are the Legacy MTEP Costs and the Transition Costs, which have an NPV of $518.4 million. Consequently, the expected benefits exceed the expected costs.

Q. UNDER THE ATSI STANDARD FOR COST RECOVERY, WHAT CONCLUSION DO YOU DRAW FROM THIS RESULT?

A. As I understand the *ATSI Order* standard, because the analysis demonstrates that the costs associated with the Companies' RTO transition that are in the categories identified in the *ATSI Order* are less than the reasonably expected benefits from the RTO transition, thus resulting in a substantial net benefit, the Commission should grant the Companies' request to include these costs in rates. This conclusion is further supported by the net benefit of the RTO transition in the unquantified cost/benefit categories I described earlier, principally arising from RTO market design factors.

Q. DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM INTERCONNECTION, L.L.C.,	)	
DUKE ENERGY OHIO, INC., AND DUKE ENERGY KENTUCKY, INC.	))	DOCKET NO. ER12-_____

DIRECT TESTIMONY OF

ROBERT B. STODDARD

ON BEHALF OF

DUKE ENERGY OHIO, INC., AND

DUKE ENERGY KENTUCKY, INC.

I, Robert B. Stoddard, being duly sworn, depose and state that the contents of the foregoing Affidavit on behalf of Duke Energy Ohio and Duke Energy Kentucky is true, correct, accurate and complete to the best of my knowledge, information, and belief:

Robert B. Stoddard

SUBSCRIBED AND SWORN to
before me this 14 day of October, 2011

Suzanne M. Walsh
Notary Public
My commission expires: 2/9/2018

SUZANNE M. WALSH
MY COMM. EXPIRES FEB. 9, 2018
NOTARY PUBLIC
COMMONWEALTH OF MASSACHUSETTS

Robert B. Stoddard

Vice President and
Practice Leader, Energy & Environment

MA and MPhil Economics
Yale University

BA Economics and Music
summa cum laude
Amherst College

Vice President Robert Stoddard heads CRA's Energy & Environment Practice. He has over twenty years of experience assisting clients in defining, analyzing, and interpreting the economic issues involved with competition and product valuation in energy and other markets. His recent work has focused on electricity industry restructuring and on providing both strategic analyses and testimony for utilities, generation owners, and governments regarding the practical implications of market design and structure, particularly in New York, New England, and PJM. He has submitted testimony to the Federal Energy Regulatory Commission as well as to the utility commissions and legislatures of several states on competitive market design and market power issues, and he as testified in civil litigation and arbitration on the interpretation of, and damages relating to, energy contracts. He recently was the lead economist for capacity suppliers in developing the New England capacity market, played a central role in negotiating the settlement of the PJM Reliability Pricing Model, and developed the leading proposal for the design of a capacity market for California. In related areas, Mr. Stoddard has served as the special economic counsel to the Rhode Island House of Representatives for electricity restructuring and acted as overseer for Connecticut's standard offer energy auction; devised an energy trading strategy audit and strategy redesign for a major northeastern utility; conducted a comprehensive review of operating flaws within the structure of an ISO; designed a market-based transfer pricing system for the distribution, trading, and generation subsidiaries of a leading western utility; and managed the federal and state regulatory filings for several large utility mergers and asset sales.

Experience

Mr. Stoddard has been a consultant on electric market issues to Abrams Capital, ArcLight Capital Management, AES, Astoria Generating, Bangor Hydro Electric Company, Boston Generating, California Independent System Operator, Citibank, City of New York, ConEdison Energy, Connecticut Department of Public Utility Control, Consolidated Edison Co. of New York, Constellation Energy Commodities Group, CSG Investments, Dayton Power & Light, Devon Canada Corp., Dominion, Duke Energy, Edison Mission Energy, EdF, Electricity Supply Board of Ireland, Emera, Energia dos Portugal, Energy Capital Partners, Energy East, Energy Plus Holdings, Entergy Nuclear, FirstEnergy, FirstLight, Independent Energy Producers Association, Hydro Québec, International Power, J. Aron & Company, Maine Energy Recovery Co., Maine Public Service, MASSPower, Midlands Cogeneration Venture, Mirant Corporation, Morgan Stanley Capital Group, Morris Energy Group, New England Power Generators Association, New York City Economic Development Corporation, New York Energy Buyers Forum, NextEra Energy Resources, Northeast Utilities, NRG Energy, Orange & Rockland Utilities, Pepco Energy Services, Pinnacle West, Portland General Electric, Powerex Corporation, Rhode Island Speaker of the House and the House of Representatives, RRI Energy, San Diego Gas & Electric, Southern California Edison, Sunoco, Tenaska, Tonbridge Power, USGen New England, USPowerGen, and Williams Power.

Strategy

- Led creation of business model and market-entry strategy for company developing an innovative renewable power technology.
- Led creation of business model and business plan for a combined wind-farm / transmission company in Canada.
- Assisted major utility in strategic and tactical plan to support transfer between Regional Transmission Organizations, providing both analytic and regulatory advisory support.
- Directed the development of the master energy infrastructure strategy for the City of New York, working with key stakeholders to develop a strategy to develop the infrastructure needed to meet the city's future energy needs economically and reliably.
- Developing a detailed forecasting model for capacity prices in PJM resulting from the new capacity market design and, using this information, worked with a major market participant's strategy and financing staff to identify under-valued assets for acquisition.
- With senior management of a major utility, developing a transmission investment strategy to reflect shifting competitive opportunities, RTO market design, and state and federal regulation. Identifying of key opportunities to leverage and redirect capital expenditures to significantly decrease cost of delivered power and increase rate of return to corporate shareholders.
- Developing a competitive bidding strategy for a complex hydroelectric generation asset to recognize opportunity costs, limitations of market rules, and effects of key transmission constraints in a two-settlement, locational pricing regime.
- Assisting a leading provider of utility outsourcing services to develop a comprehensive regulatory strategy for its service offerings to a major utility.

Electricity contracts and project valuation

- Testimony (in progress) to support the tax valuation of independent power production facilities in New York and Maryland, evaluating the free cash flows from sales of energy and other products' net of fuel, emissions, and other relevant costs.
- Testimony successfully supporting claims against industrial customer in breach-of-contract claims by a retail energy provider.
- Testimony supporting the cost-effectiveness of a long-term power purchase agreement between Cape Wind and National Grid in furtherance of Massachusetts policy goals.
- Testimony regarding the market value of a nuclear power facility excluding idiosyncratic nuclear risks using a comparable transactions analysis.
- Expert testimony supporting the reliability must-run (RMR) applications of over 2 GW of generation in New England, documenting need for RMR contracts to maintain the financial viability of needed resources. The case resulted in a settlement agreement that provided for significant support payments for these resources during the transition to compensatory market payments.

- Testimony for a bankruptcy court regarding damages arising from a power purchase agreement that had been rejected at the time of bankruptcy.
- Testimony in arbitration proceedings to determine the product specification and price of the capacity product contracted for in a period of regulatory change.
- Support of project financials for major purchase of New York City generation to investor community.
- Testimony in arbitration proceedings about the interpretation of, and damages owed under, the electricity section of a contract for the purchase of a large petrochemical refinery and resale of the refinery's output.
- State-appointed auditor of Connecticut's utilities' first Standard Offer power procurement auction, reviewing reasonableness of pricing and the terms and conditions of contract offers to supply essentially all of the state's power needs for a three-year period.
- Testimony on fuel costs adders reasonably allowable in a long-term power contract between NRG and Connecticut Light & Power and attendant retail rate design to fairly allocate the incremental costs.
- Assisting Consolidated Edison Co. of New York negotiate the sale of its nuclear facilities and linked buyback of power for the license life of the units.
- Working with Pinnacle West staff to develop options-based contracts to transfer power between its generating, trading, and distribution affiliates to preserve appropriate performance incentives.
- Project manager for bankruptcy evaluation of a New England cooperative, involving assessment of value of hydroelectric, nuclear assets, and long-term contracts.

Electricity market design

- Project director and testifying expert for capacity market design litigation and settlement negotiations for the New England and PJM markets, representing coalitions of the major generation owners in the region.
- Principal author of SDG&E and California Forward Capacity Market Advocates' proposal for a centralized capacity market structure to address resource adequacy needs of the California electricity markets. Subsequently offered a market-based approach to backstop capacity pricing in California on behalf of NRG Energy and the Independent Energy Producers Association.
- Working with other CRA experts, prepared a white paper on capacity market design for Energia dos Portugal.
- Principle drafter of the current form of the utility restructuring laws in Rhode Island, implementing improved retail market access.
- Project director for a major policy initiative by a major generation owner to review key flaws in modern RTO design that distort competitive pricing and outcomes.

- Project manager and testifying expert for litigation regarding the market rules governing use of phase angle regulators between New York and PJM. Subsequently, assisting the negotiated design of these rules pursuant to the FERC orders.
- In the redesign of the wholesale power market for the Republic of Ireland, responsible for development of rules regarding demand-side integration, interconnection management, financial transmission rights, and transmission loss representation.
- Testifying expert on behalf of a major importer into the California electricity market on the allocation of financial transmission rights across external interties.
- Project director for a review for the California Independent System Operator of transmission rights allocations in the proposed California wholesale market.

Market power analysis and mitigation

- Testifying expert successfully defending against charges of market manipulation by largest capacity importer to New England.
- Led preparation of report successfully defending against charges of market manipulation by a power marketer scheduling transactions through multiple jurisdictions.
- Lead expert defending a major financial institution against charges of manipulating ICE index markets (ongoing).
- Lead economist in team developing alternative mitigation measures for buyer-side market power in the New England capacity market.
- Testified on appropriate metrics for market power in PJM energy and capacity markets.
- Testifying expert and project director supporting the integration of Virginia Electric and Power (Dominion) into the PJM marketplace.
- Project manager for an acquisition of generation assets in Connecticut by a competing supplier, using detailed hourly analyses of power flows and potential future competition, and presenting the results to the FERC, US Department of Justice, and the Connecticut Office of the Attorney General.
- Project manager for a market power analyses needed to obtain federal and state regulatory approval of the merger of the leading natural gas transporter and distributor in the eastern US with a vertically integrated utility with substantial gas holdings.
- Project manager for study of the potential competitive effects of the divestiture of substantially all the New York City utility generation to independent power producers, including detailed behavioral modeling that took account of the complex transmission system and design of market power mitigation measures for the energy and capacity markets.

Testimony and reports

In the Matter of Portland General Electric Company 2012 Annual Power Cost Update Tariff (Schedule 125), Oregon Public Utilities Commission Docket No. UE-228. Rebuttal testimony on behalf of Portland General Electric assessing reasonableness of its mid-term hedging strategy for gas and electricity procurement, August 2011.

California Independent System Operator Corporation, FERC Docket No. ER11-2256. Affidavit on behalf of the Independent Energy Producers Association protesting flawed elements of the Capacity Procurement Mechanism, December 2010; presentation to FERC Technical Conference, March 2011.

Expert Report on behalf of Mirant Mid-Atlantic, LLC, Maryland Tax Court Case Nos. 09-RP-CH-261-265; 09-RP-CH-280-294; and 09-RP-CH-294-298, July 2010; live testimony, February 2011.

PJM Interconnection, LLC, FERC Docket No. ER11-2288. Affidavit on behalf of GenOn Energy Management, LLC and Edison Mission Energy protesting the creation of a summer-only demand resource capacity product and the continuation of a limited demand resource capacity product in the PJM Reliability Pricing Model, December 2010.

Testimony on behalf of the PJM Power Providers before the Maryland Public Service Commission in Administrative Docket PC22 regarding the PJM Reliability Pricing Model and the 2013/2014 Delivery Year Base Residual Auction Results, October 2010.

ISO New England Inc. and New England Power Pool, FERC Docket No. ER10-787-000, and *New England Power Generators Association v. ISO New England, Inc.*, FERC Docket No. EL10-50-000 (combined). Affidavit on behalf of New England Power Generators Association supporting need for revisions to Forward Capacity Market design, March 2010. Rebuttal affidavit, April 2010. Pre-filed testimony, July 2010; supplemental affidavits, September 2010.

Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid for Approval of Proposed Long-Term Contracts for Renewable Energy with Cape Wind Associates, LLC Pursuant to St. 2008, c. 169, § 83, Massachusetts D.P.U. Docket No. 10-54. Direct testimony on behalf of Cape Wind Associates, LLC, June 2010.

Richard Blumenthal, Attorney General for The State of Connecticut v. ISO New England Inc., Brookfield Energy Marketing Inc., et al. FERC Docket No. EL09-47-000, and *The Connecticut Department of Public Utility Control and the Connecticut Office of Consumer Counsel v. ISO New England Inc., Brookfield Energy Marketing Inc., et al.*, FERC Docket No. EL09-48-000. Prefiled testimony on behalf of Brookfield Energy Marketing Inc. regarding scheduling of capacity imports. June 2009. Answering testimony, February 2010.

Pepco Energy Services, Inc. v. Constellation Energy Commodities Group, Inc. (ad hoc arbitration); expert report on behalf of Constellation on alleged mis-payment under a bilateral contract for PJM capacity, April 2008; testimony, October 2009.

Application of MidAmerican Energy Company for the Determination of Ratemaking Principles, IUB Docket No. RPU-2009-0003. Rebuttal testimony on behalf of NextEra Energy Resources, June 2009; surrebuttal testimony, July 2009, live testimony, August 2009.

Midwest Independent Transmission System Operator Inc., FERC Docket Nos. ER08-394-007 and -009. Affidavit regarding monitoring and mitigation of resource adequacy auctions on behalf of Duke Energy Corp., July 2009.

Calpine Corporation, Citigroup Energy Inc., Dynegy Power Marketing, Inc., J.P. Morgan Ventures Energy Corporation, BE CA, LLC, Mirant Energy Trading, LLC, NRG Energy, Inc., Powerex Corporation, and RRI Energy, Inc. v. California Independent System Operator Corp., FERC Docket No. EL09-62-000. Affidavit on behalf of complainants, June 2009; reply affidavit, July 2009.

Report on ISO New England Internal Market Monitoring Unit Review of the Forward Capacity Market Auction Results and Design Elements, prepared for New England Power Generators Association, Inc. and filed in *ISO New England, Inc.*, FERC Docket No. ER09-1282-000 (June 2009).

*Richard Blumenthal, Attorney General for Connecticut, v. ISO New England Inc. et al.,*Docket Nos. EL09-47-000 and EL09-48-000. Prefiled testimony on behalf of Brookfield Energy Marketing Inc. regarding scheduling of capacity imports, June 2009.

Master Transmission Plan for New York City, report prepared for the New York City Economic Development Corporation, April 2009.

California Independent System Operator Corporation, FERC Docket No. ER09-589-000. Affidavit on behalf of Powerex Corp. regarding changes to the CAISO credit policy regarding unsecured credit, February 2009.

“Contracting and Investment: A Cross-Industry Assessment” report filed with Post-Conference Comments of Reliant Energy, Inc., *Credit and Capital Issues Affecting the Electric Power Industry*, FERC Docket No. AD09-002-000, January 2009.

PJM Interconnection, LLC FERC Docket No. ER09-412-000. Affidavit and reply affidavit on behalf of Mirant, Edison Mission Energy, International Power, and FPL (NextEra Energy Resources) regarding omnibus changes to the PJM RPM capacity market tariff, January 2009.

Midwest Independent System Transmission Operator, Inc. FERC Docket Nos. ER08-394-000, -003, -007. Affidavit on behalf of Duke Energy protesting the market monitoring standards proposed for the voluntary capacity auction in Midwest ISO, January 2009.

Devon Canada Corp. et al. v. Pittsfield Generating Company LP et al. Expert report for defendant regarding damages from alleged breach of natural gas supply contract to a reliability must-run electric generator, December 2008.

Maryland Public Service Commission v. PJM Interconnection, LLC, FERC Docket Nos. EL08-34-000 and EL08-47-000. Affidavit on behalf on Mirant Parties on appropriate structural and behavioral market power tests in PJM, October 2008; reply affidavit, November 2008.

ISO New England, Inc., FERC Docket No. ER08-1209-000. Affidavit on behalf of the New England Power Generation Association on compensation to reliability resources, July 2008; reply affidavit, September 2008.

Midwest Independent Transmission System Operator, Inc. FERC Docket No. ER08-1169-000. Affidavit on behalf of FPL Energy, LLC, regarding revisions to Generation Interconnection Procedures, July 2008.

RPM Buyers v. PJM Interconnection, LLC, FERC Docket No. EL08-67-000. Affidavit on behalf of PJM Power Providers opposing *ex post* changes to initial RPM auction results, June 2008.

Assessment of Maine's Continued Participation in ISO New England and Alternatives, Expert report in Maine Public Utilities Commission Docket No. 2008-156, prepared on behalf of Bangor Hydro-Electric Company, June 2008; testimony to the MPUC, October 2008.

"Reliability at Stake: PJM's Reliability Pricing Model" report prepared for PJM Power Providers in conjunction with FERC technical conference to discuss the operation of forward capacity markets in New England and the PJM region, FERC Docket No. AD08-4-000, May 2008.

Estimation of Indian Point 2 Fair Market Value Using a Statistical Analysis of Comparable Transactions, Testimony in *Consolidated. Edison Co. of New York v. United States*, No. 04-0033C (Fed.Cl.), February 2008.

Critique of the APPA/CMU Study "Do RTOs Promote Renewables?" (with David Riker) commissioned by Electric Power Supply Association, January 2008.

Midwest Independent Transmission System Operator, Inc. Electric Tariff Failing Regarding Resource Adequacy, FERC Docket No. ER08-394-000. Affidavit on behalf of Duke Energy Corp. and FirstEnergy Services Co. on the urgency of implementing a uniform resource adequacy requirement, January 2008.

Mirant Energy Trading, LLC, et al. v PJM Interconnection, LLC, FERC Docket No. EL08-8-000. Affidavit on the flaws in the market power mitigation rules for the Third Incremental Auction of the PJM Reliability Pricing Model capacity market., November 2007.

Wholesale Competition in Regions with Organized Electric Markets, FERC Docket Nos. RM07-19-000 and AD07-7-000. Affidavit on role of demand-side resources in organized electric markets on behalf of Duke Energy Corp., September 2007.

Order Instituting Rulemaking to Consider Refinements to and Further Development of the Commission's Resource Adequacy Requirements Program, California PUC Rulemaking 05-12-013. Principal author of SDG&E Track 2 Resource Adequacy Program Proposal, March 2007; principal author, "Joint Pre-Workshop Comments of the California Forward Capacity Market Advocates," May 2007, and "Proposal for a Forward California Capacity Market," August 2007.

People of the State of Illinois, ex rel. Illinois Attorney General Lisa Madigan v. Exelon Generating Co., LLC et al., FERC Docket No. EL07-47-000. Affidavit assessing reasonableness of outcomes in the Illinois power procurement auction on behalf of J. Aron & Company and Morgan Stanley Capital Group, July 2007.

PJM Interconnection, LLC, FERC Docket Nos. EL03-236-000 *et al.* Affidavit regarding three-pivotal-supplier market power test and scarcity pricing in PJM's energy markets on behalf of Mirant Energy Trading et al., May 2007.

Midwest Independent Transmission System Operator, FERC Docket No. ER07-550-000. Affidavit regarding resource adequacy issues in ancillary services market design on behalf of Duke Energy Co., March 2007.

PJM Interconnection LLC, FERC Docket No. EL05-148-000 *et al.* Affidavit regarding redesign of the long-run resource adequacy market in PJM on behalf of the Mirant Parties, October 2005; supplemental affidavit on behalf of the Mirant Parties, NRG and Williams Power Co., November 2005; presentation to FERC Technical Conference, February 2006; prefiled comments to FERC Technical Conference Panel 1, May 2006, on behalf of the Mirant Parties, Williams Power Co., and Dayton Power & Light; prefiled comments to FERC Technical Conference Panel 2, May 2006, on behalf of the Mirant Parties; supplemental affidavit on behalf of the Mirant Parties, June 2006; affidavit and reply affidavit supporting settlement agreement, September and October 2006.

Mystic Development, LLC, FERC Docket No. ER06-427-000. Affidavit analyzing future revenues in support of RMR filing, December 2005; supplemental affidavit, September 2006.

In re USGen New England, Inc. Debtor. United States Bankruptcy Court for the District of Maryland, Case No. 03-30465. Expert report on damage resulting from PPA rejection on behalf of USGen New England, March 2006; supplemental report, September 2006.

California Independent System Operator Corporation, FERC Docket No. ER06-615-000. Joint affidavit with Paul Kevin Wellenius regarding FTR allocations under new CAISO market design on behalf of Powerex Corp, June 2006

Fore River Development, LLC, FERC Docket No. ER06-822-000. Affidavit analyzing future revenues in support of RMR filing, December 2005.

Assessment of the New York City Electricity Market and Astoria, Gowanus, and Narrows Generating Stations. Report prepared for Morgan Stanley Senior Funding, Inc. related to financing for US Power Generating Co. and Madison Dearborn Capital Partners IV, L.P., January 2006.

Review of Initial Execution of Protocol for Implementation of Commission Order No. 476. Report to FERC in Docket EL02-23-000, regarding operation of controllable lines between NYISO and PJM, on behalf of Con Edison, September and December 2005.

Honeywell International Inc. v. Sunoco, Inc. AAA Case No. 13 181 Y 02588 04. Expert report, deposition and live testimony on contract energy pricing in petrochemicals, May 2005.

Con Edison Energy, Inc. v. ISO New England, Inc. and New England Power Pool, FERC Docket No. EL05-61-000. Affidavit on behalf of complainant regarding bidding rules in capacity deficiency auction, February 2005.

KeySpan Ravenswood LLC v. New York Independent System Operator, Inc., FERC Docket No. EL05-17-000. Affidavit on behalf of Consolidated Edison Company of New York, Inc. regarding retroactive damage claims from a capacity market, November 2004.

Devon Power LLC et al., FERC Docket No. ER03-563-030. Affidavit and rebuttal affidavit regarding design of locational installed capacity markets on behalf of FPL Energy, April and May 2004; answering testimony on behalf of Capacity Suppliers, November 2004; cross-answering testimony, December 2004; supplemental cross-answering testimony, January 2005; deposition and hearing testimony, February to March 2005; affidavit supporting Settlement Agreement, March 2006.

Application of Dominion North Carolina Power to Join PJM as PJM South, North Carolina Utilities Commission, Case No. E-22 SUB 418. Direct testimony and cost-benefit study on behalf of applicant, April 2004; rebuttal testimony, December 2004; examination, January 2005.

Application of Virginia Electric and Power Company to Join PJM as PJM South, State Corporation Commission of Virginia Case No. PUE-2000-00551; direct testimony and cost-benefit study on behalf of applicant, June 2003; supplemental direct testimony, March 2004; rebuttal testimony, September 2004; examination, October 2004.

Consolidated Edison v. Public Service Electric and Gas Co. et al., FERC Docket No. EL02-23-000 (Phase II); direct testimony on behalf of Consolidated Edison Company of New York, Inc., June 2002 regarding transmission facilities contracts. Remand testimony, January to March 2003.

In the Matter of the Siting of Electric Transmission Facilities Proposed to be Located at the West 49th Street Substation of Consolidated Edison Company of New York, Inc. et al., New York State Public Service Commission Case Nos. 02-M-0132, 01-T-1474, 02-T-0036, 02-T-0061; testimony on behalf of Consolidated Edison Company of New York, Inc., April 2002 (direct) and May 2002 (rebuttal).

Testimony before the Rhode Island Special Legislative Commission on the Quonset-Davisville Steamplant, January and April 2002.

Testimony before the Committee on Corporations, Rhode Island House of Representatives, regarding 2002 House Bill 7786, *An Act Relating to Public Utilities and Carriers,* April 2002.

Keyspan-Ravenswood, Inc. v. New York Independent System Operator, FERC Docket No. EL02-59-000, direct testimony on behalf of Consolidated Edison Company of New York, Inc. regarding implementation of market power mitigation in installed capacity markets, March 2002.

DPUC Investigation Into Viability of Power Supply Contracts to the Connecticut Light and Power Company and the United Illuminating Company, Connecticut DPUC Docket No. 01-12-05, direct testimony on behalf of NRG Energy, Inc. and affiliates, February 2002.

Joint Study by the Department of Public Utility Control and the Office of the Consumer Counsel Regarding Electric Deregulation and How Best to Provide Electric Default Service After January 1, 2004, Connecticut DPUC Docket No. 01-12-06, direct testimony on behalf of NRG Energy, Inc. and affiliates, January 2002.

The Narragansett Electric Co. Rate Changes for January 1, 2002, Rhode Island PUC Docket No. 3402, direct testimony on behalf of the Hon. John B. Harwood, Speaker of the House of Representatives, State of Rhode Island and Providence Plantations, December 2001.

Wisvest-Connecticut, LLC et al., FERC Docket No. EC01-70-000, technical conference presentation on behalf of NRG Energy, Inc. and affiliates, September 2001.

New York Independent System Operator, Inc., FERC Docket No. ER01-2536-000, affidavit on behalf of Consolidated Edison Co. of New York, the City of New York, the New York Energy Buyers Forum, and the Association for Energy Affordability, Inc., July 2001.

Testimony before the Committee on Corporations, Rhode Island House of Representatives regarding electricity restructuring; various dates, 2001.

Consolidated Edison Co. of New York, Inc., FERC Docket Nos. EL01-45-000 and ER01-1385-000, affidavit and rebuttal affidavit (joint with William H. Hieronymus) on behalf of Consolidated Edison Co. of New York, March and April, 2001.

Joint Petition of Consolidated Edison Co. of New York, Inc. and Entergy Nuclear Indian Point 2, LLC, for Authority to Transfer Certain Generating and Related Assets and for Related Relief, NYSPSC Case 01-E-0040, technical conference presentation on behalf of applicants, February 2001.

Professional history

2009–Present	*Vice President and Practice Leader*, Charles River Associates, Boston, MA
2003–2009	*Vice President*, Charles River Associates, Boston, MA
2001–2003	*Principal*, Charles River Associates, Boston, MA
1995–2001	*Managing Consultant*, PA Consulting Group, Cambridge, MA PA purchased PHB Hagler Bailly, formed by the merger of Hagler Bailly and Putnam, Hayes & Bartlett, where Mr. Stoddard had been a Principal.
1993–1995	*Senior Health Economist and Acting Managing Director*, Benefit Research USA, a Quintiles company, Cambridge, MA
1990–1993	*Senior Associate*, Charles River Associates, Boston, MA
1985–1990	*Teaching and Research Fellow*, Department of Economics, Yale University
1983–1985	*Assistant Economist*, Federal Reserve Bank of New York

Exhibit DUK-202

Deduced annual allocation beginning with first full year in service (2016)
Revenue Requirement (as percent of project cost) is allocated among Transmission Owners in each year.
Source: Calculations on tab "Approved MVPs"

(First full year in service)

Year	1	2	3	4	5	6	7	8	9
Rev Reqt	20.00%	19.66%	19.33%	19.00%	18.67%	18.34%	18.01%	17.68%	17.35%

19	20	21	22	23	24	25	26	27
14.03%	13.70%	13.37%	13.04%	12.71%	12.38%	12.05%	11.72%	11.39%

(Transpose)

Project Service Year	**Annual Charge Rate**	
1	20.00%	(First full year in service)
2	19.66%	
3	19.33%	
4	19.00%	
5	18.67%	
6	18.34%	
7	18.01%	
8	17.68%	
9	17.35%	
10	17.02%	
11	16.68%	
12	16.35%	
13	16.02%	
14	15.69%	
15	15.36%	
16	15.03%	
17	14.70%	
18	14.37%	
19	14.03%	
20	13.70%	
21	13.37%	
22	13.04%	
23	12.71%	
24	12.38%	
25	12.05%	
26	11.72%	
27	11.39%	
28	11.05%	
29	10.72%	
30	10.39%	
31	10.06%	
32	9.73%	
33	9.40%	
34	9.07%	
35	8.74%	
36	8.41%	

10	11	12	13	14	15	16	17	18
17.02%	16.68%	16.35%	16.02%	15.69%	15.36%	15.03%	14.70%	14.37%

28	29	30	31	32	33	34	35	36
11.05%	10.72%	10.39%	10.06%	9.73%	9.40%	9.07%	8.74%	8.41%

Project Service Year	Annual Charge Rate
1	20.00%
2	19.66%
3	19.33%
4	19.00%
5	18.67%
6	18.34%
7	18.01%
8	17.68%
9	17.35%
10	17.02%
11	16.68%
12	16.35%

Project Service Year	Annual Charge Rate
13	16.02%
14	15.69%
15	15.36%
16	15.03%
17	14.70%
18	14.37%
19	14.03%
20	13.70%
21	13.37%
22	13.04%
23	12.71%
24	12.38%

Project Service Year	Annual Charge Rate
25	12.05%
26	11.72%
27	11.39%
28	11.05%
29	10.72%
30	10.39%
31	10.06%
32	9.73%
33	9.40%
34	9.07%
35	8.74%
36	8.41%

Exhibit DUK-202

Source: MISO, 20110712 MSWG Item 03 Schedule 26-A Indicative Annual Charges.xlsx
Available via links at https://www.midwestiso.org/Library/MeetingMaterials/Pages/MSWG.aspx

Figure 1. *Indicative* Multi-Value Project (MVP) Schedule 26-A Annual Charges by MISO Local Balancing Authority (LBA) for Approved and Conditionally Approved MVPs

Values shown below (in 2011$) are subject to change depending on actual withdrawals (MWh), actual project costs including Construction Work in Progress, actual In-service Dates, and actual Annual Charge Rates for Transmission Owners

Figure 1.1 Approved and Conditionally Approved MVPs

Project ID	Project Name	Transmission Owner(s)	Estimated In-Service Date	Estimated Project Cost	Approval Status
3168	Candidate MVP Portfolio 1 - Michigan Thumb	ITC	2013-2015	$510,000,000	Approved MTEP 10
1203	Candidate MVP Portfolio 1 - Brookings, SD - SE Twin Cities 345 kV	XEL/GRE/OTP/ MRES/CMMPA	5/1/2015	$730,000,000	Conditionally Approved June 2011
			Total	$1,240,000,000	

Total costs to load and percent of project cost

Percent of total project costs allocated to load	0.89%	6.94%	13.37%	20.33%	20.00%	19.66%	19.33%	19.00%	18.67%	18.34%
Total charges to load	11,089,489	85,999,931	165,796,477	252,049,267	247,943,053	243,836,838	239,730,624	235,624,409	231,518,195	227,411,980

Figure 1.2 *Indicative* MVP Usage Rates for Approved and Conditionally Approved MVPs

				1.000	0.970	0.941	0.912	0.884	0.856	0.829
Indicative MVP Usage Rate 2012 - 2031 ($/MWh)	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Michigan Thumb	$0.00	$0.08	$0.15	$0.23	$0.22	$0.21	$0.21	$0.20	$0.19	$0.19
Brooking, SD - SE Twin Cities 345 kV	$0.02	$0.08	$0.15	$0.24	$0.23	$0.22	$0.22	$0.21	$0.20	$0.20
Total Indicative MVP Usage Rate ($/MWh)	$0.02	$0.16	$0.31	$0.46	$0.45	$0.43	$0.42	$0.41	$0.40	$0.38
	0.569	0.548	0.528	0.509	0.489	0.470	0.452	0.434	0.417	0.400
Indicative MVP Usage Rate 2032 - 2051 ($/MWh)	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
Michigan Thumb	$0.13	$0.12	$0.12	$0.11	$0.11	$0.10	$0.10	$0.10	$0.09	$0.09
Brooking, SD - SE Twin Cities 345 kV	$0.14	$0.13	$0.13	$0.12	$0.12	$0.11	$0.11	$0.10	$0.10	$0.10
Total Indicative MVP Usage Rate ($/MWh)	$0.26	$0.25	$0.24	$0.24	$0.23	$0.22	$0.21	$0.20	$0.19	$0.18
	14.70%	14.37%	14.03%	13.70%	13.37%	13.04%	12.71%	12.38%	12.05%	11.72%
	182,243,621	178,137,406	174,031,192	169,924,977	165,818,763	161,712,548	157,606,334	153,500,119	149,393,905	145,287,690

Notes:

1) Indicative MVP Usage Rate based on the approved and conditionally approved MVPs listed in Figure 1.1.

2) Annual MISO Withdrawals based on 2010 values with years 2012-2021 escalated assuming an annual energy growth rate of 1.42% consistent with the assumed energy growth rate used in the MTEP 11 Business as Usual Future with historical energy growth rates, see tab "Indicative LBA Energy Values" for individual LBA energy values.

3) Annual Revenue Requirement calculated using an estimated Annual Charge Rate for each Transmission Owner based on the methodology described in Attachment MM. Annual Charge Rate estimated using Transmission Owner's Attachment O data as of January 2011 and assumes 40-year straight-line depreciation.

4) Construction Work in Progress charges are assumed only for the Brooking, SD - SE Twin Cities 345 kV project using the following estimated schedule: 2012 = 10% of estimated project cost; 2013 = 40%; 2014 = 75%; and 2015 = 100%.

5) For the Michigan Thumb MVP the project is assumed to be phased in-service equally over the 2013-2015 period.

6) The Indicative MVP Usage Rate for the Michigan Thumb project reflects First Energy's obligation for a portion of the Michigan Thumb project.

Figure 1.3 *Indicative* Annual MVP Charges for Approved and Conditionally Approved MVPs by Local Balancing Authority for 2012-2021 (2011$ in Millions)

LBA	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
ALTE	$0.27	$2.07	$3.98	$6.05	$5.95	$5.85	$5.75	$5.65	$5.56	$5.46
ALTW	$0.43	$3.36	$6.45	$9.81	$9.65	$9.49	$9.33	$9.17	$9.01	$8.85
AMIL	$1.01	$7.81	$15.00	$22.81	$22.44	$22.07	$21.70	$21.32	$20.95	$20.58
AMMO	$0.94	$7.28	$13.99	$21.26	$20.92	$20.57	$20.22	$19.88	$19.53	$19.18
BREC	$0.07	$0.81	$2.08	$3.16	$3.10	$3.05	$3.00	$2.95	$2.90	$2.85
CIN	$1.45	$11.24	$21.59	$32.83	$32.29	$31.76	$31.22	$30.69	$30.15	$29.62
CONS	$0.95	$7.34	$14.10	$21.43	$21.08	$20.73	$20.38	$20.03	$19.69	$19.34
CWLD	$0.03	$0.24	$0.47	$0.71	$0.70	$0.69	$0.68	$0.67	$0.65	$0.64
CWLP	$0.04	$0.33	$0.64	$0.98	$0.96	$0.95	$0.93	$0.91	$0.90	$0.88
DECO	$1.14	$8.80	$16.91	$25.71	$25.29	$24.87	$24.45	$24.03	$23.61	$23.19
DPC	$0.12	$0.94	$1.81	$2.76	$2.71	$2.67	$2.62	$2.58	$2.53	$2.49
GRE	$0.27	$2.07	$3.98	$6.06	$5.96	$5.86	$5.76	$5.66	$5.56	$5.47
HE	$0.01	$0.07	$0.13	$0.20	$0.19	$0.19	$0.19	$0.18	$0.18	$0.18
IPL	$0.33	$2.57	$4.95	$7.52	$7.40	$7.28	$7.15	$7.03	$6.91	$6.79
MDU	$0.06	$0.45	$0.86	$1.30	$1.28	$1.26	$1.24	$1.22	$1.20	$1.18
MEC	$0.52	$4.04	$7.76	$11.80	$11.61	$11.41	$11.22	$11.03	$10.84	$10.64
MGE	$0.07	$0.58	$1.11	$1.69	$1.66	$1.63	$1.60	$1.58	$1.55	$1.52
MP	$0.23	$1.77	$3.40	$5.16	$5.08	$5.00	$4.91	$4.83	$4.74	$4.66
MPW	$0.02	$0.15	$0.29	$0.43	$0.43	$0.42	$0.41	$0.41	$0.40	$0.39
NIPS	$0.41	$3.18	$6.11	$9.29	$9.14	$8.98	$8.83	$8.68	$8.53	$8.38
NSP	$1.02	$7.86	$15.11	$22.97	$22.60	$22.22	$21.85	$21.48	$21.10	$20.73
OTP	$0.17	$1.32	$2.53	$3.84	$3.78	$3.72	$3.65	$3.59	$3.53	$3.47
SIGE	$0.17	$1.32	$2.54	$3.86	$3.79	$3.73	$3.67	$3.61	$3.54	$3.48
SIPC	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SMP	$0.04	$0.28	$0.54	$0.82	$0.81	$0.80	$0.78	$0.77	$0.76	$0.74
UPPC	$0.02	$0.19	$0.37	$0.56	$0.55	$0.54	$0.53	$0.52	$0.51	$0.50
WEC	$0.73	$5.67	$10.89	$16.55	$16.28	$16.01	$15.74	$15.47	$15.20	$14.93
WPS	$0.31	$2.38	$4.57	$6.94	$6.83	$6.72	$6.61	$6.49	$6.38	$6.27
Exports and Wheel-Throughs excluding those sinking in PJM	$0.25	$1.90	$3.66	$5.56	$5.47	$5.38	$5.29	$5.20	$5.11	$5.02
Total	$11.09	$86.00	$165.80	$252.05	$247.94	$243.84	$239.73	$235.62	$231.52	$227.41

Cin Zone share	13.11%	13.06%	13.02%	13.02%	13.02%	13.02%	13.02%	13.02%	13.02%	13.02%

18.01%	17.68%	17.35%	17.02%	16.68%	16.35%	16.02%	15.69%	15.36%	15.03%
223,305,766	219,199,551	215,093,337	210,987,122	206,880,908	202,774,693	198,668,479	194,562,264	190,456,050	186,349,835
0.803	0.777	0.752	0.727	0.703	0.679	0.656	0.634	0.612	0.590
2022	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
$0.18	$0.17	$0.17	$0.16	$0.16	$0.15	$0.15	$0.14	$0.14	$0.13
$0.19	$0.18	$0.18	$0.17	$0.17	$0.16	$0.16	$0.15	$0.15	$0.14
$0.37	$0.36	$0.35	$0.34	$0.33	$0.31	$0.30	$0.29	$0.28	$0.27
0.383	0.366	0.350	0.335	0.320	0.305	0.290	0.276	0.262	0.249
2042	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**
$0.08	$0.08	$0.08	$0.07	$0.07	$0.07	$0.06	$0.06	$0.06	$0.05
$0.09	$0.09	$0.09	$0.08	$0.08	$0.07	$0.07	$0.07	$0.06	$0.06
$0.18	$0.17	$0.16	$0.15	$0.15	$0.14	$0.13	$0.13	$0.12	$0.12
11.39%	11.05%	10.72%	10.39%	10.06%	9.73%	9.40%	9.07%	8.74%	8.41%
141,181,476	137,075,261	132,969,047	128,862,832	124,756,617	120,650,403	116,544,188	112,437,974	108,331,759	104,225,545

Source: MISO, 20110712 MSWG Item 03 Schedule 26-A Indicative Annual Charges.xlsx

Exhibit DUK-202

Available via links at https://www.midwestiso.org/Library/MeetingMaterials/Pages/MSWG.aspx

Figure 2 *Indicative* Annual Monthly Net Actual Energy Withdrawals by Local Balancing Authority for 2012-2021

Local Balancing Authority	2010 Withdrawals (MWh)	2012	2013	2014
ALTE	12,186,226	12,534,772	12,712,766	12,893,287
ALTW	19,763,102	20,328,360	20,617,022	20,909,784
AMIL	45,963,542	47,278,174	47,949,524	48,630,408
AMMO	42,844,500	44,069,923	44,695,716	45,330,395
BREC	6,358,573	3,270,219	4,974,985	6,727,506
CIN	66,143,914	68,035,739	69,001,846	69,981,672
CONS	43,183,494	44,418,613	45,049,357	45,689,058
CWLD	1,434,449	1,475,476	1,496,428	1,517,678
CWLP	1,969,123	2,025,443	2,054,204	2,083,374
DECO	51,796,627	53,278,095	54,034,644	54,801,936
DPC	5,555,689	5,714,591	5,795,738	5,878,038
GRE	12,206,726	12,555,858	12,734,151	12,914,976
HE	395,476	406,787	412,563	418,422
IPL	15,157,443	15,590,971	15,812,363	16,036,898
MDU	2,624,984	2,700,063	2,738,404	2,777,290
MEC	23,772,354	24,452,282	24,799,504	25,151,657
MGE	3,397,476	3,494,649	3,544,273	3,594,602
MP	10,405,799	10,703,422	10,855,411	11,009,558
MPW	874,017	899,015	911,781	924,729
NIPS	18,713,128	19,248,354	19,521,680	19,798,888
NSP	46,290,179	47,614,154	48,290,275	48,975,997
OTP	7,741,784	7,963,211	8,076,289	8,190,972
SIGE	7,771,825	7,994,112	8,107,629	8,222,757
SIPC	0	0	0	0
SMP	1,658,694	1,706,136	1,730,363	1,754,934
UPPC	1,125,810	1,158,010	1,174,453	1,191,131
WEC	33,353,045	34,306,997	34,794,156	35,288,233
WPS	13,993,353	14,393,586	14,597,975	14,805,266
Exports and Wheel-Throughs excluding those sinking in PJM	11,203,439	11,523,876	11,687,515	11,853,478
	507,884,771	519,140,889	528,171,018	537,352,923

Note: Energy Values exclude load under Carve-Out Grandfathered Agreements. Assumes an annual energy growth rate of 1.42% consistent with the MT

Cinergy zone share (Duke + WVPA+IMPA)	13.02%	13.11%	13.06%	13.02%

2032	2033	2034	2035
692,603,254	702,438,220	712,412,843	722,529,105

2015	2016	2017	2018	2019	2020	2021	2022	2023
13,076,371	13,262,056	13,450,377	13,641,373	13,835,080	14,031,538	14,230,786		
21,206,703	21,507,838	21,813,249	22,122,998	22,437,144	22,755,752	23,078,883		
49,320,959	50,021,317	50,731,620	51,452,009	52,182,627	52,923,621	53,675,136		
45,974,087	46,626,919	47,289,021	47,960,525	48,641,565	49,332,275	50,032,793		
6,823,037	6,919,924	7,018,187	7,117,845	7,218,918	7,321,427	7,425,391		
70,975,412	71,983,263	73,005,425	74,042,102	75,093,500	76,159,828	77,241,298		
46,337,843	46,995,840	47,663,181	48,339,998	49,026,426	49,722,601	50,428,662		
1,539,229	1,561,086	1,583,253	1,605,735	1,628,537	1,651,662	1,675,115		
2,112,958	2,142,962	2,173,392	2,204,254	2,235,554	2,267,299	2,299,495		
55,580,123	56,369,361	57,169,806	57,981,617	58,804,956	59,639,987	60,486,875		
5,961,506	6,046,159	6,132,015	6,219,090	6,307,401	6,396,966	6,487,803		
13,098,369	13,284,366	13,473,004	13,664,320	13,858,354	14,055,142	14,254,725		
424,363	430,389	436,501	442,699	448,986	455,361	461,827		
16,264,622	16,495,580	16,729,817	16,967,380	17,208,317	17,452,675	17,700,503		
2,816,727	2,856,725	2,897,290	2,938,432	2,980,157	3,022,476	3,065,395		
25,508,811	25,871,036	26,238,405	26,610,990	26,988,866	27,372,108	27,760,792		
3,645,645	3,697,413	3,749,916	3,803,165	3,857,170	3,911,942	3,967,491		
11,165,893	11,324,449	11,485,256	11,648,347	11,813,753	11,981,509	12,151,646		
937,860	951,177	964,684	978,383	992,276	1,006,366	1,020,656		
20,080,032	20,365,169	20,654,354	20,947,646	21,245,103	21,546,783	21,852,747		
49,671,457	50,376,791	51,092,142	51,817,650	52,553,461	53,299,720	54,056,576		
8,307,284	8,425,247	8,544,886	8,666,223	8,789,284	8,914,091	9,040,672		
8,339,520	8,457,941	8,578,044	8,699,852	8,823,390	8,948,683	9,075,754		
0	0	0	0	0	0	0		
1,779,854	1,805,128	1,830,761	1,856,757	1,883,123	1,909,864	1,936,984		
1,208,045	1,225,199	1,242,597	1,260,242	1,278,137	1,296,287	1,314,694		
35,789,326	36,297,535	36,812,960	37,335,704	37,865,871	38,403,566	38,948,897		
15,015,501	15,228,721	15,444,969	15,664,287	15,886,720	16,112,312	16,341,106		
12,021,797	12,192,506	12,365,640	12,541,232	12,719,318	12,899,932	13,083,111		
544,983,335	552,722,098	560,570,752	568,530,856	576,603,995	584,791,771	593,095,814	601,517,775	610,059,327

'EP 11 Business as Usual with historic demand and energy growth rates Future

						1.01420		
13.02%	13.02%	13.02%	13.02%	13.02%	13.02%	13.02%		

2036	2037	2038	2039	2040	2041	2042	2043	2044
732,789,018	743,194,622	753,747,986	764,451,208	775,306,415	786,315,766	797,481,450	808,805,686	820,290,727

2024	2025	2026	2027	2028	2029	2030	2031	2032
618,722,170	627,508,025	636,418,639	645,455,783	654,621,255	663,916,877	673,344,497	682,905,989	692,603,254

2045	2046	2047	2048	2049	2050	2051
831,938,855	843,752,387	855,733,671	867,885,089	880,209,057	892,708,026	905,384,480

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Indicative **Transmission Owner Annual Charge Rates used to calculate Annual Revenue Requirements for Cost Shared Projects**

Period	AMIL	AMMO	ATC	BREC	CWLD	CWLP	DPC	DUK	GRE
1	20.6%	17.5%	18.5%	16.6%	15.2%	14.5%	15.3%	16.7%	18.4%
2	20.2%	17.2%	18.2%	16.3%	14.9%	14.3%	15.1%	16.5%	18.2%
3	19.8%	16.9%	18.0%	16.1%	14.7%	14.1%	15.0%	16.2%	18.0%
4	19.5%	16.6%	17.7%	15.9%	14.5%	13.9%	14.8%	15.9%	17.7%
5	19.1%	16.4%	17.4%	15.7%	14.2%	13.7%	14.6%	15.7%	17.5%
6	18.7%	16.1%	17.1%	15.4%	14.0%	13.5%	14.5%	15.4%	17.3%
7	18.4%	15.8%	16.8%	15.2%	13.7%	13.3%	14.3%	15.2%	17.1%
8	18.0%	15.6%	16.5%	15.0%	13.5%	13.1%	14.1%	14.9%	16.9%
9	17.6%	15.3%	16.2%	14.8%	13.3%	12.9%	14.0%	14.6%	16.7%
10	17.3%	15.0%	15.9%	14.5%	13.0%	12.7%	13.8%	14.4%	16.5%
11	16.9%	14.8%	15.6%	14.3%	12.8%	12.5%	13.6%	14.1%	16.3%
12	16.5%	14.5%	15.3%	14.1%	12.5%	12.3%	13.5%	13.9%	16.0%
13	16.2%	14.2%	15.0%	13.9%	12.3%	12.1%	13.3%	13.6%	15.8%
14	15.8%	14.0%	14.7%	13.6%	12.1%	11.9%	13.2%	13.3%	15.6%
15	15.4%	13.7%	14.4%	13.4%	11.8%	11.7%	13.0%	13.1%	15.4%
16	15.1%	13.4%	14.1%	13.2%	11.6%	11.5%	12.8%	12.8%	15.2%
17	14.7%	13.2%	13.8%	13.0%	11.3%	11.3%	12.7%	12.6%	15.0%
18	14.3%	12.9%	13.5%	12.7%	11.1%	11.1%	12.5%	12.3%	14.8%
19	14.0%	12.6%	13.2%	12.5%	10.9%	10.9%	12.3%	12.1%	14.6%
20	13.6%	12.4%	12.9%	12.3%	10.6%	10.7%	12.2%	11.8%	14.3%
21	13.2%	12.1%	12.7%	12.1%	10.4%	10.5%	12.0%	11.5%	14.1%
22	12.9%	11.8%	12.4%	11.8%	10.1%	10.3%	11.8%	11.3%	13.9%
23	12.5%	11.6%	12.1%	11.6%	9.9%	10.1%	11.7%	11.0%	13.7%
24	12.1%	11.3%	11.8%	11.4%	9.7%	9.9%	11.5%	10.8%	13.5%
25	11.8%	11.0%	11.5%	11.2%	9.4%	9.7%	11.3%	10.5%	13.3%
26	11.4%	10.8%	11.2%	10.9%	9.2%	9.5%	11.2%	10.2%	13.1%
27	11.0%	10.5%	10.9%	10.7%	9.0%	9.3%	11.0%	10.0%	12.9%
28	10.7%	10.2%	10.6%	10.5%	8.7%	9.1%	10.9%	9.7%	12.6%
29	10.3%	10.0%	10.3%	10.3%	8.5%	8.9%	10.7%	9.5%	12.4%
30	9.9%	9.7%	10.0%	10.0%	8.2%	8.7%	10.5%	9.2%	12.2%
31	9.6%	9.4%	9.7%	9.8%	8.0%	8.5%	10.4%	8.9%	12.0%
32	9.2%	9.2%	9.4%	9.6%	7.8%	8.2%	10.2%	8.7%	11.8%
33	8.9%	8.9%	9.1%	9.4%	7.5%	8.0%	10.0%	8.4%	11.6%
34	8.5%	8.6%	8.8%	9.1%	7.3%	7.8%	9.9%	8.2%	11.4%
35	8.1%	8.4%	8.5%	8.9%	7.0%	7.6%	9.7%	7.9%	11.2%
36	7.8%	8.1%	8.2%	8.7%	6.8%	7.4%	9.5%	7.6%	10.9%
37	7.4%	7.8%	7.9%	8.5%	6.6%	7.2%	9.4%	7.4%	10.7%
38	7.0%	7.6%	7.6%	8.2%	6.3%	7.0%	9.2%	7.1%	10.5%
39	6.7%	7.3%	7.3%	8.0%	6.1%	6.8%	9.1%	6.9%	10.3%
40	6.3%	7.0%	7.1%	7.8%	5.8%	6.6%	8.9%	6.6%	10.1%

Assumptions: 1) Annual Charge Rate calculated in accordance with Att. MM of the Tariff; 2) components of Annual Charge Rate based on Attachment O data

Source file: MISO Tariff, January 2011 Attachment O (201102 Attachment O.xlsx)
Blue = Historic Transmission Owner
Green: Forward Looking Transmission Owner

HE	IPL	ITC	ITCM	MDU	MEC	METC	MP	MPW	NIPS	NSP
19.4%	20.4%	27.7%	24.7%	25.4%	18.6%	27.5%	22.7%	23.5%	20.0%	17.3%
19.2%	20.1%	27.3%	24.3%	25.0%	18.3%	27.1%	22.3%	23.2%	19.7%	17.0%
19.0%	19.8%	26.8%	23.9%	24.5%	17.9%	26.7%	22.0%	22.9%	19.4%	16.7%
18.9%	19.5%	26.4%	23.5%	24.1%	17.6%	26.3%	21.6%	22.6%	19.1%	16.4%
18.7%	19.2%	25.9%	23.1%	23.7%	17.3%	25.9%	21.3%	22.2%	18.8%	16.1%
18.5%	18.9%	25.4%	22.7%	23.3%	17.0%	25.5%	20.9%	21.9%	18.5%	15.8%
18.3%	18.6%	25.0%	22.3%	22.9%	16.7%	25.1%	20.6%	21.6%	18.2%	15.5%
18.2%	18.3%	24.5%	21.9%	22.4%	16.4%	24.7%	20.2%	21.3%	17.9%	15.2%
18.0%	18.0%	24.1%	21.5%	22.0%	16.1%	24.3%	19.9%	21.0%	17.6%	15.0%
17.8%	17.7%	23.6%	21.1%	21.6%	15.8%	23.9%	19.5%	20.7%	17.3%	14.7%
17.7%	17.4%	23.1%	20.8%	21.2%	15.4%	23.5%	19.2%	20.3%	17.0%	14.4%
17.5%	17.1%	22.7%	20.4%	20.8%	15.1%	23.1%	18.8%	20.0%	16.7%	14.1%
17.3%	16.8%	22.2%	20.0%	20.3%	14.8%	22.7%	18.5%	19.7%	16.3%	13.8%
17.1%	16.5%	21.8%	19.6%	19.9%	14.5%	22.3%	18.1%	19.4%	16.0%	13.5%
17.0%	16.2%	21.3%	19.2%	19.5%	14.2%	21.8%	17.8%	19.1%	15.7%	13.2%
16.8%	16.0%	20.8%	18.8%	19.1%	13.9%	21.4%	17.4%	18.8%	15.4%	12.9%
16.6%	15.7%	20.4%	18.4%	18.6%	13.6%	21.0%	17.1%	18.5%	15.1%	12.6%
16.5%	15.4%	19.9%	18.0%	18.2%	13.3%	20.6%	16.7%	18.1%	14.8%	12.3%
16.3%	15.1%	19.5%	17.6%	17.8%	12.9%	20.2%	16.4%	17.8%	14.5%	12.0%
16.1%	14.8%	19.0%	17.2%	17.4%	12.6%	19.8%	16.1%	17.5%	14.2%	11.8%
16.0%	14.5%	18.6%	16.8%	17.0%	12.3%	19.4%	15.7%	17.2%	13.9%	11.5%
15.8%	14.2%	18.1%	16.4%	16.5%	12.0%	19.0%	15.4%	16.9%	13.6%	11.2%
15.6%	13.9%	17.6%	16.0%	16.1%	11.7%	18.6%	15.0%	16.6%	13.3%	10.9%
15.4%	13.6%	17.2%	15.6%	15.7%	11.4%	18.2%	14.7%	16.3%	13.0%	10.6%
15.3%	13.3%	16.7%	15.2%	15.3%	11.1%	17.8%	14.3%	15.9%	12.6%	10.3%
15.1%	13.0%	16.3%	14.8%	14.8%	10.8%	17.4%	14.0%	15.6%	12.3%	10.0%
14.9%	12.7%	15.8%	14.4%	14.4%	10.4%	17.0%	13.6%	15.3%	12.0%	9.7%
14.8%	12.4%	15.3%	14.0%	14.0%	10.1%	16.6%	13.3%	15.0%	11.7%	9.4%
14.6%	12.1%	14.9%	13.6%	13.6%	9.8%	16.2%	12.9%	14.7%	11.4%	9.1%
14.4%	11.8%	14.4%	13.2%	13.2%	9.5%	15.8%	12.6%	14.4%	11.1%	8.8%
14.2%	11.5%	14.0%	12.9%	12.7%	9.2%	15.4%	12.2%	14.0%	10.8%	8.5%
14.1%	11.2%	13.5%	12.5%	12.3%	8.9%	15.0%	11.9%	13.7%	10.5%	8.3%
13.9%	10.9%	13.1%	12.1%	11.9%	8.6%	14.6%	11.5%	13.4%	10.2%	8.0%
13.7%	10.6%	12.6%	11.7%	11.5%	8.3%	14.2%	11.2%	13.1%	9.9%	7.7%
13.6%	10.3%	12.1%	11.3%	11.0%	7.9%	13.7%	10.8%	12.8%	9.6%	7.4%
13.4%	10.0%	11.7%	10.9%	10.6%	7.6%	13.3%	10.5%	12.5%	9.3%	7.1%
13.2%	9.7%	11.2%	10.5%	10.2%	7.3%	12.9%	10.1%	12.2%	9.0%	6.8%
13.0%	9.4%	10.8%	10.1%	9.8%	7.0%	12.5%	9.8%	11.8%	8.6%	6.5%
12.9%	9.1%	10.3%	9.7%	9.4%	6.7%	12.1%	9.4%	11.5%	8.3%	6.2%
12.7%	8.8%	9.8%	9.3%	8.9%	6.4%	11.7%	9.1%	11.2%	8.0%	5.9%

Average is comparable to deduced values from Approved MVPs

OTP	SIPC	VECT	Average
22.2%	16.5%	17.0%	19.83%
21.9%	16.4%	16.7%	19.54%
21.6%	16.3%	16.3%	19.25%
21.2%	16.2%	16.0%	18.95%
20.9%	16.1%	15.7%	18.66%
20.6%	15.9%	15.3%	18.37%
20.3%	15.8%	15.0%	18.08%
19.9%	15.7%	14.7%	17.78%
19.6%	15.6%	14.4%	17.49%
19.3%	15.5%	14.0%	17.20%
18.9%	15.4%	13.7%	16.91%
18.6%	15.3%	13.4%	16.61%
18.3%	15.1%	13.0%	16.32%
17.9%	15.0%	12.7%	16.03%
17.6%	14.9%	12.4%	15.73%
17.3%	14.8%	12.0%	15.44%
16.9%	14.7%	11.7%	15.15%
16.6%	14.6%	11.4%	14.86%
16.3%	14.4%	11.0%	14.56%
15.9%	14.3%	10.7%	14.27%
15.6%	14.2%	10.4%	13.98%
15.3%	14.1%	10.1%	13.69%
14.9%	14.0%	9.7%	13.39%
14.6%	13.9%	9.4%	13.10%
14.3%	13.7%	9.1%	12.81%
14.0%	13.6%	8.7%	12.51%
13.6%	13.5%	8.4%	12.22%
13.3%	13.4%	8.1%	11.93%
13.0%	13.3%	7.7%	11.64%
12.6%	13.2%	7.4%	11.34%
12.3%	13.0%	7.1%	11.05%
12.0%	12.9%	6.7%	10.76%
11.6%	12.8%	6.4%	10.47%
11.3%	12.7%	6.1%	10.17%
11.0%	12.6%	5.7%	9.88%
10.6%	12.5%	5.4%	9.59%
10.3%	12.3%	5.1%	9.29%
10.0%	12.2%	4.8%	9.00%
9.6%	12.1%	4.4%	8.71%
9.3%	12.0%	4.1%	8.42%

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Sources: All fields on this page are pulled or calculated from other tabs in this workbook except transition fees supplied by MISO and estimated PJM integration costs.

Discount Factor	Calendar Year	Part I: Already approved Schedule 26 (Non-MVP) from Sched 26 Indicatives	Part II: Already approved 2011a MVP share from Sched 26A indicatives	Remaining RGOS MVPs	Non-MVP Cost Growth Estimate	MISO Costs Already Incurred
		from Table 6	from Table 7	from Table 8		
97.59%	2012	$5,859,002	$414,897	6,813,913	261,058	$6,273,899
92.94%	2013	$6,881,170	$3,380,428	13,627,826	789,518	$10,261,597
88.52%	2014	$7,874,182	$8,770,352	22,713,043	1,317,734	$16,644,534
84.30%	2015	$8,265,110	$12,929,810	31,647,798	1,845,596	$21,194,921
80.29%	2016	$8,176,256	$22,864,414	40,432,093	2,372,993	$31,040,670
76.46%	2017	$8,255,000	$24,742,163	49,065,926	2,899,811	$32,997,163
72.82%	2018	$8,163,247	$30,263,140	57,549,297	3,425,931	$38,426,387
69.36%	2019	$8,072,180	$35,273,887	65,882,207	3,951,235	$43,346,067
66.05%	2020	$7,948,944	$38,925,792	74,064,656	4,475,601	$46,874,736
62.91%	2021	$7,825,708	$40,418,698	82,096,644	4,998,904	$48,244,406
59.91%	2022	$7,664,517	$39,974,579	87,706,866	5,521,018	$47,639,096
57.06%	2023	$7,503,326	$39,506,641	90,895,322	6,041,813	$47,009,967
54.34%	2024	$7,342,136	$39,017,854	91,662,012	6,561,157	$46,359,990
51.75%	2025	$7,180,945	$38,510,625	90,006,937	7,078,915	$45,691,570
49.29%	2026	$7,019,755	$37,986,927	88,351,862	7,594,949	$45,006,682
46.94%	2027	$6,858,564	$37,448,394	86,696,787	8,109,120	$44,306,958
44.71%	2028	$6,697,373	$36,896,390	85,041,712	8,621,283	$43,593,763
42.58%	2029	$6,536,183	$36,332,064	83,386,637	9,131,294	$42,868,246
40.55%	2030	$6,374,992	$35,756,388	81,731,562	9,639,003	$42,131,381
38.62%	2031	$6,213,802	$35,170,194	80,076,487	10,144,259	$41,383,995
36.78%	2032	$6,052,611	$34,574,191	78,421,412	10,646,907	$40,626,802
35.03%	2033	$5,891,420	$33,968,993	76,766,337	11,146,789	$39,860,413
33.36%	2034	$5,730,230	$33,355,131	75,111,262	11,643,744	$39,085,360
31.77%	2035	$5,569,039	$32,733,065	73,456,187	12,137,609	$38,302,104
30.26%	2036	$5,407,848	$32,103,200	71,801,112	12,628,216	$37,511,048
SUM		$175,363,539	$761,318,215	$1,685,005,899	$162,984,456	$936,681,755
NPV		**$104,272,868**	**$396,959,885**	**$872,748,653**	**$75,655,349**	**$501,232,754**

Total

	Table 14		Table 15 - from Admin Costs		
Prospective (Post-2012) MISO Costs	PJM Load Ratio Costs	PJM DFAX Costs	MISO Admin Costs	PJM Admin Costs	Savings from Joining PJM
$7,074,971	$9,176,599	$31,444	$9,855,766	$7,834,071	(111,377)
$14,417,343	$12,741,961	$125,761	$9,420,697	$7,935,914	3,034,405
$24,030,776	$17,505,085	$281,910	$9,698,762	$8,039,080	7,903,462
$33,493,394	$22,892,537	$498,849	$9,824,845	$8,143,588	11,783,265
$42,805,086	$30,166,027	$775,538	$9,952,568	$8,249,455	13,566,634
$51,965,736	$37,385,659	$1,110,936	$10,081,952	$8,356,698	15,194,395
$60,975,228	$41,518,092	$1,475,839	$10,213,017	$8,465,335	19,728,979
$69,833,442	$45,606,335	$1,841,116	$10,345,786	$8,575,384	24,156,394
$78,540,257	$47,553,049	$2,206,772	$10,480,282	$8,686,864	30,573,853
$87,095,548	$49,455,572	$2,572,816	$10,616,525	$8,799,794	36,883,891
$93,227,884	$51,313,905	$2,939,253	$10,754,540	$8,914,191	40,815,075
$96,937,135	$52,460,959	$3,306,090	$10,894,349	$9,030,075	43,034,360
$98,223,169	$56,558,437	$3,673,334	$11,035,976	$9,147,466	39,879,907
$97,085,852	$59,944,637	$4,040,993	$11,179,443	$9,266,384	35,013,282
$95,946,812	$62,619,558	$4,409,073	$11,324,776	$9,386,847	30,856,110
$94,805,907	$65,294,479	$4,777,582	$11,471,998	$9,508,876	26,696,969
$93,662,996	$64,065,129	$5,146,528	$11,621,134	$9,632,491	26,439,982
$92,517,932	$62,835,779	$5,515,917	$11,772,209	$9,757,713	26,180,731
$91,370,566	$61,606,429	$5,885,758	$11,925,248	$9,884,564	25,919,063
$90,220,746	$60,377,079	$6,256,058	$12,080,276	$10,013,063	25,654,822
$89,068,319	$59,147,729	$6,626,826	$12,237,319	$10,143,233	25,387,851
$87,913,126	$57,918,379	$6,998,070	$12,396,405	$10,275,095	25,117,987
$86,755,006	$56,689,028	$7,369,797	$12,557,558	$10,408,671	24,845,067
$85,593,796	$55,459,678	$7,742,017	$12,720,806	$10,543,984	24,568,923
$84,429,329	$54,230,328	$8,114,738	$12,886,177	$10,681,055	24,289,384
$1,847,990,356	$1,194,522,448	$93,723,015	$277,348,415	$229,679,890	$607,413,417
$948,404,003	**$615,417,308**	**$41,583,352**	**$155,247,608**	**$128,472,431**	**$318,178,519**
		$657,000,660			
$1,449,636,756		$1,158,233,414		$26,775,177	

Discount Factor	Calendar Year	Future Costs to remain in MISO ($M)	Costs to move to PJM ($M)	Savings from Joining PJM ($M) Before Fees & Integration
97.6%	2012	16.9	17.0	(0.1)
92.9%	2013	23.8	20.8	3.0
88.5%	2014	33.7	25.8	7.9
84.3%	2015	43.3	31.5	11.8
80.3%	2016	52.8	39.2	13.6
76.5%	2017	62.0	46.9	15.2
72.8%	2018	71.2	51.5	19.7
69.4%	2019	80.2	56.0	24.2
66.1%	2020	89.0	58.4	30.6
62.9%	2021	97.7	60.8	36.9
59.9%	2022	104.0	63.2	40.8
57.1%	2023	107.8	64.8	43.0
54.3%	2024	109.3	69.4	39.9
51.8%	2025	108.3	73.3	35.0
49.3%	2026	107.3	76.4	30.9
46.9%	2027	106.3	79.6	26.7
44.7%	2028	105.3	78.8	26.4
42.6%	2029	104.3	78.1	26.2
40.6%	2030	103.3	77.4	25.9
38.6%	2031	102.3	76.6	25.7
36.8%	2032	101.3	75.9	25.4
35.0%	2033	100.3	75.2	25.1
33.4%	2034	99.3	74.5	24.8
31.8%	2035	98.3	73.7	24.6
30.3%	2036	97.3	73.0	24.3
	NPV ($M)	**1,103.7**	**785.5**	**318.2**

Table 1 Components

Cost Item ($M, NPV over 25 years)	If DEO & DEK stay in MISO	If DEO & DEK move to PJM	Benefit of moving from MISO to PJM
MISO Legacy TX costs	$501.2	$501.2	$0.0
MISO Future TX costs	$948.4	$0.0	$948.4
MISO Admin Rate Costs	$155.2	$0.0	$155.2
PJM Future TX Costs	$0.0	$657.0	($657.0)
PJM Admin Rate Costs	$0.0	$128.5	($128.5)
Integration Costs to PJM	$0.0	$1.0	($1.0)
Exit fees to MISO		$16.2	($16.2)
Total Costs (Net Benefit)	$1,604.9	$1,303.9	$301.0

Gross Benefit			$819.4
Tranisition Costs			$518.4
Net Benefit			$301.0

Table 15

	(a)	(b)	(c)	(d) = (a) + (b) + (c)	(e)	(f)	(g) = (e) + (f)	(h) = (d) - (g)	(i)	(j) = (h) - (a) - (i)
Year	Legacy MTEP Costs	Future MTEP Costs	MISO Admin Costs	Total MISO Costs	PJM RTEP Costs	PJM Admin Costs	Total PJM Costs	Gross Benefit to Move to PJM	Other Tran-sition Costs	Net Benefit after Trans & Legacy Costs
2012	6.3	7.1	9.9	23.2	9.2	7.8	17.0	6.2	17.2	(17.3)
2013	10.3	14.4	9.4	34.1	12.9	7.9	20.8	13.3		3.0
2014	16.6	24.0	9.7	50.4	17.8	8.0	25.8	24.5		7.9
2015	21.2	33.5	9.8	64.5	23.4	8.1	31.5	33.0		11.8
2016	31.0	42.8	10.0	83.8	30.9	8.2	39.2	44.6		13.6
2017	33.0	52.0	10.1	95.0	38.5	8.4	46.9	48.2		15.2
2018	38.4	61.0	10.2	109.6	43.0	8.5	51.5	58.2		19.7
2019	43.3	69.8	10.3	123.5	47.4	8.6	56.0	67.5		24.2
2020	46.9	78.5	10.5	135.9	49.8	8.7	58.4	77.4		30.6
2021	48.2	87.1	10.6	146.0	52.0	8.8	60.8	85.1		36.9
2022	47.6	93.2	10.8	151.6	54.3	8.9	63.2	88.5		40.8
2023	47.0	96.9	10.9	154.8	55.8	9.0	64.8	90.0		43.0
2024	46.4	98.2	11.0	155.6	60.2	9.1	69.4	86.2		39.9
2025	45.7	97.1	11.2	154.0	64.0	9.3	73.3	80.7		35.0
2026	45.0	95.9	11.3	152.3	67.0	9.4	76.4	75.9		30.9
2027	44.3	94.8	11.5	150.6	70.1	9.5	79.6	71.0		26.7
2028	43.6	93.7	11.6	148.9	69.2	9.6	78.8	70.0		26.4
2029	42.9	92.5	11.8	147.2	68.4	9.8	78.1	69.0		26.2
2030	42.1	91.4	11.9	145.4	67.5	9.9	77.4	68.1		25.9
2031	41.4	90.2	12.1	143.7	66.6	10.0	76.6	67.0		25.7
2032	40.6	89.1	12.2	141.9	65.8	10.1	75.9	66.0		25.4
2033	39.9	87.9	12.4	140.2	64.9	10.3	75.2	65.0		25.1
2034	39.1	86.8	12.6	138.4	64.1	10.4	74.5	63.9		24.8
2035	38.3	85.6	12.7	136.6	63.2	10.5	73.7	62.9		24.6
2036	37.5	84.4	12.9	134.8	62.3	10.7	73.0	61.8		24.3
SUM	936.7	1,848.0	277.3	3,062.0	1,288.2	229.7	1,517.9	1,544.1	17.2	590.2
NPV*	**501.2**	**948.4**	**155.2**	**1,604.9**	**657.0**	**128.5**	**785.5**	**819.4**	**17.2**	**301.0**

*NPV discounts annual costs to 2011 at a discount rate of 5 percent per year. This does not include inflation, as costs are already in real 2011$.

Exhibit DUK-203

part of Table 15 - Administrative Costs

Year	MISO rate	PJM rate	DUK load (TWh)	Costs in MISO	Costs in PJM	Difference
2009	$ 0.400	$ 0.220	24.3	$ 9,724,280	$ 5,348,354	$ 4,375,926
2010	$ 0.380	$ 0.260	24.6	$ 9,358,161	$ 6,402,952	$ 2,955,209
2011	$ 0.385	$ 0.310	24.9	$ 9,604,551	$ 7,733,535	$ 1,871,016
2012	$ 0.390	$ 0.310	25.3	$ 9,855,766	$ 7,834,071	$ 2,021,696
2013	$ 0.368	$ 0.310	25.6	$ 9,420,697	$ 7,935,914	$ 1,484,784
2014	$ 0.374	$ 0.310	25.9	$ 9,698,762	$ 8,039,080	$ 1,659,681
2015	$ 0.374	$ 0.310	26.3	$ 9,824,845	$ 8,143,588	$ 1,681,257
2016	$ 0.374	$ 0.310	26.6	$ 9,952,568	$ 8,249,455	$ 1,703,113
2017	$ 0.374	$ 0.310	27.0	$ 10,081,952	$ 8,356,698	$ 1,725,254
2018	$ 0.374	$ 0.310	27.3	$ 10,213,017	$ 8,465,335	$ 1,747,682
2019	$ 0.374	$ 0.310	27.7	$ 10,345,786	$ 8,575,384	$ 1,770,402
2020	$ 0.374	$ 0.310	28.0	$ 10,480,282	$ 8,686,864	$ 1,793,417
2021	$ 0.374	$ 0.310	28.4	$ 10,616,525	$ 8,799,794	$ 1,816,732
2022	$ 0.374	$ 0.310	28.8	$ 10,754,540	$ 8,914,191	$ 1,840,349
2023	$ 0.374	$ 0.310	29.1	$ 10,894,349	$ 9,030,075	$ 1,864,274
2024	$ 0.374	$ 0.310	29.5	$ 11,035,976	$ 9,147,466	$ 1,888,509
2025	$ 0.374	$ 0.310	29.9	$ 11,179,443	$ 9,266,384	$ 1,913,060
2026	$ 0.374	$ 0.310	30.3	$ 11,324,776	$ 9,386,847	$ 1,937,930
2027	$ 0.374	$ 0.310	30.7	$ 11,471,998	$ 9,508,876	$ 1,963,123
2028	$ 0.374	$ 0.310	31.1	$ 11,621,134	$ 9,632,491	$ 1,988,643
2029	$ 0.374	$ 0.310	31.5	$ 11,772,209	$ 9,757,713	$ 2,014,496
2030	$ 0.374	$ 0.310	31.9	$ 11,925,248	$ 9,884,564	$ 2,040,684
2031	$ 0.374	$ 0.310	32.3	$ 12,080,276	$ 10,013,063	$ 2,067,213
2032	$ 0.374	$ 0.310	32.7	$ 12,237,319	$ 10,143,233	$ 2,094,087
2033	$ 0.374	$ 0.310	33.1	$ 12,396,405	$ 10,275,095	$ 2,121,310
2034	$ 0.374	$ 0.310	33.6	$ 12,557,558	$ 10,408,671	$ 2,148,887
2035	$ 0.374	$ 0.310	34.0	$ 12,720,806	$ 10,543,984	$ 2,176,822
2036	$ 0.374	$ 0.310	34.5	$ 12,886,177	$ 10,681,055	$ 2,205,121

Source: Rates from 2011 FERC Performance Metrics report

Appendix A-3. *Indicative* Multi-Value Project (MVP) Schedule 26-A Annual Charges by MISO Local Balancing Authority (LBA) for Approved and Pending Approval MVPs

Values shown below (in 2011 Dollars) are subject to change depending on actual withdrawals (MWh), actual project costs including Construction Work in Progress, actual In-service Dates, and actual Annual Charge Rates for Transmission Owners

Dollar-W

Table 2

F

Figure A-3.1 Approved and Pending Approval MVPs

Project ID	Project Name	by TO Member System	ated In-Service Date	ed Project Cost (2011$)	Approval Status
[1]	[2]	[3]	[4]	[5]	[6]
1203	Brookings, SD - SE Twin Cities 345 kV	RE/OTP/MRES/CMMPA	5/1/2015	$695,000,000	itionally Approved June 2011
2202	New Reynolds to Greentown 765 kV line	DUK	8/1/2018	$245,300,000	Pending Dec 2011
2220	Ellendale to Big Stone South	OTP, MDU	12/31/2019	$260,700,000	Pending Dec 2011
2221	Big Stone South to Brookings	OTP, XEL	12/31/2017	$190,800,000	Pending Dec 2011
2237	Pana - Mt. Zion - Kansas - Sugar Creek 345 kV line	AMIL	6/1/2020	$284,100,000	Pending Dec 2011
2239	Sidney to Rising 345 kV line	AMIL	6/1/2017	$90,100,000	Pending Dec 2011
2248	Adair - Ottumwa 345	AMMO, ITCM, MEC	6/1/2017	$152,037,000	Pending Dec 2011
2844	Pleasant Prairie-Zion Energy Center 345 kV line	ATC	12/31/2014	$26,400,000	Pending Dec 2011
3017	Palmyra -Quincy-Meredosia - Ipava & Meredosia-Pawnee 345 kV Line	AMIL	6/1/2018	$392,400,000	Pending Dec 2011
3022	Fargo-Oak Grove 345 kV Line	AMIL, MEC	6/1/2018	$193,200,000	Pending Dec 2011
3127	N LaCrosse-N Madison-Cardinal -Spring Green - Dubuque area 345-kV	ATC, XEL, ITCM	12/31/2020	$714,430,000	Pending Dec 2011
3168	Michigan Thumb Wind Zone	ITC	12/31/2015	$510,000,000	Approved MTEP 10
3169	New Pawnee to Pana - 345 kV Line	AMIL	6/1/2018	$88,100,000	Pending Dec 2011
3170	West Adair-Palmyra Tap 345 kV Line	AMMO	6/1/2018	$97,600,000	Pending Dec 2011
3203	New Reynolds to E. Winnamac to Burr Oak to Hiple 345 kV	NIPS	12/31/2013	$271,200,000	Pending Dec 2011
3205	Lakefield-Burt & Sheldon-Webseter 345 kV line	MEC, ITCM	12/31/2015	$505,650,000	Pending Dec 2011
3213	Winco-Lime Creek-Emery-Blackhawk-Hazelton 345 kV line	MEC, ITCM	12/31/2015	$480,050,000	Pending Dec 2011
			Total	$5,197,067,000	
		Total for Projects Pending Approval in Dec. 2011		$3,992,067,000	

'eighted In-Service Date
'or all 17 projects
7/19/2017

Year	Cost
2015	$695
2018	$245
2019	$261
2017	$191
2020	$284
2017	$90
2017	$152
2014	$26
2018	$392
2018	$193
2020	$714
2015	$510
2018	$88
2018	$98
2013	$271
2015	$506
2015	$480

Row Labels	Sum of Cost
2013	271
2014	26
2015	2191
2017	433
2018	1017
2019	261
2020	999
Grand Total	**5197**

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Figure A-3.2 *Indicative* MVP Usage Rates for Approved and Pending Approval MVPs (2011 dollars)

Year (2012-2031)	2012	2013	2014	2015	2016
Indicative MVP Usage Rate ($/MWh)	$0.02	$0.14	$0.35	$0.50	$0.88
DEOK TWh	25.27	25.60	25.93	26.27	26.61
DEOK Cost	$0.43	$3.46	$8.97	$13.21	$23.33
CIN TWh	68.04	69.00	69.98	70.98	71.98
Cin Cost	$1.15	$9.33	$24.20	$35.68	$63.10
	1.0000	1.0000	1.0000	1.0000	1.0000
From June Indicative Sched 26A - CIN load (TWh)	68,035,739	69,001,846	69,981,672	70,975,412	71,983,263
		1.0142	1.0142	1.0142	1.0142

	Year (2032-2051)	2032	2033	2034	2035	2036
	Indicative MVP Usage Rate by 2032 - 2051 ($/MWh)	$1.06	$1.02	$0.99	$0.96	$0.93
DEOK TWh		33.15	33.58	34.01	34.46	
DEOK Cost		$35.06	$34.41	$33.75	$33.08	
CIN TWh	88.94	90.20	91.48	92.78	94.10	95.43
Cin Cost	97.06	$95.42	$93.75	$92.05	$90.34	$88.60

2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	
$0.94	$1.13	$1.30	$1.41	$1.44	$1.41	$1.37	$1.34	$1.30	$1.26	$1.23	$1.19	$1.16	$1.13	$1.09	
26.96	27.31	27.66	28.02	28.39	28.76	29.13	29.51	29.89	30.28	30.67	31.07	31.48	31.89	32.30	32.72
$25.21	$30.80	$35.86	$39.53	$40.99	$40.50	$39.97	$39.43	$38.87	$38.30	$37.71	$37.11	$36.50	$35.88	$35.25	
73.01	74.04	75.09	76.16	77.24	78.34	79.45	80.58	81.72	82.88	84.06	85.25	86.46	87.69	88.94	
$68.28	$83.52	$97.35	$107.43	$111.55	$110.32	$109.03	$107.68	$106.28	$104.83	$103.35	$101.83	$100.27	$98.68	$97.06	
1.0000															
73,005,425	74,042,102	75,093,500	76,159,828	77,241,298											
1.0142	1.0142	1.0142	1.0142	1.0142											

2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
$0.90	$0.87	$0.84	$0.81	$0.78	$0.75	$0.72	$0.69	$0.67	$0.64	$0.61	$0.59	$0.56	$0.54	$0.51

Notes:

1) Indicative Schedule 26-A MVP Usage Rate not intended to be used for rate making purposes.

2) Indicative MVP Usage Rate based on the approved and pending approval MVPs listed in Figure A-3.1.

3) Annual MISO Withdrawals based on 2010 values with years 2012-2051 escalated assuming an annual energy growth rate of 1.42% consistent with the assumed energy growth rate used in the MTEP 11 Business as Usual Future with historical energy growth rates.

4) Annual Revenue Requirement calculated using an estimated Annual Charge Rate for each Transmission. Annual Charge Rate estimated using Transmission Owner's Attachment O data as of January 2011 and assumes 40-year straight-line depreciation.

5) Construction Work in Progress (CWIP) charges are assumed only for projects that have FERC approval for CWIP recovery. Estimated annual CWIP charges are based on an assumed phase-in schedule depending on the in-service date. For example, if a project has an in-service date in 2016 then CWIP charges occur as follows: 2012 = 7.5% of estimated project cost; 2013 = 20%; 2014 = 45%; 2015 = 75%; 2016=100%. The annual charge rate is reduced by 2.5% during the years of CWIP recovery to reflect that depreciation expense reletated charges are not incurred.

6) For the Michigan Thumb MVP the project is assumed to be phased in-service equally over the 2013-2015 period.

7) The Indicative MVP Usage Rate for the Michigan Thumb project reflects First Energy's obligation for a portion of the Michigan Thumb project.

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Figure A-3.3 *Indicative* Annual MVP Charges for Approved and Pending Approval MVPs by Local Balancing Authority for 2012-2021 (in Millions of 2011 Dollars)

LBA	2012	2013	2014	2015	2016
ALTE	$0.21	$1.72	$4.46	$6.57	$11.63
ALTW	$0.34	$2.79	$7.23	$10.66	$18.85
AMIL	$0.80	$6.48	$16.82	$24.80	$43.85
AMMO	$0.74	$6.04	$15.68	$23.11	$40.87
BREC	$0.06	$0.67	$2.33	$3.43	$6.07
CIN	$1.15	$9.33	$24.20	$35.68	$63.10
CONS	$0.75	$6.09	$15.80	$23.30	$41.20
CWLD	$0.02	$0.20	$0.52	$0.77	$1.37
CWLP	$0.03	$0.28	$0.72	$1.06	$1.88
DECO	$0.90	$7.31	$18.95	$27.94	$49.41
DPC	$0.10	$0.78	$2.03	$3.00	$5.30
GRE	$0.21	$1.72	$4.47	$6.59	$11.65
HE	$0.01	$0.06	$0.14	$0.21	$0.38
IPL	$0.26	$2.14	$5.55	$8.18	$14.46
MDU	$0.05	$0.37	$0.96	$1.42	$2.50
MEC	$0.41	$3.35	$8.70	$12.82	$22.68
MGE	$0.06	$0.48	$1.24	$1.83	$3.24
MP	$0.18	$1.47	$3.81	$5.61	$9.93
MPW	$0.02	$0.12	$0.32	$0.47	$0.83
NIPS	$0.32	$2.64	$6.85	$10.10	$17.85
NSP	$0.80	$6.53	$16.94	$24.97	$44.16
OTP	$0.13	$1.09	$2.83	$4.18	$7.39
SIGE	$0.13	$1.10	$2.84	$4.19	$7.41
SIPC	$0.00	$0.00	$0.00	$0.00	$0.00
SMP	$0.03	$0.23	$0.61	$0.89	$1.58
UPPC	$0.02	$0.16	$0.41	$0.61	$1.07
WEC	$0.58	$4.70	$12.20	$17.99	$31.82
WPS	$0.24	$1.97	$5.12	$7.55	$13.35
Exports and Wheel-Throughs excluding those sinking in PJM	$0.19	$1.58	$4.10	$6.04	$10.69
Total	$8.74	$71.41	$185.85	$273.99	$484.52
	13.11%	13.06%	13.02%	13.02%	13.02%

Source: MTEP11 Appendices A1 A2 A3

2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
$12.58	$15.39	$17.94	$19.79	$20.55										
$20.40	$24.95	$29.09	$32.10	$33.33										
$47.45	$58.04	$67.65	$74.65	$77.51										
$44.23	$54.10	$63.06	$69.58	$72.25										
$6.56	$8.03	$9.36	$10.33	$10.72										
$68.28	$83.52	$97.35	$107.43	$111.55	$110.32	$109.03	$107.68	$106.28	$104.83	$103.35	$101.83	$100.27	$98.68	$97.06
$44.58	$54.53	$63.56	$70.14	$72.83										
$1.48	$1.81	$2.11	$2.33	$2.42										
$2.03	$2.49	$2.90	$3.20	$3.32										
$53.47	$65.40	$76.23	$84.12	$87.35										
$5.74	$7.02	$8.18	$9.02	$9.37										
$12.60	$15.41	$17.97	$19.83	$20.59										
$0.41	$0.50	$0.58	$0.64	$0.67										
$15.65	$19.14	$22.31	$24.62	$25.56										
$2.71	$3.31	$3.86	$4.26	$4.43										
$24.54	$30.02	$34.99	$38.61	$40.09										
$3.51	$4.29	$5.00	$5.52	$5.73										
$10.74	$13.14	$15.31	$16.90	$17.55										
$0.90	$1.10	$1.29	$1.42	$1.47										
$19.32	$23.63	$27.54	$30.39	$31.56										
$47.79	$58.45	$68.13	$75.18	$78.06										
$7.99	$9.78	$11.39	$12.57	$13.06										
$8.02	$9.81	$11.44	$12.62	$13.11										
$0.00	$0.00	$0.00	$0.00	$0.00										
$1.71	$2.09	$2.44	$2.69	$2.80										
$1.16	$1.42	$1.66	$1.83	$1.90										
$34.43	$42.11	$49.09	$54.17	$56.25										
$14.45	$17.67	$20.59	$22.73	$23.60										
$11.57	$14.15	$16.49	$18.20	$18.89										
$524.31	$641.30	$747.48	$824.87	$856.50										
13.02%	13.02%	13.02%	13.02%	13.02%										

2032	2033	2034	2035	2036
$95.42	$93.75	$92.05	$90.34	$88.60

Exhibit DUK-203

Table 3

Energy Basis (MVP): Share of MISO GWh annual energy

Exhibit DUK-004, Indicative Sched. 26-A charges for MVP (as of June 2011) shows CIN zone share is 13.02% DEOK =

Supplier	MWH sales to customers**		DEO+DEK		DEO+DEK
DEO	20,830,286.00	30.26%	36.23%	3.94%	4.72%
DEK	4,116,600	5.98%		0.78%	
DEI	28,258,839	41.05%		5.34%	
WVPA	9,529,250	13.84%		1.80%	
IMPA	6,112,550	8.88%		1.16%	
2010 total sales to Customers	68,847,525.00	100.00%		13.02%	

Source: ** FERC Forms 1 for 2010 (filed April 2011)

DUK region includes:

DEI	Duke Indiana
DEO	Duke Ohio
DEK	Duke Kentucky
WVPA	Wabash Valley Power Assn (WVPA)
IMPA	Indiana Municipal Power Assn (IMPA)

12 CP basis - uses average of 12 monthly coincident peak load shares

1-CP basis - uses ratio of single CP loads

MTEP10

Appendix A-1: *Indicative* MTEP10 Appendix A Project Cost Allocations by Pricing Zones - Subject to Approval for Appendix A

Proj ID	Project Type	Region	ISD	Zone	Total Shared Cost[2]	DUK		
2050	BRP	Central	Jun-10	DUK	12,700,000	11,023,849		
				Central Total	12,700,000	11,023,849		
2322	BRP	East	Dec-11	NIPS	7,417,000			
2916	BRP	East	Jun-13	METC	10,646,000			
3168	MVP[4]	East	Dec-15	ITC	486,663,188	57,483,011		
				East Total	504,726,188	57,483,011		
2793	GIP	West	Mar-10	ATC	1,450,000	32,762		
2837	GIP	West	Dec-09	ATC	100,000	2,259		
3104	GIP	West	Oct-09	GRE	398,000	8,993		
3105	GIP	West	Nov-09	GRE	75,000			
3106	GIP	West	Oct-11	GRE	1,315,000			
3156	BRP	West	Dec-13	OTP	11,699,000			
				West Total	15,037,000	44,014		
				Midwest ISO Total	532,463,188	68,550,874	13,710,175	20%

MTEP10 Appendix A-2: *Indicative* MTEP 10 Transmission Cost Allocation Summaries - Subject to Approval for Appendix A

Table A-2.1: MTEP10 Shared Projects - Estimated Annual Charge for Allocated Project Cost (Cumulative)

Year	DUK	
2010	8,351	Based on Annual Charge Rate of 20%
2011	2,213,573	
2012	2,213,573	
2013	2,213,573	
2014	2,213,573	
2015	13,710,175	Includes MVP Project 3168

Notes:

1. The annual cumulative charges shown above are estimates only which are based on current estimates of project costs, projected in-service dates, and an assumed Annual Charge Rate of 20%. For the purpose of these estimates, project charges were assumed to begin in the project in-service year. The actual allocations/charges will vary depending on the actual project costs, actual in-service dates, and actual Annual Charge Rates.

2. Annual charge for allocated projects costs shown above are a cumulative revenue requirement.

Estimated Annual Charge for Allocated Project Cost = Allocated Project Cost x Annual Charge Rate of Constructing TO

3. Annual charges shown above include charges due to allocations from projects that originate in a zone and those projects that originate in another zone.

4. For those Transmission Owner's that have agreements with Generators to reimburse them 100% of their Network Upgrade costs the 50% that is reimbursed to the generator is not recovered through Schedule 26 and is not included in this table.

5. The 2015 Annual Charges shown do include estimated charges for Proj 3168, which is a Multi-Value Project that will be charged based on actual net withdrawals by Midwest ISO load, export schedules, and through schedules. 2009 Net Withdrawals by Local Balancing Authority have been used to estimate the annual charges in 2015 by Pricing Zone. Note that 2009 withdrawal values used excluded Carve Out Grandfathered Load but not Option A, B, and C which also would not be charged.

MTEP10

Appendix A-3: *Indicative* MTEP 06 thru MTEP 10 Cost Allocation Summaries - Subject to Approval for MTEP 10 Appendix A projets

Table A-3.1: MTEP06 thru 10 Shared Projects - Estimated Annual Charge for Allocated Project Cost (Cumulative)

Year	DUK	
2010	8,747,690	
2011	16,825,989	
2012	18,074,168	
2013	21,650,945	
2014	22,971,358	
2015	35,957,111	Includes MVP Project 3168
2016	36,275,252	Includes MVP Project 3168

1. The annual cumulative charges shown above are estimates only which are based on current estimates of project costs, projected in-service dates, and an assumed Annual Charge Rate of 20%. For the purpose of these estimates, project charges were assumed to begin in the project in-service year. The actual allocations/charges will vary depending on the actual project costs, actual in-service dates, and actual Annual Charge Rates.

2. Annual charge for allocated projects costs shown above are a cumulative revenue requirement.
Estimated Annual Charge for Allocated Project Cost = Allocated Project Cost x Annual Charge Rate of Constructing TO

MTEP10

Table A-3.2: Cost Allocation of MTEP 06 thru 10 Appendix A Projects

	DUK		
Total Shared Project Costs	52,743,898		
Project Cost Allocation to Others	(4,561,488)		
Project Cost Allocation from Others	133,193,848		
Net Project Cost	181,376,258	36,275,252	20%
Net Transmission Plant in Service per Attachment O - June 2010	1,129,794,117		

Exhibit DUK-203

12CP Data by Pricing Zone
Utilizing Information from the June 2011 MISO Attachment O

Pricing Zone	CA Name	Zone No.	12CP (kW)	Pct of Load
ITC Midwest/ ALTW	ALTW	1	2,863,000	3.60%
ATC System	ATC	2	9,787,401	12.32%
Ameren Illinois	AMIL	3A	7,188,902	9.05%
Ameren Missouri	AMMO	3B	7,033,954	8.85%
Cinergy Services (including IMPA & WVPA)	CIN	5	9,771,871	12.30%
City of Columbia, Missouri	CWLD	6	261,000	0.33%
City Water, Light & Power (Springfield, IL)	CWLP	7	291,000	0.37%
Great River Energy	GRE	8	939,895	1.18%
Hoosier Energy	HE	9	561,292	0.71%
International Transmission Company	ITC	10	8,154,000	10.26%
Indianapolis Power & Light	IPL	11	2,459,583	3.10%
Michigan Joint Zone (METC,MPPA,Wolverine)	METC	13	6,463,000	8.13%
Michigan Joint Zone Subzone	MICH13A	13A	609,224	0.77%
Michigan Joint Zone Subzone - GFA	MI13AG	13A	482,724	0.61%
Michigan Joint Zone Subzone - Non-GFA	MI13ANG	13A	126,500	0.16%
Minnesota Power (AC)	MP	14	1,621,738	2.04%
Minnesota Power (DC) **		14a	500,000	0.63%
Montana-Dakota Utilities Co.	MDU	15	618,773	0.78%
NSP Companies *	NSP	16	7,943,924	10.00%
Northern Indiana Public Service Company	NIPS	17	2,801,001	3.53%
Otter Tail Power *	OTP	18	1,167,967	1.47%
Southern Illinois Power Cooperative	SIPC	19	385,917	0.49%
Southern Minnesota Municipal Power Agency	SMMPA	20	240,100	0.30%
Vectren Energy (SIGECO)	VECT	23	966,000	1.22%
MidAmerican Energy Company	MEC	24	3,764,227	4.74%
Muscatine Power and Water	MPW	25	122,171	0.15%
Dairyland Power Cooperative	DPC	26	955,204	1.20%
Big Rivers Electric Corporation	BREC	27	1,368,417	1.72%
Total			79,448,785	100.00%

Note: The total includes the Mich. Joint Subzone GFA and Mich. Joint Subzone Non-GFA twice.
They sum to the Mich. Joint Zone Subzone, which is included in the total as well.

* For RECB purposes NSP has load in the OTP zone, which in not recorded in the OTP zone for Schedule 7, 8 and 9 and is included in the OTP zone for Schedule 26.

** The Minnesota Power DC load is included in the total.

Table 4

Source: 2010 FERC Form 1's filed April, 2011, Page following 401.b (labeled Footnote page 450.1). Contains 12CP load for 2009.

	Peak Load (kw, 12CP)	Pct of Duk Energy	Pct of DUK zone	Pct of non-MVP Shared costs
Duke IN	4,573,333	53.44%	48.35%	5.95%
Duke OH	3,313,500	46.56%	42.12%	5.18%
Duke KY	670,583			
Duke total	8,557,416	100.00%	90.47%	11.13%

	Attach O Net Revenue Req.	Sch 26 Adjust	PZ Net RR	Rate (KW-MO)	Divisor (KW)	visor (MW)	
DUK	$177,429,459	$0	$177,429,459	$ 1.6726	8,840,250	8,840	$1.6726
WVPA	$13,771,920	$0	$13,771,920	$ 2.5122	456,833	457	$2.5122
IMPA	$11,939,326	$0	$11,939,326	$ 2.0956	474,788	475	$2.0956
Joint Transmission System	$203,140,705	$0	$203,140,705		9,771,871	9,772	$1.7324
					90.47%		

Exhibit DUK-203

Deduced annual allocation beginning with first full year in service (2016)
Revenue Requirement (as percent of project cost) is allocated among Transmission Owners in each year.

Percentages of Project Initial Costs, deduced from Source: MISO, 20110712 MSWG Item 03
(First full year in service) **Table 5** www.midwestiso.org/_layouts/miso/ecm/redirect.aspx?i

Year	1	2	3	4	5	6	7	8	9	10	11
Rev Reqt	20.00%	19.66%	19.33%	19.00%	18.67%	18.34%	18.01%	17.68%	17.35%	17.02%	16.68%

Load Ratio & RGOS

Year	**Rev Reqt**	
(2)	5.00%	(CWIP)
(1)	10.00%	(CWIP)
-	15.00%	(CWIP)
1	20.00%	(First full year in service)
2	19.66%	
3	19.33%	
4	19.00%	
5	18.67%	
6	18.34%	
7	18.01%	
8	17.68%	
9	17.35%	
10	17.02%	
11	16.68%	
12	16.35%	
13	16.02%	
14	15.69%	
15	15.36%	
16	15.03%	
17	14.70%	
18	14.37%	
19	14.03%	
20	13.70%	
21	13.37%	
22	13.04%	
23	12.71%	
24	12.38%	
25	12.05%	
26	11.72%	
27	11.39%	
28	11.05%	
29	10.72%	
30	10.39%	
31	10.06%	
32	9.73%	
33	9.40%	
34	9.07%	
35	8.74%	
36	8.41%	

DFAX & Non-RGOS

Year	**Rev Reqt**	
-	10.00%	(CWIP)
1	20.00%	
2	19.66%	
3	19.33%	
4	19.00%	
5	18.67%	
6	18.34%	
7	18.01%	
8	17.68%	
9	17.35%	
10	17.02%	
11	16.68%	
12	16.35%	
13	16.02%	
14	15.69%	
15	15.36%	
16	15.03%	
17	14.70%	
18	14.37%	
19	14.03%	
20	13.70%	
21	13.37%	
22	13.04%	
23	12.71%	
24	12.38%	
25	12.05%	
26	11.72%	
27	11.39%	
28	11.05%	
29	10.72%	
30	10.39%	
31	10.06%	
32	9.73%	
33	9.40%	
34	9.07%	
35	8.74%	
36	8.41%	

; Schedule 26-A Indicative Annual Charges.xlsx

d=106954

12	13	14	15	16	17	18	19	20	21	22	23	24
16.35%	16.02%	15.69%	15.36%	15.03%	14.70%	14.37%	14.03%	13.70%	13.37%	13.04%	12.71%	12.38%

25	26	27	28	29	30	31	32	33	34	35	36
12.05%	11.72%	11.39%	11.05%	10.72%	10.39%	10.06%	9.73%	9.40%	9.07%	8.74%	8.41%

Table 5

Project Service Year	Annual Charge Rate
1	20.00%
2	19.66%
3	19.33%
4	19.00%
5	18.67%
6	18.34%
7	18.01%
8	17.68%
9	17.35%
10	17.02%
11	16.68%
12	16.35%

Project Service Year	Annual Charge Rate
13	16.02%
14	15.69%
15	15.36%
16	15.03%
17	14.70%
18	14.37%
19	14.03%
20	13.70%
21	13.37%
22	13.04%
23	12.71%
24	12.38%

Project Service Year	Annual Charge Rate
25	12.05%
26	11.72%
27	11.39%
28	11.05%
29	10.72%
30	10.39%
31	10.06%
32	9.73%
33	9.40%
34	9.07%
35	8.74%
36	8.41%

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12-CP ratios
42.118%

Table 6

Calendar Year	Years in Service Estimate	Revenue Requirement	CIN zone charges for Non-MVP Projects Through MTEP10	Years in Service Estimate	Revenue Requirement	CIN zone charges for Non-MVP Projects Pending in MTEP11	DEO-DEK share of CIN total (42.1% based on 12-CP ratios)
2012	4	19.00%	$13,885,664			$25,104	$5,859,002
2013	5	18.67%	$16,312,953			$24,702	$6,881,170
2014	6	18.34%	$18,657,090			$38,228	$7,874,182
2015	7	18.01%	$19,557,803			$65,681	$8,265,110
2016	8	17.68%	$19,277,607			$134,915	$8,176,256
2017	9	17.35%	$19,316,181			$283,297	$8,255,000
2018	10	17.02%	$19,030,314	1	20.00%	$351,320	$8,163,247
2019	11	16.68%	$18,744,448	2	19.66%	$420,969	$8,072,180
2020	12	16.35%	$18,458,581	3	19.33%	$414,242	$7,948,944
2021	13	16.02%	$18,172,714	4	19.00%	$407,515	$7,825,708
2022	14	15.69%	$17,797,108	5	18.67%	$400,413	$7,664,517
2023	15	15.36%	$17,421,502	6	18.34%	$393,312	$7,503,326
2024	16	15.03%	$17,045,896	7	18.01%	$386,210	$7,342,136
2025	17	14.70%	$16,670,290	8	17.68%	$379,108	$7,180,945
2026	18	14.37%	$16,294,684	9	17.35%	$372,006	$7,019,755
2027	19	14.03%	$15,919,078	10	17.02%	$364,905	$6,858,564
2028	20	13.70%	$15,543,472	11	16.68%	$357,803	$6,697,373
2029	21	13.37%	$15,167,866	12	16.35%	$350,701	$6,536,183
2030	22	13.04%	$14,792,260	13	16.02%	$343,599	$6,374,992
2031	23	12.71%	$14,416,655	14	15.69%	$336,498	$6,213,802
2032	24	12.38%	$14,041,049	15	15.36%	$329,396	$6,052,611
2033	25	12.05%	$13,665,443	16	15.03%	$322,294	$5,891,420
2034	26	11.72%	$13,289,837	17	14.70%	$315,192	$5,730,230
2035	27	11.39%	$12,914,231	18	14.37%	$308,091	$5,569,039
2036	28	11.05%	$12,538,625	19	14.03%	$300,989	$5,407,848

Source: Excel spreadsheets entitled "Schedule 26 Indicative Annual Charges," "Schedule 26-A Indicative Annual Charges" and "MTEP 11_Appendix A-1.xlsx" (for charges through 2021)
https://www.midwestiso.org/Planning/TransmissionExpansionPlanning/Pages/TransmissionExpansionPlan.aspx.

Exhibit DUK-203

Revenue Share
36.235%

Table 7

Calendar Year	MTEP 2011 Approved plus pending 2011 MVP charges for CIN zone ($M)	DEO-DEK share (36.2% based on GWh ratios)	Calc from Appendix A-3 tab									
2012	$1.15	$414,897	1.15	9.33	24.20	35.68	63.10	68.28	83.52	97.35	107.43	111.55
2013	$9.33	$3,380,428	9.33									
2014	$24.20	$8,770,352	24.20									
2015	$35.68	$12,929,810	35.68									
2016	$63.10	$22,864,414	63.10									
2017	$68.28	$24,742,163	68.28									
2018	$83.52	$30,263,140	83.52									
2019	$97.35	$35,273,887	97.35									
2020	$107.43	$38,925,792	107.43									
2021	$111.55	$40,418,698	111.55									
2022	$110.32	$39,974,579	110.32	109.03	107.68	106.28	104.83	103.35	101.83	100.27		
2023	$109.03	$39,506,641	109.03									
2024	$107.68	$39,017,854	107.68									
2025	$106.28	$38,510,625	106.28									
2026	$104.83	$37,986,927	104.83									
2027	$103.35	$37,448,394	103.35									
2028	$101.83	$36,896,390	101.83									
2029	$100.27	$36,332,064	100.27									
2030	$98.68	$35,756,388	98.68		98.68	97.06	95.42	93.75	92.05	90.34	88.60	
2031	$97.06	$35,170,194	97.06									
2032	$95.42	$34,574,191	95.42									
2033	$93.75	$33,968,993	93.75									
2034	$92.05	$33,355,131	92.05									
2035	$90.34	$32,733,065	90.34									
2036	$88.60	$32,103,200	88.60									

Source: MTEP11 Appendix A-3.3.
https://www.midwestiso.org/Planning/TransmissionExpansionPlanning/Pages/TransmissionExpansionPlan.aspx .

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Table 8

Calendar Year	RGOS MVP Estimate	Non-RGOS Estimate
2012	6,813,913	261,058
2013	13,627,826	789,518
2014	22,713,043	1,317,734
2015	31,647,798	1,845,596
2016	40,432,093	2,372,993
2017	49,065,926	2,899,811
2018	57,549,297	3,425,931
2019	65,882,207	3,951,235
2020	74,064,656	4,475,601
2021	82,096,644	4,998,904
2022	87,706,866	5,521,018
2023	90,895,322	6,041,813
2024	91,662,012	6,561,157
2025	90,006,937	7,078,915
2026	88,351,862	7,594,949
2027	86,696,787	8,109,120
2028	85,041,712	8,621,283
2029	83,386,637	9,131,294
2030	81,731,562	9,639,003
2031	80,076,487	10,144,259
2032	78,421,412	10,646,907
2033	76,766,337	11,146,789
2034	75,111,262	11,643,744
2035	73,456,187	12,137,609
2036	71,801,112	12,628,216

Source: Values are derived from calculations contained in the "Non RGOS" and "Table 9-RGOS MVPs" Tabs.

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DEO-DEK share							Investment ($B)
4.72%	**Table 9**						DEO-DEK Shar
	Scenario 1	**Scenario 2**	**Scenario 3**	**Estimated**			2011
	Native Voltage	**765 kV**	**Native DC**	**Capital Cost**			2012
MISO ($B)	13.868	15.099	12.662	13.876			2013
PJM ($B)	1.952	4.196	2.138	2.762			2014
Shared ($B)	0.484	0.955	6.744	2.728			2015
Total Projects ($B)	16.304	20.250	21.544	19.366			2016
							2017
MISO Shared Percent	50.00%	50.00%	50.00%				2018
50% of Shared	0.242	0.4775	3.372	1.364			2019
Total MISO ($B)	14.110	15.577	16.034	15.240			2020
Total PJM ($B)	2.194	4.6735	5.51	4.126			2021
							2022
Average MISO ($B)	**15.24**						2023
Average PJM ($B)	**4.13**						2024
						14.2	2025
Average MISO ($B) in 2011$	**15.54**					9.2	2026
Average PJM ($B) in 2011$	**4.21**					1.4	2027
							2028
MVP Portfolio 1 ($B)	**4.951**	(Note; This was MISO's earlier estimate, althougth the total has now grown to $5.2 billion.)					2029
		The earlier number is used because it is closer to contemporaneous with the RGOS Report.					2030
Remaining MISO Investments Required (Not in MVP Portfolio 1)	**10.59**						2031
							2032
$	**963.1**	**$M/year for 11 years (assumed costs are spread evenly, 2014 through 2024)**					2033
							2034
Source: RGOS Study, https://www.midwestiso.org/Library/Repository/Study/RGOS/Regional%20Generation%20Outlet%20Study.pdf							2035
							2036

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96
$45,436,519	$45,436,519	$45,436,519	$45,436,519	$45,436,519	$45,436,519	$45,436,519	$45,436,519	$45,436,519	$45,436,519
$2,271,304	$0	$0	$0	$0	$0	$0	$0	$0	$0
$4,542,609	$2,271,304	$0	$0	$0	$0	$0	$0	$0	$0
$6,813,913	$4,542,609	$2,271,304	$0	$0	$0	$0	$0	$0	$0
$9,085,217	$6,813,913	$4,542,609	$2,271,304	$0	$0	$0	$0	$0	$0
$8,934,756	$9,085,217	$6,813,913	$4,542,609	$2,271,304	$0	$0	$0	$0	$0
$8,784,294	$8,934,756	$9,085,217	$6,813,913	$4,542,609	$2,271,304	$0	$0	$0	$0
$8,633,833	$8,784,294	$8,934,756	$9,085,217	$6,813,913	$4,542,609	$2,271,304	$0	$0	$0
$8,483,372	$8,633,833	$8,784,294	$8,934,756	$9,085,217	$6,813,913	$4,542,609	$2,271,304	$0	$0
$8,332,910	$8,483,372	$8,633,833	$8,784,294	$8,934,756	$9,085,217	$6,813,913	$4,542,609	$2,271,304	$0
$8,182,449	$8,332,910	$8,483,372	$8,633,833	$8,784,294	$8,934,756	$9,085,217	$6,813,913	$4,542,609	$2,271,304
$8,031,987	$8,182,449	$8,332,910	$8,483,372	$8,633,833	$8,784,294	$8,934,756	$9,085,217	$6,813,913	$4,542,609
$7,881,526	$8,031,987	$8,182,449	$8,332,910	$8,483,372	$8,633,833	$8,784,294	$8,934,756	$9,085,217	$6,813,913
$7,731,065	$7,881,526	$8,031,987	$8,182,449	$8,332,910	$8,483,372	$8,633,833	$8,784,294	$8,934,756	$9,085,217
$7,580,603	$7,731,065	$7,881,526	$8,031,987	$8,182,449	$8,332,910	$8,483,372	$8,633,833	$8,784,294	$8,934,756
$7,430,142	$7,580,603	$7,731,065	$7,881,526	$8,031,987	$8,182,449	$8,332,910	$8,483,372	$8,633,833	$8,784,294
$7,279,681	$7,430,142	$7,580,603	$7,731,065	$7,881,526	$8,031,987	$8,182,449	$8,332,910	$8,483,372	$8,633,833
$7,129,219	$7,279,681	$7,430,142	$7,580,603	$7,731,065	$7,881,526	$8,031,987	$8,182,449	$8,332,910	$8,483,372
$6,978,758	$7,129,219	$7,279,681	$7,430,142	$7,580,603	$7,731,065	$7,881,526	$8,031,987	$8,182,449	$8,332,910
$6,828,297	$6,978,758	$7,129,219	$7,279,681	$7,430,142	$7,580,603	$7,731,065	$7,881,526	$8,031,987	$8,182,449
$6,677,835	$6,828,297	$6,978,758	$7,129,219	$7,279,681	$7,430,142	$7,580,603	$7,731,065	$7,881,526	$8,031,987
$6,527,374	$6,677,835	$6,828,297	$6,978,758	$7,129,219	$7,279,681	$7,430,142	$7,580,603	$7,731,065	$7,881,526
$6,376,912	$6,527,374	$6,677,835	$6,828,297	$6,978,758	$7,129,219	$7,279,681	$7,430,142	$7,580,603	$7,731,065
$6,226,451	$6,376,912	$6,527,374	$6,677,835	$6,828,297	$6,978,758	$7,129,219	$7,279,681	$7,430,142	$7,580,603
$6,075,990	$6,226,451	$6,376,912	$6,527,374	$6,677,835	$6,828,297	$6,978,758	$7,129,219	$7,279,681	$7,430,142
$5,925,528	$6,075,990	$6,226,451	$6,376,912	$6,527,374	$6,677,835	$6,828,297	$6,978,758	$7,129,219	$7,279,681
$5,775,067	$5,925,528	$6,075,990	$6,226,451	$6,376,912	$6,527,374	$6,677,835	$6,828,297	$6,978,758	$7,129,219

2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	
$0.96	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
$45,436,519	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
													Total
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$2,271,304**
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$6,813,913**
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$13,627,826**
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$22,713,043**
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$31,647,798**
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$40,432,093**
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$49,065,926**
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$57,549,297**
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$65,882,207**
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$74,064,656**
$2,271,304	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$82,096,644**
$4,542,609	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$87,706,866**
$6,813,913	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$90,895,322**
$9,085,217	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$91,662,012**
$8,934,756	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$90,006,937**
$8,784,294	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$88,351,862**
$8,633,833	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$86,696,787**
$8,483,372	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$85,041,712**
$8,332,910	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$83,386,637**
$8,182,449	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$81,731,562**
$8,031,987	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$80,076,487**
$7,881,526	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$78,421,412**
$7,731,065	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$76,766,337**
$7,580,603	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$75,111,262**
$7,430,142	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$73,456,187**
$7,279,681	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$71,801,112**

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	$	4.2	($B In Service 2007 - 201
	$	3.7	($B In Service 2011 - 201
Table 12a	$	616	**Table 10**

Calendar Year	RGOS Allocation ($M)	Existing Load Ratio Project Costs ($M)	DFAX allocated Project Costs ($M)	(Extended) Anticipated DFAX Costs ($M)
2007	0	3	27	
2008	0	51	135	
2009	0	57	82	
2010	0	68	205	
2011	0	93	82	
2012	0	1,250	179	
2013	0	23	496	
2014	383	20	185	
2015	383	5	1,311	
2016	383	1,637	1,445	
2017	383	0	85	627
2018	383	1,128	0	638
2019	383	0	0	649
2020	383	0	0	660
2021	383	0	0	672
2022	383	0	0	683
2023	383	0	0	695
2024	383	0	0	707
2025	0	0	0	720
2026	0	2,100	0	732
2027	0	0	0	745
2028	0	0	0	758
2029	0	0	0	771
2030	0	0	0	785
2031	0	0	0	798
2032	0	0	0	812
2033	0	0	0	826
2034	0	0	0	841
2035	0	0	0	855
2036	0	0	0	870

Source: Values are derived from calculations using inputs contained in other Tabs (Table

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6)

Calendar Year	Total Forecast Load Ratio Project Costs ($M)	Total DFAX allocated Project Costs ($M)	Dayton Share of DFAX	Duke Share of new DFAX	Table 12b Duke Load Ratio Project Costs ($M)	Table 13 DFAX allocated Project Costs
2007	3	27	0.182%	0.301%	0	0.00
2008	51	135	0.182%	0.301%	2	0.00
2009	57	82	0.182%	0.301%	2	0.00
2010	68	205	0.182%	0.301%	2	0.00
2011	93	82	0.182%	0.301%	3	0.00
2012	1,250	179	0.182%	0.301%	44	0.31
2013	23	496	0.182%	0.301%	1	0.63
2014	402	185	0.182%	0.301%	14	0.94
2015	388	1,311	0.182%	0.301%	14	1.26
2016	2,019	1,445	0.182%	0.301%	70	1.57
2017	383	712	0.182%	0.301%	13	1.89
2018	1,511	638	0.182%	0.301%	53	1.92
2019	383	649	0.182%	0.301%	13	1.95
2020	383	660	0.182%	0.301%	13	1.99
2021	383	672	0.182%	0.301%	13	2.02
2022	383	683	0.182%	0.301%	13	2.06
2023	383	695	0.182%	0.301%	13	2.09
2024	383	707	0.182%	0.301%	13	2.13
2025	0	720	0.182%	0.301%	0	2.17
2026	2,100	732	0.182%	0.301%	73	2.20
2027	0	745	0.182%	0.301%	0.00	2.24
2028	0	758	0.182%	0.301%	0.00	2.28
2029	0	771	0.182%	0.301%	0.00	2.32
2030	0	785	0.182%	0.301%	0.00	2.36
2031	0	798	0.182%	0.301%	0.00	2.40
2032	0	812	0.182%	0.301%	0.00	2.44
2033	0	826	0.182%	0.301%	0.00	2.49
2034	0	841	0.182%	0.301%	0.00	2.53
2035	0	855	0.182%	0.301%	0.00	2.57
2036	0	870	0.182%	0.301%	0.00	2.62
	10,642.950	**19,078.532**			**371.241**	**49.388**

5, Table 9, Allocation % Summary w calcs, Assumptions)

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Load Ratio Annual Cost **Table 14a**

Calendar Year	2012	2013	2014	2015	2016	2017	2018	2019	2020
2007	0.021	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2008	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
2009	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3
2010	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4
2011	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
2012	6.5	8.7	8.6	8.4	8.3	8.1	8.0	7.8	7.7
2013	0.1	0.1	0.2	0.2	0.2	0.2	0.1	0.1	0.1
2014	0.7	1.4	2.1	2.8	2.8	2.7	2.7	2.6	2.6
2015	0.0	0.7	1.4	2.0	2.7	2.7	2.6	2.6	2.5
2016	0.0	0.0	3.5	7.0	10.6	14.1	13.9	13.6	13.4
2017	0.0	0.0	0.0	0.7	1.3	2.0	2.7	2.6	2.6
2018	0.0	0.0	0.0	0.0	2.6	5.3	7.9	10.5	10.4
2019	0.0	0.0	0.0	0.0	0.0	0.7	1.3	2.0	2.7
2020	0.0	0.0	0.0	0.0	0.0	0.0	0.7	1.3	2.0
2021	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	1.3
2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7
2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2029	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2030	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2032	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2033	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2034	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2035	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2036	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	9.177	**12.742**	**17.505**	**22.893**	**30.166**	**37.386**	**41.518**	**45.606**	**47.553**

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Calendar Year	2021	2022	2023	2024	2025	2026	2027	2028	2029
2007	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2008	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2
2009	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
2010	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3
2011	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
2012	7.6	7.4	7.3	7.1	7.0	6.8	6.7	6.6	6.4
2013	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
2014	2.5	2.5	2.4	2.4	2.3	2.3	2.2	2.2	2.2
2015	2.5	2.4	2.4	2.3	2.3	2.3	2.2	2.2	2.1
2016	13.2	12.9	12.7	12.5	12.2	12.0	11.8	11.5	11.3
2017	2.5	2.5	2.4	2.4	2.4	2.3	2.3	2.2	2.2
2018	10.2	10.0	9.8	9.7	9.5	9.3	9.1	9.0	8.8
2019	2.6	2.6	2.5	2.5	2.4	2.4	2.4	2.3	2.3
2020	2.7	2.6	2.6	2.5	2.5	2.4	2.4	2.4	2.3
2021	2.0	2.7	2.6	2.6	2.5	2.5	2.4	2.4	2.4
2022	1.3	2.0	2.7	2.6	2.6	2.5	2.5	2.4	2.4
2023	0.7	1.3	2.0	2.7	2.6	2.6	2.5	2.5	2.4
2024	0.0	0.7	1.3	2.0	2.7	2.6	2.6	2.5	2.5
2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2026	0.0	0.0	0.0	3.7	7.3	11.0	14.6	14.4	14.2
2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2029	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2030	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2032	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2033	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2034	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2035	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2036	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	49.456	**51.314**	**52.461**	**56.558**	**59.945**	**62.620**	**65.294**	**64.065**	**62.836**

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Calendar Year	2030	2031	2032	2033	2034	2035	2036
2007	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2008	0.2	0.2	0.2	0.2	0.2	0.2	0.2
2009	0.3	0.3	0.3	0.2	0.2	0.2	0.2
2010	0.3	0.3	0.3	0.3	0.3	0.3	0.3
2011	0.5	0.4	0.4	0.4	0.4	0.4	0.4
2012	6.3	6.1	6.0	5.8	5.7	5.5	5.4
2013	0.1	0.1	0.1	0.1	0.1	0.1	0.1
2014	2.1	2.1	2.0	2.0	1.9	1.9	1.8
2015	2.1	2.0	2.0	1.9	1.9	1.9	1.8
2016	11.1	10.8	10.6	10.4	10.1	9.9	9.7
2017	2.1	2.1	2.0	2.0	2.0	1.9	1.9
2018	8.6	8.4	8.3	8.1	7.9	7.7	7.6
2019	2.2	2.2	2.1	2.1	2.0	2.0	2.0
2020	2.3	2.2	2.2	2.1	2.1	2.0	2.0
2021	2.3	2.3	2.2	2.2	2.1	2.1	2.0
2022	2.4	2.3	2.3	2.2	2.2	2.1	2.1
2023	2.4	2.4	2.3	2.3	2.2	2.2	2.1
2024	2.4	2.4	2.4	2.3	2.3	2.2	2.2
2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2026	13.9	13.7	13.4	13.2	12.9	12.7	12.5
2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2029	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2030	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2032	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2033	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2034	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2035	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2036	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	61.606	**60.377**	**59.148**	**57.918**	**56.689**	**55.460**	**54.230**

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DFAX Annual Cost

Table 14b

Calendar Year	2012	2013	2014	2015	2016	2017	2018	2019	2020
2007	0.000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2008	0.000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2009	0.000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2010	0.000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2011	0.000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2012	0.031	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
2013	0.000	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
2014	0.000	0.0	0.1	0.2	0.2	0.2	0.2	0.2	0.2
2015	0.000	0.0	0.0	0.1	0.3	0.2	0.2	0.2	0.2
2016	0.000	0.0	0.0	0.0	0.2	0.3	0.3	0.3	0.3
2017	0.000	0.0	0.0	0.0	0.0	0.2	0.4	0.4	0.4
2018	0.000	0.0	0.0	0.0	0.0	0.0	0.2	0.4	0.4
2019	0.000	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.4
2020	0.000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
2021	0.000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2022	0.000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2023	0.000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2024	0.000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2025	0.000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2026	0.000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2027	0.000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2028	0.000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2029	0.000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2030	0.000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2031	0.000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2032	0.000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2033	0.000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2034	0.000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2035	0.000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2036	0.000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.031	**0.126**	**0.282**	**0.499**	**0.776**	**1.111**	**1.476**	**1.841**	**2.207**

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Calendar Year	2021	2022	2023	2024	2025	2026	2027	2028	2029
2007	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2008	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2009	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2010	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2011	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2012	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0
2013	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
2014	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1
2015	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
2016	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
2017	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3
2018	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3
2019	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3
2020	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.3
2021	0.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
2022	0.0	0.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4
2023	0.0	0.0	0.2	0.4	0.4	0.4	0.4	0.4	0.4
2024	0.0	0.0	0.0	0.2	0.4	0.4	0.4	0.4	0.4
2025	0.0	0.0	0.0	0.0	0.2	0.4	0.4	0.4	0.4
2026	0.0	0.0	0.0	0.0	0.0	0.2	0.4	0.4	0.4
2027	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.4	0.4
2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.5
2029	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
2030	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2032	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2033	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2034	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2035	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2036	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2.573	**2.939**	**3.306**	**3.673**	**4.041**	**4.409**	**4.778**	**5.147**	**5.516**

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Calendar Year	2030	2031	2032	2033	2034	2035	2036
2007	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2008	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2009	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2010	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2011	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2012	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2013	0.1	0.1	0.1	0.1	0.1	0.1	0.1
2014	0.1	0.1	0.1	0.1	0.1	0.1	0.1
2015	0.2	0.2	0.2	0.2	0.2	0.2	0.2
2016	0.2	0.2	0.2	0.2	0.2	0.2	0.2
2017	0.3	0.3	0.3	0.3	0.3	0.3	0.3
2018	0.3	0.3	0.3	0.3	0.3	0.3	0.3
2019	0.3	0.3	0.3	0.3	0.3	0.3	0.3
2020	0.3	0.3	0.3	0.3	0.3	0.3	0.3
2021	0.4	0.3	0.3	0.3	0.3	0.3	0.3
2022	0.4	0.4	0.3	0.3	0.3	0.3	0.3
2023	0.4	0.4	0.4	0.4	0.3	0.3	0.3
2024	0.4	0.4	0.4	0.4	0.4	0.4	0.3
2025	0.4	0.4	0.4	0.4	0.4	0.4	0.4
2026	0.4	0.4	0.4	0.4	0.4	0.4	0.4
2027	0.4	0.4	0.4	0.4	0.4	0.4	0.4
2028	0.4	0.4	0.4	0.4	0.4	0.4	0.4
2029	0.5	0.5	0.4	0.4	0.4	0.4	0.4
2030	0.2	0.5	0.5	0.5	0.4	0.4	0.4
2031	0.0	0.2	0.5	0.5	0.5	0.5	0.4
2032	0.0	0.0	0.2	0.5	0.5	0.5	0.5
2033	0.0	0.0	0.0	0.2	0.5	0.5	0.5
2034	0.0	0.0	0.0	0.0	0.3	0.5	0.5
2035	0.0	0.0	0.0	0.0	0.0	0.3	0.5
2036	0.0	0.0	0.0	0.0	0.0	0.0	0.3
	5.886	**6.256**	**6.627**	**6.998**	**7.370**	**7.742**	**8.115**

Exhibit DUK-203

http://www.pjm.com/~/media/documents/ferc/2011-filings/20110104-er11-2622-000.ashx

● Cost Allocation

	Transmission Zone	2010 Peak Load (MW)	Allocation (%)
	AEC	2,936.30	2.09%
	AEP	23,492.30	16.70%
	APS	8,479.60	6.03%
	BGE	6,923.90	4.92%
	ComEd	21,914.50	15.58%
	Dayton	3,397.80	2.41%
	DL	2,888.70	2.05%
	DPL	4,055.10	2.88%
	Dominion	19,140.00	13.61%
	JCPL	6,420.10	4.56%
	ME	2,940.30	2.09%
	NEPTUNE*	682.7	0.49%
	PECO	8,865.00	6.30%
	PENELEC	2,970.40	2.11%
	PEPCO	6,654.20	4.73%
	PPL	7,411.00	5.27%
	PSEG	10,761.40	7.65%
	RECO	430.4	0.31%
	ECP**	306.35	0.22%
		140,670	100%
(from FERC Form 1, p.400)	Add ATSI	13195	
(from FERC Form 1, p.400)	Add DEO	5561	
	Total	153,865	
	DEO (+DEK) share	3.614%	
	Dayton	2.208%	
	non-Duke	96.386%	

*Neptune Regional Transmission System, LLC
**East Coast Power, LLC

	2010 Peak Load (MW)	Load Ratio	Load Growth Rate
PJM RTO	153,865	96.39%	1.74%
Dayton	3,368	2.21%	1.30%
Duke	5,561	3.61%	1.30%
Duke	3,182	0.020261	
Duke	5,561		
PJM Peak	142,390		
ATSI Peak	12,634		
Duke Peak	5,242		3.27%
	160,266		

Table 11 - With ATSI, DEO and DEK

http://www.pjm.com/~/media/documents/ferc/2011-filings/20110104-er11-2622-000.ashx

● Cost Allocation

Transmission Zone	2010 Peak Load (MW)	Allocation (%)
Atlantic City Elec. Co. (AEC)	2,936	1.84%
American Elec. Power (AEP)	23,492	14.74%
Allegheny Energy (APS)	8,480	5.32%
Baltimore Gas & Elec. (BGE)	6,924	4.34%
Commonwealth Edison (ComEd)	21,915	13.75%
Dayton Power & Light	3,398	2.13%
Duquesne Light Co. (DL)	2,889	1.81%
DelMarVa Power & Light (DPL)	4,055	2.54%
Dominion Virginia Power	19,140	12.01%
Jersey City Power & Light (JCPL)	6,420	4.03%
Metropolitan Edison (ME)	2,940	1.84%
NEPTUNE Regional Trans. System*	683	0.43%
PECO Energy Co.	8,865	5.56%
Penn. Elec. Co (PENELEC)	2,970	1.86%
Potomac Elec. Power Co. (PEPCO)	6,654	4.17%
PPL Electric Utilities Corp. (PPL)	7,411	4.65%
Public Svc. Elec. & Gas Co. (PSEG)	10,761	6.75%
Rockland Elec. Co. (RECO)	430	0.27%
East Cost Power (ECP)*	306	0.19%
American Trans. System Inc. (ATSI)	13,195	8.28%
Duke Energy OH-KY (DEOK)	**5,561**	**3.49%**
PJM Total	**159,426**	**100%**

* ECP and Neptune are merchant transmission facilities assessed based on annual peak load.
Sources: (excluding DEOK and ATSI): PJM Tariff, amendments to Schedule 12-Appendix filed with FERC January 4, 2011, available at
http://www.pjm.com/~/media/documents/ferc/2011-filings/20110104-er11-2622-000.ashx
DEOK and ATSI Peak loads taken from DEO and ATSI 2010 FERC filings (Form 1, p. 400).

*Neptune Regional Transmission System, LLC
**East Coast Power, LLC

Exhibit DUK-203

RGOS Assumptions	
MISO Percent Shared RGOS Projects	50%
2011 PJM Inflation	2%
RGOS Years	11
RGOS Start Year	2014

MISO - Part III Calculations	
Multiplier for non-MVP projects	1.00
Multiplier pending MVP projects	1.00

MISO - Part IV and V Calculations	
Multiplier for remaining MVPs	1.00
MISO Peak Load Growth	0.81%

PJM	
Peak Load Growth	1.74%
DEOK Peak Load Growth	1.30%
Dayton Peak Load Growth	1.30%
PJM 2010 Peak Load	153,865
DEOK 2010 Peak Load	5,561
Dayton 2010 Peak Load	3,368

Financial Assumptions	
Discount Rate	5%

Sources: Peak Loads from FERC Form 1 filings
Load growth rates from MTEP and RTEP filings
(DEOK assumed to mirror nearby Dayton)
Other values assumed

Exhibit DUK-203
MISO Costs for non-MVP projects

MTEP10 Shared costs for non-MVP projects* ($M)	$49
Assumed non-MVP level for 2012	$50
DEO-DEK share	5.18%
Duke Share of Non-RGOS Projects ($M)	**$2.59**

Escalate annual costs with MISO projected growth rate for peak load
First full year in service assumed one year after investment year

*Source: MTEP 10, Appendix A-1

Share of Project Costs	Charge Year	Charges by MTEP Investment Year 2012	2013	2014	2015
2.61	2012	$261,058	$0	$0	$0
2.63	2013	$526,345	$263,173	$0	$0
2.65	2014	$521,821	$530,608	$265,304	$0
2.68	2015	$517,189	$526,048	$534,906	$267,453
2.70	2016	$512,448	$521,378	$530,309	$539,239
2.72	2017	$507,596	$516,599	$525,601	$534,604
2.74	2018	$502,632	$511,707	$520,783	$529,859
2.76	2019	$497,554	$506,703	$515,852	$525,001
2.79	2020	$492,361	$501,584	$510,807	$520,031
2.81	2021	$487,051	$496,349	$505,647	$514,945
2.83	2022	$481,623	$490,996	$500,369	$509,743
2.85	2023	$476,075	$485,524	$494,973	$504,422
2.88	2024	$470,405	$479,931	$489,457	$498,982
2.90	2025	$464,613	$474,215	$483,818	$493,421
2.92	2026	$458,695	$468,376	$478,057	$487,737
2.95	2027	$452,651	$462,411	$472,170	$481,929
2.97	2028	$446,480	$456,318	$466,156	$475,994
3.00	2029	$440,178	$450,096	$460,014	$469,932
3.02	2030	$433,746	$443,744	$453,742	$463,740
3.04	2031	$427,180	$437,259	$447,338	$457,417
3.07	2032	$420,479	$430,640	$440,801	$450,962
3.09	2033	$413,642	$423,885	$434,128	$444,371
3.12	2034	$406,666	$416,992	$427,319	$437,645
3.14	2035	$399,551	$409,960	$420,370	$430,780
3.17	2036	$392,293	$402,787	$413,281	$423,775

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$269,620	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$543,607	$271,803	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$538,934	$548,010	$274,005	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$534,151	$543,300	$552,449	$276,225	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$529,254	$538,477	$547,701	$556,924	$278,462	$0	$0	$0	$0	$0	$0	$0	$0	$0
$524,243	$533,541	$542,839	$552,137	$561,435	$280,717	$0	$0	$0	$0	$0	$0	$0	$0
$519,116	$528,489	$537,863	$547,236	$556,609	$565,983	$282,991	$0	$0	$0	$0	$0	$0	$0
$513,872	$523,321	$532,770	$542,219	$551,669	$561,118	$570,567	$285,284	$0	$0	$0	$0	$0	$0
$508,508	$518,034	$527,560	$537,086	$546,611	$556,137	$565,663	$575,189	$287,594	$0	$0	$0	$0	$0
$503,024	$512,627	$522,230	$531,833	$541,436	$551,039	$560,642	$570,245	$579,848	$289,924	$0	$0	$0	$0
$497,418	$507,099	$516,779	$526,460	$536,141	$545,822	$555,502	$565,183	$574,864	$584,544	$292,272	$0	$0	$0
$491,688	$501,447	$511,206	$520,965	$530,724	$540,484	$550,243	$560,002	$569,761	$579,520	$589,279	$294,640	$0	$0
$485,832	$495,671	$505,509	$515,347	$525,185	$535,023	$544,862	$554,700	$564,538	$574,376	$584,214	$594,052	$297,026	$0
$479,850	$489,768	$499,686	$509,603	$519,521	$529,439	$539,357	$549,275	$559,193	$569,111	$579,028	$588,946	$598,864	$299,432
$473,738	$483,737	$493,735	$503,733	$513,731	$523,729	$533,728	$543,726	$553,724	$563,722	$573,720	$583,719	$593,717	$603,715
$467,497	$477,576	$487,655	$497,734	$507,813	$517,892	$527,972	$538,051	$548,130	$558,209	$568,288	$578,368	$588,447	$598,526
$461,122	$471,283	$481,444	$491,605	$501,766	$511,927	$522,087	$532,248	$542,409	$552,570	$562,731	$572,891	$583,052	$593,213
$454,614	$464,858	$475,101	$485,344	$495,587	$505,830	$516,073	$526,316	$536,559	$546,803	$557,046	$567,289	$577,532	$587,775
$447,971	$458,297	$468,623	$478,949	$489,275	$499,601	$509,927	$520,253	$530,579	$540,906	$551,232	$561,558	$571,884	$582,210
$441,190	$451,599	$462,009	$472,419	$482,828	$493,238	$503,648	$514,058	$524,467	$534,877	$545,287	$555,697	$566,106	$576,516
$434,269	$444,763	$455,257	$465,751	$476,245	$486,739	$497,233	$507,727	$518,222	$528,716	$539,210	$549,704	$560,198	$570,692

2030	2031	2032	2033	2034	2035	2036	**Total**
$0	$0	$0	$0	$0	$0	$0	**$261,058**
$0	$0	$0	$0	$0	$0	$0	**$789,518**
$0	$0	$0	$0	$0	$0	$0	**$1,317,734**
$0	$0	$0	$0	$0	$0	$0	**$1,845,596**
$0	$0	$0	$0	$0	$0	$0	**$2,372,993**
$0	$0	$0	$0	$0	$0	$0	**$2,899,811**
$0	$0	$0	$0	$0	$0	$0	**$3,425,931**
$0	$0	$0	$0	$0	$0	$0	**$3,951,235**
$0	$0	$0	$0	$0	$0	$0	**$4,475,601**
$0	$0	$0	$0	$0	$0	$0	**$4,998,904**
$0	$0	$0	$0	$0	$0	$0	**$5,521,018**
$0	$0	$0	$0	$0	$0	$0	**$6,041,813**
$0	$0	$0	$0	$0	$0	$0	**$6,561,157**
$0	$0	$0	$0	$0	$0	$0	**$7,078,915**
$0	$0	$0	$0	$0	$0	$0	**$7,594,949**
$0	$0	$0	$0	$0	$0	$0	**$8,109,120**
$0	$0	$0	$0	$0	$0	$0	**$8,621,283**
$0	$0	$0	$0	$0	$0	$0	**$9,131,294**
$301,857	$0	$0	$0	$0	$0	$0	**$9,639,003**
$608,605	$304,303	$0	$0	$0	$0	$0	**$10,144,259**
$603,374	$613,535	$306,767	$0	$0	$0	$0	**$10,646,907**
$598,018	$608,261	$618,504	$309,252	$0	$0	$0	**$11,146,789**
$592,536	$602,862	$613,188	$623,514	$311,757	$0	$0	**$11,643,744**
$586,926	$597,336	$607,745	$618,155	$628,565	$314,282	$0	**$12,137,609**
$581,186	$591,680	$602,174	$612,668	$623,162	$633,656	$316,828	**$12,628,216**

	A	B	C	D	E	F	G	H	I	J	K
1		**Exhibit DUK-203**									
2											
3											
4		Source and Disclaimer: Data valid as of June 2011									
5	This document is a summary of the RTEP cost allocation data contained in Schedule 12										
6	of the PJM Open Acess Transmission Tariff (OATT.) Schedule 12 of the OATT contains the official cost allocations and this document should be used only as a reference. See										
7	links at http://www.pjm.com/committees-and-groups/committees/teac.aspx#6										
8											

		Column Labels					
10		0		1		Total Sum o	Total Sum o
11	Row Labels	Sum of Cost Estimate ($M)	Sum of Projects	Sum of Cost	Sum of Projects Attributed to one enti		
12	2005	0.00000	2.00000			0.00000	2.00000
13	2006	12.103	12			12.103	12
14	2007	180.3	36	3.2	0	183.5	36
15	2008	294.314	45	50.7	0	345.014	45
16	2009	597.2965	69	56.626	0	653.9225	69
17	2010	422.228775	117	68.365	0	490.59378	117
18	2011	428.043	143	93.239	0	521.282	143
19	2012	704.1452	204	1249.625	0	1953.7702	204
20	2013	1284.80704	114	23	0	1307.807	114
21	2014	908.0961	111	19.795	0	927.8911	111
22	2015	1939.531	133	5.2	0	1944.731	133
23	2016	2062.242	121	1636.75	0	3698.992	121
24	2017	100.03	4			100.03	4
25	2018	8.559	2	1128.1	0	1136.659	2
26	2026			2100	0	2100	0
27	**Grand Total**	**8941.695615**	**1113**	**6434.6**	**0**	**15376.296**	**1113**

	Row Labels	Sum of Load Ratio Project Costs	Sum of One Enti	Sum of DFA	Sum of Dayto
31	2005	0	0	0	0
32	2006	0	12.103	0	0
33	2007	3.2	152.93	27.37	0
34	2008	50.7	159.574	134.74	0
35	2009	56.626	514.9765	82.32	0
36	2010	68.365	217.147775	205.081	0
37	2011	93.239	345.843	82.2	0
38	2012	1249.625	525.5882	178.557	0
39	2013	23	788.85204	495.955	0.39389
40	2014	19.795	722.9861	185.11	0
41	2015	5.2	628.706	1310.825	5.1517
42	2016	1636.75	617.217	1445.025	2.1672
43	2017	0	14.93	85.1	0
44	2018	1128.1	8.559	0	0
45	2026	2100	0	0	0
46	**Grand Total**	**6434.6**	**4709.412615**	**4232.283**	**7.71279**

51 **Exhibit DUK-203**

53 Source and Disclaimer: Data valid as of June 2011

54 This document is a summary of the RTEP cost allocation data contained in Schedule 12

55 of the PJM Open Acess Transmission Tariff (OATT.) Schedule 12 of the OATT contains

56 the official cost allocations and this document should be used only as a reference. See

57 links at http://www.pjm.com/committees-and-groups/committees/teac.aspx#6

58	Upgrade ID	Description	TO	AEC	AEP	APS	BGE	ComEd	Dayton	DL	DPL
59	b0025	Convert the Bergen-Leonia 138 kV circuit to 230 kV circ	PSEG								
60	b0074	Rebuild 12 miles of S. Akron – Berks 230 kV to double c	PPL								
61	b0090	Add 150 MVAR capacitor at Camden 230 kV	PSEG								
62	b0121	Add 150 MVAR capacitor at Aldene 230 kV	PSEG								
63	b0122	Bypass the Essex 138 kV series reactors	PSEG								
64	b0123	Add 180 MVAR of distributed capacitors. 65 MVAR in nc	JCPL								
65	b0124.1	Add a 72 MVAR capacitor at Kittatinny 230 kV	JCPL								
66	b0124.2	Add a 130 MVAR capacitor at Manitou 230 kV	JCPL								
67	b0125	Add Special Protection Scheme at Bridgewater to autom	PSEG								
68	b0126	Replace wavetrap on Branchburg – Flagtown 230 kV	PSEG								
69	b0127	Replace terminal equipment to increase Brunswick – Ad	PSEG								
70	b0129	Replace wavetrap on Flagtown – Somerville 230 kV	PSEG								
71	b0130	Replace all derated Branchburg 500/230 kV transformer	PSEG	0.01							
72	b0132	Reconductor Portland – Kittatinny 230 kV with 1590 ACS	JCPL								

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11	**Row Labels**
12	2005
13	2006
14	2007
15	2008
16	2009
17	2010
18	2011
19	2012
20	2013
21	2014
22	2015
23	2016
24	2017
25	2018
26	2026
27	**Grand Total**
28	
29	
30	**Row Labels**
31	2005
32	2006
33	2007
34	2008
35	2009
36	2010
37	2011
38	2012
39	2013
40	2014
41	2015
42	2016
43	2017
44	2018
45	2026
46	**Grand Total**
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	A	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
58	Upgrade ID	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL	PSEG	RE	UGI	Cost Estimate ($M)
59	b0025											1.00			$25.00
60	b0074										1.00				$48.27
61	b0090											1.00			$1.25
62	b0121											1.00			$1.25
63	b0122											1.00			$0.50
64	b0123				1.00										$2.70
65	b0124.1				1.00										$0.80
66	b0124.2				1.00										$1.00
67	b0125											1.00			$0.10
68	b0126											1.00			$0.50
69	b0127											1.00			$0.50
70	b0129											1.00			$0.50
71	b0130				0.48							0.51			$20.00
72	b0132				1.00										$4.40

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21	2014													
22	2015													
23	2016													
24	2017							THIS PART OF THE EXCEL SPREADSHEET IS BLANK.						
25	2018													
26	2026													
27	**Grand Total**													
28														
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30	Row Labels													
31	2005													
32	2006													
33	2007													
34	2008													
35	2009													
36	2010													
37	2011													
38	2012													
39	2013													
40	2014													
41	2015													
42	2016													
43	2017													
44	2018													
45	2026													
46	**Grand Total**													
47														
48														
49														
50														
51						****** Disclaimer ******								
52						* Data valid as of June 2011								
53						This document is a summary of the RTEP cost allocation								
54	This documen					data contained in Schedule 12 of the PJM Open Acess								
55	of the PJM Op					Transmission Tariff (OATT.) Schedule 12 of the OATT								
56	the official cos					contains the official cost allocations and this document								
57	links at htt					should be used only as a reference								
58	Upgrade ID	Project ID	Upgrade Date In-Service	Project Average In-Service Date	Date to use	Upgrade Source	Project Source	Project Status	Projects Allocated by Load	Projects Attributed to one entity	Projects Attributed to Dayton entity	Year In Service Override	First Full Year in Service	Project Age
59	b0025	b0025	5/23/2008	5/23/2008	5/23/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
60	b0074	b0074	5/2/2008	5/2/2008	5/2/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
61	b0090	b0090	7/14/2005	7/14/2005	7/14/2005	Post-2005	Post-2005	IS	0	1	0		2006	5
62	b0121	b0121	7/7/2005	7/7/2005	7/7/2005	Post-2005	Post-2005	IS	0	1	0		2006	5
63	b0122	b0122	5/14/2005	5/14/2005	5/14/2005	Post-2005	Post-2005	IS	0	1	0		2006	5
64	b0123	b0123	8/1/2005	8/1/2005	8/1/2005	Post-2005	Post-2005	IS	0	1	0		2006	5
65	b0124.1	b0124	8/10/2005	12/9/2005	8/10/2005	Post-2005	Post-2005	IS	0	1	0		2006	5
66	b0124.2	b0124	4/10/2006	12/9/2005	4/10/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
67	b0125	b0125	7/29/2005	7/29/2005	7/29/2005	Post-2005	Post-2005	IS	0	1	0		2006	5
68	b0126	b0126	5/24/2005	5/24/2005	5/24/2005	Post-2005	Post-2005	IS	0	1	0		2006	5
69	b0127	b0127	5/28/2005	5/28/2005	5/28/2005	Post-2005	Post-2005	IS	0	1	0		2006	5
70	b0129	b0129	5/25/2006	5/25/2006	5/25/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
71	b0130	b0130	5/19/2006	5/19/2006	5/19/2006	Post-2005	Post-2005	IS	0	0	0		2007	4
72	b0132	b0132	5/31/2007	8/30/2009	5/31/2007	Post-2005	Planned	IS	0	1	0		2008	3

	A	AM	AN	AO	AP	AQ	AR	AS
1								
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5	This documen							
	of the PJM Op							
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7	links at htt							
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11	**Row Labels**							
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20	2013							
21	2014							
22	2015	THIS PART OF THE EXCEL SPREADSHEET IS BLANK.						
23	2016							
24	2017							
25	2018							
26	2026							
27	**Grand Total**							
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30	**Row Labels**							
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58	**Upgrade ID**	Load Ratio Project Costs	One Entity Project Costs	DFAX allocated Project Costs	Dayton DFAX Project Costs			
59	b0025	0	25	0	0			
60	b0074	0	48.268	0	0			
61	b0090	0	1.25	0	0			
62	b0121	0	1.25	0	0			
63	b0122	0	0.5	0	0			
64	b0123	0	2.7	0	0			
65	b0124.1	0	0.8	0	0			
66	b0124.2	0	1	0	0			
67	b0125	0	0.1	0	0			
68	b0126	0	0.5	0	0			
69	b0127	0	0.5	0	0			
70	b0129	0	0.5	0	0			
71	b0130	0	0	20	0			
72	b0132	0	4.4	0	0			

	A	B	C	D	E	F	G	H	I	J	K
58	Upgrade ID	Description	TO	AEC	AEP	APS	BGE	ComEd	Dayton	DL	DPL
73	b0134	Upgrade or Retension PSEG portion of Kittatinny – New	PSEG								
74	b0135	Build new Cumberland - Dennis 230 kV circuit which rep	AEC	1.00							
75	b0136	Install Dennis 230/138 kV transformer, Dennis 150 MVA	AEC	1.00							
76	b0137	Build new Dennis – Corson 138 kV circuit	AEC	1.00							
77	b0138	Install Cardiff 230/138 kV transformer and a 50 MVAR c	AEC	1.00							
78	b0139	Build new Cardiff – Lewis 138 kV circuit	AEC	1.00							
79	b0140	Reconductor Laurel – Woodstown 69 kV	AEC	1.00							
80	b0141	Reconductor Monroe – North Central 69 kV	AEC	1.00							
81	b0142	Reconductor Landis – Minotola 138 kV	AEC	1.00							
82	b0143	Reconductor Beckett – Paulsboro 69 kV	AEC	1.00							
83	b0144.1	Build new Red Lion – Milford – Indian River 230 kV circu	DPL								1.00
84	b0144.2	Indian River Sub – 230 kV Terminal Position	DPL								1.00
85	b0144.3	Red Lion Sub – 230 kV Terminal Position	DPL								1.00
86	b0144.4	Milford Sub – (2) 230 kV Terminal Positions	DPL								1.00
87	b0144.5	Indian River – 138 kV Transmission Line to AT-20	DPL								1.00
88	b0144.6	Indian River – 138 & 69 kV Transmission Ckts. Undergro	DPL								1.00
89	b0144.7	Indian River – (2) 230 kV bus ties	DPL								1.00
90	b0145	Build new Essex – Aldene 230 kV cable connected throu	PSEG								
91	b0146	Installation of (2) new 230 kV circuit breakers at Quince	PEPCO								
92	b0148	Re-rate Glasgow – Mt. Pleasant 138 kV and North Seafo	DPL								1.00
93	b0149	Complete structure work to increase rating of Cheswold	DPL								1.00
94	b0152	Add (2) 230 kV Breakers at High Ridge and install two N	BGE				1.00				
95	b0157	Add 100MVAR capacitor at West Orange 138kV substat	PSEG								
96	b0158	Close the Sunnymeade "C" and "F" bus tie	PSEG								
97	b0159	Make the Bayonne reactor permanent installation	PSEG								
98	b0161	Install 230/138kV transformer at Metuchen substation	PSEG								
99	b0162	Upgrade the Edison – Meadow Rd 138kV “Q” circuit	PSEG								
100	b0163	Upgrade the Edison – Meadow Rd 138kV “R” circuit	PSEG								
101	b0164	Reconductor Wolfs - Oswego 138kV with 636 ACSS	ComEd					1.00			
102	b0169	Build a new 230 kV section from Branchburg – Flagtown	PSEG	0.02							
103	b0170	Reconductor the Flagtown-Somerville-Bridgewater 230 k	PSEG								
104	b0171.1	Replace two 500 kV circuit breakers and two wave traps	PECO	0.02	0.17	0.06	0.05	0.16	0.02	0.02	0.03
105	b0171.2	Replace wavetrap at Hosensack 500kV substation to inc	PPL	0.02	0.18	0.06	0.05	0.16	0.02	0.02	0.03
106	b0172.1	Replace wave trap at Alburtis 500kV substation	PPL	0.02	0.18	0.06	0.05	0.16	0.02	0.02	0.03
107	b0172.2	Replace wave trap at Branchburg 500kV substation	PSEG	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
108	b0173	Replace a line trap at Newton 230kV substation for the K	JCPL								
109	b0174	Upgrade the Portland – Greystone 230kV circuit	JCPL								
110	b0180	Replace Whitpain 230kV circuit breaker #165	PECO								
111	b0181	Replace Whitpain 230kV circuit breaker #J105	PECO								
112	b0182	Upgrade Plymouth Meeting 230kV circuit breaker #125	PECO								
113	b0184	Replace Hudson 230kV circuit breakers #1-2	PSEG								
114	b0185	Replace Deans 230kV circuit breakers #9-10	PSEG								
115	b0186	Replace Essex 230kV circuit breaker #5-6	PSEG								
116	b0199	Greystone 230kV substation: Change Tap of limiting CT	JCPL								
117	b0200	Greystone 230kV substation: Change Tap of limiting CT	JCPL								
118	b0201	Branchburg substation: replace wave trap on Branchbur	PSEG								
119	b0202	Kittatinny 230kV substation: Replace line trap on Kittatir	JCPL								
120	b0203	Smithburg 230kV Substation: Replace line trap on the E	JCPL								
121	b0204	Install 72Mvar capacitor at Cookstown 230kV substation	JCPL								
122	b0205	Install three 28.8Mvar capacitors at Planebrook 35kV su	PECO								
123	b0206	Install 161Mvar capacitor at Planebrook 230kV substatic	PECO	14.2%							24.4%
124	b0207	Install 161Mvar capacitor at Newlinville 230kV substatio	PECO	14.2%							24.4%
125	b0208	Install 161Mvar capacitor Heaton 230kV substation	PECO	14.2%							24.4%
126	b0209	Install 2% series reactor at Chichester substation on the	PECO	65.2%							
127	b0210	Install a new 500/230kV substation in AEC area. The hig	AEC	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
128	b0210	Install a new 500/230kV substation in AEC area, the hig	AEC	65.2%							
129	b0211	Reconductor Union - Corson 138kV circuit	AEC	65.2%							
130	b0212	Substation upgrades at Union and Corson 138kV	AEC	65.2%							
131	b0213.1	Replace New Freedom 230 kV breaker BS2-6	PSEG								
132	b0213.3	Replace New Freedom 230 kV breaker BS2-8	PSEG								
133	b0214	Install 50 MVAR capacitor at Cardiff 230kV substation	AEC	100.0%							
134	b0215	Install 230Kv series reactor and 2- 100MVAR PLC switc	ME	6.7%		4.0%					9.1%
135	b0216	Install -100/+525 MVAR dynamic reactive device at Blac	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
136	b0217	Upgrade Mt. Storm - Doubs 500kV	Dominion	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
137	b0218	Install third Wylie Ridge 500/345kV transformer	APS	11.8%							19.4%
138	b0219	Install two new 230 kV circuits between Palmers Corner	PEPCO								
139	b0220	Upgrade coolers on Wylie Ridge 500/345 kV #7	APS	11.8%							19.4%
140	b0221	Replace disconnect switch on Edgewood-N. Salisbury 6	DPL								100.0%
141	b0222	Install 150 MVAR capacitor at Loudoun 500 kV	Dominion	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
142	b0223	Install 150 MVAR capacitor at Asburn 230 kV	Dominion								
143	b0224	Install 150 MVAR capacitor at Dranesville 230 kV	Dominion								
144	b0225	Install 33 MVAR capacitor at Possum Pt. 115 kV	Dominion								

	A	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
58	Upgrade ID	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL	PSEG	RE	UGI	Cost Estimate ($M)
73	b0134				0.51							0.46	0.03		$20.00
74	b0135														$17.05
75	b0136														$27.45
76	b0137														$1.16
77	b0138														$8.07
78	b0139														$3.69
79	b0140														$4.99
80	b0141														$4.90
81	b0142														$1.93
82	b0143														$1.63
83	b0144.1														$44.91
84	b0144.2														$7.47
85	b0144.3														$0.97
86	b0144.4														$2.10
87	b0144.5														$0.12
88	b0144.6														$3.65
89	b0144.7														$1.23
90	b0145				0.73							0.22	0.05		$65.00
91	b0146									1.00					$4.79
92	b0148														$0.00
93	b0149														$0.00
94	b0152														$1.18
95	b0157											1.00			$2.00
96	b0158											1.00			$4.63
97	b0159											1.00			$2.00
98	b0161											1.00	0.00		$29.00
99	b0162											1.00			$1.00
100	b0163											1.00			$1.00
101	b0164														$2.00
102	b0169		0.02		0.26		0.11					0.60			$17.00
103	b0170				0.43		0.18					0.38	0.01		$12.00
104	b0171.1	0.14	0.00		0.05	0.02	0.00	0.06	0.02	0.05	0.05	0.08	0.00		$2.20
105	b0171.2	0.13	0.00		0.04	0.02	0.01	0.06	0.02	0.05	0.06	0.07	0.00		$0.13
106	b0172.1	0.13	0.00		0.04	0.02	0.01	0.06	0.02	0.05	0.06	0.07	0.00		$0.07
107	b0172.2	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.05
108	b0173				100.0%										$0.10
109	b0174		1.6%		35.4%		5.7%					54.4%	2.9%		$20.00
110	b0180							100.0%							$0.25
111	b0181							100.0%							$0.44
112	b0182							100.0%							$0.10
113	b0184											100.0%			$0.48
114	b0185											100.0%			$0.48
115	b0186											100.0%			$0.48
116	b0199				100.0%										$0.35
117	b0200				100.0%										$0.01
118	b0201											100.0%			$0.50
119	b0202				100.0%										$0.04
120	b0203				100.0%										$0.08
121	b0204				100.0%										$1.00
122	b0205							100.0%							$2.20
123	b0206							57.9%				3.5%			$2.00
124	b0207							57.9%				3.5%			$2.00
125	b0208							57.9%				3.5%			$2.00
126	b0209				25.9%		2.6%					6.4%			$3.00
127	b0210	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$37.09
128	b0210				25.9%		2.6%					6.4%			$15.00
129	b0211				25.9%		2.6%					6.4%			$6.22
130	b0212				25.9%		2.6%					6.4%			$0.07
131	b0213.1											100.0%			$0.38
132	b0213.3											100.0%			$0.38
133	b0214														$2.65
134	b0215		0.6%		16.9%	10.5%	1.7%	19.0%			7.6%	22.7%	0.3%	1.0%	$10.00
135	b0216	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$50.00
136	b0217	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$1.70
137	b0218	13.8%			15.6%			39.4%							$14.50
138	b0219									100.0%					$91.00
139	b0220	13.8%			15.6%			39.4%							$0.36
140	b0221														$0.02
141	b0222	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$1.50
142	b0223	100.0%													$1.00
143	b0224	100.0%													$1.00
144	b0225	100.0%													$0.60

	A	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL
58	Upgrade ID	Project ID	Upgrade Date In-Service	Project Average In-Service Date	Date to use	Upgrade Source	Project Source	Project Status	Projects Allocated by Load	Projects Attributed to one entity	Projects Attributed to Dayton entity	Year In Service Override	First Full Year in Service	Project Age
73	b0134	b0134	5/15/2007	5/15/2007	5/15/2007	Post-2005	Post-2005	IS	0	0	0		2008	3
74	b0135	b0135	12/24/2007	12/24/2007	12/24/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
75	b0136	b0136	2/28/2008	2/28/2008	2/28/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
76	b0137	b0137	12/15/2007	12/15/2007	12/15/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
77	b0138	b0138	3/31/2008	3/31/2008	3/31/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
78	b0139	b0139	12/24/2007	12/24/2007	12/24/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
79	b0140	b0140	1/15/2007	1/15/2007	1/15/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
80	b0141	b0141	3/14/2006	3/14/2006	3/14/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
81	b0142	b0142	4/28/2006	4/28/2006	4/28/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
82	b0143	b0143	12/15/2007	12/15/2007	12/15/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
83	b0144.1	b0144	6/20/2006	5/2/2006	6/20/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
84	b0144.2	b0144	6/20/2006	5/2/2006	6/20/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
85	b0144.3	b0144	11/15/2005	5/2/2006	11/15/2005	Post-2005	Post-2005	IS	0	1	0		2006	5
86	b0144.4	b0144	12/23/2005	5/2/2006	12/23/2005	Post-2005	Post-2005	IS	0	1	0		2006	5
87	b0144.5	b0144	5/26/2006	5/2/2006	5/26/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
88	b0144.6	b0144	4/18/2006	5/2/2006	4/18/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
89	b0144.7	b0144	11/11/2006	5/2/2006	11/11/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
90	b0145	b0145	6/5/2007	6/5/2007	6/5/2007	Post-2005	Post-2005	IS	0	0	0		2008	3
91	b0146	b0146	#N/A	9/3/2006	9/3/2006	#N/A	Post-2005	#N/A	0	1	0		2007	4
92	b0148	b0148	8/23/2004	8/23/2004	8/23/2004	Post-2005	Post-2005	IS	0	1	0		2005	6
93	b0149	b0149	12/14/2004	12/14/2004	12/14/2004	Post-2005	Post-2005	IS	0	1	0		2005	6
94	b0152	b0152	#N/A	11/22/2005	11/22/2005	#N/A	Post-2005	#N/A	0	1	0		2006	5
95	b0157	b0157	6/29/2007	6/29/2007	6/29/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
96	b0158	b0158	5/21/2009	5/21/2009	5/21/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
97	b0159	b0159	5/29/2009	5/29/2009	5/29/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
98	b0161	b0161	5/29/2009	5/29/2009	5/29/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
99	b0162	b0162	12/1/2008	12/1/2008	12/1/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
100	b0163	b0163	4/22/2009	4/22/2009	4/22/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
101	b0164	b0164	5/13/2006	5/13/2006	5/13/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
102	b0169	b0169	5/20/2009	5/20/2009	5/20/2009	Post-2005	Post-2005	IS	0	0	0		2010	1
103	b0170	b0170	5/7/2009	5/7/2009	5/7/2009	Post-2005	Post-2005	IS	0	0	0		2010	1
104	b0171.1	b0171	4/18/2008	4/18/2008	4/18/2008	Post-2005	Post-2005	IS	1	0	0		2009	2
105	b0171.2	b0171	4/18/2008	4/18/2008	4/18/2008	Post-2005	Post-2005	IS	1	0	0		2009	2
106	b0172.1	b0172	5/21/2008	5/20/2008	5/21/2008	Post-2005	Post-2005	IS	1	0	0		2009	2
107	b0172.2	b0172	5/20/2008	5/20/2008	5/20/2008	Post-2005	Post-2005	IS	1	0	0		2009	2
108	b0173	b0173	10/8/2008	10/8/2008	10/8/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
109	b0174	b0174	5/7/2008	5/7/2008	5/7/2008	Post-2005	Post-2005	IS	0	0	0		2009	2
110	b0180	b0180	9/15/2006	9/15/2006	9/15/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
111	b0181	b0181	12/15/2006	12/15/2006	12/15/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
112	b0182	b0182	12/15/2006	12/15/2006	12/15/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
113	b0184	b0184	12/8/2008	12/8/2008	12/8/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
114	b0185	b0185	5/19/2006	5/19/2006	5/19/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
115	b0186	b0186	12/14/2008	12/14/2008	12/14/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
116	b0199	b0199	2/19/2009	2/19/2009	2/19/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
117	b0200	b0200	10/8/2008	10/8/2008	10/8/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
118	b0201	b0201	5/23/2008	5/23/2008	5/23/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
119	b0202	b0202	10/8/2008	10/8/2008	10/8/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
120	b0203	b0203	5/30/2008	5/30/2008	5/30/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
121	b0204	b0204	5/31/2006	5/31/2006	5/31/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
122	b0205	b0205	6/1/2008	1/0/1900	6/1/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
123	b0206	b0206	5/22/2007	5/22/2007	5/22/2007	Post-2005	Post-2005	IS	0	0	0		2008	3
124	b0207	b0207	5/25/2008	5/25/2008	5/25/2008	Post-2005	Post-2005	IS	0	0	0		2009	2
125	b0208	b0208	4/12/2008	4/12/2008	4/12/2008	Post-2005	Post-2005	IS	0	0	0		2009	2
126	b0209	b0209	3/27/2008	3/27/2008	3/27/2008	Post-2005	Post-2005	IS	0	0	0		2009	2
127	b0210	b0210	5/7/2008	9/3/2010	5/7/2008	Post-2005	Planned	IS	1	0	0		2009	2
128	b0210	b0210	5/7/2008	9/3/2010	5/7/2008	Post-2005	Planned	IS	0	0	0		2009	2
129	b0211	b0211	2/15/2008	2/15/2008	2/15/2008	Post-2005	Post-2005	IS	0	0	0		2009	2
130	b0212	b0212	2/28/2008	2/28/2008	2/28/2008	Post-2005	Post-2005	IS	0	0	0		2009	2
131	b0213.1	b0213	4/13/2007	4/5/2007	4/13/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
132	b0213.3	b0213	3/29/2007	4/5/2007	3/29/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
133	b0214	b0214	2/28/2009	2/28/2009	2/28/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
134	b0215	b0215	6/1/2008	6/1/2008	6/1/2008	Post-2005	Post-2005	IS	0	0	0		2009	2
135	b0216	b0216	12/5/2007	12/5/2007	12/5/2007	Post-2005	Post-2005	IS	1	0	0		2008	3
136	b0217	b0217	6/3/2006	6/3/2006	6/3/2006	Post-2005	Post-2005	IS	1	0	0		2007	4
137	b0218	b0218	12/20/2007	12/20/2007	12/20/2007	Post-2005	Post-2005	IS	0	0	0		2008	3
138	b0219	b0219	7/1/2007	7/1/2007	7/1/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
139	b0220	b0220	4/18/2006	4/18/2006	4/18/2006	Post-2005	Post-2005	IS	0	0	0		2007	4
140	b0221	b0221	3/29/2006	3/29/2006	3/29/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
141	b0222	b0222	5/31/2006	5/31/2006	5/31/2006	Post-2005	Post-2005	IS	1	0	0		2007	4
142	b0223	b0223	5/31/2006	5/31/2006	5/31/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
143	b0224	b0224	5/31/2006	5/31/2006	5/31/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
144	b0225	b0225	5/31/2006	5/31/2006	5/31/2006	Post-2005	Post-2005	IS	0	1	0		2007	4

	A	AM	AN	AO	AP	AQ	AR	AS
58	Upgrade ID	Load Ratio Project Costs	One Entity Project Costs	DFAX allocated Project Costs	Dayton DFAX Project Costs			
73	b0134	0	0	20	0			
74	b0135	0	17.05	0	0			
75	b0136	0	27.45	0	0			
76	b0137	0	1.16	0	0			
77	b0138	0	8.069	0	0			
78	b0139	0	3.69	0	0			
79	b0140	0	4.99	0	0			
80	b0141	0	4.9	0	0			
81	b0142	0	1.93	0	0			
82	b0143	0	1.63	0	0			
83	b0144.1	0	44.909	0	0			
84	b0144.2	0	7.465	0	0			
85	b0144.3	0	0.969	0	0			
86	b0144.4	0	2.104	0	0			
87	b0144.5	0	0.119	0	0			
88	b0144.6	0	3.654	0	0			
89	b0144.7	0	1.232	0	0			
90	b0145	0	0	65	0			
91	b0146	0	4.79	0	0			
92	b0148	0	0	0	0			
93	b0149	0	0	0	0			
94	b0152	0	1.18	0	0			
95	b0157	0	2	0	0			
96	b0158	0	4.63	0	0			
97	b0159	0	2	0	0			
98	b0161	0	29	0	0			
99	b0162	0	1	0	0			
100	b0163	0	1	0	0			
101	b0164	0	2	0	0			
102	b0169	0	0	17	0			
103	b0170	0	0	12	0			
104	b0171.1	2.2	0	0	0.00			
105	b0171.2	0.126	0	0	0.00			
106	b0172.1	0.07	0	0	0.00			
107	b0172.2	0.05	0	0	0.00			
108	b0173	0	0.1	0	0			
109	b0174	0	0	20	0			
110	b0180	0	0.25	0	0			
111	b0181	0	0.44	0	0			
112	b0182	0	0.1	0	0			
113	b0184	0	0.475	0	0			
114	b0185	0	0.475	0	0			
115	b0186	0	0.475	0	0			
116	b0199	0	0.35	0	0			
117	b0200	0	0.005	0	0			
118	b0201	0	0.5	0	0			
119	b0202	0	0.035	0	0			
120	b0203	0	0.08	0	0			
121	b0204	0	0.995	0	0			
122	b0205	0	2.2	0	0			
123	b0206	0	0	2	0			
124	b0207	0	0	2	0			
125	b0208	0	0	2	0			
126	b0209	0	0	3	0			
127	b0210	37.09	0	0	0.00			
128	b0210	0	0	15	0			
129	b0211	0	0	6.22	0			
130	b0212	0	0	0.07	0			
131	b0213.1	0	0.375	0	0			
132	b0213.3	0	0.375	0	0			
133	b0214	0	2.65	0	0			
134	b0215	0	0	10	0			
135	b0216	50	0	0	0.00			
136	b0217	1.7	0	0	0.00			
137	b0218	0	0	14.5	0			
138	b0219	0	90.997	0	0			
139	b0220	0	0	0.36	0			
140	b0221	0	0.02	0	0			
141	b0222	1.5	0	0	0.00			
142	b0223	0	1	0	0			
143	b0224	0	1	0	0			
144	b0225	0	0.6	0	0			

	A	B	C	D	E	F	G	H	I	J	K
58	Upgrade ID	Description	TO	AEC	AEP	APS	BGE	ComEd	Dayton	DL	DPL
145	b0226	Install 500/230 kV transformer at Clifton and Clifton 500	Dominion			3.7%	3.5%			85.7%	
146	b0227	Install 500/230 kV transformer at Bristers; build new 230	Dominion	0.7%		3.4%	10.9%				1.7%
147	b0227.1	Loudoun Sub – upgrade 6-230 kV breakers	Dominion								
148	b0228	Upgrade Burtonsville – Sandy Springs 230 kV circuit	PEPCO								
149	b0229	Install fourth Bedington 500/138 kV	APS			51.0%	13.4%				2.0%
150	b0230	Install fourth Meadowbrook 500/138 kV	APS			79.2%	3.6%				0.9%
151	b0231	Install 500 kV breakers & 500 kV bus work at Suffolk	Dominion	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
152	b0231.2	Install 500/230 kV Transformer, 230 kV breakers, & 230	Dominion								
153	b0232	Install 150 MVAR capacitor at Lynnhaven 230 kV	Dominion								
154	b0233	Install 150 MVAR capacitor at Landstown 230 kV	Dominion								
155	b0234	Install 150 MVAR capacitor at Greenwich 230 kV	Dominion								
156	b0235	Install 150 MVAR capacitor at Fentress 230 kV	Dominion								
157	b0236.1	Build new West Loop 138 kV substation	ComEd					100.0%			
158	b0236.2	Install two new 345 kV circuits from Crawford and Taylor	ComEd					100.0%			
159	b0238	Reconductor Doubs – Dickerson and Doubs – Aqueduct	APS				16.7%				
160	b0238.1	Modify Dickerson Station H 230 kV	PEPCO								
161	b0240	Open the Black Oak #3 500/138 kV transformer for the l	APS			100.0%					
162	b0241.2	Edgemoor Sub – Replace overstressed breakers	DPL								100.0%
163	b0241.3	Red Lion Sub – Substation reconfigure to provide for se	DPL								84.5%
164	b0244	Install a 4th Waugh Chapel 500/230kV transformer, tern	BGE				85.6%				
165	b0245	Replacement of the existing 954 ACSR conductor on the	APS			100.0%					
166	b0246	Rebuild of the Double Tollgate – Old Chapel 138 kV line	APS			100.0%					
167	b0251	Install 100 MVAR of 230 kV capacitors at Bells Mill	PEPCO								
168	b0252	Install 100 MVAR of 230 kV capacitors at Bells Mill	PEPCO								
169	b0253	Convert Pine Creek substation from 69 kV to 138 kV	DL							100.0%	
170	b0254	Convert North substation from 69 kV to 138 kV	DL							100.0%	
171	b0255	Convert Highland substation from 69 kV to 138 kV and L	DL							100.0%	
172	b0256.1	Convert Valley substation from 69 kV to 138 kV	DL							100.0%	
173	b0256.2	Reconductor Valley – Phillips at 138 kV	DL							100.0%	
174	b0257.1	Convert Wilmerding substation from 69 kV to 138 kV	DL							100.0%	
175	b0257.2	Convert Dravosburg – Wilmerding from 69 kV to 138 kV	DL							100.0%	
176	b0258	Elrama replace 41 MVA 138/69 kV transformer with a mi	DL							100.0%	
177	b0261	Replace 1200 Amp disconnect switch on the Red Lion –	DPL								100.0%
178	b0262	Reconductor 0.5 miles of Christiana – Edgemoor 138 kV	DPL								100.0%
179	b0263	Replace 1200 Amp wavetrap at Indian River on the India	DPL								100.0%
180	b0264	Upgrade Chichester – Delco Tap 230 kV and the PECO	PECO	89.9%							
181	b0265	Upgrade AE portion of Delco Tap – Mickleton 230 kV cir	AEC	89.9%							
182	b0266	Replace two wave traps and ammeter at Peach Bottom,	PECO								
183	b0267	Reconductor JCPL 2 mile portion of Kittatinny – Newton	JCPL								
184	b0268	Reconductor the 8 mile Gilbert – Glen Gardner 230 kV c	JCPL								
185	b0269	Install a new 500/230 kV substation in PECO, and tap th	PECO	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
186	b0269	Install a new 500/230 kV substation in PECO, and tap th	PECO	8.3%							9.6%
187	b0269.6	Add a new 500 kV breaker at Whitpain between #3 trans	PECO	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
188	b0269.7	Replace North Wales 230 kV breaker #105	PECO								
189	b0274	Replace both 230/138 kV transformers at Roseland	PSEG								
190	b0275	Upgrade the two 138 kV circuits between Roseland and	PSEG								
191	b0276	Replace both Monroe 230/69 kV transformers	AEC	91.3%							
192	b0276.1	Upgrade a strand bus at Monroe to increase the rating c	AEC	100.0%							
193	b0277	Install a second Cumberland 230/138 kV transformer	AEC	100.0%							
194	b0278	Install 228 MVAR capacitor at Roseland 230 kV substati	PSEG								
195	b0279.1	Install 100 MVAR capacitor at Glen Gardner substation	JCPL								
196	b0279.10	Install 6.6 MVAR capacitor at Hamburg Boro Q Bus 34.5	JCPL								
197	b0279.11	Install 6.6 MVAR capacitor at Newburg Q Bus 34.5 kV su	JCPL								
198	b0279.2	Install MVAR capacitor at Kittatinny 230 kV substation	JCPL								
199	b0279.4	Install 6.6 MVAR capacitor at Waretown #1 bank 34.5 kV	JCPL								
200	b0279.5	Install 10.8 MVAR capacitor at Spottswood #2 bank .4.5	JCPL								
201	b0279.6	Install 6.6 MVAR capacitor at Pequannock N bus 34.5 kV	JCPL								
202	b0279.7	Install 6.6 MVAR capacitor at Haskell P bus 34.5 kV sub	JCPL								
203	b0279.9	Install 6.6 MVAR capacitor at Matrix 34.5 kV substation	JCPL								
204	b0280.1	Install 161 MVAR capacitor at Warrington 230 kV substa	PECO								
205	b0280.2	Install 161 MVAR capacitor at Bradford 230 kV substatic	PECO								
206	b0280.3	Install 28.8 MVAR capacitor at Warrington 34 kV substa	PECO								
207	b0280.4	Install 18 MVAR capacitor at Waverly 13.8 kV substation	PECO								
208	b0281.1	Install 35 MVAR capacitor at Lake Ave 69 kV substation	AEC	100.0%							
209	b0281.2	Install 15 MVAR capacitor at Shipbottom 69 kV substatic	AEC	100.0%							
210	b0281.3	Install 8 MVAR capacitors on the AE distribution system	AEC	100.0%							
211	b0282	Install 46 MVAR capacitors on the DPL distribution syste	DPL								100.0%
212	b0284.1	Build 500 kV substation in PENELEC – Tap the Keyston	PENELEC	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
213	b0284.2	Replace two wave traps at Juniata 500 kV – on the two .	PPL	2.0%	18.0%	6.3%	4.9%	15.6%	2.5%	2.0%	2.8%
214	b0284.3	Replace wave trap and upgrade a bus section at Keysto	PENELEC	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
215	b0285.1	Replace wave trap at Keystone 500 kV – on the Keystor	PENELEC	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
216	b0285.2	Replace wave trap and relay at Conemaugh 500 kV – or	PENELEC	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%

	A	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
58	Upgrade ID	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL	PSEG	RE	UGI	Cost Estimate ($M)
145	b0226									7.0%					$7.01
146	b0227	67.4%				0.9%		2.3%		12.2%	0.5%				$5.80
147	b0227.1	100.0%													$2.00
148	b0228									100.0%					$0.93
149	b0229	14.5%				1.4%				17.6%					$7.00
150	b0230	11.8%				0.7%				4.0%					$7.00
151	b0231	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$5.03
152	b0231.2	100.0%													$12.30
153	b0232	100.0%													$1.00
154	b0233	100.0%													$1.84
155	b0234	100.0%													$1.86
156	b0235	100.0%													$1.89
157	b0236.1														$61.00
158	b0236.2														$331.00
159	b0238	33.7%								49.7%					$9.60
160	b0238.1									100.0%					$1.10
161	b0240														$0.00
162	b0241.2														$0.83
163	b0241.3							15.5%							$12.63
164	b0244					0.8%				13.6%					$40.40
165	b0245														$1.70
166	b0246														$1.95
167	b0251									100.0%					$3.90
168	b0252									100.0%					$3.00
169	b0253														$5.70
170	b0254														$3.90
171	b0255														$21.10
172	b0256.1														$1.60
173	b0256.2														$6.90
174	b0257.1														$2.70
175	b0257.2														$0.42
176	b0258														$2.30
177	b0261														$0.08
178	b0262														$0.33
179	b0263														$0.16
180	b0264				9.5%		0.7%								$4.50
181	b0265				9.5%		0.7%								$6.00
182	b0266							100.0%							$0.80
183	b0267				100.0%										$1.25
184	b0268		1.1%		61.8%		3.0%					32.7%	1.5%		$7.00
185	b0269	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$30.20
186	b0269							82.2%							$15.00
187	b0269.6	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$2.50
188	b0269.7							100.0%							$0.15
189	b0274		3.2%									96.8%			$15.00
190	b0275											100.0%			$5.00
191	b0276		0.2%									8.3%	0.2%		$6.88
192	b0276.1														$0.25
193	b0277														$4.90
194	b0278											100.0%			$6.00
195	b0279.1				100.0%										$0.99
196	b0279.10				100.0%										$0.27
197	b0279.11				100.0%										$0.27
198	b0279.2				100.0%										$0.96
199	b0279.4				100.0%										$0.27
200	b0279.5				100.0%										$0.43
201	b0279.6				100.0%										$0.27
202	b0279.7				100.0%										$0.27
203	b0279.9				100.0%										$0.27
204	b0280.1							100.0%							$2.80
205	b0280.2							100.0%							$3.00
206	b0280.3							100.0%							$0.75
207	b0280.4							100.0%							$0.50
208	b0281.1														$2.40
209	b0281.2														$1.40
210	b0281.3														$0.20
211	b0282														$1.20
212	b0284.1	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$25.00
213	b0284.2	13.3%	0.2%		4.2%	2.1%	0.5%	5.9%	2.1%	4.7%	5.6%	7.1%	0.3%		$0.24
214	b0284.3	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.25
215	b0285.1	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.20
216	b0285.2	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.30

	A	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL
58	Upgrade ID	Project ID	Upgrade Date In-Service	Project Average In-Service Date	Date to use	Upgrade Source	Project Source	Project Status	Projects Allocated by Load	Projects Attributed to one entity	Projects Attributed to Dayton entity	Year In Service Override	First Full Year in Service	Project Age
145	b0226	b0226	7/6/2006	7/6/2006	7/6/2006	Post-2005	Post-2005	IS	0	0	0		2007	4
146	b0227	b0227	6/11/2009	8/19/2008	6/11/2009	Post-2005	Post-2005	IS	0	0	0		2010	1
147	b0227.1	b0227	2/28/2009	8/19/2008	2/28/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
148	b0228	b0228	11/22/2010	11/22/2010	11/22/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
149	b0229	b0229	4/23/2009	4/23/2009	4/23/2009	Post-2005	Post-2005	IS	0	0	0		2010	1
150	b0230	b0230	5/31/2008	5/31/2008	5/31/2008	Post-2005	Post-2005	IS	0	0	0		2009	2
151	b0231	b0231	6/1/2009	6/1/2009	6/1/2009	Post-2005	Post-2005	IS	1	0	0		2010	1
152	b0231.2	b0231	6/1/2009	6/1/2009	6/1/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
153	b0232	b0232	5/15/2006	5/15/2006	5/15/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
154	b0233	b0233	6/15/2009	6/15/2009	6/15/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
155	b0234	b0234	5/21/2009	5/21/2009	5/21/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
156	b0235	b0235	5/21/2009	5/21/2009	5/21/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
157	b0236.1	b0236	12/9/2006	8/18/2007	12/9/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
158	b0236.2	b0236	4/26/2008	8/18/2007	4/26/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
159	b0238	b0238	6/1/2009	6/1/2009	6/1/2009	Post-2005	Post-2005	IS	0	0	0		2010	1
160	b0238.1	b0238	6/1/2009	6/1/2009	6/1/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
161	b0240	b0240	1/13/2006	1/13/2006	1/13/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
162	b0241.2	b0241	6/1/2008	11/9/2007	6/1/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
163	b0241.3	b0241	12/31/2008	11/9/2007	12/31/2008	Post-2005	Post-2005	IS	0	0	0		2009	2
164	b0244	b0244	5/15/2010	5/15/2010	5/15/2010	Post-2005	Post-2005	IS	0	0	0		2011	0
165	b0245	b0245	4/4/2008	4/4/2008	4/4/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
166	b0246	b0246	10/30/2008	10/30/2008	10/30/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
167	b0251	b0251	4/3/2010	4/17/2010	4/3/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
168	b0252	b0252	8/8/2010	8/15/2010	8/8/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
169	b0253	b0253	1/9/2008	1/9/2008	1/9/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
170	b0254	b0254	12/31/2006	12/31/2006	12/31/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
171	b0255	b0255	1/6/2010	1/6/2010	1/6/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
172	b0256.1	b0256	2/16/2007	9/10/2008	2/16/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
173	b0256.2	b0256	4/6/2010	9/10/2008	4/6/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
174	b0257.1	b0257	6/1/2007	3/12/2007	6/1/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
175	b0257.2	b0257	12/21/2006	3/12/2007	12/21/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
176	b0258	b0258	2/19/2009	2/19/2009	2/19/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
177	b0261	b0261	5/13/2009	5/13/2009	5/13/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
178	b0262	b0262	11/13/2009	11/13/2009	11/13/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
179	b0263	b0263	5/23/2010	5/23/2010	5/23/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
180	b0264	b0264	1/13/2009	1/13/2009	1/13/2009	Post-2005	Post-2005	IS	0	0	0		2010	1
181	b0265	b0265	6/1/2009	1/0/1900	6/1/2009	Post-2005	Post-2005	IS	0	0	0		2010	1
182	b0266	b0266	3/11/2009	3/11/2009	3/11/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
183	b0267	b0267	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	UC	0	1	0		2012	-1
184	b0268	b0268	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	UC	0	0	0		2012	-1
185	b0269	b0269	5/3/2011	3/2/2011	5/3/2011	Post-2005	Post-2005	IS	1	0	0		2012	-1
186	b0269	b0269	5/3/2011	3/2/2011	5/3/2011	Post-2005	Post-2005	IS	0	0	0		2012	-1
187	b0269.6	b0269	5/3/2011	3/2/2011	5/3/2011	Post-2005	Post-2005	IS	1	0	0		2012	-1
188	b0269.7	b0269	3/4/2011	3/2/2011	3/4/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
189	b0274	b0274	5/31/2009	5/31/2009	5/31/2009	Post-2005	Post-2005	IS	0	0	0		2010	1
190	b0275	b0275	4/1/2010	4/1/2010	4/1/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
191	b0276	b0276	5/14/2009	5/14/2010	5/14/2009	Post-2005	Post-2005	IS	0	0	0		2010	1
192	b0276.1	b0276	5/15/2011	5/14/2010	5/15/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
193	b0277	b0277	7/1/2009	7/1/2009	7/1/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
194	b0278	b0278	5/30/2009	5/30/2009	5/30/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
195	b0279.1	b0279	6/1/2011	10/22/2008	6/1/2011	Planned	Planned	UC	0	1	0		2012	-1
196	b0279.10	b0279	1/13/2010	10/22/2008	1/13/2010	Post-2005	Planned	IS	0	1	0		2011	0
197	b0279.11	b0279	8/25/2009	10/22/2008	8/25/2009	Post-2005	Planned	IS	0	1	0		2010	1
198	b0279.2	b0279	7/27/2007	10/22/2008	7/27/2007	Post-2005	Planned	IS	0	1	0		2008	3
199	b0279.4	b0279	6/5/2007	10/22/2008	6/5/2007	Post-2005	Planned	IS	0	1	0		2008	3
200	b0279.5	b0279	6/1/2007	10/22/2008	6/1/2007	Post-2005	Planned	IS	0	1	0		2008	3
201	b0279.6	b0279	5/24/2007	10/22/2008	5/24/2007	Post-2005	Planned	IS	0	1	0		2008	3
202	b0279.7	b0279	5/24/2007	10/22/2008	5/24/2007	Post-2005	Planned	IS	0	1	0		2008	3
203	b0279.9	b0279	12/31/2010	10/22/2008	12/31/2010	Post-2005	Planned	IS	0	1	0		2011	0
204	b0280.1	b0280	3/22/2009	5/9/2008	3/22/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
205	b0280.2	b0280	5/15/2009	5/9/2008	5/15/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
206	b0280.3	b0280	6/1/2007	5/9/2008	6/1/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
207	b0280.4	b0280	6/1/2007	5/9/2008	6/1/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
208	b0281.1	b0281	5/15/2009	8/2/2009	5/15/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
209	b0281.2	b0281	5/24/2010	8/2/2009	5/24/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
210	b0281.3	b0281	12/31/2008	8/2/2009	12/31/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
211	b0282	b0282	12/31/2008	12/31/2008	12/31/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
212	b0284.1	b0284	6/1/2015	3/1/2013	6/1/2015	Planned	Planned	EP	1	0	0		2016	-5
213	b0284.2	b0284	5/31/2009	3/1/2013	5/31/2009	Post-2005	Planned	IS	1	0	0		2010	1
214	b0284.3	b0284	6/1/2015	3/1/2013	6/1/2015	Planned	Planned	EP	1	0	0		2016	-5
215	b0285.1	b0285	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	1	0	0		2016	-5
216	b0285.2	b0285	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	1	0	0		2016	-5

	A	AM	AN	AO	AP	AQ	AR	AS
58	Upgrade ID	Load Ratio Project Costs	One Entity Project Costs	DFAX allocated Project Costs	Dayton DFAX Project Costs			
145	b0226	0	0	7.01	0			
146	b0227	0	0	5.8	0			
147	b0227.1	0	2	0	0			
148	b0228	0	0.926	0	0			
149	b0229	0	0	7	0			
150	b0230	0	0	7	0			
151	b0231	5.03	0	0	0.00			
152	b0231.2	0	12.3	0	0			
153	b0232	0	1	0	0			
154	b0233	0	1.84	0	0			
155	b0234	0	1.858	0	0			
156	b0235	0	1.89	0	0			
157	b0236.1	0	61	0	0			
158	b0236.2	0	331	0	0			
159	b0238	0	0	9.6	0			
160	b0238.1	0	1.1	0	0			
161	b0240	0	0	0	0			
162	b0241.2	0	0.83	0	0			
163	b0241.3	0	0	12.63	0			
164	b0244	0	0	40.4	0			
165	b0245	0	1.7	0	0			
166	b0246	0	1.95	0	0			
167	b0251	0	3.9	0	0			
168	b0252	0	3	0	0			
169	b0253	0	5.7	0	0			
170	b0254	0	3.9	0	0			
171	b0255	0	21.1	0	0			
172	b0256.1	0	1.6	0	0			
173	b0256.2	0	6.9	0	0			
174	b0257.1	0	2.7	0	0			
175	b0257.2	0	0.42	0	0			
176	b0258	0	2.3	0	0			
177	b0261	0	0.075	0	0			
178	b0262	0	0.333	0	0			
179	b0263	0	0.164	0	0			
180	b0264	0	0	4.5	0			
181	b0265	0	0	6	0			
182	b0266	0	0.8	0	0			
183	b0267	0	1.25	0	0			
184	b0268	0	0	7	0			
185	b0269	30.2	0	0	0.00			
186	b0269	0	0	15	0			
187	b0269.6	2.5	0	0	0.00			
188	b0269.7	0	0.15	0	0			
189	b0274	0	0	15	0			
190	b0275	0	5	0	0			
191	b0276	0	0	6.881	0			
192	b0276.1	0	0.25	0	0			
193	b0277	0	4.9	0	0			
194	b0278	0	6	0	0			
195	b0279.1	0	0.99	0	0			
196	b0279.10	0	0.265	0	0			
197	b0279.11	0	0.265	0	0			
198	b0279.2	0	0.96	0	0			
199	b0279.4	0	0.265	0	0			
200	b0279.5	0	0.434	0	0			
201	b0279.6	0	0.265	0	0			
202	b0279.7	0	0.265	0	0			
203	b0279.9	0	0.265	0	0			
204	b0280.1	0	2.8	0	0			
205	b0280.2	0	3	0	0			
206	b0280.3	0	0.75	0	0			
207	b0280.4	0	0.5	0	0			
208	b0281.1	0	2.4	0	0			
209	b0281.2	0	1.4	0	0			
210	b0281.3	0	0.2	0	0			
211	b0282	0	1.2	0	0			
212	b0284.1	25	0	0	0.00			
213	b0284.2	0.242	0	0	0.00			
214	b0284.3	0.25	0	0	0.00			
215	b0285.1	0.2	0	0	0.00			
216	b0285.2	0.3	0	0	0.00			

	A	B	C	D	E	F	G	H	I	J	K
58	Upgrade ID	Description	TO	AEC	AEP	APS	BGE	ComEd	Dayton	DL	DPL
217	b0286	Install 130 MVAR capacitor at Whippany 230 kV	JCPL								
218	b0287	Install 600 MVAR Dynamic Reactive Device in Whitpain	PECO	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
219	b0288	Brighton Substation – add 2nd 1000 MVA 500/230 kV tr	PEPCO				19.3%				
220	b0289.1	Install additional 130 MVAR capacitor at West Wharton	JCPL								
221	b0290	Install 400 MVAR capacitor in the Branchburg 500 kV vi	PSEG	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
222	b0291	Replace 1600A disconnect switch at Harmony 230 kV ar	DPL								100.0%
223	b0292	Replace a 1600A line trap at Atlantic Larrabee 230 kV s	JCPL								
224	b0293.1	Replace wavetrap at the Martins Creek 230 kV bus	PPL								
225	b0295	Raise conductor temperature of North Seaford – Pine St	DPL								100.0%
226	b0296	Rehoboth/Cedar Neck Tap (6733-2) upgrade	DPL								100.0%
227	b0298	Replace both Conastone 500/230 kV transformers with l	BGE				75.9%				
228	b0298.1	Replace Conastone 230 kV breaker 500-3/2323	BGE				100.0%				
229	b0299	Upgrade line 0108 – LaSalle County – Mazon 138 kV wi	ComEd					100.0%			
230	b0301	Increase capacity of Wolfs – Oswego 138 kV line 14304	ComEd					100.0%			
231	b0302	Dixon – McGirr 138kV – Replace small piece of conduct	ComEd					100.0%			
232	b0303	Install 345 kV CB and change Elwood 345 kV BT to norr	ComEd					100.0%			
233	b0305	Normally open East Frankfort 138 kV red-blue bus tie	ComEd					100.0%			
234	b0306	Reconductor line Electric Junction – North Aurora (1110	ComEd					100.0%			
235	b0307	Reconductor Endless Caverns – Mt. Jackson 115 kV	Dominion								
236	b0308	Replace L breaker and switches at Endless Caverns 11!	Dominion								
237	b0309	Install SPS at Earleys 115 kV	Dominion								
238	b0310	Reconductor Club House – South Hill and Chase City –	Dominion								
239	b0311	Reconductor Idylwood to Arlington 230 kV	Dominion								
240	b0312	Reconductor Gallows to Ox 230 kV	Dominion								
241	b0314	Install 35 MVAR capacitor at Closter 69 kV substation	RECO								
242	b0318	Install a 765/138 kV transformer at Amos	AEP		99.0%						
243	b0319	Add a second 1000 MVA Bruches Hill 500/230 kV transf	PEPCO								
244	b0320	Create a new 230 kV station that splits the 2nd Milford to	DPL								100.0%
245	b0322	Convert Lime Kiln substation to 230 kV operation	APS			100.0%					
246	b0323	Replace the North Shenandoah 138/115 kV transformer	APS			100.0%					
247	b0325	Install a 2nd Everetts 230/115 kV transformer	Dominion								
248	b0326	Uprate/resag Remington-Brandywine-Culppr 115 kV	Dominion								
249	b0327	Build 2nd Harrisonburg – Valley 230 kV	Dominion			19.8%					
250	b0328.1	Build new Meadow Brook – Loudoun 500 kV circuit (30 c	Dominion	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
251	b0328.2	Build new Meadow Brook – Loudoun 500 kV circuit (20 c	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
252	b0328.3	Upgrade Mt. Storm 500 kV substation	Dominion	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
253	b0328.4	Upgrade Loudoun 500 kV substation	Dominion	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
254	b0329	Build Carson – Suffolk 500 kV, install 2nd Suffolk 500/2:	Dominion	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
255	b0329	Build Carson – Suffolk 500 kV, install 2nd Suffolk 500/2:	Dominion								
256	b0329.1	Replace Thole Street 115 kV breaker '48T196'	Dominion								
257	b0329.2	Replace Chesapeake 115 kV breaker 'T242'	Dominion								
258	b0329.3	Replace Chesapeake 115 kV breaker '8722'	Dominion								
259	b0329.4	Replace Chesapeake 115 kV breaker '16422'	Dominion								
260	b0331	Upgrade/resag Shell Bank – Whealton 115 kV (Line 165	Dominion								
261	b0332	Uprate/resag Chesapeake – Cradock 115 kV	Dominion								
262	b0333	Replace wave trap on Elmont – Replace (Line #231)	Dominion								
263	b0334	Uprate/resag Iron Bridge-Walmsley-Southwest 230 kV	Dominion								
264	b0335	Build Chase City – Clarksville 115 kV	Dominion								
265	b0336	Reconductor one span of Chesapeake – Dozier 115 kV	Dominion								
266	b0337	Build Lexington 230 kV ring bus	Dominion								
267	b0338	Replace Gordonsville 230/115 kV transformer for larger	Dominion								
268	b0339	Install Breaker at Dooms 230 kV Sub	Dominion								
269	b0340	Reconductor one span Peninsula – Magruder 115 kV cl	Dominion								
270	b0341	Install a breaker at Northern Neck 115 kV	Dominion								
271	b0342	Replace Trowbridge 230/115 kV transformer	Dominion								
272	b0343	Replace Doubs 500/230 kV transformer #2	APS	1.9%			21.5%				3.9%
273	b0344	Replace Doubs 500/230 kV transformer #3	APS	1.9%			21.5%				3.9%
274	b0345	Replace Doubs 500/230 kV transformer #4	APS	1.9%			21.5%				3.9%
275	b0347.1	Build new Mt. Storm – 502 Junction 500 kV circuit	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
276	b0347.10	Upgrade (per ABB Inspection) Hatfield 500 kV breakers	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
277	b0347.11	Upgrade (per ABB Inspection) Hatfield 500 kV breakers	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
278	b0347.12	Upgrade (per ABB Inspection) Hatfield 500 kV breakers	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
279	b0347.13	Upgrade (per ABB Inspection) Hatfield 500 kV breakers	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
280	b0347.14	Upgrade (per ABB Inspection) Hatfield 500 kV breakers	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
281	b0347.15	Upgrade (per ABB Inspection) Hatfield 500 kV breakers	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
282	b0347.16	Upgrade (per ABB inspection) Harrison 500 kV breaker	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
283	b0347.17	Replace Meadow Brook 138 kV breaker 'MD-10'	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
284	b0347.18	Replace Meadow Brook 138 kV breaker 'MD-11'	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
285	b0347.19	Replace Meadow Brook 138 kV breaker 'MD-12'	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
286	b0347.2	Build new Mt. Storm – Meadow Brook 500 kV circuit	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
287	b0347.20	Replace Meadow Brook 138 kV breaker 'MD-13'	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
288	b0347.21	Replace Meadow Brook 138 kV breaker 'MD-14'	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%

	A	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
58	Upgrade ID	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL	PSEG	RE	UGI	Cost Estimate ($M)
217	b0286				100.0%										$1.40
218	b0287	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$10.50
219	b0288	17.0%								63.7%					$33.40
220	b0289.1				100.0%										$2.36
221	b0290	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$18.00
222	b0291														$0.85
223	b0292				100.0%										$0.10
224	b0293.1										100.0%				$0.23
225	b0295														$0.30
226	b0296														$1.70
227	b0298	11.5%				4.7%				7.9%					$55.00
228	b0298.1														$1.00
229	b0299														$2.13
230	b0301														$2.13
231	b0302														$3.73
232	b0303														$2.00
233	b0305														$0.00
234	b0306														$1.00
235	b0307	100.0%													$4.60
236	b0308	100.0%													$0.60
237	b0309	100.0%													$1.00
238	b0310	100.0%													$20.30
239	b0311	100.0%													$3.10
240	b0312	100.0%													$5.40
241	b0314												100.0%		$0.38
242	b0318									1.0%					$13.44
243	b0319									100.0%					$36.70
244	b0320														$15.00
245	b0322														$4.20
246	b0323														$2.00
247	b0325	100.0%													$5.60
248	b0326	100.0%													$12.80
249	b0327	76.2%								4.0%					$6.00
250	b0328.1	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$243.00
251	b0328.2	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$119.00
252	b0328.3	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$10.00
253	b0328.4	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$10.00
254	b0329	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$173.49
255	b0329	100.0%													$49.73
256	b0329.1	100.0%													$0.16
257	b0329.2	100.0%													$0.18
258	b0329.3	100.0%													$0.18
259	b0329.4	100.0%													$0.18
260	b0331	100.0%													$11.00
261	b0332	100.0%													$0.70
262	b0333	100.0%													$0.01
263	b0334	100.0%													$0.70
264	b0335	100.0%													$15.00
265	b0336	100.0%													$0.05
266	b0337	100.0%													$6.50
267	b0338	100.0%													$3.30
268	b0339	100.0%													$2.50
269	b0340	100.0%													$0.05
270	b0341	100.0%													$0.50
271	b0342	100.0%													$3.30
272	b0343	28.9%				3.0%		5.7%		35.2%					$5.20
273	b0344	28.8%				3.0%		5.7%		35.2%					$0.35
274	b0345	28.8%				3.0%		5.8%		35.2%					$5.30
275	b0347.1	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$310.00
276	b0347.10	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.06
277	b0347.11	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.06
278	b0347.12	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.06
279	b0347.13	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.06
280	b0347.14	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.06
281	b0347.15	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.06
282	b0347.16	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.06
283	b0347.17	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.19
284	b0347.18	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.19
285	b0347.19	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.19
286	b0347.2	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$308.00
287	b0347.20	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.19
288	b0347.21	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.19

	A	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL
58	Upgrade ID	Project ID	Upgrade Date In-Service	Project Average In-Service Date	Date to use	Upgrade Source	Project Source	Project Status	Projects Allocated by Load	Projects Attributed to one entity	Projects Attributed to Dayton entity	Year In Service Override	First Full Year in Service	Project Age
217	b0286	b0286	11/15/2007	11/15/2007	11/15/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
218	b0287	b0287	5/29/2009	5/29/2009	5/29/2009	Post-2005	Post-2005	IS	1	0	0		2010	1
219	b0288	b0288	6/21/2009	6/21/2009	6/21/2009	Post-2005	Post-2005	IS	0	0	0		2010	1
220	b0289.1	b0289	6/1/2011	11/30/2010	6/1/2011	Planned	Planned	UC	0	1	0		2012	-1
221	b0290	b0290	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	1	0	0		2013	-2
222	b0291	b0291	5/15/2009	5/15/2009	5/15/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
223	b0292	b0292	5/22/2009	5/22/2009	5/22/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
224	b0293.1	b0293	10/22/2010	10/22/2010	10/22/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
225	b0295	b0295	4/30/2009	4/30/2009	4/30/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
226	b0296	b0296	6/1/2008	6/1/2008	6/1/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
227	b0298	b0298	5/20/2009	7/21/2008	5/20/2009	Post-2005	Post-2005	IS	0	0	0		2010	1
228	b0298.1	b0298	9/23/2007	7/21/2008	9/23/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
229	b0299	b0299	4/29/2007	4/29/2007	4/29/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
230	b0301	b0301	2/22/2007	2/22/2007	2/22/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
231	b0302	b0302	5/12/2007	5/12/2007	5/12/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
232	b0303	b0303	4/9/2008	4/9/2008	4/9/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
233	b0305	b0305	5/1/2008	5/1/2008	5/1/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
234	b0306	b0306	4/7/2007	4/7/2007	4/7/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
235	b0307	b0307	6/19/2009	6/19/2009	6/19/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
236	b0308	b0308	3/15/2007	3/15/2007	3/15/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
237	b0309	b0309	5/31/2007	5/31/2007	5/31/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
238	b0310	b0310	11/10/2010	11/10/2010	11/10/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
239	b0311	b0311	8/11/2010	8/11/2010	8/11/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
240	b0312	b0312	8/11/2010	8/11/2010	8/11/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
241	b0314	b0314	4/15/2007	4/15/2007	4/15/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
242	b0318	b0318	6/25/2008	6/25/2008	6/25/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
243	b0319	b0319	6/8/2011	6/8/2011	6/8/2011	Planned	Planned	UC	0	1	0		2012	-1
244	b0320	b0320	7/5/2010	7/5/2010	7/5/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
245	b0322	b0322	5/29/2008	5/29/2008	5/29/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
246	b0323	b0323	5/23/2008	5/23/2008	5/23/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
247	b0325	b0325	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	UC	0	1	0		2012	-1
248	b0326	b0326	6/18/2009	6/18/2009	6/18/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
249	b0327	b0327	6/11/2010	6/11/2010	6/11/2010	Post-2005	Post-2005	IS	0	0	0		2011	0
250	b0328.1	b0328	6/1/2011	5/18/2011	6/1/2011	Planned	Planned	UC	1	0	0		2012	-1
251	b0328.2	b0328	4/8/2011	5/18/2011	4/8/2011	Planned	Planned	UC	1	0	0		2012	-1
252	b0328.3	b0328	6/1/2011	5/18/2011	6/1/2011	Planned	Planned	UC	1	0	0		2012	-1
253	b0328.4	b0328	6/1/2011	5/18/2011	6/1/2011	Planned	Planned	UC	1	0	0		2012	-1
254	b0329	b0329	5/27/2011	1/11/2011	5/27/2011	Planned	Planned	UC	1	0	0		2012	-1
255	b0329	b0329	5/27/2011	1/11/2011	5/27/2011	Planned	Planned	UC	0	1	0		2012	-1
256	b0329.1	b0329	6/10/2009	1/11/2011	6/10/2009	Post-2005	Planned	IS	0	1	0		2010	1
257	b0329.2	b0329	2/10/2011	1/11/2011	2/10/2011	Post-2005	Planned	IS	0	1	0		2012	-1
258	b0329.3	b0329	6/1/2011	1/11/2011	6/1/2011	Planned	Planned	UC	0	1	0		2012	-1
259	b0329.4	b0329	6/1/2011	1/11/2011	6/1/2011	Planned	Planned	UC	0	1	0		2012	-1
260	b0331	b0331	5/21/2009	5/21/2009	5/21/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
261	b0332	b0332	5/30/2013	5/30/2013	5/30/2013	Planned	Planned	EP	0	1	0		2014	-3
262	b0333	b0333	12/14/2007	12/14/2007	12/14/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
263	b0334	b0334	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	UC	0	1	0		2012	-1
264	b0335	b0335	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	UC	0	1	0		2012	-1
265	b0336	b0336	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	EP	0	1	0		2012	-1
266	b0337	b0337	5/14/2009	5/14/2009	5/14/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
267	b0338	b0338	5/14/2010	5/14/2010	5/14/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
268	b0339	b0339	3/27/2009	3/27/2009	3/27/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
269	b0340	b0340	4/20/2009	4/20/2009	4/20/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
270	b0341	b0341	4/10/2006	4/10/2006	4/10/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
271	b0342	b0342	5/19/2010	5/19/2010	5/19/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
272	b0343	b0343	11/19/2010	11/19/2010	11/19/2010	Post-2005	Post-2005	IS	0	0	0		2011	0
273	b0344	b0344	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	UC	0	0	0		2012	-1
274	b0345	b0345	5/28/2010	5/28/2010	5/28/2010	Post-2005	Post-2005	IS	0	0	0		2011	0
275	b0347.1	b0347	5/20/2011	10/8/2010	5/20/2011	Planned	Planned	UC	1	0	0		2012	-1
276	b0347.10	b0347	6/4/2010	10/8/2010	6/4/2010	Post-2005	Planned	IS	1	0	0		2011	0
277	b0347.11	b0347	6/4/2010	10/8/2010	6/4/2010	Post-2005	Planned	IS	1	0	0		2011	0
278	b0347.12	b0347	6/4/2010	10/8/2010	6/4/2010	Post-2005	Planned	IS	1	0	0		2011	0
279	b0347.13	b0347	6/4/2010	10/8/2010	6/4/2010	Post-2005	Planned	IS	1	0	0		2011	0
280	b0347.14	b0347	6/4/2010	10/8/2010	6/4/2010	Post-2005	Planned	IS	1	0	0		2011	0
281	b0347.15	b0347	6/4/2010	10/8/2010	6/4/2010	Post-2005	Planned	IS	1	0	0		2011	0
282	b0347.16	b0347	4/23/2010	10/8/2010	4/23/2010	Post-2005	Planned	IS	1	0	0		2011	0
283	b0347.17	b0347	11/12/2010	10/8/2010	11/12/2010	Post-2005	Planned	IS	1	0	0		2011	0
284	b0347.18	b0347	1/18/2011	10/8/2010	1/18/2011	Post-2005	Planned	IS	1	0	0		2012	-1
285	b0347.19	b0347	4/1/2011	10/8/2010	4/1/2011	Planned	Planned	UC	1	0	0		2012	-1
286	b0347.2	b0347	5/13/2011	10/8/2010	5/13/2011	Planned	Planned	UC	1	0	0		2012	-1
287	b0347.20	b0347	12/2/2010	10/8/2010	12/2/2010	Post-2005	Planned	IS	1	0	0		2011	0
288	b0347.21	b0347	2/9/2011	10/8/2010	2/9/2011	Post-2005	Planned	IS	1	0	0		2012	-1

	A	AM	AN	AO	AP	AQ	AR	AS
58	Upgrade ID	Load Ratio Project Costs	One Entity Project Costs	DFAX allocated Project Costs	Dayton DFAX Project Costs			
217	b0286	0	1.4	0	0			
218	b0287	10.5	0	0	0.00			
219	b0288	0	0	33.4	0			
220	b0289.1	0	2.361	0	0			
221	b0290	18	0	0	0.00			
222	b0291	0	0.85	0	0			
223	b0292	0	0.1	0	0			
224	b0293.1	0	0.228	0	0			
225	b0295	0	0.3	0	0			
226	b0296	0	1.704	0	0			
227	b0298	0	0	55	0			
228	b0298.1	0	1	0	0			
229	b0299	0	2.125	0	0			
230	b0301	0	2.125	0	0			
231	b0302	0	3.725	0	0			
232	b0303	0	2	0	0			
233	b0305	0	0	0	0			
234	b0306	0	1	0	0			
235	b0307	0	4.6	0	0			
236	b0308	0	0.6	0	0			
237	b0309	0	1	0	0			
238	b0310	0	20.295	0	0			
239	b0311	0	3.1	0	0			
240	b0312	0	5.4	0	0			
241	b0314	0	0.375	0	0			
242	b0318	0	13.442	0	0			
243	b0319	0	36.7	0	0			
244	b0320	0	15	0	0			
245	b0322	0	4.2	0	0			
246	b0323	0	2	0	0			
247	b0325	0	5.6	0	0			
248	b0326	0	12.8	0	0			
249	b0327	0	0	6	0			
250	b0328.1	243	0	0	0.00			
251	b0328.2	119	0	0	0.00			
252	b0328.3	10	0	0	0.00			
253	b0328.4	10	0	0	0.00			
254	b0329	173.491	0	0	0.00			
255	b0329	0	49.73	0	0			
256	b0329.1	0	0.158	0	0			
257	b0329.2	0	0.184	0	0			
258	b0329.3	0	0.184	0	0			
259	b0329.4	0	0.184	0	0			
260	b0331	0	11	0	0			
261	b0332	0	0.7	0	0			
262	b0333	0	0.01	0	0			
263	b0334	0	0.7	0	0			
264	b0335	0	15	0	0			
265	b0336	0	0.05	0	0			
266	b0337	0	6.5	0	0			
267	b0338	0	3.3	0	0			
268	b0339	0	2.5	0	0			
269	b0340	0	0.05	0	0			
270	b0341	0	0.5	0	0			
271	b0342	0	3.3	0	0			
272	b0343	0	0	5.2	0			
273	b0344	0	0	0.35	0			
274	b0345	0	0	5.3	0			
275	b0347.1	310	0	0	0.00			
276	b0347.10	0.06	0	0	0.00			
277	b0347.11	0.06	0	0	0.00			
278	b0347.12	0.06	0	0	0.00			
279	b0347.13	0.06	0	0	0.00			
280	b0347.14	0.06	0	0	0.00			
281	b0347.15	0.06	0	0	0.00			
282	b0347.16	0.06	0	0	0.00			
283	b0347.17	0.193	0	0	0.00			
284	b0347.18	0.193	0	0	0.00			
285	b0347.19	0.193	0	0	0.00			
286	b0347.2	308	0	0	0.00			
287	b0347.20	0.193	0	0	0.00			
288	b0347.21	0.193	0	0	0.00			

	A	B	C	D	E	F	G	H	I	J	K
58	Upgrade ID	Description	TO	AEC	AEP	APS	BGE	ComEd	Dayton	DL	DPL
289	b0347.22	Replace Meadow Brook 138 kV breaker ‘MD-15’	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
290	b0347.23	Replace Meadow Brook 138 kV breaker ‘MD-16’	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
291	b0347.24	Replace Meadow Brook 138 kV breaker ‘MD-17’	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
292	b0347.25	Replace Meadow Brook 138 kV breaker ‘MD-18’	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
293	b0347.26	Replace Meadow Brook 138 kV breaker ‘MD-22#1 CAP’	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
294	b0347.27	Replace Meadow Brook 138 kV breaker ‘MD-4’	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
295	b0347.28	Replace Meadow Brook 138 kV breaker ‘MD-5’	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
296	b0347.29	Replace Meadowbrook 138 kV breaker ‘MD-6’	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
297	b0347.3	Build new 502 Junction 500 kV substation	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
298	b0347.30	Replace Meadowbrook 138 kV breaker ‘MD-7’	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
299	b0347.31	Replace Meadowbrook 138 kV breaker ‘MD-8’	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
300	b0347.32	Replace Meadowbrook 138 kV breaker ‘MD-9’	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
301	b0347.4	Upgrade Meadow Brook 500 kV substation	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
302	b0347.5	Replace Harrison 500 kV breaker HL-3	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
303	b0347.6	Upgrade (per ABB inspection) breaker HL-6	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
304	b0347.7	Upgrade (per ABB inspection) breaker HL-7	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
305	b0347.8	Upgrade (per ABB inspection) breaker HL-8	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
306	b0347.9	Upgrade (per ABB inspection) breaker HL-10	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
307	b0348	Upgrade Stonewall – Inwood 138 kV with 954 ACSR cor	APS			100.0%					
308	b0350	Implement Operating Procedure of closing the Glendon	JCPL								
309	b0351	Reconductor Tunnel – Grays Ferry 230 kV	PECO								
310	b0352	Reconductor Tunnel – Parrish 230 kV	PECO								
311	b0353.1	Install 2% reactors on both lines from Eddystone – Llane	PECO								
312	b0353.2	Install identical second 230/138 kV transformer in parall	PECO								
313	b0353.3	Replace Whitpain 230 kV breaker 135	PECO								
314	b0353.4	Replace Whitpain 230 kV breaker 145	PECO								
315	b0354	Eddystone – Island Road Upgrade line terminal equipme	PECO								
316	b0355	Reconductor Master – North Philadelphia 230 kV line	PECO								
317	b0356	Replace wave trap on the Portland – Greystone 230 kV	JCPL/ME								
318	b0357	Reconductor Buckingham – Pleasant Valley 230 kV	PECO								
319	b0358	Reconductor the PSEG portion of Buckingham – Pleasa	PSEG								
320	b0361	Change tap of limiting CT at Morristown 230 kV	JCPL								
321	b0362	Change tap setting of limiting CT at Pohatcong 230 kV	JCPL								
322	b0363	Change tap setting of limiting CT at Windsor 230 kV	JCPL								
323	b0364	Change tap setting of CT at Cookstown 230 kV	JCPL								
324	b0366	Install a 4th Ritchie 230/69 kV transformer	PEPCO								
325	b0367.1	Reconductor circuit “23035” for Dickerson – Quince Orc	PEPCO	1.8%			26.5%				3.3%
326	b0367.2	Reconductor circuit “23033” for Dickerson – Quince Orc	PEPCO	1.8%			26.5%				3.3%
327	b0369	Install 100 MVAR Dynamic Reactive Device at Airydale	PENELEC	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
328	b0370	Install 500 MVAR Dynamic Reactive Device at Airydale	PENELEC	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
329	b0371	Make the Metuchen 138 kV bus solid and upgrade 6 bre	PSEG								
330	b0372	Make the Athenia 138 kV bus solid and upgrade 2 break	PSEG								
331	b0373	Convert Doubs – Monocacy 138 kV facilities to 230 kV c	APS	1.8%		76.8%					2.6%
332	b0376	Install 300 MVAR capacitor at Conemaugh 500 kV subst	PENELEC	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
333	b0380	Reconductor 17713 from Burnham – Wildwood and 761	ComEd					100.0%			
334	b0382	Cambridge Sub – Close through to Todd Substation	DPL								100.0%
335	b0383	Wye Mills AT-1 and AT-2 138/69 kV Replacements	DPL								100.0%
336	b0384	Replace Indian River AT-20 (400 MVA)	DPL								100.0%
337	b0385	Oak Hall to New Church (13765) Upgrade	DPL								100.0%
338	b0386	Cheswold/Kent (6768) Rebuild	DPL								100.0%
339	b0387	N. Seaford – Add a 2nd 138/69 kV autotransformer	DPL								100.0%
340	b0388	Hallwood/Parksley (6790-2) Upgrade	DPL								100.0%
341	b0389	Indian River AT-1 and AT-2 138/69 kV Replacements	DPL								100.0%
342	b0390	Rehoboth/Lewes (6751-1 and 6751-2) Upgrade	DPL								100.0%
343	b0392	East New Market Sub – Establish a 69 kV Bus Arrangen	DPL								100.0%
344	b0393	Replace terminal equipment at Harrison 500 kV and Bel	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
345	b0394	Reconductor 2.8 miles of Wolfs – Frontenac 138 kV line	ComEd					100.0%			
346	b0401.1	Replace Roseland 230 kV breaker BS6-7	PSEG								
347	b0401.2	Replace Roseland 138 kV breaker O-1315	PSEG								
348	b0401.3	Replace Roseland 138 kV breaker S-1319	PSEG								
349	b0401.4	Replace Roseland 138 kV breaker T-1320	PSEG								
350	b0401.5	Replace Roseland 138 kV breaker G-1307	PSEG								
351	b0401.6	Replace Roseland 138 kV breaker P-1316	PSEG								
352	b0401.7	Replace Roseland 138 kV breaker 220-4	PSEG								
353	b0401.8	Replace W. Orange 138 kV breaker 132-4	PSEG								
354	b0403	2nd Dooms 500/230 kV transformer addition	Dominion			3.4%	4.2%				1.1%
355	b0404.1	Replace South Reading 230 kV breaker 107252	ME								
356	b0404.2	Replace South Reading 230 kV breaker 100652	ME								
357	b0406.1	Replace Mitchell 138 kV breaker “#4 bank”	APS			100.0%					
358	b0406.2	Replace Mitchell 138 kV breaker “#5 bank”	APS			100.0%					
359	b0406.3	Replace Mitchell 138 kV breaker “#2 transf”	APS			100.0%					
360	b0406.4	Replace Mitchell 138 kV breaker “#3 bank”	APS			100.0%					

	A	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
58	Upgrade ID	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL	PSEG	RE	UGI	Cost Estimate ($M)
289	b0347.22	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.19
290	b0347.23	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.19
291	b0347.24	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.19
292	b0347.25	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.19
293	b0347.26	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.19
294	b0347.27	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.19
295	b0347.28	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.19
296	b0347.29	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.19
297	b0347.3	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$88.00
298	b0347.30	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.19
299	b0347.31	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.19
300	b0347.32	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.19
301	b0347.4	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$25.00
302	b0347.5	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.70
303	b0347.6	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.06
304	b0347.7	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.06
305	b0347.8	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.06
306	b0347.9	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.06
307	b0348														$1.60
308	b0350				100.0%										$0.40
309	b0351							100.0%							$0.75
310	b0352							100.0%							$0.15
311	b0353.1							100.0%							$2.10
312	b0353.2							100.0%							$8.54
313	b0353.3							100.0%							$0.50
314	b0353.4							100.0%							$0.50
315	b0354							100.0%							$1.10
316	b0355							100.0%							$4.20
317	b0356				100.0%										$0.08
318	b0357		1.9%		37.2%		4.5%					54.1%	2.3%		$6.20
319	b0358											100.0%			$3.00
320	b0361				100.0%										$0.03
321	b0362				100.0%										$0.03
322	b0363				100.0%										$0.03
323	b0364				100.0%										$0.03
324	b0366									100.0%					$13.10
325	b0367.1		0.1%		2.7%	1.2%	0.3%	4.8%		52.5%	3.2%	3.8%			$10.00
326	b0367.2		0.1%		2.7%	1.2%	0.3%	4.8%		52.5%	3.2%	3.8%			$10.00
327	b0369	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$12.00
328	b0370	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$32.00
329	b0371											100.0%			$2.25
330	b0372											100.0%			$0.75
331	b0373				4.5%	9.2%	0.4%				4.6%				$9.40
332	b0376	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$2.00
333	b0380														$7.00
334	b0382														$1.49
335	b0383														$2.29
336	b0384														$3.74
337	b0385														$0.87
338	b0386														$1.56
339	b0387														$3.12
340	b0388														$0.47
341	b0389														$7.80
342	b0390														$1.54
343	b0392														$2.16
344	b0393	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.09
345	b0394														$3.00
346	b0401.1											100.0%			$0.38
347	b0401.2											100.0%			$0.38
348	b0401.3											100.0%			$0.38
349	b0401.4											100.0%			$0.38
350	b0401.5											100.0%			$0.38
351	b0401.6											100.0%			$0.38
352	b0401.7											100.0%			$0.38
353	b0401.8											100.0%			$0.38
354	b0403	83.9%								7.4%					$8.00
355	b0404.1					100.0%									$0.23
356	b0404.2					100.0%									$0.23
357	b0406.1														$0.12
358	b0406.2														$0.12
359	b0406.3														$0.12
360	b0406.4														$0.12

	A	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL
58	Upgrade ID	Project ID	Upgrade Date In-Service	Project Average In-Service Date	Date to use	Upgrade Source	Project Source	Project Status	Projects Allocated by Load	Projects Attributed to one entity	Projects Attributed to Dayton entity	Year In Service Override	First Full Year in Service	Project Age
289	b0347.22	b0347	5/1/2011	10/8/2010	5/1/2011	Planned	Planned	UC	1	0	0		2012	-1
290	b0347.23	b0347	11/2/2010	10/8/2010	11/2/2010	Post-2005	Planned	IS	1	0	0		2011	0
291	b0347.24	b0347	1/14/2011	10/8/2010	1/14/2011	Post-2005	Planned	IS	1	0	0		2012	-1
292	b0347.25	b0347	5/1/2011	10/8/2010	5/1/2011	Planned	Planned	UC	1	0	0		2012	-1
293	b0347.26	b0347	4/1/2011	10/8/2010	4/1/2011	Planned	Planned	UC	1	0	0		2012	-1
294	b0347.27	b0347	6/1/2011	10/8/2010	6/1/2011	Planned	Planned	UC	1	0	0		2012	-1
295	b0347.28	b0347	2/23/2011	10/8/2010	2/23/2011	Post-2005	Planned	IS	1	0	0		2012	-1
296	b0347.29	b0347	6/1/2011	10/8/2010	6/1/2011	Planned	Planned	UC	1	0	0		2012	-1
297	b0347.3	b0347	4/17/2010	10/8/2010	4/17/2010	Post-2005	Planned	IS	1	0	0		2011	0
298	b0347.30	b0347	1/6/2011	10/8/2010	1/6/2011	Post-2005	Planned	IS	1	0	0		2012	-1
299	b0347.31	b0347	2/15/2011	10/8/2010	2/15/2011	Post-2005	Planned	IS	1	0	0		2012	-1
300	b0347.32	b0347	5/1/2011	10/8/2010	5/1/2011	Planned	Planned	UC	1	0	0		2012	-1
301	b0347.4	b0347	5/13/2011	10/8/2010	5/13/2011	Planned	Planned	UC	1	0	0		2012	-1
302	b0347.5	b0347	12/11/2007	10/8/2010	12/11/2007	Post-2005	Planned	IS	1	0	0		2008	3
303	b0347.6	b0347	4/1/2010	10/8/2010	4/1/2010	Post-2005	Planned	IS	1	0	0		2011	0
304	b0347.7	b0347	4/1/2010	10/8/2010	4/1/2010	Post-2005	Planned	IS	1	0	0		2011	0
305	b0347.8	b0347	4/1/2010	10/8/2010	4/1/2010	Post-2005	Planned	IS	1	0	0		2011	0
306	b0347.9	b0347	4/1/2010	10/8/2010	4/1/2010	Post-2005	Planned	IS	1	0	0		2011	0
307	b0348	b0348	11/12/2010	11/12/2010	11/12/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
308	b0350	b0350	11/19/2007	11/19/2007	11/19/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
309	b0351	b0351	2/11/2011	2/11/2011	2/11/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
310	b0352	b0352	5/20/2011	5/20/2011	5/20/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
311	b0353.1	b0353	11/19/2010	3/4/2011	11/19/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
312	b0353.2	b0353	4/27/2011	3/4/2011	4/27/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
313	b0353.3	b0353	5/13/2011	3/4/2011	5/13/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
314	b0353.4	b0353	2/15/2011	3/4/2011	2/15/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
315	b0354	b0354	12/10/2010	12/10/2010	12/10/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
316	b0355	b0355	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
317	b0356	b0356	5/5/2008	5/5/2008	5/5/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
318	b0357	b0357	5/16/2011	5/16/2011	5/16/2011	Post-2005	Post-2005	IS	0	0	0		2012	-1
319	b0358	b0358	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	EP	0	1	0		2012	-1
320	b0361	b0361	1/19/2010	1/19/2010	1/19/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
321	b0362	b0362	1/19/2010	1/19/2010	1/19/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
322	b0363	b0363	1/19/2010	1/19/2010	1/19/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
323	b0364	b0364	1/19/2010	1/19/2010	1/19/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
324	b0366	b0366	10/8/2010	10/8/2010	10/8/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
325	b0367.1	b0367	#N/A	6/19/2011	6/19/2011	#N/A	Planned	#N/A	0	0	0		2012	-1
326	b0367.2	b0367	#N/A	6/19/2011	6/19/2011	#N/A	Planned	#N/A	0	0	0		2012	-1
327	b0369	b0369	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	1	0	0		2016	-5
328	b0370	b0370	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	1	0	0		2016	-5
329	b0371	b0371	2/28/2009	2/28/2009	2/28/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
330	b0372	b0372	5/1/2010	5/1/2010	5/1/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
331	b0373	b0373	5/29/2009	5/29/2009	5/29/2009	Post-2005	Post-2005	IS	0	0	0		2010	1
332	b0376	b0376	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	1	0	0		2016	-5
333	b0380	b0380	3/15/2008	3/15/2008	3/15/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
334	b0382	b0382	6/1/2007	6/1/2007	6/1/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
335	b0383	b0383	6/6/2006	6/6/2006	6/6/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
336	b0384	b0384	6/12/2006	6/12/2006	6/12/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
337	b0385	b0385	5/31/2008	5/31/2008	5/31/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
338	b0386	b0386	5/22/2007	5/22/2007	5/22/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
339	b0387	b0387	5/31/2008	5/31/2008	5/31/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
340	b0388	b0388	12/1/2008	12/1/2008	12/1/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
341	b0389	b0389	10/23/2009	10/23/2009	10/23/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
342	b0390	b0390	5/25/2006	5/25/2006	5/25/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
343	b0392	b0392	6/8/2007	6/8/2007	6/8/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
344	b0393	b0393	5/1/2008	5/1/2008	5/1/2008	Post-2005	Post-2005	IS	1	0	0		2009	2
345	b0394	b0394	4/27/2008	4/27/2008	4/27/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
346	b0401.1	b0401	10/30/2008	9/19/2008	10/30/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
347	b0401.2	b0401	10/30/2008	9/19/2008	10/30/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
348	b0401.3	b0401	2/26/2009	9/19/2008	2/26/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
349	b0401.4	b0401	1/15/2009	9/19/2008	1/15/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
350	b0401.5	b0401	12/31/2008	9/19/2008	12/31/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
351	b0401.6	b0401	2/7/2009	9/19/2008	2/7/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
352	b0401.7	b0401	6/16/2009	9/19/2008	6/16/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
353	b0401.8	b0401	5/6/2006	9/19/2008	5/6/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
354	b0403	b0403	5/30/2007	5/30/2007	5/30/2007	Post-2005	Post-2005	IS	0	0	0		2008	3
355	b0404.1	b0404	3/26/2008	1/13/2009	3/26/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
356	b0404.2	b0404	11/3/2009	1/13/2009	11/3/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
357	b0406.1	b0406	6/1/2006	5/6/2007	6/1/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
358	b0406.2	b0406	6/1/2006	5/6/2007	6/1/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
359	b0406.3	b0406	5/17/2007	5/6/2007	5/17/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
360	b0406.4	b0406	5/17/2007	5/6/2007	5/17/2007	Post-2005	Post-2005	IS	0	1	0		2008	3

	A	AM	AN	AO	AP	AQ	AR	AS
58	Upgrade ID	Load Ratio Project Costs	One Entity Project Costs	DFAX allocated Project Costs	Dayton DFAX Project Costs			
289	b0347.22	0.193	0	0	0.00			
290	b0347.23	0.193	0	0	0.00			
291	b0347.24	0.193	0	0	0.00			
292	b0347.25	0.193	0	0	0.00			
293	b0347.26	0.193	0	0	0.00			
294	b0347.27	0.193	0	0	0.00			
295	b0347.28	0.193	0	0	0.00			
296	b0347.29	0.193	0	0	0.00			
297	b0347.3	88	0	0	0.00			
298	b0347.30	0.193	0	0	0.00			
299	b0347.31	0.193	0	0	0.00			
300	b0347.32	0.193	0	0	0.00			
301	b0347.4	25	0	0	0.00			
302	b0347.5	0.7	0	0	0.00			
303	b0347.6	0.06	0	0	0.00			
304	b0347.7	0.06	0	0	0.00			
305	b0347.8	0.06	0	0	0.00			
306	b0347.9	0.06	0	0	0.00			
307	b0348	0	1.6	0	0			
308	b0350	0	0.4	0	0			
309	b0351	0	0.75	0	0			
310	b0352	0	0.15	0	0			
311	b0353.1	0	2.1	0	0			
312	b0353.2	0	8.54	0	0			
313	b0353.3	0	0.5	0	0			
314	b0353.4	0	0.5	0	0			
315	b0354	0	1.1	0	0			
316	b0355	0	4.2	0	0			
317	b0356	0	0.08	0	0			
318	b0357	0	0	6.2	0			
319	b0358	0	3	0	0			
320	b0361	0	0.025	0	0			
321	b0362	0	0.025	0	0			
322	b0363	0	0.025	0	0			
323	b0364	0	0.025	0	0			
324	b0366	0	13.1	0	0			
325	b0367.1	0	0	10	0			
326	b0367.2	0	0	10	0			
327	b0369	12	0	0	0.00			
328	b0370	32	0	0	0.00			
329	b0371	0	2.25	0	0			
330	b0372	0	0.75	0	0			
331	b0373	0	0	9.4	0			
332	b0376	2	0	0	0.00			
333	b0380	0	7	0	0			
334	b0382	0	1.493	0	0			
335	b0383	0	2.293	0	0			
336	b0384	0	3.743	0	0			
337	b0385	0	0.865	0	0			
338	b0386	0	1.555	0	0			
339	b0387	0	3.121	0	0			
340	b0388	0	0.47	0	0			
341	b0389	0	7.8	0	0			
342	b0390	0	1.54	0	0			
343	b0392	0	2.16	0	0			
344	b0393	0.09	0	0	0.00			
345	b0394	0	3	0	0			
346	b0401.1	0	0.375	0	0			
347	b0401.2	0	0.375	0	0			
348	b0401.3	0	0.375	0	0			
349	b0401.4	0	0.375	0	0			
350	b0401.5	0	0.375	0	0			
351	b0401.6	0	0.375	0	0			
352	b0401.7	0	0.375	0	0			
353	b0401.8	0	0.375	0	0			
354	b0403	0	0	8	0			
355	b0404.1	0	0.2325	0	0			
356	b0404.2	0	0.2325	0	0			
357	b0406.1	0	0.12	0	0			
358	b0406.2	0	0.12	0	0			
359	b0406.3	0	0.12	0	0			
360	b0406.4	0	0.12	0	0			

	A	B	C	D	E	F	G	H	I	J	K
58	Upgrade ID	Description	TO	AEC	AEP	APS	BGE	ComEd	Dayton	DL	DPL
361	b0406.5	Replace Mitchell 138 kV breaker “Charlerio #2”	APS			100.0%					
362	b0406.6	Replace Mitchell 138 kV breaker “Charlerio #1”	APS			100.0%					
363	b0406.7	Replace Mitchell 138 kV breaker “Shepler Hill Jct”	APS			100.0%					
364	b0406.8	Replace Mitchell 138 kV breaker “Union Jct”	APS			100.0%					
365	b0406.9	Replace Mitchell 138 kV breaker “#1-2 138 kV bus tie”	APS			100.0%					
366	b0407.1	Replace Marlowe 138 kV breaker “#1 transf”	APS			100.0%					
367	b0407.2	Replace Marlowe 138 kV breaker “MBO”	APS			100.0%					
368	b0407.3	Replace Marlowe 138 kV breaker “BMA”	APS			100.0%					
369	b0407.4	Replace Marlowe 138 kV breaker “BMR”	APS			100.0%					
370	b0407.5	Replace Marlowe 138 kV breaker “WC-1”	APS			100.0%					
371	b0407.6	Replace Marlowe 138 kV breaker “R11”	APS			100.0%					
372	b0407.7	Replace Marlowe 138 kV breaker “W”	APS			100.0%					
373	b0407.8	Replace Marlowe 138 kV breaker “138 kV bus tie”	APS			100.0%					
374	b0408.1	Replace Trissler 138 kV breaker “Belmont 604”	APS			100.0%					
375	b0408.2	Replace Trissler 138 kV breaker “Edgelawn 90”	APS			100.0%					
376	b0409.1	Replace Weirton 138 kV breaker “Wylie Ridge 210”	APS			100.0%					
377	b0409.2	Replace Weirton 138 kV breaker “Wylie Ridge 216”	APS			100.0%					
378	b0410	Replace Glen Falls 138 kV breaker “McAlpin 30”	APS			100.0%					
379	b0411	Install 4th 500/230 kV transformer at New Freedom	PSEG	47.0%							
380	b0412	Retension Pruntytown – Mt. Storm 500 kV to a 3502 MV	Dominion	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
381	b0415	Increase the temperature ratings of the Edgemoor – Chr	DPL								100.0%
382	b0417	Reconductor Mitchell – Shepler Hill Junction 138kV with	APS			100.0%					
383	b0419	Install a breaker failure auto-restoration scheme at Bedi	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
384	b0420	Operating Procedure to open the Black Oak 500/138 kV	APS			100.0%					
385	b0423	Reconductor Readington (2555) – Branchburg (4962) 2	PSEG								
386	b0423.1	Upgrade terminal equipment at Readington (substation	JCPL								
387	b0424	Replace Readington wavetrap on Readington (2555) – I	PSEG								
388	b0425	Reconductor Linden (4996) – Tosco (5190) 230 kV circu	PSEG								
389	b0426	Reconductor Tosco (5190) – G22_MTX5 (90220) 230 k	PSEG								
390	b0427	Reconductor Athenia (4954) – Saddle Brook (5020) 230	PSEG								
391	b0428	Replace Roseland wavetrap on Roseland (5019) – Wes	PSEG								
392	b0431	Monroe Upgrade New Freedom strand bus	AEC	100.0%							
393	b0437	Spare Keeney 500/230 kV transformer	DPL								100.0%
394	b0438	Spare Whitpain 500/230 kV transformer	PECO								
395	b0439	Spare Deans 500/230 kV transformer	PSEG								
396	b0440	Spare Juniata 500/230 kV transformer	PPL								
397	b0441	Additional spare Keeney 500/230 kV transformer	DPL								100.0%
398	b0442	Spare Keystone 500/230 kV transformer	PENELEC								
399	b0443	Spare Peach Bottom 500/230 kV transformer	PECO								
400	b0445	Upgrade substation equipment and reconductor the Tidd	APS			100.0%					
401	b0446.1	Upgrade Bayway 138 kV breaker #2-3	PSEG								
402	b0446.2	Upgrade Bayway 138 kV breaker #3-4	PSEG								
403	b0446.3	Upgrade Bayway 138 kV breaker #6-7	PSEG								
404	b0446.4	Upgrade the breaker associated with TX 132-5 on Linde	PSEG								
405	b0447	Replace Cook 345 kV breaker M2	AEP		100.0%						
406	b0448	Replace Cook 345 kV breaker N2	AEP		100.0%						
407	b0450	Install 150 MVAR Capacitor at Fredricksburg 230 kV	Dominion								
408	b0451	Install 25 MVAR Capacitor at Somerset 115 kV	Dominion								
409	b0453.1	Convert Remingtion – Sowego 115 kV to 230 kV	Dominion			0.3%	3.0%				0.0%
410	b0453.2	Add Sowego – Gainsville 230 kV	Dominion			0.3%	3.0%				0.0%
411	b0453.3	Add Sowego 230/115 kV transformer	Dominion			0.3%	3.0%				0.0%
412	b0454	Reconductor 2.4 miles of Newport News – Chuckatuck 2	Dominion								
413	b0455	Add 2nd Endless Caverns 230/115 kV transformer	Dominion			32.7%	7.0%				1.8%
414	b0456	Reconductor 9.4 miles of Edinburg – Mt. Jackson 115 k	Dominion			33.7%	12.2%				
415	b0457	Replace both wave traps on Dooms – Lexington 500 kV	Dominion	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
416	b0460	Raise limiting structures on Albright – Bethelboro 138 k	APS			100.0%					
417	b0461	Install a 115.2 MVAR capacitor at Will County 138 kV	ComEd					100.0%			
418	b0462	Install a 57.6 MVAR capacitor at Joliet 138 kV	ComEd					100.0%			
419	b0463	Install a 115.2 MVAR capacitor at East Frankfort 138 kV	ComEd					100.0%			
420	b0465	Install a 115.2 MVAR capacitor at Libertyville 138 kV	ComEd					100.0%			
421	b0466	Install a 115.2 MVAR capacitor at Prospect Heights 138	ComEd					100.0%			
422	b0467.1	Reconductor the Dickerson – Pleasant View 230 kV circ	PEPCO	1.8%		19.7%	22.1%				3.7%
423	b0467.2	Reconductor the Dickerson – Pleasant View 230 kV circ	Dominion	1.8%		19.7%	22.1%				3.7%
424	b0468	Build a new substation with two 150 MVA transformers b	PPL								
425	b0469	Install 130 MVAR capacitor at West Shore 230 kV line	PPL								
426	b0470	Install 138 kV breaker at Roseland and close the Rosela	PSEG								
427	b0471	Replace the wave traps at both Lawrence and Pleasant	PSEG								
428	b0472	Increase the emergency rating of Saddle Brook – Atheni	PSEG								
429	b0473	Move the 150 MVAR mobile capacitor from Aldene 230 k	PSEG								
430	b0474	Add a fourth 230/115 kV transformer, two 230 kV circuit	BGE				100.0%				
431	b0475	Create two 230 kV ring buses at North West, add two 23	BGE				100.0%				
432	b0476	Rebuild High Ridge 230 kV substation to Breaker and H	BGE				100.0%				

	A	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
58	Upgrade ID	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL	PSEG	RE	UGI	Cost Estimate ($M)
361	b0406.5														$0.12
362	b0406.6														$0.12
363	b0406.7														$0.12
364	b0406.8														$0.12
365	b0406.9														$0.12
366	b0407.1														$0.12
367	b0407.2														$0.12
368	b0407.3														$0.12
369	b0407.4														$0.12
370	b0407.5														$0.12
371	b0407.6														$0.12
372	b0407.7														$0.12
373	b0407.8														$0.12
374	b0408.1														$0.12
375	b0408.2														$0.12
376	b0409.1														$0.12
377	b0409.2														$0.12
378	b0410														$0.12
379	b0411				7.0%		0.3%	23.4%				22.3%			$25.24
380	b0412	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.00
381	b0415														$0.00
382	b0417														$3.00
383	b0419	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.00
384	b0420														$0.00
385	b0423											100.0%			$7.00
386	b0423.1				100.0%										$0.10
387	b0424											100.0%			$0.16
388	b0425											100.0%			$2.18
389	b0426											100.0%			$0.61
390	b0427											100.0%			$1.50
391	b0428											100.0%			$0.05
392	b0431														$0.10
393	b0437														$2.50
394	b0438							100.0%							$2.50
395	b0439											100.0%			$2.50
396	b0440										100.0%				$7.56
397	b0441														$2.50
398	b0442								100.0%						$2.50
399	b0443							100.0%							$2.50
400	b0445														$0.03
401	b0446.1											100.0%			$0.30
402	b0446.2											100.0%			$0.30
403	b0446.3											100.0%			$0.30
404	b0446.4											100.0%			$0.30
405	b0447														$0.80
406	b0448														$0.80
407	b0450	100.0%													$1.20
408	b0451	100.0%													$0.80
409	b0453.1	92.8%				0.0%				3.9%					$8.10
410	b0453.2	92.8%				0.0%				3.9%					$22.00
411	b0453.3	92.8%				0.0%				3.9%					$5.00
412	b0454	100.0%													$1.17
413	b0455	50.8%								7.7%					$6.00
414	b0456	40.1%								14.1%					$7.00
415	b0457	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.50
416	b0460														$0.04
417	b0461														$2.30
418	b0462														$2.30
419	b0463														$2.30
420	b0465														$2.30
421	b0466														$1.50
422	b0467.1				0.7%	2.5%	0.0%	5.5%		41.9%	2.1%				$9.00
423	b0467.2				0.7%	2.5%	0.0%	5.5%		41.9%	2.1%				$5.00
424	b0468		0.1%		4.6%		0.2%	1.8%	0.3%		86.9%	6.0%	0.2%		$22.40
425	b0469										100.0%				$3.78
426	b0470											100.0%			$1.00
427	b0471											100.0%			$0.50
428	b0472		1.0%									95.4%	3.6%		$25.00
429	b0473											100.0%			$1.50
430	b0474														$10.30
431	b0475														$38.00
432	b0476														$44.00

	A	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL
58	Upgrade ID	Project ID	Upgrade Date In-Service	Project Average In-Service Date	Date to use	Upgrade Source	Project Source	Project Status	Projects Allocated by Load	Projects Attributed to one entity	Projects Attributed to Dayton entity	Year In Service Override	First Full Year in Service	Project Age
361	b0406.5	b0406	4/16/2007	5/6/2007	4/16/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
362	b0406.6	b0406	5/17/2007	5/6/2007	5/17/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
363	b0406.7	b0406	3/14/2008	5/6/2007	3/14/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
364	b0406.8	b0406	11/2/2007	5/6/2007	11/2/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
365	b0406.9	b0406	10/31/2007	5/6/2007	10/31/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
366	b0407.1	b0407	11/7/2008	8/26/2008	11/7/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
367	b0407.2	b0407	11/21/2007	8/26/2008	11/21/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
368	b0407.3	b0407	11/12/2008	8/26/2008	11/12/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
369	b0407.4	b0407	10/6/2008	8/26/2008	10/6/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
370	b0407.5	b0407	11/12/2008	8/26/2008	11/12/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
371	b0407.6	b0407	11/7/2008	8/26/2008	11/7/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
372	b0407.7	b0407	5/18/2008	8/26/2008	5/18/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
373	b0407.8	b0407	10/4/2008	8/26/2008	10/4/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
374	b0408.1	b0408	12/7/2007	12/19/2007	12/7/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
375	b0408.2	b0408	12/31/2007	12/19/2007	12/31/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
376	b0409.1	b0409	6/1/2006	8/19/2006	6/1/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
377	b0409.2	b0409	11/6/2006	8/19/2006	11/6/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
378	b0410	b0410	10/12/2007	10/12/2007	10/12/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
379	b0411	b0411	11/2/2007	11/2/2007	11/2/2007	Post-2005	Post-2005	IS	0	0	0		2008	3
380	b0412	b0412	4/20/2007	4/20/2007	4/20/2007	Post-2005	Post-2005	IS	1	0	0		2008	3
381	b0415	b0415	12/15/2006	12/15/2006	12/15/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
382	b0417	b0417	5/6/2010	5/6/2010	5/6/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
383	b0419	b0419	6/15/2010	6/15/2010	6/15/2010	Post-2005	Post-2005	IS	1	0	0		2011	0
384	b0420	b0420	6/7/2010	6/7/2010	6/7/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
385	b0423	b0423	11/3/2010	8/18/2011	11/3/2010	Post-2005	Planned	IS	0	1	0		2011	0
386	b0423.1	b0423	6/1/2012	8/18/2011	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
387	b0424	b0424	11/15/2009	11/15/2009	11/15/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
388	b0425	b0425	11/15/2010	11/15/2010	11/15/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
389	b0426	b0426	1/7/2011	1/7/2011	1/7/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
390	b0427	b0427	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	UC	0	1	0		2013	-2
391	b0428	b0428	10/10/2009	10/10/2009	10/10/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
392	b0431	b0431	6/7/2010	6/7/2010	6/7/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
393	b0437	b0437	6/1/2008	6/1/2008	6/1/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
394	b0438	b0438	6/1/2007	6/1/2007	6/1/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
395	b0439	b0439	12/1/2009	12/1/2009	12/1/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
396	b0440	b0440	12/31/2010	12/31/2010	12/31/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
397	b0441	b0441	6/1/2008	6/1/2008	6/1/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
398	b0442	b0442	8/30/2010	8/30/2010	8/30/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
399	b0443	b0443	6/1/2007	6/1/2007	6/1/2007	Post-2005	Post-2005	IS	0	1	0		2008	3
400	b0445	b0445	7/1/2011	7/1/2011	7/1/2011	Planned	Planned	UC	0	1	0		2012	-1
401	b0446.1	b0446	2/9/2008	7/7/2006	2/9/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
402	b0446.2	b0446	2/22/2008	7/7/2006	2/22/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
403	b0446.3	b0446	6/1/1997	7/7/2006	7/7/2006	Post-2005	Post-2005	IS	0	1	0		2007	4
404	b0446.4	b0446	12/28/2009	7/7/2006	12/28/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
405	b0447	b0447	11/20/2008	11/20/2008	11/20/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
406	b0448	b0448	11/2/2009	11/2/2009	11/2/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
407	b0450	b0450	5/31/2012	5/31/2012	5/31/2012	Planned	Planned	EP	0	1	0		2013	-2
408	b0451	b0451	5/4/2012	5/4/2012	5/4/2012	Planned	Planned	EP	0	1	0		2013	-2
409	b0453.1	b0453	5/4/2012	6/15/2011	5/4/2012	Planned	Planned	EP	0	0	0		2013	-2
410	b0453.2	b0453	7/30/2012	6/15/2011	7/30/2012	Planned	Planned	EP	0	0	0		2013	-2
411	b0453.3	b0453	6/11/2009	6/15/2011	6/11/2009	Post-2005	Planned	IS	0	0	0		2010	1
412	b0454	b0454	5/31/2012	5/31/2012	5/31/2012	Planned	Planned	EP	0	1	0		2013	-2
413	b0455	b0455	5/13/2009	5/13/2009	5/13/2009	Post-2005	Post-2005	IS	0	0	0		2010	1
414	b0456	b0456	10/16/2009	10/16/2009	10/16/2009	Post-2005	Post-2005	IS	0	0	0		2010	1
415	b0457	b0457	5/31/2012	5/31/2012	5/31/2012	Planned	Planned	EP	1	0	0		2013	-2
416	b0460	b0460	1/1/2012	1/1/2012	1/1/2012	Planned	Planned	UC	0	1	0		2013	-2
417	b0461	b0461	5/30/2009	5/30/2009	5/30/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
418	b0462	b0462	4/28/2010	4/28/2010	4/28/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
419	b0463	b0463	5/30/2009	5/30/2009	5/30/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
420	b0465	b0465	5/16/2008	5/16/2008	5/16/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
421	b0466	b0466	4/2/2008	4/2/2008	4/2/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
422	b0467.1	b0467	6/1/2011	5/31/2011	6/1/2011	Planned	Planned	UC	0	0	0		2012	-1
423	b0467.2	b0467	5/31/2011	5/31/2011	5/31/2011	Planned	Planned	UC	0	0	0		2012	-1
424	b0468	b0468	5/31/2012	5/31/2012	5/31/2012	Planned	Planned	EP	0	0	0		2013	-2
425	b0469	b0469	5/31/2012	5/31/2012	5/31/2012	Planned	Planned	EP	0	1	0		2013	-2
426	b0470	b0470	4/1/2009	4/1/2009	4/1/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
427	b0471	b0471	6/1/2010	6/1/2010	6/1/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
428	b0472	b0472	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	0	0		2013	-2
429	b0473	b0473	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
430	b0474	b0474	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
431	b0475	b0475	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	UC	0	1	0		2013	-2
432	b0476	b0476	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	UC	0	1	0		2013	-2

	A	AM	AN	AO	AP	AQ	AR	AS
58	Upgrade ID	Load Ratio Project Costs	One Entity Project Costs	DFAX allocated Project Costs	Dayton DFAX Project Costs			
361	b0406.5	0	0.12	0	0			
362	b0406.6	0	0.12	0	0			
363	b0406.7	0	0.12	0	0			
364	b0406.8	0	0.12	0	0			
365	b0406.9	0	0.12	0	0			
366	b0407.1	0	0.12	0	0			
367	b0407.2	0	0.12	0	0			
368	b0407.3	0	0.12	0	0			
369	b0407.4	0	0.12	0	0			
370	b0407.5	0	0.12	0	0			
371	b0407.6	0	0.12	0	0			
372	b0407.7	0	0.12	0	0			
373	b0407.8	0	0.12	0	0			
374	b0408.1	0	0.12	0	0			
375	b0408.2	0	0.12	0	0			
376	b0409.1	0	0.12	0	0			
377	b0409.2	0	0.12	0	0			
378	b0410	0	0.12	0	0			
379	b0411	0	0	25.24	0			
380	b0412	0	0	0	0.00			
381	b0415	0	0	0	0			
382	b0417	0	3	0	0			
383	b0419	0	0	0	0.00			
384	b0420	0	0	0	0			
385	b0423	0	7	0	0			
386	b0423.1	0	0.1	0	0			
387	b0424	0	0.16	0	0			
388	b0425	0	2.18	0	0			
389	b0426	0	0.61	0	0			
390	b0427	0	1.5	0	0			
391	b0428	0	0.05	0	0			
392	b0431	0	0.1	0	0			
393	b0437	0	2.5	0	0			
394	b0438	0	2.5	0	0			
395	b0439	0	2.5	0	0			
396	b0440	0	7.555	0	0			
397	b0441	0	2.5	0	0			
398	b0442	0	2.5	0	0			
399	b0443	0	2.5	0	0			
400	b0445	0	0.03	0	0			
401	b0446.1	0	0.3	0	0			
402	b0446.2	0	0.3	0	0			
403	b0446.3	0	0.3	0	0			
404	b0446.4	0	0.3	0	0			
405	b0447	0	0.8	0	0			
406	b0448	0	0.8	0	0			
407	b0450	0	1.2	0	0			
408	b0451	0	0.8	0	0			
409	b0453.1	0	0	8.097	0			
410	b0453.2	0	0	22	0			
411	b0453.3	0	0	5	0			
412	b0454	0	1.17	0	0			
413	b0455	0	0	6	0			
414	b0456	0	0	7	0			
415	b0457	0.5	0	0	0.00			
416	b0460	0	0.04	0	0			
417	b0461	0	2.3	0	0			
418	b0462	0	2.3	0	0			
419	b0463	0	2.3	0	0			
420	b0465	0	2.3	0	0			
421	b0466	0	1.5	0	0			
422	b0467.1	0	0	9	0			
423	b0467.2	0	0	5	0			
424	b0468	0	0	22.4	0			
425	b0469	0	3.777	0	0			
426	b0470	0	1	0	0			
427	b0471	0	0.5	0	0			
428	b0472	0	0	25	0			
429	b0473	0	1.5	0	0			
430	b0474	0	10.3	0	0			
431	b0475	0	38	0	0			
432	b0476	0	44	0	0			

	A	B	C	D	E	F	G	H	I	J	K
58	Upgrade ID	Description	TO	AEC	AEP	APS	BGE	ComEd	Dayton	DL	DPL
433	b0477	500/230 kV transformer #1 with three single phase trans	BGE				90.6%				
434	b0478	Reconductor the four circuits from Burches Hill to Palme	PEPCO			1.7%	1.8%				
435	b0480	Rebuild Lank – Five Points 69 kV	DPL								100.0%
436	b0481	Replace wave trap at Indian River 138 kV on the Omar -	DPL								100.0%
437	b0482	Rebuild Millsboro – Zoar REA 69 kV	DPL								100.0%
438	b0483	Replace Church 138/69 kV transformer and add two bre	DPL								100.0%
439	b0483.1	Build Oak Hall – Wattsville 138 kV line	DPL								100.0%
440	b0483.2	Add 138/69 kV transformer at Wattsville	DPL								100.0%
441	b0483.3	Establish 138 kV bus position at Oak Hall	DPL								100.0%
442	b0484	Re-tension Worcester – Berlin 69 kV for 125ºC	DPL								100.0%
443	b0485	Re-tension Taylor – North Seaford 69 kV for 125ºC	DPL								100.0%
444	b0487	Build new 500 kV transmission facilities from Susquehar	PPL	1.9%	17.3%	6.0%	5.0%	15.0%	2.5%	2.0%	2.9%
445	b0487.1	Install Lackawanna 500/230 kV transformer and upgrade	PPL								
446	b0489	Build new 500 kV transmission facilities from Pennsylva	PSEG	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
447	b0489.1	Replace Athenia 230 kV breaker 31H	PSEG								
448	b0489.2	Replace Bergen 230 kV breaker 10H	PSEG								
449	b0489.3	Replace Saddlebrook 230 kV breaker 21P	PSEG								
450	b0489.4	Install two Roseland 500/230 kV transformers as part of	PSEG	5.2%				0.3%	0.0%		1.8%
451	b0489.5	Replace Roseland 230 kV breaker '42H' with 80 kA	PSEG	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
452	b0489.6	Replace Roseland 230 kV breaker '51H' with 80 kA	PSEG	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
453	b0489.7	Replace Roseland 230 kV breaker '71H' with 80 kA	PSEG	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
454	b0489.8	Replace Roseland 230 kV breaker '31H' with 80 kA	PSEG	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
455	b0489.9	Replace Roseland 230 kV breaker '11H' with 80 kA	PSEG	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
456	b0490	Construct an Amos – Bedington 765 kV circuit (AEP equ	AEP	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
457	b0491	Construct an Amos – Bedington 765 kV circuit (APS equ	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
458	b0492	Construct a Bedington – Kemptown 500 kV circuit	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
459	b0493	Reconductor both Cheswick – Logan's Ferry 138 kV circ	DL							100.0%	
460	b0494.1	Install a 2nd Red Lion 230/138 kV	DPL								100.0%
461	b0494.2	Hares Corner – Relay Improvement	DPL								100.0%
462	b0494.3	Reybold – Relay Improvement	DPL								100.0%
463	b0494.4	New Castle – Relay Improvement	DPL								100.0%
464	b0495	Replace existing Kammer 765/500 kV transformer with a	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
465	b0496	Replace existing 500/230 kV transformer at Brighton	PEPCO			5.7%	29.7%				
466	b0497	Install a second Conastone – Graceton 230 kV circuit	BGE	9.1%							17.0%
467	b0498	Loop the 5021 circuit into New Freedom 500 kV substati	PSEG	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
468	b0498.1	Upgrade the 20H circuit breaker	PSEG								
469	b0498.2	Upgrade the 22H circuit breaker	PSEG								
470	b0498.3	Upgrade the 30H circuit breaker	PSEG								
471	b0498.4	Upgrade the 32H circuit breaker	PSEG								
472	b0498.5	Upgrade the 40H circuit breaker	PSEG								
473	b0498.6	Upgrade the 42H circuit breaker	PSEG								
474	b0499	Install third Burches Hill 500/230 kV transformer	PEPCO			3.5%	7.3%				
475	b0501	New Brady 345 kV substation and 345 / 138 kV transforı	DL			6.7%				93.3%	
476	b0502	New Underground Carson – Brady – Brunot Island 345 k	DL			6.7%				93.3%	
477	b0502.1	Replace Dravosburg 138 kV breaker 'Z79 Illinois'	DL							100.0%	
478	b0502.2	Replace Dravosburg 138 kV breaker 'Z15 Elrama'	DL							100.0%	
479	b0502.3	Replace Dravosburg 138 kV breaker 'Z73 West Mifflin'	DL							100.0%	
480	b0502.4	Replace Dravosburg 138 kV breaker 'Z70 Elywn'	DL							100.0%	
481	b0502.5	Replace Elrama 138 kV breaker 'No. 1 69 kV Autofmr'	DL							100.0%	
482	b0503	Loop existing Carson – Oakland 138 kV into new Brady	DL			6.7%				93.3%	
483	b0504	Add two advanced technology circuit breakers at Hangir	AEP	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
484	b0505	Reconductor the North Wales – Whitpain 230 kV circuit	PECO	8.6%							7.8%
485	b0506	Reconductor the North Wales – Hartman 230 kV circuit	PECO	8.6%							7.8%
486	b0508.1	Replace station cable at Hartman on the Warrington - H	PECO								
487	b0509	Reconductor the Jarrett – Heaton 230 kV circuit	PECO								
488	b0510	Install two 115.3 MVAR capacitors at Elmhurst 138 kV	ComEd					100.0%			
489	b0511	Reconductor the Pleasant Valley – Woodstock 138 kV li	ComEd					100.0%			
490	b0512	MAPP Project – install new 500 kV transmission from Pc	BGE	2.0%	18.0%	6.3%	4.9%	15.6%	2.5%	2.0%	2.8%
491	b0512	MAPP Project – install new 500 kV transmission from Pc	PEPCO	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
492	b0512	MAPP Project – install new 500 kV transmission from Pc	Dominion	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
493	b0512	MAPP Project – install new 500 kV transmission from Pc	BGE	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
494	b0512.5	Advance n0716 (Ox - Replace 230kV breaker L242)	Dominion	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
495	b0512.6	Advance n0717 (Possum Point - Replace 230kV breake	Dominion	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
496	b0513	Rebuild the Ocean Bay – Maridel 69 kV line	DPL								100.0%
497	b0515	Replace Lewistown circuit breaker 1LY Yeagertown	PENELEC								
498	b0516	Replace Lewistown circuit breaker 2LY Yeagertown	PENELEC								
499	b0517	Replace Shawville bus section circuit breaker	PENELEC								
500	b0518	Replace Homer City circuit breaker 201 Johnstown	PENELEC								
501	b0519	Replace Keystone circuit breaker 4 Transformer - 20	PENELEC								
502	b0520	Replace Gilbert circuit breaker 12A	JCPL								
503	b0526	Build two Ritchie – Benning Station A 230 kV lines	PEPCO	0.8%			16.8%				1.2%
504	b0527	Replace existing 12 MVAR capacitor at Bethany with a 3	DPL								100.0%

	A	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
58	Upgrade ID	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL	PSEG	RE	UGI	Cost Estimate ($M)
433	b0477					1.5%		0.9%		4.0%	3.0%				$29.90
434	b0478									96.5%					$16.00
435	b0480														$1.40
436	b0481														$0.20
437	b0482														$1.80
438	b0483														$5.00
439	b0483.1														$2.60
440	b0483.2														$1.40
441	b0483.3														$0.53
442	b0484														$0.44
443	b0485														$0.36
444	b0487	13.6%	0.2%		4.5%	2.2%	0.5%	6.3%	2.1%	4.8%	5.4%	7.6%	0.3%		$427.00
445	b0487.1		0.1%						16.9%		77.7%	5.1%	0.2%		$59.00
446	b0489	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$705.00
447	b0489.1											100.0%			$0.40
448	b0489.2											100.0%			$0.40
449	b0489.3											100.0%			$0.40
450	b0489.4		0.5%		34.1%		3.4%	10.3%	0.6%			42.2%	1.6%		$45.00
451	b0489.5	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.80
452	b0489.6	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.80
453	b0489.7	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.80
454	b0489.8	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.80
455	b0489.9	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.80
456	b0490	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$698.00
457	b0491	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$772.09
458	b0492	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$629.91
459	b0493														$2.40
460	b0494.1														$2.52
461	b0494.2														$0.80
462	b0494.3														$0.17
463	b0494.4														$0.17
464	b0495	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$42.00
465	b0496	10.9%								53.7%					$18.00
466	b0497		0.2%		9.7%	1.5%	0.5%	31.0%			16.5%	14.2%	0.5%		$49.20
467	b0498	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$17.00
468	b0498.1											100.0%			$0.40
469	b0498.2											100.0%			$0.40
470	b0498.3											100.0%			$0.40
471	b0498.4											100.0%			$0.40
472	b0498.5											100.0%			$0.40
473	b0498.6											100.0%			$0.40
474	b0499									89.2%					$31.00
475	b0501														$82.00
476	b0502														$85.10
477	b0502.1														$0.33
478	b0502.2														$0.33
479	b0502.3														$0.35
480	b0502.4														$0.35
481	b0502.5														$0.35
482	b0503														$18.30
483	b0504	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$5.17
484	b0505							83.7%							$2.00
485	b0506							83.7%							$2.20
486	b0508.1							100.0%							$0.38
487	b0509							100.0%							$0.53
488	b0510														$4.40
489	b0511														$3.30
490	b0512	13.3%	0.2%		4.2%	2.1%	0.5%	5.9%	2.1%	4.7%	5.6%	7.1%	0.3%		$60.40
491	b0512	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$1,055.00
492	b0512	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$8.10
493	b0512	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$4.60
494	b0512.5	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.03
495	b0512.6	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.03
496	b0513														$2.10
497	b0515								100.0%						$0.40
498	b0516								100.0%						$0.40
499	b0517								100.0%						$0.31
500	b0518								100.0%						$0.31
501	b0519								100.0%						$0.31
502	b0520				100.0%										$0.31
503	b0526				1.4%	0.6%	0.1%	2.1%		74.9%		2.1%	0.1%		$71.30
504	b0527														$1.76

	A	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL
58	Upgrade ID	Project ID	Upgrade Date In-Service	Project Average In-Service Date	Date to use	Upgrade Source	Project Source	Project Status	Projects Allocated by Load	Projects Attributed to one entity	Projects Attributed to Dayton entity	Year In Service Override	First Full Year in Service	Project Age
433	b0477	b0477	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	UC	0	0	0		2012	-1
434	b0478	b0478	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	0	0		2013	-2
435	b0480	b0480	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	EP	0	1	0		2012	-1
436	b0481	b0481	12/31/2008	12/31/2008	12/31/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
437	b0482	b0482	12/31/2008	12/31/2008	12/31/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
438	b0483	b0483	1/14/2010	7/5/2011	1/14/2010	Post-2005	Planned	IS	0	1	0		2011	0
439	b0483.1	b0483	12/31/2011	7/5/2011	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
440	b0483.2	b0483	12/31/2011	7/5/2011	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
441	b0483.3	b0483	12/31/2011	7/5/2011	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
442	b0484	b0484	4/30/2010	4/30/2010	4/30/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
443	b0485	b0485	5/13/2010	5/13/2010	5/13/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
444	b0487	b0487	4/24/2015	4/24/2015	4/24/2015	Planned	Planned	EP	1	0	0		2016	-5
445	b0487.1	b0487	4/24/2015	4/24/2015	4/24/2015	Planned	Planned	UC	0	0	0		2016	-5
446	b0489	b0489	6/1/2015	1/19/2012	6/1/2015	Planned	Planned	EP	1	0	0		2016	-5
447	b0489.1	b0489	6/1/2012	1/19/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
448	b0489.2	b0489	6/1/2013	1/19/2012	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
449	b0489.3	b0489	10/1/2009	1/19/2012	10/1/2009	Post-2005	Planned	IS	0	1	0		2010	1
450	b0489.4	b0489	6/1/2014	1/19/2012	6/1/2014	Planned	Planned	UC	0	0	0		2015	-4
451	b0489.5	b0489	12/7/2010	1/19/2012	12/7/2010	Post-2005	Planned	IS	1	0	0		2011	0
452	b0489.6	b0489	12/23/2010	1/19/2012	12/23/2010	Post-2005	Planned	IS	1	0	0		2011	0
453	b0489.7	b0489	2/28/2011	1/19/2012	2/28/2011	Planned	Planned	EP	1	0	0		2012	-1
454	b0489.8	b0489	2/28/2011	1/19/2012	2/28/2011	Planned	Planned	EP	1	0	0		2012	-1
455	b0489.9	b0489	11/14/2010	1/19/2012	11/14/2010	Post-2005	Planned	IS	1	0	0		2011	0
456	b0490	b0490	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	1	0	0	2026	2026	-15
457	b0491	b0491	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	1	0	0	2026	2026	-15
458	b0492	b0492	6/1/2015	8/21/2014	6/1/2015	Planned	Planned	EP	1	0	0	2026	2026	-15
459	b0493	b0493	5/16/2009	5/16/2009	5/16/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
460	b0494.1	b0494	5/13/2009	5/14/2009	5/13/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
461	b0494.2	b0494	5/14/2009	5/14/2009	5/14/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
462	b0494.3	b0494	5/15/2009	5/14/2009	5/15/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
463	b0494.4	b0494	5/16/2009	5/14/2009	5/16/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
464	b0495	b0495	10/24/2009	10/24/2009	10/24/2009	Post-2005	Post-2005	IS	1	0	0		2010	1
465	b0496	b0496	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	0	0		2014	-3
466	b0497	b0497	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	0	0		2015	-4
467	b0498	b0498	11/12/2008	8/14/2008	11/12/2008	Post-2005	Post-2005	IS	1	0	0		2009	2
468	b0498.1	b0498	9/12/2008	8/14/2008	9/12/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
469	b0498.2	b0498	9/27/2008	8/14/2008	9/27/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
470	b0498.3	b0498	6/19/2008	8/14/2008	6/19/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
471	b0498.4	b0498	6/5/2008	8/14/2008	6/5/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
472	b0498.5	b0498	10/14/2008	8/14/2008	10/14/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
473	b0498.6	b0498	5/12/2008	8/14/2008	5/12/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
474	b0499	b0499	12/31/2012	12/31/2012	12/31/2012	Planned	Planned	EP	0	0	0		2013	-2
475	b0501	b0501	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	UC	0	0	0		2013	-2
476	b0502	b0502	6/1/2016	3/12/2015	6/1/2016	Planned	Planned	EP	0	0	0		2017	-6
477	b0502.1	b0502	10/1/2015	3/12/2015	10/1/2015	Planned	Planned	EP	0	1	0		2016	-5
478	b0502.2	b0502	12/31/2015	3/12/2015	12/31/2015	Planned	Planned	EP	0	1	0		2016	-5
479	b0502.3	b0502	6/1/2016	3/12/2015	6/1/2016	Planned	Planned	EP	0	1	0		2017	-6
480	b0502.4	b0502	8/3/2009	3/12/2015	8/3/2009	Post-2005	Planned	IS	0	1	0		2010	1
481	b0502.5	b0502	12/31/2016	3/12/2015	12/31/2016	Planned	Planned	EP	0	1	0		2017	-6
482	b0503	b0503	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	0	0		2013	-2
483	b0504	b0504	3/16/2009	3/16/2009	3/16/2009	Post-2005	Post-2005	IS	1	0	0		2010	1
484	b0505	b0505	5/22/2010	5/22/2010	5/22/2010	Post-2005	Post-2005	IS	0	0	0		2011	0
485	b0506	b0506	1/15/2010	1/15/2010	1/15/2010	Post-2005	Post-2005	IS	0	0	0		2011	0
486	b0508.1	b0508	5/19/2011	5/19/2011	5/19/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
487	b0509	b0509	3/1/2011	3/1/2011	3/1/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
488	b0510	b0510	12/10/2009	12/10/2009	12/10/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
489	b0511	b0511	5/30/2009	5/30/2009	5/30/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
490	b0512	b0512	#N/A	3/20/2013	3/20/2013	#N/A	Planned	#N/A	1	0	0	2018	2018	-7
491	b0512	b0512	#N/A	3/20/2013	3/20/2013	#N/A	Planned	#N/A	1	0	0	2018	2018	-7
492	b0512	b0512	#N/A	3/20/2013	3/20/2013	#N/A	Planned	#N/A	1	0	0	2018	2018	-7
493	b0512	b0512	#N/A	3/20/2013	3/20/2013	#N/A	Planned	#N/A	1	0	0	2018	2018	-7
494	b0512.5	b0512	6/1/2013	3/20/2013	6/1/2013	Planned	Planned	EP	1	0	0		2014	-3
495	b0512.6	b0512	6/1/2011	3/20/2013	6/1/2011	Planned	Planned	UC	1	0	0		2012	-1
496	b0513	b0513	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
497	b0515	b0515	12/7/2009	12/7/2009	12/7/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
498	b0516	b0516	12/7/2009	12/7/2009	12/7/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
499	b0517	b0517	10/15/2009	10/15/2009	10/15/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
500	b0518	b0518	10/30/2008	10/30/2008	10/30/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
501	b0519	b0519	3/18/2009	3/18/2009	3/18/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
502	b0520	b0520	12/10/2009	12/10/2009	12/10/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
503	b0526	b0526	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	0	0		2013	-2
504	b0527	b0527	2/28/2010	2/28/2010	2/28/2010	Post-2005	Post-2005	IS	0	1	0		2011	0

	A	AM	AN	AO	AP	AQ	AR	AS
58	Upgrade ID	Load Ratio Project Costs	One Entity Project Costs	DFAX allocated Project Costs	Dayton DFAX Project Costs			
433	b0477	0	0	29.9	0			
434	b0478	0	0	16	0			
435	b0480	0	1.4	0	0			
436	b0481	0	0.2	0	0			
437	b0482	0	1.8	0	0			
438	b0483	0	5	0	0			
439	b0483.1	0	2.6	0	0			
440	b0483.2	0	1.4	0	0			
441	b0483.3	0	0.53	0	0			
442	b0484	0	0.44	0	0			
443	b0485	0	0.36	0	0			
444	b0487	427	0	0	0.00			
445	b0487.1	0	0	59	0			
446	b0489	705	0	0	0.00			
447	b0489.1	0	0.4	0	0			
448	b0489.2	0	0.4	0	0			
449	b0489.3	0	0.4	0	0			
450	b0489.4	0	0	45	0.01			
451	b0489.5	0.8	0	0	0.00			
452	b0489.6	0.8	0	0	0.00			
453	b0489.7	0.8	0	0	0.00			
454	b0489.8	0.8	0	0	0.00			
455	b0489.9	0.8	0	0	0.00			
456	b0490	698	0	0	0.00			
457	b0491	772.089	0	0	0.00			
458	b0492	629.911	0	0	0.00			
459	b0493	0	2.4	0	0			
460	b0494.1	0	2.523	0	0			
461	b0494.2	0	0.798998	0	0			
462	b0494.3	0	0.165277	0	0			
463	b0494.4	0	0.165	0	0			
464	b0495	42	0	0	0.00			
465	b0496	0	0	18	0			
466	b0497	0	0	49.2	0			
467	b0498	17	0	0	0.00			
468	b0498.1	0	0.4	0	0			
469	b0498.2	0	0.4	0	0			
470	b0498.3	0	0.4	0	0			
471	b0498.4	0	0.4	0	0			
472	b0498.5	0	0.4	0	0			
473	b0498.6	0	0.4	0	0			
474	b0499	0	0	31	0			
475	b0501	0	0	82	0			
476	b0502	0	0	85.1	0			
477	b0502.1	0	0.33	0	0			
478	b0502.2	0	0.33	0	0			
479	b0502.3	0	0.35	0	0			
480	b0502.4	0	0.35	0	0			
481	b0502.5	0	0.35	0	0			
482	b0503	0	0	18.3	0			
483	b0504	5.168	0	0	0.00			
484	b0505	0	0	2	0			
485	b0506	0	0	2.2	0			
486	b0508.1	0	0.38	0	0			
487	b0509	0	0.53	0	0			
488	b0510	0	4.4	0	0			
489	b0511	0	3.3	0	0			
490	b0512	60.4	0	0	0.00			
491	b0512	1055	0	0	0.00			
492	b0512	8.1	0	0	0.00			
493	b0512	4.6	0	0	0.00			
494	b0512.5	0.025	0	0	0.00			
495	b0512.6	0.025	0	0	0.00			
496	b0513	0	2.1	0	0			
497	b0515	0	0.4	0	0			
498	b0516	0	0.4	0	0			
499	b0517	0	0.31	0	0			
500	b0518	0	0.31	0	0			
501	b0519	0	0.31	0	0			
502	b0520	0	0.31	0	0			
503	b0526	0	0	71.3	0			
504	b0527	0	1.76	0	0			

	A	B	C	D	E	F	G	H	I	J	K
58	Upgrade ID	Description	TO	AEC	AEP	APS	BGE	ComEd	Dayton	DL	DPL
505	b0528	Replace existing 69/12 kV transformer at Bethany with a	DPL								100.0%
506	b0529	Install an additional 8.4 MVAR capacitor at Grasonville 6	DPL								100.0%
507	b0530	Replace existing 12 MVAR capacitor at Wye Mills with a	DPL								100.0%
508	b0531	Create a four breaker 138 kV ring bus at Wye Mills and	DPL								100.0%
509	b0533	Reconductor the Powell Mountain – Sutton 138 kV line	APS			100.0%					
510	b0534	Install a 28.61 MVAR capacitor on Sutton 138 kV	APS			100.0%					
511	b0535	Install a 44 MVAR capacitor on Dutch Fork 138 kV	APS			100.0%					
512	b0536	Replace Doubs circuit breaker DJ1	APS			100.0%					
513	b0537	Replace Doubs circuit breaker DJ7	APS			100.0%					
514	b0538	Replace Doubs circuit breaker DJ10	APS			100.0%					
515	b0539	Replace Doubs circuit breaker DJ11	APS			100.0%					
516	b0540	Replace Doubs circuit breaker DJ12	APS			100.0%					
517	b0541	Replace Doubs circuit breaker DJ13	APS			100.0%					
518	b0542	Replace Doubs circuit breaker DJ20	APS			100.0%					
519	b0543	Replace Doubs circuit breaker DJ21	APS			100.0%					
520	b0546	Install a 20 MVAR capacitor at Shorewood substation	ComEd					100.0%			
521	b0547	Install a 15 MVAR capacitor at Wilmington substation	ComEd					100.0%			
522	b0549	Install 250 MVAR capacitor at Keystone 500 kV	PENELEC	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
523	b0550	Install 25 MVAR capacitor at Lewis Run 115 kV substati	PENELEC	8.0%		2.6%					10.9%
524	b0551	Install 25 MVAR capacitor at Saxton 115 kV substation	PENELEC	8.0%		2.6%					10.9%
525	b0552	Install 50 MVAR capacitor at Altoona 230 kV substation	PENELEC	8.0%		2.6%					10.9%
526	b0553	Install 50 MVAR capacitor at Raystown 230 kV substatic	PENELEC	8.0%		2.6%					10.9%
527	b0555	Install 100 MVAR capacitor at Johnstown 230 kV substa	PENELEC	8.0%		2.6%					10.9%
528	b0556	Install 50 MVAR capacitor at Grover 230 kV substation	PENELEC	8.0%		2.6%					10.9%
529	b0557	Install 75 MVAR capacitor at East Towanda 230 kV subs	PENELEC	8.0%		2.6%					10.9%
530	b0559	Install 200 MVAR capacitor at Meadow Brook 500 kV su	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
531	b0560	Install 250 MVAR capacitor at Kemptown 500 kV substa	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
532	b0563	Install 25 MVAR capacitor at Farmers Valley 115 kV sub	PENELEC								
533	b0564	Install 10 MVAR capacitor at Ridgeway 115 kV substatic	PENELEC								
534	b0565	Install 100 MVAR capacitor at Cox's Corner 230 kV subs	PSEG								
535	b0566	Rebuild the Trappe Tap – Todd 69 kV line	DPL								100.0%
536	b0567	Rebuild the Mt. Pleasant – Townsend 138 kV line	DPL								100.0%
537	b0568	Install a third Indian River 230/138 kV transformer	DPL								100.0%
538	b0569.1	Install a second East Frankfort 345/138 kV autotransforr	ComEd					100.0%			
539	b0569.2	Reconductor County Club Hills – Matteson 138 kV circu	ComEd					100.0%			
540	b0570	Reconductor East Side Lima – Sterling 138 kV	AEP		42.0%			58.0%			
541	b0572.1	Reconductor Albright – Mettiki – Williams – Parsons – L	APS			100.0%					
542	b0572.2	Reconductor Albright – Mettiki – Williams – Parsons – L	APS			100.0%					
543	b0573	Reconfigure circuits in Butler – Cabot 138 kV area	APS			100.0%					
544	b0575.1	Rebuild Hunterstown – Texas Eastern Tap 115 kV	ME								
545	b0575.2	Rebuild Texas Eastern Tap – Gardners 115 kV and ass	ME								
546	b0576	Move the Monroe 230/69 kV to Mickleton	AEC	100.0%							
547	b0577	Replace Fort Martin 500 kV breaker FL-1	APS	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
548	b0578	Replace Essex 138 kV breaker 4LM (C1355 line to ECR	PSEG								
549	b0579	Replace Essex 138 kV breaker 1LM (220-1 TX)	PSEG								
550	b0580	Replace Essex 138 kV breaker 1BM (BS1-3 tie)	PSEG								
551	b0581	Replace Essex 138 kV breaker 2BM (BS3-4 tie)	PSEG								
552	b0582	Replace Linden 138 kV breaker 3 (132-7 TX)	PSEG								
553	b0583	Install dual primary protection schemes on Gosport lines	Dominion								
554	b0584	Install 33 MVAR 138 kV capacitor at Necessity 138 kV	APS			100.0%					
555	b0585	Increase Cecil 138 kV capacitor size to 44 MVAR, repla	APS			100.0%					
556	b0586	Increase Whiteley 138 kV capacitor size to 44 MVAR	APS			100.0%					
557	b0587	Reconductor AP portion of Tidd – Carnegie 138 kV and	APS			100.0%					
558	b0588	Install a 40.8 MVAR 138 kV capacitor at Grassy Falls	APS			100.0%					
559	b0590	Replace #1 and #2 breakers at Charleroi 138 kV	APS			100.0%					
560	b0591	Install a 25.2 MVAR capacitor at Seneca Caverns 138 k	APS			100.0%					
561	b0592	Replace Metuchen 138 kV breaker '2-2 Transfer'	PSEG								
562	b0593	Eldred – Pine Grove 69 kV line Rebuild Part 2: 8 miles	PPL								
563	b0595	Rebuild Lackawanna – Edella 69 kV line to double circu	PPL								
564	b0596	Reconductor and rebuild Stanton – Providence 69 kV #1	PPL								
565	b0597	Reconductor Suburban – Providence 69 kV #1 and rese	PPL								
566	b0598	Reconductor Suburban Taps #1 and #2 for 69 kV line pc	PPL								
567	b0600	Tripp Park Substation: 69 kV tap off Stanton – Providen	PPL								
568	b0604	Add 150 MVA, 230/138/69 transformer #6 to Harwood su	PPL								
569	b0605	Reconductor Stanton – Old Forge 69 kV line and resecti	PPL								
570	b0606	New 138 kV tap off Monroe – Jackson 138 kV #1 line to	PPL								
571	b0607	New 138 kV taps off Monroe – Jackson 138 kV lines to S	PPL								
572	b0608	New 138 kV tap off Siegfried – Jackson 138 kV #2 to tra	PPL								
573	b0610	At South Farmersville substation, a new 69 kV tap off Na	PPL								
574	b0612	Rebuild Siegfried – North Bethlehem portion (6.7 miles)	PPL								
575	b0613	East Tannersville Substation: New 138 kV tap to new su	PPL								
576	b0614	Elroy substation expansion and new Elroy – Hatfield 138	PPL								

	A	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
58	Upgrade ID	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL	PSEG	RE	UGI	Cost Estimate ($M)
505	b0528														$5.30
506	b0529														$1.30
507	b0530														$1.80
508	b0531														$6.00
509	b0533														$7.10
510	b0534														$1.10
511	b0535														$0.50
512	b0536														$0.30
513	b0537														$0.30
514	b0538														$0.30
515	b0539														$0.30
516	b0540														$0.30
517	b0541														$0.30
518	b0542														$0.30
519	b0543														$0.30
520	b0546														$0.40
521	b0547														$0.30
522	b0549	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$4.50
523	b0550		0.5%		19.2%	1.6%	1.0%	21.4%			5.7%	28.2%	1.1%		$2.60
524	b0551		0.5%		19.2%	1.6%	1.0%	21.4%			5.7%	28.2%	1.1%		$1.30
525	b0552		0.5%		19.2%	1.6%	1.0%	21.4%			5.7%	28.2%	1.1%		$3.75
526	b0553		0.5%		19.2%	1.6%	1.0%	21.4%			5.7%	28.2%	1.1%		$3.75
527	b0555		0.5%		19.2%	1.6%	1.0%	21.4%			5.7%	28.2%	1.1%		$4.50
528	b0556		0.5%		19.2%	1.6%	1.0%	21.4%			5.7%	28.2%	1.1%		$3.75
529	b0557		0.5%		19.2%	1.6%	1.0%	21.4%			5.7%	28.2%	1.1%		$2.25
530	b0559	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$3.00
531	b0560	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$4.00
532	b0563								100.0%						$0.80
533	b0564								100.0%						$0.40
534	b0565											100.0%			$9.00
535	b0566														$12.00
536	b0567														$3.92
537	b0568														$7.30
538	b0569.1														$10.00
539	b0569.2														$1.25
540	b0570														$16.10
541	b0572.1														$4.56
542	b0572.2														$10.15
543	b0573														$1.18
544	b0575.1					100.0%									$2.10
545	b0575.2					100.0%									$1.90
546	b0576														$6.88
547	b0577	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.70
548	b0578											100.0%			$0.40
549	b0579											100.0%			$0.40
550	b0580											100.0%			$0.40
551	b0581											100.0%			$0.40
552	b0582											100.0%			$0.40
553	b0583	100.0%													$0.50
554	b0584														$0.77
555	b0585														$0.10
556	b0586														$0.64
557	b0587														$3.16
558	b0588														$0.50
559	b0590														$0.45
560	b0591														$0.63
561	b0592											100.0%			$0.40
562	b0593										100.0%				$7.67
563	b0595										100.0%				$5.09
564	b0596										100.0%				$6.20
565	b0597										100.0%				$1.20
566	b0598										100.0%				$4.08
567	b0600										100.0%				$0.70
568	b0604										100.0%				$14.93
569	b0605										100.0%				$4.48
570	b0606										100.0%				$0.49
571	b0607										100.0%				$0.85
572	b0608										100.0%				$0.56
573	b0610										100.0%				$0.33
574	b0612										100.0%				$5.80
575	b0613										100.0%				$0.42
576	b0614										100.0%				$34.24

	A	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL
58	Upgrade ID	Project ID	Upgrade Date In-Service	Project Average In-Service Date	Date to use	Upgrade Source	Project Source	Project Status	Projects Allocated by Load	Projects Attributed to one entity	Projects Attributed to Dayton entity	Year In Service Override	First Full Year in Service	Project Age
505	b0528	b0528	7/13/2010	7/13/2010	7/13/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
506	b0529	b0529	11/19/2010	11/19/2010	11/19/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
507	b0530	b0530	5/10/2010	5/10/2010	5/10/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
508	b0531	b0531	9/17/2010	9/17/2010	9/17/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
509	b0533	b0533	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	UC	0	1	0		2013	-2
510	b0534	b0534	7/7/2010	7/7/2010	7/7/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
511	b0535	b0535	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	UC	0	1	0		2012	-1
512	b0536	b0536	12/19/2008	12/19/2008	12/19/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
513	b0537	b0537	5/30/2008	5/30/2008	5/30/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
514	b0538	b0538	11/10/2008	11/10/2008	11/10/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
515	b0539	b0539	12/4/2009	12/4/2009	12/4/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
516	b0540	b0540	11/10/2008	11/10/2008	11/10/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
517	b0541	b0541	11/6/2009	11/6/2009	11/6/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
518	b0542	b0542	9/22/2008	9/22/2008	9/22/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
519	b0543	b0543	6/26/2009	6/26/2009	6/26/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
520	b0546	b0546	12/31/2010	12/31/2010	12/31/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
521	b0547	b0547	12/31/2010	12/31/2010	12/31/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
522	b0549	b0549	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	1	0	0		2013	-2
523	b0550	b0550	4/21/2008	4/21/2008	4/21/2008	Post-2005	Post-2005	IS	0	0	0		2009	2
524	b0551	b0551	4/8/2008	4/8/2008	4/8/2008	Post-2005	Post-2005	IS	0	0	0		2009	2
525	b0552	b0552	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	0	0		2013	-2
526	b0553	b0553	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	0	0		2013	-2
527	b0555	b0555	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5
528	b0556	b0556	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5
529	b0557	b0557	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	0	0		2013	-2
530	b0559	b0559	10/26/2009	10/26/2009	10/26/2009	Post-2005	Post-2005	IS	1	0	0		2010	1
531	b0560	b0560	1/1/2013	1/1/2013	1/1/2013	Planned	Planned	EP	1	0	0		2014	-3
532	b0563	b0563	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
533	b0564	b0564	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
534	b0565	b0565	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
535	b0566	b0566	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
536	b0567	b0567	6/8/2010	6/8/2010	6/8/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
537	b0568	b0568	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	UC	0	1	0		2012	-1
538	b0569.1	b0569	6/1/2013	11/30/2012	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
539	b0569.2	b0569	6/1/2012	11/30/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
540	b0570	b0570	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	0	0		2013	-2
541	b0572.1	b0572	6/1/2011	5/31/2012	6/1/2011	Planned	Planned	UC	0	1	0		2012	-1
542	b0572.2	b0572	6/1/2013	5/31/2012	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
543	b0573	b0573	9/1/2011	9/1/2011	9/1/2011	Planned	Planned	UC	0	1	0		2012	-1
544	b0575.1	b0575	5/7/2008	10/31/2008	5/7/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
545	b0575.2	b0575	4/27/2009	10/31/2008	4/27/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
546	b0576	b0576	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
547	b0577	b0577	10/1/2009	10/1/2009	10/1/2009	Post-2005	Post-2005	IS	1	0	0		2010	1
548	b0578	b0578	5/15/2009	5/15/2009	5/15/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
549	b0579	b0579	5/8/2009	5/8/2009	5/8/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
550	b0580	b0580	4/17/2009	4/17/2009	4/17/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
551	b0581	b0581	4/24/2009	4/24/2009	4/24/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
552	b0582	b0582	5/23/2009	5/23/2009	5/23/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
553	b0583	b0583	11/30/2010	11/30/2010	11/30/2010	Planned	Planned	EP	0	1	0		2011	0
554	b0584	b0584	5/8/2009	5/8/2009	5/8/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
555	b0585	b0585	11/29/2009	11/29/2009	11/29/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
556	b0586	b0586	12/31/2009	12/31/2009	12/31/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
557	b0587	b0587	7/1/2012	7/1/2012	7/1/2012	Planned	Planned	EP	0	1	0		2013	-2
558	b0588	b0588	11/16/2010	11/16/2010	11/16/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
559	b0590	b0590	10/21/2009	10/21/2009	10/21/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
560	b0591	b0591	11/22/2010	11/22/2010	11/22/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
561	b0592	b0592	5/24/2009	5/24/2009	5/24/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
562	b0593	b0593	5/31/2012	5/31/2012	5/31/2012	Planned	Planned	EP	0	1	0		2013	-2
563	b0595	b0595	12/31/2009	12/31/2009	12/31/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
564	b0596	b0596	5/31/2011	5/31/2011	5/31/2011	Planned	Planned	UC	0	1	0		2012	-1
565	b0597	b0597	11/30/2012	11/30/2012	11/30/2012	Planned	Planned	EP	0	1	0		2013	-2
566	b0598	b0598	11/30/2017	11/30/2017	11/30/2017	Planned	Planned	EP	0	1	0		2018	-7
567	b0600	b0600	5/31/2013	5/31/2013	5/31/2013	Planned	Planned	EP	0	1	0		2014	-3
568	b0604	b0604	5/31/2012	5/31/2012	5/31/2012	Planned	Planned	EP	0	1	0		2013	-2
569	b0605	b0605	11/30/2017	11/30/2017	11/30/2017	Planned	Planned	EP	0	1	0		2018	-7
570	b0606	b0606	12/31/2009	12/31/2009	12/31/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
571	b0607	b0607	10/25/2010	10/25/2010	10/25/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
572	b0608	b0608	7/7/2010	7/7/2010	7/7/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
573	b0610	b0610	5/31/2014	5/31/2014	5/31/2014	Planned	Planned	EP	0	1	0		2015	-4
574	b0612	b0612	10/22/2010	10/22/2010	10/22/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
575	b0613	b0613	5/30/2012	5/30/2012	5/30/2012	Planned	Planned	EP	0	1	0		2013	-2
576	b0614	b0614	5/31/2013	5/31/2013	5/31/2013	Planned	Planned	EP	0	1	0		2014	-3

	A	AM	AN	AO	AP	AQ	AR	AS
58	Upgrade ID	Load Ratio Project Costs	One Entity Project Costs	DFAX allocated Project Costs	Dayton DFAX Project Costs			
505	b0528	0	5.3	0	0			
506	b0529	0	1.3	0	0			
507	b0530	0	1.8	0	0			
508	b0531	0	6	0	0			
509	b0533	0	7.1	0	0			
510	b0534	0	1.1	0	0			
511	b0535	0	0.5	0	0			
512	b0536	0	0.3	0	0			
513	b0537	0	0.3	0	0			
514	b0538	0	0.3	0	0			
515	b0539	0	0.3	0	0			
516	b0540	0	0.3	0	0			
517	b0541	0	0.3	0	0			
518	b0542	0	0.3	0	0			
519	b0543	0	0.3	0	0			
520	b0546	0	0.4	0	0			
521	b0547	0	0.3	0	0			
522	b0549	4.5	0	0	0.00			
523	b0550	0	0	2.6	0			
524	b0551	0	0	1.3	0			
525	b0552	0	0	3.75	0			
526	b0553	0	0	3.75	0			
527	b0555	0	0	4.5	0			
528	b0556	0	0	3.75	0			
529	b0557	0	0	2.25	0			
530	b0559	3	0	0	0.00			
531	b0560	4	0	0	0.00			
532	b0563	0	0.8	0	0			
533	b0564	0	0.4	0	0			
534	b0565	0	9	0	0			
535	b0566	0	12	0	0			
536	b0567	0	3.92	0	0			
537	b0568	0	7.3	0	0			
538	b0569.1	0	10	0	0			
539	b0569.2	0	1.25	0	0			
540	b0570	0	0	16.1	0			
541	b0572.1	0	4.559	0	0			
542	b0572.2	0	10.154	0	0			
543	b0573	0	1.18	0	0			
544	b0575.1	0	2.1	0	0			
545	b0575.2	0	1.9	0	0			
546	b0576	0	6.875	0	0			
547	b0577	0.7	0	0	0.00			
548	b0578	0	0.4	0	0			
549	b0579	0	0.4	0	0			
550	b0580	0	0.4	0	0			
551	b0581	0	0.4	0	0			
552	b0582	0	0.4	0	0			
553	b0583	0	0.5	0	0			
554	b0584	0	0.77	0	0			
555	b0585	0	0.1	0	0			
556	b0586	0	0.64	0	0			
557	b0587	0	3.16	0	0			
558	b0588	0	0.5	0	0			
559	b0590	0	0.45	0	0			
560	b0591	0	0.63	0	0			
561	b0592	0	0.4	0	0			
562	b0593	0	7.669	0	0			
563	b0595	0	5.093	0	0			
564	b0596	0	6.203	0	0			
565	b0597	0	1.2	0	0			
566	b0598	0	4.084	0	0			
567	b0600	0	0.703	0	0			
568	b0604	0	14.925	0	0			
569	b0605	0	4.475	0	0			
570	b0606	0	0.491	0	0			
571	b0607	0	0.848	0	0			
572	b0608	0	0.56	0	0			
573	b0610	0	0.327	0	0			
574	b0612	0	5.798	0	0			
575	b0613	0	0.424	0	0			
576	b0614	0	34.238	0	0			

	A	B	C	D	E	F	G	H	I	J	K
58	Upgrade ID	Description	TO	AEC	AEP	APS	BGE	ComEd	Dayton	DL	DPL
577	b0615	Reconductor and rebuild 12 miles of Seidersville – Quak	PPL								
578	b0616	New Springfield 230/69 kV substation and transmission	PPL								
579	b0620	New 138 kV line and terminal at Monroe 230/138 substa	PPL								
580	b0621	New 138 kV line and terminal at Siegfried 230/138 kV su	PPL								
581	b0622	138 kV yard upgrades and transmission line rearrangem	PPL								
582	b0623	New West Shore – Whitehill Taps 138/69 kV double circ	PPL								
583	b0624	Reconductor Cumberland – Wertzville 69 kV portion (3.7	PPL								
584	b0625	Reconductor Mt. Allen – Rossmoyne 69 kV portions (1.6	PPL								
585	b0627	Replace UG cable from Walnut substation to Center City	PPL								
586	b0629	Lincoln substation: 69 kV tap to convert to modified Twin	PPL								
587	b0630	W. Hempfield – Donegal 69 kV line: Reconductor / rebu	PPL								
588	b0631	W. Hempfield – Donegal 69 kV line: Reconductor / rebu	PPL								
589	b0632	Terminate new S. Manheim – Donegal 69 kV circuit into	PPL								
590	b0634	Rebuild S. Manheim – Fuller 69 kV portion (1.0 mile) of	PPL								
591	b0635	Reconductor Fuller Tap – Landisville 69 kV (4.1 miles) i	PPL								
592	b0637	Replace 13 Oak Grove 230 kV breakers	PEPCO								
593	b0638	Replace 13 Oak Grove 230 kV breakers	PEPCO								
594	b0639	Replace 13 Oak Grove 230 kV breakers	PEPCO								
595	b0640	Replace 13 Oak Grove 230 kV breakers	PEPCO								
596	b0641	Replace 13 Oak Grove 230 kV breakers	PEPCO								
597	b0642	Replace 13 Oak Grove 230 kV breakers	PEPCO								
598	b0643	Replace 13 Oak Grove 230 kV breakers	PEPCO								
599	b0644	Replace 13 Oak Grove 230 kV breakers	PEPCO								
600	b0645	Replace 13 Oak Grove 230 kV breakers	PEPCO								
601	b0646	Replace 13 Oak Grove 230 kV breakers	PEPCO								
602	b0647	Replace 13 Oak Grove 230 kV breakers	PEPCO								
603	b0648	Replace 13 Oak Grove 230 kV breakers	PEPCO								
604	b0649	Replace 13 Oak Grove 230 kV breakers	PEPCO								
605	b0650	Reconductor Jackson – JE Baker – Taxville 115 kV line	ME								
606	b0652	Install bus tie circuit breaker on Yorkana 115 kV bus and	ME								
607	b0654	Reconfigure the Cambria Slope 115 kV and Wilmore Jun	PENELEC								
608	b0655	Reconfigure and expand the Glade 230 kV ring bus to e	PENELEC								
609	b0656	Add three breakers to form a ring bus at Altoona 230 kV	PENELEC								
610	b0657	Construct Boston Road 34.5 kV stations, construct Hysc	JCPL								
611	b0661	Replace existing baseline upgrade to install a 2nd Wolfs	ComEd					100.0%			
612	b0663	Reconductor East Frankfort - Goodings Grove 345 kV 'F	ComEd					100.0%			
613	b0664	Reconductor with 2x1033 ACSS conductor	PSEG								
614	b0665	Reconductor with 2x1033 ACSS conductor	PSEG								
615	b0668	Reconductor with 2x1033 ACSS conductor	PSEG								
616	b0671	Replace terminal equipment at both ends of line	PSEG								
617	b0673	Rebuild Elko – Carbon Center Junction using 230 kV co	APS			100.0%					
618	b0674	Construct new Osage – Whiteley 138 kV circuit	APS			97.7%				1.0%	
619	b0674.1	Replace the Osage 138 kV breaker 'CollinsF126'	APS			100.0%					
620	b0675.1	Convert Monocacy - Walkersville 138 kV to 230 kV	APS	1.0%		82.0%					0.9%
621	b0675.2	Convert Walkersville - Catoctin 138 kV to 230 kV	APS	1.0%		82.0%					0.9%
622	b0675.3	Convert Ringgold - Catoctin 138 kV to 230 kV	APS	1.0%		82.0%					0.9%
623	b0675.4	Convert Catoctin - Carroll 138 kV to 230 kV	APS	1.0%		82.0%					0.9%
624	b0675.5	Convert portion of Ringgold Substation from 138 kV to 2	APS	1.0%		82.0%					0.9%
625	b0675.6	Convert Catoctin Substation from 138 kV to 230 kV	APS	1.0%		82.0%					0.9%
626	b0675.7	Convert portion of Carroll Substation from 138 kV to 230	APS	1.0%		82.0%					0.9%
627	b0675.8	Convert Monocacy Substation from 138 kV to 230 kV	APS	1.0%		82.0%					0.9%
628	b0675.9	Convert Walkersville Substation from 138 kV to 230 kV	APS	1.0%		82.0%					0.9%
629	b0676.1	Reconductor Doubs - Lime Kiln (#207) 230kV	APS	0.6%		86.8%					0.5%
630	b0676.2	Reconductor Doubs - Lime Kiln (#231) 230kV	APS	0.6%		86.8%					0.5%
631	b0677	Reconductor Double Toll Gate – Riverton with 954 ACS	APS			100.0%					
632	b0678	Reconductor Glen Falls - Oak Mound 138kV with 954 AC	APS			100.0%					
633	b0679	Reconductor Grand Point – Letterkenny with 954 ACSR	APS			100.0%					
634	b0680	Reconductor Greene – Letterkenny with 954 ACSR	APS			100.0%					
635	b0681	Replace 600/5 CT's at Franklin 138 kV	APS			100.0%					
636	b0682	Replace 600/5 CT's at Whiteley 138 kV	APS			100.0%					
637	b0684	Reconductor Guilford – South Chambersburg with 954 A	APS			100.0%					
638	b0685	Replace Ringgold 230/138 kV #3 with larger transformer	APS			72.1%					
639	b0686	Install a 115.2 MVAR switched capacitor at East Frankfo	ComEd					100.0%			
640	b0687	Install a 115.2 MVAR switched capacitor at Plano 138 kV	ComEd					100.0%			
641	b0688	Install a 115.2 MVAR switched capacitor at Plano 138 kV	ComEd					100.0%			
642	b0689	Install a 115.2 MVAR switched capacitor at McCook 138	ComEd					100.0%			
643	b0690	Install a 115.2 MVAR switched capacitor at McCook 138	ComEd					100.0%			
644	b0691	Install a 115.2 MVAR switched capacitor at Wayne 138	ComEd					100.0%			
645	b0692	Install a 115.2 MVAR switched capacitor at Wayne 138	ComEd					100.0%			
646	b0693	Install a 115.2 MVAR switched capacitor at Crawford 13	ComEd					100.0%			
647	b0694	Install a 115.2 MVAR switched capacitor at Crawford 13	ComEd					100.0%			
648	b0695	Add a 300 MVAR SVC at Elmhurst 138 kV 'Red'	ComEd					100.0%			

	A	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
58	Upgrade ID	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL	PSEG	RE	UGI	Cost Estimate ($M)
577	b0615										100.0%				$22.58
578	b0616										100.0%				$16.71
579	b0620										100.0%				$1.32
580	b0621										100.0%				$4.24
581	b0622										100.0%				$6.08
582	b0623										100.0%				$5.67
583	b0624										100.0%				$2.87
584	b0625										100.0%				$0.99
585	b0627										100.0%				$7.63
586	b0629										100.0%				$0.05
587	b0630										100.0%				$3.31
588	b0631										100.0%				$3.36
589	b0632										100.0%				$0.30
590	b0634										100.0%				$10.10
591	b0635										100.0%				$3.65
592	b0637									100.0%					$1.50
593	b0638									100.0%					$1.50
594	b0639									100.0%					$1.50
595	b0640									100.0%					$1.50
596	b0641									100.0%					$1.50
597	b0642									100.0%					$1.50
598	b0643									100.0%					$1.50
599	b0644									100.0%					$1.50
600	b0645									100.0%					$1.50
601	b0646									100.0%					$1.50
602	b0647									100.0%					$1.50
603	b0648									100.0%					$1.50
604	b0649									100.0%					$1.50
605	b0650					100.0%									$2.25
606	b0652					100.0%									$2.10
607	b0654								100.0%						$1.28
608	b0655								100.0%						$5.64
609	b0656								100.0%						$2.73
610	b0657				100.0%										$5.81
611	b0661														$20.00
612	b0663														$15.00
613	b0664				40.1%		10.4%					47.7%	1.8%		$12.00
614	b0665				40.1%		10.4%					47.7%	1.8%		$15.00
615	b0668				43.9%		11.4%					43.2%	1.6%		$9.00
616	b0671											100.0%			$0.25
617	b0673														$7.50
618	b0674		0.0%						1.1%			0.3%	0.0%		$21.00
619	b0674.1														$0.19
620	b0675.1		0.1%		1.8%	6.4%	0.2%	3.1%			2.2%	2.4%	0.1%		$4.50
621	b0675.2		0.1%		1.8%	6.4%	0.2%	3.1%			2.2%	2.4%	0.1%		$11.20
622	b0675.3		0.1%		1.8%	6.4%	0.2%	3.1%			2.2%	2.4%	0.1%		$7.40
623	b0675.4		0.0%		1.8%	6.4%	0.1%	3.1%			2.3%	2.4%	0.1%		$9.80
624	b0675.5		0.0%		1.8%	6.4%	0.1%	3.1%			2.3%	2.4%	0.1%		$1.80
625	b0675.6		0.0%		1.8%	6.4%	0.1%	3.1%			2.3%	2.4%	0.1%		$7.50
626	b0675.7		0.0%		1.8%	6.4%	0.1%	3.1%			2.3%	2.4%	0.1%		$4.70
627	b0675.8		0.0%		1.8%	6.4%	0.1%	3.1%			2.3%	2.4%	0.1%		$3.80
628	b0675.9		0.0%		1.8%	6.4%	0.1%	3.1%			2.3%	2.4%	0.1%		$5.00
629	b0676.1		0.0%		1.9%	4.1%	0.1%	1.9%	0.9%			2.9%	0.1%		$3.50
630	b0676.2		0.0%		1.9%	4.1%	0.1%	1.9%	0.9%			2.9%	0.1%		$3.10
631	b0677														$2.70
632	b0678														$1.00
633	b0679														$2.10
634	b0680														$1.70
635	b0681														$0.01
636	b0682														$0.01
637	b0684														$3.20
638	b0685		0.1%		4.2%	6.8%	0.2%	4.1%	5.9%			6.4%	0.3%		$5.80
639	b0686														$2.90
640	b0687														$2.30
641	b0688														$2.30
642	b0689														$2.30
643	b0690														$2.30
644	b0691														$2.30
645	b0692														$2.30
646	b0693														$2.30
647	b0694														$2.30
648	b0695														$32.50

	A	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL
58	Upgrade ID	Project ID	Upgrade Date In-Service	Project Average In-Service Date	Date to use	Upgrade Source	Project Source	Project Status	Projects Allocated by Load	Projects Attributed to one entity	Projects Attributed to Dayton entity	Year In Service Override	First Full Year in Service	Project Age
577	b0615	b0615	5/31/2012	5/31/2012	5/31/2012	Planned	Planned	UC	0	1	0		2013	-2
578	b0616	b0616	12/31/2012	12/31/2012	12/31/2012	Planned	Planned	EP	0	1	0		2013	-2
579	b0620	b0620	8/26/2010	8/26/2010	8/26/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
580	b0621	b0621	8/26/2010	8/26/2010	8/26/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
581	b0622	b0622	7/6/2010	7/6/2010	7/6/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
582	b0623	b0623	5/31/2013	5/31/2013	5/31/2013	Planned	Planned	EP	0	1	0		2014	-3
583	b0624	b0624	12/31/2009	12/31/2009	12/31/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
584	b0625	b0625	5/31/2013	5/31/2013	5/31/2013	Planned	Planned	EP	0	1	0		2014	-3
585	b0627	b0627	12/23/2010	12/23/2010	12/23/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
586	b0629	b0629	11/30/2012	11/30/2012	11/30/2012	Planned	Planned	EP	0	1	0		2013	-2
587	b0630	b0630	9/30/2012	9/30/2012	9/30/2012	Planned	Planned	EP	0	1	0		2013	-2
588	b0631	b0631	9/30/2012	9/30/2012	9/30/2012	Planned	Planned	EP	0	1	0		2013	-2
589	b0632	b0632	11/30/2013	1/0/1900	11/30/2013	Planned	Planned	EP	0	1	0		2014	-3
590	b0634	b0634	11/30/2013	11/30/2013	11/30/2013	Planned	Planned	EP	0	1	0		2014	-3
591	b0635	b0635	11/30/2013	11/30/2013	11/30/2013	Planned	Planned	EP	0	1	0		2014	-3
592	b0637	b0637	3/5/2010	3/5/2010	3/5/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
593	b0638	b0638	5/4/2010	5/4/2010	5/4/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
594	b0639	b0639	6/18/2010	6/18/2010	6/18/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
595	b0640	b0640	11/11/2010	11/11/2010	11/11/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
596	b0641	b0641	12/21/2010	12/21/2010	12/21/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
597	b0642	b0642	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	EP	0	1	0		2012	-1
598	b0643	b0643	12/31/2011	12/31/2011	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
599	b0644	b0644	12/21/2012	12/21/2012	12/21/2012	Planned	Planned	EP	0	1	0		2013	-2
600	b0645	b0645	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	EP	0	1	0		2012	-1
601	b0646	b0646	12/31/2011	12/31/2011	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
602	b0647	b0647	12/21/2012	12/21/2012	12/21/2012	Planned	Planned	EP	0	1	0		2013	-2
603	b0648	b0648	12/21/2012	12/21/2012	12/21/2012	Planned	Planned	EP	0	1	0		2013	-2
604	b0649	b0649	12/21/2012	12/21/2012	12/21/2012	Planned	Planned	EP	0	1	0		2013	-2
605	b0650	b0650	6/7/2010	6/7/2010	6/7/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
606	b0652	b0652	5/28/2010	5/28/2010	5/28/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
607	b0654	b0654	5/30/2009	5/30/2009	5/30/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
608	b0655	b0655	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	UC	0	1	0		2012	-1
609	b0656	b0656	5/29/2010	5/29/2010	5/29/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
610	b0657	b0657	4/21/2011	4/21/2011	4/21/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
611	b0661	b0661	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
612	b0663	b0663	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
613	b0664	b0664	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	0	0		2013	-2
614	b0665	b0665	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	0	0		2013	-2
615	b0668	b0668	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	0	0		2013	-2
616	b0671	b0671	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	EP	0	1	0		2012	-1
617	b0673	b0673	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
618	b0674	b0674	6/1/2013	8/31/2012	6/1/2013	Planned	Planned	EP	0	0	0		2014	-3
619	b0674.1	b0674	12/1/2011	8/31/2012	12/1/2011	Planned	Planned	EP	0	1	0		2012	-1
620	b0675.1	b0675	1/1/2012	10/14/2012	1/1/2012	Planned	Planned	EP	0	0	0		2013	-2
621	b0675.2	b0675	6/1/2012	10/14/2012	6/1/2012	Planned	Planned	EP	0	0	0		2013	-2
622	b0675.3	b0675	6/1/2013	10/14/2012	6/1/2013	Planned	Planned	EP	0	0	0		2014	-3
623	b0675.4	b0675	1/1/2013	10/14/2012	1/1/2013	Planned	Planned	EP	0	0	0		2014	-3
624	b0675.5	b0675	6/1/2013	10/14/2012	6/1/2013	Planned	Planned	EP	0	0	0		2014	-3
625	b0675.6	b0675	1/1/2013	10/14/2012	1/1/2013	Planned	Planned	EP	0	0	0		2014	-3
626	b0675.7	b0675	6/1/2013	10/14/2012	6/1/2013	Planned	Planned	EP	0	0	0		2014	-3
627	b0675.8	b0675	1/1/2012	10/14/2012	1/1/2012	Planned	Planned	UC	0	0	0		2013	-2
628	b0675.9	b0675	6/1/2012	10/14/2012	6/1/2012	Planned	Planned	EP	0	0	0		2013	-2
629	b0676.1	b0676	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	0	0		2014	-3
630	b0676.2	b0676	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	0	0		2014	-3
631	b0677	b0677	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
632	b0678	b0678	12/1/2012	12/1/2012	12/1/2012	Planned	Planned	EP	0	1	0		2013	-2
633	b0679	b0679	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
634	b0680	b0680	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
635	b0681	b0681	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
636	b0682	b0682	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
637	b0684	b0684	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
638	b0685	b0685	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	0	0		2014	-3
639	b0686	b0686	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
640	b0687	b0687	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
641	b0688	b0688	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
642	b0689	b0689	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	EP	0	1	0		2012	-1
643	b0690	b0690	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	EP	0	1	0		2012	-1
644	b0691	b0691	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
645	b0692	b0692	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
646	b0693	b0693	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
647	b0694	b0694	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
648	b0695	b0695	4/30/2010	4/30/2010	4/30/2010	Post-2005	Post-2005	IS	0	1	0		2011	0

	A	AM	AN	AO	AP	AQ	AR	AS
58	Upgrade ID	Load Ratio Project Costs	One Entity Project Costs	DFAX allocated Project Costs	Dayton DFAX Project Costs			
577	b0615	0	22.58	0	0			
578	b0616	0	16.714	0	0			
579	b0620	0	1.323	0	0			
580	b0621	0	4.239	0	0			
581	b0622	0	6.079	0	0			
582	b0623	0	5.665	0	0			
583	b0624	0	2.869	0	0			
584	b0625	0	0.99	0	0			
585	b0627	0	7.634	0	0			
586	b0629	0	0.054	0	0			
587	b0630	0	3.314	0	0			
588	b0631	0	3.355	0	0			
589	b0632	0	0.303	0	0			
590	b0634	0	10.104	0	0			
591	b0635	0	3.649	0	0			
592	b0637	0	1.5	0	0			
593	b0638	0	1.5	0	0			
594	b0639	0	1.5	0	0			
595	b0640	0	1.5	0	0			
596	b0641	0	1.5	0	0			
597	b0642	0	1.5	0	0			
598	b0643	0	1.5	0	0			
599	b0644	0	1.5	0	0			
600	b0645	0	1.5	0	0			
601	b0646	0	1.5	0	0			
602	b0647	0	1.5	0	0			
603	b0648	0	1.5	0	0			
604	b0649	0	1.5	0	0			
605	b0650	0	2.25	0	0			
606	b0652	0	2.1	0	0			
607	b0654	0	1.28	0	0			
608	b0655	0	5.64	0	0			
609	b0656	0	2.73	0	0			
610	b0657	0	5.81	0	0			
611	b0661	0	20	0	0			
612	b0663	0	15	0	0			
613	b0664	0	0	12	0			
614	b0665	0	0	15	0			
615	b0668	0	0	9	0			
616	b0671	0	0.25	0	0			
617	b0673	0	7.5	0	0			
618	b0674	0	0	21	0			
619	b0674.1	0	0.191	0	0			
620	b0675.1	0	0	4.5	0			
621	b0675.2	0	0	11.2	0			
622	b0675.3	0	0	7.4	0			
623	b0675.4	0	0	9.8	0			
624	b0675.5	0	0	1.8	0			
625	b0675.6	0	0	7.5	0			
626	b0675.7	0	0	4.7	0			
627	b0675.8	0	0	3.8	0			
628	b0675.9	0	0	5	0			
629	b0676.1	0	0	3.5	0			
630	b0676.2	0	0	3.1	0			
631	b0677	0	2.7	0	0			
632	b0678	0	1	0	0			
633	b0679	0	2.1	0	0			
634	b0680	0	1.7	0	0			
635	b0681	0	0.01	0	0			
636	b0682	0	0.01	0	0			
637	b0684	0	3.2	0	0			
638	b0685	0	0	5.8	0			
639	b0686	0	2.9	0	0			
640	b0687	0	2.3	0	0			
641	b0688	0	2.3	0	0			
642	b0689	0	2.3	0	0			
643	b0690	0	2.3	0	0			
644	b0691	0	2.3	0	0			
645	b0692	0	2.3	0	0			
646	b0693	0	2.3	0	0			
647	b0694	0	2.3	0	0			
648	b0695	0	32.5	0	0			

	A	B	C	D	E	F	G	H	I	J	K
58	Upgrade ID	Description	TO	AEC	AEP	APS	BGE	ComEd	Dayton	DL	DPL
649	b0696	Add a 300 MVAR SVC at Elmhurst 138 kV 'Blue'	ComEd					100.0%			
650	b0700	Install a third 345/138 kV transformer at Goodings Grov	ComEd					100.0%			
651	b0701	Expand Benning 230 kV station, add a new 250 MVA 23	PEPCO				30.6%				
652	b0702	Add a second 50 MVAR 230 kV shunt reactor at the Ber	PEPCO								
653	b0703	Berks substation modification on Berks – South Akron 2	PPL								
654	b0705	New Derry – Millville 69 kV line	PPL								
655	b0707	Construct Bohemia – Twin Lakes 69 kV line, install a 10	PPL								
656	b0708	New 69 kV double circuit from Jackson – Lake Naomi Ta	PPL								
657	b0709	Install new 69 kV double circuit from Carlisle – West Ca	PPL								
658	b0710	Install a third 69 kV line from Reese's Tap to Hershey su	PPL								
659	b0711	New 69 kV that taps West Shore – Cumberland 69 kV #	PPL								
660	b0712	Construct a new 69 kV line between Strassburg Tap and	PPL								
661	b0713	Construct a new 138 kV double circuit line between Dille	PPL								
662	b0714	Prepare Roseville Tap for 138 kV conversion	PPL								
663	b0715	Transfer S. Akron – S. Manheim #1 and #2 lines from th	PPL								
664	b0716	Add a second 69 kV line from Morgantown – Twin Valley	PPL								
665	b0717	Rebuild existing Brunner Island – West Shore 230 kV lir	PPL								
666	b0718	SPS scheme to drop 190 MVA of 69 kV radial load at W	PPL								
667	b0719	SPS scheme at Jenkins substation to open the Stanton	PPL								
668	b0720	Upgrade terminal equipment on both lines	PEPCO								
669	b0721	Upgrade Oak Grove – Ritchie 23061 230 kV line	PEPCO								
670	b0722	Upgrade Oak Grove – Ritchie 23058 230 kV line	PEPCO								
671	b0723	Upgrade Oak Grove – Ritchie 23059 230 kV line	PEPCO								
672	b0724	Upgrade Oak Grove – Ritchie 23060 230 kV line	PEPCO								
673	b0725	Add a third Steele 230/138 kV transformer	DPL								100.0%
674	b0726	Add a 2nd Raritan River 230/115 kV transformer	JCPL	2.5%							
675	b0727	Rebuild Bryn Mawr – Plymouth Meeting 138 kV line	PECO	1.3%							3.1%
676	b0729	Rebuild both Harford – Perryman 110615-A and 110616	BGE				100.0%				
677	b0730	Add slow oil circulation to the 4 Bells Mill Road – Bethes	PEPCO								
678	b0731	Implement an SPS to automatically shed load on the 34	PEPCO								
679	b0732	Rebuild Vaugh – Wells 69 kV	DPL								100.0%
680	b0733	Add a second 230/138 kV transformer at Harmony	DPL								97.1%
681	b0737	Build a new Indian River – Bishop 138 kV line	DPL								100.0%
682	b0738	Install a 115.2 MVAR switched capacitor at Bedford Parl	ComEd					100.0%			
683	b0739	Install a 115.2 MVAR switched capacitor at Bedford Parl	ComEd					100.0%			
684	b0740	Install a 57.6 MVAR switched capacitor at Wolfs 138 kV	ComEd					100.0%			
685	b0740.2	Increase the size of the Wolfs 138 kV Blue cap from 57.	ComEd					100.0%			
686	b0743	Add a bus tie breaker at Roseland 138 kV	PSEG								
687	b0744	Upgrade a strand bus at Mill 138 kV	AEC	100.0%							
688	b0748	Establish a new 69 kV circuit between the Canal Road a	AEP		100.0%						
689	b0749	Replace 230 kV breaker and associated CT's at Riversi	BGE				100.0%				
690	b0750	Convert 138 kV network path from Vienna – Loretto – Pi	DPL								100.0%
691	b0751	Add two additional breakers at Keeney 500 kV	DPL	2.0%	18.0%	6.3%	4.9%	15.6%	2.5%	2.0%	2.8%
692	b0752	Replace two circuit breakers to bring the emergency rati	DPL								100.0%
693	b0753	Add a second Loretto 230/138 kV transformer	DPL								100.0%
694	b0754	Rebuild 10 miles of Glasgow to Mt. Pleasant 138 kV line	DPL								100.0%
695	b0756	Install a second 500/115 kV autotransformer at Chancel	Dominion								
696	b0756.1	Install two 500 kV breakers at Chancellor 500 kV	Dominion	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
697	b0757	Reconductor one mile of Chesapeake – Reeves Avenue	Dominion								
698	b0758	Install a second Fredericksburg 230/115 kV autotransfo	Dominion								
699	b0759	Build a second Dooms – Dupont – Waynesboro 115 kV	Dominion								
700	b0760	Build 115 kV line from Kitty Hawk to Colington 115 kV (C	Dominion								
701	b0761	Install a second 230/115 kV transformer at Possum Poir	Dominion								
702	b0762	Build a new Elko station and transfer load from Turner a	Dominion								
703	b0763	Rebuild 17.5 miles of the line for a new summer rating o	Dominion								
704	b0764	Increase the rating on 2.56 miles of the line between Gr	Dominion								
705	b0765	Add a second Bull Run 230/115 kV autotransformer	Dominion								
706	b0766	Increase the rating of the line between Loudoun and Ce	Dominion								
707	b0767	Extend the line from Old Church – Chickahominy 230 kV	Dominion								
708	b0768	Loop line #251 Idylwood – Arlington into the GIS sub	Dominion								
709	b0769	Re-tension 15 miles of the line for a new summer rating	Dominion								
710	b0770	Add a second 230/115 kV autotransformer at Lanexa	Dominion								
711	b0770.1	Replace Lanexa 115 kV breaker '8532'	Dominion								
712	b0770.2	Replace Lanexa 115 kV breaker '9232'	Dominion								
713	b0771	Build a parallel Chickahominy – Lanexa 230 kV line	Dominion								
714	b0772	Install a second Elmont 230/115 kV autotransformer	Dominion								
715	b0772.1	Replace Elmont 115 kV breaker '7392'	Dominion								
716	b0774	Install a 33 MVAR capacitor at Bremo 115 kV	Dominion								
717	b0775	Reconductor the Greenwich – Virginia Beach line to brir	Dominion								
718	b0776	Re-build Trowbridge – Winfall 115 kV	Dominion								
719	b0777	Terminate the Thelma – Carolina 230 kV circuit into Lak	Dominion								
720	b0778	Install 29.7 MVAR capacitor at Lebanon 115 kV	Dominion								

	A	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
58	Upgrade ID	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL	PSEG	RE	UGI	Cost Estimate ($M)
649	b0696														$32.50
650	b0700														$15.00
651	b0701									69.4%					$56.10
652	b0702									100.0%					$6.40
653	b0703										100.0%				$0.84
654	b0705										100.0%				$6.50
655	b0707										100.0%				$8.20
656	b0708										100.0%				$7.49
657	b0709										100.0%				$8.11
658	b0710										100.0%				$14.00
659	b0711										100.0%				$3.28
660	b0712										100.0%				$1.45
661	b0713										100.0%				$0.60
662	b0714										100.0%				$1.00
663	b0715										100.0%				$2.41
664	b0716										100.0%				$0.74
665	b0717										100.0%				$37.57
666	b0718										100.0%				$0.37
667	b0719										100.0%				$0.10
668	b0720									100.0%					$1.42
669	b0721									100.0%					$3.25
670	b0722									100.0%					$3.25
671	b0723									100.0%					$3.25
672	b0724									100.0%					$3.25
673	b0725														$8.00
674	b0726				97.6%										$7.10
675	b0727							95.6%							$16.60
676	b0729														$4.40
677	b0730									100.0%					$15.00
678	b0731									100.0%					$0.00
679	b0732														$1.60
680	b0733							2.9%							$7.50
681	b0737														$18.00
682	b0738														$2.30
683	b0739														$2.30
684	b0740														$1.15
685	b0740.2														$1.15
686	b0743											100.0%			$0.50
687	b0744														$0.10
688	b0748														$27.00
689	b0749														$1.50
690	b0750														$40.00
691	b0751	13.3%	0.2%		4.2%	2.1%	0.5%	5.9%	2.1%	4.7%	5.6%	7.1%	0.3%		$4.50
692	b0752														$1.00
693	b0753														$4.50
694	b0754														$5.70
695	b0756	100.0%													$16.00
696	b0756.1	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$2.00
697	b0757	100.0%													$1.00
698	b0758	100.0%													$5.50
699	b0759	100.0%													$20.50
700	b0760	100.0%													$14.30
701	b0761	100.0%													$3.50
702	b0762	100.0%													$2.20
703	b0763	100.0%													$10.20
704	b0764	100.0%													$4.00
705	b0765	100.0%													$3.00
706	b0766	100.0%													$0.20
707	b0767	100.0%													$39.00
708	b0768	100.0%													$22.50
709	b0769	100.0%													$5.80
710	b0770	100.0%													$6.19
711	b0770.1	100.0%													$0.16
712	b0770.2	100.0%													$0.16
713	b0771	100.0%													$7.70
714	b0772	100.0%													$4.50
715	b0772.1	100.0%													$0.16
716	b0774	100.0%													$0.60
717	b0775	100.0%													$2.10
718	b0776	100.0%													$16.40
719	b0777	100.0%													$3.50
720	b0778	100.0%													$0.50

	A	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL
58	Upgrade ID	Project ID	Upgrade Date In-Service	Project Average In-Service Date	Date to use	Upgrade Source	Project Source	Project Status	Projects Allocated by Load	Projects Attributed to one entity	Projects Attributed to Dayton entity	Year In Service Override	First Full Year in Service	Project Age
649	b0696	b0696	4/30/2010	4/30/2010	4/30/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
650	b0700	b0700	5/3/2011	5/3/2011	5/3/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
651	b0701	b0701	4/15/2011	11/5/2011	4/15/2011	Post-2005	Planned	IS	0	0	0		2012	-1
652	b0702	b0702	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	UC	0	1	0		2013	-2
653	b0703	b0703	10/23/2009	10/23/2009	10/23/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
654	b0705	b0705	1/17/2011	1/17/2011	1/17/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
655	b0707	b0707	11/30/2013	11/30/2013	11/30/2013	Planned	Planned	EP	0	1	0		2014	-3
656	b0708	b0708	11/30/2013	11/30/2013	11/30/2013	Planned	Planned	EP	0	1	0		2014	-3
657	b0709	b0709	11/30/2013	11/30/2013	11/30/2013	Planned	Planned	EP	0	1	0		2014	-3
658	b0710	b0710	5/31/2013	5/31/2013	5/31/2013	Planned	Planned	EP	0	1	0		2014	-3
659	b0711	b0711	11/30/2013	11/30/2013	11/30/2013	Planned	Planned	EP	0	1	0		2014	-3
660	b0712	b0712	10/26/2009	10/26/2009	10/26/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
661	b0713	b0713	12/9/2009	12/9/2009	12/9/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
662	b0714	b0714	10/29/2010	10/29/2010	10/29/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
663	b0715	b0715	11/30/2012	11/30/2012	11/30/2012	Planned	Planned	EP	0	1	0		2013	-2
664	b0716	b0716	5/31/2015	5/31/2015	5/31/2015	Planned	Planned	EP	0	1	0		2016	-5
665	b0717	b0717	5/31/2013	5/31/2013	5/31/2013	Planned	Planned	EP	0	1	0		2014	-3
666	b0718	b0718	6/1/2010	1/0/1900	6/1/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
667	b0719	b0719	11/30/2012	11/30/2012	11/30/2012	Planned	Planned	EP	0	1	0		2013	-2
668	b0720	b0720	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
669	b0721	b0721	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
670	b0722	b0722	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
671	b0723	b0723	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
672	b0724	b0724	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
673	b0725	b0725	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
674	b0726	b0726	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	0	0		2014	-3
675	b0727	b0727	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	0	0		2014	-3
676	b0729	b0729	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
677	b0730	b0730	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
678	b0731	b0731	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
679	b0732	b0732	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
680	b0733	b0733	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	0	0		2013	-2
681	b0737	b0737	5/31/2013	5/31/2013	5/31/2013	Planned	Planned	EP	0	1	0		2014	-3
682	b0738	b0738	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
683	b0739	b0739	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
684	b0740	b0740	#N/A	6/1/2012	6/1/2012	#N/A	Planned	#N/A	0	1	0		2013	-2
685	b0740.2	b0740	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
686	b0743	b0743	4/1/2009	4/1/2009	4/1/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
687	b0744	b0744	5/31/2011	5/31/2011	5/31/2011	Planned	Planned	UC	0	1	0		2012	-1
688	b0748	b0748	12/1/2011	12/1/2011	12/1/2011	Planned	Planned	EP	0	1	0		2012	-1
689	b0749	b0749	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
690	b0750	b0750	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
691	b0751	b0751	12/31/2011	12/31/2011	12/31/2011	Planned	Planned	EP	1	0	0		2012	-1
692	b0752	b0752	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
693	b0753	b0753	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
694	b0754	b0754	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
695	b0756	b0756	11/29/2013	11/29/2013	11/29/2013	Planned	Planned	EP	0	1	0		2014	-3
696	b0756.1	b0756	11/29/2013	11/29/2013	11/29/2013	Planned	Planned	EP	1	0	0		2014	-3
697	b0757	b0757	5/30/2013	5/30/2013	5/30/2013	Planned	Planned	EP	0	1	0		2014	-3
698	b0758	b0758	5/1/2012	5/1/2012	5/1/2012	Planned	Planned	EP	0	1	0		2013	-2
699	b0759	b0759	5/1/2012	5/1/2012	5/1/2012	Planned	Planned	EP	0	1	0		2013	-2
700	b0760	b0760	12/30/2010	12/30/2010	12/30/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
701	b0761	b0761	4/30/2009	4/30/2009	4/30/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
702	b0762	b0762	5/18/2010	5/18/2010	5/18/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
703	b0763	b0763	12/31/2010	12/31/2010	12/31/2010	Planned	Planned	UC	0	1	0		2011	0
704	b0764	b0764	10/18/2011	10/18/2011	10/18/2011	Planned	Planned	UC	0	1	0		2012	-1
705	b0765	b0765	5/21/2009	5/21/2009	5/21/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
706	b0766	b0766	5/20/2009	5/20/2009	5/20/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
707	b0767	b0767	3/2/2011	3/2/2011	3/2/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
708	b0768	b0768	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	UC	0	1	0		2012	-1
709	b0769	b0769	9/1/2013	9/1/2013	9/1/2013	Planned	Planned	EP	0	1	0		2014	-3
710	b0770	b0770	6/4/2010	6/4/2010	6/4/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
711	b0770.1	b0770	6/4/2010	6/4/2010	6/4/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
712	b0770.2	b0770	6/4/2010	6/4/2010	6/4/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
713	b0771	b0771	6/30/2011	6/30/2011	6/30/2011	Planned	Planned	UC	0	1	0		2012	-1
714	b0772	b0772	5/20/2010	4/4/2010	5/20/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
715	b0772.1	b0772	2/18/2010	4/4/2010	2/18/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
716	b0774	b0774	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
717	b0775	b0775	5/31/2012	5/31/2012	5/31/2012	Planned	Planned	EP	0	1	0		2013	-2
718	b0776	b0776	10/13/2011	10/13/2011	10/13/2011	Planned	Planned	UC	0	1	0		2012	-1
719	b0777	b0777	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	UC	0	1	0		2012	-1
720	b0778	b0778	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2

	A	AM	AN	AO	AP	AQ	AR	AS
58	Upgrade ID	Load Ratio Project Costs	One Entity Project Costs	DFAX allocated Project Costs	Dayton DFAX Project Costs			
649	b0696	0	32.5	0	0			
650	b0700	0	15	0	0			
651	b0701	0	0	56.1	0			
652	b0702	0	6.4	0	0			
653	b0703	0	0.838	0	0			
654	b0705	0	6.5	0	0			
655	b0707	0	8.198	0	0			
656	b0708	0	7.485	0	0			
657	b0709	0	8.106	0	0			
658	b0710	0	14	0	0			
659	b0711	0	3.278	0	0			
660	b0712	0	1.445	0	0			
661	b0713	0	0.604	0	0			
662	b0714	0	0.998	0	0			
663	b0715	0	2.412	0	0			
664	b0716	0	0.738	0	0			
665	b0717	0	37.573	0	0			
666	b0718	0	0.371	0	0			
667	b0719	0	0.1	0	0			
668	b0720	0	1.415	0	0			
669	b0721	0	3.25	0	0			
670	b0722	0	3.25	0	0			
671	b0723	0	3.25	0	0			
672	b0724	0	3.25	0	0			
673	b0725	0	8	0	0			
674	b0726	0	0	7.1	0			
675	b0727	0	0	16.6	0			
676	b0729	0	4.4	0	0			
677	b0730	0	15	0	0			
678	b0731	0	0	0	0			
679	b0732	0	1.6	0	0			
680	b0733	0	0	7.5	0			
681	b0737	0	18	0	0			
682	b0738	0	2.3	0	0			
683	b0739	0	2.3	0	0			
684	b0740	0	1.15	0	0			
685	b0740.2	0	1.15	0	0			
686	b0743	0	0.5	0	0			
687	b0744	0	0.097	0	0			
688	b0748	0	27	0	0			
689	b0749	0	1.5	0	0			
690	b0750	0	40	0	0			
691	b0751	4.5	0	0	0.00			
692	b0752	0	1	0	0			
693	b0753	0	4.5	0	0			
694	b0754	0	5.7	0	0			
695	b0756	0	16	0	0			
696	b0756.1	2	0	0	0.00			
697	b0757	0	1	0	0			
698	b0758	0	5.5	0	0			
699	b0759	0	20.5	0	0			
700	b0760	0	14.3	0	0			
701	b0761	0	3.5	0	0			
702	b0762	0	2.2	0	0			
703	b0763	0	10.2	0	0			
704	b0764	0	4	0	0			
705	b0765	0	3	0	0			
706	b0766	0	0.2	0	0			
707	b0767	0	39	0	0			
708	b0768	0	22.5	0	0			
709	b0769	0	5.8	0	0			
710	b0770	0	6.188	0	0			
711	b0770.1	0	0.158	0	0			
712	b0770.2	0	0.158	0	0			
713	b0771	0	7.7	0	0			
714	b0772	0	4.5	0	0			
715	b0772.1	0	0.158	0	0			
716	b0774	0	0.6	0	0			
717	b0775	0	2.1	0	0			
718	b0776	0	16.4	0	0			
719	b0777	0	3.5	0	0			
720	b0778	0	0.5	0	0			

	A	B	C	D	E	F	G	H	I	J	K
58	Upgrade ID	Description	TO	AEC	AEP	APS	BGE	ComEd	Dayton	DL	DPL
721	b0779	Build a new 230 kV line from Yorktown to Hayes but ope	Dominion								
722	b0780	Reconductor Chesapeake – Yadkin 115 kV line	Dominion								
723	b0781	Reconductor and replace terminal equipment on line 17	Dominion								
724	b0782	Install a new 115 kV capacitor at Dupont Waynesboro su	Dominion								
725	b0784	Replace wave traps on North Anna to Ladysmith 500 kV	Dominion	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
726	b0785	Rebuild the Chase City – Crewe 115 kV line	Dominion								
727	b0786	Reconductor the Moran DP – Crewe 115 kV segment	Dominion								
728	b0787	Upgrade the Chase City – Twitty's Creek 115 kV segme	Dominion								
729	b0788	Reconductor the line from Farmville – Pamplin 115 kV	Dominion								
730	b0789	Reconductor the line to provide a normal rating of 677 M	PECO	0.7%							
731	b0790	Reconductor the Bradford – Planebrook 230 kV Ckt. 22(	PECO								
732	b0791	Add a fourth 230/69 kV transformer at Stanton	PPL								
733	b0792	Reconfigure Cecil Sub into 230 and 138 kV ring buses, a	DPL								100.0%
734	b0793	Close switch 145T183 to network the lines. Rebuild the	Dominion								
735	b0794	Upgrade the Homer City 230 kV breaker 'Pierce Road'	PENELEC								
736	b0795	Install a 115 kV breaker at Chesaco Park	BGE				100.0%				
737	b0796	Install 2, 115 kV breakers at Gwynnbrook	BGE				100.0%				
738	b0797	Advance n0321 (Replace Doubs Circuit Breaker DJ2)	APS			100.0%					
739	b0798	Advance n0322 (Replace Doubs Circuit Breaker DJ3)	APS			100.0%					
740	b0799	Advance n0323 (Replace Doubs Circuit Breaker DJ6)	APS			100.0%					
741	b0800	Advance n0327 (Replace Doubs Circuit Breaker DJ16)	APS			100.0%					
742	b0802	Advance n0259 (Replace Dickerson Station H Circuit Br	PEPCO								
743	b0803	Advance n0260 (Replace Dickerson Station H Circuit Br	PEPCO								
744	b0804	Advance n0261 (Replace Dickerson Station H Circuit Br	PEPCO								
745	b0805	Advance n0262 (Replace Dickerson Station H Circuit Br	PEPCO								
746	b0806	Advance n0264 (Replace Dickerson Station H Circuit Br	PEPCO								
747	b0809	Advance n0267 (Replace Dickerson Station H Circuit Br	PEPCO								
748	b0810	Advance n0270 (Replace Dickerson Station H Circuit Br	PEPCO								
749	b0811	Advance n0726 (Replace Dickerson Station H Circuit Br	PEPCO								
750	b0812	Increase operating temperature on line for one year to g	PSEG								
751	b0813	Reconductor Hudson – South Waterfront 230 kV circuit	PSEG				1.3%				
752	b0814	New Essex – Kearney 138 kV circuit and Kearney 138 k	PSEG								
753	b0814.1	Replace Kearny 138 kV breaker '1-SHT' with 80 kA brea	PSEG								
754	b0814.10	Replace Essex 138 kV breaker '1BT' with 63 kA breaker	PSEG								
755	b0814.11	Replace Essex 138 kV breaker '2PM' with 63 kA breaker	PSEG								
756	b0814.12	Replace Marion 138 kV breaker '2HM' with 63 kA breake	PSEG								
757	b0814.13	Replace Marion 138 kV breaker '2LM' with 63 kA breake	PSEG								
758	b0814.14	Replace Marion 138 kV breaker '1LM' with 63 kA breake	PSEG								
759	b0814.15	Replace Marion 138 kV breaker '6PM' with 63 kA breake	PSEG								
760	b0814.16	Replace Marion 138 kV breaker '3PM' with 63 kA breake	PSEG								
761	b0814.17	Replace Marion 138 kV breaker '4LM' with 63 kA breake	PSEG								
762	b0814.18	Replace Marion 138 kV breaker '3LM' with 63 kA breake	PSEG								
763	b0814.19	Replace Marion 138 kV breaker '1HM' with 63 kA breake	PSEG								
764	b0814.2	Replace Kearny 138 kV breaker '15HF' with 80 kA break	PSEG								
765	b0814.20	Replace Marion 138 kV breaker '2PM3' with 63 kA break	PSEG								
766	b0814.21	Replace Marion 138 kV breaker '2PM1' with 63 kA break	PSEG								
767	b0814.22	Replace ECRR 138 kV breaker '903'	PSEG								
768	b0814.23	Replace Foundry 138 kV breaker '21P'	PSEG								
769	b0814.25	Change the contact parting time on Essex 138 kV break	PSEG								
770	b0814.26	Change the contact parting time on Essex 138 kV break	PSEG								
771	b0814.27	Change the contact parting time on Essex 138 kV break	PSEG								
772	b0814.28	Change the contact parting time on Essex 138 kV break	PSEG								
773	b0814.29	Change the contact parting time on Essex 138 kV break	PSEG								
774	b0814.3	Replace Kearny 138 kV breaker '14HF' with 80 kA break	PSEG								
775	b0814.30	Change the contact parting time on Essex 138 kV break	PSEG								
776	b0814.4	Replace Kearny 138 kV breaker '10HF' with 80 kA break	PSEG								
777	b0814.5	Replace Kearny 138 kV breaker '2HT' with 80 kA breake	PSEG								
778	b0814.6	Replace Kearny 138 kV breaker '22HF' with 80 kA break	PSEG								
779	b0814.7	Replace Kearny 138 kV breaker '4HT' with 80 kA breake	PSEG								
780	b0814.8	Replace Kearny 138 kV breaker '25HF' with 80 kA break	PSEG								
781	b0814.9	Replace Essex 138 kV breaker '2LM' with 63 kA breaker	PSEG								
782	b0815	Replace Elmont 230 kV breaker '22192'	Dominion								
783	b0816	Replace Elmont 230 kV breaker '21692'	Dominion								
784	b0817	Replace Elmont 230 kV breaker '200992'	Dominion								
785	b0818	Replace Elmont 230 kV breaker '2009T2032'	Dominion								
786	b0820	Remove line drop limitations at the substation terminatio	BGE				100.0%				
787	b0821	Remove line drop limitations at the substation terminatio	BGE				100.0%				
788	b0822	Remove line drop limitations at the substation terminatio	BGE				100.0%				
789	b0823	Remove line drop limitations at the substation terminatio	BGE				100.0%				
790	b0824	Remove line drop limitations at the substation terminatio	BGE				100.0%				
791	b0825	Remove line drop limitations at the substation terminatio	BGE				100.0%				
792	b0826	Remove line drop limitations at the substation terminatio	BGE				100.0%				

	A	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
58	Upgrade ID	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL	PSEG	RE	UGI	Cost Estimate ($M)
721	b0779	100.0%													$74.00
722	b0780	100.0%													$2.00
723	b0781	100.0%													$0.30
724	b0782	100.0%													$0.73
725	b0784	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.30
726	b0785	100.0%													$11.17
727	b0786	100.0%													$6.00
728	b0787	100.0%													$7.90
729	b0788	100.0%													$9.00
730	b0789		0.5%		17.6%		0.9%	45.1%				34.0%	1.3%		$3.70
731	b0790		0.5%		17.5%		0.9%	45.7%				34.1%	1.3%		$4.60
732	b0791								9.6%		90.5%				$4.81
733	b0792														$6.00
734	b0793	100.0%													$24.00
735	b0794								100.0%						$0.23
736	b0795														$2.90
737	b0796														$1.30
738	b0797														$0.01
739	b0798														$0.01
740	b0799														$0.01
741	b0800														$0.01
742	b0802									100.0%					$0.01
743	b0803									100.0%					$0.01
744	b0804									100.0%					$0.01
745	b0805									100.0%					$0.01
746	b0806									100.0%					$0.01
747	b0809									100.0%					$0.01
748	b0810									100.0%					$0.01
749	b0811									100.0%					$0.01
750	b0812											100.0%			$0.10
751	b0813				10.0%		0.4%			1.1%		84.1%	3.1%		$16.50
752	b0814				23.7%		0.8%		5.4%			67.6%	2.5%		$71.20
753	b0814.1				23.7%		0.8%		5.4%			67.6%	2.5%		$1.00
754	b0814.10				23.7%		0.8%		5.4%			67.6%	2.5%		$0.50
755	b0814.11				23.7%		0.8%		5.4%			67.6%	2.5%		$0.50
756	b0814.12				23.7%		0.8%		5.4%			67.6%	2.5%		$0.50
757	b0814.13				23.7%		0.8%		5.4%			67.6%	2.5%		$0.50
758	b0814.14				23.7%		0.8%		5.4%			67.6%	2.5%		$0.50
759	b0814.15				23.7%		0.8%		5.4%			67.6%	2.5%		$0.50
760	b0814.16				23.7%		0.8%		5.4%			67.6%	2.5%		$0.50
761	b0814.17				23.7%		0.8%		5.4%			67.6%	2.5%		$0.50
762	b0814.18				23.7%		0.8%		5.4%			67.6%	2.5%		$0.50
763	b0814.19				23.7%		0.8%		5.4%			67.6%	2.5%		$0.50
764	b0814.2				23.7%		0.8%		5.4%			67.6%	2.5%		$1.00
765	b0814.20				23.7%		0.8%		5.4%			67.6%	2.5%		$0.50
766	b0814.21				23.7%		0.8%		5.4%			67.6%	2.5%		$0.50
767	b0814.22				23.7%		0.8%		5.4%			67.6%	2.5%		$0.50
768	b0814.23				23.7%		0.8%		5.4%			67.6%	2.5%		$0.50
769	b0814.25				23.7%		0.8%		5.4%			67.6%	2.5%		$0.00
770	b0814.26				23.7%		0.8%		5.4%			67.6%	2.5%		$0.00
771	b0814.27				23.7%		0.8%		5.4%			67.6%	2.5%		$0.00
772	b0814.28				23.7%		0.8%		5.4%			67.6%	2.5%		$0.00
773	b0814.29				23.7%		0.8%		5.4%			67.6%	2.5%		$0.00
774	b0814.3				23.7%		0.8%		5.4%			67.6%	2.5%		$1.00
775	b0814.30				23.7%		0.8%		5.4%			67.6%	2.5%		$0.00
776	b0814.4				23.7%		0.8%		5.4%			67.6%	2.5%		$1.00
777	b0814.5				23.7%		0.8%		5.4%			67.6%	2.5%		$1.00
778	b0814.6				23.7%		0.8%		5.4%			67.6%	2.5%		$1.00
779	b0814.7				23.7%		0.8%		5.4%			67.6%	2.5%		$1.00
780	b0814.8				23.7%		0.8%		5.4%			67.6%	2.5%		$1.00
781	b0814.9				23.7%		0.8%		5.4%			67.6%	2.5%		$0.50
782	b0815	100.0%													$0.18
783	b0816	100.0%													$0.18
784	b0817	100.0%													$0.18
785	b0818	100.0%													$0.18
786	b0820														$0.40
787	b0821														$0.10
788	b0822														$0.40
789	b0823														$0.10
790	b0824														$0.10
791	b0825														$0.10
792	b0826														$0.10

	A	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL
58	Upgrade ID	Project ID	Upgrade Date In-Service	Project Average In-Service Date	Date to use	Upgrade Source	Project Source	Project Status	Projects Allocated by Load	Projects Attributed to one entity	Projects Attributed to Dayton entity	Year In Service Override	First Full Year in Service	Project Age
721	b0779	b0779	5/30/2012	5/30/2012	5/30/2012	Planned	Planned	EP	0	1	0		2013	-2
722	b0780	b0780	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
723	b0781	b0781	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	UC	0	1	0		2013	-2
724	b0782	b0782	6/10/2011	6/10/2011	6/10/2011	Planned	Planned	EP	0	1	0		2012	-1
725	b0784	b0784	5/30/2013	5/30/2013	5/30/2013	Planned	Planned	EP	1	0	0		2014	-3
726	b0785	b0785	1/5/2009	1/5/2009	1/5/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
727	b0786	b0786	5/31/2011	5/31/2011	5/31/2011	Planned	Planned	UC	0	1	0		2012	-1
728	b0787	b0787	5/31/2011	5/31/2011	5/31/2011	Planned	Planned	UC	0	1	0		2012	-1
729	b0788	b0788	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
730	b0789	b0789	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	0	0		2014	-3
731	b0790	b0790	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	0	0		2014	-3
732	b0791	b0791	11/30/2011	11/30/2011	11/30/2011	Planned	Planned	UC	0	0	0		2012	-1
733	b0792	b0792	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
734	b0793	b0793	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
735	b0794	b0794	6/1/2009	1/0/1900	6/1/2009	Planned	Planned	EP	0	1	0		2010	1
736	b0795	b0795	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
737	b0796	b0796	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
738	b0797	b0797	12/19/2008	12/19/2008	12/19/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
739	b0798	b0798	3/1/2009	3/1/2009	3/1/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
740	b0799	b0799	3/1/2009	3/1/2009	3/1/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
741	b0800	b0800	11/13/2009	11/13/2009	11/13/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
742	b0802	b0802	10/24/2008	10/24/2008	10/24/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
743	b0803	b0803	9/18/2009	9/18/2009	9/18/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
744	b0804	b0804	9/25/2009	9/25/2009	9/25/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
745	b0805	b0805	12/4/2009	12/4/2009	12/4/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
746	b0806	b0806	10/30/2009	10/30/2009	10/30/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
747	b0809	b0809	10/27/2008	10/27/2008	10/27/2008	Post-2005	Post-2005	IS	0	1	0		2009	2
748	b0810	b0810	11/20/2009	11/20/2009	11/20/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
749	b0811	b0811	6/1/2009	6/1/2009	6/1/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
750	b0812	b0812	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	EP	0	1	0		2012	-1
751	b0813	b0813	12/22/2010	12/22/2010	12/22/2010	Post-2005	Post-2005	IS	0	0	0		2011	0
752	b0814	b0814	6/1/2012	10/31/2006	6/1/2012	Planned	Planned	UC	0	0	0		2013	-2
753	b0814.1	b0814	6/1/2012	10/31/2006	6/1/2012	Planned	Planned	EP	0	0	0		2013	-2
754	b0814.10	b0814	4/17/2009	10/31/2006	4/17/2009	Post-2005	Planned	IS	0	0	0		2010	1
755	b0814.11	b0814	6/1/2012	10/31/2006	6/1/2012	Planned	Planned	EP	0	0	0		2013	-2
756	b0814.12	b0814	10/1/2009	10/31/2006	10/1/2009	Post-2005	Planned	IS	0	0	0		2010	1
757	b0814.13	b0814	10/1/2009	10/31/2006	10/1/2009	Post-2005	Planned	IS	0	0	0		2010	1
758	b0814.14	b0814	10/1/2009	10/31/2006	10/1/2009	Post-2005	Planned	IS	0	0	0		2010	1
759	b0814.15	b0814	12/15/2009	10/31/2006	12/15/2009	Post-2005	Planned	IS	0	0	0		2010	1
760	b0814.16	b0814	12/7/2009	10/31/2006	12/7/2009	Post-2005	Planned	IS	0	0	0		2010	1
761	b0814.17	b0814	11/1/2009	10/31/2006	11/1/2009	Post-2005	Planned	IS	0	0	0		2010	1
762	b0814.18	b0814	10/19/2009	10/31/2006	10/19/2009	Post-2005	Planned	IS	0	0	0		2010	1
763	b0814.19	b0814	10/11/2009	10/31/2006	10/11/2009	Post-2005	Planned	IS	0	0	0		2010	1
764	b0814.2	b0814	6/1/2012	10/31/2006	6/1/2012	Planned	Planned	EP	0	0	0		2013	-2
765	b0814.20	b0814	11/7/2009	10/31/2006	11/7/2009	Post-2005	Planned	IS	0	0	0		2010	1
766	b0814.21	b0814	11/13/2009	10/31/2006	11/13/2009	Post-2005	Planned	IS	0	0	0		2010	1
767	b0814.22	b0814	6/1/2013	10/31/2006	6/1/2013	Planned	Planned	EP	0	0	0		2014	-3
768	b0814.23	b0814	5/7/2010	10/31/2006	5/7/2010	Post-2005	Planned	IS	0	0	0		2011	0
769	b0814.25	b0814	4/24/2009	10/31/2006	4/24/2009	Post-2005	Planned	IS	0	0	0		2010	1
770	b0814.26	b0814	4/17/2009	10/31/2006	4/17/2009	Post-2005	Planned	IS	0	0	0		2010	1
771	b0814.27	b0814	11/7/2008	10/31/2006	11/7/2008	Post-2005	Planned	IS	0	0	0		2009	2
772	b0814.28	b0814	5/15/2009	10/31/2006	5/15/2009	Post-2005	Planned	IS	0	0	0		2010	1
773	b0814.29	b0814	10/11/2007	10/31/2006	10/11/2007	Post-2005	Planned	IS	0	0	0		2008	3
774	b0814.3	b0814	6/1/2012	10/31/2006	6/1/2012	Planned	Planned	EP	0	0	0		2013	-2
775	b0814.30	b0814	5/9/2009	10/31/2006	5/9/2009	Post-2005	Planned	IS	0	0	0		2010	1
776	b0814.4	b0814	6/1/2012	10/31/2006	6/1/2012	Planned	Planned	EP	0	0	0		2013	-2
777	b0814.5	b0814	6/1/2012	10/31/2006	6/1/2012	Planned	Planned	EP	0	0	0		2013	-2
778	b0814.6	b0814	6/1/2012	10/31/2006	6/1/2012	Planned	Planned	EP	0	0	0		2013	-2
779	b0814.7	b0814	6/1/2012	10/31/2006	6/1/2012	Planned	Planned	EP	0	0	0		2013	-2
780	b0814.8	b0814	6/1/2012	10/31/2006	6/1/2012	Planned	Planned	EP	0	0	0		2013	-2
781	b0814.9	b0814	12/20/2008	10/31/2006	12/20/2008	Post-2005	Planned	IS	0	0	0		2009	2
782	b0815	b0815	7/9/2009	7/9/2009	7/9/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
783	b0816	b0816	3/24/2011	3/24/2011	3/24/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
784	b0817	b0817	8/6/2009	8/6/2009	8/6/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
785	b0818	b0818	10/30/2009	10/30/2009	10/30/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
786	b0820	b0820	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	EP	0	1	0		2012	-1
787	b0821	b0821	12/31/2010	12/31/2010	12/31/2010	Planned	Planned	EP	0	1	0		2011	0
788	b0822	b0822	10/31/2009	10/31/2009	10/31/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
789	b0823	b0823	6/24/2011	6/24/2011	6/24/2011	Planned	Planned	EP	0	1	0		2012	-1
790	b0824	b0824	12/31/2010	12/31/2010	12/31/2010	Planned	Planned	EP	0	1	0		2011	0
791	b0825	b0825	12/31/2010	12/31/2010	12/31/2010	Planned	Planned	EP	0	1	0		2011	0
792	b0826	b0826	12/31/2010	12/31/2010	12/31/2010	Planned	Planned	EP	0	1	0		2011	0

	A	AM	AN	AO	AP	AQ	AR	AS
58	Upgrade ID	Load Ratio Project Costs	One Entity Project Costs	DFAX allocated Project Costs	Dayton DFAX Project Costs			
721	b0779	0	74	0	0			
722	b0780	0	2	0	0			
723	b0781	0	0.3	0	0			
724	b0782	0	0.734	0	0			
725	b0784	0.3	0	0	0.00			
726	b0785	0	11.173	0	0			
727	b0786	0	6	0	0			
728	b0787	0	7.9	0	0			
729	b0788	0	9	0	0			
730	b0789	0	0	3.7	0			
731	b0790	0	0	4.6	0			
732	b0791	0	0	4.807	0			
733	b0792	0	6	0	0			
734	b0793	0	24	0	0			
735	b0794	0	0.23	0	0			
736	b0795	0	2.9	0	0			
737	b0796	0	1.3	0	0			
738	b0797	0	0.01	0	0			
739	b0798	0	0.01	0	0			
740	b0799	0	0.01	0	0			
741	b0800	0	0.01	0	0			
742	b0802	0	0.01	0	0			
743	b0803	0	0.01	0	0			
744	b0804	0	0.01	0	0			
745	b0805	0	0.01	0	0			
746	b0806	0	0.01	0	0			
747	b0809	0	0.01	0	0			
748	b0810	0	0.01	0	0			
749	b0811	0	0.01	0	0			
750	b0812	0	0.1	0	0			
751	b0813	0	0	16.5	0			
752	b0814	0	0	71.2	0			
753	b0814.1	0	0	1	0			
754	b0814.10	0	0	0.5	0			
755	b0814.11	0	0	0.5	0			
756	b0814.12	0	0	0.5	0			
757	b0814.13	0	0	0.5	0			
758	b0814.14	0	0	0.5	0			
759	b0814.15	0	0	0.5	0			
760	b0814.16	0	0	0.5	0			
761	b0814.17	0	0	0.5	0			
762	b0814.18	0	0	0.5	0			
763	b0814.19	0	0	0.5	0			
764	b0814.2	0	0	1	0			
765	b0814.20	0	0	0.5	0			
766	b0814.21	0	0	0.5	0			
767	b0814.22	0	0	0.5	0			
768	b0814.23	0	0	0.5	0			
769	b0814.25	0	0	0	0			
770	b0814.26	0	0	0	0			
771	b0814.27	0	0	0	0			
772	b0814.28	0	0	0	0			
773	b0814.29	0	0	0	0			
774	b0814.3	0	0	1	0			
775	b0814.30	0	0	0	0			
776	b0814.4	0	0	1	0			
777	b0814.5	0	0	1	0			
778	b0814.6	0	0	1	0			
779	b0814.7	0	0	1	0			
780	b0814.8	0	0	1	0			
781	b0814.9	0	0	0.5	0			
782	b0815	0	0.18	0	0			
783	b0816	0	0.18	0	0			
784	b0817	0	0.18	0	0			
785	b0818	0	0.18	0	0			
786	b0820	0	0.4	0	0			
787	b0821	0	0.1	0	0			
788	b0822	0	0.395	0	0			
789	b0823	0	0.1	0	0			
790	b0824	0	0.1	0	0			
791	b0825	0	0.1	0	0			
792	b0826	0	0.1	0	0			

	A	B	C	D	E	F	G	H	I	J	K
58	Upgrade ID	Description	TO	AEC	AEP	APS	BGE	ComEd	Dayton	DL	DPL
793	b0827	Install an SPS for one year to trip a Mays Chapel 115 kV	BGE				100.0%				
794	b0828	Disable the HS throwover at Harrisonville for one year	BGE				100.0%				
795	b0829.1	Replace Whitpain 230 kV breaker '155	PECO	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
796	b0829.11	Replace Branchburg 230 kV breaker 32H	PSEG	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
797	b0829.12	Replace Branchburg 230 kV breaker 52H	PSEG	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
798	b0829.2	Replace Whitpain 230 kV breaker '525'	PECO	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
799	b0829.3	Replace Whitpain 230 kV breaker '175'	PECO	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
800	b0829.4	Replace Plymouth Meeting 230 kV breaker '225'	PECO	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
801	b0829.5	Replace Plymouth Meeting 230 kV breaker '335'	PECO	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
802	b0829.6	Replace Branchburg 500 kV breaker 91X	PSEG	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
803	b0829.9	Replace Branchburg 230 kV breaker 102H	PSEG	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
804	b0830.1	Replace Roseland 230 kV breaker '82H' with 80 kA	PSEG	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
805	b0830.2	Replace Roseland 230 kV breaker '91H' with 80 kA	PSEG	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
806	b0830.3	Replace Roseland 230 kV breaker '22H' with 80 kA	PSEG	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
807	b0837	At Mt. Storm, replace the existing MOD on the 500 kV si	Dominion	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
808	b0838	Hazard Area 138 kV and 69 kV Improvement Projects	AEP		100.0%						
809	b0839	Replace existing 450 MVA transformer at Twin Branch 3	AEP		99.7%				0.3%		
810	b0840	String a second 138 kV circuit on the open tower positio	AEP		100.0%						
811	b0840.1	Establish a new 138/69-34.5kV Station to interconnect tl	AEP		100.0%						
812	b0842	Install a 2nd 230/138 kV XFMR and 35 MVAR CAP at H	PECO								
813	b0842.1	Replace Heaton 138 kV breaker '150'	PECO								
814	b0843	Install a 75 MVAR CAP at Llanerch 138 kV bus	PECO								
815	b0844	Move the connection point for the Llanerch 138/69 kV X	PECO								
816	b0845	Replace Chalk Point 230 kV breaker (1A) with 80 kA bre	PEPCO								
817	b0846	Replace Chalk Point 230 kV breaker (1B) with 80 kA bre	PEPCO								
818	b0847	Replace Chalk Point 230 kV breaker (2A) with 80 kA bre	PEPCO								
819	b0848	Replace Chalk Point 230 kV breaker (2B) with 80 kA bre	PEPCO								
820	b0849	Replace Chalk Point 230 kV breaker (2C) with 80 kA bre	PEPCO								
821	b0850	Replace Chalk Point 230 kV breaker (3A) with 80 kA bre	PEPCO								
822	b0851	Replace Chalk Point 230 kV breaker (3B) with 80 kA bre	PEPCO								
823	b0852	Replace Chalk Point 230 kV breaker (3C) with 80 kA bre	PEPCO								
824	b0853	Replace Chalk Point 230 kV breaker (4A) with 80 kA bre	PEPCO								
825	b0854	Replace Chalk Point 230 kV breaker (4B) with 80 kA bre	PEPCO								
826	b0855	Replace Chalk Point 230 kV breaker (5A) with 80 kA bre	PEPCO								
827	b0856	Replace Chalk Point 230 kV breaker (5B) with 80 kA bre	PEPCO								
828	b0857	Replace Chalk Point 230 kV breaker (6A) with 80 kA bre	PEPCO								
829	b0858	Replace Chalk Point 230 kV breaker (6B) with 80 kA bre	PEPCO								
830	b0859	Replace Chalk Point 230 kV breaker (7B) with 80 kA bre	PEPCO								
831	b0860	Replace Chalk Point 230 kV breaker (8A) with 80 kA bre	PEPCO								
832	b0861	Replace Chalk Point 230 kV breaker (8B) with 80 kA bre	PEPCO								
833	b0862	Replace Chalk Point 230 kV breaker (7A) with 80 kA bre	PEPCO								
834	b0863	Replace Chalk Point 230 kV breaker (1C) with 80 kA bre	PEPCO								
835	b0870	Rebuild each line (0.2 miles each) to increase the norma	BGE				100.0%				
836	b0871	Install 35 MVAR capacitor at Motts Farm 69 kV	AEC	100.0%							
837	b0873	Build 2nd Glasgow-Mt Pleasant 138 kV line	DPL								100.0%
838	b0874	Reconfigure Brandywine substation	DPL								100.0%
839	b0876	Install 50 MVAR SVC at 138th St 138 kV	DPL								100.0%
840	b0877	Build a 2nd Vienna-Steele 230 kV line	DPL								100.0%
841	b0879.1	Apply a special protection scheme (load drop at Stevens	DPL								100.0%
842	b0881	Install motor operators on Susquehanna T21 - Susqueh	PPL								
843	b0882	Replace Hudson 230 kV breaker 1HA with 80 kA	PSEG								
844	b0883	Replace Hudson 230 kV breaker 2HA with 80 kA	PSEG								
845	b0884	Replace Hudson 230 kV breaker 3HB with 80 kA	PSEG								
846	b0885	Replace Hudson 230 kV breaker 4HA with 80 kA	PSEG								
847	b0886	Replace Hudson 230 kV breaker 4HB with 80 kA	PSEG								
848	b0888	Replace Loudoun 230 kV Cap breaker 'SC352'	Dominion								
849	b0889	Replace Bergen 230 kV breaker '21H'	PSEG								
850	b0892	Replace Chesapeake 115 kV breaker SX522	Dominion								
851	b0893	Replace Chesapeake 115 kV breaker T202	Dominion								
852	b0894	Replace Possum Point 115 kV breaker SX-32	Dominion								
853	b0895	Replace Possum Point 115 kV breaker L92-1	Dominion								
854	b0896	Replace Possum Point 115 kV breaker L92-2	Dominion								
855	b0897	Replace Suffolk 115 kV breaker T202	Dominion								
856	b0898	Replace Peninsula 115 kV breaker SC202	Dominion								
857	b0899	Replace ECRR 138 kV breaker 901	PSEG								
858	b0900	Replace ECRR 138 kV breaker 902	PSEG								
859	b0901	Replace Greene 138 kV breaker GJ-D	Dayton						100.0%		
860	b0902	Replace Greene 138 kV breaker GJ-E	Dayton						100.0%		
861	b0903	Replace Greene 138 kV breaker GJ-F	Dayton						100.0%		
862	b0904	Replace Greene 138 kV breaker GJ-H	Dayton						100.0%		
863	b0905	Replace Greene 138 kV breaker GJ-I	Dayton						100.0%		
864	b0906	Increase contact parting time on Wagner 115 kV breake	BGE				100.0%				

	A	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
58	Upgrade ID	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL	PSEG	RE	UGI	Cost Estimate ($M)
793	b0827														$0.02
794	b0828														$0.00
795	b0829.1	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.50
796	b0829.11	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.50
797	b0829.12	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.50
798	b0829.2	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.50
799	b0829.3	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.50
800	b0829.4	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.50
801	b0829.5	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.23
802	b0829.6	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.80
803	b0829.9	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.50
804	b0830.1	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.80
805	b0830.2	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.80
806	b0830.3	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$0.80
807	b0837	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$1.50
808	b0838														$44.00
809	b0839														$8.50
810	b0840														$6.00
811	b0840.1														$3.50
812	b0842							100.0%							$9.50
813	b0842.1							100.0%							$0.24
814	b0843							100.0%							$2.60
815	b0844							100.0%							$0.50
816	b0845									100.0%					$2.00
817	b0846									100.0%					$2.00
818	b0847									100.0%					$2.00
819	b0848									100.0%					$2.00
820	b0849									100.0%					$2.00
821	b0850									100.0%					$2.00
822	b0851									100.0%					$2.00
823	b0852									100.0%					$2.00
824	b0853									100.0%					$2.00
825	b0854									100.0%					$2.00
826	b0855									100.0%					$2.00
827	b0856									100.0%					$2.00
828	b0857									100.0%					$2.00
829	b0858									100.0%					$2.00
830	b0859									100.0%					$2.00
831	b0860									100.0%					$2.00
832	b0861									100.0%					$2.00
833	b0862									100.0%					$2.00
834	b0863									100.0%					$2.00
835	b0870														$0.54
836	b0871														$2.80
837	b0873														$16.30
838	b0874														$10.55
839	b0876														$22.80
840	b0877														$44.61
841	b0879.1														$0.05
842	b0881										100.0%				$0.29
843	b0882											100.0%			$0.80
844	b0883											100.0%			$0.01
845	b0884											100.0%			$0.01
846	b0885											100.0%			$0.16
847	b0886											100.0%			$0.16
848	b0888	100.0%													$0.25
849	b0889											100.0%			$0.50
850	b0892	100.0%													$0.20
851	b0893	100.0%													$0.20
852	b0894	100.0%													$0.20
853	b0895	100.0%													$0.20
854	b0896	100.0%													$0.20
855	b0897	100.0%													$0.20
856	b0898	100.0%													$0.20
857	b0899											100.0%			$0.50
858	b0900											100.0%			$0.50
859	b0901														$0.19
860	b0902														$0.19
861	b0903														$0.19
862	b0904														$0.19
863	b0905														$0.19
864	b0906														$0.00

	A	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL
58	Upgrade ID	Project ID	Upgrade Date In-Service	Project Average In-Service Date	Date to use	Upgrade Source	Project Source	Project Status	Projects Allocated by Load	Projects Attributed to one entity	Projects Attributed to Dayton entity	Year In Service Override	First Full Year in Service	Project Age
793	b0827	b0827	5/27/2011	5/27/2011	5/27/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
794	b0828	b0828	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	EP	0	1	0		2012	-1
795	b0829.1	b0829	6/1/2013	1/4/2013	6/1/2013	Planned	Planned	EP	1	0	0		2014	-3
796	b0829.11	b0829	6/1/2013	1/4/2013	6/1/2013	Planned	Planned	EP	1	0	0		2014	-3
797	b0829.12	b0829	6/1/2013	1/4/2013	6/1/2013	Planned	Planned	EP	1	0	0		2014	-3
798	b0829.2	b0829	6/1/2013	1/4/2013	6/1/2013	Planned	Planned	EP	1	0	0		2014	-3
799	b0829.3	b0829	6/1/2013	1/4/2013	6/1/2013	Planned	Planned	EP	1	0	0		2014	-3
800	b0829.4	b0829	6/1/2013	1/4/2013	6/1/2013	Planned	Planned	EP	1	0	0		2014	-3
801	b0829.5	b0829	10/9/2009	1/4/2013	10/9/2009	Post-2005	Planned	IS	1	0	0		2010	1
802	b0829.6	b0829	6/1/2013	1/4/2013	6/1/2013	Planned	Planned	EP	1	0	0		2014	-3
803	b0829.9	b0829	6/1/2013	1/4/2013	6/1/2013	Planned	Planned	EP	1	0	0		2014	-3
804	b0830.1	b0830	2/28/2011	12/19/2010	2/28/2011	Planned	Planned	EP	1	0	0		2012	-1
805	b0830.2	b0830	11/14/2010	12/19/2010	11/14/2010	Post-2005	Planned	IS	1	0	0		2011	0
806	b0830.3	b0830	11/14/2010	12/19/2010	11/14/2010	Post-2005	Planned	IS	1	0	0		2011	0
807	b0837	b0837	3/26/2009	3/26/2009	3/26/2009	Post-2005	Post-2005	IS	1	0	0		2010	1
808	b0838	b0838	12/31/2014	12/31/2014	12/31/2014	Planned	Planned	EP	0	1	0		2015	-4
809	b0839	b0839	6/2/2009	6/2/2009	6/2/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
810	b0840	b0840	6/1/2013	11/30/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
811	b0840.1	b0840	6/1/2014	11/30/2013	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
812	b0842	b0842	10/31/2011	10/31/2011	10/31/2011	Planned	Planned	UC	0	1	0		2012	-1
813	b0842.1	b0842	10/31/2011	10/31/2011	10/31/2011	Planned	Planned	UC	0	1	0		2012	-1
814	b0843	b0843	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
815	b0844	b0844	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
816	b0845	b0845	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	EP	0	1	0		2012	-1
817	b0846	b0846	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	EP	0	1	0		2012	-1
818	b0847	b0847	12/31/2014	12/31/2014	12/31/2014	Planned	Planned	EP	0	1	0		2015	-4
819	b0848	b0848	11/22/2009	11/22/2009	11/22/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
820	b0849	b0849	12/3/2010	12/3/2010	12/3/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
821	b0850	b0850	12/31/2011	12/31/2011	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
822	b0851	b0851	12/31/2011	12/31/2011	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
823	b0852	b0852	12/31/2014	12/31/2014	12/31/2014	Planned	Planned	EP	0	1	0		2015	-4
824	b0853	b0853	12/31/2014	12/31/2014	12/31/2014	Planned	Planned	EP	0	1	0		2015	-4
825	b0854	b0854	12/31/2014	12/31/2014	12/31/2014	Planned	Planned	EP	0	1	0		2015	-4
826	b0855	b0855	12/31/2014	12/31/2014	12/31/2014	Planned	Planned	EP	0	1	0		2015	-4
827	b0856	b0856	12/31/2014	12/31/2014	12/31/2014	Planned	Planned	EP	0	1	0		2015	-4
828	b0857	b0857	12/31/2014	12/31/2014	12/31/2014	Planned	Planned	EP	0	1	0		2015	-4
829	b0858	b0858	12/31/2014	12/31/2014	12/31/2014	Planned	Planned	EP	0	1	0		2015	-4
830	b0859	b0859	12/31/2014	12/31/2014	12/31/2014	Planned	Planned	EP	0	1	0		2015	-4
831	b0860	b0860	12/31/2014	12/31/2014	12/31/2014	Planned	Planned	EP	0	1	0		2015	-4
832	b0861	b0861	12/31/2014	12/31/2014	12/31/2014	Planned	Planned	EP	0	1	0		2015	-4
833	b0862	b0862	12/31/2014	12/31/2014	12/31/2014	Planned	Planned	EP	0	1	0		2015	-4
834	b0863	b0863	11/13/2010	11/13/2010	11/13/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
835	b0870	b0870	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
836	b0871	b0871	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
837	b0873	b0873	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
838	b0874	b0874	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
839	b0876	b0876	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
840	b0877	b0877	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
841	b0879.1	b0879	6/1/2013	9/15/1956	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
842	b0881	b0881	5/31/2012	5/31/2012	5/31/2012	Planned	Planned	EP	0	1	0		2013	-2
843	b0882	b0882	4/26/2010	4/26/2010	4/26/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
844	b0883	b0883	9/24/2010	9/24/2010	9/24/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
845	b0884	b0884	9/1/2010	9/1/2010	9/1/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
846	b0885	b0885	12/15/2010	12/15/2010	12/15/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
847	b0886	b0886	12/15/2010	12/15/2010	12/15/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
848	b0888	b0888	4/30/2005	4/30/2005	4/30/2005	Post-2005	Post-2005	IS	0	1	0		2006	5
849	b0889	b0889	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
850	b0892	b0892	1/30/2011	1/30/2011	1/30/2011	Planned	Planned	EP	0	1	0		2012	-1
851	b0893	b0893	9/25/2009	9/25/2009	9/25/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
852	b0894	b0894	2/24/2009	2/24/2009	2/24/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
853	b0895	b0895	5/1/2009	5/1/2009	5/1/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
854	b0896	b0896	5/1/2009	5/1/2009	5/1/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
855	b0897	b0897	6/22/2009	6/22/2009	6/22/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
856	b0898	b0898	4/9/2009	4/9/2009	4/9/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
857	b0899	b0899	10/1/2009	10/1/2009	10/1/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
858	b0900	b0900	10/1/2009	10/1/2009	10/1/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
859	b0901	b0901	9/21/2010	9/21/2010	9/21/2010	Post-2005	Post-2005	IS	0	1	1		2011	0
860	b0902	b0902	11/2/2010	11/2/2010	11/2/2010	Post-2005	Post-2005	IS	0	1	1		2011	0
861	b0903	b0903	11/19/2010	11/19/2010	11/19/2010	Post-2005	Post-2005	IS	0	1	1		2011	0
862	b0904	b0904	10/9/2010	10/9/2010	10/9/2010	Post-2005	Post-2005	IS	0	1	1		2011	0
863	b0905	b0905	10/19/2010	10/19/2010	10/19/2010	Post-2005	Post-2005	IS	0	1	1		2011	0
864	b0906	b0906	3/15/2010	3/15/2010	3/15/2010	Post-2005	Post-2005	IS	0	1	0		2011	0

	A	AM	AN	AO	AP	AQ	AR	AS
58	Upgrade ID	Load Ratio Project Costs	One Entity Project Costs	DFAX allocated Project Costs	Dayton DFAX Project Costs			
793	b0827	0	0.02	0	0			
794	b0828	0	0	0	0			
795	b0829.1	0.5	0	0	0.00			
796	b0829.11	0.5	0	0	0.00			
797	b0829.12	0.5	0	0	0.00			
798	b0829.2	0.5	0	0	0.00			
799	b0829.3	0.5	0	0	0.00			
800	b0829.4	0.5	0	0	0.00			
801	b0829.5	0.225	0	0	0.00			
802	b0829.6	0.8	0	0	0.00			
803	b0829.9	0.5	0	0	0.00			
804	b0830.1	0.8	0	0	0.00			
805	b0830.2	0.8	0	0	0.00			
806	b0830.3	0.8	0	0	0.00			
807	b0837	1.5	0	0	0.00			
808	b0838	0	44	0	0			
809	b0839	0	8.5	0	0.00			
810	b0840	0	6	0	0			
811	b0840.1	0	3.5	0	0			
812	b0842	0	9.5	0	0			
813	b0842.1	0	0.239	0	0			
814	b0843	0	2.6	0	0			
815	b0844	0	0.5	0	0			
816	b0845	0	2	0	0			
817	b0846	0	2	0	0			
818	b0847	0	2	0	0			
819	b0848	0	2	0	0			
820	b0849	0	2	0	0			
821	b0850	0	2	0	0			
822	b0851	0	2	0	0			
823	b0852	0	2	0	0			
824	b0853	0	2	0	0			
825	b0854	0	2	0	0			
826	b0855	0	2	0	0			
827	b0856	0	2	0	0			
828	b0857	0	2	0	0			
829	b0858	0	2	0	0			
830	b0859	0	2	0	0			
831	b0860	0	2	0	0			
832	b0861	0	2	0	0			
833	b0862	0	2	0	0			
834	b0863	0	2	0	0			
835	b0870	0	0.54	0	0			
836	b0871	0	2.8	0	0			
837	b0873	0	16.3	0	0			
838	b0874	0	10.55	0	0			
839	b0876	0	22.8	0	0			
840	b0877	0	44.613	0	0			
841	b0879.1	0	0.05	0	0			
842	b0881	0	0.292	0	0			
843	b0882	0	0.8	0	0			
844	b0883	0	0.01	0	0			
845	b0884	0	0.01	0	0			
846	b0885	0	0.155	0	0			
847	b0886	0	0.155	0	0			
848	b0888	0	0.25	0	0			
849	b0889	0	0.5	0	0			
850	b0892	0	0.2	0	0			
851	b0893	0	0.2	0	0			
852	b0894	0	0.2	0	0			
853	b0895	0	0.2	0	0			
854	b0896	0	0.2	0	0			
855	b0897	0	0.2	0	0			
856	b0898	0	0.2	0	0			
857	b0899	0	0.5	0	0			
858	b0900	0	0.5	0	0			
859	b0901	0	0.185	0	0			
860	b0902	0	0.185	0	0			
861	b0903	0	0.185	0	0			
862	b0904	0	0.185	0	0			
863	b0905	0	0.185	0	0			
864	b0906	0	0	0	0			

	A	B	C	D	E	F	G	H	I	J	K
58	Upgrade ID	Description	TO	AEC	AEP	APS	BGE	ComEd	Dayton	DL	DPL
865	b0907	Increase contact parting time on Wagner 115 kV breake	BGE				100.0%				
866	b0908	Install motor operators at South Akron 230 kV	PPL								
867	b0909	Convert Jenkins 230 kV yard into a 3-breaker ring bus	PPL								
868	b0910	Install a second 230 kV line between Jenkins and Stant	PPL								
869	b0911	Install motor operators at Frackville 230 kV	PPL								
870	b0912	Install 2, 10.8 MVAR capacitor banks at Scranton 69 kV	PPL								
871	b0913	Extend Cando Tap to the Harwood-Jenkins #2 69 kV lin	PPL								
872	b0914	Build a 3rd 69 kV line from Harwood to Valmont Taps	PPL								
873	b0915	Replace Walnut-Center City 69 kV cable	PPL								
874	b0916	Reconductor Sunbury-Dalmatia 69 kV line	PPL								
875	b0917	Replace Baileysville 138 kV breaker 'P'	AEP		100.0%						
876	b0918	Replace Riverview 138 kV breaker '634'	AEP		100.0%						
877	b0919	Replace Torrey 138 kV breaker 'W'	AEP		100.0%						
878	b0920	Replace station cable at Whitpain and Jarrett substatior	PECO								
879	b0921	Reconductor Brambleton - Cochran Mill 230 kV line with	Dominion								
880	b0923	Install 50-100 MVAR variable reactor banks at Carson 2	Dominion								
881	b0924	Install 50-100 MVAR variable reactor banks at Dooms 2	Dominion								
882	b0925	Install 50-100 MVAR variable reactor banks at Garrison	Dominion								
883	b0926	Install 50-100 MVAR variable reactor banks at Hamilton	Dominion								
884	b0927	Install 50-100 MVAR variable reactor banks at Yadkin 2	Dominion								
885	b0928	Install 50-100 MVAR variable reactor banks at Carolina,	Dominion								
886	b0929	Replace Universal 138 kV breaker 'Z-152'	DL							100.0%	
887	b0930	Replace Universal 138 kV breaker 'Z-78'	DL							100.0%	
888	b0931	Replace Universal 138 kV breaker 'NO 1-3'	DL							100.0%	
889	b0932	Replace Brunot Island 138 kV breaker 'GEN2 69 XFMR	DL							100.0%	
890	b0933	Replace Dravosburg 138 kV breaker 'Z-91'	DL							100.0%	
891	b0934	Replace Dravosburg 138 kV breaker 'Z-87'	DL							100.0%	
892	b0935	Replace Dravosburg 138 kV breaker 'Z-76'	DL							100.0%	
893	b0936	Replace Dravosburg 138 kV breaker 'Z-77'	DL							100.0%	
894	b0937	Replace Dravosburg 138 kV breaker 'Z-74'	DL							100.0%	
895	b0938	Replace Elrama 138 kV breaker '#3 SYN B'	DL							100.0%	
896	b0939	Replace Elrama 138 kV breaker '#4 SYN REA'	DL							100.0%	
897	b0940	Replace Cheswick 138 kV breaker '2a/2B CAP'	DL							100.0%	
898	b0950	Replace Yukon 138 kV breaker 'Y-4'	APS			100.0%					
899	b0951	Replace Yukon 138 kV breaker 'Y-9'	APS			100.0%					
900	b0952	Replace Yukon 138 kV breaker 'Y-11'	APS			100.0%					
901	b0953	Replace Yukon 138 kV breaker 'Y-13'	APS			100.0%					
902	b0954	Replace Charleroi 138 kV breaker '#1 XFMR BANK'	APS			100.0%					
903	b0955	Replace Yukon 138 kV breaker 'Y-7'	APS			100.0%					
904	b0956	Replace Pruntytown 138 kV breaker 'P-9'	APS			100.0%					
905	b0957	Replace Pruntytown 138 kV breaker 'P-12'	APS			100.0%					
906	b0958	Replace Pruntytown 138 kV breaker 'P-15'	APS			100.0%					
907	b0959	Replace Charleroi 138 kV breaker '#2 XFMR BANK'	APS			100.0%					
908	b0960	Replace Pruntytown 138 kV breaker 'P-2'	APS			100.0%					
909	b0961	Replace Pruntytown 138 kV breaker 'P-5'	APS			100.0%					
910	b0962	Replace Yukon 138 kV breaker 'Y-18'	APS			100.0%					
911	b0963	Replace Yukon 138 kV breaker 'Y-10'	APS			100.0%					
912	b0964	Replace Pruntytown 138 kV breaker 'P-11'	APS			100.0%					
913	b0965	Replace Springdale 138 kV breaker '138E'	APS			100.0%					
914	b0966	Replace Pruntytown 138 kV breaker 'P-8'	APS			100.0%					
915	b0967	Replace Pruntytown 138 kV breaker 'P-14'	APS			100.0%					
916	b0968	Replace Ringgold 138 kV breaker '#3 XFMR BANK'	APS			100.0%					
917	b0969	Replace Springdale 138 kV breaker '138C'	APS			100.0%					
918	b0970	Replace Rivesville 138 kV breaker '#8 XFMR BANK'	APS			100.0%					
919	b0971	Replace Springdale 138 kV breaker '138F'	APS			100.0%					
920	b0972	Replace Belmont 138 kV breaker 'B-16'	APS			100.0%					
921	b0973	Replace Springdale 138 kV breaker '138G'	APS			100.0%					
922	b0974	Replace Springdale 138 kV breaker '138V'	APS			100.0%					
923	b0975	Replace Armstrong 138 kV breaker 'BROOKVILLE'	APS			100.0%					
924	b0976	Replace Springdale 138 kV breaker '138P'	APS			100.0%					
925	b0977	Replace Belmont 138 kV breaker 'B-17'	APS			100.0%					
926	b0978	Replace Springdale 138 kV breaker '138U'	APS			100.0%					
927	b0979	Replace Springdale 138 kV breaker '138D'	APS			100.0%					
928	b0980	Replace Springdale 138 kV breaker '138R'	APS			100.0%					
929	b0981	Replace Yukon 138 kV breaker 'Y-12'	APS			100.0%					
930	b0982	Replace Yukon 138 kV breaker 'Y-17'	APS			100.0%					
931	b0983	Replace Yukon 138 kV breaker 'Y-14'	APS			100.0%					
932	b0984	Replace Rivesville 138 kV breaker '#10 XFMR BANK'	APS			100.0%					
933	b0985	Replace Belmont 138 kV breaker 'B-14'	APS			100.0%					
934	b0986	Replace Armstrong 138 kV breaker 'RESERVE BUS'	APS			100.0%					
935	b0987	Replace Yukon 138 kV breaker 'Y-16'	APS			100.0%					
936	b0988	Replace Springdale 138 kV breaker '138T'	APS			100.0%					

	A	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
58	Upgrade ID	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL	PSEG	RE	UGI	Cost Estimate ($M)
865	b0907														$0.00
866	b0908										100.0%				$0.73
867	b0909										100.0%				$8.74
868	b0910										100.0%				$3.81
869	b0911										100.0%				$0.45
870	b0912										100.0%				$1.61
871	b0913										100.0%				$0.81
872	b0914										100.0%				$2.95
873	b0915										100.0%				$1.73
874	b0916										100.0%				$10.48
875	b0917														$0.40
876	b0918														$0.40
877	b0919														$0.40
878	b0920							100.0%							$0.18
879	b0921	100.0%													$2.80
880	b0923	100.0%													$5.50
881	b0924	100.0%													$5.50
882	b0925	100.0%													$5.50
883	b0926	100.0%													$5.70
884	b0927	100.0%													$5.50
885	b0928	100.0%													$48.00
886	b0929														$0.30
887	b0930														$0.30
888	b0931														$0.30
889	b0932														$0.30
890	b0933														$0.31
891	b0934														$0.31
892	b0935														$0.31
893	b0936														$0.31
894	b0937														$0.32
895	b0938														$0.32
896	b0939														$0.32
897	b0940														$0.32
898	b0950														$0.20
899	b0951														$0.20
900	b0952														$0.20
901	b0953														$0.20
902	b0954														$0.17
903	b0955														$0.20
904	b0956														$0.20
905	b0957														$0.20
906	b0958														$0.20
907	b0959														$0.17
908	b0960														$0.20
909	b0961														$0.20
910	b0962														$0.20
911	b0963														$0.20
912	b0964														$0.20
913	b0965														$0.20
914	b0966														$0.20
915	b0967														$0.20
916	b0968														$0.14
917	b0969														$0.20
918	b0970														$0.14
919	b0971														$0.20
920	b0972														$0.20
921	b0973														$0.20
922	b0974														$0.20
923	b0975														$0.14
924	b0976														$0.20
925	b0977														$0.20
926	b0978														$0.20
927	b0979														$0.20
928	b0980														$0.20
929	b0981														$0.20
930	b0982														$0.20
931	b0983														$0.20
932	b0984														$0.14
933	b0985														$0.20
934	b0986														$0.14
935	b0987														$0.20
936	b0988														$0.20

	A	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL
58	Upgrade ID	Project ID	Upgrade Date In-Service	Project Average In-Service Date	Date to use	Upgrade Source	Project Source	Project Status	Projects Allocated by Load	Projects Attributed to one entity	Projects Attributed to Dayton entity	Year In Service Override	First Full Year in Service	Project Age
865	b0907	b0907	3/15/2010	3/15/2010	3/15/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
866	b0908	b0908	12/29/2010	12/29/2010	12/29/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
867	b0909	b0909	11/30/2012	11/30/2012	11/30/2012	Planned	Planned	EP	0	1	0		2013	-2
868	b0910	b0910	11/30/2014	11/30/2014	11/30/2014	Planned	Planned	EP	0	1	0		2015	-4
869	b0911	b0911	5/31/2011	5/31/2011	5/31/2011	Planned	Planned	EP	0	1	0		2012	-1
870	b0912	b0912	11/30/2011	11/30/2011	11/30/2011	Planned	Planned	EP	0	1	0		2012	-1
871	b0913	b0913	11/30/2012	11/30/2012	11/30/2012	Planned	Planned	EP	0	1	0		2013	-2
872	b0914	b0914	11/30/2012	11/30/2012	11/30/2012	Planned	Planned	EP	0	1	0		2013	-2
873	b0915	b0915	5/31/2016	5/31/2016	5/31/2016	Planned	Planned	EP	0	1	0		2017	-6
874	b0916	b0916	5/31/2012	5/31/2012	5/31/2012	Planned	Planned	EP	0	1	0		2013	-2
875	b0917	b0917	5/27/2010	5/27/2010	5/27/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
876	b0918	b0918	5/28/2010	5/28/2010	5/28/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
877	b0919	b0919	6/25/2010	6/25/2010	6/25/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
878	b0920	b0920	4/15/2011	4/15/2011	4/15/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
879	b0921	b0921	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	UC	0	1	0		2012	-1
880	b0923	b0923	5/27/2010	5/27/2010	5/27/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
881	b0924	b0924	12/31/2011	12/31/2011	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
882	b0925	b0925	11/3/2010	11/3/2010	11/3/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
883	b0926	b0926	1/30/2011	1/30/2011	1/30/2011	Planned	Planned	UC	0	1	0		2012	-1
884	b0927	b0927	5/6/2010	5/6/2010	5/6/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
885	b0928	b0928	#N/A	5/18/2011	5/18/2011	#N/A	Planned	#N/A	0	1	0		2012	-1
886	b0929	b0929	4/10/2010	4/10/2010	4/10/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
887	b0930	b0930	12/31/2010	12/31/2010	12/31/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
888	b0931	b0931	12/15/2010	12/15/2010	12/15/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
889	b0932	b0932	5/20/2011	5/20/2011	5/20/2011	Planned	Planned	EP	0	1	0		2012	-1
890	b0933	b0933	4/21/2011	4/21/2011	4/21/2011	Planned	Planned	EP	0	1	0		2012	-1
891	b0934	b0934	5/20/2011	5/20/2011	5/20/2011	Planned	Planned	EP	0	1	0		2012	-1
892	b0935	b0935	3/31/2011	3/31/2011	3/31/2011	Planned	Planned	EP	0	1	0		2012	-1
893	b0936	b0936	9/23/2011	9/23/2011	9/23/2011	Planned	Planned	EP	0	1	0		2012	-1
894	b0937	b0937	10/14/2011	10/14/2011	10/14/2011	Planned	Planned	EP	0	1	0		2012	-1
895	b0938	b0938	4/1/2012	4/1/2012	4/1/2012	Planned	Planned	EP	0	1	0		2013	-2
896	b0939	b0939	12/31/2012	12/31/2012	12/31/2012	Planned	Planned	EP	0	1	0		2013	-2
897	b0940	b0940	12/31/2012	12/31/2012	12/31/2012	Planned	Planned	EP	0	1	0		2013	-2
898	b0950	b0950	8/31/2010	8/31/2010	8/31/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
899	b0951	b0951	9/29/2010	9/29/2010	9/29/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
900	b0952	b0952	10/12/2010	10/12/2010	10/12/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
901	b0953	b0953	12/1/2011	12/1/2011	12/1/2011	Planned	Planned	EP	0	1	0		2012	-1
902	b0954	b0954	2/15/2010	2/15/2010	2/15/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
903	b0955	b0955	12/1/2011	12/1/2011	12/1/2011	Planned	Planned	EP	0	1	0		2012	-1
904	b0956	b0956	5/27/2010	5/27/2010	5/27/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
905	b0957	b0957	6/25/2010	6/25/2010	6/25/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
906	b0958	b0958	7/29/2010	7/29/2010	7/29/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
907	b0959	b0959	4/2/2010	4/2/2010	4/2/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
908	b0960	b0960	4/15/2010	4/15/2010	4/15/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
909	b0961	b0961	4/28/2010	4/28/2010	4/28/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
910	b0962	b0962	11/1/2011	11/1/2011	11/1/2011	Planned	Planned	EP	0	1	0		2012	-1
911	b0963	b0963	11/1/2011	11/1/2011	11/1/2011	Planned	Planned	EP	0	1	0		2012	-1
912	b0964	b0964	6/10/2010	6/10/2010	6/10/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
913	b0965	b0965	11/17/2010	11/17/2010	11/17/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
914	b0966	b0966	5/13/2010	5/13/2010	5/13/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
915	b0967	b0967	7/14/2010	7/14/2010	7/14/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
916	b0968	b0968	11/22/2010	11/22/2010	11/22/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
917	b0969	b0969	11/17/2010	11/17/2010	11/17/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
918	b0970	b0970	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
919	b0971	b0971	11/17/2010	11/17/2010	11/17/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
920	b0972	b0972	6/25/2010	6/25/2010	6/25/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
921	b0973	b0973	12/1/2011	12/1/2011	12/1/2011	Planned	Planned	EP	0	1	0		2012	-1
922	b0974	b0974	12/1/2011	12/1/2011	12/1/2011	Planned	Planned	EP	0	1	0		2012	-1
923	b0975	b0975	10/26/2010	10/26/2010	10/26/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
924	b0976	b0976	12/1/2011	12/1/2011	12/1/2011	Planned	Planned	EP	0	1	0		2012	-1
925	b0977	b0977	7/14/2010	7/14/2010	7/14/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
926	b0978	b0978	12/1/2011	12/1/2011	12/1/2011	Planned	Planned	EP	0	1	0		2012	-1
927	b0979	b0979	12/1/2011	12/1/2011	12/1/2011	Planned	Planned	EP	0	1	0		2012	-1
928	b0980	b0980	12/1/2011	12/1/2011	12/1/2011	Planned	Planned	EP	0	1	0		2012	-1
929	b0981	b0981	10/1/2011	10/1/2011	10/1/2011	Planned	Planned	EP	0	1	0		2012	-1
930	b0982	b0982	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	EP	0	1	0		2012	-1
931	b0983	b0983	12/31/2011	12/31/2011	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
932	b0984	b0984	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
933	b0985	b0985	10/24/2010	10/24/2010	10/24/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
934	b0986	b0986	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	UC	0	1	0		2012	-1
935	b0987	b0987	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	EP	0	1	0		2012	-1
936	b0988	b0988	12/1/2011	12/1/2011	12/1/2011	Planned	Planned	EP	0	1	0		2012	-1

	A	AM	AN	AO	AP	AQ	AR	AS
58	Upgrade ID	Load Ratio Project Costs	One Entity Project Costs	DFAX allocated Project Costs	Dayton DFAX Project Costs			
865	b0907	0	0	0	0			
866	b0908	0	0.731	0	0			
867	b0909	0	8.738	0	0			
868	b0910	0	3.814	0	0			
869	b0911	0	0.445	0	0			
870	b0912	0	1.607	0	0			
871	b0913	0	0.811	0	0			
872	b0914	0	2.953	0	0			
873	b0915	0	1.73	0	0			
874	b0916	0	10.481	0	0			
875	b0917	0	0.4	0	0			
876	b0918	0	0.4	0	0			
877	b0919	0	0.4	0	0			
878	b0920	0	0.18	0	0			
879	b0921	0	2.8	0	0			
880	b0923	0	5.5	0	0			
881	b0924	0	5.5	0	0			
882	b0925	0	5.5	0	0			
883	b0926	0	5.7	0	0			
884	b0927	0	5.5	0	0			
885	b0928	0	48	0	0			
886	b0929	0	0.3	0	0			
887	b0930	0	0.3	0	0			
888	b0931	0	0.3	0	0			
889	b0932	0	0.3	0	0			
890	b0933	0	0.309	0	0			
891	b0934	0	0.309	0	0			
892	b0935	0	0.309	0	0			
893	b0936	0	0.309	0	0			
894	b0937	0	0.318	0	0			
895	b0938	0	0.318	0	0			
896	b0939	0	0.318	0	0			
897	b0940	0	0.318	0	0			
898	b0950	0	0.203	0	0			
899	b0951	0	0.203	0	0			
900	b0952	0	0.203	0	0			
901	b0953	0	0.203	0	0			
902	b0954	0	0.168	0	0			
903	b0955	0	0.203	0	0			
904	b0956	0	0.203	0	0			
905	b0957	0	0.203	0	0			
906	b0958	0	0.203	0	0			
907	b0959	0	0.168	0	0			
908	b0960	0	0.203	0	0			
909	b0961	0	0.203	0	0			
910	b0962	0	0.203	0	0			
911	b0963	0	0.203	0	0			
912	b0964	0	0.203	0	0			
913	b0965	0	0.203	0	0			
914	b0966	0	0.203	0	0			
915	b0967	0	0.203	0	0			
916	b0968	0	0.142	0	0			
917	b0969	0	0.203	0	0			
918	b0970	0	0.142	0	0			
919	b0971	0	0.203	0	0			
920	b0972	0	0.203	0	0			
921	b0973	0	0.203	0	0			
922	b0974	0	0.203	0	0			
923	b0975	0	0.142	0	0			
924	b0976	0	0.203	0	0			
925	b0977	0	0.203	0	0			
926	b0978	0	0.203	0	0			
927	b0979	0	0.203	0	0			
928	b0980	0	0.203	0	0			
929	b0981	0	0.203	0	0			
930	b0982	0	0.203	0	0			
931	b0983	0	0.203	0	0			
932	b0984	0	0.142	0	0			
933	b0985	0	0.203	0	0			
934	b0986	0	0.142	0	0			
935	b0987	0	0.203	0	0			
936	b0988	0	0.203	0	0			

	A	B	C	D	E	F	G	H	I	J	K
58	Upgrade ID	Description	TO	AEC	AEP	APS	BGE	ComEd	Dayton	DL	DPL
937	b0989	Replace Edgelawn 138 kV breaker 'GOFF RUN #632'	APS			100.0%					
938	b0990	Change reclosing on Cabot 138 kV breaker 'C-9'	APS			100.0%					
939	b0991	Change reclosing on Belmont 138 kV breaker 'B-7'	APS			100.0%					
940	b0992	Change reclosing on Belmont 138 kV breaker 'B-12'	APS			100.0%					
941	b0993	Change reclosing on Belmont 138 kV breaker 'B-9'	APS			100.0%					
942	b0994	Change reclosing on Belmont 138 kV breaker 'B-19'	APS			100.0%					
943	b0995	Change reclosing on Belmont 138 kV breaker 'B-21'	APS			100.0%					
944	b0996	Change reclosing on Willow Island 138 kV breaker 'FAII	APS			100.0%					
945	b0997	Change reclosing on Cabot 138 kV breaker 'C-4'	APS			100.0%					
946	b0998	Change reclosing on Cabot 138 kV breaker 'C-1'	APS			100.0%					
947	b0999	Replace Redbud 138 kV breaker 'BUS TIE'	APS			100.0%					
948	b1002	Replace Hunterstown 115 kV breaker '96392'	ME								
949	b1003	Replace Hunterstown 115 kV breaker '96292'	ME								
950	b1004	Replace Hunterstown 115 kV breaker '99192'	ME								
951	b1005	Replace Glory 115 kV breaker '#7 XFMR'	PENELEC								
952	b1006	Replace Shawville 115 kV breaker 'NO.14 XFMR'	PENELEC								
953	b1007	Replace Shawville 115 kV breaker 'NO.15 XFMR'	PENELEC								
954	b1008	Replace Shawville 115 kV breaker '#1B XFMR'	PENELEC								
955	b1009	Replace Shawville 115 kV breaker '#2B XFMR	PENELEC								
956	b1010	Replace Shawville 115 kV breaker 'Dubois'	PENELEC								
957	b1011	Replace Shawville 115 kV breaker 'Philipsburg'	PENELEC								
958	b1012	Replace Shawville 115 kV breaker 'Garman'	PENELEC								
959	b1013	Replace Linden 138 kV breaker '7PB'	PSEG								
960	b1014.1	Replace Circuit breaker, Station Cable, CTs and Wave T	PECO								
961	b1014.2	Replace Circuit breaker, Station Cable, CTs Disconnect	PECO								
962	b1015	Replace Breakers #115 and #125 at Printz 230 kV subst	PECO								
963	b1016	Rebuild Graceton - Bagley 230 kV as double circuit line	BGE			2.0%	75.2%				
964	b1017	Reconductor South Mahwah -Waldwick 345 kV J-3410 c	PSEG								
965	b1018	Reconductor South Mahwah -Waldwick 345 kV K-3411 c	PSEG								
966	b1019.1	Replace wave trap, line disconnect and ground switch a	PSEG								
967	b1019.10	Replace wave trap, line, ground 230 kV breaker disconn	PSEG								
968	b1019.2	Replace wave trap, line disconnect and ground switch a	PSEG								
969	b1019.3	Replace 1-2 and 2-3 section disconnect and ground swi	PSEG								
970	b1019.4	Replace 1-2 and 2-3 section disconnect and ground swi	PSEG								
971	b1019.5	Replace wave trap, line disconnect and ground switch a	PSEG								
972	b1019.6	Replace line disconnect and ground switch at Cedar Gro	PSEG								
973	b1019.7	Replace 2-4 and 4-5 section disconnect and ground swi	PSEG								
974	b1019.8	Replace 1-2 and 2-3 section disconnect and ground swi	PSEG								
975	b1019.9	Replace line, ground, 230 kV main bus disconnects at A	PSEG								
976	b1020	Replace wave trap at Englishtown on the Englishtown -	JCPL								
977	b1021	Install a new (#4) 138/69 kV transformer at Wescosville	PPL								
978	b1022.1	Reconfigure the Peters to Bethel Park 138 kV line and E	APS/DL			97.0%				3.0%	
979	b1022.2	Reconductor both Collier - Woodville 138 kV lines	DL							100.0%	
980	b1022.3	Add static capacitors at Smith 138 kV	APS			97.0%				3.0%	
981	b1022.4	Add static capacitors at North Fayette 138 kV	APS			97.0%				3.0%	
982	b1022.5	Add static capacitors at South Fayette 138 kV	APS			97.0%				3.0%	
983	b1022.6	Add static capacitors at Manifold 138 kV	APS			97.0%				3.0%	
984	b1022.7	Add static capacitors at Houston 138 kV	APS			97.0%				3.0%	
985	b1023.1	Install a 500/138 kV transformer at 502 Junction	APS			100.0%					
986	b1023.2	Construct a new Franklin - 502 Junction 138 kV line incl	APS			100.0%					
987	b1023.3	Construct a new 502 Junction - Osage 138 kV line	APS			100.0%					
988	b1023.4	Construct Braddock 138 kV breaker station that connect	APS			100.0%					
989	b1027	Increase the size of the shunt capacitors at Enon 138 kV	APS			100.0%					
990	b1028	Raise three structures on the Osage - Collins Ferry 138	APS			100.0%					
991	b1029	Upgrade wire sections at Wagner on both 110534 and 1	BGE				100.0%				
992	b1030	Move the Hillen Rd substation from circuits 110507/1105	BGE				100.0%				
993	b1031	Replace wire sections on Westport - Pumphrey 115 kV c	BGE				100.0%				
994	b1032.1	Construct a new 345/138kV station on the Marquis-Bixby	AEP		90.0%				10.0%		
995	b1032.2	Construct two 138kV outlets to Delano 138kV station an	AEP		90.0%				10.0%		
996	b1032.3	Convert Ross - Circleville 69kV to 138kV	AEP		90.0%				10.0%		
997	b1032.4	Install 138/69kV transformer at new station and connect	AEP		90.0%				10.0%		
998	b1033	Add a third delivery point from AEP's East Danville Stati	AEP		100.0%						
999	b1034.1	Establish new South Canton - West Canton 138kV line (	AEP		96.0%	0.6%		0.2%	0.4%	0.1%	
1000	b1034.2	Loop the existing South Canton -Wayview 138kV circuit	AEP		96.0%	0.6%		0.2%	0.4%	0.1%	
1001	b1034.3	Install a 345/138kV 450 MVA transformer at Canton Cen	AEP		96.0%	0.6%		0.2%	0.4%	0.1%	
1002	b1034.4	Rebuild/reconductor the Sunnyside - Torrey 138kV line	AEP		96.0%	0.6%		0.2%	0.4%	0.1%	
1003	b1034.5	Disconnect/eliminate the West Canton 138kV terminal a	AEP		96.0%	0.6%		0.2%	0.4%	0.1%	
1004	b1034.6	Replace all 138kV circuit breakers at South Canton Stat	AEP		96.0%	0.6%		0.2%	0.4%	0.1%	
1005	b1034.7	Replace all obsolete 138kV circuit breakers at the Torre	AEP		96.0%	0.6%		0.2%	0.4%	0.1%	
1006	b1034.8	Install additional 138kV circuit breakers at the West Can	AEP		96.0%	0.6%		0.2%	0.4%	0.1%	
1007	b1035	Establish a third 345kV breaker string in the West Miller	AEP		100.0%						
1008	b1036	Upgrade terminal equipment at Poston Station and upda	AEP		100.0%						

	A	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
58	Upgrade ID	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL	PSEG	RE	UGI	Cost Estimate ($M)
937	b0989														$0.14
938	b0990														$0.00
939	b0991														$0.00
940	b0992														$0.00
941	b0993														$0.00
942	b0994														$0.00
943	b0995														$0.00
944	b0996														$0.00
945	b0997														$0.00
946	b0998														$0.00
947	b0999														$0.14
948	b1002					100.0%									$0.23
949	b1003					100.0%									$0.23
950	b1004					100.0%									$0.23
951	b1005								100.0%						$0.23
952	b1006								100.0%						$0.23
953	b1007								100.0%						$0.23
954	b1008								100.0%						$0.23
955	b1009								100.0%						$0.23
956	b1010								100.0%						$0.23
957	b1011								100.0%						$0.23
958	b1012								100.0%						$0.23
959	b1013											100.0%			$0.50
960	b1014.1							100.0%							$1.00
961	b1014.2							100.0%							$1.00
962	b1015							100.0%							$1.00
963	b1016	16.1%								6.6%					$42.60
964	b1017		0.4%		29.5%		1.4%					66.1%	2.6%		$11.45
965	b1018		0.4%		29.7%		1.4%					65.9%	2.6%		$11.45
966	b1019.1											100.0%			$0.35
967	b1019.10											100.0%			$0.35
968	b1019.2											100.0%			$0.35
969	b1019.3											100.0%			$0.35
970	b1019.4											100.0%			$0.35
971	b1019.5											100.0%			$0.35
972	b1019.6											100.0%			$0.35
973	b1019.7											100.0%			$0.35
974	b1019.8											100.0%			$0.35
975	b1019.9											100.0%			$0.35
976	b1020				100.0%										$0.07
977	b1021										100.0%				$4.50
978	b1022.1														$2.30
979	b1022.2														$3.10
980	b1022.3														$0.80
981	b1022.4														$0.90
982	b1022.5														$0.80
983	b1022.6														$0.80
984	b1022.7														$0.80
985	b1023.1														$27.20
986	b1023.2														$13.00
987	b1023.3														$4.20
988	b1023.4														$15.10
989	b1027														$4.20
990	b1028														$2.30
991	b1029														$0.10
992	b1030														$0.09
993	b1031														$0.20
994	b1032.1														$50.00
995	b1032.2														$0.00
996	b1032.3														$0.00
997	b1032.4														$0.00
998	b1033														$1.60
999	b1034.1								2.6%						$28.00
1000	b1034.2								2.6%						$0.00
1001	b1034.3								2.6%						$0.00
1002	b1034.4								2.6%						$0.00
1003	b1034.5								2.6%						$0.00
1004	b1034.6								2.6%						$0.00
1005	b1034.7								2.6%						$0.00
1006	b1034.8								2.6%						$0.00
1007	b1035														$28.00
1008	b1036														$1.40

	A	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL
58	Upgrade ID	Project ID	Upgrade Date In-Service	Project Average In-Service Date	Date to use	Upgrade Source	Project Source	Project Status	Projects Allocated by Load	Projects Attributed to one entity	Projects Attributed to Dayton entity	Year In Service Override	First Full Year in Service	Project Age
937	b0989	b0989	11/11/2010	11/11/2010	11/11/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
938	b0990	b0990	8/24/2010	8/24/2010	8/24/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
939	b0991	b0991	9/9/2010	9/9/2010	9/9/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
940	b0992	b0992	9/9/2010	9/9/2010	9/9/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
941	b0993	b0993	9/9/2010	9/9/2010	9/9/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
942	b0994	b0994	9/9/2010	9/9/2010	9/9/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
943	b0995	b0995	9/9/2010	9/9/2010	9/9/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
944	b0996	b0996	8/23/2010	8/23/2010	8/23/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
945	b0997	b0997	8/24/2010	8/24/2010	8/24/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
946	b0998	b0998	8/24/2010	8/24/2010	8/24/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
947	b0999	b0999	11/1/2011	11/1/2011	11/1/2011	Planned	Planned	EP	0	1	0		2012	-1
948	b1002	b1002	12/1/2011	12/1/2011	12/1/2011	Planned	Planned	EP	0	1	0		2012	-1
949	b1003	b1003	12/1/2011	12/1/2011	12/1/2011	Planned	Planned	EP	0	1	0		2012	-1
950	b1004	b1004	12/31/2011	12/31/2011	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
951	b1005	b1005	12/31/2011	12/31/2011	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
952	b1006	b1006	12/31/2011	12/31/2011	12/31/2011	Planned	Planned	UC	0	1	0		2012	-1
953	b1007	b1007	12/31/2011	12/31/2011	12/31/2011	Planned	Planned	UC	0	1	0		2012	-1
954	b1008	b1008	6/1/2009	1/0/1900	6/1/2009	Planned	Planned	EP	0	1	0		2010	1
955	b1009	b1009	6/1/2009	1/0/1900	6/1/2009	Planned	Planned	EP	0	1	0		2010	1
956	b1010	b1010	9/27/2010	9/27/2010	9/27/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
957	b1011	b1011	12/31/2011	12/31/2011	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
958	b1012	b1012	12/31/2011	12/31/2011	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
959	b1013	b1013	6/1/2010	6/1/2010	6/1/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
960	b1014.1	b1014	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
961	b1014.2	b1014	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
962	b1015	b1015	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
963	b1016	b1016	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	0	0		2015	-4
964	b1017	b1017	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	UC	0	0	0		2012	-1
965	b1018	b1018	12/1/2011	12/1/2011	12/1/2011	Planned	Planned	EP	0	0	0		2012	-1
966	b1019.1	b1019	6/1/2011	4/19/2011	6/1/2011	Planned	Planned	EP	0	1	0		2012	-1
967	b1019.10	b1019	5/1/2011	4/19/2011	5/1/2011	Planned	Planned	EP	0	1	0		2012	-1
968	b1019.2	b1019	6/1/2011	4/19/2011	6/1/2011	Planned	Planned	EP	0	1	0		2012	-1
969	b1019.3	b1019	4/1/2011	4/19/2011	4/1/2011	Planned	Planned	EP	0	1	0		2012	-1
970	b1019.4	b1019	3/1/2011	4/19/2011	3/1/2011	Planned	Planned	EP	0	1	0		2012	-1
971	b1019.5	b1019	4/1/2011	4/19/2011	4/1/2011	Planned	Planned	EP	0	1	0		2012	-1
972	b1019.6	b1019	4/1/2011	4/19/2011	4/1/2011	Planned	Planned	EP	0	1	0		2012	-1
973	b1019.7	b1019	5/1/2011	4/19/2011	5/1/2011	Planned	Planned	EP	0	1	0		2012	-1
974	b1019.8	b1019	4/1/2011	4/19/2011	4/1/2011	Planned	Planned	EP	0	1	0		2012	-1
975	b1019.9	b1019	5/1/2011	4/19/2011	5/1/2011	Planned	Planned	EP	0	1	0		2012	-1
976	b1020	b1020	4/8/2011	4/8/2011	4/8/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
977	b1021	b1021	7/22/2009	7/22/2009	7/22/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
978	b1022.1	b1022	#N/A	1/7/2011	1/7/2011	#N/A	Planned	#N/A	0	0	0		2012	-1
979	b1022.2	b1022	5/5/2011	1/7/2011	5/5/2011	Planned	Planned	UC	0	1	0		2012	-1
980	b1022.3	b1022	6/21/2010	1/7/2011	6/21/2010	Post-2005	Planned	IS	0	0	0		2011	0
981	b1022.4	b1022	12/23/2010	1/7/2011	12/23/2010	Post-2005	Planned	IS	0	0	0		2011	0
982	b1022.5	b1022	9/25/2010	1/7/2011	9/25/2010	Post-2005	Planned	IS	0	0	0		2011	0
983	b1022.6	b1022	6/21/2010	1/7/2011	6/21/2010	Post-2005	Planned	IS	0	0	0		2011	0
984	b1022.7	b1022	11/2/2010	1/7/2011	11/2/2010	Post-2005	Planned	IS	0	0	0		2011	0
985	b1023.1	b1023	6/1/2013	3/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
986	b1023.2	b1023	6/1/2012	3/1/2013	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
987	b1023.3	b1023	6/1/2013	3/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
988	b1023.4	b1023	6/1/2013	3/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
989	b1027	b1027	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	EP	0	1	0		2012	-1
990	b1028	b1028	1/20/2011	1/20/2011	1/20/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
991	b1029	b1029	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
992	b1030	b1030	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	EP	0	1	0		2012	-1
993	b1031	b1031	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	EP	0	1	0		2012	-1
994	b1032.1	b1032	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	0	0		2015	-4
995	b1032.2	b1032	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	0	0		2015	-4
996	b1032.3	b1032	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	0	0		2015	-4
997	b1032.4	b1032	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	0	0		2015	-4
998	b1033	b1033	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
999	b1034.1	b1034	6/1/2014	3/16/1957	6/1/2014	Planned	Planned	EP	0	0	0		2015	-4
1000	b1034.2	b1034	6/1/2014	3/16/1957	6/1/2014	Planned	Planned	EP	0	0	0		2015	-4
1001	b1034.3	b1034	6/1/2014	3/16/1957	6/1/2014	Planned	Planned	EP	0	0	0		2015	-4
1002	b1034.4	b1034	6/1/2014	3/16/1957	6/1/2014	Planned	Planned	EP	0	0	0		2015	-4
1003	b1034.5	b1034	6/1/2014	3/16/1957	6/1/2014	Planned	Planned	EP	0	0	0		2015	-4
1004	b1034.6	b1034	6/1/2014	3/16/1957	6/1/2014	Planned	Planned	EP	0	0	0		2015	-4
1005	b1034.7	b1034	6/1/2014	3/16/1957	6/1/2014	Planned	Planned	EP	0	0	0		2015	-4
1006	b1034.8	b1034	6/1/2014	3/16/1957	6/1/2014	Planned	Planned	EP	0	0	0		2015	-4
1007	b1035	b1035	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1008	b1036	b1036	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4

	A	AM	AN	AO	AP	AQ	AR	AS
58	Upgrade ID	Load Ratio Project Costs	One Entity Project Costs	DFAX allocated Project Costs	Dayton DFAX Project Costs			
937	b0989	0	0.142	0	0			
938	b0990	0	0.001	0	0			
939	b0991	0	0.001	0	0			
940	b0992	0	0.001	0	0			
941	b0993	0	0.001	0	0			
942	b0994	0	0.001	0	0			
943	b0995	0	0.001	0	0			
944	b0996	0	0.001	0	0			
945	b0997	0	0.001	0	0			
946	b0998	0	0.001	0	0			
947	b0999	0	0.142	0	0			
948	b1002	0	0.225	0	0			
949	b1003	0	0.225	0	0			
950	b1004	0	0.225	0	0			
951	b1005	0	0.225	0	0			
952	b1006	0	0.225	0	0			
953	b1007	0	0.225	0	0			
954	b1008	0	0.225	0	0			
955	b1009	0	0.225	0	0			
956	b1010	0	0.225	0	0			
957	b1011	0	0.225	0	0			
958	b1012	0	0.225	0	0			
959	b1013	0	0.5	0	0			
960	b1014.1	0	1	0	0			
961	b1014.2	0	1	0	0			
962	b1015	0	1	0	0			
963	b1016	0	0	42.6	0			
964	b1017	0	0	11.45	0			
965	b1018	0	0	11.45	0			
966	b1019.1	0	0.35	0	0			
967	b1019.10	0	0.35	0	0			
968	b1019.2	0	0.35	0	0			
969	b1019.3	0	0.35	0	0			
970	b1019.4	0	0.35	0	0			
971	b1019.5	0	0.35	0	0			
972	b1019.6	0	0.35	0	0			
973	b1019.7	0	0.35	0	0			
974	b1019.8	0	0.35	0	0			
975	b1019.9	0	0.35	0	0			
976	b1020	0	0.065	0	0			
977	b1021	0	4.5	0	0			
978	b1022.1	0	0	2.3	0			
979	b1022.2	0	3.1	0	0			
980	b1022.3	0	0	0.8	0			
981	b1022.4	0	0	0.9	0			
982	b1022.5	0	0	0.8	0			
983	b1022.6	0	0	0.8	0			
984	b1022.7	0	0	0.8	0			
985	b1023.1	0	27.2	0	0			
986	b1023.2	0	13	0	0			
987	b1023.3	0	4.2	0	0			
988	b1023.4	0	15.1	0	0			
989	b1027	0	4.2	0	0			
990	b1028	0	2.3	0	0			
991	b1029	0	0.1	0	0			
992	b1030	0	0.093	0	0			
993	b1031	0	0.2	0	0			
994	b1032.1	0	0	50	5.015			
995	b1032.2	0	0	0	0			
996	b1032.3	0	0	0	0			
997	b1032.4	0	0	0	0			
998	b1033	0	1.6	0	0			
999	b1034.1	0	0	28	0.12			
1000	b1034.2	0	0	0	0.00			
1001	b1034.3	0	0	0	0.00			
1002	b1034.4	0	0	0	0.00			
1003	b1034.5	0	0	0	0.00			
1004	b1034.6	0	0	0	0.00			
1005	b1034.7	0	0	0	0.00			
1006	b1034.8	0	0	0	0.00			
1007	b1035	0	28	0	0			
1008	b1036	0	1.4	0	0			

	A	B	C	D	E	F	G	H	I	J	K
58	Upgrade ID	Description	TO	AEC	AEP	APS	BGE	ComEd	Dayton	DL	DPL
1009	b1037	Sag check Bonsack–Cloverdale 138 kV, Cloverdale–Ce	AEP		100.0%						
1010	b1038	Check the Crooksville - Muskingum 138 kV sag and per	AEP		100.0%						
1011	b1039	Perform a sag study for the Madison – Cross Street 138	AEP		100.0%						
1012	b1040	Rebuild an 0.065 mile section of the New Carlisle – Oliv	AEP		100.0%						
1013	b1041	Perform a sag study for the Moseley - Roanoke 138 kV t	AEP		100.0%						
1014	b1042	Perform sag studies to raise the emergency rating of An	AEP		100.0%						
1015	b1043	Perform sag studies to raise the emergency rating of Tu	AEP		100.0%						
1016	b1044	Perform sag studies to raise the emergency rating of Ke	AEP		100.0%						
1017	b1045	Perform sag studies of Tri State - Darrah 138 kV	AEP		100.0%						
1018	b1046	Perform sag study of Scottsville – Bremo 138kV to raise	AEP		100.0%						
1019	b1047	Perform sag study of Otter Switch - Altavista 138kV to ra	AEP		100.0%						
1020	b1048	Reconductor the Bixby - Three C - Groves and Bixby - G	AEP		100.0%						
1021	b1049	Upgrade the risers at the Riverside station to increase th	AEP		100.0%						
1022	b1050	Rebuilding and reconductor the Bixby – Pickerington Ro	AEP		100.0%						
1023	b1051	Perform a sag study for the Kenzie Creek – Pokagon 13	AEP		100.0%						
1024	b1052	Unsix-wire the existing Hyatt - Sawmill 138 kV line to for	AEP		100.0%						
1025	b1053	Perform a sag study and remediation of 32 miles betwee	AEP		100.0%						
1026	b1054	Change relay settings on Byron -Wempletown 345 kV to	ComEd					100.0%			
1027	b1055	Upgrade wire drops at Center 115kV on the Center - We	BGE				100.0%				
1028	b1058	Add a third 230/115 kV transformer at Suffolk substation	Dominion								
1029	b1058.1	Replace Suffolk 115 kV breaker ‘T122’ with a 40 kA brea	Dominion								
1030	b1059	Replace a CRS relay at Hooversville 115 kV station	PENELEC								
1031	b1060	Replace a CRS relay at Rachel Hill 115 kV station	PENELEC								
1032	b1061	Replace existing Yorkana 230/115 kV transformer banks	ME								
1033	b1062	Add 2nd 345/138 kV transformer at Shelby	Dayton						100.0%		
1034	b1063	Add two 30 MVAR capacitor banks at Sidney 69 kV stati	Dayton						100.0%		
1035	b1064	Add a 30 MVAR capacitor bank at Eldean 69 kV station	Dayton						100.0%		
1036	b1065.1	Install a new Shelby 138/69 kV transformer at Shelby sta	Dayton						100.0%		
1037	b1065.2	Install a 69 kV line between Shelby 69kV station and Blu	Dayton						100.0%		
1038	b1065.3	Install a new 30 MVAR capacitor bank at Blue Jacket 69	Dayton						100.0%		
1039	b1066	Install a new 30 MVAR shunt at Amsterdam 69 kV statio	Dayton						100.0%		
1040	b1067	Install a new 30 MVAR shunt at Logan 69 kV station	Dayton						100.0%		
1041	b1068	Install a new 30 MVAR shunt at Darby 69 kV station	Dayton						100.0%		
1042	b1071	Rebuild the existing 115 kV corridor between Landstown	Dominion								
1043	b1072	Modify the existing EMS load shedding scheme at Ceda	AEC	100.0%							
1044	b1073	Install 2 new 230 kV breakers at Planebrook (on the 220	PECO								
1045	b1074	Install motor operators on the Jenkins 230 kV ‘2W’ disco	PPL								
1046	b1075	Replace the West Wharton - Franklin - Vermont D931 a	JCPL								
1047	b1076	Replace existing North Anna 500-230kV transformer wit	Dominion								
1048	b1077	Reconductor East Sidney-Shelby 138 kV	Dayton						100.0%		
1049	b1078	Reconductor Greene - Alpha 138 kV	Dayton						100.0%		
1050	b1079	Perform sag study on Bath - Trebein 138 kV line to ensu	Dayton						100.0%		
1051	b1080	Restudy rating of Arsenal – Highland 138 kV undergrou	DL							100.0%	
1052	b1081	Increase rating by forced cooling on Brunot Island – Bra	DL							100.0%	
1053	b1082	Install 230/138 kV transformer at Bergen substation	PSEG								
1054	b1083	Upgrade wire sections of the Mays Chapel – Mt Washin	BGE				100.0%				
1055	b1084	Extend circuit 110570 from Deer Park to Northwest, and	BGE				100.0%				
1056	b1085	Upgrade substation wire conductors at Lipins Corner to	BGE				100.0%				
1057	b1086	Build a new 115 kV switching station between Orchard S	BGE				100.0%				
1058	b1087	Replace Cannon Branch 230-115 kV with larger transfor	Dominion								
1059	b1088	Build new Radnor Heights Sub, add new underground c	Dominion								
1060	b1089	Install 2nd Burke to Sideburn 230 kV underground cable	Dominion								
1061	b1090	Install a 150 MVAR 230 kV capacitor and one 230 kV br	Dominion								
1062	b1091	Add 28.8 MVAR 138 kV capacitor bank at Huffman and	AEP		100.0%						
1063	b1092	Add 28.8 MVAR 138 kV capacitor bank at Sullivan Gard	AEP		100.0%						
1064	b1093	Add a 43.2 MVAR capacitor bank at the Morgan Fork 13	AEP		100.0%						
1065	b1094	Add a 64.8 MVAR capacitor bank at the West Huntingto	AEP		100.0%						
1066	b1095	Reconductor Chase City 115 kV bus and add a new tie b	Dominion								
1067	b1096	Construct 10 mile double ckt. 230kV tower line from Lou	Dominion								
1068	b1097	Add a 138 kV bus tie CB and two other 138 kV CB's at F	ComEd					100.0%			
1069	b1098	Re-configure the Bayway 138 kV substation and install t	PSEG								
1070	b1099	Build a new 230 kV substation by tapping the Aldene – E	PSEG								
1071	b1100	Build a new 138 kV circuit from Bayonne to Marion	PSEG								
1072	b1101	Re-configure the Cedar Grove substation with breaker a	PSEG								
1073	b1102	Replace Bremo 115 kV breaker ‘9122’	Dominion								
1074	b1103	Replace Bremo 115 kV breaker ‘822’	Dominion								
1075	b1104	Replace Burtonsville 230 kV breaker ‘1C’	PEPCO								
1076	b1105	Replace Burtonsville 230 kV breaker ‘2C’	PEPCO								
1077	b1106	Replace Burtonsville 230 kV breaker ‘3C’	PEPCO								
1078	b1107	Replace Burtonsville 230 kV breaker ‘4C’	PEPCO								
1079	b1108	Replace Ohio Central 138 kV breaker ‘C2’	AEP		100.0%						
1080	b1109	Replace Ohio Central 138 kV breaker ‘D1’	AEP		100.0%						

	A	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
58	Upgrade ID	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL	PSEG	RE	UGI	Cost Estimate ($M)
1009	b1037														$3.00
1010	b1038														$1.00
1011	b1039														$0.15
1012	b1040														$1.00
1013	b1041														$1.05
1014	b1042														$0.06
1015	b1043														$0.02
1016	b1044														$0.07
1017	b1045														$0.66
1018	b1046														$0.35
1019	b1047														$0.05
1020	b1048														$5.90
1021	b1049														$0.10
1022	b1050														$12.50
1023	b1051														$0.15
1024	b1052														$3.10
1025	b1053														$1.60
1026	b1054														$0.01
1027	b1055														$0.20
1028	b1058	100.0%													$6.00
1029	b1058.1	100.0%													$0.17
1030	b1059								100.0%						$0.07
1031	b1060								100.0%						$0.07
1032	b1061					100.0%									$4.20
1033	b1062														$7.00
1034	b1063														$0.60
1035	b1064														$0.40
1036	b1065.1														$5.00
1037	b1065.2														$7.50
1038	b1065.3														$0.40
1039	b1066														$0.40
1040	b1067														$0.40
1041	b1068														$0.40
1042	b1071	100.0%													$38.00
1043	b1072														$0.05
1044	b1073							100.0%							$1.30
1045	b1074										100.0%				$1.06
1046	b1075				100.0%										$0.07
1047	b1076	100.0%													$16.00
1048	b1077														$0.53
1049	b1078														$1.63
1050	b1079														$0.00
1051	b1080														$0.00
1052	b1081														$0.00
1053	b1082								16.5%			80.3%	3.2%		$22.60
1054	b1083														$0.10
1055	b1084														$5.00
1056	b1085														$1.50
1057	b1086														$26.00
1058	b1087	100.0%													$5.00
1059	b1088	100.0%													$87.50
1060	b1089	100.0%													$9.00
1061	b1090	100.0%													$1.70
1062	b1091														$2.40
1063	b1092														$2.00
1064	b1093														$0.80
1065	b1094														$0.80
1066	b1095	100.0%													$2.40
1067	b1096	100.0%													$27.20
1068	b1097														$4.50
1069	b1098											100.0%			$15.00
1070	b1099											100.0%			$137.00
1071	b1100											100.0%			$137.00
1072	b1101											100.0%			$76.40
1073	b1102	100.0%													$0.16
1074	b1103	100.0%													$0.16
1075	b1104									100.0%					$1.38
1076	b1105									100.0%					$1.38
1077	b1106									100.0%					$1.38
1078	b1107									100.0%					$1.38
1079	b1108														$0.80
1080	b1109														$0.80

	A	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL
58	Upgrade ID	Project ID	Upgrade Date In-Service	Project Average In-Service Date	Date to use	Upgrade Source	Project Source	Project Status	Projects Allocated by Load	Projects Attributed to one entity	Projects Attributed to Dayton entity	Year In Service Override	First Full Year in Service	Project Age
1009	b1037	b1037	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1010	b1038	b1038	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1011	b1039	b1039	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1012	b1040	b1040	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1013	b1041	b1041	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1014	b1042	b1042	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1015	b1043	b1043	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1016	b1044	b1044	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1017	b1045	b1045	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1018	b1046	b1046	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1019	b1047	b1047	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1020	b1048	b1048	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1021	b1049	b1049	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1022	b1050	b1050	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1023	b1051	b1051	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1024	b1052	b1052	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1025	b1053	b1053	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1026	b1054	b1054	6/1/2014	1/0/1900	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1027	b1055	b1055	12/31/2010	12/31/2010	12/31/2010	Planned	Planned	EP	0	1	0		2011	0
1028	b1058	b1058	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1029	b1058.1	b1058	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1030	b1059	b1059	12/31/2011	12/31/2011	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
1031	b1060	b1060	12/31/2011	12/31/2011	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
1032	b1061	b1061	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	UC	0	1	0		2012	-1
1033	b1062	b1062	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	1		2015	-4
1034	b1063	b1063	#N/A	#DIV/0!	#DIV/0!	#N/A	#N/A	#N/A	0	1	1		2016	-5
1035	b1064	b1064	#N/A	#DIV/0!	#DIV/0!	#N/A	#N/A	#N/A	0	1	1		2016	-5
1036	b1065.1	b1065	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	1		2015	-4
1037	b1065.2	b1065	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	1		2015	-4
1038	b1065.3	b1065	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	1		2015	-4
1039	b1066	b1066	#N/A	#DIV/0!	#DIV/0!	#N/A	#N/A	#N/A	0	1	1		2016	-5
1040	b1067	b1067	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	1		2015	-4
1041	b1068	b1068	#N/A	#DIV/0!	#DIV/0!	#N/A	#N/A	#N/A	0	1	1		2016	-5
1042	b1071	b1071	12/31/2012	12/31/2012	12/31/2012	Planned	Planned	EP	0	1	0		2013	-2
1043	b1072	b1072	12/31/2011	12/31/2011	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
1044	b1073	b1073	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1045	b1074	b1074	6/1/2014	1/0/1900	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1046	b1075	b1075	12/1/2011	12/1/2011	12/1/2011	Planned	Planned	UC	0	1	0		2012	-1
1047	b1076	b1076	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1048	b1077	b1077	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	1		2015	-4
1049	b1078	b1078	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	1		2015	-4
1050	b1079	b1079	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	1		2015	-4
1051	b1080	b1080	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1052	b1081	b1081	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	UC	0	1	0		2012	-1
1053	b1082	b1082	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	0	0		2015	-4
1054	b1083	b1083	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1055	b1084	b1084	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1056	b1085	b1085	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1057	b1086	b1086	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1058	b1087	b1087	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1059	b1088	b1088	5/31/2012	5/31/2012	5/31/2012	Planned	Planned	EP	0	1	0		2013	-2
1060	b1089	b1089	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1061	b1090	b1090	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
1062	b1091	b1091	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1063	b1092	b1092	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1064	b1093	b1093	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1065	b1094	b1094	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1066	b1095	b1095	4/16/2010	4/16/2010	4/16/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
1067	b1096	b1096	5/30/2013	5/30/2013	5/30/2013	Planned	Planned	EP	0	1	0		2014	-3
1068	b1097	b1097	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	EP	0	1	0		2012	-1
1069	b1098	b1098	3/15/2011	3/15/2011	3/15/2011	Planned	Planned	UC	0	1	0		2012	-1
1070	b1099	b1099	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
1071	b1100	b1100	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
1072	b1101	b1101	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
1073	b1102	b1102	7/11/2009	7/11/2009	7/11/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
1074	b1103	b1103	11/20/2009	11/20/2009	11/20/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
1075	b1104	b1104	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1076	b1105	b1105	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1077	b1106	b1106	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1078	b1107	b1107	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1079	b1108	b1108	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1080	b1109	b1109	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4

	A	AM	AN	AO	AP	AQ	AR	AS
58	Upgrade ID	Load Ratio Project Costs	One Entity Project Costs	DFAX allocated Project Costs	Dayton DFAX Project Costs			
1009	b1037	0	3	0	0			
1010	b1038	0	1	0	0			
1011	b1039	0	0.15	0	0			
1012	b1040	0	1	0	0			
1013	b1041	0	1.05	0	0			
1014	b1042	0	0.055	0	0			
1015	b1043	0	0.02	0	0			
1016	b1044	0	0.067	0	0			
1017	b1045	0	0.662	0	0			
1018	b1046	0	0.35	0	0			
1019	b1047	0	0.05	0	0			
1020	b1048	0	5.9	0	0			
1021	b1049	0	0.1	0	0			
1022	b1050	0	12.5	0	0			
1023	b1051	0	0.15	0	0			
1024	b1052	0	3.1	0	0			
1025	b1053	0	1.6	0	0			
1026	b1054	0	0.005	0	0			
1027	b1055	0	0.2	0	0			
1028	b1058	0	6	0	0			
1029	b1058.1	0	0.17	0	0			
1030	b1059	0	0.0659	0	0			
1031	b1060	0	0.0659	0	0			
1032	b1061	0	4.2	0	0			
1033	b1062	0	7	0	0			
1034	b1063	0	0.6	0	0			
1035	b1064	0	0.4	0	0			
1036	b1065.1	0	5	0	0			
1037	b1065.2	0	7.5	0	0			
1038	b1065.3	0	0.4	0	0			
1039	b1066	0	0.4	0	0			
1040	b1067	0	0.4	0	0			
1041	b1068	0	0.4	0	0			
1042	b1071	0	38	0	0			
1043	b1072	0	0.05	0	0			
1044	b1073	0	1.3	0	0			
1045	b1074	0	1.06	0	0			
1046	b1075	0	0.065	0	0			
1047	b1076	0	16	0	0			
1048	b1077	0	0.532	0	0			
1049	b1078	0	1.63	0	0			
1050	b1079	0	0	0	0			
1051	b1080	0	0	0	0			
1052	b1081	0	0	0	0			
1053	b1082	0	0	22.6	0			
1054	b1083	0	0.1	0	0			
1055	b1084	0	5	0	0			
1056	b1085	0	1.5	0	0			
1057	b1086	0	26	0	0			
1058	b1087	0	5	0	0			
1059	b1088	0	87.5	0	0			
1060	b1089	0	9	0	0			
1061	b1090	0	1.7	0	0			
1062	b1091	0	2.4	0	0			
1063	b1092	0	2	0	0			
1064	b1093	0	0.8	0	0			
1065	b1094	0	0.8	0	0			
1066	b1095	0	2.4	0	0			
1067	b1096	0	27.2	0	0			
1068	b1097	0	4.5	0	0			
1069	b1098	0	15	0	0			
1070	b1099	0	137	0	0			
1071	b1100	0	137	0	0			
1072	b1101	0	76.4	0	0			
1073	b1102	0	0.158	0	0			
1074	b1103	0	0.158	0	0			
1075	b1104	0	1.375	0	0			
1076	b1105	0	1.375	0	0			
1077	b1106	0	1.375	0	0			
1078	b1107	0	1.375	0	0			
1079	b1108	0	0.8	0	0			
1080	b1109	0	0.8	0	0			

	A	B	C	D	E	F	G	H	I	J	K
58	Upgrade ID	Description	TO	AEC	AEP	APS	BGE	ComEd	Dayton	DL	DPL
1081	b1110	Replace Sporn A 138 kV breaker ‘J’	AEP		100.0%						
1082	b1111	Replace Sporn A 138 kV breaker ‘J2’	AEP		100.0%						
1083	b1112	Replace Sporn A 138 kV breaker ‘L’	AEP		100.0%						
1084	b1113	Replace Sporn A 138 kV breaker ‘L1’	AEP		100.0%						
1085	b1114	Replace Sporn A 138 kV breaker ‘L2’	AEP		100.0%						
1086	b1115	Replace Sporn A 138 kV breaker ‘N’	AEP		100.0%						
1087	b1116	Replace Sporn A 138 kV breaker ‘N2’	AEP		100.0%						
1088	b1117	Replace Beaver Valley 138 kV breaker ‘1A & 3A SS tfmı	DL							100.0%	
1089	b1118	Replace Beaver Valley 138 kV breaker ‘1B & 3B SS tfmı	DL							100.0%	
1090	b1119	Replace Beaver Valley 138 kV breaker ‘2B SS tfmr’	DL							100.0%	
1091	b1120	Replace Beaver Valley 138 kV breaker ‘Z30 Midland	DL							100.0%	
1092	b1121	Replace Beaver Valley 138 kV breaker ‘Z33 J&L Midlan	DL							100.0%	
1093	b1122	Replace Elwyn 138 kV breaker ‘Z62 Collier’	DL							100.0%	
1094	b1123	Replace Elwyn 138 kV breaker ‘No. 1-2 138 kV bus’	DL							100.0%	
1095	b1124	Replace Elwyn 138 kV breaker ‘No. 2-3 138 kV bus’	DL							100.0%	
1096	b1125	Convert the 138 kV line from Buzzard 138 - Ritchie 851	PEPCO			4.7%					
1097	b1126	Upgrade the 230 kV line from Buzzard 016 – Ritchie 05(	PEPCO			4.7%					
1098	b1127	Build a new Lincoln-Minitola 138 kV line	AEC	100.0%							
1099	b1128	Reconductor the Edgewater – Vasco Tap; Edgewater –	APS			100.0%					
1100	b1129	Reconductor the East Waynesboro – Ringgold 138 kV li	APS			100.0%					
1101	b1131	Upgrade Double Tollgate – Meadowbrook MDT Termina	APS			100.0%					
1102	b1132	Upgrade Double Tollgate-Meadowbrook MBG terminal e	APS			100.0%					
1103	b1133	Upgrade terminal equipment at Springdale	APS			100.0%					
1104	b1135	Reconductor the Bartonville – Meadowbrook 138 kV line	APS			100.0%					
1105	b1137	Reconductor the Eastgate – Luxor 138 kV; Eastgate – S	APS			78.6%					
1106	b1138	Reconductor the King Farm – Sony 138 kV line with 954	APS			100.0%					
1107	b1139	Reconductor the Yukon – Waltz Mills 138 kV line with hi	APS			100.0%					
1108	b1140	Reconductor the Bracken Junction – Luxor 138 kV line v	APS			100.0%					
1109	b1141	Reconductor the Sewickley – Waltz Mills Tap 138 kV lin	APS			100.0%					
1110	b1142	Reconductor the Bartonsville – Stephenson 138 kV; Sto	APS			100.0%					
1111	b1143	Reconductor the Youngwood – Yukon 138 kV line with h	APS			89.9%					
1112	b1144	Reconductor the Bull Creek Junction – Cabot 138 kV lin	APS			100.0%					
1113	b1145	Reconductor the Lawson Junction – Cabot 138 kV line v	APS			100.0%					
1114	b1146	Replace Layton - Smithton #61 138 kV line structures to	APS			100.0%					
1115	b1147	Replace Smith – Yukon 138 kV line structures to increas	APS			100.0%					
1116	b1148	Reconductor the Loyalhanna – Luxor 138 kV line with 9!	APS			100.0%					
1117	b1149	Reconductor the Luxor – Stony Springs Junction 138 kV	APS			100.0%					
1118	b1150	Upgrade terminal equipment at Social Hall	APS			100.0%					
1119	b1151	Reconductor the Greenwood – Redbud 138 kV line with	APS			100.0%					
1120	b1152	Reconductor Grand Point – South Chambersburg	APS			100.0%					
1121	b1153	Upgrade Conemaugh 500/230 kV transformer and add a	PENELEC	3.7%		6.3%	16.8%			0.3%	
1122	b1154	Convert the West Orange 138 kV substation, the two Ro	PSEG								
1123	b1155	Build a new 230 kV circuit from Branchburg to Middlese:	PSEG								
1124	b1156	Convert the Burlington, Camden, and Cuthbert Blvd 138	PSEG								
1125	b1156.1	Upgrade at Richmond 230 kV breaker ‘525’	PECO								
1126	b1156.10	Upgrade at Plymouth Meeting 230 kV breaker ‘265’	PECO								
1127	b1156.2	Upgrade at Richmond 230 kV breaker ‘415’	PECO								
1128	b1156.3	Upgrade at Richmond 230 kV breaker ‘475’	PECO								
1129	b1156.4	Upgrade at Richmond 230 kV breaker ‘575’	PECO								
1130	b1156.5	Upgrade at Richmond 230 kV breaker ‘185’	PECO								
1131	b1156.6	Upgrade at Richmond 230 kV breaker ‘285’	PECO								
1132	b1156.7	Upgrade at Richmond 230 kV breaker ‘85’	PECO								
1133	b1156.8	Upgrade at Waneeta 230 kV breaker ‘425’	PECO								
1134	b1156.9	Upgrade at Emilie 230 kV breaker ‘815’	PECO								
1135	b1157	Replace the 345 kV bus tie CB 2-3 at Lisle	ComEd					100.0%			
1136	b1158	Add a 57.6 MVAR capacitor at Prospect Heights 138 kV	ComEd					100.0%			
1137	b1159	Replace Peters 138 kV breaker ‘Bethel P OCB’	APS			100.0%					
1138	b1160	Replace Peters 138 kV breaker ‘Cecil OCB’	APS			100.0%					
1139	b1161	Replace Peters 138 kV breaker ‘Union JctOCB’	APS			100.0%					
1140	b1162	Replace Double Toll Gate 138 kV breaker ‘DRB-2’	APS			100.0%					
1141	b1163	Replace Double Toll Gate 138 kV breaker ‘DT 138 kV O	APS			100.0%					
1142	b1164	Replace Cecil 138 kV breaker ‘Enlow OCB’	APS			100.0%					
1143	b1165	Replace Cecil 138 kV breaker ‘South Fayette’	APS			100.0%					
1144	b1166	Replace Wylie Ridge 138 kV breaker ‘W-9’	APS			100.0%					
1145	b1167	Replace Reid 138 kV breaker ‘RI-2’	APS			100.0%					
1146	b1169	Replace Shawville 115 kV breaker ‘#1A XFMR	PENELEC								
1147	b1170	Replace Shawville 115 kV breaker ‘#2A XFMR’	PENELEC								
1148	b1171.1	Install the second Black Oak 500/138 kV transformer, tw	APS				20.8%				3.1%
1149	b1171.3	Install six 500 kV breakers and remove BOL1 500 kV bre	APS	2.0%	18.0%	6.3%	4.9%	15.6%	2.5%	2.0%	2.8%
1150	b1174	Create a second Collier-Elwyn 138 kV circuit (Z-162) by	DL							100.0%	
1151	b1178	Add a second 230/138 kV transformer at Chichester. Ad	PECO								
1152	b1179	Replace terminal equipment at Eddystone and Saville aı	PECO								

	A	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
58	Upgrade ID	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL	PSEG	RE	UGI	Cost Estimate ($M)
1081	b1110														$0.80
1082	b1111														$0.80
1083	b1112														$0.80
1084	b1113														$0.80
1085	b1114														$0.80
1086	b1115														$0.80
1087	b1116														$0.80
1088	b1117														$0.40
1089	b1118														$0.40
1090	b1119														$0.40
1091	b1120														$0.40
1092	b1121														$0.00
1093	b1122														$0.33
1094	b1123														$0.33
1095	b1124														$0.33
1096	b1125									95.3%					$56.00
1097	b1126									95.3%					$39.00
1098	b1127														$12.50
1099	b1128														$2.30
1100	b1129														$3.00
1101	b1131														$0.03
1102	b1132														$0.03
1103	b1133														$0.02
1104	b1135														$2.90
1105	b1137		0.2%						14.1%			6.8%	0.3%		$5.80
1106	b1138														$0.70
1107	b1139														$2.00
1108	b1140														$0.80
1109	b1141														$1.00
1110	b1142														$2.30
1111	b1143								10.1%						$5.90
1112	b1144														$1.60
1113	b1145														$1.60
1114	b1146														$0.30
1115	b1147														$0.30
1116	b1148														$3.20
1117	b1149														$1.70
1118	b1150														$0.02
1119	b1151														$2.70
1120	b1152														$2.90
1121	b1153		3.0%		12.6%	6.9%	1.7%	11.5%		0.6%	15.4%	20.5%	0.7%		$29.80
1122	b1154											96.2%	3.8%		$336.00
1123	b1155				4.6%							91.8%	3.6%		$125.00
1124	b1156											96.2%	3.8%		$381.00
1125	b1156.1							100.0%							$0.10
1126	b1156.10							100.0%							$0.50
1127	b1156.2							100.0%							$0.10
1128	b1156.3							100.0%							$0.10
1129	b1156.4							100.0%							$0.10
1130	b1156.5							100.0%							$0.10
1131	b1156.6							100.0%							$0.10
1132	b1156.7							100.0%							$0.10
1133	b1156.8							100.0%							$0.50
1134	b1156.9							100.0%							$0.50
1135	b1157														$0.01
1136	b1158														$1.55
1137	b1159														$0.19
1138	b1160														$0.19
1139	b1161														$0.19
1140	b1162														$0.19
1141	b1163														$0.19
1142	b1164														$0.19
1143	b1165														$0.19
1144	b1166														$0.22
1145	b1167														$0.19
1146	b1169								100.0%						$0.31
1147	b1170								100.0%						$0.31
1148	b1171.1	39.6%				2.7%		3.4%		30.5%					$9.11
1149	b1171.3	13.3%	0.2%		4.2%	2.1%	0.5%	5.9%	2.1%	4.7%	5.6%	7.1%	0.3%		$9.17
1150	b1174														$3.88
1151	b1178		0.3%	0.3%	4.1%		0.4%	82.2%				12.1%	0.5%		$5.91
1152	b1179							100.0%							$3.94

	A	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL
58	Upgrade ID	Project ID	Upgrade Date In-Service	Project Average In-Service Date	Date to use	Upgrade Source	Project Source	Project Status	Projects Allocated by Load	Projects Attributed to one entity	Projects Attributed to Dayton entity	Year In Service Override	First Full Year in Service	Project Age
1081	b1110	b1110	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1082	b1111	b1111	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1083	b1112	b1112	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1084	b1113	b1113	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1085	b1114	b1114	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1086	b1115	b1115	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1087	b1116	b1116	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1088	b1117	b1117	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
1089	b1118	b1118	10/1/2013	10/1/2013	10/1/2013	Planned	Planned	EP	0	1	0		2014	-3
1090	b1119	b1119	12/31/2013	12/31/2013	12/31/2013	Planned	Planned	EP	0	1	0		2014	-3
1091	b1120	b1120	4/1/2014	4/1/2014	4/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1092	b1121	b1121	8/5/2009	8/5/2009	8/5/2009	Post-2005	Post-2005	IS	0	1	0		2010	1
1093	b1122	b1122	10/1/2014	10/1/2014	10/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1094	b1123	b1123	1/15/2010	1/15/2010	1/15/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
1095	b1124	b1124	4/1/2015	4/1/2015	4/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1096	b1125	b1125	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	0	0		2015	-4
1097	b1126	b1126	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	0	0		2015	-4
1098	b1127	b1127	5/31/2016	5/31/2016	5/31/2016	Planned	Planned	EP	0	1	0		2017	-6
1099	b1128	b1128	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1100	b1129	b1129	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1101	b1131	b1131	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1102	b1132	b1132	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1103	b1133	b1133	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1104	b1135	b1135	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
1105	b1137	b1137	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	0	0		2015	-4
1106	b1138	b1138	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1107	b1139	b1139	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1108	b1140	b1140	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1109	b1141	b1141	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1110	b1142	b1142	12/1/2013	12/1/2013	12/1/2013	Planned	Planned	EP	0	1	0		2014	-3
1111	b1143	b1143	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	0	0		2014	-3
1112	b1144	b1144	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1113	b1145	b1145	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
1114	b1146	b1146	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1115	b1147	b1147	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1116	b1148	b1148	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1117	b1149	b1149	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1118	b1150	b1150	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1119	b1151	b1151	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
1120	b1152	b1152	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
1121	b1153	b1153	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	0	0		2015	-4
1122	b1154	b1154	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	0	0		2015	-4
1123	b1155	b1155	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	0	0		2015	-4
1124	b1156	b1156	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	0	0		2015	-4
1125	b1156.1	b1156	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1126	b1156.10	b1156	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1127	b1156.2	b1156	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1128	b1156.3	b1156	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1129	b1156.4	b1156	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1130	b1156.5	b1156	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1131	b1156.6	b1156	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1132	b1156.7	b1156	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1133	b1156.8	b1156	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1134	b1156.9	b1156	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1135	b1157	b1157	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
1136	b1158	b1158	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
1137	b1159	b1159	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	UC	0	1	0		2012	-1
1138	b1160	b1160	11/15/2011	11/15/2011	11/15/2011	Planned	Planned	UC	0	1	0		2012	-1
1139	b1161	b1161	11/15/2011	11/15/2011	11/15/2011	Planned	Planned	EP	0	1	0		2012	-1
1140	b1162	b1162	12/1/2011	12/1/2011	12/1/2011	Planned	Planned	EP	0	1	0		2012	-1
1141	b1163	b1163	12/1/2011	12/1/2011	12/1/2011	Planned	Planned	EP	0	1	0		2012	-1
1142	b1164	b1164	11/15/2011	11/15/2011	11/15/2011	Planned	Planned	EP	0	1	0		2012	-1
1143	b1165	b1165	11/15/2011	11/15/2011	11/15/2011	Planned	Planned	EP	0	1	0		2012	-1
1144	b1166	b1166	12/1/2011	12/1/2011	12/1/2011	Planned	Planned	EP	0	1	0		2012	-1
1145	b1167	b1167	12/1/2011	12/1/2011	12/1/2011	Planned	Planned	EP	0	1	0		2012	-1
1146	b1169	b1169	12/31/2014	12/31/2014	12/31/2014	Planned	Planned	EP	0	1	0		2015	-4
1147	b1170	b1170	12/31/2014	12/31/2014	12/31/2014	Planned	Planned	EP	0	1	0		2015	-4
1148	b1171.1	b1171	6/1/2013	9/15/1956	6/1/2013	Planned	Planned	EP	0	0	0		2014	-3
1149	b1171.3	b1171	6/1/2013	9/15/1956	6/1/2013	Planned	Planned	EP	1	0	0		2014	-3
1150	b1174	b1174	11/4/2011	11/4/2011	11/4/2011	Planned	Planned	UC	0	1	0		2012	-1
1151	b1178	b1178	4/30/2012	4/30/2012	4/30/2012	Planned	Planned	EP	0	0	0		2013	-2
1152	b1179	b1179	2/11/2011	2/11/2011	2/11/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1

	A	AM	AN	AO	AP	AQ	AR	AS
58	Upgrade ID	Load Ratio Project Costs	One Entity Project Costs	DFAX allocated Project Costs	Dayton DFAX Project Costs			
1081	b1110	0	0.8	0	0			
1082	b1111	0	0.8	0	0			
1083	b1112	0	0.8	0	0			
1084	b1113	0	0.8	0	0			
1085	b1114	0	0.8	0	0			
1086	b1115	0	0.8	0	0			
1087	b1116	0	0.8	0	0			
1088	b1117	0	0.4	0	0			
1089	b1118	0	0.4	0	0			
1090	b1119	0	0.4	0	0			
1091	b1120	0	0.4	0	0			
1092	b1121	0	0	0	0			
1093	b1122	0	0.33	0	0			
1094	b1123	0	0.33	0	0			
1095	b1124	0	0.33	0	0			
1096	b1125	0	0	56	0			
1097	b1126	0	0	39	0			
1098	b1127	0	12.5	0	0			
1099	b1128	0	2.3	0	0			
1100	b1129	0	3	0	0			
1101	b1131	0	0.03	0	0			
1102	b1132	0	0.03	0	0			
1103	b1133	0	0.02	0	0			
1104	b1135	0	2.9	0	0			
1105	b1137	0	0	5.8	0			
1106	b1138	0	0.7	0	0			
1107	b1139	0	2	0	0			
1108	b1140	0	0.8	0	0			
1109	b1141	0	1	0	0			
1110	b1142	0	2.3	0	0			
1111	b1143	0	0	5.9	0			
1112	b1144	0	1.6	0	0			
1113	b1145	0	1.6	0	0			
1114	b1146	0	0.3	0	0			
1115	b1147	0	0.3	0	0			
1116	b1148	0	3.2	0	0			
1117	b1149	0	1.7	0	0			
1118	b1150	0	0.02	0	0			
1119	b1151	0	2.7	0	0			
1120	b1152	0	2.9	0	0			
1121	b1153	0	0	29.8	0			
1122	b1154	0	0	336	0			
1123	b1155	0	0	125	0			
1124	b1156	0	0	381	0			
1125	b1156.1	0	0.1	0	0			
1126	b1156.10	0	0.5	0	0			
1127	b1156.2	0	0.1	0	0			
1128	b1156.3	0	0.1	0	0			
1129	b1156.4	0	0.1	0	0			
1130	b1156.5	0	0.1	0	0			
1131	b1156.6	0	0.1	0	0			
1132	b1156.7	0	0.1	0	0			
1133	b1156.8	0	0.5	0	0			
1134	b1156.9	0	0.5	0	0			
1135	b1157	0	0.01	0	0			
1136	b1158	0	1.55	0	0			
1137	b1159	0	0.191	0	0			
1138	b1160	0	0.191	0	0			
1139	b1161	0	0.191	0	0			
1140	b1162	0	0.191	0	0			
1141	b1163	0	0.191	0	0			
1142	b1164	0	0.191	0	0			
1143	b1165	0	0.191	0	0			
1144	b1166	0	0.22	0	0			
1145	b1167	0	0.191	0	0			
1146	b1169	0	0.313	0	0			
1147	b1170	0	0.313	0	0			
1148	b1171.1	0	0	9.11	0			
1149	b1171.3	9.17	0	0	0.00			
1150	b1174	0	3.88	0	0			
1151	b1178	0	0	5.908	0			
1152	b1179	0	3.94	0	0			

	A	B	C	D	E	F	G	H	I	J	K
58	Upgrade ID	Description	TO	AEC	AEP	APS	BGE	ComEd	Dayton	DL	DPL
1153	b1180.1	Replace terminal equipment at Chichester	PECO								
1154	b1180.2	Replace terminal equipment at Chichester	PECO								
1155	b1181	Install 230/138 kV transformer at Eddystone	PECO								
1156	b1182	Reconductor Chichester – Saville 138 kV line and upgra	PECO								
1157	b1183	Replace 230/69 kV transformer #6 at Cromby. Add two 5	PECO								
1158	b1184	Add 138 kV breakers at Cromby, Perkiomen, and North	PECO								
1159	b1185	Upgrade Eddystone 230 kV breaker #365	PECO								
1160	b1186	Upgrade Eddystone 230 kV breaker #785	PECO								
1161	b1188	Build new Brambleton 500 kV three breaker ring bus cor	Dominion	2.0%	18.0%	6.3%	4.9%	15.6%	2.5%	2.0%	2.8%
1162	b1188.1	Replace Loudoun 230 kV breaker '200852' with a 63 kA	Dominion								
1163	b1188.2	Replace Loudoun 230 kV breaker '2008T2094' with a 63	Dominion								
1164	b1188.3	Replace Loudoun 230 kV breaker '204552' with a 63 kA	Dominion								
1165	b1188.4	Replace Loudoun 230 kV breaker '209452' with a 63 kA	Dominion								
1166	b1188.5	Replace Loudoun 230 kV breaker 'WT2045' with a 63 k/	Dominion								
1167	b1188.6	Install one 500/230 kV transformer and two 230 kV brea	Dominion	0.2%			7.9%				0.6%
1168	b1195.1	Upgrade the Corson sub T2 terminal	AEC	100.0%							
1169	b1195.2	Upgrade the Corson sub T1 terminal	AEC	100.0%							
1170	b1196	Remove the Siegfried bus tie breaker and install a new l	PPL								
1171	b1197	Reconductor the PECO portion of the Burlington – Croy	PECO								
1172	b1197.1	Reconductor the PSEG portion of the Burlington – Croy	PSEG								
1173	b1198	Replace terminal equipments including station cable, dis	PECO								
1174	b1200	Reconductor Double Toll Gate – Greenwood 138 kV witl	APS			100.0%					
1175	b1201	Rebuild the Hercules Tap to Double Circuit 69 kV	PPL								
1176	b1202	Mack-Macungie Double Tap, Single Feed Arrangement	PPL								
1177	b1203	Add the 2nd Circuit to the East Palmerton-Wagners-Lak	PPL								
1178	b1204	New Breinigsville 230-69 kV Substation	PPL								
1179	b1205	Siegfried-East Palmerton #1 69 kV Line- Install new 69 l	PPL								
1180	b1206	Siegfried-Quarry #1 & #2 69 kV Lines- Rebuild 3.3 mi fr	PPL								
1181	b1209	Convert Neffsville Taps from 69 kV to 138 kV Operation	PPL								
1182	b1210	Convert Roseville Taps from 69 kV to 138 kV Operation	PPL								
1183	b1211	Convert Roseville Taps from 69 kV to 138 kV Operation	PPL								
1184	b1212	New 138 kV Taps to Flory Mill 138/69 kV Substation	PPL								
1185	b1213	Convert East Petersburg Taps from 69 kV to 138 kV ope	PPL								
1186	b1214	Terminate South Manheim-Donegal #2 at South Manhei	PPL								
1187	b1215	Reconductor and rebuild 16 miles of Peckville-Varden 6	PPL								
1188	b1216	Build approximately 2.5 miles of new 69 kV transmissior	PPL								
1189	b1217	Provide a "double tap – single feed" connection to Tafto	PPL								
1190	b1221.1	Convert Carbon Center from 138 kV to a 230 kV ring bu	APS			100.0%					
1191	b1221.2	Construct Bear Run 230 kV substation with 230/138 kV	APS			100.0%					
1192	b1221.3	Loop Carbon Center Junction – Williamette line into Bea	APS			100.0%					
1193	b1221.4	Carbon Center – Carbon Center Junction & Carbon Cen	APS			100.0%					
1194	b1224	Install 2nd Clover 500/230 kV transformer and a 150 MV	Dominion				7.6%				1.0%
1195	b1225	Replace Yorktown 115 kV breaker 'L982-1'	Dominion								
1196	b1226	Replace Yorktown 115 kV breaker 'L982-2'	Dominion								
1197	b1227	Perform a sag study on Altavista – Leesville 138 kV circ	AEP		100.0%						
1198	b1228	Re-configure the Lawrence 230 kV substation to breake	PSEG								
1199	b1230	Reconductor Willow-Eureka & Eurkea-St Mary 138 kV li	APS			100.0%					
1200	b1231	Replace the existing 138/69-12 kV transformer at West l	AEP		96.7%				3.3%		
1201	b1232	Reconductor Nipetown – Reid 138 kV with 1033 ACCR	APS	1.8%		69.7%					2.4%
1202	b1233.1	Upgrade terminal equipment at Washington	APS			100.0%					
1203	b1234	Replace structures between Ridgeway and Paper city	APS			100.0%					
1204	b1235	Reconductor the Albright – Black Oak AFA 138 kV line v	APS				23.1%				
1205	b1237	Upgrade terminal equipment at Albright, replace bus anc	APS			100.0%					
1206	b1238	Install a 138 kV 44 MVAR capacitor at Edgelawn substa	APS			100.0%					
1207	b1239	Install a 138 kV 44 MVAR capacitor at Ridgeway substa	APS			100.0%					
1208	b1240	Install a 138 kV 44 MVAR capacitor at Elko Substation	APS			100.0%					
1209	b1241	Upgrade terminal equipment at Washington substation c	APS			100.0%					
1210	b1242	Replace structures between Collins Ferry and West Rur	APS			100.0%					
1211	b1243	Install a 138 kV capacitor at Potter Substation	APS			100.0%					
1212	b1244	Install 10 MVAR capacitor at Peermont 69 kV substation	AEC	100.0%							
1213	b1245	Rebuild the Newport-South Millville 69 kV line	AEC	100.0%							
1214	b1246	Re-build the Townsend – Church 138 kV circuit	DPL								100.0%
1215	b1247	Re-build the Glasgow – Cecil 138 kV circuit	DPL								72.1%
1216	b1248	Install two 15 MVAR capacitor at Loretto 69 kV	DPL								100.0%
1217	b1249	Reconfigure the existing Sussex 69 kV capacitor	DPL								100.0%
1218	b1250	Reconductor the Monroe – Glassboro 69 kV	AEC	100.0%							
1219	b1250.1	Upgrade substation equipment at Glassboro	AEC	100.0%							
1220	b1251	Build a second Raphael – Bagley 230 kV	BGE			4.4%	67.0%	4.1%	0.5%		
1221	b1251.1	Re-build the existing Raphael – Bagley 230 kV	BGE			4.4%	67.0%	4.1%	0.5%		
1222	b1252	Upgrade terminal equipment (remove terminal limitation	BGE				100.0%				
1223	b1253	Replace the existing Northeast 230/115 kV transformer	BGE				100.0%				
1224	b1254	Build a new 500/230 kV substation (Emory Grove)	BGE			4.1%	53.2%	3.7%	0.5%		

	A	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
58	Upgrade ID	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL	PSEG	RE	UGI	Cost Estimate ($M)
1153	b1180.1							100.0%							$0.48
1154	b1180.2							100.0%							$0.48
1155	b1181							100.0%							$3.60
1156	b1182		0.4%	0.4%	5.1%		0.5%	78.9%				14.2%	0.6%		$8.50
1157	b1183							100.0%							$6.14
1158	b1184							100.0%							$3.90
1159	b1185							100.0%							$0.13
1160	b1186							100.0%							$0.13
1161	b1188	13.3%	0.2%		4.2%	2.1%	0.5%	5.9%	2.1%	4.7%	5.6%	7.1%	0.3%		$5.20
1162	b1188.1	100.0%													$0.22
1163	b1188.2	100.0%													$0.22
1164	b1188.3	100.0%													$0.22
1165	b1188.4	100.0%													$0.22
1166	b1188.5	100.0%													$0.22
1167	b1188.6	75.6%				0.2%		0.7%		14.8%					$16.83
1168	b1195.1														$0.10
1169	b1195.2														$0.03
1170	b1196										100.0%				$1.00
1171	b1197							100.0%							$1.00
1172	b1197.1											100.0%			$3.00
1173	b1198							100.0%							$0.50
1174	b1200														$3.00
1175	b1201										100.0%				$1.95
1176	b1202										100.0%				$0.33
1177	b1203										100.0%				$12.30
1178	b1204										100.0%				$40.13
1179	b1205										100.0%				$0.28
1180	b1206										100.0%				$3.80
1181	b1209										100.0%				$0.00
1182	b1210										100.0%				$1.27
1183	b1211										100.0%				$0.03
1184	b1212										100.0%				$0.69
1185	b1213										100.0%				$0.00
1186	b1214										100.0%				$0.08
1187	b1215										100.0%				$22.40
1188	b1216										100.0%				$2.69
1189	b1217										100.0%				$2.00
1190	b1221.1														$2.00
1191	b1221.2														$6.00
1192	b1221.3														$3.20
1193	b1221.4														$4.30
1194	b1224	78.2%				0.8%		1.4%		11.0%					$17.10
1195	b1225	100.0%													$0.20
1196	b1226	100.0%													$0.20
1197	b1227														$0.02
1198	b1228		0.2%	0.1%								95.8%	3.8%		$9.00
1199	b1230														$4.00
1200	b1231														$11.90
1201	b1232				3.7%	7.6%	0.3%	5.5%	4.1%		5.0%				$15.00
1202	b1233.1														$0.05
1203	b1234														$0.75
1204	b1235	43.8%								33.2%					$55.00
1205	b1237														$0.50
1206	b1238														$1.20
1207	b1239														$1.50
1208	b1240														$1.50
1209	b1241														$0.05
1210	b1242														$0.35
1211	b1243														$2.80
1212	b1244														$0.75
1213	b1245														$1.90
1214	b1246														$5.96
1215	b1247							27.9%							$16.00
1216	b1248														$1.30
1217	b1249														$0.50
1218	b1250														$1.55
1219	b1250.1														$0.00
1220	b1251	18.8%							0.1%	5.2%					$18.00
1221	b1251.1	18.8%							0.1%	5.2%					$0.00
1222	b1252														$0.10
1223	b1253														$10.10
1224	b1254	16.4%							0.6%	21.5%					$71.00

	A	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL
58	Upgrade ID	Project ID	Upgrade Date In-Service	Project Average In-Service Date	Date to use	Upgrade Source	Project Source	Project Status	Projects Allocated by Load	Projects Attributed to one entity	Projects Attributed to Dayton entity	Year In Service Override	First Full Year in Service	Project Age
1153	b1180.1	b1180	3/31/2011	3/31/2011	3/31/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
1154	b1180.2	b1180	3/31/2011	3/31/2011	3/31/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
1155	b1181	b1181	2/11/2011	2/11/2011	2/11/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
1156	b1182	b1182	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	0	0		2013	-2
1157	b1183	b1183	12/31/2011	12/31/2011	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
1158	b1184	b1184	11/13/2011	11/13/2011	11/13/2011	Planned	Planned	UC	0	1	0		2012	-1
1159	b1185	b1185	2/1/2011	2/1/2011	2/1/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
1160	b1186	b1186	2/1/2011	2/1/2011	2/1/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
1161	b1188	b1188	5/30/2014	5/30/2014	5/30/2014	Planned	Planned	EP	1	0	0		2015	-4
1162	b1188.1	b1188	5/30/2014	5/30/2014	5/30/2014	Planned	Planned	EP	0	1	0		2015	-4
1163	b1188.2	b1188	5/30/2014	5/30/2014	5/30/2014	Planned	Planned	EP	0	1	0		2015	-4
1164	b1188.3	b1188	5/30/2014	5/30/2014	5/30/2014	Planned	Planned	EP	0	1	0		2015	-4
1165	b1188.4	b1188	5/30/2014	5/30/2014	5/30/2014	Planned	Planned	EP	0	1	0		2015	-4
1166	b1188.5	b1188	5/30/2014	5/30/2014	5/30/2014	Planned	Planned	EP	0	1	0		2015	-4
1167	b1188.6	b1188	5/30/2014	5/30/2014	5/30/2014	Planned	Planned	EP	0	0	0		2015	-4
1168	b1195.1	b1195	5/1/2011	10/31/2011	5/1/2011	Planned	Planned	EP	0	1	0		2012	-1
1169	b1195.2	b1195	5/1/2012	10/31/2011	5/1/2012	Planned	Planned	EP	0	1	0		2013	-2
1170	b1196	b1196	5/31/2013	5/31/2013	5/31/2013	Planned	Planned	EP	0	1	0		2014	-3
1171	b1197	b1197	6/1/2015	9/15/1957	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1172	b1197.1	b1197	6/1/2015	9/15/1957	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1173	b1198	b1198	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1174	b1200	b1200	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
1175	b1201	b1201	5/31/2013	5/31/2013	5/31/2013	Planned	Planned	EP	0	1	0		2014	-3
1176	b1202	b1202	5/31/2013	5/31/2013	5/31/2013	Planned	Planned	EP	0	1	0		2014	-3
1177	b1203	b1203	11/30/2014	11/30/2014	11/30/2014	Planned	Planned	EP	0	1	0		2015	-4
1178	b1204	b1204	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1179	b1205	b1205	5/31/2014	5/31/2014	5/31/2014	Planned	Planned	EP	0	1	0		2015	-4
1180	b1206	b1206	5/31/2015	5/31/2015	5/31/2015	Planned	Planned	EP	0	1	0		2016	-5
1181	b1209	b1209	11/30/2012	11/30/2012	11/30/2012	Planned	Planned	EP	0	1	0		2013	-2
1182	b1210	b1210	5/31/2011	5/31/2011	5/31/2011	Planned	Planned	UC	0	1	0		2012	-1
1183	b1211	b1211	5/31/2013	5/31/2013	5/31/2013	Planned	Planned	EP	0	1	0		2014	-3
1184	b1212	b1212	11/30/2013	11/30/2013	11/30/2013	Planned	Planned	EP	0	1	0		2014	-3
1185	b1213	b1213	11/30/2013	11/30/2013	11/30/2013	Planned	Planned	EP	0	1	0		2014	-3
1186	b1214	b1214	11/30/2014	11/30/2014	11/30/2014	Planned	Planned	EP	0	1	0		2015	-4
1187	b1215	b1215	11/30/2014	11/30/2014	11/30/2014	Planned	Planned	EP	0	1	0		2015	-4
1188	b1216	b1216	11/30/2013	11/30/2013	11/30/2013	Planned	Planned	EP	0	1	0		2014	-3
1189	b1217	b1217	11/30/2012	11/30/2012	11/30/2012	Planned	Planned	EP	0	1	0		2013	-2
1190	b1221.1	b1221	6/1/2014	3/1/2013	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1191	b1221.2	b1221	12/1/2011	3/1/2013	12/1/2011	Planned	Planned	EP	0	1	0		2012	-1
1192	b1221.3	b1221	12/1/2011	3/1/2013	12/1/2011	Planned	Planned	EP	0	1	0		2012	-1
1193	b1221.4	b1221	6/1/2014	3/1/2013	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1194	b1224	b1224	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5
1195	b1225	b1225	5/31/2011	5/31/2011	5/31/2011	Planned	Planned	EP	0	1	0		2012	-1
1196	b1226	b1226	5/31/2011	5/31/2011	5/31/2011	Planned	Planned	EP	0	1	0		2012	-1
1197	b1227	b1227	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	EP	0	1	0		2012	-1
1198	b1228	b1228	6/1/2014	1/0/1900	6/1/2014	Planned	Planned	EP	0	0	0		2015	-4
1199	b1230	b1230	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
1200	b1231	b1231	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	0	0		2013	-2
1201	b1232	b1232	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5
1202	b1233.1	b1233	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1203	b1234	b1234	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1204	b1235	b1235	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	0	0		2014	-3
1205	b1237	b1237	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1206	b1238	b1238	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1207	b1239	b1239	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1208	b1240	b1240	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1209	b1241	b1241	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1210	b1242	b1242	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1211	b1243	b1243	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
1212	b1244	b1244	5/1/2014	5/1/2014	5/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1213	b1245	b1245	5/31/2012	5/31/2012	5/31/2012	Planned	Planned	EP	0	1	0		2013	-2
1214	b1246	b1246	5/31/2014	5/31/2014	5/31/2014	Planned	Planned	EP	0	1	0		2015	-4
1215	b1247	b1247	5/31/2015	5/31/2015	5/31/2015	Planned	Planned	EP	0	0	0		2016	-5
1216	b1248	b1248	5/31/2015	5/31/2015	5/31/2015	Planned	Planned	EP	0	1	0		2016	-5
1217	b1249	b1249	5/31/2014	5/31/2014	5/31/2014	Planned	Planned	EP	0	1	0		2015	-4
1218	b1250	b1250	5/31/2015	5/31/2015	5/31/2015	Planned	Planned	EP	0	1	0		2016	-5
1219	b1250.1	b1250	#N/A	5/31/2015	5/31/2015	#N/A	Planned	#N/A	0	1	0		2016	-5
1220	b1251	b1251	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5
1221	b1251.1	b1251	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5
1222	b1252	b1252	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1223	b1253	b1253	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1224	b1254	b1254	6/1/2015	9/15/1957	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5

	A	AM	AN	AO	AP	AQ	AR	AS
58	Upgrade ID	Load Ratio Project Costs	One Entity Project Costs	DFAX allocated Project Costs	Dayton DFAX Project Costs			
1153	b1180.1	0	0.475	0	0			
1154	b1180.2	0	0.475	0	0			
1155	b1181	0	3.6	0	0			
1156	b1182	0	0	8.5	0			
1157	b1183	0	6.142	0	0			
1158	b1184	0	3.9	0	0			
1159	b1185	0	0.125	0	0			
1160	b1186	0	0.125	0	0			
1161	b1188	5.2	0	0	0.00			
1162	b1188.1	0	0.215	0	0			
1163	b1188.2	0	0.215	0	0			
1164	b1188.3	0	0.215	0	0			
1165	b1188.4	0	0.215	0	0			
1166	b1188.5	0	0.215	0	0			
1167	b1188.6	0	0	16.825	0			
1168	b1195.1	0	0.1	0	0			
1169	b1195.2	0	0.03	0	0			
1170	b1196	0	1	0	0			
1171	b1197	0	1	0	0			
1172	b1197.1	0	3	0	0			
1173	b1198	0	0.5	0	0			
1174	b1200	0	3	0	0			
1175	b1201	0	1.95	0	0			
1176	b1202	0	0.332	0	0			
1177	b1203	0	12.3	0	0			
1178	b1204	0	40.13	0	0			
1179	b1205	0	0.28	0	0			
1180	b1206	0	3.8	0	0			
1181	b1209	0	0	0	0			
1182	b1210	0	1.27	0	0			
1183	b1211	0	0.03	0	0			
1184	b1212	0	0.69	0	0			
1185	b1213	0	0	0	0			
1186	b1214	0	0.08	0	0			
1187	b1215	0	22.4	0	0			
1188	b1216	0	2.69	0	0			
1189	b1217	0	2	0	0			
1190	b1221.1	0	2	0	0			
1191	b1221.2	0	6	0	0			
1192	b1221.3	0	3.2	0	0			
1193	b1221.4	0	4.3	0	0			
1194	b1224	0	0	17.1	0			
1195	b1225	0	0.2	0	0			
1196	b1226	0	0.2	0	0			
1197	b1227	0	0.02	0	0			
1198	b1228	0	0	9	0			
1199	b1230	0	4	0	0			
1200	b1231	0	0	11.9	0.39			
1201	b1232	0	0	15	0			
1202	b1233.1	0	0.05	0	0			
1203	b1234	0	0.75	0	0			
1204	b1235	0	0	55	0			
1205	b1237	0	0.5	0	0			
1206	b1238	0	1.2	0	0			
1207	b1239	0	1.5	0	0			
1208	b1240	0	1.5	0	0			
1209	b1241	0	0.05	0	0			
1210	b1242	0	0.35	0	0			
1211	b1243	0	2.8	0	0			
1212	b1244	0	0.75	0	0			
1213	b1245	0	1.9	0	0			
1214	b1246	0	5.96	0	0			
1215	b1247	0	0	16	0			
1216	b1248	0	1.3	0	0			
1217	b1249	0	0.5	0	0			
1218	b1250	0	1.55	0	0			
1219	b1250.1	0	0	0	0			
1220	b1251	0	0	18	0.09			
1221	b1251.1	0	0	0	0.00			
1222	b1252	0	0.1	0	0			
1223	b1253	0	10.1	0	0			
1224	b1254	0	0	71	0.36			

	A	B	C	D	E	F	G	H	I	J	K
58	Upgrade ID	Description	TO	AEC	AEP	APS	BGE	ComEd	Dayton	DL	DPL
1225	b1254.1	Bundle the Emory – North West 230 kV circuits	BGE				100.0%				
1226	b1255	Build a new 69 kV substation (Ridge Road) and build ne	PSEG								
1227	b1256	Replace the State Line Station 7 138 kV breaker 'Bustie	ComEd					100.0%			
1228	b1257	Eliminate the J322 138 kV breaker 'L0906' and move cu	ComEd					100.0%			
1229	b1258	Revise the reclosing on the Elmhurst 138 kV bus B brea	ComEd					100.0%			
1230	b1259	Revise the reclosing on the Elmhurst 138 kV bus R brea	ComEd					100.0%			
1231	b1260	Replace Beaver Valley 138 kV breaker 'Z33 J&L Midlan	DL							100.0%	
1232	b1261	Replace Butler 138 kV breaker '1-2 BUS 138'	APS			100.0%					
1233	b1263	Move line 16703 termination from bus 4 to bus 3 at Elec	ComEd					100.0%			
1234	b1264	Replace 345 kV bus ties 1-2 and 1-9 at Plano to increas	ComEd					100.0%			
1235	b1265	Reconductor approximately 2 miles of Will County – Ro	ComEd					100.0%			
1236	b1266	Normally close 345 kV BT 2-3 at TSS 103 Lisle, replace	ComEd					100.0%			
1237	b1267	Rebuild existing Erdman 115 kV substation to a dual rin	BGE				100.0%				
1238	b1267.1	Construct 115 kV double circuit underground line from e	BGE				100.0%				
1239	b1268	Reconductor Shelby – Sidney 138 kV	Dayton						100.0%		
1240	b1269	Reconductor West Milton – Salem 69 kV and West Milto	Dayton						100.0%		
1241	b1270	Reconductor Bath – Trebein 138 kV	Dayton						100.0%		
1242	b1271	Reconductor Underground Section of OHH – Sugarcree	Dayton						100.0%		
1243	b1272	Reconductor Burdox – Webster 138 kV	Dayton						100.0%		
1244	b1273	Add 2nd Bath 345/138 kV Xfr	Dayton						100.0%		
1245	b1274	Add 2nd Trebien 138/69 kV Xfr	Dayton						100.0%		
1246	b1275	Add 2nd W. Milton 138/69 kV Xfr	Dayton						100.0%		
1247	b1276	Add 2nd W. Milton 345/138 Xfr	Dayton						100.0%		
1248	b1277	Build a new Osterburg East – Bedford North 115 kV Line	PENELEC								
1249	b1278	Install 25 MVAR Capacitor Bank at Somerset 115 kV	PENELEC								
1250	b1279	Line #69 Uprate – Increase rating on Locks – Purdy 115	Dominion								
1251	b1280	Sherman: Upgrade 138/69 kV transformers	AEC	100.0%							
1252	b1300	Reconductor the East Frankfort – Goodings Grove 345 k	ComEd					100.0%			
1253	b1301	Upgrade both Garfield – Taylor 345 kV lines (17723 and	ComEd					100.0%			
1254	b1302	Replace the limiting bus conductor and wave trap at the	ME								
1255	b1304.1	Convert the existing 'D1304' and 'G1307' 138 kV circuits	PSEG	0.2%			1.0%	2.2%	0.1%		
1256	b1304.2	Expand existing Bergen 230 kV substation and reconfigu	PSEG	0.2%			1.0%	2.2%	0.1%		
1257	b1304.3	Build second 230 kV underground cable from Bergen to	PSEG	0.2%			1.0%	2.2%	0.1%		
1258	b1304.4	Build second 230 kV underground cable from Hudson to	PSEG	0.2%			1.0%	2.2%	0.1%		
1259	b1306	Reconfigure 115 kV bus at Endless Caverns substation	Dominion								
1260	b1307	Install a 2nd 230/115 kV transformer at Northern Neck S	Dominion								
1261	b1308	Improve LSE's power factor factor in zone to .973 PF, ac	Dominion								
1262	b1309	Install a 230 kV line from Lakeside to Northwest utilizing	Dominion								
1263	b1310	Install a 115 kV breaker at Broadnax substation on the S	Dominion								
1264	b1311	Install a 230 kV 3000 amp breaker at Cranes Corner sub	Dominion								
1265	b1312	Loop the 2054 line in and out of Hollymeade and place a	Dominion								
1266	b1313	Resag wire to 125C from Chesterfield – Shockoe and re	Dominion								
1267	b1314	Rebuild the 6.8 mile line #100 from Chesterfield to Harro	Dominion								
1268	b1315	Convert line #64 Trowbridge to Winfall to 230 kV and ins	Dominion								
1269	b1316	Rebuild 10.7 miles of 115 kV line #80, Battleboro – Hea	Dominion								
1270	b1317	LSE load power factor on the #47 line will need to meet	Dominion								
1271	b1318	Install a 115 kV bus tie breaker at Acca substation betw	Dominion								
1272	b1319	Resag line #222 to 150 C and upgrade any associated e	Dominion								
1273	b1320	Install a 230 kV, 150 MVAR capacitor bank at Southwes	Dominion								
1274	b1321	Build a new 230 kV line North Anna – Oak Green and in	Dominion				0.9%				
1275	b1322	Rebuild the 39 Line (Dooms – Sherwood) and the 91 Lin	Dominion								
1276	b1323	Install a 224 MVA 230/115 kV transformer at Staunton. R	Dominion								
1277	b1324	Install a 115 kV capacitor bank at Oak Ridge. Install a ca	Dominion								
1278	b1325	Rebuild 15 miles of line #2020 Winfall – Elizabeth City w	Dominion								
1279	b1326	Install a third 168 MVA 230/115 kV transformer at Kitty H	Dominion								
1280	b1327	Rebuild the 20 mile section of line #22 between Kerr Da	Dominion								
1281	b1328	Uprate the 3.63 mile line section between Possum and D	Dominion	0.7%		3.6%					0.9%
1282	b1329	Install line-tie breakers at Sterling Park substation and B	Dominion								
1283	b1330	Install a five breaker ring bus at the expanded Dulles su	Dominion								
1284	b1331	Build a 230 kV line from Shawboro to Aydlett tap and co	Dominion								
1285	b1332	Build Cannon Branch to Nokesville 230 kV line	Dominion								
1286	b1333	Advance n1728 (Replace Possum Point 230 kV breaker	Dominion								
1287	b1334	Advance n1748 (Replace Ox 230 kV breaker 22042 with	Dominion								
1288	b1335	Advance n1749 (Replace Ox 230 kV breaker 220T2603	Dominion								
1289	b1336	Advance n1750 (Replace Ox 230 kV breaker 24842 with	Dominion								
1290	b1337	Advance n1751 (Replace Ox 230 kV breaker 248T2013	Dominion								
1291	b1338	Replace Printz 230 kV breaker '225'	PECO								
1292	b1339	Replace Printz 230 kV breaker '315'	PECO								
1293	b1340	Replace Printz 230 kV breaker '215'	PECO								
1294	b1343	Replace Collier 138 kV breaker '2-3 Bus Tie'	DL							100.0%	
1295	b1344	Replace St Joe Resources 138 kV breaker 'Z-81 Valley'	DL							100.0%	
1296	b1345	Install Martinsville 4-breaker 34.5 rink bus	JCPL								

	A	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
58	Upgrade ID	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL	PSEG	RE	UGI	Cost Estimate ($M)
1225	b1254.1														$0.00
1226	b1255											96.2%	3.8%		$22.50
1227	b1256														$0.76
1228	b1257														$0.04
1229	b1258														$0.08
1230	b1259														$0.08
1231	b1260														$0.40
1232	b1261														$0.30
1233	b1263														$3.00
1234	b1264														$2.00
1235	b1265														$1.50
1236	b1266														$1.00
1237	b1267														$7.60
1238	b1267.1														$142.00
1239	b1268														$2.60
1240	b1269														$4.80
1241	b1270														$1.30
1242	b1271														$2.40
1243	b1272														$1.00
1244	b1273														$7.00
1245	b1274														$5.30
1246	b1275														$8.80
1247	b1276														$5.50
1248	b1277								100.0%						$3.68
1249	b1278								100.0%						$0.47
1250	b1279	100.0%													$9.40
1251	b1280														$7.70
1252	b1300														$22.00
1253	b1301														$150.00
1254	b1302					100.0%									$0.10
1255	b1304.1		2.2%	19.0%	1.2%		0.1%		2.8%	1.1%		67.5%	2.7%		$650.00
1256	b1304.2		2.2%	19.0%	1.2%		0.1%		2.8%	1.1%		67.5%	2.7%		$0.00
1257	b1304.3		2.2%	19.0%	1.2%		0.1%		2.8%	1.1%		67.5%	2.7%		$0.00
1258	b1304.4		2.2%	19.0%	1.2%		0.1%		2.8%	1.1%		67.5%	2.7%		$50.00
1259	b1306	100.0%													$0.50
1260	b1307	100.0%													$5.10
1261	b1308	100.0%													$0.50
1262	b1309	100.0%													$21.00
1263	b1310	100.0%													$0.50
1264	b1311	100.0%													$1.10
1265	b1312	100.0%													$41.00
1266	b1313	100.0%													$8.90
1267	b1314	100.0%													$8.00
1268	b1315	100.0%													$23.00
1269	b1316	100.0%													$11.00
1270	b1317	100.0%													$0.50
1271	b1318	100.0%													$0.50
1272	b1319	100.0%													$1.10
1273	b1320	100.0%													$1.30
1274	b1321	98.0%								1.2%					$70.00
1275	b1322	100.0%													$100.00
1276	b1323	100.0%													$16.50
1277	b1324	100.0%													$3.00
1278	b1325	100.0%													$18.00
1279	b1326	100.0%													$8.10
1280	b1327	100.0%													$20.00
1281	b1328	92.9%						1.9%							$5.50
1282	b1329	100.0%													$1.00
1283	b1330	100.0%													$6.00
1284	b1331	100.0%													$23.30
1285	b1332	100.0%													$40.00
1286	b1333	100.0%													$0.03
1287	b1334	100.0%													$0.03
1288	b1335	100.0%													$0.03
1289	b1336	100.0%													$0.03
1290	b1337	100.0%													$0.03
1291	b1338							100.0%							$0.50
1292	b1339							100.0%							$0.50
1293	b1340							100.0%							$0.50
1294	b1343														$0.36
1295	b1344														$0.36
1296	b1345				100.0%										$2.82

	A	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL
58	Upgrade ID	Project ID	Upgrade Date In-Service	Project Average In-Service Date	Date to use	Upgrade Source	Project Source	Project Status	Projects Allocated by Load	Projects Attributed to one entity	Projects Attributed to Dayton entity	Year In Service Override	First Full Year in Service	Project Age
1225	b1254.1	b1254	6/1/2015	9/15/1957	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1226	b1255	b1255	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5
1227	b1256	b1256	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	EP	0	1	0		2012	-1
1228	b1257	b1257	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	EP	0	1	0		2012	-1
1229	b1258	b1258	12/17/2010	12/17/2010	12/17/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
1230	b1259	b1259	12/17/2010	12/17/2010	12/17/2010	Post-2005	Post-2005	IS	0	1	0		2011	0
1231	b1260	b1260	6/30/2014	6/30/2014	6/30/2014	Planned	Planned	EP	0	1	0		2015	-4
1232	b1261	b1261	7/1/2011	7/1/2011	7/1/2011	Planned	Planned	EP	0	1	0		2012	-1
1233	b1263	b1263	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1234	b1264	b1264	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1235	b1265	b1265	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1236	b1266	b1266	6/1/2015	3/16/1956	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1237	b1267	b1267	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1238	b1267.1	b1267	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1239	b1268	b1268	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	1		2016	-5
1240	b1269	b1269	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	1		2016	-5
1241	b1270	b1270	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	1		2016	-5
1242	b1271	b1271	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	1		2016	-5
1243	b1272	b1272	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	1		2016	-5
1244	b1273	b1273	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	1		2016	-5
1245	b1274	b1274	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	1		2016	-5
1246	b1275	b1275	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	1		2016	-5
1247	b1276	b1276	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	1		2016	-5
1248	b1277	b1277	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
1249	b1278	b1278	11/1/2012	11/1/2012	11/1/2012	Planned	Planned	EP	0	1	0		2013	-2
1250	b1279	b1279	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1251	b1280	b1280	12/31/2011	3/16/2012	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
1252	b1300	b1300	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
1253	b1301	b1301	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1254	b1302	b1302	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1255	b1304.1	b1304	6/1/2015	6/6/1993	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5
1256	b1304.2	b1304	6/1/2015	6/6/1993	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5
1257	b1304.3	b1304	6/1/2015	6/6/1993	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5
1258	b1304.4	b1304	6/1/2015	6/6/1993	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5
1259	b1306	b1306	10/1/2011	10/1/2011	10/1/2011	Planned	Planned	EP	0	1	0		2012	-1
1260	b1307	b1307	3/11/2011	3/11/2011	3/11/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
1261	b1308	b1308	3/31/2012	3/31/2012	3/31/2012	Planned	Planned	EP	0	1	0		2013	-2
1262	b1309	b1309	5/30/2013	5/30/2013	5/30/2013	Planned	Planned	EP	0	1	0		2014	-3
1263	b1310	b1310	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
1264	b1311	b1311	5/1/2014	5/1/2014	5/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1265	b1312	b1312	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1266	b1313	b1313	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1267	b1314	b1314	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1268	b1315	b1315	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1269	b1316	b1316	6/1/2014	6/1/2014	6/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1270	b1317	b1317	5/1/2015	5/1/2015	5/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1271	b1318	b1318	5/1/2015	5/1/2015	5/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1272	b1319	b1319	5/1/2015	5/1/2015	5/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1273	b1320	b1320	5/1/2015	5/1/2015	5/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1274	b1321	b1321	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5
1275	b1322	b1322	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1276	b1323	b1323	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
1277	b1324	b1324	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1278	b1325	b1325	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1279	b1326	b1326	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1280	b1327	b1327	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1281	b1328	b1328	5/1/2015	5/1/2015	5/1/2015	Planned	Planned	EP	0	0	0		2016	-5
1282	b1329	b1329	5/1/2015	5/1/2015	5/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1283	b1330	b1330	5/1/2014	5/1/2014	5/1/2014	Planned	Planned	EP	0	1	0		2015	-4
1284	b1331	b1331	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1285	b1332	b1332	5/31/2015	5/31/2015	5/31/2015	Planned	Planned	EP	0	1	0		2016	-5
1286	b1333	b1333	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1287	b1334	b1334	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1288	b1335	b1335	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1289	b1336	b1336	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1290	b1337	b1337	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1291	b1338	b1338	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1292	b1339	b1339	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1293	b1340	b1340	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1294	b1343	b1343	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1295	b1344	b1344	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1296	b1345	b1345	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2

	A	AM	AN	AO	AP	AQ	AR	AS
58	Upgrade ID	Load Ratio Project Costs	One Entity Project Costs	DFAX allocated Project Costs	Dayton DFAX Project Costs			
1225	b1254.1	0	0	0	0			
1226	b1255	0	0	22.5	0			
1227	b1256	0	0.76	0	0			
1228	b1257	0	0.035	0	0			
1229	b1258	0	0.075	0	0			
1230	b1259	0	0.075	0	0			
1231	b1260	0	0.4	0	0			
1232	b1261	0	0.3	0	0			
1233	b1263	0	3	0	0			
1234	b1264	0	2	0	0			
1235	b1265	0	1.5	0	0			
1236	b1266	0	1	0	0			
1237	b1267	0	7.6	0	0			
1238	b1267.1	0	142	0	0			
1239	b1268	0	2.6	0	0			
1240	b1269	0	4.8	0	0			
1241	b1270	0	1.3	0	0			
1242	b1271	0	2.4	0	0			
1243	b1272	0	1	0	0			
1244	b1273	0	7	0	0			
1245	b1274	0	5.3	0	0			
1246	b1275	0	8.8	0	0			
1247	b1276	0	5.5	0	0			
1248	b1277	0	3.68	0	0			
1249	b1278	0	0.473	0	0			
1250	b1279	0	9.4	0	0			
1251	b1280	0	7.7	0	0			
1252	b1300	0	22	0	0			
1253	b1301	0	150	0	0			
1254	b1302	0	0.1	0	0			
1255	b1304.1	0	0	650	0.78			
1256	b1304.2	0	0	0	0.00			
1257	b1304.3	0	0	0	0.00			
1258	b1304.4	0	0	50	0.06			
1259	b1306	0	0.5	0	0			
1260	b1307	0	5.1	0	0			
1261	b1308	0	0.5	0	0			
1262	b1309	0	21	0	0			
1263	b1310	0	0.5	0	0			
1264	b1311	0	1.1	0	0			
1265	b1312	0	41	0	0			
1266	b1313	0	8.9	0	0			
1267	b1314	0	8	0	0			
1268	b1315	0	23	0	0			
1269	b1316	0	11	0	0			
1270	b1317	0	0.5	0	0			
1271	b1318	0	0.5	0	0			
1272	b1319	0	1.1	0	0			
1273	b1320	0	1.3	0	0			
1274	b1321	0	0	70	0			
1275	b1322	0	100	0	0			
1276	b1323	0	16.5	0	0			
1277	b1324	0	3	0	0			
1278	b1325	0	18	0	0			
1279	b1326	0	8.1	0	0			
1280	b1327	0	20	0	0			
1281	b1328	0	0	5.5	0			
1282	b1329	0	1	0	0			
1283	b1330	0	6	0	0			
1284	b1331	0	23.3	0	0			
1285	b1332	0	40	0	0			
1286	b1333	0	0.03	0	0			
1287	b1334	0	0.03	0	0			
1288	b1335	0	0.03	0	0			
1289	b1336	0	0.03	0	0			
1290	b1337	0	0.03	0	0			
1291	b1338	0	0.5	0	0			
1292	b1339	0	0.5	0	0			
1293	b1340	0	0.5	0	0			
1294	b1343	0	0.36	0	0			
1295	b1344	0	0.36	0	0			
1296	b1345	0	2.818	0	0			

	A	B	C	D	E	F	G	H	I	J	K
58	Upgrade ID	Description	TO	AEC	AEP	APS	BGE	ComEd	Dayton	DL	DPL
1297	b1346	Reconductor the Franklin – Humburg (R746) 4.7 miles 3	JCPL								
1298	b1347	Replace 500 CU substation conductor with 795 ACSR o	JCPL								
1299	b1348	Upgrade the Newton – North Newton 34.5 kV (F708) lin	JCPL								
1300	b1349	Reconductor 5.2 miles of the Newton – Woodruffs Gap 3	JCPL								
1301	b1350	Upgrade the East Flemington – Flemington 34.5 kV (V7	JCPL								
1302	b1351	Add 34.5 kV breaker on the Larrabee A and D bus tie	JCPL								
1303	b1352	Upgrade the Smithburg – Centerstate Tap 34.5 kV (X75	JCPL								
1304	b1353	Upgrade the Larrabee – Laurelton 34.5 kV (Q43) line by	JCPL								
1305	b1354	Add four 34.5 kV breakers and re-configure A/B bus at F	JCPL								
1306	b1355	Build a new section 3.3 miles 34.5 kV 556 ACSR line fro	JCPL								
1307	b1357	Build 10.2 miles new 34.5 kV line from Larrabee – Howe	JCPL								
1308	b1359	Install a Troy Hills 34.5 kV by-pass switch and reconfigu	JCPL								
1309	b1360	Reconductor 0.7 miles of the Englishtown – Freehold Ta	JCPL								
1310	b1361	Reconductor the Oceanview – Neptune Tap 34.5 kV (D1	JCPL								
1311	b1362	Install a 23.8 MVAR capacitor at Wood Street 69 kV	ME								
1312	b1364	Upgrade South Lebanon 230/69 kV transformer #1 by re	ME								
1313	b1365	Reconductor the Middletown – Collins 115 kV (975) line	ME								
1314	b1366	Reconductor the Collins – Cly – Newberry 115 kV (975)	ME								
1315	b1367	Replace the Cambria Slope 115/46 kV 50 MVA transforr	PENELEC								
1316	b1368	Replace the Claysburg 115/46 kV 30 MVA transformer v	PENELEC								
1317	b1369	Replace the 4/0 CU substation conductor with 795 ACSI	PENELEC								
1318	b1370	Install a 3rd 115/46 kV transformer at Westfall	PENELEC								
1319	b1371	Reconductor 2.6 miles of the Claysburg – HCR 46 kV lir	PENELEC								
1320	b1372	Replace 4/0 CU substation conductor with 795 ACSR or	PENELEC								
1321	b1373	Re-configure the Erie West 345 kV substation, add a ne	PENELEC								
1322	b1374	Replace wave traps at Raritan River and Deep Run 115	JCPL								
1323	b1375	Replace Roanoke 138 kV breaker 'T'	AEP		100.0%						
1324	b1376	Replace Roanoke 138 kV breaker 'E'	AEP		100.0%						
1325	b1377	Replace Roanoke 138 kV breaker 'F'	AEP		100.0%						
1326	b1378	Replace Roanoke 138 kV breaker 'G'	AEP		100.0%						
1327	b1379	Replace Roanoke 138 kV breaker 'B'	AEP		100.0%						
1328	b1380	Replace Roanoke 138 kV breaker 'A'	AEP		100.0%						
1329	b1381	Replace Olive 345 kV breaker 'E'	AEP		100.0%						
1330	b1382	Replace Olive 345 kV breaker 'R2'	AEP		100.0%						
1331	b1383	Install 2nd 500/138 kV transformer at 502 Junction	APS			93.3%				5.4%	
1332	b1384	Reconductor approximately 2.17 miles of Bedington – S	APS			100.0%					
1333	b1385	Reconductor Halfway – Paramount 138 kV with 1033 AC	APS			100.0%					
1334	b1386	Reconductor Double Tollgate – Meadow Brook 138 kV c	APS			93.3%	3.4%				
1335	b1387	Reconductor Double Tollgate – Meadow Brook 138 kV	APS			93.3%	3.4%				
1336	b1388	Reconductor Feagans Mill – Millville 138 kV with 954 AC	APS			100.0%					
1337	b1389	Reconductor Bens Run – St. Mary's 138 kV with 954 AC	APS		12.4%	17.8%				69.8%	
1338	b1390	Replace Bus Tie Breaker at Opequon	APS			100.0%					
1339	b1391	Replace Line Trap at Gore	APS			100.0%					
1340	b1392	Replace structure on Belmont – Trissler 138 kV line	APS			100.0%					
1341	b1393	Replace structures Kingwood – Pruntytown 138 kV line	APS			100.0%					
1342	b1395	Upgrade Terminal Equipment at Kittanning	APS			100.0%					
1343	b1396	Replace Lewis 138 kV breaker 'L'	AEC	100.0%							
1344	b1398	Build two new parallel underground circuits from Glouce	PSEG								
1345	b1398.1	Install shunt reactor at Gloucester to offset cable chargi	PSEG								
1346	b1398.2	Reconfigure the Cuthbert station to breaker and a half s	PSEG								
1347	b1398.3	Build a second 230 kV parallel overhead circuit from Mic	PSEG								
1348	b1398.4	Reconductor the existing Mickleton – Gloucester 230 kV	PSEG								
1349	b1398.5	Reconductor the existing Mickleton – Goucester 230 kV	AEC								
1350	b1398.6	Reconductor the Camden – Richmond 230 kV circuit (PI	PECO								
1351	b1398.7	Reconductor the Camden – Richmond 230 kV circuit (PS	PSEG								
1352	b1398.8	Reconductor Richmond – Waneeta 230 kV and replace	PECO								
1353	b1399	Convert the 138 kV path from Aldene – Springfield Rd. -	PSEG								
1354	b1400	Install 230 kV circuit breakers at Bennetts Ln. "F" and "X	PSEG								
1355	b1401	Change reclosing on Pruntytown 138 kV breaker 'P-16' t	APS			100.0%					
1356	b1402	Change reclosing on Rivesville 138 kV breaker 'Pruntyto	APS			100.0%					
1357	b1403	Change reclosing on Yukon 138 kV breaker 'Y21 Sheple	APS			100.0%					
1358	b1404	Replace the Kiski Valley 138 kV breaker 'Vandergrift' wi	APS			100.0%					
1359	b1405	Change reclosing on Armstrong 138 kV breaker 'GARET	APS			100.0%					
1360	b1406	Change reclosing on Armstrong 138 kV breaker 'KITTAN	APS			100.0%					
1361	b1407	Change reclosing on Armstrong 138 kV breaker 'BURMA	APS			100.0%					
1362	b1408	Replace the Weirton 138 kV breaker 'Tidd 224' with a 40	APS			100.0%					
1363	b1409	Replace the Cabot 138 kV breaker 'C9 Kiski Valley' with	APS			100.0%					
1364	b1410	Replace Salem 500 kV breaker '11X'	PSEG	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
1365	b1411	Replace Salem 500 kV breaker '12X'	PSEG	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
1366	b1412	Replace Salem 500 kV breaker '20X'	PSEG	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
1367	b1413	Replace Salem 500 kV breaker '21X'	PSEG	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
1368	b1414	Replace Salem 500 kV breaker '31X'	PSEG	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%

	A	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
58	Upgrade ID	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL	PSEG	RE	UGI	Cost Estimate ($M)
1297	b1346				100.0%										$3.98
1298	b1347				100.0%										$0.02
1299	b1348				100.0%										$0.09
1300	b1349				100.0%										$0.93
1301	b1350				100.0%										$0.13
1302	b1351				100.0%										$0.25
1303	b1352				100.0%										$0.09
1304	b1353				100.0%										$0.09
1305	b1354				100.0%										$1.46
1306	b1355				100.0%										$2.29
1307	b1357				100.0%										$9.48
1308	b1359				100.0%										$0.03
1309	b1360				100.0%										$0.42
1310	b1361				100.0%										$0.44
1311	b1362				100.0%										$0.52
1312	b1364				100.0%										$0.03
1313	b1365					100.0%									$0.34
1314	b1366					100.0%									$2.39
1315	b1367								100.0%						$1.26
1316	b1368								100.0%						$1.49
1317	b1369								100.0%						$0.03
1318	b1370								100.0%						$3.83
1319	b1371								100.0%						$0.63
1320	b1372								100.0%						$0.04
1321	b1373								100.0%						$0.96
1322	b1374								100.0%						$0.18
1323	b1375														$0.80
1324	b1376														$0.80
1325	b1377														$0.80
1326	b1378														$0.80
1327	b1379														$0.80
1328	b1380														$0.80
1329	b1381														$1.00
1330	b1382														$1.00
1331	b1383								1.3%						$15.00
1332	b1384														$1.75
1333	b1385														$4.75
1334	b1386									3.3%					$9.00
1335	b1387									3.3%					$9.00
1336	b1388														$3.50
1337	b1389														$5.80
1338	b1390														$0.25
1339	b1391														$0.25
1340	b1392														$0.50
1341	b1393														$1.00
1342	b1395														$0.05
1343	b1396														$0.40
1344	b1398		0.9%	0.8%	12.8%		1.2%	51.1%		0.6%		31.5%	1.3%		$230.00
1345	b1398.1		0.9%	0.8%	12.8%		1.2%	51.1%		0.6%		31.5%	1.3%		$0.00
1346	b1398.2		0.9%	0.8%	12.8%		1.2%	51.1%		0.6%		31.5%	1.3%		$0.00
1347	b1398.3		0.9%	0.8%	12.8%		1.2%	51.1%		0.6%		31.5%	1.3%		$0.00
1348	b1398.4		0.9%	0.8%	12.8%		1.2%	51.1%		0.6%		31.5%	1.3%		$0.00
1349	b1398.5		0.9%	0.8%	12.8%		1.2%	51.1%		0.6%		31.5%	1.3%		$5.90
1350	b1398.6		0.9%	0.8%	12.8%		1.2%	51.1%		0.6%		31.5%	1.3%		$0.98
1351	b1398.7		0.9%	0.8%	12.8%		1.2%	51.1%		0.6%		31.5%	1.3%		$8.00
1352	b1398.8		0.9%	0.8%	12.8%		1.2%	51.1%		0.6%		31.5%	1.3%		$4.00
1353	b1399											96.2%	3.8%		$75.00
1354	b1400											100.0%			$3.00
1355	b1401														$0.00
1356	b1402														$0.00
1357	b1403														$0.00
1358	b1404														$0.25
1359	b1405														$0.00
1360	b1406														$0.00
1361	b1407														$0.00
1362	b1408														$0.25
1363	b1409														$0.30
1364	b1410	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$1.50
1365	b1411	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$1.50
1366	b1412	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$1.50
1367	b1413	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$1.50
1368	b1414	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$1.50

	A	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL
58	Upgrade ID	Project ID	Upgrade Date In-Service	Project Average In-Service Date	Date to use	Upgrade Source	Project Source	Project Status	Projects Allocated by Load	Projects Attributed to one entity	Projects Attributed to Dayton entity	Year In Service Override	First Full Year in Service	Project Age
1297	b1346	b1346	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
1298	b1347	b1347	3/30/2011	3/30/2011	3/30/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
1299	b1348	b1348	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	UC	0	1	0		2012	-1
1300	b1349	b1349	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
1301	b1350	b1350	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	UC	0	1	0		2012	-1
1302	b1351	b1351	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
1303	b1352	b1352	3/21/2011	3/21/2011	3/21/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
1304	b1353	b1353	4/14/2011	4/14/2011	4/14/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
1305	b1354	b1354	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	UC	0	1	0		2012	-1
1306	b1355	b1355	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
1307	b1357	b1357	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
1308	b1359	b1359	4/14/2011	4/14/2011	4/14/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
1309	b1360	b1360	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
1310	b1361	b1361	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
1311	b1362	b1362	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	UC	0	1	0		2012	-1
1312	b1364	b1364	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	EP	0	1	0		2012	-1
1313	b1365	b1365	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	UC	0	1	0		2012	-1
1314	b1366	b1366	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
1315	b1367	b1367	6/1/2011	6/1/2011	6/1/2011	Planned	Planned	EP	0	1	0		2012	-1
1316	b1368	b1368	4/15/2011	4/15/2011	4/15/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
1317	b1369	b1369	12/31/2011	12/31/2011	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
1318	b1370	b1370	12/31/2011	12/31/2011	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
1319	b1371	b1371	4/15/2011	4/15/2011	4/15/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
1320	b1372	b1372	2/28/2011	2/28/2011	2/28/2011	Post-2005	Post-2005	IS	0	1	0		2012	-1
1321	b1373	b1373	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
1322	b1374	b1374	6/1/2013	6/1/2013	6/1/2013	Planned	Planned	EP	0	1	0		2014	-3
1323	b1375	b1375	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
1324	b1376	b1376	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
1325	b1377	b1377	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
1326	b1378	b1378	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
1327	b1379	b1379	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
1328	b1380	b1380	6/1/2012	6/1/2012	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
1329	b1381	b1381	5/31/2011	5/31/2011	5/31/2011	Planned	Planned	EP	0	1	0		2012	-1
1330	b1382	b1382	5/31/2011	5/31/2011	5/31/2011	Planned	Planned	EP	0	1	0		2012	-1
1331	b1383	b1383	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5
1332	b1384	b1384	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1333	b1385	b1385	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1334	b1386	b1386	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5
1335	b1387	b1387	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5
1336	b1388	b1388	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1337	b1389	b1389	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5
1338	b1390	b1390	12/1/2011	12/1/2011	12/1/2011	Planned	Planned	EP	0	1	0		2012	-1
1339	b1391	b1391	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1340	b1392	b1392	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1341	b1393	b1393	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1342	b1395	b1395	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1343	b1396	b1396	5/31/2015	5/31/2015	5/31/2015	Planned	Planned	EP	0	1	0		2016	-5
1344	b1398	b1398	6/1/2015	11/21/1967	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5
1345	b1398.1	b1398	6/1/2015	11/21/1967	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5
1346	b1398.2	b1398	6/1/2015	11/21/1967	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5
1347	b1398.3	b1398	6/1/2015	11/21/1967	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5
1348	b1398.4	b1398	6/1/2015	11/21/1967	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5
1349	b1398.5	b1398	6/1/2015	11/21/1967	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5
1350	b1398.6	b1398	6/1/2015	11/21/1967	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5
1351	b1398.7	b1398	6/1/2015	11/21/1967	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5
1352	b1398.8	b1398	6/1/2015	11/21/1967	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5
1353	b1399	b1399	6/1/2014	3/16/1957	6/1/2014	Planned	Planned	EP	0	0	0		2015	-4
1354	b1400	b1400	6/1/2012	1/0/1900	6/1/2012	Planned	Planned	EP	0	1	0		2013	-2
1355	b1401	b1401	6/1/2011	1/0/1900	6/1/2011	Planned	Planned	EP	0	1	0		2012	-1
1356	b1402	b1402	6/1/2011	1/0/1900	6/1/2011	Planned	Planned	EP	0	1	0		2012	-1
1357	b1403	b1403	6/1/2011	1/0/1900	6/1/2011	Planned	Planned	EP	0	1	0		2012	-1
1358	b1404	b1404	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1359	b1405	b1405	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1360	b1406	b1406	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1361	b1407	b1407	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1362	b1408	b1408	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1363	b1409	b1409	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1364	b1410	b1410	6/1/2011	1/0/1900	6/1/2011	Planned	Planned	EP	1	0	0		2012	-1
1365	b1411	b1411	6/1/2011	1/0/1900	6/1/2011	Planned	Planned	EP	1	0	0		2012	-1
1366	b1412	b1412	6/1/2011	1/0/1900	6/1/2011	Planned	Planned	EP	1	0	0		2012	-1
1367	b1413	b1413	6/1/2011	1/0/1900	6/1/2011	Planned	Planned	EP	1	0	0		2012	-1
1368	b1414	b1414	6/1/2011	1/0/1900	6/1/2011	Planned	Planned	EP	1	0	0		2012	-1

	A	AM	AN	AO	AP	AQ	AR	AS
58	Upgrade ID	Load Ratio Project Costs	One Entity Project Costs	DFAX allocated Project Costs	Dayton DFAX Project Costs			
1297	b1346	0	3.979	0	0			
1298	b1347	0	0.015	0	0			
1299	b1348	0	0.092	0	0			
1300	b1349	0	0.932	0	0			
1301	b1350	0	0.126	0	0			
1302	b1351	0	0.249	0	0			
1303	b1352	0	0.093	0	0			
1304	b1353	0	0.092	0	0			
1305	b1354	0	1.456	0	0			
1306	b1355	0	2.286	0	0			
1307	b1357	0	9.483	0	0			
1308	b1359	0	0.032	0	0			
1309	b1360	0	0.422	0	0			
1310	b1361	0	0.436	0	0			
1311	b1362	0	0.518	0	0			
1312	b1364	0	0.034	0	0			
1313	b1365	0	0.344	0	0			
1314	b1366	0	2.387	0	0			
1315	b1367	0	1.26	0	0			
1316	b1368	0	1.492	0	0			
1317	b1369	0	0.034	0	0			
1318	b1370	0	3.832	0	0			
1319	b1371	0	0.633	0	0			
1320	b1372	0	0.044	0	0			
1321	b1373	0	0.955	0	0			
1322	b1374	0	0.1772	0	0			
1323	b1375	0	0.8	0	0			
1324	b1376	0	0.8	0	0			
1325	b1377	0	0.8	0	0			
1326	b1378	0	0.8	0	0			
1327	b1379	0	0.8	0	0			
1328	b1380	0	0.8	0	0			
1329	b1381	0	1	0	0			
1330	b1382	0	1	0	0			
1331	b1383	0	0	15	0			
1332	b1384	0	1.75	0	0			
1333	b1385	0	4.75	0	0			
1334	b1386	0	0	9	0			
1335	b1387	0	0	9	0			
1336	b1388	0	3.5	0	0			
1337	b1389	0	0	5.8	0			
1338	b1390	0	0.25	0	0			
1339	b1391	0	0.25	0	0			
1340	b1392	0	0.5	0	0			
1341	b1393	0	1	0	0			
1342	b1395	0	0.05	0	0			
1343	b1396	0	0.4	0	0			
1344	b1398	0	0	230	0			
1345	b1398.1	0	0	0	0			
1346	b1398.2	0	0	0	0			
1347	b1398.3	0	0	0	0			
1348	b1398.4	0	0	0	0			
1349	b1398.5	0	0	5.9	0			
1350	b1398.6	0	0	0.975	0			
1351	b1398.7	0	0	8	0			
1352	b1398.8	0	0	4	0			
1353	b1399	0	0	75	0			
1354	b1400	0	3	0	0			
1355	b1401	0	0.002	0	0			
1356	b1402	0	0.002	0	0			
1357	b1403	0	0.002	0	0			
1358	b1404	0	0.25	0	0			
1359	b1405	0	0.002	0	0			
1360	b1406	0	0.002	0	0			
1361	b1407	0	0.002	0	0			
1362	b1408	0	0.25	0	0			
1363	b1409	0	0.3	0	0			
1364	b1410	1.5	0	0	0.00			
1365	b1411	1.5	0	0	0.00			
1366	b1412	1.5	0	0	0.00			
1367	b1413	1.5	0	0	0.00			
1368	b1414	1.5	0	0	0.00			

	A	B	C	D	E	F	G	H	I	J	K
58	Upgrade ID	Description	TO	AEC	AEP	APS	BGE	ComEd	Dayton	DL	DPL
1369	b1415	Replace Salem 500 kV breaker ‘32X’	PSEG	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
1370	b1416	Perform a sag study on the Desoto – Deer Creek 138 k\	AEP		100.0%						
1371	b1417	Perform a sag study on the Delaware – Madison 138 kV	AEP		100.0%						
1372	b1418	Perform a sag study on the Rockhill – East Lima 138 kV	AEP		100.0%						
1373	b1419	Perform a sag study on the Findlay Center – Fostoria Ct	AEP		100.0%						
1374	b1420	A sag study will be required to increase the emergency r	AEP		100.0%						
1375	b1421	Perform a sag study on the Sorenson – McKinley 138 k\	AEP		100.0%						
1376	b1422	Perform a sag study on John Amos – St. Albans 138 kV	AEP		100.0%						
1377	b1423	A sag study will be performed on the Chemical – Capitol	AEP		100.0%						
1378	b1424	Perform a sag study for Benton Harbor – West Street – I	AEP		100.0%						
1379	b1425	Perform a sag study for the East Monument – East Dan\	AEP		100.0%						
1380	b1426	Perform a sag study for the Reusens – Graves 138 kV li	AEP		100.0%						
1381	b1427	Perform a sag study on Smith Mountain – Leesville – Alt	AEP		100.0%						
1382	b1428	Perform a sag study on Smith Mountain – Candlers Mou	AEP		100.0%						
1383	b1429	Perform a sag study on Fremont – Clinch River 138 kV t	AEP		100.0%						
1384	b1430	Install a new 138 kV circuit breaker at Benton Harbor sta	AEP		100.0%						
1385	b1432	Perform a sag study on the Kenova – Tri State 138 kV li	AEP		100.0%						
1386	b1433	Replace risers in the West Huntington Station to increas	AEP		100.0%						
1387	b1434	Perform a sag study on the line from Desoto to Madison	AEP		100.0%						
1388	b1435	Replace the 2870 MCM ACSR riser at the Sporn station	AEP		100.0%						
1389	b1436	Perform a sag study on the Sorenson – Illinois Road 13	AEP		100.0%						
1390	b1437	Perform sag study on Rock Cr. – Hummel Cr. 138 kV to	AEP		100.0%						
1391	b1438	Replacement of risers at McKinley and Industrial Park st	AEP		100.0%						
1392	b1439	By replacing the risers at Lincoln both the Summar Norn	AEP		100.0%						
1393	b1440	By replacing the breakers at Lincoln the Summer Emerg	AEP		100.0%						
1394	b1441	Replacement of risers at South Side and performance o	AEP		100.0%						
1395	b1442	Replacement of 954 ACSR conductor with 1033 ACSR a	AEP		100.0%						
1396	b1443	Station work at Thelma and Busseyville Stations will be	AEP		100.0%						
1397	b1444	Perform electrical clearance studies on Clinch River – C	AEP		100.0%						
1398	b1445	Perform a sag study on the Addison (Buckeye CO-OP) -	AEP		100.0%						
1399	b1446	Perform a sag study on the Parkersburg (Allegheny Pow	AEP		100.0%						
1400	b1447	Dexter – Elliot tap 138 kV sag check	AEP		100.0%						
1401	b1448	Dexter – Meigs 138 kV Electrical Clearance Study	AEP		100.0%						
1402	b1449	Meigs tap – Rutland 138 kV sag check	AEP		100.0%						
1403	b1450	Muskingum – North Muskingum 138 kV sag check	AEP		100.0%						
1404	b1451	North Newark – Sharp Road 138 kV sag check	AEP		100.0%						
1405	b1452	North Zanesville – Zanesville 138 kV sag check	AEP		100.0%						
1406	b1453	North Zanesville – Powelson and Ohio Central – Powels	AEP		100.0%						
1407	b1454	Perform an electrical clearance study on the Ross – Del	AEP		100.0%						
1408	b1455	Perform a sag check on the Sunny – Canton Central – V	AEP		100.0%						
1409	b1456	The Tidd – West Bellaire 345 kV circuit has been de-rat	AEP		100.0%						
1410	b1457	The Tiltonsville – Windsor 138 kV circuit has been derat	AEP		100.0%						
1411	b1458	Install three new 345 kV breakers at Bixby to separate tl	AEP		100.0%						
1412	b1459	Several circuits have been de-rated to their normal conc	AEP		100.0%						
1413	b1460	Replace 2156 & 2874 risers	AEP		100.0%						
1414	b1461	Replace meter, metering CTs and associated equipmen	AEP		100.0%						
1415	b1462	Replace relays at both South Cadiz 138 kV and Tidd 13	AEP		100.0%						
1416	b1463	Reconductor the Bexley – Groves 138 kV circuit	AEP		100.0%						
1417	b1464	Corner 138 kV upgrades	AEP		100.0%						
1418	b1465.1	Add a 3rd 2250 MVA 765/345 kV transformer at Sullivan	AEP	0.7%	75.1%	1.3%	1.8%	5.9%	0.9%	1.2%	1.0%
1419	b1465.2	Replace the 100 MVAR 765 kV shunt reactor bank on R	AEP	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
1420	b1465.3	Transpose the Rockport – Sullivan 765 kV line and the I	AEP	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
1421	b1465.4	Make switching improvements at Sullivan and Jefferson	AEP	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
1422	b1466.1	Create an in and out loop at Adams Station by removing	AEP		100.0%						
1423	b1466.2	Upgrade the Adams transformer to 90 MVA	AEP		100.0%						
1424	b1466.3	At Seaman Station install a new 138 kV bus and two nev	AEP		100.0%						
1425	b1466.4	Convert South Central Co-op's New Market 69 kV Statio	AEP		100.0%						
1426	b1466.5	The Seaman – Highland circuit is already built to 138 kV	AEP		100.0%						
1427	b1466.6	At Highland Station, install a new 138 kV bus, three new	AEP		100.0%						
1428	b1466.7	Using one of the bays at Highland, build a 138 kV circuit	AEP		100.0%						
1429	b1467.1	Install a 14.4 MVAr Capacitor Bank at New Buffalo statio	AEP		100.0%						
1430	b1467.2	Reconfigure the 138 kV bus at LaPorte Junction station	AEP		100.0%						
1431	b1468.1	Expand Selma Parker Station and install a 138/69/34.5 I	AEP		100.0%						
1432	b1468.2	Rebuild and convert 34.5 kV line to Winchester to 69 kV	AEP		100.0%						
1433	b1468.3	Retire the 34.5 kV line from Haymond to Selma Wire	AEP		100.0%						
1434	b1469.1	Conversion of the Newcomerstown – Cambridge 34.5 k\	AEP		100.0%						
1435	b1469.2	Expansion of the Derwent 69 kV Station (including recor	AEP		100.0%						
1436	b1469.3	Rebuild 11.8 miles of 69 kV line, and convert additional	AEP		100.0%						
1437	b1470.1	Build a new 138 kV double circuit off the Kanawha – Bai	AEP		100.0%						
1438	b1470.2	Install a new 138/46 kV transformer at Skin Fork	AEP		100.0%						
1439	b1470.3	Replace 5 Moab's on the Kanawha – Baileysville line wi	AEP		100.0%						
1440	b1471	Perform a sag study on the East Lima – For Lima – Rocl	AEP		100.0%						

	A	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
58	Upgrade ID	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL	PSEG	RE	UGI	Cost Estimate ($M)
1369	b1415	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$1.50
1370	b1416														$0.12
1371	b1417														$0.07
1372	b1418														$0.02
1373	b1419														$0.08
1374	b1420														$0.10
1375	b1421														$0.05
1376	b1422														$0.30
1377	b1423														$0.10
1378	b1424														$0.05
1379	b1425														$0.02
1380	b1426														$0.02
1381	b1427														$0.18
1382	b1428														$0.13
1383	b1429														$0.17
1384	b1430														$1.50
1385	b1432														$0.05
1386	b1433														$0.10
1387	b1434														$0.50
1388	b1435														$0.30
1389	b1436														$0.20
1390	b1437														$0.30
1391	b1438														$0.15
1392	b1439														$0.05
1393	b1440														$0.55
1394	b1441														$0.30
1395	b1442														$0.50
1396	b1443														$0.20
1397	b1444														$0.10
1398	b1445														$0.08
1399	b1446														$0.01
1400	b1447														$0.07
1401	b1448														$0.01
1402	b1449														$0.02
1403	b1450														$0.01
1404	b1451														$0.08
1405	b1452														$0.02
1406	b1453														$0.13
1407	b1454														$0.06
1408	b1455														$0.03
1409	b1456														$0.08
1410	b1457														$0.02
1411	b1458														$0.08
1412	b1459														$0.01
1413	b1460														$0.50
1414	b1461														$0.40
1415	b1462														$0.50
1416	b1463														$2.90
1417	b1464														$0.15
1418	b1465.1	3.9%	0.1%	0.1%	1.6%		0.2%	2.1%		1.7%		2.6%	0.1%		$37.00
1419	b1465.2	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$16.00
1420	b1465.3	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$10.00
1421	b1465.4	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$37.00
1422	b1466.1														$13.50
1423	b1466.2														$0.00
1424	b1466.3														$0.00
1425	b1466.4														$0.00
1426	b1466.5														$0.00
1427	b1466.6														$0.00
1428	b1466.7														$0.00
1429	b1467.1														$3.00
1430	b1467.2														$0.00
1431	b1468.1														$8.00
1432	b1468.2														$0.00
1433	b1468.3														$0.00
1434	b1469.1														$23.00
1435	b1469.2														$0.00
1436	b1469.3														$0.00
1437	b1470.1														$8.50
1438	b1470.2														$0.00
1439	b1470.3														$0.00
1440	b1471														$0.02

	A	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL
58	Upgrade ID	Project ID	Upgrade Date In-Service	Project Average In-Service Date	Date to use	Upgrade Source	Project Source	Project Status	Projects Allocated by Load	Projects Attributed to one entity	Projects Attributed to Dayton entity	Year In Service Override	First Full Year in Service	Project Age
1369	b1415	b1415	6/1/2011	1/0/1900	6/1/2011	Planned	Planned	EP	1	0	0		2012	-1
1370	b1416	b1416	12/31/2011	1/0/1900	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
1371	b1417	b1417	12/31/2011	1/0/1900	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
1372	b1418	b1418	12/31/2011	1/0/1900	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
1373	b1419	b1419	12/31/2011	1/0/1900	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
1374	b1420	b1420	12/31/2011	1/0/1900	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
1375	b1421	b1421	12/31/2011	1/0/1900	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
1376	b1422	b1422	12/21/2011	1/0/1900	12/21/2011	Planned	Planned	EP	0	1	0		2012	-1
1377	b1423	b1423	12/31/2011	1/0/1900	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
1378	b1424	b1424	12/31/2011	1/0/1900	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
1379	b1425	b1425	12/31/2011	1/0/1900	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
1380	b1426	b1426	12/31/2011	1/0/1900	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
1381	b1427	b1427	12/31/2011	1/0/1900	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
1382	b1428	b1428	12/31/2011	1/0/1900	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
1383	b1429	b1429	12/31/2011	1/0/1900	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
1384	b1430	b1430	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1385	b1432	b1432	12/31/2011	1/0/1900	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
1386	b1433	b1433	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1387	b1434	b1434	12/31/2011	1/0/1900	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
1388	b1435	b1435	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1389	b1436	b1436	12/31/2011	1/0/1900	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
1390	b1437	b1437	12/31/2011	1/0/1900	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
1391	b1438	b1438	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1392	b1439	b1439	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1393	b1440	b1440	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1394	b1441	b1441	12/31/2011	1/0/1900	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
1395	b1442	b1442	12/31/2011	1/0/1900	12/31/2011	Planned	Planned	EP	0	1	0		2012	-1
1396	b1443	b1443	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1397	b1444	b1444	12/31/2012	1/0/1900	12/31/2012	Planned	Planned	EP	0	1	0		2013	-2
1398	b1445	b1445	12/31/2012	1/0/1900	12/31/2012	Planned	Planned	EP	0	1	0		2013	-2
1399	b1446	b1446	12/31/2012	1/0/1900	12/31/2012	Planned	Planned	EP	0	1	0		2013	-2
1400	b1447	b1447	12/31/2012	1/0/1900	12/31/2012	Planned	Planned	EP	0	1	0		2013	-2
1401	b1448	b1448	12/31/2012	1/0/1900	12/31/2012	Planned	Planned	EP	0	1	0		2013	-2
1402	b1449	b1449	12/31/2012	1/0/1900	12/31/2012	Planned	Planned	EP	0	1	0		2013	-2
1403	b1450	b1450	12/31/2012	1/0/1900	12/31/2012	Planned	Planned	EP	0	1	0		2013	-2
1404	b1451	b1451	12/31/2012	1/0/1900	12/31/2012	Planned	Planned	EP	0	1	0		2013	-2
1405	b1452	b1452	12/31/2012	1/0/1900	12/31/2012	Planned	Planned	EP	0	1	0		2013	-2
1406	b1453	b1453	12/31/2012	1/0/1900	12/31/2012	Planned	Planned	EP	0	1	0		2013	-2
1407	b1454	b1454	12/31/2012	1/0/1900	12/31/2012	Planned	Planned	EP	0	1	0		2013	-2
1408	b1455	b1455	12/31/2012	1/0/1900	12/31/2012	Planned	Planned	EP	0	1	0		2013	-2
1409	b1456	b1456	12/31/2012	1/0/1900	12/31/2012	Planned	Planned	EP	0	1	0		2013	-2
1410	b1457	b1457	12/31/2012	1/0/1900	12/31/2012	Planned	Planned	EP	0	1	0		2013	-2
1411	b1458	b1458	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1412	b1459	b1459	12/31/2012	1/0/1900	12/31/2012	Planned	Planned	EP	0	1	0		2013	-2
1413	b1460	b1460	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1414	b1461	b1461	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1415	b1462	b1462	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1416	b1463	b1463	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1417	b1464	b1464	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1418	b1465.1	b1465	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5
1419	b1465.2	b1465	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	1	0	0		2016	-5
1420	b1465.3	b1465	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	1	0	0		2016	-5
1421	b1465.4	b1465	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	1	0	0		2016	-5
1422	b1466.1	b1466	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1423	b1466.2	b1466	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1424	b1466.3	b1466	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1425	b1466.4	b1466	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1426	b1466.5	b1466	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1427	b1466.6	b1466	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1428	b1466.7	b1466	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1429	b1467.1	b1467	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1430	b1467.2	b1467	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1431	b1468.1	b1468	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1432	b1468.2	b1468	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1433	b1468.3	b1468	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1434	b1469.1	b1469	12/1/2012	1/0/1900	12/1/2012	Planned	Planned	EP	0	1	0		2013	-2
1435	b1469.2	b1469	12/1/2012	1/0/1900	12/1/2012	Planned	Planned	EP	0	1	0		2013	-2
1436	b1469.3	b1469	12/1/2012	1/0/1900	12/1/2012	Planned	Planned	EP	0	1	0		2013	-2
1437	b1470.1	b1470	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1438	b1470.2	b1470	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1439	b1470.3	b1470	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1440	b1471	b1471	12/31/2012	1/0/1900	12/31/2012	Planned	Planned	EP	0	1	0		2013	-2

	A	AM	AN	AO	AP	AQ	AR	AS
58	Upgrade ID	Load Ratio Project Costs	One Entity Project Costs	DFAX allocated Project Costs	Dayton DFAX Project Costs			
1369	b1415	1.5	0	0	0.00			
1370	b1416	0	0.1216	0	0			
1371	b1417	0	0.0744	0	0			
1372	b1418	0	0.0176	0	0			
1373	b1419	0	0.0804	0	0			
1374	b1420	0	0.1012	0	0			
1375	b1421	0	0.0472	0	0			
1376	b1422	0	0.3	0	0			
1377	b1423	0	0.1	0	0			
1378	b1424	0	0.05	0	0			
1379	b1425	0	0.016	0	0			
1380	b1426	0	0.02	0	0			
1381	b1427	0	0.184	0	0			
1382	b1428	0	0.132	0	0			
1383	b1429	0	0.172	0	0			
1384	b1430	0	1.5	0	0			
1385	b1432	0	0.048	0	0			
1386	b1433	0	0.1	0	0			
1387	b1434	0	0.5	0	0			
1388	b1435	0	0.3	0	0			
1389	b1436	0	0.2	0	0			
1390	b1437	0	0.3	0	0			
1391	b1438	0	0.15	0	0			
1392	b1439	0	0.05	0	0			
1393	b1440	0	0.55	0	0			
1394	b1441	0	0.3	0	0			
1395	b1442	0	0.5	0	0			
1396	b1443	0	0.2	0	0			
1397	b1444	0	0.096	0	0			
1398	b1445	0	0.08	0	0			
1399	b1446	0	0.007	0	0			
1400	b1447	0	0.0672	0	0			
1401	b1448	0	0.00824	0	0			
1402	b1449	0	0.01964	0	0			
1403	b1450	0	0.0148	0	0			
1404	b1451	0	0.0776	0	0			
1405	b1452	0	0.0188	0	0			
1406	b1453	0	0.1304	0	0			
1407	b1454	0	0.064	0	0			
1408	b1455	0	0.032	0	0			
1409	b1456	0	0.078	0	0			
1410	b1457	0	0.02	0	0			
1411	b1458	0	0.078	0	0			
1412	b1459	0	0.00536	0	0			
1413	b1460	0	0.5	0	0			
1414	b1461	0	0.4	0	0			
1415	b1462	0	0.5	0	0			
1416	b1463	0	2.9	0	0			
1417	b1464	0	0.15	0	0			
1418	b1465.1	0	0	37	0.32			
1419	b1465.2	16	0	0	0.00			
1420	b1465.3	10	0	0	0.00			
1421	b1465.4	37	0	0	0.00			
1422	b1466.1	0	13.5	0	0			
1423	b1466.2	0	0	0	0			
1424	b1466.3	0	0	0	0			
1425	b1466.4	0	0	0	0			
1426	b1466.5	0	0	0	0			
1427	b1466.6	0	0	0	0			
1428	b1466.7	0	0	0	0			
1429	b1467.1	0	3	0	0			
1430	b1467.2	0	0	0	0			
1431	b1468.1	0	8	0	0			
1432	b1468.2	0	0	0	0			
1433	b1468.3	0	0	0	0			
1434	b1469.1	0	23	0	0			
1435	b1469.2	0	0	0	0			
1436	b1469.3	0	0	0	0			
1437	b1470.1	0	8.5	0	0			
1438	b1470.2	0	0	0	0			
1439	b1470.3	0	0	0	0			
1440	b1471	0	0.018	0	0			

	A	B	C	D	E	F	G	H	I	J	K
58	Upgrade ID	Description	TO	AEC	AEP	APS	BGE	ComEd	Dayton	DL	DPL
1441	b1472	Perform a sag study on the East Lima – Haviland 138 kV	AEP		100.0%						
1442	b1473	Perform a sag study on the East New Concord – Muskin	AEP		100.0%						
1443	b1474	Perform a sag study on the Ohio Central – Prep Plant ta	AEP		100.0%						
1444	b1475	Perform a sag study on the S73 – North Delphos 138 kV	AEP		100.0%						
1445	b1476	Perform a sag study on the S73 – T131 138 kV line to in	AEP		100.0%						
1446	b1477	The Natrium – North Martin 138 kV circuit would need a	AEP		100.0%						
1447	b1478	Upgrade Strouds Run – Strouds Tap 138 kV relay and r	AEP		100.0%						
1448	b1479	West Hebron station upgrades	AEP		100.0%						
1449	b1480	Perform upgrades and a sag study on the Corner – Layr	AEP		100.0%						
1450	b1481	Perform a sag study on the West Lima – Eastown Road	AEP		100.0%						
1451	b1482	Perform a sag study for the Albion – Robison Park 138 k	AEP		100.0%						
1452	b1483	Sag study 1 mile of the Clinch River – Saltville 138 kV li	AEP		100.0%						
1453	b1484	Perform a sag study on the Hacienda – Harper 138 kV li	AEP		100.0%						
1454	b1485	Perform a sag study on the Jackson Road – Concord 13	AEP		100.0%						
1455	b1486	The Matt Funk – Poages Mill – Starkey 138 kV line requ	AEP		100.0%						
1456	b1487	Perform a sag study on the New Carlisle – Trail Creek 1	AEP		100.0%						
1457	b1488	Perform a sag study on the Olive – LaPorte Junction 13	AEP		100.0%						
1458	b1489	A sag study must be performed for the 5.40 mile Tristate	AEP		100.0%						
1459	b1490.1	Establish a new 138/69 kV Butler Center station	AEP		100.0%						
1460	b1490.2	Build a new 14 mile 138 kV line from Auburn station to V	AEP		100.0%						
1461	b1490.3	Replace the existing 40 MVA 138/69 kV transformer at A	AEP		100.0%						
1462	b1490.4	Improve the switching arrangement at Kendallville statio	AEP		100.0%						
1463	b1491	Replace bus and risers at Thelma and Busseyville statio	AEP		100.0%						
1464	b1492	Reconductor 0.65 miles of the Glen Lyn – Wythe 138 kV	AEP		100.0%						
1465	b1493	Perform a sag study for the Bellefonte – Grantston 138 k	AEP		100.0%						
1466	b1494	Perform a sag study for the North Proctorville – Solida –	AEP		100.0%						
1467	b1495	Add an additional 765/345 kV transformer at Baker Stati	AEP	0.4%	87.2%		1.0%	3.4%	1.2%	1.5%	0.5%
1468	b1496	Replace 138 kV bus and risers at Johnson Mountain Sta	AEP		100.0%						
1469	b1497	Replace 138 kV bus and risers at Leesville Station	AEP		100.0%						
1470	b1498	Replace 138 kV risers at Wurno Station	AEP		100.0%						
1471	b1499	Perform a sag study on Sporn A – Gavin 138 kV to dete	AEP		100.0%						
1472	b1500	The North East Canton – Wagenhals 138 kV circuit wou	AEP		100.0%						
1473	b1501	The Moseley – Reusens 138 kV circuit requires a sag st	AEP		100.0%						
1474	b1502	Reconductor the Conesville East – Conesville Prep Plar	AEP		100.0%						
1475	b1507	Rebuild Mt Storm – Doubs 500 kV	Dominion	2.1%	16.7%	6.0%	4.9%	15.6%	2.4%	2.1%	2.9%
1476	b1508.1	Build a 2nd 230 kV Line Harrisonburg to Endless Caver	Dominion			37.1%					
1477	b1508.2	Install a 3rd 230-115 kV Tx at Endless Caverns	Dominion			37.1%					
1478	b1508.3	Upgrade a 115 kV shunt capacitor banks at Merck and E	Dominion			37.1%					

	A	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
58	Upgrade ID	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL	PSEG	RE	UGI	Cost Estimate ($M)
1441	b1472														$0.14
1442	b1473														$0.15
1443	b1474														$0.04
1444	b1475														$0.08
1445	b1476														$0.03
1446	b1477														$0.10
1447	b1478														$0.06
1448	b1479														$0.05
1449	b1480														$0.20
1450	b1481														$0.07
1451	b1482														$0.09
1452	b1483														$0.22
1453	b1484														$0.06
1454	b1485														$0.09
1455	b1486														$0.03
1456	b1487														$0.01
1457	b1488														$0.01
1458	b1489														$0.30
1459	b1490.1														$25.00
1460	b1490.2														$0.00
1461	b1490.3														$0.00
1462	b1490.4														$0.00
1463	b1491														$0.65
1464	b1492														$0.70
1465	b1493														$0.07
1466	b1494														$0.09
1467	b1495		0.0%	0.0%	0.9%		0.1%	1.2%		0.9%		1.5%	0.1%		$46.00
1468	b1496														$0.60
1469	b1497														$0.60
1470	b1498														$0.15
1471	b1499														$0.16
1472	b1500														$0.02
1473	b1501														$0.09
1474	b1502														$2.00
1475	b1507	13.6%	0.2%		4.6%	2.1%	0.5%	6.3%	2.1%	4.7%	5.3%	7.7%	0.3%		$370.00
1476	b1508.1	63.0%													$70.00
1477	b1508.2	63.0%													$1.70
1478	b1508.3	63.0%													$0.30

	A	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL
58	Upgrade ID	Project ID	Upgrade Date In-Service	Project Average In-Service Date	Date to use	Upgrade Source	Project Source	Project Status	Projects Allocated by Load	Projects Attributed to one entity	Projects Attributed to Dayton entity	Year In Service Override	First Full Year in Service	Project Age
1441	b1472	b1472	12/31/2012	1/0/1900	12/31/2012	Planned	Planned	EP	0	1	0		2013	-2
1442	b1473	b1473	12/31/2012	1/0/1900	12/31/2012	Planned	Planned	EP	0	1	0		2013	-2
1443	b1474	b1474	12/31/2012	1/0/1900	12/31/2012	Planned	Planned	EP	0	1	0		2013	-2
1444	b1475	b1475	12/31/2012	1/0/1900	12/31/2012	Planned	Planned	EP	0	1	0		2013	-2
1445	b1476	b1476	12/31/2012	1/0/1900	12/31/2012	Planned	Planned	EP	0	1	0		2013	-2
1446	b1477	b1477	12/31/2013	1/0/1900	12/31/2013	Planned	Planned	EP	0	1	0		2014	-3
1447	b1478	b1478	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1448	b1479	b1479	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1449	b1480	b1480	12/31/2013	1/0/1900	12/31/2013	Planned	Planned	EP	0	1	0		2014	-3
1450	b1481	b1481	12/31/2013	1/0/1900	12/31/2013	Planned	Planned	EP	0	1	0		2014	-3
1451	b1482	b1482	12/31/2013	1/0/1900	12/31/2013	Planned	Planned	EP	0	1	0		2014	-3
1452	b1483	b1483	12/31/2013	1/0/1900	12/31/2013	Planned	Planned	EP	0	1	0		2014	-3
1453	b1484	b1484	12/31/2013	1/0/1900	12/31/2013	Planned	Planned	EP	0	1	0		2014	-3
1454	b1485	b1485	12/31/2013	1/0/1900	12/31/2013	Planned	Planned	EP	0	1	0		2014	-3
1455	b1486	b1486	12/31/2013	1/0/1900	12/31/2013	Planned	Planned	EP	0	1	0		2014	-3
1456	b1487	b1487	12/31/2013	1/0/1900	12/31/2013	Planned	Planned	EP	0	1	0		2014	-3
1457	b1488	b1488	12/31/2013	1/0/1900	12/31/2013	Planned	Planned	EP	0	1	0		2014	-3
1458	b1489	b1489	12/31/2013	1/0/1900	12/31/2013	Planned	Planned	EP	0	1	0		2014	-3
1459	b1490.1	b1490	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1460	b1490.2	b1490	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1461	b1490.3	b1490	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1462	b1490.4	b1490	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1463	b1491	b1491	12/31/2013	1/0/1900	12/31/2013	Planned	Planned	EP	0	1	0		2014	-3
1464	b1492	b1492	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1465	b1493	b1493	12/31/2013	1/0/1900	12/31/2013	Planned	Planned	EP	0	1	0		2014	-3
1466	b1494	b1494	12/31/2013	1/0/1900	12/31/2013	Planned	Planned	EP	0	1	0		2014	-3
1467	b1495	b1495	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5
1468	b1496	b1496	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1469	b1497	b1497	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1470	b1498	b1498	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1471	b1499	b1499	12/31/2013	1/0/1900	12/31/2013	Planned	Planned	EP	0	1	0		2014	-3
1472	b1500	b1500	12/31/2013	1/0/1900	12/31/2013	Planned	Planned	EP	0	1	0		2014	-3
1473	b1501	b1501	12/31/2013	1/0/1900	12/31/2013	Planned	Planned	EP	0	1	0		2014	-3
1474	b1502	b1502	6/1/2015	1/0/1900	6/1/2015	Planned	Planned	EP	0	1	0		2016	-5
1475	b1507	b1507	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	1	0	0		2016	-5
1476	b1508.1	b1508	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5
1477	b1508.2	b1508	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5
1478	b1508.3	b1508	6/1/2015	6/1/2015	6/1/2015	Planned	Planned	EP	0	0	0		2016	-5

	A	AM	AN	AO	AP	AQ	AR	AS
58	Upgrade ID	Load Ratio Project Costs	One Entity Project Costs	DFAX allocated Project Costs	Dayton DFAX Project Costs			
1441	b1472	0	0.14	0	0			
1442	b1473	0	0.15	0	0			
1443	b1474	0	0.044	0	0			
1444	b1475	0	0.075	0	0			
1445	b1476	0	0.03	0	0			
1446	b1477	0	0.0995	0	0			
1447	b1478	0	0.055	0	0			
1448	b1479	0	0.05	0	0			
1449	b1480	0	0.2	0	0			
1450	b1481	0	0.065	0	0			
1451	b1482	0	0.0888	0	0			
1452	b1483	0	0.22	0	0			
1453	b1484	0	0.0596	0	0			
1454	b1485	0	0.087	0	0			
1455	b1486	0	0.032	0	0			
1456	b1487	0	0.01	0	0			
1457	b1488	0	0.01	0	0			
1458	b1489	0	0.3	0	0			
1459	b1490.1	0	25	0	0			
1460	b1490.2	0	0	0	0			
1461	b1490.3	0	0	0	0			
1462	b1490.4	0	0	0	0			
1463	b1491	0	0.65	0	0			
1464	b1492	0	0.7	0	0			
1465	b1493	0	0.07	0	0			
1466	b1494	0	0.09	0	0			
1467	b1495	0	0	46	0.57			
1468	b1496	0	0.6	0	0			
1469	b1497	0	0.6	0	0			
1470	b1498	0	0.15	0	0			
1471	b1499	0	0.16	0	0			
1472	b1500	0	0.02	0	0			
1473	b1501	0	0.088	0	0			
1474	b1502	0	2	0	0			
1475	b1507	370	0	0	0.00			
1476	b1508.1	0	0	70	0			
1477	b1508.2	0	0	1.7	0			
1478	b1508.3	0	0	0.3	0			

	A	B	C	D	E	F	G	H	I	J
1		**Exhibit DUK-203**								
2		******Source and Disclaimer ******								
3	* Data valid as of June 2011									
4	This document is a summary of the RTEP cost allocation data contained in Schedule 12 of the PJM Open Acess									
5	Transmission Tariff (OATT.) Schedule 12 of the OATT contains the official cost allocations and this document									
6	should be used only as a reference. See links at http://www.pjm.com/committees-and-									
7	groups/committees/teac.aspx#6									
8	Upgrade ID	Description	TO	Cost Estimate	AEC	AEP	APS	BGE	ComEd	Dayton
9	b0025	Convert the Bergen-Leonia 138 kV circuit to 230 kV circ	PSEG	$25.00						
10	b0074	Rebuild 12 miles of S. Akron – Berks 230 kV to double c	PPL	$48.27						
11	b0090	Add 150 MVAR capacitor at Camden 230 kV	PSEG	$1.25						
12	b0121	Add 150 MVAR capacitor at Aldene 230 kV	PSEG	$1.25						
13	b0122	Bypass the Essex 138 kV series reactors	PSEG	$0.50						
14	b0123	Add 180 MVAR of distributed capacitors. 65 MVAR in ne	JCPL	$2.70						
15	b0124.1	Add a 72 MVAR capacitor at Kittatinny 230 kV	JCPL	$0.80						
16	b0124.2	Add a 130 MVAR capacitor at Manitou 230 kV	JCPL	$1.00						
17	b0125	Add Special Protection Scheme at Bridgewater to auton	PSEG	$0.10						
18	b0126	Replace wavetrap on Branchburg – Flagtown 230 kV	PSEG	$0.50						
19	b0127	Replace terminal equipment to increase Brunswick – Ad	PSEG	$0.50						
20	b0129	Replace wavetrap on Flagtown – Somerville 230 kV	PSEG	$0.50						
21	b0130	Replace all derated Branchburg 500/230 kV transformer	PSEG	$20.00	$0.27					
22	b0132	Reconductor Portland – Kittatinny 230 kV with 1590 AC	JCPL	$4.40						
23	b0134	Upgrade or Retension PSEG portion of Kittatinny – New	PSEG	$20.00						
24	b0135	Build new Cumberland - Dennis 230 kV circuit which rep	AEC	$17.05	$17.05					
25	b0136	Install Dennis 230/138 kV transformer, Dennis 150 MVA	AEC	$27.45	$27.45					
26	b0137	Build new Dennis – Corson 138 kV circuit	AEC	$1.16	$1.16					
27	b0138	Install Cardiff 230/138 kV transformer and a 50 MVAR c	AEC	$8.07	$8.07					
28	b0139	Build new Cardiff – Lewis 138 kV circuit	AEC	$3.69	$3.69					
29	b0140	Reconductor Laurel – Woodstown 69 kV	AEC	$4.99	$4.99					
30	b0141	Reconductor Monroe – North Central 69 kV	AEC	$4.90	$4.90					
31	b0142	Reconductor Landis – Minotola 138 kV	AEC	$1.93	$1.93					
32	b0143	Reconductor Beckett – Paulsboro 69 kV	AEC	$1.63	$1.63					
33	b0144.1	Build new Red Lion – Milford – Indian River 230 kV circu	DPL	$44.91						
34	b0144.2	Indian River Sub – 230 kV Terminal Position	DPL	$7.47						
35	b0144.3	Red Lion Sub – 230 kV Terminal Position	DPL	$0.97						
36	b0144.4	Milford Sub – (2) 230 kV Terminal Positions	DPL	$2.10						
37	b0144.5	Indian River – 138 kV Transmission Line to AT-20	DPL	$0.12						
38	b0144.6	Indian River – 138 & 69 kV Transmission Ckts. Undergr	DPL	$3.65						
39	b0144.7	Indian River – (2) 230 kV bus ties	DPL	$1.23						
40	b0145	Build new Essex – Aldene 230 kV cable connected thro	PSEG	$65.00						
41	b0146	Installation of (2) new 230 kV circuit breakers at Quince	PEPCO	$4.79						
42	b0148	Re-rate Glasgow – Mt. Pleasant 138 kV and North Seaf	DPL							
43	b0149	Complete structure work to increase rating of Cheswold	DPL							
44	b0152	Add (2) 230 kV Breakers at High Ridge and install two N	BGE	$1.18				$1.18		
45	b0157	Add 100MVAR capacitor at West Orange 138kV substa	PSEG	$2.00						
46	b0158	Close the Sunnymeade "C" and "F" bus tie	PSEG	$4.63						
47	b0159	Make the Bayonne reactor permanent installation	PSEG	$2.00						
48	b0161	Install 230/138kV transformer at Metuchen substation	PSEG	$29.00						
49	b0162	Upgrade the Edison – Meadow Rd 138kV “Q” circuit	PSEG	$1.00						
50	b0163	Upgrade the Edison – Meadow Rd 138kV “R” circuit	PSEG	$1.00						
51	b0164	Reconductor Wolfs - Oswego 138kV with 636 ACSS	ComEd	$2.00					$2.00	
52	b0169	Build a new 230 kV section from Branchburg – Flagtown	PSEG	$17.00	$0.29					
53	b0170	Reconductor the Flagtown-Somerville-Bridgewater 230	PSEG	$12.00						
54	b0171.1	Replace two 500 kV circuit breakers and two wave traps	PECO	$2.20	$0.05	$0.37	$0.13	$0.11	$0.34	$0.05
55	b0171.2	Replace wavetrap at Hosensack 500kV substation to inc	PPL	$0.13	$0.00	$0.02	$0.01	$0.01	$0.02	$0.00
56	b0172.1	Replace wave trap at Alburtis 500kV substation	PPL	$0.07	$0.00	$0.01	$0.00	$0.00	$0.01	$0.00
57	b0172.2	Replace wave trap at Branchburg 500kV substation	PSEG	$0.05	$0.00	$0.01	$0.00	$0.00	$0.01	$0.00
58	b0173	Replace a line trap at Newton 230kV substation for the I	JCPL	$0.10						
59	b0174	Upgrade the Portland – Greystone 230kV circuit	JCPL	$20.00						
60	b0180	Replace Whitpain 230kV circuit breaker #165	PECO	$0.25						
61	b0181	Replace Whitpain 230kV circuit breaker #J105	PECO	$0.44						
62	b0182	Upgrade Plymouth Meeting 230kV circuit breaker #125	PECO	$0.10						
63	b0184	Replace Hudson 230kV circuit breakers #1-2	PSEG	$0.48						
64	b0185	Replace Deans 230kV circuit breakers #9-10	PSEG	$0.48						
65	b0186	Replace Essex 230kV circuit breaker #5-6	PSEG	$0.48						
66	b0199	Greystone 230kV substation: Change Tap of limiting CT	JCPL	$0.35						
67	b0200	Greystone 230kV substation: Change Tap of limiting CT	JCPL	$0.01						
68	b0201	Branchburg substation: replace wave trap on Branchbur	PSEG	$0.50						
69	b0202	Kittatinny 230kV substation: Replace line trap on Kittatir	JCPL	$0.04						
70	b0203	Smithburg 230kV Substation: Replace line trap on the E	JCPL	$0.08						
71	b0204	Install 72Mvar capacitor at Cookstown 230kV substatior	JCPL	$1.00						
72	b0205	Install three 28.8Mvar capacitors at Planebrook 35kV su	PECO	$2.20						
73	b0206	Install 161Mvar capacitor at Planebrook 230kV substatio	PECO	$2.00	$0.28					
74	b0207	Install 161Mvar capacitor at Newlinville 230kV substatio	PECO	$2.00	$0.28					
75	b0208	Install 161Mvar capacitor Heaton 230kV substation	PECO	$2.00	$0.28					
76	b0209	Install 2% series reactor at Chichester substation on the	PECO	$3.00	$1.96					
77	b0210	Install a new 500/230kV substation in AEC area. The hi	AEC	$37.09	$0.78	$6.20	$2.24	$1.82	$5.78	$0.89
78	b0210	Install a new 500/230kV substation in AEC area, the hig	AEC	$15.00	$9.78					
79	b0211	Reconductor Union - Corson 138kV circuit	AEC	$6.22	$4.06					
80	b0212	Substation upgrades at Union and Corson 138kV	AEC	$0.07	$0.05					
81	b0213.1	Replace New Freedom 230 kV breaker BS2-6	PSEG	$0.38						
82	b0213.3	Replace New Freedom 230 kV breaker BS2-8	PSEG	$0.38						
83	b0214	Install 50 MVAR capacitor at Cardiff 230kV substation	AEC	$2.65	$2.65					
84	b0215	Install 230Kv series reactor and 2- 100MVAR PLC switc	ME	$10.00	$0.67		$0.40			
85	b0216	Install -100/+525 MVAR dynamic reactive device at Blac	APS	$50.00	$1.05	$8.36	$3.02	$2.46	$7.79	$1.21
86	b0217	Upgrade Mt. Storm - Doubs 500kV	Dominion	$1.70	$0.04	$0.28	$0.10	$0.08	$0.26	$0.04
87	b0218	Install third Wylie Ridge 500/345kV transformer	APS	$14.50	$1.72					
88	b0219	Install two new 230 kV circuits between Palmers Corner	PEPCO	$91.00						
89	b0220	Upgrade coolers on Wylie Ridge 500/345 kV #7	APS	$0.36	$0.04					
90	b0221	Replace disconnect switch on Edgewood-N. Salisbury 6	DPL	$0.02						
91	b0222	Install 150 MVAR capacitor at Loudoun 500 kV	Dominion	$1.50	$0.03	$0.25	$0.09	$0.07	$0.23	$0.04

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8	Upgrade ID	DL	DPL	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL
9	b0025												
10	b0074												$48.27
11	b0090												
12	b0121												
13	b0122												
14	b0123						$2.70						
15	b0124.1						$0.80						
16	b0124.2						$1.00						
17	b0125												
18	b0126												
19	b0127												
20	b0129												
21	b0130						$9.55						
22	b0132						$4.40						
23	b0134						$10.22						
24	b0135												
25	b0136												
26	b0137												
27	b0138												
28	b0139												
29	b0140												
30	b0141												
31	b0142												
32	b0143												
33	b0144.1		$44.91										
34	b0144.2		$7.47										
35	b0144.3		$0.97										
36	b0144.4		$2.10										
37	b0144.5		$0.12										
38	b0144.6		$3.65										
39	b0144.7		$1.23										
40	b0145						$47.74						
41	b0146											$4.79	
42	b0148												
43	b0149												
44	b0152												
45	b0157												
46	b0158												
47	b0159												
48	b0161												
49	b0162												
50	b0163												
51	b0164												
52	b0169				$0.36		$4.41		$1.81				
53	b0170						$5.15		$2.15				
54	b0171.1	$0.05	$0.06	$0.30	$0.00		$0.10	$0.05	$0.01	$0.14	$0.05	$0.10	$0.12
55	b0171.2	$0.00	$0.00	$0.02	$0.00		$0.01	$0.00	$0.00	$0.01	$0.00	$0.01	$0.01
56	b0172.1	$0.00	$0.00	$0.01	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
57	b0172.2	$0.00	$0.00	$0.01	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
58	b0173						$0.10						
59	b0174				$0.32		$7.08		$1.13				
60	b0180									$0.25			
61	b0181									$0.44			
62	b0182									$0.10			
63	b0184												
64	b0185												
65	b0186												
66	b0199						$0.35						
67	b0200						$0.01						
68	b0201												
69	b0202						$0.04						
70	b0203						$0.08						
71	b0204						$1.00						
72	b0205									$2.20			
73	b0206		$0.49							$1.16			
74	b0207		$0.49							$1.16			
75	b0208		$0.49							$1.16			
76	b0209						$0.78		$0.08				
77	b0210	$0.76	$1.07	$5.05	$0.08		$1.69	$0.78	$0.18	$2.34	$0.78	$1.75	$1.95
78	b0210						$3.88		$0.38				
79	b0211						$1.61		$0.16				
80	b0212						$0.02		$0.00				
81	b0213.1												
82	b0213.3												
83	b0214												
84	b0215		$0.91		$0.06		$1.69	$1.05	$0.17	$1.90			$0.76
85	b0216	$1.03	$1.44	$6.81	$0.11		$2.28	$1.05	$0.25	$3.15	$1.06	$2.37	$2.64
86	b0217	$0.03	$0.05	$0.23	$0.00		$0.08	$0.04	$0.01	$0.11	$0.04	$0.08	$0.09
87	b0218		$2.81	$2.00			$2.26			$5.71			
88	b0219											$91.00	
89	b0220		$0.07	$0.05			$0.06			$0.14			
90	b0221		$0.02										
91	b0222	$0.03	$0.04	$0.20	$0.00		$0.07	$0.03	$0.01	$0.09	$0.03	$0.07	$0.08

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8	Upgrade ID	PSEG	RE	UGI
9	b0025	$25.00		
10	b0074			
11	b0090	$1.25		
12	b0121	$1.25		
13	b0122	$0.50		
14	b0123			
15	b0124.1			
16	b0124.2			
17	b0125	$0.10		
18	b0126	$0.50		
19	b0127	$0.50		
20	b0129	$0.50		
21	b0130	$10.18		
22	b0132			
23	b0134	$9.19	$0.59	
24	b0135			
25	b0136			
26	b0137			
27	b0138			
28	b0139			
29	b0140			
30	b0141			
31	b0142			
32	b0143			
33	b0144.1			
34	b0144.2			
35	b0144.3			
36	b0144.4			
37	b0144.5			
38	b0144.6			
39	b0144.7			
40	b0145	$14.16	$3.10	
41	b0146			
42	b0148			
43	b0149			
44	b0152			
45	b0157	$2.00		
46	b0158	$4.63		
47	b0159	$2.00		
48	b0161	$28.94	$0.06	
49	b0162	$1.00		
50	b0163	$1.00		
51	b0164			
52	b0169	$10.13		
53	b0170	$4.60	$0.09	
54	b0171.1	$0.17	$0.01	
55	b0171.2	$0.01	$0.00	
56	b0172.1	$0.00	$0.00	
57	b0172.2	$0.00	$0.00	
58	b0173			
59	b0174	$10.87	$0.59	
60	b0180			
61	b0181			
62	b0182			
63	b0184	$0.48		
64	b0185	$0.48		
65	b0186	$0.48		
66	b0199			
67	b0200			
68	b0201	$0.50		
69	b0202			
70	b0203			
71	b0204			
72	b0205			
73	b0206	$0.07		
74	b0207	$0.07		
75	b0208	$0.07		
76	b0209	$0.19		
77	b0210	$2.84	$0.11	
78	b0210	$0.95		
79	b0211	$0.39		
80	b0212	$0.00		
81	b0213.1	$0.38		
82	b0213.3	$0.38		
83	b0214			
84	b0215	$2.27	$0.03	$0.10
85	b0216	$3.83	$0.16	
86	b0217	$0.13	$0.01	
87	b0218			
88	b0219			
89	b0220			
90	b0221			
91	b0222	$0.11	$0.00	

	A	B	C	D	E	F	G	H	I	J
8	Upgrade ID	Description	TO	Cost Estimate	AEC	AEP	APS	BGE	ComEd	Dayton
92	b0223	Install 150 MVAR capacitor at Asburn 230 kV	Dominion	$1.00						
93	b0224	Install 150 MVAR capacitor at Dranesville 230 kV	Dominion	$1.00						
94	b0225	Install 33 MVAR capacitor at Possum Pt. 115 kV	Dominion	$0.60						
95	b0226	Install 500/230 kV transformer at Clifton and Clifton 500	Dominion	$7.01			$0.26	$0.25		
96	b0227	Install 500/230 kV transformer at Bristers; build new 23(	Dominion	$5.80	$0.04		$0.19	$0.63		
97	b0227.1	Loudoun Sub – upgrade 6-230 kV breakers	Dominion	$2.00						
98	b0228	Upgrade Burtonsville – Sandy Springs 230 kV circuit	PEPCO	$0.93						
99	b0229	Install fourth Bedington 500/138 kV	APS	$7.00			$3.57	$0.94		
100	b0230	Install fourth Meadowbrook 500/138 kV	APS	$7.00			$5.54	$0.25		
101	b0231	Install 500 kV breakers & 500 kV bus work at Suffolk	Dominion	$5.03	$0.11	$0.84	$0.30	$0.25	$0.78	$0.12
102	b0231.2	Install 500/230 kV Transformer, 230 kV breakers, & 230	Dominion	$12.30						
103	b0232	Install 150 MVAR capacitor at Lynnhaven 230 kV	Dominion	$1.00						
104	b0233	Install 150 MVAR capacitor at Landstown 230 kV	Dominion	$1.84						
105	b0234	Install 150 MVAR capacitor at Greenwich 230 kV	Dominion	$1.86						
106	b0235	Install 150 MVAR capacitor at Fentress 230 kV	Dominion	$1.89						
107	b0236.1	Build new West Loop 138 kV substation	ComEd	$61.00					$61.00	
108	b0236.2	Install two new 345 kV circuits from Crawford and Taylo	ComEd	$331.00					$331.00	
109	b0238	Reconductor Doubs – Dickerson and Doubs – Aqueduc	APS	$9.60				$1.60		
110	b0238.1	Modify Dickerson Station H 230 kV	PEPCO	$1.10						
111	b0240	Open the Black Oak #3 500/138 kV transformer for the I	APS							
112	b0241.2	Edgemoor Sub – Replace overstressed breakers	DPL	$0.83						
113	b0241.3	Red Lion Sub – Substation reconfigure to provide for se	DPL	$12.63						
114	b0244	Install a 4th Waugh Chapel 500/230kV transformer, tern	BGE	$40.40				$34.57		
115	b0245	Replacement of the existing 954 ACSR conductor on th	APS	$1.70			$1.70			
116	b0246	Rebuild of the Double Tollgate – Old Chapel 138 kV line	APS	$1.95			$1.95			
117	b0251	Install 100 MVAR of 230 kV capacitors at Bells Mill	PEPCO	$3.90						
118	b0252	Install 100 MVAR of 230 kV capacitors at Bells Mill	PEPCO	$3.00						
119	b0253	Convert Pine Creek substation from 69 kV to 138 kV	DL	$5.70						
120	b0254	Convert North substation from 69 kV to 138 kV	DL	$3.90						
121	b0255	Convert Highland substation from 69 kV to 138 kV and I	DL	$21.10						
122	b0256.1	Convert Valley substation from 69 kV to 138 kV	DL	$1.60						
123	b0256.2	Reconductor Valley – Phillips at 138 kV	DL	$6.90						
124	b0257.1	Convert Wilmerding substation from 69 kV to 138 kV	DL	$2.70						
125	b0257.2	Convert Dravosburg – Wilmerding from 69 kV to 138 kV	DL	$0.42						
126	b0258	Elrama replace 41 MVA 138/69 kV transformer with a m	DL	$2.30						
127	b0261	Replace 1200 Amp disconnect switch on the Red Lion –	DPL	$0.08						
128	b0262	Reconductor 0.5 miles of Christiana – Edgemoor 138 k\	DPL	$0.33						
129	b0263	Replace 1200 Amp wavetrap at Indian River on the Indi	DPL	$0.16						
130	b0264	Upgrade Chichester – Delco Tap 230 kV and the PECO	PECO	$4.50	$4.04					
131	b0265	Upgrade AE portion of Delco Tap – Mickleton 230 kV ci	AEC	$6.00	$5.39					
132	b0266	Replace two wave traps and ammeter at Peach Bottom,	PECO	$0.80						
133	b0267	Reconductor JCPL 2 mile portion of Kittatinny – Newton	JCPL	$1.25						
134	b0268	Reconductor the 8 mile Gilbert – Glen Gardner 230 kV (	JCPL	$7.00						
135	b0269	Install a new 500/230 kV substation in PECO, and tap th	PECO	$30.20	$0.63	$5.05	$1.82	$1.49	$4.71	$0.73
136	b0269	Install a new 500/230 kV substation in PECO, and tap th	PECO	$15.00	$1.24					
137	b0269.6	Add a new 500 kV breaker at Whitpain between #3 tran:	PECO	$2.50	$0.05	$0.42	$0.15	$0.12	$0.39	$0.06
138	b0269.7	Replace North Wales 230 kV breaker #105	PECO	$0.15						
139	b0274	Replace both 230/138 kV transformers at Roseland	PSEG	$15.00						
140	b0275	Upgrade the two 138 kV circuits between Roseland and	PSEG	$5.00						
141	b0276	Replace both Monroe 230/69 kV transformers	AEC	$6.88	$6.28					
142	b0276.1	Upgrade a strand bus at Monroe to increase the rating (	AEC	$0.25	$0.25					
143	b0277	Install a second Cumberland 230/138 kV transformer	AEC	$4.90	$4.90					
144	b0278	Install 228 MVAR capacitor at Roseland 230 kV substat	PSEG	$6.00						
145	b0279.1	Install 100 MVAR capacitor at Glen Gardner substation	JCPL	$0.99						
146	b0279.10	Install 6.6 MVAR capacitor at Hamburg Boro Q Bus 34.!	JCPL	$0.27						
147	b0279.11	Install 6.6 MVAR capacitor at Newburg Q Bus 34.5 kV s	JCPL	$0.27						
148	b0279.2	Install MVAR capacitor at Kittatinny 230 kV substation	JCPL	$0.96						
149	b0279.4	Install 6.6 MVAR capacitor at Waretown #1 bank 34.5 k'	JCPL	$0.27						
150	b0279.5	Install 10.8 MVAR capacitor at Spottswood #2 bank .4.5	JCPL	$0.43						
151	b0279.6	Install 6.6 MVAR capacitor at Pequannock N bus 34.5 k	JCPL	$0.27						
152	b0279.7	Install 6.6 MVAR capacitor at Haskell P bus 34.5 kV sul	JCPL	$0.27						
153	b0279.9	Install 6.6 MVAR capacitor at Matrix 34.5 kV substation	JCPL	$0.27						
154	b0280.1	Install 161 MVAR capacitor at Warrington 230 kV substa	PECO	$2.80						
155	b0280.2	Install 161 MVAR capacitor at Bradford 230 kV substatio	PECO	$3.00						
156	b0280.3	Install 28.8 MVAR capacitor at Warrington 34 kV substa	PECO	$0.75						
157	b0280.4	Install 18 MVAR capacitor at Waverly 13.8 kV substatio	PECO	$0.50						
158	b0281.1	Install 35 MVAR capacitor at Lake Ave 69 kV substation	AEC	$2.40	$2.40					
159	b0281.2	Install 15 MVAR capacitor at Shipbottom 69 kV substati	AEC	$1.40	$1.40					
160	b0281.3	Install 8 MVAR capacitors on the AE distribution system	AEC	$0.20	$0.20					
161	b0282	Install 46 MVAR capacitors on the DPL distribution syst	DPL	$1.20						
162	b0284.1	Build 500 kV substation in PENELEC – Tap the Keystor	PENELEC	$25.00	$0.52	$4.18	$1.51	$1.23	$3.90	$0.60
163	b0284.2	Replace two wave traps at Juniata 500 kV – on the two	PPL	$0.24	$0.00	$0.04	$0.02	$0.01	$0.04	$0.01
164	b0284.3	Replace wave trap and upgrade a bus section at Keystc	PENELEC	$0.25	$0.01	$0.04	$0.02	$0.01	$0.04	$0.01
165	b0285.1	Replace wave trap at Keystone 500 kV – on the Keystoi	PENELEC	$0.20	$0.00	$0.03	$0.01	$0.01	$0.03	$0.00
166	b0285.2	Replace wave trap and relay at Conemaugh 500 kV – o	PENELEC	$0.30	$0.01	$0.05	$0.02	$0.01	$0.05	$0.01
167	b0286	Install 130 MVAR capacitor at Whippany 230 kV	JCPL	$1.40						
168	b0287	Install 600 MVAR Dynamic Reactive Device in Whitpain	PECO	$10.50	$0.22	$1.75	$0.63	$0.52	$1.64	$0.25
169	b0288	Brighton Substation – add 2nd 1000 MVA 500/230 kV tr	PEPCO	$33.40				$6.46		
170	b0289.1	Install additional 130 MVAR capacitor at West Wharton	JCPL	$2.36						
171	b0290	Install 400 MVAR capacitor in the Branchburg 500 kV vi	PSEG	$18.00	$0.38	$3.01	$1.09	$0.89	$2.80	$0.43
172	b0291	Replace 1600A disconnect switch at Harmony 230 kV a	DPL	$0.85						
173	b0292	Replace a 1600A line trap at Atlantic Larrabee 230 kV s	JCPL	$0.10						
174	b0293.1	Replace wavetrap at the Martins Creek 230 kV bus	PPL	$0.23						
175	b0295	Raise conductor temperature of North Seaford – Pine S	DPL	$0.30						
176	b0296	Rehoboth/Cedar Neck Tap (6733-2) upgrade	DPL	$1.70						
177	b0298	Replace both Conastone 500/230 kV transformers with	BGE	$55.00				$41.72		
178	b0298.1	Replace Conastone 230 kV breaker 500-3/2323	BGE	$1.00				$1.00		
179	b0299	Upgrade line 0108 – LaSalle County – Mazon 138 kV w	ComEd	$2.13					$2.13	
180	b0301	Increase capacity of Wolfs – Oswego 138 kV line 14304	ComEd	$2.13					$2.13	
181	b0302	Dixon – McGirr 138kV – Replace small piece of conduct	ComEd	$3.73					$3.73	
182	b0303	Install 345 kV CB and change Elwood 345 kV BT to nor	ComEd	$2.00					$2.00	

	A	K	L	M	N	O	P	Q	R	S	T	U	V
8	Upgrade ID	DL	DPL	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL
92	b0223			$1.00									
93	b0224			$1.00									
94	b0225			$0.60									
95	b0226	$6.01										$0.49	
96	b0227		$0.10	$3.91				$0.05		$0.14		$0.71	$0.03
97	b0227.1			$2.00									
98	b0228											$0.93	
99	b0229		$0.14	$1.02				$0.10				$1.23	
100	b0230		$0.06	$0.82				$0.05				$0.28	
101	b0231	$0.10	$0.14	$0.68	$0.01		$0.23	$0.11	$0.02	$0.32	$0.11	$0.24	$0.27
102	b0231.2			$12.30									
103	b0232			$1.00									
104	b0233			$1.84									
105	b0234			$1.86									
106	b0235			$1.89									
107	b0236.1												
108	b0236.2												
109	b0238			$3.23								$4.77	
110	b0238.1											$1.10	
111	b0240												
112	b0241.2		$0.83										
113	b0241.3		$10.67							$1.96			
114	b0244							$0.34				$5.50	
115	b0245												
116	b0246												
117	b0251											$3.90	
118	b0252											$3.00	
119	b0253	$5.70											
120	b0254	$3.90											
121	b0255	$21.10											
122	b0256.1	$1.60											
123	b0256.2	$6.90											
124	b0257.1	$2.70											
125	b0257.2	$0.42											
126	b0258	$2.30											
127	b0261		$0.08										
128	b0262		$0.33										
129	b0263		$0.16										
130	b0264						$0.43		$0.03				
131	b0265						$0.57		$0.04				
132	b0266									$0.80			
133	b0267						$1.25						
134	b0268				$0.07		$4.32		$0.21				
135	b0269	$0.62	$0.87	$4.11	$0.07		$1.38	$0.63	$0.15	$1.90	$0.64	$1.43	$1.59
136	b0269		$1.43							$12.33			
137	b0269.6	$0.05	$0.07	$0.34	$0.01		$0.11	$0.05	$0.01	$0.16	$0.05	$0.12	$0.13
138	b0269.7									$0.15			
139	b0274				$0.48								
140	b0275												
141	b0276				$0.01								
142	b0276.1												
143	b0277												
144	b0278												
145	b0279.1						$0.99						
146	b0279.10						$0.27						
147	b0279.11						$0.27						
148	b0279.2						$0.96						
149	b0279.4						$0.27						
150	b0279.5						$0.43						
151	b0279.6						$0.27						
152	b0279.7						$0.27						
153	b0279.9						$0.27						
154	b0280.1									$2.80			
155	b0280.2									$3.00			
156	b0280.3									$0.75			
157	b0280.4									$0.50			
158	b0281.1												
159	b0281.2												
160	b0281.3												
161	b0282		$1.20										
162	b0284.1	$0.51	$0.72	$3.40	$0.06		$1.14	$0.52	$0.12	$1.58	$0.53	$1.18	$1.32
163	b0284.2	$0.00	$0.01	$0.03	$0.00		$0.01	$0.01	$0.00	$0.01	$0.01	$0.01	$0.01
164	b0284.3	$0.01	$0.01	$0.03	$0.00		$0.01	$0.01	$0.00	$0.02	$0.01	$0.01	$0.01
165	b0285.1	$0.00	$0.01	$0.03	$0.00		$0.01	$0.00	$0.00	$0.01	$0.00	$0.01	$0.01
166	b0285.2	$0.01	$0.01	$0.04	$0.00		$0.01	$0.01	$0.00	$0.02	$0.01	$0.01	$0.02
167	b0286						$1.40						
168	b0287	$0.22	$0.30	$1.43	$0.02		$0.48	$0.22	$0.05	$0.66	$0.22	$0.50	$0.55
169	b0288			$5.68								$21.27	
170	b0289.1						$2.36						
171	b0290	$0.37	$0.52	$2.45	$0.04		$0.82	$0.38	$0.09	$1.13	$0.38	$0.85	$0.95
172	b0291		$0.85										
173	b0292						$0.10						
174	b0293.1												$0.23
175	b0295		$0.30										
176	b0296		$1.70										
177	b0298			$6.35				$2.60				$4.33	
178	b0298.1												
179	b0299												
180	b0301												
181	b0302												
182	b0303												

	A	W	X	Y
8	Upgrade ID	PSEG	RE	UGI
92	b0223			
93	b0224			
94	b0225			
95	b0226			
96	b0227			
97	b0227.1			
98	b0228			
99	b0229			
100	b0230			
101	b0231	$0.38	$0.02	
102	b0231.2			
103	b0232			
104	b0233			
105	b0234			
106	b0235			
107	b0236.1			
108	b0236.2			
109	b0238			
110	b0238.1			
111	b0240			
112	b0241.2			
113	b0241.3			
114	b0244			
115	b0245			
116	b0246			
117	b0251			
118	b0252			
119	b0253			
120	b0254			
121	b0255			
122	b0256.1			
123	b0256.2			
124	b0257.1			
125	b0257.2			
126	b0258			
127	b0261			
128	b0262			
129	b0263			
130	b0264			
131	b0265			
132	b0266			
133	b0267			
134	b0268	$2.29	$0.10	
135	b0269	$2.31	$0.09	
136	b0269			
137	b0269.6	$0.19	$0.01	
138	b0269.7			
139	b0274	$14.52		
140	b0275	$5.00		
141	b0276	$0.57	$0.02	
142	b0276.1			
143	b0277			
144	b0278	$6.00		
145	b0279.1			
146	b0279.10			
147	b0279.11			
148	b0279.2			
149	b0279.4			
150	b0279.5			
151	b0279.6			
152	b0279.7			
153	b0279.9			
154	b0280.1			
155	b0280.2			
156	b0280.3			
157	b0280.4			
158	b0281.1			
159	b0281.2			
160	b0281.3			
161	b0282			
162	b0284.1	$1.91	$0.08	
163	b0284.2	$0.02	$0.00	
164	b0284.3	$0.02	$0.00	
165	b0285.1	$0.02	$0.00	
166	b0285.2	$0.02	$0.00	
167	b0286			
168	b0287	$0.80	$0.03	
169	b0288			
170	b0289.1			
171	b0290	$1.38	$0.06	
172	b0291			
173	b0292			
174	b0293.1			
175	b0295			
176	b0296			
177	b0298			
178	b0298.1			
179	b0299			
180	b0301			
181	b0302			
182	b0303			

	A	B	C	D	E	F	G	H	I	J
8	Upgrade ID	Description	TO	Cost Estimate	AEC	AEP	APS	BGE	ComEd	Dayton
183	b0305	Normally open East Frankfort 138 kV red-blue bus tie	ComEd							
184	b0306	Reconductor line Electric Junction – North Aurora (1110	ComEd	$1.00					$1.00	
185	b0307	Reconductor Endless Caverns – Mt. Jackson 115 kV	Dominion	$4.60						
186	b0308	Replace L breaker and switches at Endless Caverns 11	Dominion	$0.60						
187	b0309	Install SPS at Earleys 115 kV	Dominion	$1.00						
188	b0310	Reconductor Club House – South Hill and Chase City –	Dominion	$20.30						
189	b0311	Reconductor Idylwood to Arlington 230 kV	Dominion	$3.10						
190	b0312	Reconductor Gallows to Ox 230 kV	Dominion	$5.40						
191	b0314	Install 35 MVAR capacitor at Closter 69 kV substation	RECO	$0.38						
192	b0318	Install a 765/138 kV transformer at Amos	AEP	$13.44		$13.31				
193	b0319	Add a second 1000 MVA Bruches Hill 500/230 kV trans	PEPCO	$36.70						
194	b0320	Create a new 230 kV station that splits the 2nd Milford t	DPL	$15.00						
195	b0322	Convert Lime Kiln substation to 230 kV operation	APS	$4.20			$4.20			
196	b0323	Replace the North Shenandoah 138/115 kV transformer	APS	$2.00			$2.00			
197	b0325	Install a 2nd Everetts 230/115 kV transformer	Dominion	$5.60						
198	b0326	Uprate/resag Remington-Brandywine-Culppr 115 kV	Dominion	$12.80						
199	b0327	Build 2nd Harrisonburg – Valley 230 kV	Dominion	$6.00			$1.19			
200	b0328.1	Build new Meadow Brook – Loudoun 500 kV circuit (30	Dominion	$243.00	$5.08	$40.61	$14.65	$11.96	$37.86	$5.86
201	b0328.2	Build new Meadow Brook – Loudoun 500 kV circuit (20	APS	$119.00	$2.49	$19.88	$7.18	$5.85	$18.54	$2.87
202	b0328.3	Upgrade Mt. Storm 500 kV substation	Dominion	$10.00	$0.21	$1.67	$0.60	$0.49	$1.56	$0.24
203	b0328.4	Upgrade Loudoun 500 kV substation	Dominion	$10.00	$0.21	$1.67	$0.60	$0.49	$1.56	$0.24
204	b0329	Build Carson – Suffolk 500 kV, install 2nd Suffolk 500/2	Dominion	$173.49	$3.63	$28.99	$10.46	$8.54	$27.03	$4.18
205	b0329	Build Carson – Suffolk 500 kV, install 2nd Suffolk 500/2	Dominion	$49.73						
206	b0329.1	Replace Thole Street 115 kV breaker ‘48T196’	Dominion	$0.16						
207	b0329.2	Replace Chesapeake 115 kV breaker ‘T242’	Dominion	$0.18						
208	b0329.3	Replace Chesapeake 115 kV breaker ‘8722’	Dominion	$0.18						
209	b0329.4	Replace Chesapeake 115 kV breaker ‘16422’	Dominion	$0.18						
210	b0331	Upgrade/resag Shell Bank – Whealton 115 kV (Line 165	Dominion	$11.00						
211	b0332	Uprate/resag Chesapeake – Cradock 115 kV	Dominion	$0.70						
212	b0333	Replace wave trap on Elmont – Replace (Line #231)	Dominion	$0.01						
213	b0334	Uprate/resag Iron Bridge-Walmsley-Southwest 230 kV	Dominion	$0.70						
214	b0335	Build Chase City – Clarksville 115 kV	Dominion	$15.00						
215	b0336	Reconductor one span of Chesapeake – Dozier 115 kV	Dominion	$0.05						
216	b0337	Build Lexington 230 kV ring bus	Dominion	$6.50						
217	b0338	Replace Gordonsville 230/115 kV transformer for larger	Dominion	$3.30						
218	b0339	Install Breaker at Dooms 230 kV Sub	Dominion	$2.50						
219	b0340	Reconductor one span Peninsula – Magruder 115 kV cl	Dominion	$0.05						
220	b0341	Install a breaker at Northern Neck 115 kV	Dominion	$0.50						
221	b0342	Replace Trowbridge 230/115 kV transformer	Dominion	$3.30						
222	b0343	Replace Doubs 500/230 kV transformer #2	APS	$5.20	$0.10			$1.12		
223	b0344	Replace Doubs 500/230 kV transformer #3	APS	$0.35	$0.01			$0.08		
224	b0345	Replace Doubs 500/230 kV transformer #4	APS	$5.30	$0.10			$1.14		
225	b0347.1	Build new Mt. Storm – 502 Junction 500 kV circuit	APS	$310.00	$6.48	$51.80	$18.69	$15.25	$48.30	$7.47
226	b0347.10	Upgrade (per ABB Inspection) Hatfield 500 kV breakers	APS	$0.06	$0.00	$0.01	$0.00	$0.00	$0.01	$0.00
227	b0347.11	Upgrade (per ABB Inspection) Hatfield 500 kV breakers	APS	$0.06	$0.00	$0.01	$0.00	$0.00	$0.01	$0.00
228	b0347.12	Upgrade (per ABB Inspection) Hatfield 500 kV breakers	APS	$0.06	$0.00	$0.01	$0.00	$0.00	$0.01	$0.00
229	b0347.13	Upgrade (per ABB Inspection) Hatfield 500 kV breakers	APS	$0.06	$0.00	$0.01	$0.00	$0.00	$0.01	$0.00
230	b0347.14	Upgrade (per ABB Inspection) Hatfield 500 kV breakers	APS	$0.06	$0.00	$0.01	$0.00	$0.00	$0.01	$0.00
231	b0347.15	Upgrade (per ABB Inspection) Hatfield 500 kV breakers	APS	$0.06	$0.00	$0.01	$0.00	$0.00	$0.01	$0.00
232	b0347.16	Upgrade (per ABB inspection) Harrison 500 kV breaker	APS	$0.06	$0.00	$0.01	$0.00	$0.00	$0.01	$0.00
233	b0347.17	Replace Meadow Brook 138 kV breaker ‘MD-10’	APS	$0.19	$0.00	$0.03	$0.01	$0.01	$0.03	$0.00
234	b0347.18	Replace Meadow Brook 138 kV breaker ‘MD-11’	APS	$0.19	$0.00	$0.03	$0.01	$0.01	$0.03	$0.00
235	b0347.19	Replace Meadow Brook 138 kV breaker ‘MD-12’	APS	$0.19	$0.00	$0.03	$0.01	$0.01	$0.03	$0.00
236	b0347.2	Build new Mt. Storm – Meadow Brook 500 kV circuit	APS	$308.00	$6.44	$51.47	$18.57	$15.15	$47.99	$7.42
237	b0347.20	Replace Meadow Brook 138 kV breaker ‘MD-13’	APS	$0.19	$0.00	$0.03	$0.01	$0.01	$0.03	$0.00
238	b0347.21	Replace Meadow Brook 138 kV breaker ‘MD-14’	APS	$0.19	$0.00	$0.03	$0.01	$0.01	$0.03	$0.00
239	b0347.22	Replace Meadow Brook 138 kV breaker ‘MD-15’	APS	$0.19	$0.00	$0.03	$0.01	$0.01	$0.03	$0.00
240	b0347.23	Replace Meadow Brook 138 kV breaker ‘MD-16’	APS	$0.19	$0.00	$0.03	$0.01	$0.01	$0.03	$0.00
241	b0347.24	Replace Meadow Brook 138 kV breaker ‘MD-17’	APS	$0.19	$0.00	$0.03	$0.01	$0.01	$0.03	$0.00
242	b0347.25	Replace Meadow Brook 138 kV breaker ‘MD-18’	APS	$0.19	$0.00	$0.03	$0.01	$0.01	$0.03	$0.00
243	b0347.26	Replace Meadow Brook 138 kV breaker ‘MD-22#1 CAP	APS	$0.19	$0.00	$0.03	$0.01	$0.01	$0.03	$0.00
244	b0347.27	Replace Meadow Brook 138 kV breaker ‘MD-4’	APS	$0.19	$0.00	$0.03	$0.01	$0.01	$0.03	$0.00
245	b0347.28	Replace Meadow Brook 138 kV breaker ‘MD-5’	APS	$0.19	$0.00	$0.03	$0.01	$0.01	$0.03	$0.00
246	b0347.29	Replace Meadowbrook 138 kV breaker ‘MD-6’	APS	$0.19	$0.00	$0.03	$0.01	$0.01	$0.03	$0.00
247	b0347.3	Build new 502 Junction 500 kV substation	APS	$88.00	$1.84	$14.70	$5.31	$4.33	$13.71	$2.12
248	b0347.30	Replace Meadowbrook 138 kV breaker ‘MD-7’	APS	$0.19	$0.00	$0.03	$0.01	$0.01	$0.03	$0.00
249	b0347.31	Replace Meadowbrook 138 kV breaker ‘MD-8’	APS	$0.19	$0.00	$0.03	$0.01	$0.01	$0.03	$0.00
250	b0347.32	Replace Meadowbrook 138 kV breaker ‘MD-9’	APS	$0.19	$0.00	$0.03	$0.01	$0.01	$0.03	$0.00
251	b0347.4	Upgrade Meadow Brook 500 kV substation	APS	$25.00	$0.52	$4.18	$1.51	$1.23	$3.90	$0.60
252	b0347.5	Replace Harrison 500 kV breaker HL-3	APS	$0.70	$0.01	$0.12	$0.04	$0.03	$0.11	$0.02
253	b0347.6	Upgrade (per ABB inspection) breaker HL-6	APS	$0.06	$0.00	$0.01	$0.00	$0.00	$0.01	$0.00
254	b0347.7	Upgrade (per ABB inspection) breaker HL-7	APS	$0.06	$0.00	$0.01	$0.00	$0.00	$0.01	$0.00
255	b0347.8	Upgrade (per ABB inspection) breaker HL-8	APS	$0.06	$0.00	$0.01	$0.00	$0.00	$0.01	$0.00
256	b0347.9	Upgrade (per ABB inspection) breaker HL-10	APS	$0.06	$0.00	$0.01	$0.00	$0.00	$0.01	$0.00
257	b0348	Upgrade Stonewall – Inwood 138 kV with 954 ACSR co	APS	$1.60			$1.60			
258	b0350	Implement Operating Procedure of closing the Glendon	JCPL	$0.40						
259	b0351	Reconductor Tunnel – Grays Ferry 230 kV	PECO	$0.75						
260	b0352	Reconductor Tunnel – Parrish 230 kV	PECO	$0.15						
261	b0353.1	Install 2% reactors on both lines from Eddystone – Llan	PECO	$2.10						
262	b0353.2	Install identical second 230/138 kV transformer in parall	PECO	$8.54						
263	b0353.3	Replace Whitpain 230 kV breaker 135	PECO	$0.50						
264	b0353.4	Replace Whitpain 230 kV breaker 145	PECO	$0.50						
265	b0354	Eddystone – Island Road Upgrade line terminal equipm	PECO	$1.10						
266	b0355	Reconductor Master – North Philadelphia 230 kV line	PECO	$4.20						
267	b0356	Replace wave trap on the Portland – Greystone 230 kV	JCPL/ME	$0.08						
268	b0357	Reconductor Buckingham – Pleasant Valley 230 kV	PECO	$6.20						
269	b0358	Reconductor the PSEG portion of Buckingham – Pleasa	PSEG	$3.00						
270	b0361	Change tap of limiting CT at Morristown 230 kV	JCPL	$0.03						
271	b0362	Change tap setting of limiting CT at Pohatcong 230 kV	JCPL	$0.03						
272	b0363	Change tap setting of limiting CT at Windsor 230 kV	JCPL	$0.03						
273	b0364	Change tap setting of CT at Cookstown 230 kV	JCPL	$0.03						

	A	K	L	M	N	O	P	Q	R	S	T	U	V
8	Upgrade ID	DL	DPL	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL
183	b0305												
184	b0306												
185	b0307			$4.60									
186	b0308			$0.60									
187	b0309			$1.00									
188	b0310			$20.30									
189	b0311			$3.10									
190	b0312			$5.40									
191	b0314												
192	b0318											$0.13	
193	b0319											$36.70	
194	b0320		$15.00										
195	b0322												
196	b0323												
197	b0325			$5.60									
198	b0326			$12.80									
199	b0327			$4.57								$0.24	
200	b0328.1	$4.98	$7.00	$33.07	$0.53		$11.08	$5.08	$1.19	$15.31	$5.13	$11.49	$12.81
201	b0328.2	$2.44	$3.43	$16.20	$0.26		$5.43	$2.49	$0.58	$7.50	$2.51	$5.63	$6.27
202	b0328.3	$0.21	$0.29	$1.36	$0.02		$0.46	$0.21	$0.05	$0.63	$0.21	$0.47	$0.53
203	b0328.4	$0.21	$0.29	$1.36	$0.02		$0.46	$0.21	$0.05	$0.63	$0.21	$0.47	$0.53
204	b0329	$3.56	$5.00	$23.61	$0.38		$7.91	$3.63	$0.85	$10.93	$3.66	$8.21	$9.14
205	b0329			$49.73									
206	b0329.1			$0.16									
207	b0329.2			$0.18									
208	b0329.3			$0.18									
209	b0329.4			$0.18									
210	b0331			$11.00									
211	b0332			$0.70									
212	b0333			$0.01									
213	b0334			$0.70									
214	b0335			$15.00									
215	b0336			$0.05									
216	b0337			$6.50									
217	b0338			$3.30									
218	b0339			$2.50									
219	b0340			$0.05									
220	b0341			$0.50									
221	b0342			$3.30									
222	b0343		$0.20	$1.50				$0.15		$0.30		$1.83	
223	b0344		$0.01	$0.10				$0.01		$0.02		$0.12	
224	b0345		$0.21	$1.53				$0.16		$0.30		$1.87	
225	b0347.1	$6.36	$8.93	$42.19	$0.68		$14.14	$6.48	$1.52	$19.53	$6.54	$14.66	$16.34
226	b0347.10	$0.00	$0.00	$0.01	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
227	b0347.11	$0.00	$0.00	$0.01	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
228	b0347.12	$0.00	$0.00	$0.01	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
229	b0347.13	$0.00	$0.00	$0.01	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
230	b0347.14	$0.00	$0.00	$0.01	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
231	b0347.15	$0.00	$0.00	$0.01	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
232	b0347.16	$0.00	$0.00	$0.01	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
233	b0347.17	$0.00	$0.01	$0.03	$0.00		$0.01	$0.00	$0.00	$0.01	$0.00	$0.01	$0.01
234	b0347.18	$0.00	$0.01	$0.03	$0.00		$0.01	$0.00	$0.00	$0.01	$0.00	$0.01	$0.01
235	b0347.19	$0.00	$0.01	$0.03	$0.00		$0.01	$0.00	$0.00	$0.01	$0.00	$0.01	$0.01
236	b0347.2	$6.31	$8.87	$41.92	$0.68		$14.04	$6.44	$1.51	$19.40	$6.50	$14.57	$16.23
237	b0347.20	$0.00	$0.01	$0.03	$0.00		$0.01	$0.00	$0.00	$0.01	$0.00	$0.01	$0.01
238	b0347.21	$0.00	$0.01	$0.03	$0.00		$0.01	$0.00	$0.00	$0.01	$0.00	$0.01	$0.01
239	b0347.22	$0.00	$0.01	$0.03	$0.00		$0.01	$0.00	$0.00	$0.01	$0.00	$0.01	$0.01
240	b0347.23	$0.00	$0.01	$0.03	$0.00		$0.01	$0.00	$0.00	$0.01	$0.00	$0.01	$0.01
241	b0347.24	$0.00	$0.01	$0.03	$0.00		$0.01	$0.00	$0.00	$0.01	$0.00	$0.01	$0.01
242	b0347.25	$0.00	$0.01	$0.03	$0.00		$0.01	$0.00	$0.00	$0.01	$0.00	$0.01	$0.01
243	b0347.26	$0.00	$0.01	$0.03	$0.00		$0.01	$0.00	$0.00	$0.01	$0.00	$0.01	$0.01
244	b0347.27	$0.00	$0.01	$0.03	$0.00		$0.01	$0.00	$0.00	$0.01	$0.00	$0.01	$0.01
245	b0347.28	$0.00	$0.01	$0.03	$0.00		$0.01	$0.00	$0.00	$0.01	$0.00	$0.01	$0.01
246	b0347.29	$0.00	$0.01	$0.03	$0.00		$0.01	$0.00	$0.00	$0.01	$0.00	$0.01	$0.01
247	b0347.3	$1.80	$2.53	$11.98	$0.19		$4.01	$1.84	$0.43	$5.54	$1.86	$4.16	$4.64
248	b0347.30	$0.00	$0.01	$0.03	$0.00		$0.01	$0.00	$0.00	$0.01	$0.00	$0.01	$0.01
249	b0347.31	$0.00	$0.01	$0.03	$0.00		$0.01	$0.00	$0.00	$0.01	$0.00	$0.01	$0.01
250	b0347.32	$0.00	$0.01	$0.03	$0.00		$0.01	$0.00	$0.00	$0.01	$0.00	$0.01	$0.01
251	b0347.4	$0.51	$0.72	$3.40	$0.06		$1.14	$0.52	$0.12	$1.58	$0.53	$1.18	$1.32
252	b0347.5	$0.01	$0.02	$0.10	$0.00		$0.03	$0.01	$0.00	$0.04	$0.01	$0.03	$0.04
253	b0347.6	$0.00	$0.00	$0.01	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
254	b0347.7	$0.00	$0.00	$0.01	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
255	b0347.8	$0.00	$0.00	$0.01	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
256	b0347.9	$0.00	$0.00	$0.01	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
257	b0348												
258	b0350						$0.40						
259	b0351									$0.75			
260	b0352									$0.15			
261	b0353.1									$2.10			
262	b0353.2									$8.54			
263	b0353.3									$0.50			
264	b0353.4									$0.50			
265	b0354									$1.10			
266	b0355									$4.20			
267	b0356						$0.08						
268	b0357				$0.12		$2.30		$0.28				
269	b0358												
270	b0361						$0.03						
271	b0362						$0.03						
272	b0363						$0.03						
273	b0364						$0.03						

	A	W	X	Y
8	Upgrade ID	PSEG	RE	UGI
183	b0305			
184	b0306			
185	b0307			
186	b0308			
187	b0309			
188	b0310			
189	b0311			
190	b0312			
191	b0314		$0.38	
192	b0318			
193	b0319			
194	b0320			
195	b0322			
196	b0323			
197	b0325			
198	b0326			
199	b0327			
200	b0328.1	$18.59	$0.75	
201	b0328.2	$9.10	$0.37	
202	b0328.3	$0.77	$0.03	
203	b0328.4	$0.77	$0.03	
204	b0329	$13.27	$0.54	
205	b0329			
206	b0329.1			
207	b0329.2			
208	b0329.3			
209	b0329.4			
210	b0331			
211	b0332			
212	b0333			
213	b0334			
214	b0335			
215	b0336			
216	b0337			
217	b0338			
218	b0339			
219	b0340			
220	b0341			
221	b0342			
222	b0343			
223	b0344			
224	b0345			
225	b0347.1	$23.72	$0.96	
226	b0347.10	$0.00	$0.00	
227	b0347.11	$0.00	$0.00	
228	b0347.12	$0.00	$0.00	
229	b0347.13	$0.00	$0.00	
230	b0347.14	$0.00	$0.00	
231	b0347.15	$0.00	$0.00	
232	b0347.16	$0.00	$0.00	
233	b0347.17	$0.01	$0.00	
234	b0347.18	$0.01	$0.00	
235	b0347.19	$0.01	$0.00	
236	b0347.2	$23.56	$0.95	
237	b0347.20	$0.01	$0.00	
238	b0347.21	$0.01	$0.00	
239	b0347.22	$0.01	$0.00	
240	b0347.23	$0.01	$0.00	
241	b0347.24	$0.01	$0.00	
242	b0347.25	$0.01	$0.00	
243	b0347.26	$0.01	$0.00	
244	b0347.27	$0.01	$0.00	
245	b0347.28	$0.01	$0.00	
246	b0347.29	$0.01	$0.00	
247	b0347.3	$6.73	$0.27	
248	b0347.30	$0.01	$0.00	
249	b0347.31	$0.01	$0.00	
250	b0347.32	$0.01	$0.00	
251	b0347.4	$1.91	$0.08	
252	b0347.5	$0.05	$0.00	
253	b0347.6	$0.00	$0.00	
254	b0347.7	$0.00	$0.00	
255	b0347.8	$0.00	$0.00	
256	b0347.9	$0.00	$0.00	
257	b0348			
258	b0350			
259	b0351			
260	b0352			
261	b0353.1			
262	b0353.2			
263	b0353.3			
264	b0353.4			
265	b0354			
266	b0355			
267	b0356			
268	b0357	$3.36	$0.14	
269	b0358	$3.00		
270	b0361			
271	b0362			
272	b0363			
273	b0364			

	A	B	C	D	E	F	G	H	I	J
8	Upgrade ID	Description	TO	Cost Estimate	AEC	AEP	APS	BGE	ComEd	Dayton
274	b0366	Install a 4th Ritchie 230/69 kV transformer	PEPCO	$13.10						
275	b0367.1	Reconductor circuit “23035” for Dickerson – Quince Orc	PEPCO	$10.00	$0.18			$2.65		
276	b0367.2	Reconductor circuit “23033” for Dickerson – Quince Orc	PEPCO	$10.00	$0.18			$2.65		
277	b0369	Install 100 MVAR Dynamic Reactive Device at Airydale	PENELEC	$12.00	$0.25	$2.01	$0.72	$0.59	$1.87	$0.29
278	b0370	Install 500 MVAR Dynamic Reactive Device at Airydale	PENELEC	$32.00	$0.67	$5.35	$1.93	$1.57	$4.99	$0.77
279	b0371	Make the Metuchen 138 kV bus solid and upgrade 6 bre	PSEG	$2.25						
280	b0372	Make the Athenia 138 kV bus solid and upgrade 2 breal	PSEG	$0.75						
281	b0373	Convert Doubs – Monocacy 138 kV facilities to 230 kV (	APS	$9.40	$0.17		$7.22			
282	b0376	Install 300 MVAR capacitor at Conemaugh 500 kV subs	PENELEC	$2.00	$0.04	$0.33	$0.12	$0.10	$0.31	$0.05
283	b0380	Reconductor 17713 from Burnham – Wildwood and 761	ComEd	$7.00					$7.00	
284	b0382	Cambridge Sub – Close through to Todd Substation	DPL	$1.49						
285	b0383	Wye Mills AT-1 and AT-2 138/69 kV Replacements	DPL	$2.29						
286	b0384	Replace Indian River AT-20 (400 MVA)	DPL	$3.74						
287	b0385	Oak Hall to New Church (13765) Upgrade	DPL	$0.87						
288	b0386	Cheswold/Kent (6768) Rebuild	DPL	$1.56						
289	b0387	N. Seaford – Add a 2nd 138/69 kV autotransformer	DPL	$3.12						
290	b0388	Hallwood/Parksley (6790-2) Upgrade	DPL	$0.47						
291	b0389	Indian River AT-1 and AT-2 138/69 kV Replacements	DPL	$7.80						
292	b0390	Rehoboth/Lewes (6751-1 and 6751-2) Upgrade	DPL	$1.54						
293	b0392	East New Market Sub – Establish a 69 kV Bus Arranger	DPL	$2.16						
294	b0393	Replace terminal equipment at Harrison 500 kV and Bel	APS	$0.09	$0.00	$0.02	$0.01	$0.00	$0.01	$0.00
295	b0394	Reconductor 2.8 miles of Wolfs – Frontenac 138 kV line	ComEd	$3.00					$3.00	
296	b0401.1	Replace Roseland 230 kV breaker BS6-7	PSEG	$0.38						
297	b0401.2	Replace Roseland 138 kV breaker O-1315	PSEG	$0.38						
298	b0401.3	Replace Roseland 138 kV breaker S-1319	PSEG	$0.38						
299	b0401.4	Replace Roseland 138 kV breaker T-1320	PSEG	$0.38						
300	b0401.5	Replace Roseland 138 kV breaker G-1307	PSEG	$0.38						
301	b0401.6	Replace Roseland 138 kV breaker P-1316	PSEG	$0.38						
302	b0401.7	Replace Roseland 138 kV breaker 220-4	PSEG	$0.38						
303	b0401.8	Replace W. Orange 138 kV breaker 132-4	PSEG	$0.38						
304	b0403	2nd Dooms 500/230 kV transformer addition	Dominion	$8.00			$0.27	$0.34		
305	b0404.1	Replace South Reading 230 kV breaker 107252	ME	$0.23						
306	b0404.2	Replace South Reading 230 kV breaker 100652	ME	$0.23						
307	b0406.1	Replace Mitchell 138 kV breaker “#4 bank”	APS	$0.12			$0.12			
308	b0406.2	Replace Mitchell 138 kV breaker “#5 bank”	APS	$0.12			$0.12			
309	b0406.3	Replace Mitchell 138 kV breaker “#2 transf”	APS	$0.12			$0.12			
310	b0406.4	Replace Mitchell 138 kV breaker “#3 bank”	APS	$0.12			$0.12			
311	b0406.5	Replace Mitchell 138 kV breaker “Charlerio #2”	APS	$0.12			$0.12			
312	b0406.6	Replace Mitchell 138 kV breaker “Charlerio #1”	APS	$0.12			$0.12			
313	b0406.7	Replace Mitchell 138 kV breaker “Shepler Hill Jct”	APS	$0.12			$0.12			
314	b0406.8	Replace Mitchell 138 kV breaker “Union Jct”	APS	$0.12			$0.12			
315	b0406.9	Replace Mitchell 138 kV breaker “#1-2 138 kV bus tie”	APS	$0.12			$0.12			
316	b0407.1	Replace Marlowe 138 kV breaker “#1 transf”	APS	$0.12			$0.12			
317	b0407.2	Replace Marlowe 138 kV breaker “MBO”	APS	$0.12			$0.12			
318	b0407.3	Replace Marlowe 138 kV breaker “BMA”	APS	$0.12			$0.12			
319	b0407.4	Replace Marlowe 138 kV breaker “BMR”	APS	$0.12			$0.12			
320	b0407.5	Replace Marlowe 138 kV breaker “WC-1”	APS	$0.12			$0.12			
321	b0407.6	Replace Marlowe 138 kV breaker “R11”	APS	$0.12			$0.12			
322	b0407.7	Replace Marlowe 138 kV breaker “W”	APS	$0.12			$0.12			
323	b0407.8	Replace Marlowe 138 kV breaker “138 kV bus tie”	APS	$0.12			$0.12			
324	b0408.1	Replace Trissler 138 kV breaker “Belmont 604”	APS	$0.12			$0.12			
325	b0408.2	Replace Trissler 138 kV breaker “Edgelawn 90”	APS	$0.12			$0.12			
326	b0409.1	Replace Weirton 138 kV breaker “Wylie Ridge 210”	APS	$0.12			$0.12			
327	b0409.2	Replace Weirton 138 kV breaker “Wylie Ridge 216”	APS	$0.12			$0.12			
328	b0410	Replace Glen Falls 138 kV breaker “McAlpin 30”	APS	$0.12			$0.12			
329	b0411	Install 4th 500/230 kV transformer at New Freedom	PSEG	$25.24	$11.87					
330	b0412	Retension Pruntytown – Mt. Storm 500 kV to a 3502 MV	Dominion							
331	b0415	Increase the temperature ratings of the Edgemoor – Chi	DPL							
332	b0417	Reconductor Mitchell – Shepler Hill Junction 138kV with	APS	$3.00			$3.00			
333	b0419	Install a breaker failure auto-restoration scheme at Bedi	APS							
334	b0420	Operating Procedure to open the Black Oak 500/138 kV	APS							
335	b0423	Reconductor Readington (2555) – Branchburg (4962) 2:	PSEG	$7.00						
336	b0423.1	Upgrade terminal equipment at Readington (substation	JCPL	$0.10						
337	b0424	Replace Readington wavetrap on Readington (2555) – I	PSEG	$0.16						
338	b0425	Reconductor Linden (4996) – Tosco (5190) 230 kV circu	PSEG	$2.18						
339	b0426	Reconductor Tosco (5190) – G22_MTX5 (90220) 230 k	PSEG	$0.61						
340	b0427	Reconductor Athenia (4954) – Saddle Brook (5020) 230	PSEG	$1.50						
341	b0428	Replace Roseland wavetrap on Roseland (5019) – Wes	PSEG	$0.05						
342	b0431	Monroe Upgrade New Freedom strand bus	AEC	$0.10	$0.10					
343	b0437	Spare Keeney 500/230 kV transformer	DPL	$2.50						
344	b0438	Spare Whitpain 500/230 kV transformer	PECO	$2.50						
345	b0439	Spare Deans 500/230 kV transformer	PSEG	$2.50						
346	b0440	Spare Juniata 500/230 kV transformer	PPL	$7.56						
347	b0441	Additional spare Keeney 500/230 kV transformer	DPL	$2.50						
348	b0442	Spare Keystone 500/230 kV transformer	PENELEC	$2.50						
349	b0443	Spare Peach Bottom 500/230 kV transformer	PECO	$2.50						
350	b0445	Upgrade substation equipment and reconductor the Tid	APS	$0.03			$0.03			
351	b0446.1	Upgrade Bayway 138 kV breaker #2-3	PSEG	$0.30						
352	b0446.2	Upgrade Bayway 138 kV breaker #3-4	PSEG	$0.30						
353	b0446.3	Upgrade Bayway 138 kV breaker #6-7	PSEG	$0.30						
354	b0446.4	Upgrade the breaker associated with TX 132-5 on Linde	PSEG	$0.30						
355	b0447	Replace Cook 345 kV breaker M2	AEP	$0.80		$0.80				
356	b0448	Replace Cook 345 kV breaker N2	AEP	$0.80		$0.80				
357	b0450	Install 150 MVAR Capacitor at Fredricksburg 230 kV	Dominion	$1.20						
358	b0451	Install 25 MVAR Capacitor at Somerset 115 kV	Dominion	$0.80						
359	b0453.1	Convert Remington – Sowego 115 kV to 230 kV	Dominion	$8.10			$0.03	$0.24		
360	b0453.2	Add Sowego – Gainsville 230 kV	Dominion	$22.00			$0.07	$0.66		
361	b0453.3	Add Sowego 230/115 kV transformer	Dominion	$5.00			$0.02	$0.15		
362	b0454	Reconductor 2.4 miles of Newport News – Chuckatuck :	Dominion	$1.17						
363	b0455	Add 2nd Endless Caverns 230/115 kV transformer	Dominion	$6.00			$1.96	$0.42		
364	b0456	Reconductor 9.4 miles of Edinburg – Mt. Jackson 115 k	Dominion	$7.00			$2.36	$0.85		

	A	K	L	M	N	O	P	Q	R	S	T	U	V
8	Upgrade ID	DL	DPL	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL
274	b0366											$13.10	
275	b0367.1		$0.33		$0.01		$0.27	$0.12	$0.03	$0.48		$5.25	$0.32
276	b0367.2		$0.33		$0.01		$0.27	$0.12	$0.03	$0.48		$5.25	$0.32
277	b0369	$0.25	$0.35	$1.63	$0.03		$0.55	$0.25	$0.06	$0.76	$0.25	$0.57	$0.63
278	b0370	$0.66	$0.92	$4.36	$0.07		$1.46	$0.67	$0.16	$2.02	$0.68	$1.51	$1.69
279	b0371												
280	b0372												
281	b0373		$0.25				$0.43	$0.86	$0.04				$0.43
282	b0376	$0.04	$0.06	$0.27	$0.00		$0.09	$0.04	$0.01	$0.13	$0.04	$0.09	$0.11
283	b0380												
284	b0382		$1.49										
285	b0383		$2.29										
286	b0384		$3.74										
287	b0385		$0.87										
288	b0386		$1.56										
289	b0387		$3.12										
290	b0388		$0.47										
291	b0389		$7.80										
292	b0390		$1.54										
293	b0392		$2.16										
294	b0393	$0.00	$0.00	$0.01	$0.00		$0.00	$0.00	$0.00	$0.01	$0.00	$0.00	$0.00
295	b0394												
296	b0401.1												
297	b0401.2												
298	b0401.3												
299	b0401.4												
300	b0401.5												
301	b0401.6												
302	b0401.7												
303	b0401.8												
304	b0403		$0.09	$6.72								$0.59	
305	b0404.1							$0.23					
306	b0404.2							$0.23					
307	b0406.1												
308	b0406.2												
309	b0406.3												
310	b0406.4												
311	b0406.5												
312	b0406.6												
313	b0406.7												
314	b0406.8												
315	b0406.9												
316	b0407.1												
317	b0407.2												
318	b0407.3												
319	b0407.4												
320	b0407.5												
321	b0407.6												
322	b0407.7												
323	b0407.8												
324	b0408.1												
325	b0408.2												
326	b0409.1												
327	b0409.2												
328	b0410												
329	b0411						$1.78		$0.07	$5.90			
330	b0412												
331	b0415												
332	b0417												
333	b0419												
334	b0420												
335	b0423												
336	b0423.1						$0.10						
337	b0424												
338	b0425												
339	b0426												
340	b0427												
341	b0428												
342	b0431												
343	b0437		$2.50										
344	b0438									$2.50			
345	b0439												
346	b0440												$7.56
347	b0441		$2.50										
348	b0442										$2.50		
349	b0443									$2.50			
350	b0445												
351	b0446.1												
352	b0446.2												
353	b0446.3												
354	b0446.4												
355	b0447												
356	b0448												
357	b0450			$1.20									
358	b0451			$0.80									
359	b0453.1		$0.00	$7.51				$0.00				$0.31	
360	b0453.2		$0.01	$20.41				$0.01				$0.85	
361	b0453.3		$0.00	$4.64				$0.00				$0.19	
362	b0454			$1.17									
363	b0455		$0.11	$3.05								$0.46	
364	b0456			$2.81								$0.98	

	A	W	X	Y
8	Upgrade ID	PSEG	RE	UGI
274	b0366			
275	b0367.1	$0.38		
276	b0367.2	$0.38		
277	b0369	$0.92	$0.04	
278	b0370	$2.45	$0.10	
279	b0371	$2.25		
280	b0372	$0.75		
281	b0373			
282	b0376	$0.15	$0.01	
283	b0380			
284	b0382			
285	b0383			
286	b0384			
287	b0385			
288	b0386			
289	b0387			
290	b0388			
291	b0389			
292	b0390			
293	b0392			
294	b0393	$0.01	$0.00	
295	b0394			
296	b0401.1	$0.38		
297	b0401.2	$0.38		
298	b0401.3	$0.38		
299	b0401.4	$0.38		
300	b0401.5	$0.38		
301	b0401.6	$0.38		
302	b0401.7	$0.38		
303	b0401.8	$0.38		
304	b0403			
305	b0404.1			
306	b0404.2			
307	b0406.1			
308	b0406.2			
309	b0406.3			
310	b0406.4			
311	b0406.5			
312	b0406.6			
313	b0406.7			
314	b0406.8			
315	b0406.9			
316	b0407.1			
317	b0407.2			
318	b0407.3			
319	b0407.4			
320	b0407.5			
321	b0407.6			
322	b0407.7			
323	b0407.8			
324	b0408.1			
325	b0408.2			
326	b0409.1			
327	b0409.2			
328	b0410			
329	b0411	$5.63		
330	b0412			
331	b0415			
332	b0417			
333	b0419			
334	b0420			
335	b0423	$7.00		
336	b0423.1			
337	b0424	$0.16		
338	b0425	$2.18		
339	b0426	$0.61		
340	b0427	$1.50		
341	b0428	$0.05		
342	b0431			
343	b0437			
344	b0438			
345	b0439	$2.50		
346	b0440			
347	b0441			
348	b0442			
349	b0443			
350	b0445			
351	b0446.1	$0.30		
352	b0446.2	$0.30		
353	b0446.3	$0.30		
354	b0446.4	$0.30		
355	b0447			
356	b0448			
357	b0450			
358	b0451			
359	b0453.1			
360	b0453.2			
361	b0453.3			
362	b0454			
363	b0455			
364	b0456			

	A	B	C	D	E	F	G	H	I	J
8	Upgrade ID	Description	TO	Cost Estimate	AEC	AEP	APS	BGE	ComEd	Dayton
365	b0457	Replace both wave traps on Dooms – Lexington 500 kV	Dominion	$0.50	$0.01	$0.08	$0.03	$0.02	$0.08	$0.01
366	b0460	Raise limiting structures on Albright – Bethelboro 138 k\	APS	$0.04			$0.04			
367	b0461	Install a 115.2 MVAR capacitor at Will County 138 kV	ComEd	$2.30					$2.30	
368	b0462	Install a 57.6 MVAR capacitor at Joliet 138 kV	ComEd	$2.30					$2.30	
369	b0463	Install a 115.2 MVAR capacitor at East Frankfort 138 kV	ComEd	$2.30					$2.30	
370	b0465	Install a 115.2 MVAR capacitor at Libertyville 138 kV	ComEd	$2.30					$2.30	
371	b0466	Install a 115.2 MVAR capacitor at Prospect Heights 138	ComEd	$1.50					$1.50	
372	b0467.1	Reconductor the Dickerson – Pleasant View 230 kV circ	PEPCO	$9.00	$0.16		$1.77	$1.99		
373	b0467.2	Reconductor the Dickerson – Pleasant View 230 kV circ	Dominion	$5.00	$0.09		$0.99	$1.11		
374	b0468	Build a new substation with two 150 MVA transformers I	PPL	$22.40						
375	b0469	Install 130 MVAR capacitor at West Shore 230 kV line	PPL	$3.78						
376	b0470	Install 138 kV breaker at Roseland and close the Rosela	PSEG	$1.00						
377	b0471	Replace the wave traps at both Lawrence and Pleasant	PSEG	$0.50						
378	b0472	Increase the emergency rating of Saddle Brook – Athen	PSEG	$25.00						
379	b0473	Move the 150 MVAR mobile capacitor from Aldene 230	PSEG	$1.50						
380	b0474	Add a fourth 230/115 kV transformer, two 230 kV circuit	BGE	$10.30				$10.30		
381	b0475	Create two 230 kV ring buses at North West, add two 2:	BGE	$38.00				$38.00		
382	b0476	Rebuild High Ridge 230 kV substation to Breaker and H	BGE	$44.00				$44.00		
383	b0477	500/230 kV transformer #1 with three single phase trans	BGE	$29.90				$27.08		
384	b0478	Reconductor the four circuits from Burches Hill to Palme	PEPCO	$16.00			$0.27	$0.29		
385	b0480	Rebuild Lank – Five Points 69 kV	DPL	$1.40						
386	b0481	Replace wave trap at Indian River 138 kV on the Omar -	DPL	$0.20						
387	b0482	Rebuild Millsboro – Zoar REA 69 kV	DPL	$1.80						
388	b0483	Replace Church 138/69 kV transformer and add two bre	DPL	$5.00						
389	b0483.1	Build Oak Hall – Wattsville 138 kV line	DPL	$2.60						
390	b0483.2	Add 138/69 kV transformer at Wattsville	DPL	$1.40						
391	b0483.3	Establish 138 kV bus position at Oak Hall	DPL	$0.53						
392	b0484	Re-tension Worcester – Berlin 69 kV for 125ºC	DPL	$0.44						
393	b0485	Re-tension Taylor – North Seaford 69 kV for 125ºC	DPL	$0.36						
394	b0487	Build new 500 kV transmission facilities from Susqueha	PPL	$427.00	$8.07	$73.87	$25.71	$21.14	$63.92	$10.68
395	b0487.1	Install Lackawanna 500/230 kV transformer and upgrad	PPL	$59.00						
396	b0489	Build new 500 kV transmission facilities from Pennsylva	PSEG	$705.00	$14.73	$117.81	$42.51	$34.69	$109.84	$16.99
397	b0489.1	Replace Athenia 230 kV breaker 31H	PSEG	$0.40						
398	b0489.2	Replace Bergen 230 kV breaker 10H	PSEG	$0.40						
399	b0489.3	Replace Saddlebrook 230 kV breaker 21P	PSEG	$0.40						
400	b0489.4	Install two Roseland 500/230 kV transformers as part of	PSEG	$45.00	$2.35				$0.13	$0.01
401	b0489.5	Replace Roseland 230 kV breaker '42H' with 80 kA	PSEG	$0.80	$0.02	$0.13	$0.05	$0.04	$0.12	$0.02
402	b0489.6	Replace Roseland 230 kV breaker '51H' with 80 kA	PSEG	$0.80	$0.02	$0.13	$0.05	$0.04	$0.12	$0.02
403	b0489.7	Replace Roseland 230 kV breaker '71H' with 80 kA	PSEG	$0.80	$0.02	$0.13	$0.05	$0.04	$0.12	$0.02
404	b0489.8	Replace Roseland 230 kV breaker '31H' with 80 kA	PSEG	$0.80	$0.02	$0.13	$0.05	$0.04	$0.12	$0.02
405	b0489.9	Replace Roseland 230 kV breaker '11H' with 80 kA	PSEG	$0.80	$0.02	$0.13	$0.05	$0.04	$0.12	$0.02
406	b0490	Construct an Amos – Bedington 765 kV circuit (AEP equ	AEP	$698.00	$14.59	$116.64	$42.09	$34.34	$108.75	$16.82
407	b0491	Construct an Amos – Bedington 765 kV circuit (APS equ	APS	$772.09	$16.14	$129.02	$46.56	$37.99	$120.29	$18.61
408	b0492	Construct a Bedington – Kemptown 500 kV circuit	APS	$629.91	$13.17	$105.26	$37.98	$30.99	$98.14	$15.18
409	b0493	Reconductor both Cheswick – Logan's Ferry 138 kV circ	DL	$2.40						
410	b0494.1	Install a 2nd Red Lion 230/138 kV	DPL	$2.52						
411	b0494.2	Hares Corner – Relay Improvement	DPL	$0.80						
412	b0494.3	Reybold – Relay Improvement	DPL	$0.17						
413	b0494.4	New Castle – Relay Improvement	DPL	$0.17						
414	b0495	Replace existing Kammer 765/500 kV transformer with a	APS	$42.00	$0.88	$7.02	$2.53	$2.07	$6.54	$1.01
415	b0496	Replace existing 500/230 kV transformer at Brighton	PEPCO	$18.00			$1.02	$5.34		
416	b0497	Install a second Conastone – Graceton 230 kV circuit	BGE	$49.20	$4.46					
417	b0498	Loop the 5021 circuit into New Freedom 500 kV substat	PSEG	$17.00	$0.36	$2.84	$1.03	$0.84	$2.65	$0.41
418	b0498.1	Upgrade the 20H circuit breaker	PSEG	$0.40						
419	b0498.2	Upgrade the 22H circuit breaker	PSEG	$0.40						
420	b0498.3	Upgrade the 30H circuit breaker	PSEG	$0.40						
421	b0498.4	Upgrade the 32H circuit breaker	PSEG	$0.40						
422	b0498.5	Upgrade the 40H circuit breaker	PSEG	$0.40						
423	b0498.6	Upgrade the 42H circuit breaker	PSEG	$0.40						
424	b0499	Install third Burches Hill 500/230 kV transformer	PEPCO	$31.00			$1.10	$2.27		
425	b0501	New Brady 345 kV substation and 345 / 138 kV transfor	DL	$82.00			$5.53			
426	b0502	New Underground Carson – Brady – Brunot Island 345	DL	$85.10			$5.74			
427	b0502.1	Replace Dravosburg 138 kV breaker 'Z79 Illinois'	DL	$0.33						
428	b0502.2	Replace Dravosburg 138 kV breaker 'Z15 Elrama'	DL	$0.33						
429	b0502.3	Replace Dravosburg 138 kV breaker 'Z73 West Mifflin'	DL	$0.35						
430	b0502.4	Replace Dravosburg 138 kV breaker 'Z70 Elywn'	DL	$0.35						
431	b0502.5	Replace Elrama 138 kV breaker 'No. 1 69 kV Autofmr'	DL	$0.35						
432	b0503	Loop existing Carson – Oakland 138 kV into new Brady	DL	$18.30			$1.23			
433	b0504	Add two advanced technology circuit breakers at Hangii	AEP	$5.17	$0.11	$0.86	$0.31	$0.25	$0.81	$0.12
434	b0505	Reconductor the North Wales – Whitpain 230 kV circuit	PECO	$2.00	$0.17					
435	b0506	Reconductor the North Wales – Hartman 230 kV circuit	PECO	$2.20	$0.19					
436	b0508.1	Replace station cable at Hartman on the Warrington - H	PECO	$0.38						
437	b0509	Reconductor the Jarrett – Heaton 230 kV circuit	PECO	$0.53						
438	b0510	Install two 115.3 MVAR capacitors at Elmhurst 138 kV	ComEd	$4.40					$4.40	
439	b0511	Reconductor the Pleasant Valley – Woodstock 138 kV li	ComEd	$3.30					$3.30	
440	b0512	MAPP Project – install new 500 kV transmission from P	BGE	$60.40	$1.20	$10.85	$3.79	$2.93	$9.43	$1.49
441	b0512	MAPP Project – install new 500 kV transmission from P	PEPCO	$1,055.00	$22.05	$176.29	$63.62	$51.91	$164.37	$25.43
442	b0512	MAPP Project – install new 500 kV transmission from P	Dominion	$8.10	$0.17	$1.35	$0.49	$0.40	$1.26	$0.20
443	b0512	MAPP Project – install new 500 kV transmission from P	BGE	$4.60	$0.10	$0.77	$0.28	$0.23	$0.72	$0.11
444	b0512.5	Advance n0716 (Ox - Replace 230kV breaker L242)	Dominion	$0.03	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
445	b0512.6	Advance n0717 (Possum Point - Replace 230kV breake	Dominion	$0.03	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
446	b0513	Rebuild the Ocean Bay – Maridel 69 kV line	DPL	$2.10						
447	b0515	Replace Lewistown circuit breaker 1LY Yeagertown	PENELEC	$0.40						
448	b0516	Replace Lewistown circuit breaker 2LY Yeagertown	PENELEC	$0.40						
449	b0517	Replace Shawville bus section circuit breaker	PENELEC	$0.31						
450	b0518	Replace Homer City circuit breaker 201 Johnstown	PENELEC	$0.31						
451	b0519	Replace Keystone circuit breaker 4 Transformer - 20	PENELEC	$0.31						
452	b0520	Replace Gilbert circuit breaker 12A	JCPL	$0.31						
453	b0526	Build two Ritchie – Benning Station A 230 kV lines	PEPCO	$71.30	$0.55			$11.96		
454	b0527	Replace existing 12 MVAR capacitor at Bethany with a :	DPL	$1.76						
455	b0528	Replace existing 69/12 kV transformer at Bethany with a	DPL	$5.30						

	A	K	L	M	N	O	P	Q	R	S	T	U	V
8	Upgrade ID	DL	DPL	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL
365	b0457	$0.01	$0.01	$0.07	$0.00		$0.02	$0.01	$0.00	$0.03	$0.01	$0.02	$0.03
366	b0460												
367	b0461												
368	b0462												
369	b0463												
370	b0465												
371	b0466												
372	b0467.1		$0.33				$0.06	$0.22	$0.00	$0.50		$3.77	$0.19
373	b0467.2		$0.18				$0.04	$0.12	$0.00	$0.28		$2.09	$0.10
374	b0468				$0.02		$1.02		$0.04	$0.40	$0.07		$19.46
375	b0469												$3.78
376	b0470												
377	b0471												
378	b0472				$0.26								
379	b0473												
380	b0474												
381	b0475												
382	b0476												
383	b0477							$0.45		$0.28		$1.20	$0.90
384	b0478											$15.44	
385	b0480		$1.40										
386	b0481		$0.20										
387	b0482		$1.80										
388	b0483		$5.00										
389	b0483.1		$2.60										
390	b0483.2		$1.40										
391	b0483.3		$0.53										
392	b0484		$0.44										
393	b0485		$0.36										
394	b0487	$8.63	$12.17	$58.11	$1.02		$19.22	$9.31	$2.09	$26.94	$8.80	$20.58	$22.93
395	b0487.1				$0.06						$9.98		$45.83
396	b0489	$14.45	$20.30	$95.95	$1.55		$32.15	$14.73	$3.45	$44.42	$14.88	$33.35	$37.15
397	b0489.1												
398	b0489.2												
399	b0489.3												
400	b0489.4		$0.81		$0.22		$15.35		$1.52	$4.64	$0.26		
401	b0489.5	$0.02	$0.02	$0.11	$0.00		$0.04	$0.02	$0.00	$0.05	$0.02	$0.04	$0.04
402	b0489.6	$0.02	$0.02	$0.11	$0.00		$0.04	$0.02	$0.00	$0.05	$0.02	$0.04	$0.04
403	b0489.7	$0.02	$0.02	$0.11	$0.00		$0.04	$0.02	$0.00	$0.05	$0.02	$0.04	$0.04
404	b0489.8	$0.02	$0.02	$0.11	$0.00		$0.04	$0.02	$0.00	$0.05	$0.02	$0.04	$0.04
405	b0489.9	$0.02	$0.02	$0.11	$0.00		$0.04	$0.02	$0.00	$0.05	$0.02	$0.04	$0.04
406	b0490	$14.31	$20.10	$95.00	$1.54		$31.83	$14.59	$3.42	$43.97	$14.73	$33.02	$36.78
407	b0491	$15.83	$22.24	$105.08	$1.70		$35.21	$16.14	$3.78	$48.64	$16.29	$36.52	$40.69
408	b0492	$12.91	$18.14	$85.73	$1.39		$28.72	$13.17	$3.09	$39.68	$13.29	$29.79	$33.20
409	b0493	$2.40											
410	b0494.1		$2.52										
411	b0494.2		$0.80										
412	b0494.3		$0.17										
413	b0494.4		$0.17										
414	b0495	$0.86	$1.21	$5.72	$0.09		$1.92	$0.88	$0.21	$2.65	$0.89	$1.99	$2.21
415	b0496			$1.96								$9.67	
416	b0497		$8.34		$0.07		$4.77	$0.73	$0.23	$15.24			$8.12
417	b0498	$0.35	$0.49	$2.31	$0.04		$0.78	$0.36	$0.08	$1.07	$0.36	$0.80	$0.90
418	b0498.1												
419	b0498.2												
420	b0498.3												
421	b0498.4												
422	b0498.5												
423	b0498.6												
424	b0499											$27.64	
425	b0501	$76.47											
426	b0502	$79.36											
427	b0502.1	$0.33											
428	b0502.2	$0.33											
429	b0502.3	$0.35											
430	b0502.4	$0.35											
431	b0502.5	$0.35											
432	b0503	$17.07											
433	b0504	$0.11	$0.15	$0.70	$0.01		$0.24	$0.11	$0.03	$0.33	$0.11	$0.24	$0.27
434	b0505		$0.16							$1.67			
435	b0506		$0.17							$1.84			
436	b0508.1									$0.38			
437	b0509									$0.53			
438	b0510												
439	b0511												
440	b0512	$1.21	$1.71	$8.06	$0.14		$2.55	$1.26	$0.30	$3.55	$1.27	$2.81	$3.38
441	b0512	$21.63	$30.38	$143.59	$2.32		$48.11	$22.05	$5.17	$66.47	$22.26	$49.90	$55.60
442	b0512	$0.17	$0.23	$1.10	$0.02		$0.37	$0.17	$0.04	$0.51	$0.17	$0.38	$0.43
443	b0512	$0.09	$0.13	$0.63	$0.01		$0.21	$0.10	$0.02	$0.29	$0.10	$0.22	$0.24
444	b0512.5	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
445	b0512.6	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
446	b0513		$2.10										
447	b0515										$0.40		
448	b0516										$0.40		
449	b0517										$0.31		
450	b0518										$0.31		
451	b0519										$0.31		
452	b0520						$0.31						
453	b0526		$0.87				$0.99	$0.42	$0.05	$1.50		$53.41	
454	b0527		$1.76										
455	b0528		$5.30										

	A	W	X	Y
8	Upgrade ID	PSEG	RE	UGI
365	b0457	$0.04	$0.00	
366	b0460			
367	b0461			
368	b0462			
369	b0463			
370	b0465			
371	b0466			
372	b0467.1			
373	b0467.2			
374	b0468	$1.33	$0.05	
375	b0469			
376	b0470	$1.00		
377	b0471	$0.50		
378	b0472	$23.85	$0.89	
379	b0473	$1.50		
380	b0474			
381	b0475			
382	b0476			
383	b0477			
384	b0478			
385	b0480			
386	b0481			
387	b0482			
388	b0483			
389	b0483.1			
390	b0483.2			
391	b0483.3			
392	b0484			
393	b0485			
394	b0487	$32.49	$1.32	
395	b0487.1	$3.03	$0.11	
396	b0489	$53.93	$2.19	
397	b0489.1	$0.40		
398	b0489.2	$0.40		
399	b0489.3	$0.40		
400	b0489.4	$18.99	$0.71	
401	b0489.5	$0.06	$0.00	
402	b0489.6	$0.06	$0.00	
403	b0489.7	$0.06	$0.00	
404	b0489.8	$0.06	$0.00	
405	b0489.9	$0.06	$0.00	
406	b0490	$53.40	$2.16	
407	b0491	$59.06	$2.39	
408	b0492	$48.19	$1.95	
409	b0493			
410	b0494.1			
411	b0494.2			
412	b0494.3			
413	b0494.4			
414	b0495	$3.21	$0.13	
415	b0496			
416	b0497	$6.97	$0.26	
417	b0498	$1.30	$0.05	
418	b0498.1	$0.40		
419	b0498.2	$0.40		
420	b0498.3	$0.40		
421	b0498.4	$0.40		
422	b0498.5	$0.40		
423	b0498.6	$0.40		
424	b0499			
425	b0501			
426	b0502			
427	b0502.1			
428	b0502.2			
429	b0502.3			
430	b0502.4			
431	b0502.5			
432	b0503			
433	b0504	$0.40	$0.02	
434	b0505			
435	b0506			
436	b0508.1			
437	b0509			
438	b0510			
439	b0511			
440	b0512	$4.30	$0.16	
441	b0512	$80.71	$3.27	
442	b0512	$0.62	$0.03	
443	b0512	$0.35	$0.01	
444	b0512.5	$0.00	$0.00	
445	b0512.6	$0.00	$0.00	
446	b0513			
447	b0515			
448	b0516			
449	b0517			
450	b0518			
451	b0519			
452	b0520			
453	b0526	$1.50	$0.06	
454	b0527			
455	b0528			

	A	B	C	D	E	F	G	H	I	J
8	Upgrade ID	Description	TO	Cost Estimate	AEC	AEP	APS	BGE	ComEd	Dayton
456	b0529	Install an additional 8.4 MVAR capacitor at Grasonville (	DPL	$1.30						
457	b0530	Replace existing 12 MVAR capacitor at Wye Mills with a	DPL	$1.80						
458	b0531	Create a four breaker 138 kV ring bus at Wye Mills and	DPL	$6.00						
459	b0533	Reconductor the Powell Mountain – Sutton 138 kV line	APS	$7.10			$7.10			
460	b0534	Install a 28.61 MVAR capacitor on Sutton 138 kV	APS	$1.10			$1.10			
461	b0535	Install a 44 MVAR capacitor on Dutch Fork 138 kV	APS	$0.50			$0.50			
462	b0536	Replace Doubs circuit breaker DJ1	APS	$0.30			$0.30			
463	b0537	Replace Doubs circuit breaker DJ7	APS	$0.30			$0.30			
464	b0538	Replace Doubs circuit breaker DJ10	APS	$0.30			$0.30			
465	b0539	Replace Doubs circuit breaker DJ11	APS	$0.30			$0.30			
466	b0540	Replace Doubs circuit breaker DJ12	APS	$0.30			$0.30			
467	b0541	Replace Doubs circuit breaker DJ13	APS	$0.30			$0.30			
468	b0542	Replace Doubs circuit breaker DJ20	APS	$0.30			$0.30			
469	b0543	Replace Doubs circuit breaker DJ21	APS	$0.30			$0.30			
470	b0546	Install a 20 MVAR capacitor at Shorewood substation	ComEd	$0.40					$0.40	
471	b0547	Install a 15 MVAR capacitor at Wilmington substation	ComEd	$0.30					$0.30	
472	b0549	Install 250 MVAR capacitor at Keystone 500 kV	PENELEC	$4.50	$0.09	$0.75	$0.27	$0.22	$0.70	$0.11
473	b0550	Install 25 MVAR capacitor at Lewis Run 115 kV substati	PENELEC	$2.60	$0.21		$0.07			
474	b0551	Install 25 MVAR capacitor at Saxton 115 kV substation	PENELEC	$1.30	$0.10		$0.03			
475	b0552	Install 50 MVAR capacitor at Altoona 230 kV substation	PENELEC	$3.75	$0.30		$0.10			
476	b0553	Install 50 MVAR capacitor at Raystown 230 kV substati	PENELEC	$3.75	$0.30		$0.10			
477	b0555	Install 100 MVAR capacitor at Johnstown 230 kV substa	PENELEC	$4.50	$0.36		$0.12			
478	b0556	Install 50 MVAR capacitor at Grover 230 kV substation	PENELEC	$3.75	$0.30		$0.10			
479	b0557	Install 75 MVAR capacitor at East Towanda 230 kV sub	PENELEC	$2.25	$0.18		$0.06			
480	b0559	Install 200 MVAR capacitor at Meadow Brook 500 kV su	APS	$3.00	$0.06	$0.50	$0.18	$0.15	$0.47	$0.07
481	b0560	Install 250 MVAR capacitor at Kemptown 500 kV substa	APS	$4.00	$0.08	$0.67	$0.24	$0.20	$0.62	$0.10
482	b0563	Install 25 MVAR capacitor at Farmers Valley 115 kV sub	PENELEC	$0.80						
483	b0564	Install 10 MVAR capacitor at Ridgeway 115 kV substatio	PENELEC	$0.40						
484	b0565	Install 100 MVAR capacitor at Cox's Corner 230 kV sub	PSEG	$9.00						
485	b0566	Rebuild the Trappe Tap – Todd 69 kV line	DPL	$12.00						
486	b0567	Rebuild the Mt. Pleasant – Townsend 138 kV line	DPL	$3.92						
487	b0568	Install a third Indian River 230/138 kV transformer	DPL	$7.30						
488	b0569.1	Install a second East Frankfort 345/138 kV autotransfor	ComEd	$10.00					$10.00	
489	b0569.2	Reconductor County Club Hills – Matteson 138 kV circu	ComEd	$1.25					$1.25	
490	b0570	Reconductor East Side Lima – Sterling 138 kV	AEP	$16.10		$6.76			$9.34	
491	b0572.1	Reconductor Albright – Mettiki – Williams – Parsons – L	APS	$4.56			$4.56			
492	b0572.2	Reconductor Albright – Mettiki – Williams – Parsons – L	APS	$10.15			$10.15			
493	b0573	Reconfigure circuits in Butler – Cabot 138 kV area	APS	$1.18			$1.18			
494	b0575.1	Rebuild Hunterstown – Texas Eastern Tap 115 kV	ME	$2.10						
495	b0575.2	Rebuild Texas Eastern Tap – Gardners 115 kV and ass	ME	$1.90						
496	b0576	Move the Monroe 230/69 kV to Mickleton	AEC	$6.88	$6.88					
497	b0577	Replace Fort Martin 500 kV breaker FL-1	APS	$0.70	$0.01	$0.12	$0.04	$0.03	$0.11	$0.02
498	b0578	Replace Essex 138 kV breaker 4LM (C1355 line to ECR	PSEG	$0.40						
499	b0579	Replace Essex 138 kV breaker 1LM (220-1 TX)	PSEG	$0.40						
500	b0580	Replace Essex 138 kV breaker 1BM (BS1-3 tie)	PSEG	$0.40						
501	b0581	Replace Essex 138 kV breaker 2BM (BS3-4 tie)	PSEG	$0.40						
502	b0582	Replace Linden 138 kV breaker 3 (132-7 TX)	PSEG	$0.40						
503	b0583	Install dual primary protection schemes on Gosport lines	Dominion	$0.50						
504	b0584	Install 33 MVAR 138 kV capacitor at Necessity 138 kV	APS	$0.77			$0.77			
505	b0585	Increase Cecil 138 kV capacitor size to 44 MVAR, repla	APS	$0.10			$0.10			
506	b0586	Increase Whiteley 138 kV capacitor size to 44 MVAR	APS	$0.64			$0.64			
507	b0587	Reconductor AP portion of Tidd – Carnegie 138 kV and	APS	$3.16			$3.16			
508	b0588	Install a 40.8 MVAR 138 kV capacitor at Grassy Falls	APS	$0.50			$0.50			
509	b0590	Replace #1 and #2 breakers at Charleroi 138 kV	APS	$0.45			$0.45			
510	b0591	Install a 25.2 MVAR capacitor at Seneca Caverns 138 k	APS	$0.63			$0.63			
511	b0592	Replace Metuchen 138 kV breaker '2-2 Transfer'	PSEG	$0.40						
512	b0593	Eldred – Pine Grove 69 kV line Rebuild Part 2: 8 miles	PPL	$7.67						
513	b0595	Rebuild Lackawanna – Edella 69 kV line to double circu	PPL	$5.09						
514	b0596	Reconductor and rebuild Stanton – Providence 69 kV #1	PPL	$6.20						
515	b0597	Reconductor Suburban – Providence 69 kV #1 and rese	PPL	$1.20						
516	b0598	Reconductor Suburban Taps #1 and #2 for 69 kV line p	PPL	$4.08						
517	b0600	Tripp Park Substation: 69 kV tap off Stanton – Providen	PPL	$0.70						
518	b0604	Add 150 MVA, 230/138/69 transformer #6 to Harwood s	PPL	$14.93						
519	b0605	Reconductor Stanton – Old Forge 69 kV line and resect	PPL	$4.48						
520	b0606	New 138 kV tap off Monroe – Jackson 138 kV #1 line to	PPL	$0.49						
521	b0607	New 138 kV taps off Monroe – Jackson 138 kV lines to	PPL	$0.85						
522	b0608	New 138 kV tap off Siegfried – Jackson 138 kV #2 to tra	PPL	$0.56						
523	b0610	At South Farmersville substation, a new 69 kV tap off N	PPL	$0.33						
524	b0612	Rebuild Siegfried – North Bethlehem portion (6.7 miles)	PPL	$5.80						
525	b0613	East Tannersville Substation: New 138 kV tap to new su	PPL	$0.42						
526	b0614	Elroy substation expansion and new Elroy – Hatfield 13	PPL	$34.24						
527	b0615	Reconductor and rebuild 12 miles of Seidersville – Qual	PPL	$22.58						
528	b0616	New Springfield 230/69 kV substation and transmission	PPL	$16.71						
529	b0620	New 138 kV line and terminal at Monroe 230/138 substa	PPL	$1.32						
530	b0621	New 138 kV line and terminal at Siegfried 230/138 kV su	PPL	$4.24						
531	b0622	138 kV yard upgrades and transmission line rearrangem	PPL	$6.08						
532	b0623	New West Shore – Whitehill Taps 138/69 kV double circ	PPL	$5.67						
533	b0624	Reconductor Cumberland – Wertzville 69 kV portion (3.1	PPL	$2.87						
534	b0625	Reconductor Mt. Allen – Rossmoyne 69 kV portions (1.6	PPL	$0.99						
535	b0627	Replace UG cable from Walnut substation to Center Cit	PPL	$7.63						
536	b0629	Lincoln substation: 69 kV tap to convert to modified Twi	PPL	$0.05						
537	b0630	W. Hempfield – Donegal 69 kV line: Reconductor / rebu	PPL	$3.31						
538	b0631	W. Hempfield – Donegal 69 kV line: Reconductor / rebu	PPL	$3.36						
539	b0632	Terminate new S. Manheim – Donegal 69 kV circuit into	PPL	$0.30						
540	b0634	Rebuild S. Manheim – Fuller 69 kV portion (1.0 mile) of	PPL	$10.10						
541	b0635	Reconductor Fuller Tap – Landisville 69 kV (4.1 miles) i	PPL	$3.65						
542	b0637	Replace 13 Oak Grove 230 kV breakers	PEPCO	$1.50						
543	b0638	Replace 13 Oak Grove 230 kV breakers	PEPCO	$1.50						
544	b0639	Replace 13 Oak Grove 230 kV breakers	PEPCO	$1.50						
545	b0640	Replace 13 Oak Grove 230 kV breakers	PEPCO	$1.50						
546	b0641	Replace 13 Oak Grove 230 kV breakers	PEPCO	$1.50						

	A	K	L	M	N	O	P	Q	R	S	T	U	V
8	Upgrade ID	DL	DPL	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL
456	b0529		$1.30										
457	b0530		$1.80										
458	b0531		$6.00										
459	b0533												
460	b0534												
461	b0535												
462	b0536												
463	b0537												
464	b0538												
465	b0539												
466	b0540												
467	b0541												
468	b0542												
469	b0543												
470	b0546												
471	b0547												
472	b0549	$0.09	$0.13	$0.61	$0.01		$0.21	$0.09	$0.02	$0.28	$0.09	$0.21	$0.24
473	b0550		$0.28		$0.01		$0.50	$0.04	$0.02	$0.56			$0.15
474	b0551		$0.14		$0.01		$0.25	$0.02	$0.01	$0.28			$0.07
475	b0552		$0.41		$0.02		$0.72	$0.06	$0.04	$0.80			$0.21
476	b0553		$0.41		$0.02		$0.72	$0.06	$0.04	$0.80			$0.21
477	b0555		$0.49		$0.02		$0.87	$0.07	$0.04	$0.96			$0.26
478	b0556		$0.41		$0.02		$0.72	$0.06	$0.04	$0.80			$0.21
479	b0557		$0.25		$0.01		$0.43	$0.04	$0.02	$0.48			$0.13
480	b0559	$0.06	$0.09	$0.41	$0.01		$0.14	$0.06	$0.01	$0.19	$0.06	$0.14	$0.16
481	b0560	$0.08	$0.12	$0.54	$0.01		$0.18	$0.08	$0.02	$0.25	$0.08	$0.19	$0.21
482	b0563										$0.80		
483	b0564										$0.40		
484	b0565												
485	b0566		$12.00										
486	b0567		$3.92										
487	b0568		$7.30										
488	b0569.1												
489	b0569.2												
490	b0570												
491	b0572.1												
492	b0572.2												
493	b0573												
494	b0575.1							$2.10					
495	b0575.2							$1.90					
496	b0576												
497	b0577	$0.01	$0.02	$0.10	$0.00		$0.03	$0.01	$0.00	$0.04	$0.01	$0.03	$0.04
498	b0578												
499	b0579												
500	b0580												
501	b0581												
502	b0582												
503	b0583			$0.50									
504	b0584												
505	b0585												
506	b0586												
507	b0587												
508	b0588												
509	b0590												
510	b0591												
511	b0592												
512	b0593												$7.67
513	b0595												$5.09
514	b0596												$6.20
515	b0597												$1.20
516	b0598												$4.08
517	b0600												$0.70
518	b0604												$14.93
519	b0605												$4.48
520	b0606												$0.49
521	b0607												$0.85
522	b0608												$0.56
523	b0610												$0.33
524	b0612												$5.80
525	b0613												$0.42
526	b0614												$34.24
527	b0615												$22.58
528	b0616												$16.71
529	b0620												$1.32
530	b0621												$4.24
531	b0622												$6.08
532	b0623												$5.67
533	b0624												$2.87
534	b0625												$0.99
535	b0627												$7.63
536	b0629												$0.05
537	b0630												$3.31
538	b0631												$3.36
539	b0632												$0.30
540	b0634												$10.10
541	b0635												$3.65
542	b0637											$1.50	
543	b0638											$1.50	
544	b0639											$1.50	
545	b0640											$1.50	
546	b0641											$1.50	

	A	W	X	Y
8	Upgrade ID	PSEG	RE	UGI
456	b0529			
457	b0530			
458	b0531			
459	b0533			
460	b0534			
461	b0535			
462	b0536			
463	b0537			
464	b0538			
465	b0539			
466	b0540			
467	b0541			
468	b0542			
469	b0543			
470	b0546			
471	b0547			
472	b0549	$0.34	$0.01	
473	b0550	$0.73	$0.03	
474	b0551	$0.37	$0.01	
475	b0552	$1.06	$0.04	
476	b0553	$1.06	$0.04	
477	b0555	$1.27	$0.05	
478	b0556	$1.06	$0.04	
479	b0557	$0.63	$0.02	
480	b0559	$0.23	$0.01	
481	b0560	$0.31	$0.01	
482	b0563			
483	b0564			
484	b0565	$9.00		
485	b0566			
486	b0567			
487	b0568			
488	b0569.1			
489	b0569.2			
490	b0570			
491	b0572.1			
492	b0572.2			
493	b0573			
494	b0575.1			
495	b0575.2			
496	b0576			
497	b0577	$0.05	$0.00	
498	b0578	$0.40		
499	b0579	$0.40		
500	b0580	$0.40		
501	b0581	$0.40		
502	b0582	$0.40		
503	b0583			
504	b0584			
505	b0585			
506	b0586			
507	b0587			
508	b0588			
509	b0590			
510	b0591			
511	b0592	$0.40		
512	b0593			
513	b0595			
514	b0596			
515	b0597			
516	b0598			
517	b0600			
518	b0604			
519	b0605			
520	b0606			
521	b0607			
522	b0608			
523	b0610			
524	b0612			
525	b0613			
526	b0614			
527	b0615			
528	b0616			
529	b0620			
530	b0621			
531	b0622			
532	b0623			
533	b0624			
534	b0625			
535	b0627			
536	b0629			
537	b0630			
538	b0631			
539	b0632			
540	b0634			
541	b0635			
542	b0637			
543	b0638			
544	b0639			
545	b0640			
546	b0641			

	A	B	C	D	E	F	G	H	I	J
8	Upgrade ID	Description	TO	Cost Estimate	AEC	AEP	APS	BGE	ComEd	Dayton
547	b0642	Replace 13 Oak Grove 230 kV breakers	PEPCO	$1.50						
548	b0643	Replace 13 Oak Grove 230 kV breakers	PEPCO	$1.50						
549	b0644	Replace 13 Oak Grove 230 kV breakers	PEPCO	$1.50						
550	b0645	Replace 13 Oak Grove 230 kV breakers	PEPCO	$1.50						
551	b0646	Replace 13 Oak Grove 230 kV breakers	PEPCO	$1.50						
552	b0647	Replace 13 Oak Grove 230 kV breakers	PEPCO	$1.50						
553	b0648	Replace 13 Oak Grove 230 kV breakers	PEPCO	$1.50						
554	b0649	Replace 13 Oak Grove 230 kV breakers	PEPCO	$1.50						
555	b0650	Reconductor Jackson – JE Baker – Taxville 115 kV line	ME	$2.25						
556	b0652	Install bus tie circuit breaker on Yorkana 115 kV bus an	ME	$2.10						
557	b0654	Reconfigure the Cambria Slope 115 kV and Wilmore Ju	PENELEC	$1.28						
558	b0655	Reconfigure and expand the Glade 230 kV ring bus to e	PENELEC	$5.64						
559	b0656	Add three breakers to form a ring bus at Altoona 230 kV	PENELEC	$2.73						
560	b0657	Construct Boston Road 34.5 kV stations, construct Hyso	JCPL	$5.81						
561	b0661	Replace existing baseline upgrade to install a 2nd Wolfs	ComEd	$20.00					$20.00	
562	b0663	Reconductor East Frankfort - Goodings Grove 345 kV 'F	ComEd	$15.00					$15.00	
563	b0664	Reconductor with 2x1033 ACSS conductor	PSEG	$12.00						
564	b0665	Reconductor with 2x1033 ACSS conductor	PSEG	$15.00						
565	b0668	Reconductor with 2x1033 ACSS conductor	PSEG	$9.00						
566	b0671	Replace terminal equipment at both ends of line	PSEG	$0.25						
567	b0673	Rebuild Elko – Carbon Center Junction using 230 kV co	APS	$7.50			$7.50			
568	b0674	Construct new Osage – Whiteley 138 kV circuit	APS	$21.00			$20.51			
569	b0674.1	Replace the Osage 138 kV breaker 'CollinsF126'	APS	$0.19			$0.19			
570	b0675.1	Convert Monocacy - Walkersville 138 kV to 230 kV	APS	$4.50	$0.05		$3.69			
571	b0675.2	Convert Walkersville - Catoctin 138 kV to 230 kV	APS	$11.20	$0.11		$9.18			
572	b0675.3	Convert Ringgold - Catoctin 138 kV to 230 kV	APS	$7.40	$0.08		$6.07			
573	b0675.4	Convert Catoctin - Carroll 138 kV to 230 kV	APS	$9.80	$0.10		$8.04			
574	b0675.5	Convert portion of Ringgold Substation from 138 kV to 2	APS	$1.80	$0.02		$1.48			
575	b0675.6	Convert Catoctin Substation from 138 kV to 230 kV	APS	$7.50	$0.08		$6.15			
576	b0675.7	Convert portion of Carroll Substation from 138 kV to 23(	APS	$4.70	$0.05		$3.86			
577	b0675.8	Convert Monocacy Substation from 138 kV to 230 kV	APS	$3.80	$0.04		$3.12			
578	b0675.9	Convert Walkersville Substation from 138 kV to 230 kV	APS	$5.00	$0.05		$4.10			
579	b0676.1	Reconductor Doubs - Lime Kiln (#207) 230kV	APS	$3.50	$0.02		$3.04			
580	b0676.2	Reconductor Doubs - Lime Kiln (#231) 230kV	APS	$3.10	$0.02		$2.69			
581	b0677	Reconductor Double Toll Gate – Riverton with 954 ACS	APS	$2.70			$2.70			
582	b0678	Reconductor Glen Falls - Oak Mound 138kV with 954 A	APS	$1.00			$1.00			
583	b0679	Reconductor Grand Point – Letterkenny with 954 ACSR	APS	$2.10			$2.10			
584	b0680	Reconductor Greene – Letterkenny with 954 ACSR	APS	$1.70			$1.70			
585	b0681	Replace 600/5 CT's at Franklin 138 kV	APS	$0.01			$0.01			
586	b0682	Replace 600/5 CT's at Whiteley 138 kV	APS	$0.01			$0.01			
587	b0684	Reconductor Guilford – South Chambersburg with 954 /	APS	$3.20			$3.20			
588	b0685	Replace Ringgold 230/138 kV #3 with larger transforme	APS	$5.80			$4.18			
589	b0686	Install a 115.2 MVAR switched capacitor at East Frankfo	ComEd	$2.90					$2.90	
590	b0687	Install a 115.2 MVAR switched capacitor at Plano 138 k	ComEd	$2.30					$2.30	
591	b0688	Install a 115.2 MVAR switched capacitor at Plano 138 k	ComEd	$2.30					$2.30	
592	b0689	Install a 115.2 MVAR switched capacitor at McCook 13٤	ComEd	$2.30					$2.30	
593	b0690	Install a 115.2 MVAR switched capacitor at McCook 13٤	ComEd	$2.30					$2.30	
594	b0691	Install a 115.2 MVAR switched capacitor at Wayne 138	ComEd	$2.30					$2.30	
595	b0692	Install a 115.2 MVAR switched capacitor at Wayne 138	ComEd	$2.30					$2.30	
596	b0693	Install a 115.2 MVAR switched capacitor at Crawford 13	ComEd	$2.30					$2.30	
597	b0694	Install a 115.2 MVAR switched capacitor at Crawford 13	ComEd	$2.30					$2.30	
598	b0695	Add a 300 MVAR SVC at Elmhurst 138 kV 'Red'	ComEd	$32.50					$32.50	
599	b0696	Add a 300 MVAR SVC at Elmhurst 138 kV 'Blue'	ComEd	$32.50					$32.50	
600	b0700	Install a third 345/138 kV transformer at Goodings Grov	ComEd	$15.00					$15.00	
601	b0701	Expand Benning 230 kV station, add a new 250 MVA 2:	PEPCO	$56.10				$17.15		
602	b0702	Add a second 50 MVAR 230 kV shunt reactor at the Be	PEPCO	$6.40						
603	b0703	Berks substation modification on Berks – South Akron 2	PPL	$0.84						
604	b0705	New Derry – Millville 69 kV line	PPL	$6.50						
605	b0707	Construct Bohemia – Twin Lakes 69 kV line, install a 10	PPL	$8.20						
606	b0708	New 69 kV double circuit from Jackson – Lake Naomi T	PPL	$7.49						
607	b0709	Install new 69 kV double circuit from Carlisle – West Ca	PPL	$8.11						
608	b0710	Install a third 69 kV line from Reese's Tap to Hershey si	PPL	$14.00						
609	b0711	New 69 kV that taps West Shore – Cumberland 69 kV #	PPL	$3.28						
610	b0712	Construct a new 69 kV line between Strassburg Tap an	PPL	$1.45						
611	b0713	Construct a new 138 kV double circuit line between Dille	PPL	$0.60						
612	b0714	Prepare Roseville Tap for 138 kV conversion	PPL	$1.00						
613	b0715	Transfer S. Akron – S. Manheim #1 and #2 lines from th	PPL	$2.41						
614	b0716	Add a second 69 kV line from Morgantown – Twin Valle	PPL	$0.74						
615	b0717	Rebuild existing Brunner Island – West Shore 230 kV lir	PPL	$37.57						
616	b0718	SPS scheme to drop 190 MVA of 69 kV radial load at W	PPL	$0.37						
617	b0719	SPS scheme at Jenkins substation to open the Stanton	PPL	$0.10						
618	b0720	Upgrade terminal equipment on both lines	PEPCO	$1.42						
619	b0721	Upgrade Oak Grove – Ritchie 23061 230 kV line	PEPCO	$3.25						
620	b0722	Upgrade Oak Grove – Ritchie 23058 230 kV line	PEPCO	$3.25						
621	b0723	Upgrade Oak Grove – Ritchie 23059 230 kV line	PEPCO	$3.25						
622	b0724	Upgrade Oak Grove – Ritchie 23060 230 kV line	PEPCO	$3.25						
623	b0725	Add a third Steele 230/138 kV transformer	DPL	$8.00						
624	b0726	Add a 2nd Raritan River 230/115 kV transformer	JCPL	$7.10	$0.17					
625	b0727	Rebuild Bryn Mawr – Plymouth Meeting 138 kV line	PECO	$16.60	$0.21					
626	b0729	Rebuild both Harford – Perryman 110615-A and 11061(	BGE	$4.40				$4.40		
627	b0730	Add slow oil circulation to the 4 Bells Mill Road – Bethes	PEPCO	$15.00						
628	b0731	Implement an SPS to automatically shed load on the 34	PEPCO							
629	b0732	Rebuild Vaugh – Wells 69 kV	DPL	$1.60						
630	b0733	Add a second 230/138 kV transformer at Harmony	DPL	$7.50						
631	b0737	Build a new Indian River – Bishop 138 kV line	DPL	$18.00						
632	b0738	Install a 115.2 MVAR switched capacitor at Bedford Par	ComEd	$2.30					$2.30	
633	b0739	Install a 115.2 MVAR switched capacitor at Bedford Par	ComEd	$2.30					$2.30	
634	b0740	Install a 57.6 MVAR switched capacitor at Wolfs 138 kV	ComEd	$1.15					$1.15	
635	b0740.2	Increase the size of the Wolfs 138 kV Blue cap from 57.	ComEd	$1.15					$1.15	
636	b0743	Add a bus tie breaker at Roseland 138 kV	PSEG	$0.50						
637	b0744	Upgrade a strand bus at Mill 138 kV	AEC	$0.10	$0.10					

	A	K	L	M	N	O	P	Q	R	S	T	U	V
8	Upgrade ID	DL	DPL	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL
547	b0642											$1.50	
548	b0643											$1.50	
549	b0644											$1.50	
550	b0645											$1.50	
551	b0646											$1.50	
552	b0647											$1.50	
553	b0648											$1.50	
554	b0649											$1.50	
555	b0650							$2.25					
556	b0652							$2.10					
557	b0654										$1.28		
558	b0655										$5.64		
559	b0656										$2.73		
560	b0657						$5.81						
561	b0661												
562	b0663												
563	b0664						$4.81		$1.24				
564	b0665						$6.02		$1.56				
565	b0668						$3.95		$1.02				
566	b0671												
567	b0673												
568	b0674	$0.20			$0.00						$0.23		
569	b0674.1												
570	b0675.1		$0.04		$0.00		$0.08	$0.29	$0.01	$0.14			$0.10
571	b0675.2		$0.10		$0.01		$0.20	$0.71	$0.02	$0.35			$0.25
572	b0675.3		$0.06		$0.00		$0.13	$0.47	$0.01	$0.23			$0.17
573	b0675.4		$0.08		$0.00		$0.17	$0.63	$0.01	$0.30			$0.22
574	b0675.5		$0.02		$0.00		$0.03	$0.11	$0.00	$0.06			$0.04
575	b0675.6		$0.06		$0.00		$0.13	$0.48	$0.01	$0.23			$0.17
576	b0675.7		$0.04		$0.00		$0.08	$0.30	$0.00	$0.15			$0.11
577	b0675.8		$0.03		$0.00		$0.07	$0.24	$0.00	$0.12			$0.09
578	b0675.9		$0.04		$0.00		$0.09	$0.32	$0.00	$0.15			$0.11
579	b0676.1		$0.02		$0.00		$0.07	$0.14	$0.00	$0.07	$0.03		
580	b0676.2		$0.02		$0.00		$0.06	$0.13	$0.00	$0.06	$0.03		
581	b0677												
582	b0678												
583	b0679												
584	b0680												
585	b0681												
586	b0682												
587	b0684												
588	b0685				$0.01		$0.24	$0.39	$0.01	$0.24	$0.34		
589	b0686												
590	b0687												
591	b0688												
592	b0689												
593	b0690												
594	b0691												
595	b0692												
596	b0693												
597	b0694												
598	b0695												
599	b0696												
600	b0700												
601	b0701											$38.95	
602	b0702											$6.40	
603	b0703												$0.84
604	b0705												$6.50
605	b0707												$8.20
606	b0708												$7.49
607	b0709												$8.11
608	b0710												$14.00
609	b0711												$3.28
610	b0712												$1.45
611	b0713												$0.60
612	b0714												$1.00
613	b0715												$2.41
614	b0716												$0.74
615	b0717												$37.57
616	b0718												$0.37
617	b0719												$0.10
618	b0720											$1.42	
619	b0721											$3.25	
620	b0722											$3.25	
621	b0723											$3.25	
622	b0724											$3.25	
623	b0725		$8.00										
624	b0726						$6.93						
625	b0727		$0.52							$15.88			
626	b0729												
627	b0730											$15.00	
628	b0731												
629	b0732		$1.60										
630	b0733		$7.28							$0.22			
631	b0737		$18.00										
632	b0738												
633	b0739												
634	b0740												
635	b0740.2												
636	b0743												
637	b0744												

	A	W	X	Y
8	Upgrade ID	PSEG	RE	UGI
547	b0642			
548	b0643			
549	b0644			
550	b0645			
551	b0646			
552	b0647			
553	b0648			
554	b0649			
555	b0650			
556	b0652			
557	b0654			
558	b0655			
559	b0656			
560	b0657			
561	b0661			
562	b0663			
563	b0664	$5.73	$0.21	
564	b0665	$7.16	$0.27	
565	b0668	$3.88	$0.14	
566	b0671	$0.25		
567	b0673			
568	b0674	$0.05	$0.00	
569	b0674.1			
570	b0675.1	$0.11	$0.00	
571	b0675.2	$0.27	$0.01	
572	b0675.3	$0.18	$0.01	
573	b0675.4	$0.24	$0.01	
574	b0675.5	$0.04	$0.00	
575	b0675.6	$0.18	$0.01	
576	b0675.7	$0.11	$0.00	
577	b0675.8	$0.09	$0.00	
578	b0675.9	$0.12	$0.00	
579	b0676.1	$0.10	$0.00	
580	b0676.2	$0.09	$0.00	
581	b0677			
582	b0678			
583	b0679			
584	b0680			
585	b0681			
586	b0682			
587	b0684			
588	b0685	$0.37	$0.01	
589	b0686			
590	b0687			
591	b0688			
592	b0689			
593	b0690			
594	b0691			
595	b0692			
596	b0693			
597	b0694			
598	b0695			
599	b0696			
600	b0700			
601	b0701			
602	b0702			
603	b0703			
604	b0705			
605	b0707			
606	b0708			
607	b0709			
608	b0710			
609	b0711			
610	b0712			
611	b0713			
612	b0714			
613	b0715			
614	b0716			
615	b0717			
616	b0718			
617	b0719			
618	b0720			
619	b0721			
620	b0722			
621	b0723			
622	b0724			
623	b0725			
624	b0726			
625	b0727			
626	b0729			
627	b0730			
628	b0731			
629	b0732			
630	b0733			
631	b0737			
632	b0738			
633	b0739			
634	b0740			
635	b0740.2			
636	b0743	$0.50		
637	b0744			

	A	B	C	D	E	F	G	H	I	J
8	Upgrade ID	Description	TO	Cost Estimate	AEC	AEP	APS	BGE	ComEd	Dayton
638	b0748	Establish a new 69 kV circuit between the Canal Road a	AEP	$27.00		$27.00				
639	b0749	Replace 230 kV breaker and associated CT's at Riversi	BGE	$1.50				$1.50		
640	b0750	Convert 138 kV network path from Vienna – Loretto – P	DPL	$40.00						
641	b0751	Add two additional breakers at Keeney 500 kV	DPL	$4.50	$0.09	$0.81	$0.28	$0.22	$0.70	$0.11
642	b0752	Replace two circuit breakers to bring the emergency rati	DPL	$1.00						
643	b0753	Add a second Loretto 230/138 kV transformer	DPL	$4.50						
644	b0754	Rebuild 10 miles of Glasgow to Mt. Pleasant 138 kV line	DPL	$5.70						
645	b0756	Install a second 500/115 kV autotransformer at Chancel	Dominion	$16.00						
646	b0756.1	Install two 500 kV breakers at Chancellor 500 kV	Dominion	$2.00	$0.04	$0.33	$0.12	$0.10	$0.31	$0.05
647	b0757	Reconductor one mile of Chesapeake – Reeves Avenue	Dominion	$1.00						
648	b0758	Install a second Fredericksburg 230/115 kV autotransfo	Dominion	$5.50						
649	b0759	Build a second Dooms – Dupont – Waynesboro 115 kV	Dominion	$20.50						
650	b0760	Build 115 kV line from Kitty Hawk to Colington 115 kV ((	Dominion	$14.30						
651	b0761	Install a second 230/115 kV transformer at Possum Poir	Dominion	$3.50						
652	b0762	Build a new Elko station and transfer load from Turner a	Dominion	$2.20						
653	b0763	Rebuild 17.5 miles of the line for a new summer rating o	Dominion	$10.20						
654	b0764	Increase the rating on 2.56 miles of the line between Gr	Dominion	$4.00						
655	b0765	Add a second Bull Run 230/115 kV autotransformer	Dominion	$3.00						
656	b0766	Increase the rating of the line between Loudoun and Ce	Dominion	$0.20						
657	b0767	Extend the line from Old Church – Chickahominy 230 kV	Dominion	$39.00						
658	b0768	Loop line #251 Idylwood – Arlington into the GIS sub	Dominion	$22.50						
659	b0769	Re-tension 15 miles of the line for a new summer rating	Dominion	$5.80						
660	b0770	Add a second 230/115 kV autotransformer at Lanexa	Dominion	$6.19						
661	b0770.1	Replace Lanexa 115 kV breaker '8532'	Dominion	$0.16						
662	b0770.2	Replace Lanexa 115 kV breaker '9232'	Dominion	$0.16						
663	b0771	Build a parallel Chickahominy – Lanexa 230 kV line	Dominion	$7.70						
664	b0772	Install a second Elmont 230/115 kV autotransformer	Dominion	$4.50						
665	b0772.1	Replace Elmont 115 kV breaker '7392'	Dominion	$0.16						
666	b0774	Install a 33 MVAR capacitor at Bremo 115 kV	Dominion	$0.60						
667	b0775	Reconductor the Greenwich – Virginia Beach line to brir	Dominion	$2.10						
668	b0776	Re-build Trowbridge – Winfall 115 kV	Dominion	$16.40						
669	b0777	Terminate the Thelma – Carolina 230 kV circuit into Lak	Dominion	$3.50						
670	b0778	Install 29.7 MVAR capacitor at Lebanon 115 kV	Dominion	$0.50						
671	b0779	Build a new 230 kV line from Yorktown to Hayes but ope	Dominion	$74.00						
672	b0780	Reconductor Chesapeake – Yadkin 115 kV line	Dominion	$2.00						
673	b0781	Reconductor and replace terminal equipment on line 17	Dominion	$0.30						
674	b0782	Install a new 115 kV capacitor at Dupont Waynesboro s	Dominion	$0.73						
675	b0784	Replace wave traps on North Anna to Ladysmith 500 kV	Dominion	$0.30	$0.01	$0.05	$0.02	$0.01	$0.05	$0.01
676	b0785	Rebuild the Chase City – Crewe 115 kV line	Dominion	$11.17						
677	b0786	Reconductor the Moran DP – Crewe 115 kV segment	Dominion	$6.00						
678	b0787	Upgrade the Chase City – Twitty's Creek 115 kV segme	Dominion	$7.90						
679	b0788	Reconductor the line from Farmville – Pamplin 115 kV	Dominion	$9.00						
680	b0789	Reconductor the line to provide a normal rating of 677 M	PECO	$3.70	$0.03					
681	b0790	Reconductor the Bradford – Planebrook 230 kV Ckt. 22(	PECO	$4.60						
682	b0791	Add a fourth 230/69 kV transformer at Stanton	PPL	$4.81						
683	b0792	Reconfigure Cecil Sub into 230 and 138 kV ring buses,	DPL	$6.00						
684	b0793	Close switch 145T183 to network the lines. Rebuild the	Dominion	$24.00						
685	b0794	Upgrade the Homer City 230 kV breaker 'Pierce Road'	PENELEC	$0.23						
686	b0795	Install a 115 kV breaker at Chesaco Park	BGE	$2.90				$2.90		
687	b0796	Install 2, 115 kV breakers at Gwynnbrook	BGE	$1.30				$1.30		
688	b0797	Advance n0321 (Replace Doubs Circuit Breaker DJ2)	APS	$0.01			$0.01			
689	b0798	Advance n0322 (Replace Doubs Circuit Breaker DJ3)	APS	$0.01			$0.01			
690	b0799	Advance n0323 (Replace Doubs Circuit Breaker DJ6)	APS	$0.01			$0.01			
691	b0800	Advance n0327 (Replace Doubs Circuit Breaker DJ16)	APS	$0.01			$0.01			
692	b0802	Advance n0259 (Replace Dickerson Station H Circuit Br	PEPCO	$0.01						
693	b0803	Advance n0260 (Replace Dickerson Station H Circuit Br	PEPCO	$0.01						
694	b0804	Advance n0261 (Replace Dickerson Station H Circuit Br	PEPCO	$0.01						
695	b0805	Advance n0262 (Replace Dickerson Station H Circuit Br	PEPCO	$0.01						
696	b0806	Advance n0264 (Replace Dickerson Station H Circuit Br	PEPCO	$0.01						
697	b0809	Advance n0267 (Replace Dickerson Station H Circuit Br	PEPCO	$0.01						
698	b0810	Advance n0270 (Replace Dickerson Station H Circuit Br	PEPCO	$0.01						
699	b0811	Advance n0726 (Replace Dickerson Station H Circuit Br	PEPCO	$0.01						
700	b0812	Increase operating temperature on line for one year to g	PSEG	$0.10						
701	b0813	Reconductor Hudson – South Waterfront 230 kV circuit	PSEG	$16.50				$0.21		
702	b0814	New Essex – Kearney 138 kV circuit and Kearney 138 k	PSEG	$71.20						
703	b0814.1	Replace Kearny 138 kV breaker '1-SHT' with 80 kA brea	PSEG	$1.00						
704	b0814.10	Replace Essex 138 kV breaker '1BT' with 63 kA breaker	PSEG	$0.50						
705	b0814.11	Replace Essex 138 kV breaker '2PM' with 63 kA breake	PSEG	$0.50						
706	b0814.12	Replace Marion 138 kV breaker '2HM' with 63 kA break	PSEG	$0.50						
707	b0814.13	Replace Marion 138 kV breaker '2LM' with 63 kA break	PSEG	$0.50						
708	b0814.14	Replace Marion 138 kV breaker '1LM' with 63 kA breake	PSEG	$0.50						
709	b0814.15	Replace Marion 138 kV breaker '6PM' with 63 kA break	PSEG	$0.50						
710	b0814.16	Replace Marion 138 kV breaker '3PM' with 63 kA break	PSEG	$0.50						
711	b0814.17	Replace Marion 138 kV breaker '4LM' with 63 kA breake	PSEG	$0.50						
712	b0814.18	Replace Marion 138 kV breaker '3LM' with 63 kA breake	PSEG	$0.50						
713	b0814.19	Replace Marion 138 kV breaker '1HM' with 63 kA break	PSEG	$0.50						
714	b0814.2	Replace Kearny 138 kV breaker '15HF' with 80 kA breal	PSEG	$1.00						
715	b0814.20	Replace Marion 138 kV breaker '2PM3' with 63 kA breal	PSEG	$0.50						
716	b0814.21	Replace Marion 138 kV breaker '2PM1' with 63 kA breal	PSEG	$0.50						
717	b0814.22	Replace ECRR 138 kV breaker '903'	PSEG	$0.50						
718	b0814.23	Replace Foundry 138 kV breaker '21P'	PSEG	$0.50						
719	b0814.25	Change the contact parting time on Essex 138 kV break	PSEG							
720	b0814.26	Change the contact parting time on Essex 138 kV break	PSEG							
721	b0814.27	Change the contact parting time on Essex 138 kV break	PSEG							
722	b0814.28	Change the contact parting time on Essex 138 kV break	PSEG							
723	b0814.29	Change the contact parting time on Essex 138 kV break	PSEG							
724	b0814.3	Replace Kearny 138 kV breaker '14HF' with 80 kA breal	PSEG	$1.00						
725	b0814.30	Change the contact parting time on Essex 138 kV break	PSEG							
726	b0814.4	Replace Kearny 138 kV breaker '10HF' with 80 kA breal	PSEG	$1.00						
727	b0814.5	Replace Kearny 138 kV breaker '2HT' with 80 kA breake	PSEG	$1.00						
728	b0814.6	Replace Kearny 138 kV breaker '22HF' with 80 kA breal	PSEG	$1.00						

	A	K	L	M	N	O	P	Q	R	S	T	U	V
8	Upgrade ID	DL	DPL	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL
638	b0748												
639	b0749												
640	b0750		$40.00										
641	b0751	$0.09	$0.13	$0.60	$0.01		$0.19	$0.09	$0.02	$0.26	$0.09	$0.21	$0.25
642	b0752		$1.00										
643	b0753		$4.50										
644	b0754		$5.70										
645	b0756			$16.00									
646	b0756.1	$0.04	$0.06	$0.27	$0.00		$0.09	$0.04	$0.01	$0.13	$0.04	$0.09	$0.11
647	b0757			$1.00									
648	b0758			$5.50									
649	b0759			$20.50									
650	b0760			$14.30									
651	b0761			$3.50									
652	b0762			$2.20									
653	b0763			$10.20									
654	b0764			$4.00									
655	b0765			$3.00									
656	b0766			$0.20									
657	b0767			$39.00									
658	b0768			$22.50									
659	b0769			$5.80									
660	b0770			$6.19									
661	b0770.1			$0.16									
662	b0770.2			$0.16									
663	b0771			$7.70									
664	b0772			$4.50									
665	b0772.1			$0.16									
666	b0774			$0.60									
667	b0775			$2.10									
668	b0776			$16.40									
669	b0777			$3.50									
670	b0778			$0.50									
671	b0779			$74.00									
672	b0780			$2.00									
673	b0781			$0.30									
674	b0782			$0.73									
675	b0784	$0.01	$0.01	$0.04	$0.00		$0.01	$0.01	$0.00	$0.02	$0.01	$0.01	$0.02
676	b0785			$11.17									
677	b0786			$6.00									
678	b0787			$7.90									
679	b0788			$9.00									
680	b0789				$0.02		$0.65		$0.03	$1.67			
681	b0790				$0.02		$0.81		$0.04	$2.10			
682	b0791										$0.46		$4.35
683	b0792		$6.00										
684	b0793			$24.00									
685	b0794										$0.23		
686	b0795												
687	b0796												
688	b0797												
689	b0798												
690	b0799												
691	b0800												
692	b0802											$0.01	
693	b0803											$0.01	
694	b0804											$0.01	
695	b0805											$0.01	
696	b0806											$0.01	
697	b0809											$0.01	
698	b0810											$0.01	
699	b0811											$0.01	
700	b0812												
701	b0813						$1.64		$0.07			$0.18	
702	b0814						$16.87		$0.58		$3.85		
703	b0814.1						$0.24		$0.01		$0.05		
704	b0814.10						$0.12		$0.00		$0.03		
705	b0814.11						$0.12		$0.00		$0.03		
706	b0814.12						$0.12		$0.00		$0.03		
707	b0814.13						$0.12		$0.00		$0.03		
708	b0814.14						$0.12		$0.00		$0.03		
709	b0814.15						$0.12		$0.00		$0.03		
710	b0814.16						$0.12		$0.00		$0.03		
711	b0814.17						$0.12		$0.00		$0.03		
712	b0814.18						$0.12		$0.00		$0.03		
713	b0814.19						$0.12		$0.00		$0.03		
714	b0814.2						$0.24		$0.01		$0.05		
715	b0814.20						$0.12		$0.00		$0.03		
716	b0814.21						$0.12		$0.00		$0.03		
717	b0814.22						$0.12		$0.00		$0.03		
718	b0814.23						$0.12		$0.00		$0.03		
719	b0814.25												
720	b0814.26												
721	b0814.27												
722	b0814.28												
723	b0814.29												
724	b0814.3						$0.24		$0.01		$0.05		
725	b0814.30												
726	b0814.4						$0.24		$0.01		$0.05		
727	b0814.5						$0.24		$0.01		$0.05		
728	b0814.6						$0.24		$0.01		$0.05		

	A	W	X	Y
8	Upgrade ID	PSEG	RE	UGI
638	b0748			
639	b0749			
640	b0750			
641	b0751	$0.32	$0.01	
642	b0752			
643	b0753			
644	b0754			
645	b0756			
646	b0756.1	$0.15	$0.01	
647	b0757			
648	b0758			
649	b0759			
650	b0760			
651	b0761			
652	b0762			
653	b0763			
654	b0764			
655	b0765			
656	b0766			
657	b0767			
658	b0768			
659	b0769			
660	b0770			
661	b0770.1			
662	b0770.2			
663	b0771			
664	b0772			
665	b0772.1			
666	b0774			
667	b0775			
668	b0776			
669	b0777			
670	b0778			
671	b0779			
672	b0780			
673	b0781			
674	b0782			
675	b0784	$0.02	$0.00	
676	b0785			
677	b0786			
678	b0787			
679	b0788			
680	b0789	$1.26	$0.05	
681	b0790	$1.57	$0.06	
682	b0791			
683	b0792			
684	b0793			
685	b0794			
686	b0795			
687	b0796			
688	b0797			
689	b0798			
690	b0799			
691	b0800			
692	b0802			
693	b0803			
694	b0804			
695	b0805			
696	b0806			
697	b0809			
698	b0810			
699	b0811			
700	b0812	$0.10		
701	b0813	$13.87	$0.52	
702	b0814	$48.11	$1.79	
703	b0814.1	$0.68	$0.03	
704	b0814.10	$0.34	$0.01	
705	b0814.11	$0.34	$0.01	
706	b0814.12	$0.34	$0.01	
707	b0814.13	$0.34	$0.01	
708	b0814.14	$0.34	$0.01	
709	b0814.15	$0.34	$0.01	
710	b0814.16	$0.34	$0.01	
711	b0814.17	$0.34	$0.01	
712	b0814.18	$0.34	$0.01	
713	b0814.19	$0.34	$0.01	
714	b0814.2	$0.68	$0.03	
715	b0814.20	$0.34	$0.01	
716	b0814.21	$0.34	$0.01	
717	b0814.22	$0.34	$0.01	
718	b0814.23	$0.34	$0.01	
719	b0814.25			
720	b0814.26			
721	b0814.27			
722	b0814.28			
723	b0814.29			
724	b0814.3	$0.68	$0.03	
725	b0814.30			
726	b0814.4	$0.68	$0.03	
727	b0814.5	$0.68	$0.03	
728	b0814.6	$0.68	$0.03	

	A	B	C	D	E	F	G	H	I	J
8	Upgrade ID	Description	TO	Cost Estimate	AEC	AEP	APS	BGE	ComEd	Dayton
729	b0814.7	Replace Kearny 138 kV breaker '4HT' with 80 kA breake	PSEG	$1.00						
730	b0814.8	Replace Kearny 138 kV breaker '25HF' with 80 kA breal	PSEG	$1.00						
731	b0814.9	Replace Essex 138 kV breaker '2LM' with 63 kA breake	PSEG	$0.50						
732	b0815	Replace Elmont 230 kV breaker '22192'	Dominion	$0.18						
733	b0816	Replace Elmont 230 kV breaker '21692'	Dominion	$0.18						
734	b0817	Replace Elmont 230 kV breaker '200992'	Dominion	$0.18						
735	b0818	Replace Elmont 230 kV breaker '2009T2032'	Dominion	$0.18						
736	b0820	Remove line drop limitations at the substation terminatic	BGE	$0.40				$0.40		
737	b0821	Remove line drop limitations at the substation terminatic	BGE	$0.10				$0.10		
738	b0822	Remove line drop limitations at the substation terminatic	BGE	$0.40				$0.40		
739	b0823	Remove line drop limitations at the substation terminatic	BGE	$0.10				$0.10		
740	b0824	Remove line drop limitations at the substation terminatic	BGE	$0.10				$0.10		
741	b0825	Remove line drop limitations at the substation terminatic	BGE	$0.10				$0.10		
742	b0826	Remove line drop limitations at the substation terminatic	BGE	$0.10				$0.10		
743	b0827	Install an SPS for one year to trip a Mays Chapel 115 kV	BGE	$0.02				$0.02		
744	b0828	Disable the HS throwover at Harrisonville for one year	BGE							
745	b0829.1	Replace Whitpain 230 kV breaker '155	PECO	$0.50	$0.01	$0.08	$0.03	$0.02	$0.08	$0.01
746	b0829.11	Replace Branchburg 230 kV breaker 32H	PSEG	$0.50	$0.01	$0.08	$0.03	$0.02	$0.08	$0.01
747	b0829.12	Replace Branchburg 230 kV breaker 52H	PSEG	$0.50	$0.01	$0.08	$0.03	$0.02	$0.08	$0.01
748	b0829.2	Replace Whitpain 230 kV breaker '525'	PECO	$0.50	$0.01	$0.08	$0.03	$0.02	$0.08	$0.01
749	b0829.3	Replace Whitpain 230 kV breaker '175'	PECO	$0.50	$0.01	$0.08	$0.03	$0.02	$0.08	$0.01
750	b0829.4	Replace Plymouth Meeting 230 kV breaker '225'	PECO	$0.50	$0.01	$0.08	$0.03	$0.02	$0.08	$0.01
751	b0829.5	Replace Plymouth Meeting 230 kV breaker '335'	PECO	$0.23	$0.00	$0.04	$0.01	$0.01	$0.04	$0.01
752	b0829.6	Replace Branchburg 500 kV breaker 91X	PSEG	$0.80	$0.02	$0.13	$0.05	$0.04	$0.12	$0.02
753	b0829.9	Replace Branchburg 230 kV breaker 102H	PSEG	$0.50	$0.01	$0.08	$0.03	$0.02	$0.08	$0.01
754	b0830.1	Replace Roseland 230 kV breaker '82H' with 80 kA	PSEG	$0.80	$0.02	$0.13	$0.05	$0.04	$0.12	$0.02
755	b0830.2	Replace Roseland 230 kV breaker '91H' with 80 kA	PSEG	$0.80	$0.02	$0.13	$0.05	$0.04	$0.12	$0.02
756	b0830.3	Replace Roseland 230 kV breaker '22H' with 80 kA	PSEG	$0.80	$0.02	$0.13	$0.05	$0.04	$0.12	$0.02
757	b0837	At Mt. Storm, replace the existing MOD on the 500 kV s	Dominion	$1.50	$0.03	$0.25	$0.09	$0.07	$0.23	$0.04
758	b0838	Hazard Area 138 kV and 69 kV Improvement Projects	AEP	$44.00		$44.00				
759	b0839	Replace existing 450 MVA transformer at Twin Branch 3	AEP	$8.50		$8.48				$0.02
760	b0840	String a second 138 kV circuit on the open tower positio	AEP	$6.00		$6.00				
761	b0840.1	Establish a new 138/69-34.5kV Station to interconnect t	AEP	$3.50		$3.50				
762	b0842	Install a 2nd 230/138 kV XFMR and 35 MVAR CAP at H	PECO	$9.50						
763	b0842.1	Replace Heaton 138 kV breaker '150'	PECO	$0.24						
764	b0843	Install a 75 MVAR CAP at Llanerch 138 kV bus	PECO	$2.60						
765	b0844	Move the connection point for the Llanerch 138/69 kV X	PECO	$0.50						
766	b0845	Replace Chalk Point 230 kV breaker (1A) with 80 kA bre	PEPCO	$2.00						
767	b0846	Replace Chalk Point 230 kV breaker (1B) with 80 kA bre	PEPCO	$2.00						
768	b0847	Replace Chalk Point 230 kV breaker (2A) with 80 kA bre	PEPCO	$2.00						
769	b0848	Replace Chalk Point 230 kV breaker (2B) with 80 kA bre	PEPCO	$2.00						
770	b0849	Replace Chalk Point 230 kV breaker (2C) with 80 kA bre	PEPCO	$2.00						
771	b0850	Replace Chalk Point 230 kV breaker (3A) with 80 kA bre	PEPCO	$2.00						
772	b0851	Replace Chalk Point 230 kV breaker (3B) with 80 kA bre	PEPCO	$2.00						
773	b0852	Replace Chalk Point 230 kV breaker (3C) with 80 kA bre	PEPCO	$2.00						
774	b0853	Replace Chalk Point 230 kV breaker (4A) with 80 kA bre	PEPCO	$2.00						
775	b0854	Replace Chalk Point 230 kV breaker (4B) with 80 kA bre	PEPCO	$2.00						
776	b0855	Replace Chalk Point 230 kV breaker (5A) with 80 kA bre	PEPCO	$2.00						
777	b0856	Replace Chalk Point 230 kV breaker (5B) with 80 kA bre	PEPCO	$2.00						
778	b0857	Replace Chalk Point 230 kV breaker (6A) with 80 kA bre	PEPCO	$2.00						
779	b0858	Replace Chalk Point 230 kV breaker (6B) with 80 kA bre	PEPCO	$2.00						
780	b0859	Replace Chalk Point 230 kV breaker (7B) with 80 kA bre	PEPCO	$2.00						
781	b0860	Replace Chalk Point 230 kV breaker (8A) with 80 kA bre	PEPCO	$2.00						
782	b0861	Replace Chalk Point 230 kV breaker (8B) with 80 kA bre	PEPCO	$2.00						
783	b0862	Replace Chalk Point 230 kV breaker (7A) with 80 kA bre	PEPCO	$2.00						
784	b0863	Replace Chalk Point 230 kV breaker (1C) with 80 kA bre	PEPCO	$2.00						
785	b0870	Rebuild each line (0.2 miles each) to increase the norm	BGE	$0.54				$0.54		
786	b0871	Install 35 MVAR capacitor at Motts Farm 69 kV	AEC	$2.80	$2.80					
787	b0873	Build 2nd Glasgow-Mt Pleasant 138 kV line	DPL	$16.30						
788	b0874	Reconfigure Brandywine substation	DPL	$10.55						
789	b0876	Install 50 MVAR SVC at 138th St 138 kV	DPL	$22.80						
790	b0877	Build a 2nd Vienna-Steele 230 kV line	DPL	$44.61						
791	b0879.1	Apply a special protection scheme (load drop at Stevens	DPL	$0.05						
792	b0881	Install motor operators on Susquehanna T21 - Susqueh	PPL	$0.29						
793	b0882	Replace Hudson 230 kV breaker 1HA with 80 kA	PSEG	$0.80						
794	b0883	Replace Hudson 230 kV breaker 2HA with 80 kA	PSEG	$0.01						
795	b0884	Replace Hudson 230 kV breaker 3HB with 80 kA	PSEG	$0.01						
796	b0885	Replace Hudson 230 kV breaker 4HA with 80 kA	PSEG	$0.16						
797	b0886	Replace Hudson 230 kV breaker 4HB with 80 kA	PSEG	$0.16						
798	b0888	Replace Loudoun 230 kV Cap breaker 'SC352'	Dominion	$0.25						
799	b0889	Replace Bergen 230 kV breaker '21H'	PSEG	$0.50						
800	b0892	Replace Chesapeake 115 kV breaker SX522	Dominion	$0.20						
801	b0893	Replace Chesapeake 115 kV breaker T202	Dominion	$0.20						
802	b0894	Replace Possum Point 115 kV breaker SX-32	Dominion	$0.20						
803	b0895	Replace Possum Point 115 kV breaker L92-1	Dominion	$0.20						
804	b0896	Replace Possum Point 115 kV breaker L92-2	Dominion	$0.20						
805	b0897	Replace Suffolk 115 kV breaker T202	Dominion	$0.20						
806	b0898	Replace Peninsula 115 kV breaker SC202	Dominion	$0.20						
807	b0899	Replace ECRR 138 kV breaker 901	PSEG	$0.50						
808	b0900	Replace ECRR 138 kV breaker 902	PSEG	$0.50						
809	b0901	Replace Greene 138 kV breaker GJ-D	Dayton	$0.19						$0.19
810	b0902	Replace Greene 138 kV breaker GJ-E	Dayton	$0.19						$0.19
811	b0903	Replace Greene 138 kV breaker GJ-F	Dayton	$0.19						$0.19
812	b0904	Replace Greene 138 kV breaker GJ-H	Dayton	$0.19						$0.19
813	b0905	Replace Greene 138 kV breaker GJ-I	Dayton	$0.19						$0.19
814	b0906	Increase contact parting time on Wagner 115 kV breake	BGE							
815	b0907	Increase contact parting time on Wagner 115 kV breake	BGE							
816	b0908	Install motor operators at South Akron 230 kV	PPL	$0.73						
817	b0909	Convert Jenkins 230 kV yard into a 3-breaker ring bus	PPL	$8.74						
818	b0910	Install a second 230 kV line between Jenkins and Stant	PPL	$3.81						
819	b0911	Install motor operators at Frackville 230 kV	PPL	$0.45						

	A	K	L	M	N	O	P	Q	R	S	T	U	V
8	Upgrade ID	DL	DPL	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL
729	b0814.7						$0.24		$0.01		$0.05		
730	b0814.8						$0.24		$0.01		$0.05		
731	b0814.9						$0.12		$0.00		$0.03		
732	b0815			$0.18									
733	b0816			$0.18									
734	b0817			$0.18									
735	b0818			$0.18									
736	b0820												
737	b0821												
738	b0822												
739	b0823												
740	b0824												
741	b0825												
742	b0826												
743	b0827												
744	b0828												
745	b0829.1	$0.01	$0.01	$0.07	$0.00		$0.02	$0.01	$0.00	$0.03	$0.01	$0.02	$0.03
746	b0829.11	$0.01	$0.01	$0.07	$0.00		$0.02	$0.01	$0.00	$0.03	$0.01	$0.02	$0.03
747	b0829.12	$0.01	$0.01	$0.07	$0.00		$0.02	$0.01	$0.00	$0.03	$0.01	$0.02	$0.03
748	b0829.2	$0.01	$0.01	$0.07	$0.00		$0.02	$0.01	$0.00	$0.03	$0.01	$0.02	$0.03
749	b0829.3	$0.01	$0.01	$0.07	$0.00		$0.02	$0.01	$0.00	$0.03	$0.01	$0.02	$0.03
750	b0829.4	$0.01	$0.01	$0.07	$0.00		$0.02	$0.01	$0.00	$0.03	$0.01	$0.02	$0.03
751	b0829.5	$0.00	$0.01	$0.03	$0.00		$0.01	$0.00	$0.00	$0.01	$0.00	$0.01	$0.01
752	b0829.6	$0.02	$0.02	$0.11	$0.00		$0.04	$0.02	$0.00	$0.05	$0.02	$0.04	$0.04
753	b0829.9	$0.01	$0.01	$0.07	$0.00		$0.02	$0.01	$0.00	$0.03	$0.01	$0.02	$0.03
754	b0830.1	$0.02	$0.02	$0.11	$0.00		$0.04	$0.02	$0.00	$0.05	$0.02	$0.04	$0.04
755	b0830.2	$0.02	$0.02	$0.11	$0.00		$0.04	$0.02	$0.00	$0.05	$0.02	$0.04	$0.04
756	b0830.3	$0.02	$0.02	$0.11	$0.00		$0.04	$0.02	$0.00	$0.05	$0.02	$0.04	$0.04
757	b0837	$0.03	$0.04	$0.20	$0.00		$0.07	$0.03	$0.01	$0.09	$0.03	$0.07	$0.08
758	b0838												
759	b0839												
760	b0840												
761	b0840.1												
762	b0842									$9.50			
763	b0842.1									$0.24			
764	b0843									$2.60			
765	b0844									$0.50			
766	b0845											$2.00	
767	b0846											$2.00	
768	b0847											$2.00	
769	b0848											$2.00	
770	b0849											$2.00	
771	b0850											$2.00	
772	b0851											$2.00	
773	b0852											$2.00	
774	b0853											$2.00	
775	b0854											$2.00	
776	b0855											$2.00	
777	b0856											$2.00	
778	b0857											$2.00	
779	b0858											$2.00	
780	b0859											$2.00	
781	b0860											$2.00	
782	b0861											$2.00	
783	b0862											$2.00	
784	b0863											$2.00	
785	b0870												
786	b0871												
787	b0873		$16.30										
788	b0874		$10.55										
789	b0876		$22.80										
790	b0877		$44.61										
791	b0879.1		$0.05										
792	b0881												$0.29
793	b0882												
794	b0883												
795	b0884												
796	b0885												
797	b0886												
798	b0888			$0.25									
799	b0889												
800	b0892			$0.20									
801	b0893			$0.20									
802	b0894			$0.20									
803	b0895			$0.20									
804	b0896			$0.20									
805	b0897			$0.20									
806	b0898			$0.20									
807	b0899												
808	b0900												
809	b0901												
810	b0902												
811	b0903												
812	b0904												
813	b0905												
814	b0906												
815	b0907												
816	b0908												$0.73
817	b0909												$8.74
818	b0910												$3.81
819	b0911												$0.45

	A	W	X	Y
8	Upgrade ID	PSEG	RE	UGI
729	b0814.7	$0.68	$0.03	
730	b0814.8	$0.68	$0.03	
731	b0814.9	$0.34	$0.01	
732	b0815			
733	b0816			
734	b0817			
735	b0818			
736	b0820			
737	b0821			
738	b0822			
739	b0823			
740	b0824			
741	b0825			
742	b0826			
743	b0827			
744	b0828			
745	b0829.1	$0.04	$0.00	
746	b0829.11	$0.04	$0.00	
747	b0829.12	$0.04	$0.00	
748	b0829.2	$0.04	$0.00	
749	b0829.3	$0.04	$0.00	
750	b0829.4	$0.04	$0.00	
751	b0829.5	$0.02	$0.00	
752	b0829.6	$0.06	$0.00	
753	b0829.9	$0.04	$0.00	
754	b0830.1	$0.06	$0.00	
755	b0830.2	$0.06	$0.00	
756	b0830.3	$0.06	$0.00	
757	b0837	$0.11	$0.00	
758	b0838			
759	b0839			
760	b0840			
761	b0840.1			
762	b0842			
763	b0842.1			
764	b0843			
765	b0844			
766	b0845			
767	b0846			
768	b0847			
769	b0848			
770	b0849			
771	b0850			
772	b0851			
773	b0852			
774	b0853			
775	b0854			
776	b0855			
777	b0856			
778	b0857			
779	b0858			
780	b0859			
781	b0860			
782	b0861			
783	b0862			
784	b0863			
785	b0870			
786	b0871			
787	b0873			
788	b0874			
789	b0876			
790	b0877			
791	b0879.1			
792	b0881			
793	b0882	$0.80		
794	b0883	$0.01		
795	b0884	$0.01		
796	b0885	$0.16		
797	b0886	$0.16		
798	b0888			
799	b0889	$0.50		
800	b0892			
801	b0893			
802	b0894			
803	b0895			
804	b0896			
805	b0897			
806	b0898			
807	b0899	$0.50		
808	b0900	$0.50		
809	b0901			
810	b0902			
811	b0903			
812	b0904			
813	b0905			
814	b0906			
815	b0907			
816	b0908			
817	b0909			
818	b0910			
819	b0911			

8	Upgrade ID	Description	TO	Cost Estimate	AEC	AEP	APS	BGE	ComEd	Dayton
820	b0912	Install 2, 10.8 MVAR capacitor banks at Scranton 69 kV	PPL	$1.61						
821	b0913	Extend Cando Tap to the Harwood-Jenkins #2 69 kV lin	PPL	$0.81						
822	b0914	Build a 3rd 69 kV line from Harwood to Valmont Taps	PPL	$2.95						
823	b0915	Replace Walnut-Center City 69 kV cable	PPL	$1.73						
824	b0916	Reconductor Sunbury-Dalmatia 69 kV line	PPL	$10.48						
825	b0917	Replace Baileysville 138 kV breaker 'P'	AEP	$0.40		$0.40				
826	b0918	Replace Riverview 138 kV breaker '634'	AEP	$0.40		$0.40				
827	b0919	Replace Torrey 138 kV breaker 'W'	AEP	$0.40		$0.40				
828	b0920	Replace station cable at Whitpain and Jarrett substation	PECO	$0.18						
829	b0921	Reconductor Brambleton - Cochran Mill 230 kV line with	Dominion	$2.80						
830	b0923	Install 50-100 MVAR variable reactor banks at Carson 2	Dominion	$5.50						
831	b0924	Install 50-100 MVAR variable reactor banks at Dooms 2	Dominion	$5.50						
832	b0925	Install 50-100 MVAR variable reactor banks at Garrison	Dominion	$5.50						
833	b0926	Install 50-100 MVAR variable reactor banks at Hamilton	Dominion	$5.70						
834	b0927	Install 50-100 MVAR variable reactor banks at Yadkin 2	Dominion	$5.50						
835	b0928	Install 50-100 MVAR variable reactor banks at Carolina,	Dominion	$48.00						
836	b0929	Replace Universal 138 kV breaker 'Z-152'	DL	$0.30						
837	b0930	Replace Universal 138 kV breaker 'Z-78'	DL	$0.30						
838	b0931	Replace Universal 138 kV breaker 'NO 1-3'	DL	$0.30						
839	b0932	Replace Brunot Island 138 kV breaker 'GEN2 69 XFMR	DL	$0.30						
840	b0933	Replace Dravosburg 138 kV breaker 'Z-91'	DL	$0.31						
841	b0934	Replace Dravosburg 138 kV breaker 'Z-87'	DL	$0.31						
842	b0935	Replace Dravosburg 138 kV breaker 'Z-76'	DL	$0.31						
843	b0936	Replace Dravosburg 138 kV breaker 'Z-77'	DL	$0.31						
844	b0937	Replace Dravosburg 138 kV breaker 'Z-74'	DL	$0.32						
845	b0938	Replace Elrama 138 kV breaker '#3 SYN B'	DL	$0.32						
846	b0939	Replace Elrama 138 kV breaker '#4 SYN REA'	DL	$0.32						
847	b0940	Replace Cheswick 138 kV breaker '2a/2B CAP'	DL	$0.32						
848	b0950	Replace Yukon 138 kV breaker 'Y-4'	APS	$0.20			$0.20			
849	b0951	Replace Yukon 138 kV breaker 'Y-9'	APS	$0.20			$0.20			
850	b0952	Replace Yukon 138 kV breaker 'Y-11'	APS	$0.20			$0.20			
851	b0953	Replace Yukon 138 kV breaker 'Y-13'	APS	$0.20			$0.20			
852	b0954	Replace Charleroi 138 kV breaker '#1 XFMR BANK'	APS	$0.17			$0.17			
853	b0955	Replace Yukon 138 kV breaker 'Y-7'	APS	$0.20			$0.20			
854	b0956	Replace Pruntytown 138 kV breaker 'P-9'	APS	$0.20			$0.20			
855	b0957	Replace Pruntytown 138 kV breaker 'P-12'	APS	$0.20			$0.20			
856	b0958	Replace Pruntytown 138 kV breaker 'P-15'	APS	$0.20			$0.20			
857	b0959	Replace Charleroi 138 kV breaker '#2 XFMR BANK'	APS	$0.17			$0.17			
858	b0960	Replace Pruntytown 138 kV breaker 'P-2'	APS	$0.20			$0.20			
859	b0961	Replace Pruntytown 138 kV breaker 'P-5'	APS	$0.20			$0.20			
860	b0962	Replace Yukon 138 kV breaker 'Y-18'	APS	$0.20			$0.20			
861	b0963	Replace Yukon 138 kV breaker 'Y-10'	APS	$0.20			$0.20			
862	b0964	Replace Pruntytown 138 kV breaker 'P-11'	APS	$0.20			$0.20			
863	b0965	Replace Springdale 138 kV breaker '138E'	APS	$0.20			$0.20			
864	b0966	Replace Pruntytown 138 kV breaker 'P-8'	APS	$0.20			$0.20			
865	b0967	Replace Pruntytown 138 kV breaker 'P-14'	APS	$0.20			$0.20			
866	b0968	Replace Ringgold 138 kV breaker '#3 XFMR BANK'	APS	$0.14			$0.14			
867	b0969	Replace Springdale 138 kV breaker '138C'	APS	$0.20			$0.20			
868	b0970	Replace Rivesville 138 kV breaker '#8 XFMR BANK'	APS	$0.14			$0.14			
869	b0971	Replace Springdale 138 kV breaker '138F'	APS	$0.20			$0.20			
870	b0972	Replace Belmont 138 kV breaker 'B-16'	APS	$0.20			$0.20			
871	b0973	Replace Springdale 138 kV breaker '138G'	APS	$0.20			$0.20			
872	b0974	Replace Springdale 138 kV breaker '138V'	APS	$0.20			$0.20			
873	b0975	Replace Armstrong 138 kV breaker 'BROOKVILLE'	APS	$0.14			$0.14			
874	b0976	Replace Springdale 138 kV breaker '138P'	APS	$0.20			$0.20			
875	b0977	Replace Belmont 138 kV breaker 'B-17'	APS	$0.20			$0.20			
876	b0978	Replace Springdale 138 kV breaker '138U'	APS	$0.20			$0.20			
877	b0979	Replace Springdale 138 kV breaker '138D'	APS	$0.20			$0.20			
878	b0980	Replace Springdale 138 kV breaker '138R'	APS	$0.20			$0.20			
879	b0981	Replace Yukon 138 kV breaker 'Y-12'	APS	$0.20			$0.20			
880	b0982	Replace Yukon 138 kV breaker 'Y-17'	APS	$0.20			$0.20			
881	b0983	Replace Yukon 138 kV breaker 'Y-14'	APS	$0.20			$0.20			
882	b0984	Replace Rivesville 138 kV breaker '#10 XFMR BANK'	APS	$0.14			$0.14			
883	b0985	Replace Belmont 138 kV breaker 'B-14'	APS	$0.20			$0.20			
884	b0986	Replace Armstrong 138 kV breaker 'RESERVE BUS'	APS	$0.14			$0.14			
885	b0987	Replace Yukon 138 kV breaker 'Y-16'	APS	$0.20			$0.20			
886	b0988	Replace Springdale 138 kV breaker '138T'	APS	$0.20			$0.20			
887	b0989	Replace Edgelawn 138 kV breaker 'GOFF RUN #632'	APS	$0.14			$0.14			
888	b0990	Change reclosing on Cabot 138 kV breaker 'C-9'	APS	$0.00			$0.00			
889	b0991	Change reclosing on Belmont 138 kV breaker 'B-7'	APS	$0.00			$0.00			
890	b0992	Change reclosing on Belmont 138 kV breaker 'B-12'	APS	$0.00			$0.00			
891	b0993	Change reclosing on Belmont 138 kV breaker 'B-9'	APS	$0.00			$0.00			
892	b0994	Change reclosing on Belmont 138 kV breaker 'B-19'	APS	$0.00			$0.00			
893	b0995	Change reclosing on Belmont 138 kV breaker 'B-21'	APS	$0.00			$0.00			
894	b0996	Change reclosing on Willow Island 138 kV breaker 'FAII	APS	$0.00			$0.00			
895	b0997	Change reclosing on Cabot 138 kV breaker 'C-4'	APS	$0.00			$0.00			
896	b0998	Change reclosing on Cabot 138 kV breaker 'C-1'	APS	$0.00			$0.00			
897	b0999	Replace Redbud 138 kV breaker 'BUS TIE'	APS	$0.14			$0.14			
898	b1002	Replace Hunterstown 115 kV breaker '96392'	ME	$0.23						
899	b1003	Replace Hunterstown 115 kV breaker '96292'	ME	$0.23						
900	b1004	Replace Hunterstown 115 kV breaker '99192'	ME	$0.23						
901	b1005	Replace Glory 115 kV breaker '#7 XFMR'	PENELEC	$0.23						
902	b1006	Replace Shawville 115 kV breaker 'NO.14 XFMR'	PENELEC	$0.23						
903	b1007	Replace Shawville 115 kV breaker 'NO.15 XFMR'	PENELEC	$0.23						
904	b1008	Replace Shawville 115 kV breaker '#1B XFMR'	PENELEC	$0.23						
905	b1009	Replace Shawville 115 kV breaker '#2B XFMR	PENELEC	$0.23						
906	b1010	Replace Shawville 115 kV breaker 'Dubois'	PENELEC	$0.23						
907	b1011	Replace Shawville 115 kV breaker 'Philipsburg'	PENELEC	$0.23						
908	b1012	Replace Shawville 115 kV breaker 'Garman'	PENELEC	$0.23						
909	b1013	Replace Linden 138 kV breaker '7PB'	PSEG	$0.50						
910	b1014.1	Replace Circuit breaker, Station Cable, CTs and Wave '	PECO	$1.00						

	A	K	L	M	N	O	P	Q	R	S	T	U	V
8	Upgrade ID	DL	DPL	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL
820	b0912												$1.61
821	b0913												$0.81
822	b0914												$2.95
823	b0915												$1.73
824	b0916												$10.48
825	b0917												
826	b0918												
827	b0919												
828	b0920									$0.18			
829	b0921			$2.80									
830	b0923			$5.50									
831	b0924			$5.50									
832	b0925			$5.50									
833	b0926			$5.70									
834	b0927			$5.50									
835	b0928			$48.00									
836	b0929	$0.30											
837	b0930	$0.30											
838	b0931	$0.30											
839	b0932	$0.30											
840	b0933	$0.31											
841	b0934	$0.31											
842	b0935	$0.31											
843	b0936	$0.31											
844	b0937	$0.32											
845	b0938	$0.32											
846	b0939	$0.32											
847	b0940	$0.32											
848	b0950												
849	b0951												
850	b0952												
851	b0953												
852	b0954												
853	b0955												
854	b0956												
855	b0957												
856	b0958												
857	b0959												
858	b0960												
859	b0961												
860	b0962												
861	b0963												
862	b0964												
863	b0965												
864	b0966												
865	b0967												
866	b0968												
867	b0969												
868	b0970												
869	b0971												
870	b0972												
871	b0973												
872	b0974												
873	b0975												
874	b0976												
875	b0977												
876	b0978												
877	b0979												
878	b0980												
879	b0981												
880	b0982												
881	b0983												
882	b0984												
883	b0985												
884	b0986												
885	b0987												
886	b0988												
887	b0989												
888	b0990												
889	b0991												
890	b0992												
891	b0993												
892	b0994												
893	b0995												
894	b0996												
895	b0997												
896	b0998												
897	b0999												
898	b1002							$0.23					
899	b1003							$0.23					
900	b1004							$0.23					
901	b1005										$0.23		
902	b1006										$0.23		
903	b1007										$0.23		
904	b1008										$0.23		
905	b1009										$0.23		
906	b1010										$0.23		
907	b1011										$0.23		
908	b1012										$0.23		
909	b1013												
910	b1014.1									$1.00			

	A	W	X	Y
8	Upgrade ID	PSEG	RE	UGI
820	b0912			
821	b0913			
822	b0914			
823	b0915			
824	b0916			
825	b0917			
826	b0918			
827	b0919			
828	b0920			
829	b0921			
830	b0923			
831	b0924			
832	b0925			
833	b0926			
834	b0927			
835	b0928			
836	b0929			
837	b0930			
838	b0931			
839	b0932			
840	b0933			
841	b0934			
842	b0935			
843	b0936			
844	b0937			
845	b0938			
846	b0939			
847	b0940			
848	b0950			
849	b0951			
850	b0952			
851	b0953			
852	b0954			
853	b0955			
854	b0956			
855	b0957			
856	b0958			
857	b0959			
858	b0960			
859	b0961			
860	b0962			
861	b0963			
862	b0964			
863	b0965			
864	b0966			
865	b0967			
866	b0968			
867	b0969			
868	b0970			
869	b0971			
870	b0972			
871	b0973			
872	b0974			
873	b0975			
874	b0976			
875	b0977			
876	b0978			
877	b0979			
878	b0980			
879	b0981			
880	b0982			
881	b0983			
882	b0984			
883	b0985			
884	b0986			
885	b0987			
886	b0988			
887	b0989			
888	b0990			
889	b0991			
890	b0992			
891	b0993			
892	b0994			
893	b0995			
894	b0996			
895	b0997			
896	b0998			
897	b0999			
898	b1002			
899	b1003			
900	b1004			
901	b1005			
902	b1006			
903	b1007			
904	b1008			
905	b1009			
906	b1010			
907	b1011			
908	b1012			
909	b1013	$0.50		
910	b1014.1			

	A	B	C	D	E	F	G	H	I	J
8	Upgrade ID	Description	TO	Cost Estimate	AEC	AEP	APS	BGE	ComEd	Dayton
911	b1014.2	Replace Circuit breaker, Station Cable, CTs Disconnect	PECO	$1.00						
912	b1015	Replace Breakers #115 and #125 at Printz 230 kV subs	PECO	$1.00						
913	b1016	Rebuild Graceton - Bagley 230 kV as double circuit line	BGE	$42.60			$0.86	$32.04		
914	b1017	Reconductor South Mahwah -Waldwick 345 kV J-3410 (	PSEG	$11.45						
915	b1018	Reconductor South Mahwah -Waldwick 345 kV K-3411	PSEG	$11.45						
916	b1019.1	Replace wave trap, line disconnect and ground switch a	PSEG	$0.35						
917	b1019.10	Replace wave trap, line, ground 230 kV breaker disconn	PSEG	$0.35						
918	b1019.2	Replace wave trap, line disconnect and ground switch a	PSEG	$0.35						
919	b1019.3	Replace 1-2 and 2-3 section disconnect and ground swi	PSEG	$0.35						
920	b1019.4	Replace 1-2 and 2-3 section disconnect and ground swi	PSEG	$0.35						
921	b1019.5	Replace wave trap, line disconnect and ground switch a	PSEG	$0.35						
922	b1019.6	Replace line disconnect and ground switch at Cedar Gr	PSEG	$0.35						
923	b1019.7	Replace 2-4 and 4-5 section disconnect and ground swi	PSEG	$0.35						
924	b1019.8	Replace 1-2 and 2-3 section disconnect and ground swi	PSEG	$0.35						
925	b1019.9	Replace line, ground, 230 kV main bus disconnects at A	PSEG	$0.35						
926	b1020	Replace wave trap at Englishtown on the Englishtown -	JCPL	$0.07						
927	b1021	Install a new (#4) 138/69 kV transformer at Wescosville	PPL	$4.50						
928	b1022.1	Reconfigure the Peters to Bethel Park 138 kV line and E	APS/DL	$2.30			$2.23			
929	b1022.2	Reconductor both Collier - Woodville 138 kV lines	DL	$3.10						
930	b1022.3	Add static capacitors at Smith 138 kV	APS	$0.80			$0.78			
931	b1022.4	Add static capacitors at North Fayette 138 kV	APS	$0.90			$0.87			
932	b1022.5	Add static capacitors at South Fayette 138 kV	APS	$0.80			$0.78			
933	b1022.6	Add static capacitors at Manifold 138 kV	APS	$0.80			$0.78			
934	b1022.7	Add static capacitors at Houston 138 kV	APS	$0.80			$0.78			
935	b1023.1	Install a 500/138 kV transformer at 502 Junction	APS	$27.20			$27.20			
936	b1023.2	Construct a new Franklin - 502 Junction 138 kV line incl	APS	$13.00			$13.00			
937	b1023.3	Construct a new 502 Junction - Osage 138 kV line	APS	$4.20			$4.20			
938	b1023.4	Construct Braddock 138 kV breaker station that connect	APS	$15.10			$15.10			
939	b1027	Increase the size of the shunt capacitors at Enon 138 kV	APS	$4.20			$4.20			
940	b1028	Raise three structures on the Osage - Collins Ferry 138	APS	$2.30			$2.30			
941	b1029	Upgrade wire sections at Wagner on both 110534 and 1	BGE	$0.10				$0.10		
942	b1030	Move the Hillen Rd substation from circuits 110507/110!	BGE	$0.09				$0.09		
943	b1031	Replace wire sections on Westport - Pumphrey 115 kV (	BGE	$0.20				$0.20		
944	b1032.1	Construct a new 345/138kV station on the Marquis-Bixb	AEP	$50.00		$44.99				$5.02
945	b1032.2	Construct two 138kV outlets to Delano 138kV station an	AEP							
946	b1032.3	Convert Ross - Circleville 69kV to 138kV	AEP							
947	b1032.4	Install 138/69kV transformer at new station and connect	AEP							
948	b1033	Add a third delivery point from AEP's East Danville Stati	AEP	$1.60		$1.60				
949	b1034.1	Establish new South Canton - West Canton 138kV line (	AEP	$28.00		$26.88	$0.17		$0.05	$0.12
950	b1034.2	Loop the existing South Canton -Wayview 138kV circuit	AEP							
951	b1034.3	Install a 345/138kV 450 MVA transformer at Canton Ce	AEP							
952	b1034.4	Rebuild/reconductor the Sunnyside - Torrey 138kV line	AEP							
953	b1034.5	Disconnect/eliminate the West Canton 138kV terminal a	AEP							
954	b1034.6	Replace all 138kV circuit breakers at South Canton Stat	AEP							
955	b1034.7	Replace all obsolete 138kV circuit breakers at the Torre	AEP							
956	b1034.8	Install additional 138kV circuit breakers at the West Car	AEP							
957	b1035	Establish a third 345kV breaker string in the West Miller	AEP	$28.00		$28.00				
958	b1036	Upgrade terminal equipment at Poston Station and upda	AEP	$1.40		$1.40				
959	b1037	Sag check Bonsack–Cloverdale 138 kV, Cloverdale–Ce	AEP	$3.00		$3.00				
960	b1038	Check the Crooksville - Muskingum 138 kV sag and per	AEP	$1.00		$1.00				
961	b1039	Perform a sag study for the Madison – Cross Street 138	AEP	$0.15		$0.15				
962	b1040	Rebuild an 0.065 mile section of the New Carlisle – Oliv	AEP	$1.00		$1.00				
963	b1041	Perform a sag study for the Moseley - Roanoke 138 kV	AEP	$1.05		$1.05				
964	b1042	Perform sag studies to raise the emergency rating of An	AEP	$0.06		$0.06				
965	b1043	Perform sag studies to raise the emergency rating of Tu	AEP	$0.02		$0.02				
966	b1044	Perform sag studies to raise the emergency rating of Ke	AEP	$0.07		$0.07				
967	b1045	Perform sag studies of Tri State - Darrah 138 kV	AEP	$0.66		$0.66				
968	b1046	Perform sag study of Scottsville – Bremo 138kV to raise	AEP	$0.35		$0.35				
969	b1047	Perform sag study of Otter Switch - Altavista 138kV to ra	AEP	$0.05		$0.05				
970	b1048	Reconductor the Bixby - Three C - Groves and Bixby - (	AEP	$5.90		$5.90				
971	b1049	Upgrade the risers at the Riverside station to increase th	AEP	$0.10		$0.10				
972	b1050	Rebuilding and reconductor the Bixby – Pickerington Ro	AEP	$12.50		$12.50				
973	b1051	Perform a sag study for the Kenzie Creek – Pokagon 13	AEP	$0.15		$0.15				
974	b1052	Unsix-wire the existing Hyatt - Sawmill 138 kV line to for	AEP	$3.10		$3.10				
975	b1053	Perform a sag study and remediation of 32 miles betwe	AEP	$1.60		$1.60				
976	b1054	Change relay settings on Byron -Wempletown 345 kV to	ComEd	$0.01					$0.01	
977	b1055	Upgrade wire drops at Center 115kV on the Center - We	BGE	$0.20				$0.20		
978	b1058	Add a third 230/115 kV transformer at Suffolk substation	Dominion	$6.00						
979	b1058.1	Replace Suffolk 115 kV breaker 'T122' with a 40 kA brea	Dominion	$0.17						
980	b1059	Replace a CRS relay at Hooversville 115 kV station	PENELEC	$0.07						
981	b1060	Replace a CRS relay at Rachel Hill 115 kV station	PENELEC	$0.07						
982	b1061	Replace existing Yorkana 230/115 kV transformer bank	ME	$4.20						
983	b1062	Add 2nd 345/138 kV transformer at Shelby	Dayton	$7.00						$7.00
984	b1063	Add two 30 MVAR capacitor banks at Sidney 69 kV stat	Dayton	$0.60						$0.60
985	b1064	Add a 30 MVAR capacitor bank at Eldean 69 kV station	Dayton	$0.40						$0.40
986	b1065.1	Install a new Shelby 138/69 kV transformer at Shelby st	Dayton	$5.00						$5.00
987	b1065.2	Install a 69 kV line between Shelby 69kV station and Bl	Dayton	$7.50						$7.50
988	b1065.3	Install a new 30 MVAR capacitor bank at Blue Jacket 69	Dayton	$0.40						$0.40
989	b1066	Install a new 30 MVAR shunt at Amsterdam 69 kV static	Dayton	$0.40						$0.40
990	b1067	Install a new 30 MVAR shunt at Logan 69 kV station	Dayton	$0.40						$0.40
991	b1068	Install a new 30 MVAR shunt at Darby 69 kV station	Dayton	$0.40						$0.40
992	b1071	Rebuild the existing 115 kV corridor between Landstown	Dominion	$38.00						
993	b1072	Modify the existing EMS load shedding scheme at Ceda	AEC	$0.05	$0.05					
994	b1073	Install 2 new 230 kV breakers at Planebrook (on the 22(	PECO	$1.30						
995	b1074	Install motor operators on the Jenkins 230 kV '2W' disc	PPL	$1.06						
996	b1075	Replace the West Wharton - Franklin - Vermont D931 a	JCPL	$0.07						
997	b1076	Replace existing North Anna 500-230kV transformer wit	Dominion	$16.00						
998	b1077	Reconductor East Sidney-Shelby 138 kV	Dayton	$0.53						$0.53
999	b1078	Reconductor Greene - Alpha 138 kV	Dayton	$1.63						$1.63
1000	b1079	Perform sag study on Bath - Trebein 138 kV line to ensu	Dayton							
1001	b1080	Restudy rating of Arsenal – Highland 138 kV undergrou	DL							

	A	K	L	M	N	O	P	Q	R	S	T	U	V
8	Upgrade ID	DL	DPL	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL
911	b1014.2									$1.00			
912	b1015									$1.00			
913	b1016			$6.86								$2.81	
914	b1017				$0.05		$3.38		$0.16				
915	b1018				$0.05		$3.40		$0.16				
916	b1019.1												
917	b1019.10												
918	b1019.2												
919	b1019.3												
920	b1019.4												
921	b1019.5												
922	b1019.6												
923	b1019.7												
924	b1019.8												
925	b1019.9												
926	b1020						$0.07						
927	b1021												$4.50
928	b1022.1	$0.07											
929	b1022.2	$3.10											
930	b1022.3	$0.02											
931	b1022.4	$0.03											
932	b1022.5	$0.02											
933	b1022.6	$0.02											
934	b1022.7	$0.02											
935	b1023.1												
936	b1023.2												
937	b1023.3												
938	b1023.4												
939	b1027												
940	b1028												
941	b1029												
942	b1030												
943	b1031												
944	b1032.1												
945	b1032.2												
946	b1032.3												
947	b1032.4												
948	b1033												
949	b1034.1	$0.04									$0.73		
950	b1034.2												
951	b1034.3												
952	b1034.4												
953	b1034.5												
954	b1034.6												
955	b1034.7												
956	b1034.8												
957	b1035												
958	b1036												
959	b1037												
960	b1038												
961	b1039												
962	b1040												
963	b1041												
964	b1042												
965	b1043												
966	b1044												
967	b1045												
968	b1046												
969	b1047												
970	b1048												
971	b1049												
972	b1050												
973	b1051												
974	b1052												
975	b1053												
976	b1054												
977	b1055												
978	b1058			$6.00									
979	b1058.1			$0.17									
980	b1059										$0.07		
981	b1060										$0.07		
982	b1061							$4.20					
983	b1062												
984	b1063												
985	b1064												
986	b1065.1												
987	b1065.2												
988	b1065.3												
989	b1066												
990	b1067												
991	b1068												
992	b1071			$38.00									
993	b1072												
994	b1073									$1.30			
995	b1074												$1.06
996	b1075						$0.07						
997	b1076			$16.00									
998	b1077												
999	b1078												
1000	b1079												
1001	b1080												

	A	W	X	Y
8	Upgrade ID	PSEG	RE	UGI
911	b1014.2			
912	b1015			
913	b1016			
914	b1017	$7.56	$0.30	
915	b1018	$7.54	$0.29	
916	b1019.1	$0.35		
917	b1019.10	$0.35		
918	b1019.2	$0.35		
919	b1019.3	$0.35		
920	b1019.4	$0.35		
921	b1019.5	$0.35		
922	b1019.6	$0.35		
923	b1019.7	$0.35		
924	b1019.8	$0.35		
925	b1019.9	$0.35		
926	b1020			
927	b1021			
928	b1022.1			
929	b1022.2			
930	b1022.3			
931	b1022.4			
932	b1022.5			
933	b1022.6			
934	b1022.7			
935	b1023.1			
936	b1023.2			
937	b1023.3			
938	b1023.4			
939	b1027			
940	b1028			
941	b1029			
942	b1030			
943	b1031			
944	b1032.1			
945	b1032.2			
946	b1032.3			
947	b1032.4			
948	b1033			
949	b1034.1			
950	b1034.2			
951	b1034.3			
952	b1034.4			
953	b1034.5			
954	b1034.6			
955	b1034.7			
956	b1034.8			
957	b1035			
958	b1036			
959	b1037			
960	b1038			
961	b1039			
962	b1040			
963	b1041			
964	b1042			
965	b1043			
966	b1044			
967	b1045			
968	b1046			
969	b1047			
970	b1048			
971	b1049			
972	b1050			
973	b1051			
974	b1052			
975	b1053			
976	b1054			
977	b1055			
978	b1058			
979	b1058.1			
980	b1059			
981	b1060			
982	b1061			
983	b1062			
984	b1063			
985	b1064			
986	b1065.1			
987	b1065.2			
988	b1065.3			
989	b1066			
990	b1067			
991	b1068			
992	b1071			
993	b1072			
994	b1073			
995	b1074			
996	b1075			
997	b1076			
998	b1077			
999	b1078			
1000	b1079			
1001	b1080			

	A	B	C	D	E	F	G	H	I	J
8	Upgrade ID	Description	TO	Cost Estimate	AEC	AEP	APS	BGE	ComEd	Dayton
1002	b1081	Increase rating by forced cooling on Brunot Island – Bra	DL							
1003	b1082	Install 230/138 kV transformer at Bergen substation	PSEG	$22.60						
1004	b1083	Upgrade wire sections of the Mays Chapel – Mt Washin	BGE	$0.10				$0.10		
1005	b1084	Extend circuit 110570 from Deer Park to Northwest, and	BGE	$5.00				$5.00		
1006	b1085	Upgrade substation wire conductors at Lipins Corner to	BGE	$1.50				$1.50		
1007	b1086	Build a new 115 kV switching station between Orchard S	BGE	$26.00				$26.00		
1008	b1087	Replace Cannon Branch 230-115 kV with larger transfo	Dominion	$5.00						
1009	b1088	Build new Radnor Heights Sub, add new underground c	Dominion	$87.50						
1010	b1089	Install 2nd Burke to Sideburn 230 kV underground cable	Dominion	$9.00						
1011	b1090	Install a 150 MVAR 230 kV capacitor and one 230 kV br	Dominion	$1.70						
1012	b1091	Add 28.8 MVAR 138 kV capacitor bank at Huffman and	AEP	$2.40		$2.40				
1013	b1092	Add 28.8 MVAR 138 kV capacitor bank at Sullivan Gard	AEP	$2.00		$2.00				
1014	b1093	Add a 43.2 MVAR capacitor bank at the Morgan Fork 1	AEP	$0.80		$0.80				
1015	b1094	Add a 64.8 MVAR capacitor bank at the West Huntingto	AEP	$0.80		$0.80				
1016	b1095	Reconductor Chase City 115 kV bus and add a new tie	Dominion	$2.40						
1017	b1096	Construct 10 mile double ckt. 230kV tower line from Lou	Dominion	$27.20						
1018	b1097	Add a 138 kV bus tie CB and two other 138 kV CB's at I	ComEd	$4.50					$4.50	
1019	b1098	Re-configure the Bayway 138 kV substation and install I	PSEG	$15.00						
1020	b1099	Build a new 230 kV substation by tapping the Aldene – I	PSEG	$137.00						
1021	b1100	Build a new 138 kV circuit from Bayonne to Marion	PSEG	$137.00						
1022	b1101	Re-configure the Cedar Grove substation with breaker a	PSEG	$76.40						
1023	b1102	Replace Bremo 115 kV breaker '9122'	Dominion	$0.16						
1024	b1103	Replace Bremo 115 kV breaker '822'	Dominion	$0.16						
1025	b1104	Replace Burtonsville 230 kV breaker '1C'	PEPCO	$1.38						
1026	b1105	Replace Burtonsville 230 kV breaker '2C'	PEPCO	$1.38						
1027	b1106	Replace Burtonsville 230 kV breaker '3C'	PEPCO	$1.38						
1028	b1107	Replace Burtonsville 230 kV breaker '4C'	PEPCO	$1.38						
1029	b1108	Replace Ohio Central 138 kV breaker 'C2'	AEP	$0.80		$0.80				
1030	b1109	Replace Ohio Central 138 kV breaker 'D1'	AEP	$0.80		$0.80				
1031	b1110	Replace Sporn A 138 kV breaker 'J'	AEP	$0.80		$0.80				
1032	b1111	Replace Sporn A 138 kV breaker 'J2'	AEP	$0.80		$0.80				
1033	b1112	Replace Sporn A 138 kV breaker 'L'	AEP	$0.80		$0.80				
1034	b1113	Replace Sporn A 138 kV breaker 'L1'	AEP	$0.80		$0.80				
1035	b1114	Replace Sporn A 138 kV breaker 'L2'	AEP	$0.80		$0.80				
1036	b1115	Replace Sporn A 138 kV breaker 'N'	AEP	$0.80		$0.80				
1037	b1116	Replace Sporn A 138 kV breaker 'N2'	AEP	$0.80		$0.80				
1038	b1117	Replace Beaver Valley 138 kV breaker '1A & 3A SS tfm	DL	$0.40						
1039	b1118	Replace Beaver Valley 138 kV breaker '1B & 3B SS tfm	DL	$0.40						
1040	b1119	Replace Beaver Valley 138 kV breaker '2B SS tfmr'	DL	$0.40						
1041	b1120	Replace Beaver Valley 138 kV breaker 'Z30 Midland	DL	$0.40						
1042	b1121	Replace Beaver Valley 138 kV breaker 'Z33 J&L Midlan	DL							
1043	b1122	Replace Elwyn 138 kV breaker 'Z62 Collier'	DL	$0.33						
1044	b1123	Replace Elwyn 138 kV breaker 'No. 1-2 138 kV bus'	DL	$0.33						
1045	b1124	Replace Elwyn 138 kV breaker 'No. 2-3 138 kV bus'	DL	$0.33						
1046	b1125	Convert the 138 kV line from Buzzard 138 - Ritchie 851	PEPCO	$56.00			$2.65			
1047	b1126	Upgrade the 230 kV line from Buzzard 016 – Ritchie 05	PEPCO	$39.00			$1.85			
1048	b1127	Build a new Lincoln-Minitola 138 kV line	AEC	$12.50	$12.50					
1049	b1128	Reconductor the Edgewater – Vasco Tap; Edgewater –	APS	$2.30			$2.30			
1050	b1129	Reconductor the East Waynesboro – Ringgold 138 kV li	APS	$3.00			$3.00			
1051	b1131	Upgrade Double Tollgate – Meadowbrook MDT Termina	APS	$0.03			$0.03			
1052	b1132	Upgrade Double Tollgate-Meadowbrook MBG terminal	APS	$0.03			$0.03			
1053	b1133	Upgrade terminal equipment at Springdale	APS	$0.02			$0.02			
1054	b1135	Reconductor the Bartonville – Meadowbrook 138 kV line	APS	$2.90			$2.90			
1055	b1137	Reconductor the Eastgate – Luxor 138 kV; Eastgate – S	APS	$5.80			$4.56			
1056	b1138	Reconductor the King Farm – Sony 138 kV line with 95	APS	$0.70			$0.70			
1057	b1139	Reconductor the Yukon – Waltz Mills 138 kV line with hi	APS	$2.00			$2.00			
1058	b1140	Reconductor the Bracken Junction – Luxor 138 kV line	APS	$0.80			$0.80			
1059	b1141	Reconductor the Sewickley – Waltz Mills Tap 138 kV lin	APS	$1.00			$1.00			
1060	b1142	Reconductor the Bartonsville – Stephenson 138 kV; Sto	APS	$2.30			$2.30			
1061	b1143	Reconductor the Youngwood – Yukon 138 kV line with I	APS	$5.90			$5.31			
1062	b1144	Reconductor the Bull Creek Junction – Cabot 138 kV lin	APS	$1.60			$1.60			
1063	b1145	Reconductor the Lawson Junction – Cabot 138 kV line	APS	$1.60			$1.60			
1064	b1146	Replace Layton - Smithton #61 138 kV line structures to	APS	$0.30			$0.30			
1065	b1147	Replace Smith – Yukon 138 kV line structures to increa	APS	$0.30			$0.30			
1066	b1148	Reconductor the Loyalhanna – Luxor 138 kV line with 9	APS	$3.20			$3.20			
1067	b1149	Reconductor the Luxor – Stony Springs Junction 138 kV	APS	$1.70			$1.70			
1068	b1150	Upgrade terminal equipment at Social Hall	APS	$0.02			$0.02			
1069	b1151	Reconductor the Greenwood – Redbud 138 kV line with	APS	$2.70			$2.70			
1070	b1152	Reconductor Grand Point – South Chambersburg	APS	$2.90			$2.90			
1071	b1153	Upgrade Conemaugh 500/230 kV transformer and add	PENELEC	$29.80	$1.11		$1.87	$5.01		
1072	b1154	Convert the West Orange 138 kV substation, the two R	PSEG	$336.00						
1073	b1155	Build a new 230 kV circuit from Branchburg to Middlese	PSEG	$125.00						
1074	b1156	Convert the Burlington, Camden, and Cuthbert Blvd 13	PSEG	$381.00						
1075	b1156.1	Upgrade at Richmond 230 kV breaker '525'	PECO	$0.10						
1076	b1156.10	Upgrade at Plymouth Meeting 230 kV breaker '265'	PECO	$0.50						
1077	b1156.2	Upgrade at Richmond 230 kV breaker '415'	PECO	$0.10						
1078	b1156.3	Upgrade at Richmond 230 kV breaker '475'	PECO	$0.10						
1079	b1156.4	Upgrade at Richmond 230 kV breaker '575'	PECO	$0.10						
1080	b1156.5	Upgrade at Richmond 230 kV breaker '185'	PECO	$0.10						
1081	b1156.6	Upgrade at Richmond 230 kV breaker '285'	PECO	$0.10						
1082	b1156.7	Upgrade at Richmond 230 kV breaker '85'	PECO	$0.10						
1083	b1156.8	Upgrade at Waneeta 230 kV breaker '425'	PECO	$0.50						
1084	b1156.9	Upgrade at Emilie 230 kV breaker '815'	PECO	$0.50						
1085	b1157	Replace the 345 kV bus tie CB 2-3 at Lisle	ComEd	$0.01					$0.01	
1086	b1158	Add a 57.6 MVAR capacitor at Prospect Heights 138 kV	ComEd	$1.55					$1.55	
1087	b1159	Replace Peters 138 kV breaker 'Bethel P OCB'	APS	$0.19			$0.19			
1088	b1160	Replace Peters 138 kV breaker 'Cecil OCB'	APS	$0.19			$0.19			
1089	b1161	Replace Peters 138 kV breaker 'Union JctOCB'	APS	$0.19			$0.19			
1090	b1162	Replace Double Toll Gate 138 kV breaker 'DRB-2'	APS	$0.19			$0.19			
1091	b1163	Replace Double Toll Gate 138 kV breaker 'DT 138 kV C	APS	$0.19			$0.19			
1092	b1164	Replace Cecil 138 kV breaker 'Enlow OCB'	APS	$0.19			$0.19			

	A	K	L	M	N	O	P	Q	R	S	T	U	V
8	Upgrade ID	DL	DPL	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL
1002	b1081												
1003	b1082										$3.73		
1004	b1083												
1005	b1084												
1006	b1085												
1007	b1086												
1008	b1087			$5.00									
1009	b1088			$87.50									
1010	b1089			$9.00									
1011	b1090			$1.70									
1012	b1091												
1013	b1092												
1014	b1093												
1015	b1094												
1016	b1095			$2.40									
1017	b1096			$27.20									
1018	b1097												
1019	b1098												
1020	b1099												
1021	b1100												
1022	b1101												
1023	b1102			$0.16									
1024	b1103			$0.16									
1025	b1104											$1.38	
1026	b1105											$1.38	
1027	b1106											$1.38	
1028	b1107											$1.38	
1029	b1108												
1030	b1109												
1031	b1110												
1032	b1111												
1033	b1112												
1034	b1113												
1035	b1114												
1036	b1115												
1037	b1116												
1038	b1117	$0.40											
1039	b1118	$0.40											
1040	b1119	$0.40											
1041	b1120	$0.40											
1042	b1121												
1043	b1122	$0.33											
1044	b1123	$0.33											
1045	b1124	$0.33											
1046	b1125											$53.35	
1047	b1126											$37.15	
1048	b1127												
1049	b1128												
1050	b1129												
1051	b1131												
1052	b1132												
1053	b1133												
1054	b1135												
1055	b1137				$0.01						$0.82		
1056	b1138												
1057	b1139												
1058	b1140												
1059	b1141												
1060	b1142												
1061	b1143										$0.59		
1062	b1144												
1063	b1145												
1064	b1146												
1065	b1147												
1066	b1148												
1067	b1149												
1068	b1150												
1069	b1151												
1070	b1152												
1071	b1153	$0.10			$0.88		$3.75	$2.05	$0.51	$3.44		$0.16	$4.60
1072	b1154												
1073	b1155						$5.76						
1074	b1156												
1075	b1156.1									$0.10			
1076	b1156.10									$0.50			
1077	b1156.2									$0.10			
1078	b1156.3									$0.10			
1079	b1156.4									$0.10			
1080	b1156.5									$0.10			
1081	b1156.6									$0.10			
1082	b1156.7									$0.10			
1083	b1156.8									$0.50			
1084	b1156.9									$0.50			
1085	b1157												
1086	b1158												
1087	b1159												
1088	b1160												
1089	b1161												
1090	b1162												
1091	b1163												
1092	b1164												

	A	W	X	Y
8	Upgrade ID	PSEG	RE	UGI
1002	b1081			
1003	b1082	$18.15	$0.72	
1004	b1083			
1005	b1084			
1006	b1085			
1007	b1086			
1008	b1087			
1009	b1088			
1010	b1089			
1011	b1090			
1012	b1091			
1013	b1092			
1014	b1093			
1015	b1094			
1016	b1095			
1017	b1096			
1018	b1097			
1019	b1098	$15.00		
1020	b1099	$137.00		
1021	b1100	$137.00		
1022	b1101	$76.40		
1023	b1102			
1024	b1103			
1025	b1104			
1026	b1105			
1027	b1106			
1028	b1107			
1029	b1108			
1030	b1109			
1031	b1110			
1032	b1111			
1033	b1112			
1034	b1113			
1035	b1114			
1036	b1115			
1037	b1116			
1038	b1117			
1039	b1118			
1040	b1119			
1041	b1120			
1042	b1121			
1043	b1122			
1044	b1123			
1045	b1124			
1046	b1125			
1047	b1126			
1048	b1127			
1049	b1128			
1050	b1129			
1051	b1131			
1052	b1132			
1053	b1133			
1054	b1135			
1055	b1137	$0.40	$0.02	
1056	b1138			
1057	b1139			
1058	b1140			
1059	b1141			
1060	b1142			
1061	b1143			
1062	b1144			
1063	b1145			
1064	b1146			
1065	b1147			
1066	b1148			
1067	b1149			
1068	b1150			
1069	b1151			
1070	b1152			
1071	b1153	$6.11	$0.21	
1072	b1154	$323.16	$12.84	
1073	b1155	$114.69	$4.55	
1074	b1156	$366.45	$14.55	
1075	b1156.1			
1076	b1156.10			
1077	b1156.2			
1078	b1156.3			
1079	b1156.4			
1080	b1156.5			
1081	b1156.6			
1082	b1156.7			
1083	b1156.8			
1084	b1156.9			
1085	b1157			
1086	b1158			
1087	b1159			
1088	b1160			
1089	b1161			
1090	b1162			
1091	b1163			
1092	b1164			

	A	B	C	D	E	F	G	H	I	J
8	Upgrade ID	Description	TO	Cost Estimate	AEC	AEP	APS	BGE	ComEd	Dayton
1093	b1165	Replace Cecil 138 kV breaker 'South Fayette'	APS	$0.19			$0.19			
1094	b1166	Replace Wylie Ridge 138 kV breaker 'W-9'	APS	$0.22			$0.22			
1095	b1167	Replace Reid 138 kV breaker 'RI-2'	APS	$0.19			$0.19			
1096	b1169	Replace Shawville 115 kV breaker '#1A XFMR	PENELEC	$0.31						
1097	b1170	Replace Shawville 115 kV breaker '#2A XFMR'	PENELEC	$0.31						
1098	b1171.1	Install the second Black Oak 500/138 kV transformer, tw	APS	$9.11				$1.89		
1099	b1171.3	Install six 500 kV breakers and remove BOL1 500 kV br	APS	$9.17	$0.18	$1.65	$0.57	$0.44	$1.43	$0.23
1100	b1174	Create a second Collier-Elwyn 138 kV circuit (Z-162) by	DL	$3.88						
1101	b1178	Add a second 230/138 kV transformer at Chichester. Ac	PECO	$5.91						
1102	b1179	Replace terminal equipment at Eddystone and Saville a	PECO	$3.94						
1103	b1180.1	Replace terminal equipment at Chichester	PECO	$0.48						
1104	b1180.2	Replace terminal equipment at Chichester	PECO	$0.48						
1105	b1181	Install 230/138 kV transformer at Eddystone	PECO	$3.60						
1106	b1182	Reconductor Chichester – Saville 138 kV line and upgra	PECO	$8.50						
1107	b1183	Replace 230/69 kV transformer #6 at Cromby. Add two	PECO	$6.14						
1108	b1184	Add 138 kV breakers at Cromby, Perkiomen, and North	PECO	$3.90						
1109	b1185	Upgrade Eddystone 230 kV breaker #365	PECO	$0.13						
1110	b1186	Upgrade Eddystone 230 kV breaker #785	PECO	$0.13						
1111	b1188	Build new Brambleton 500 kV three breaker ring bus co	Dominion	$5.20	$0.10	$0.93	$0.33	$0.25	$0.81	$0.13
1112	b1188.1	Replace Loudoun 230 kV breaker '200852' with a 63 kA	Dominion	$0.22						
1113	b1188.2	Replace Loudoun 230 kV breaker '2008T2094' with a 63	Dominion	$0.22						
1114	b1188.3	Replace Loudoun 230 kV breaker '204552' with a 63 kA	Dominion	$0.22						
1115	b1188.4	Replace Loudoun 230 kV breaker '209452' with a 63 kA	Dominion	$0.22						
1116	b1188.5	Replace Loudoun 230 kV breaker 'WT2045' with a 63 k	Dominion	$0.22						
1117	b1188.6	Install one 500/230 kV transformer and two 230 kV brea	Dominion	$16.83	$0.04			$1.33		
1118	b1195.1	Upgrade the Corson sub T2 terminal	AEC	$0.10	$0.10					
1119	b1195.2	Upgrade the Corson sub T1 terminal	AEC	$0.03	$0.03					
1120	b1196	Remove the Siegfried bus tie breaker and install a new	PPL	$1.00						
1121	b1197	Reconductor the PECO portion of the Burlington – Croy	PECO	$1.00						
1122	b1197.1	Reconductor the PSEG portion of the Burlington – Croy	PSEG	$3.00						
1123	b1198	Replace terminal equipments including station cable, dis	PECO	$0.50						
1124	b1200	Reconductor Double Toll Gate – Greenwood 138 kV wit	APS	$3.00			$3.00			
1125	b1201	Rebuild the Hercules Tap to Double Circuit 69 kV	PPL	$1.95						
1126	b1202	Mack-Macungie Double Tap, Single Feed Arrangement	PPL	$0.33						
1127	b1203	Add the 2nd Circuit to the East Palmerton-Wagners-Lak	PPL	$12.30						
1128	b1204	New Breinigsville 230-69 kV Substation	PPL	$40.13						
1129	b1205	Siegfried-East Palmerton #1 69 kV Line- Install new 69	PPL	$0.28						
1130	b1206	Siegfried-Quarry #1 & #2 69 kV Lines- Rebuild 3.3 mi fr	PPL	$3.80						
1131	b1209	Convert Neffsville Taps from 69 kV to 138 kV Operation	PPL							
1132	b1210	Convert Roseville Taps from 69 kV to 138 kV Operation	PPL	$1.27						
1133	b1211	Convert Roseville Taps from 69 kV to 138 kV Operation	PPL	$0.03						
1134	b1212	New 138 kV Taps to Flory Mill 138/69 kV Substation	PPL	$0.69						
1135	b1213	Convert East Petersburg Taps from 69 kV to 138 kV op	PPL							
1136	b1214	Terminate South Manheim-Donegal #2 at South Manhe	PPL	$0.08						
1137	b1215	Reconductor and rebuild 16 miles of Peckville-Varden 6	PPL	$22.40						
1138	b1216	Build approximately 2.5 miles of new 69 kV transmissio	PPL	$2.69						
1139	b1217	Provide a "double tap – single feed" connection to Tafto	PPL	$2.00						
1140	b1221.1	Convert Carbon Center from 138 kV to a 230 kV ring bu	APS	$2.00			$2.00			
1141	b1221.2	Construct Bear Run 230 kV substation with 230/138 kV	APS	$6.00			$6.00			
1142	b1221.3	Loop Carbon Center Junction – Williamette line into Bea	APS	$3.20			$3.20			
1143	b1221.4	Carbon Center – Carbon Center Junction & Carbon Cer	APS	$4.30			$4.30			
1144	b1224	Install 2nd Clover 500/230 kV transformer and a 150 MV	Dominion	$17.10				$1.29		
1145	b1225	Replace Yorktown 115 kV breaker 'L982-1'	Dominion	$0.20						
1146	b1226	Replace Yorktown 115 kV breaker 'L982-2'	Dominion	$0.20						
1147	b1227	Perform a sag study on Altavista – Leesville 138 kV circ	AEP	$0.02		$0.02				
1148	b1228	Re-configure the Lawrence 230 kV substation to breake	PSEG	$9.00						
1149	b1230	Reconductor Willow-Eureka & Eurkea-St Mary 138 kV li	APS	$4.00			$4.00			
1150	b1231	Replace the existing 138/69-12 kV transformer at West	AEP	$11.90		$11.51				$0.39
1151	b1232	Reconductor Nipetown – Reid 138 kV with 1033 ACCR	APS	$15.00	$0.26		$10.46			
1152	b1233.1	Upgrade terminal equipment at Washington	APS	$0.05			$0.05			
1153	b1234	Replace structures between Ridgeway and Paper city	APS	$0.75			$0.75			
1154	b1235	Reconductor the Albright – Black Oak AFA 138 kV line	APS	$55.00				$12.69		
1155	b1237	Upgrade terminal equipment at Albright, replace bus an	APS	$0.50			$0.50			
1156	b1238	Install a 138 kV 44 MVAR capacitor at Edgelawn substa	APS	$1.20			$1.20			
1157	b1239	Install a 138 kV 44 MVAR capacitor at Ridgeway substa	APS	$1.50			$1.50			
1158	b1240	Install a 138 kV 44 MVAR capacitor at Elko Substation	APS	$1.50			$1.50			
1159	b1241	Upgrade terminal equipment at Washington substation	APS	$0.05			$0.05			
1160	b1242	Replace structures between Collins Ferry and West Rur	APS	$0.35			$0.35			
1161	b1243	Install a 138 kV capacitor at Potter Substation	APS	$2.80			$2.80			
1162	b1244	Install 10 MVAR capacitor at Peermont 69 kV substatior	AEC	$0.75	$0.75					
1163	b1245	Rebuild the Newport-South Millville 69 kV line	AEC	$1.90	$1.90					
1164	b1246	Re-build the Townsend – Church 138 kV circuit	DPL	$5.96						
1165	b1247	Re-build the Glasgow – Cecil 138 kV circuit	DPL	$16.00						
1166	b1248	Install two 15 MVAR capacitor at Loretto 69 kV	DPL	$1.30						
1167	b1249	Reconfigure the existing Sussex 69 kV capacitor	DPL	$0.50						
1168	b1250	Reconductor the Monroe – Glassboro 69 kV	AEC	$1.55	$1.55					
1169	b1250.1	Upgrade substation equipment at Glassboro	AEC							
1170	b1251	Build a second Raphael – Bagley 230 kV	BGE	$18.00			$0.80	$12.05	$0.74	$0.09
1171	b1251.1	Re-build the existing Raphael – Bagley 230 kV	BGE							
1172	b1252	Upgrade terminal equipment (remove terminal limitation	BGE	$0.10				$0.10		
1173	b1253	Replace the existing Northeast 230/115 kV transformer	BGE	$10.10				$10.10		
1174	b1254	Build a new 500/230 kV substation (Emory Grove)	BGE	$71.00			$2.89	$37.76	$2.63	$0.36
1175	b1254.1	Bundle the Emory – North West 230 kV circuits	BGE							
1176	b1255	Build a new 69 kV substation (Ridge Road) and build ne	PSEG	$22.50						
1177	b1256	Replace the State Line Station 7 138 kV breaker 'Bustie	ComEd	$0.76					$0.76	
1178	b1257	Eliminate the J322 138 kV breaker 'L0906' and move cu	ComEd	$0.04					$0.04	
1179	b1258	Revise the reclosing on the Elmhurst 138 kV bus B brea	ComEd	$0.08					$0.08	
1180	b1259	Revise the reclosing on the Elmhurst 138 kV bus R brea	ComEd	$0.08					$0.08	
1181	b1260	Replace Beaver Valley 138 kV breaker 'Z33 J&L Midlan	DL	$0.40						
1182	b1261	Replace Butler 138 kV breaker '1-2 BUS 138'	APS	$0.30			$0.30			
1183	b1263	Move line 16703 termination from bus 4 to bus 3 at Elec	ComEd	$3.00					$3.00	

	A	K	L	M	N	O	P	Q	R	S	T	U	V
8	Upgrade ID	DL	DPL	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL
1093	b1165												
1094	b1166												
1095	b1167												
1096	b1169										$0.31		
1097	b1170										$0.31		
1098	b1171.1		$0.29	$3.60				$0.25		$0.31		$2.78	
1099	b1171.3	$0.18	$0.26	$1.22	$0.02		$0.39	$0.19	$0.05	$0.54	$0.19	$0.43	$0.51
1100	b1174	$3.88											
1101	b1178				$0.02	$0.02	$0.24		$0.03	$4.86			
1102	b1179									$3.94			
1103	b1180.1									$0.48			
1104	b1180.2									$0.48			
1105	b1181									$3.60			
1106	b1182				$0.03	$0.03	$0.43		$0.05	$6.70			
1107	b1183									$6.14			
1108	b1184									$3.90			
1109	b1185									$0.13			
1110	b1186									$0.13			
1111	b1188	$0.10	$0.15	$0.69	$0.01		$0.22	$0.11	$0.03	$0.31	$0.11	$0.24	$0.29
1112	b1188.1			$0.22									
1113	b1188.2			$0.22									
1114	b1188.3			$0.22									
1115	b1188.4			$0.22									
1116	b1188.5			$0.22									
1117	b1188.6		$0.10	$12.72				$0.04		$0.12		$2.48	
1118	b1195.1												
1119	b1195.2												
1120	b1196												$1.00
1121	b1197									$1.00			
1122	b1197.1												
1123	b1198									$0.50			
1124	b1200												
1125	b1201												$1.95
1126	b1202												$0.33
1127	b1203												$12.30
1128	b1204												$40.13
1129	b1205												$0.28
1130	b1206												$3.80
1131	b1209												
1132	b1210												$1.27
1133	b1211												$0.03
1134	b1212												$0.69
1135	b1213												
1136	b1214												$0.08
1137	b1215												$22.40
1138	b1216												$2.69
1139	b1217												$2.00
1140	b1221.1												
1141	b1221.2												
1142	b1221.3												
1143	b1221.4												
1144	b1224		$0.18	$13.37				$0.13		$0.24		$1.89	
1145	b1225			$0.20									
1146	b1226			$0.20									
1147	b1227												
1148	b1228				$0.02	$0.01							
1149	b1230												
1150	b1231												
1151	b1232		$0.36				$0.55	$1.14	$0.05	$0.83	$0.61		$0.75
1152	b1233.1												
1153	b1234												
1154	b1235			$24.06								$18.24	
1155	b1237												
1156	b1238												
1157	b1239												
1158	b1240												
1159	b1241												
1160	b1242												
1161	b1243												
1162	b1244												
1163	b1245												
1164	b1246		$5.96										
1165	b1247		$11.53							$4.47			
1166	b1248		$1.30										
1167	b1249		$0.50										
1168	b1250												
1169	b1250.1												
1170	b1251			$3.38							$0.01	$0.94	
1171	b1251.1												
1172	b1252												
1173	b1253												
1174	b1254			$11.67							$0.42	$15.27	
1175	b1254.1												
1176	b1255												
1177	b1256												
1178	b1257												
1179	b1258												
1180	b1259												
1181	b1260	$0.40											
1182	b1261												
1183	b1263												

	A	W	X	Y
8	Upgrade ID	PSEG	RE	UGI
1093	b1165			
1094	b1166			
1095	b1167			
1096	b1169			
1097	b1170			
1098	b1171.1			
1099	b1171.3	$0.65	$0.02	
1100	b1174			
1101	b1178	$0.71	$0.03	
1102	b1179			
1103	b1180.1			
1104	b1180.2			
1105	b1181			
1106	b1182	$1.21	$0.05	
1107	b1183			
1108	b1184			
1109	b1185			
1110	b1186			
1111	b1188	$0.37	$0.01	
1112	b1188.1			
1113	b1188.2			
1114	b1188.3			
1115	b1188.4			
1116	b1188.5			
1117	b1188.6			
1118	b1195.1			
1119	b1195.2			
1120	b1196			
1121	b1197			
1122	b1197.1	$3.00		
1123	b1198			
1124	b1200			
1125	b1201			
1126	b1202			
1127	b1203			
1128	b1204			
1129	b1205			
1130	b1206			
1131	b1209			
1132	b1210			
1133	b1211			
1134	b1212			
1135	b1213			
1136	b1214			
1137	b1215			
1138	b1216			
1139	b1217			
1140	b1221.1			
1141	b1221.2			
1142	b1221.3			
1143	b1221.4			
1144	b1224			
1145	b1225			
1146	b1226			
1147	b1227			
1148	b1228	$8.62	$0.34	
1149	b1230			
1150	b1231			
1151	b1232			
1152	b1233.1			
1153	b1234			
1154	b1235			
1155	b1237			
1156	b1238			
1157	b1239			
1158	b1240			
1159	b1241			
1160	b1242			
1161	b1243			
1162	b1244			
1163	b1245			
1164	b1246			
1165	b1247			
1166	b1248			
1167	b1249			
1168	b1250			
1169	b1250.1			
1170	b1251			
1171	b1251.1			
1172	b1252			
1173	b1253			
1174	b1254			
1175	b1254.1			
1176	b1255	$21.64	$0.86	
1177	b1256			
1178	b1257			
1179	b1258			
1180	b1259			
1181	b1260			
1182	b1261			
1183	b1263			

	A	B	C	D	E	F	G	H	I	J
8	Upgrade ID	Description	TO	Cost Estimate	AEC	AEP	APS	BGE	ComEd	Dayton
1184	b1264	Replace 345 kV bus ties 1-2 and 1-9 at Plano to increas	ComEd	$2.00					$2.00	
1185	b1265	Reconductor approximately 2 miles of Will County – Ro	ComEd	$1.50					$1.50	
1186	b1266	Normally close 345 kV BT 2-3 at TSS 103 Lisle, replace	ComEd	$1.00					$1.00	
1187	b1267	Rebuild existing Erdman 115 kV substation to a dual rin	BGE	$7.60				$7.60		
1188	b1267.1	Construct 115 kV double circuit underground line from e	BGE	$142.00				$142.00		
1189	b1268	Reconductor Shelby – Sidney 138 kV	Dayton	$2.60						$2.60
1190	b1269	Reconductor West Milton – Salem 69 kV and West Milto	Dayton	$4.80						$4.80
1191	b1270	Reconductor Bath – Trebein 138 kV	Dayton	$1.30						$1.30
1192	b1271	Reconductor Underground Section of OHH – Sugarcree	Dayton	$2.40						$2.40
1193	b1272	Reconductor Burdox – Webster 138 kV	Dayton	$1.00						$1.00
1194	b1273	Add 2nd Bath 345/138 kV Xfr	Dayton	$7.00						$7.00
1195	b1274	Add 2nd Trebien 138/69 kV Xfr	Dayton	$5.30						$5.30
1196	b1275	Add 2nd W. Milton 138/69 kV Xfr	Dayton	$8.80						$8.80
1197	b1276	Add 2nd W. Milton 345/138 Xfr	Dayton	$5.50						$5.50
1198	b1277	Build a new Osterburg East – Bedford North 115 kV Lin	PENELEC	$3.68						
1199	b1278	Install 25 MVAR Capacitor Bank at Somerset 115 kV	PENELEC	$0.47						
1200	b1279	Line #69 Uprate – Increase rating on Locks – Purdy 115	Dominion	$9.40						
1201	b1280	Sherman: Upgrade 138/69 kV transformers	AEC	$7.70	$7.70					
1202	b1300	Reconductor the East Frankfort – Goodings Grove 345	ComEd	$22.00					$22.00	
1203	b1301	Upgrade both Garfield – Taylor 345 kV lines (17723 and	ComEd	$150.00					$150.00	
1204	b1302	Replace the limiting bus conductor and wave trap at the	ME	$0.10						
1205	b1304.1	Convert the existing 'D1304' and 'G1307' 138 kV circuits	PSEG	$650.00	$1.50			$6.44	$14.17	$0.78
1206	b1304.2	Expand existing Bergen 230 kV substation and reconfig	PSEG							
1207	b1304.3	Build second 230 kV underground cable from Bergen to	PSEG							
1208	b1304.4	Build second 230 kV underground cable from Hudson to	PSEG	$50.00	$0.12			$0.50	$1.09	$0.06
1209	b1306	Reconfigure 115 kV bus at Endless Caverns substation	Dominion	$0.50						
1210	b1307	Install a 2nd 230/115 kV transformer at Northern Neck S	Dominion	$5.10						
1211	b1308	Improve LSE's power factor factor in zone to .973 PF, a	Dominion	$0.50						
1212	b1309	Install a 230 kV line from Lakeside to Northwest utilizing	Dominion	$21.00						
1213	b1310	Install a 115 kV breaker at Broadnax substation on the S	Dominion	$0.50						
1214	b1311	Install a 230 kV 3000 amp breaker at Cranes Corner su	Dominion	$1.10						
1215	b1312	Loop the 2054 line in and out of Hollymeade and place a	Dominion	$41.00						
1216	b1313	Resag wire to 125C from Chesterfield – Shockoe and re	Dominion	$8.90						
1217	b1314	Rebuild the 6.8 mile line #100 from Chesterfield to Harr	Dominion	$8.00						
1218	b1315	Convert line #64 Trowbridge to Winfall to 230 kV and ins	Dominion	$23.00						
1219	b1316	Rebuild 10.7 miles of 115 kV line #80, Battleboro – Hea	Dominion	$11.00						
1220	b1317	LSE load power factor on the #47 line will need to meet	Dominion	$0.50						
1221	b1318	Install a 115 kV bus tie breaker at Acca substation betw	Dominion	$0.50						
1222	b1319	Resag line #222 to 150 C and upgrade any associated e	Dominion	$1.10						
1223	b1320	Install a 230 kV, 150 MVAR capacitor bank at Southwes	Dominion	$1.30						
1224	b1321	Build a new 230 kV line North Anna – Oak Green and in	Dominion	$70.00				$0.60		
1225	b1322	Rebuild the 39 Line (Dooms – Sherwood) and the 91 Lin	Dominion	$100.00						
1226	b1323	Install a 224 MVA 230/115 kV transformer at Staunton.	Dominion	$16.50						
1227	b1324	Install a 115 kV capacitor bank at Oak Ridge. Install a c	Dominion	$3.00						
1228	b1325	Rebuild 15 miles of line #2020 Winfall – Elizabeth City w	Dominion	$18.00						
1229	b1326	Install a third 168 MVA 230/115 kV transformer at Kitty H	Dominion	$8.10						
1230	b1327	Rebuild the 20 mile section of line #22 between Kerr Da	Dominion	$20.00						
1231	b1328	Uprate the 3.63 mile line section between Possum and I	Dominion	$5.50	$0.04		$0.20			
1232	b1329	Install line-tie breakers at Sterling Park substation and E	Dominion	$1.00						
1233	b1330	Install a five breaker ring bus at the expanded Dulles su	Dominion	$6.00						
1234	b1331	Build a 230 kV line from Shawboro to Aydlett tap and co	Dominion	$23.30						
1235	b1332	Build Cannon Branch to Nokesville 230 kV line	Dominion	$40.00						
1236	b1333	Advance n1728 (Replace Possum Point 230 kV breaker	Dominion	$0.03						
1237	b1334	Advance n1748 (Replace Ox 230 kV breaker 22042 with	Dominion	$0.03						
1238	b1335	Advance n1749 (Replace Ox 230 kV breaker 220T2603	Dominion	$0.03						
1239	b1336	Advance n1750 (Replace Ox 230 kV breaker 24842 with	Dominion	$0.03						
1240	b1337	Advance n1751 (Replace Ox 230 kV breaker 248T2013	Dominion	$0.03						
1241	b1338	Replace Printz 230 kV breaker '225'	PECO	$0.50						
1242	b1339	Replace Printz 230 kV breaker '315'	PECO	$0.50						
1243	b1340	Replace Printz 230 kV breaker '215'	PECO	$0.50						
1244	b1343	Replace Collier 138 kV breaker '2-3 Bus Tie'	DL	$0.36						
1245	b1344	Replace St Joe Resources 138 kV breaker 'Z-81 Valley'	DL	$0.36						
1246	b1345	Install Martinsville 4-breaker 34.5 rink bus	JCPL	$2.82						
1247	b1346	Reconductor the Franklin – Humburg (R746) 4.7 miles 3	JCPL	$3.98						
1248	b1347	Replace 500 CU substation conductor with 795 ACSR o	JCPL	$0.02						
1249	b1348	Upgrade the Newton – North Newton 34.5 kV (F708) lin	JCPL	$0.09						
1250	b1349	Reconductor 5.2 miles of the Newton – Woodruffs Gap 3	JCPL	$0.93						
1251	b1350	Upgrade the East Flemington – Flemington 34.5 kV (V7	JCPL	$0.13						
1252	b1351	Add 34.5 kV breaker on the Larrabee A and D bus tie	JCPL	$0.25						
1253	b1352	Upgrade the Smithburg – Centerstate Tap 34.5 kV (X75	JCPL	$0.09						
1254	b1353	Upgrade the Larrabee – Laurelton 34.5 kV (Q43) line by	JCPL	$0.09						
1255	b1354	Add four 34.5 kV breakers and re-configure A/B bus at F	JCPL	$1.46						
1256	b1355	Build a new section 3.3 miles 34.5 kV 556 ACSR line fro	JCPL	$2.29						
1257	b1357	Build 10.2 miles new 34.5 kV line from Larrabee – Howe	JCPL	$9.48						
1258	b1359	Install a Troy Hills 34.5 kV by-pass switch and reconfigu	JCPL	$0.03						
1259	b1360	Reconductor 0.7 miles of the Englishtown – Freehold Ta	JCPL	$0.42						
1260	b1361	Reconductor the Oceanview – Neptune Tap 34.5 kV (D	JCPL	$0.44						
1261	b1362	Install a 23.8 MVAR capacitor at Wood Street 69 kV	ME	$0.52						
1262	b1364	Upgrade South Lebanon 230/69 kV transformer #1 by re	ME	$0.03						
1263	b1365	Reconductor the Middletown – Collins 115 kV (975) line	ME	$0.34						
1264	b1366	Reconductor the Collins – Cly – Newberry 115 kV (975)	ME	$2.39						
1265	b1367	Replace the Cambria Slope 115/46 kV 50 MVA transforn	PENELEC	$1.26						
1266	b1368	Replace the Claysburg 115/46 kV 30 MVA transformer w	PENELEC	$1.49						
1267	b1369	Replace the 4/0 CU substation conductor with 795 ACS	PENELEC	$0.03						
1268	b1370	Install a 3rd 115/46 kV transformer at Westfall	PENELEC	$3.83						
1269	b1371	Reconductor 2.6 miles of the Claysburg – HCR 46 kV lin	PENELEC	$0.63						
1270	b1372	Replace 4/0 CU substation conductor with 795 ACSR on	PENELEC	$0.04						
1271	b1373	Re-configure the Erie West 345 kV substation, add a ne	PENELEC	$0.96						
1272	b1374	Replace wave traps at Raritan River and Deep Run 115	JCPL	$0.18						
1273	b1375	Replace Roanoke 138 kV breaker 'T'	AEP	$0.80		$0.80				
1274	b1376	Replace Roanoke 138 kV breaker 'E'	AEP	$0.80		$0.80				

	A	K	L	M	N	O	P	Q	R	S	T	U	V
8	Upgrade ID	DL	DPL	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL
1184	b1264												
1185	b1265												
1186	b1266												
1187	b1267												
1188	b1267.1												
1189	b1268												
1190	b1269												
1191	b1270												
1192	b1271												
1193	b1272												
1194	b1273												
1195	b1274												
1196	b1275												
1197	b1276												
1198	b1277										$3.68		
1199	b1278										$0.47		
1200	b1279			$9.40									
1201	b1280												
1202	b1300												
1203	b1301												
1204	b1302							$0.10					
1205	b1304.1				$14.24	$123.37	$7.61		$0.39		$18.20	$6.96	
1206	b1304.2												
1207	b1304.3												
1208	b1304.4				$1.10	$9.49	$0.59		$0.03		$1.40	$0.54	
1209	b1306			$0.50									
1210	b1307			$5.10									
1211	b1308			$0.50									
1212	b1309			$21.00									
1213	b1310			$0.50									
1214	b1311			$1.10									
1215	b1312			$41.00									
1216	b1313			$8.90									
1217	b1314			$8.00									
1218	b1315			$23.00									
1219	b1316			$11.00									
1220	b1317			$0.50									
1221	b1318			$0.50									
1222	b1319			$1.10									
1223	b1320			$1.30									
1224	b1321			$68.57								$0.83	
1225	b1322			$100.00									
1226	b1323			$16.50									
1227	b1324			$3.00									
1228	b1325			$18.00									
1229	b1326			$8.10									
1230	b1327			$20.00									
1231	b1328		$0.05	$5.11						$0.10			
1232	b1329			$1.00									
1233	b1330			$6.00									
1234	b1331			$23.30									
1235	b1332			$40.00									
1236	b1333			$0.03									
1237	b1334			$0.03									
1238	b1335			$0.03									
1239	b1336			$0.03									
1240	b1337			$0.03									
1241	b1338									$0.50			
1242	b1339									$0.50			
1243	b1340									$0.50			
1244	b1343	$0.36											
1245	b1344	$0.36											
1246	b1345						$2.82						
1247	b1346						$3.98						
1248	b1347						$0.02						
1249	b1348						$0.09						
1250	b1349						$0.93						
1251	b1350						$0.13						
1252	b1351						$0.25						
1253	b1352						$0.09						
1254	b1353						$0.09						
1255	b1354						$1.46						
1256	b1355						$2.29						
1257	b1357						$9.48						
1258	b1359						$0.03						
1259	b1360						$0.42						
1260	b1361						$0.44						
1261	b1362						$0.52						
1262	b1364						$0.03						
1263	b1365							$0.34					
1264	b1366							$2.39					
1265	b1367										$1.26		
1266	b1368										$1.49		
1267	b1369										$0.03		
1268	b1370										$3.83		
1269	b1371										$0.63		
1270	b1372										$0.04		
1271	b1373										$0.96		
1272	b1374										$0.18		
1273	b1375												
1274	b1376												

	A	W	X	Y
8	Upgrade ID	PSEG	RE	UGI
1184	b1264			
1185	b1265			
1186	b1266			
1187	b1267			
1188	b1267.1			
1189	b1268			
1190	b1269			
1191	b1270			
1192	b1271			
1193	b1272			
1194	b1273			
1195	b1274			
1196	b1275			
1197	b1276			
1198	b1277			
1199	b1278			
1200	b1279			
1201	b1280			
1202	b1300			
1203	b1301			
1204	b1302			
1205	b1304.1	$438.95	$17.42	
1206	b1304.2			
1207	b1304.3			
1208	b1304.4	$33.77	$1.34	
1209	b1306			
1210	b1307			
1211	b1308			
1212	b1309			
1213	b1310			
1214	b1311			
1215	b1312			
1216	b1313			
1217	b1314			
1218	b1315			
1219	b1316			
1220	b1317			
1221	b1318			
1222	b1319			
1223	b1320			
1224	b1321			
1225	b1322			
1226	b1323			
1227	b1324			
1228	b1325			
1229	b1326			
1230	b1327			
1231	b1328			
1232	b1329			
1233	b1330			
1234	b1331			
1235	b1332			
1236	b1333			
1237	b1334			
1238	b1335			
1239	b1336			
1240	b1337			
1241	b1338			
1242	b1339			
1243	b1340			
1244	b1343			
1245	b1344			
1246	b1345			
1247	b1346			
1248	b1347			
1249	b1348			
1250	b1349			
1251	b1350			
1252	b1351			
1253	b1352			
1254	b1353			
1255	b1354			
1256	b1355			
1257	b1357			
1258	b1359			
1259	b1360			
1260	b1361			
1261	b1362			
1262	b1364			
1263	b1365			
1264	b1366			
1265	b1367			
1266	b1368			
1267	b1369			
1268	b1370			
1269	b1371			
1270	b1372			
1271	b1373			
1272	b1374			
1273	b1375			
1274	b1376			

	A	B	C	D	E	F	G	H	I	J
8	Upgrade ID	Description	TO	Cost Estimate	AEC	AEP	APS	BGE	ComEd	Dayton
1275	b1377	Replace Roanoke 138 kV breaker ‘F’	AEP	$0.80		$0.80				
1276	b1378	Replace Roanoke 138 kV breaker ‘G’	AEP	$0.80		$0.80				
1277	b1379	Replace Roanoke 138 kV breaker ‘B’	AEP	$0.80		$0.80				
1278	b1380	Replace Roanoke 138 kV breaker ‘A’	AEP	$0.80		$0.80				
1279	b1381	Replace Olive 345 kV breaker ‘E’	AEP	$1.00		$1.00				
1280	b1382	Replace Olive 345 kV breaker ‘R2’	AEP	$1.00		$1.00				
1281	b1383	Install 2nd 500/138 kV transformer at 502 Junction	APS	$15.00			$13.99			
1282	b1384	Reconductor approximately 2.17 miles of Bedington – S	APS	$1.75			$1.75			
1283	b1385	Reconductor Halfway – Paramount 138 kV with 1033 A(	APS	$4.75			$4.75			
1284	b1386	Reconductor Double Tollgate – Meadow Brook 138 kV (	APS	$9.00			$8.40	$0.31		
1285	b1387	Reconductor Double Tollgate – Meadow Brook 138 kV	APS	$9.00			$8.40	$0.31		
1286	b1388	Reconductor Feagans Mill – Millville 138 kV with 954 A(	APS	$3.50			$3.50			
1287	b1389	Reconductor Bens Run – St. Mary’s 138 kV with 954 A(	APS	$5.80		$0.72	$1.03			
1288	b1390	Replace Bus Tie Breaker at Opequon	APS	$0.25			$0.25			
1289	b1391	Replace Line Trap at Gore	APS	$0.25			$0.25			
1290	b1392	Replace structure on Belmont – Trissler 138 kV line	APS	$0.50			$0.50			
1291	b1393	Replace structures Kingwood – Pruntytown 138 kV line	APS	$1.00			$1.00			
1292	b1395	Upgrade Terminal Equipment at Kittanning	APS	$0.05			$0.05			
1293	b1396	Replace Lewis 138 kV breaker ‘L’	AEC	$0.40	$0.40					
1294	b1398	Build two new parallel underground circuits from Glouce	PSEG	$230.00						
1295	b1398.1	Install shunt reactor at Gloucester to offset cable chargi	PSEG							
1296	b1398.2	Reconfigure the Cuthbert station to breaker and a half s	PSEG							
1297	b1398.3	Build a second 230 kV parallel overhead circuit from Mi	PSEG							
1298	b1398.4	Reconductor the existing Mickleton – Gloucester 230 k\	PSEG							
1299	b1398.5	Reconductor the existing Mickleton – Goucester 230 kV	AEC	$5.90						
1300	b1398.6	Reconductor the Camden – Richmond 230 kV circuit (P	PECO	$0.98						
1301	b1398.7	Reconductor the Camden – Richmond 230 kV circuit (P	PSEG	$8.00						
1302	b1398.8	Reconductor Richmond – Waneeta 230 kV and replace	PECO	$4.00						
1303	b1399	Convert the 138 kV path from Aldene – Springfield Rd. -	PSEG	$75.00						
1304	b1400	Install 230 kV circuit breakers at Bennetts Ln. “F” and “	PSEG	$3.00						
1305	b1401	Change reclosing on Pruntytown 138 kV breaker ‘P-16’	APS	$0.00			$0.00			
1306	b1402	Change reclosing on Rivesville 138 kV breaker ‘Pruntyt	APS	$0.00			$0.00			
1307	b1403	Change reclosing on Yukon 138 kV breaker ‘Y21 Shepl	APS	$0.00			$0.00			
1308	b1404	Replace the Kiski Valley 138 kV breaker ‘Vandergrift’ w	APS	$0.25			$0.25			
1309	b1405	Change reclosing on Armstrong 138 kV breaker ‘GARE	APS	$0.00			$0.00			
1310	b1406	Change reclosing on Armstrong 138 kV breaker ‘KITTA	APS	$0.00			$0.00			
1311	b1407	Change reclosing on Armstrong 138 kV breaker ‘BURM	APS	$0.00			$0.00			
1312	b1408	Replace the Weirton 138 kV breaker ‘Tidd 224’ with a 4	APS	$0.25			$0.25			
1313	b1409	Replace the Cabot 138 kV breaker ‘C9 Kiski Valley’ with	APS	$0.30			$0.30			
1314	b1410	Replace Salem 500 kV breaker ‘11X’	PSEG	$1.50	$0.03	$0.25	$0.09	$0.07	$0.23	$0.04
1315	b1411	Replace Salem 500 kV breaker ‘12X’	PSEG	$1.50	$0.03	$0.25	$0.09	$0.07	$0.23	$0.04
1316	b1412	Replace Salem 500 kV breaker ‘20X’	PSEG	$1.50	$0.03	$0.25	$0.09	$0.07	$0.23	$0.04
1317	b1413	Replace Salem 500 kV breaker ‘21X’	PSEG	$1.50	$0.03	$0.25	$0.09	$0.07	$0.23	$0.04
1318	b1414	Replace Salem 500 kV breaker ‘31X’	PSEG	$1.50	$0.03	$0.25	$0.09	$0.07	$0.23	$0.04
1319	b1415	Replace Salem 500 kV breaker ‘32X’	PSEG	$1.50	$0.03	$0.25	$0.09	$0.07	$0.23	$0.04
1320	b1416	Perform a sag study on the Desoto – Deer Creek 138 k\	AEP	$0.12		$0.12				
1321	b1417	Perform a sag study on the Delaware – Madison 138 kV	AEP	$0.07		$0.07				
1322	b1418	Perform a sag study on the Rockhill – East Lima 138 kV	AEP	$0.02		$0.02				
1323	b1419	Perform a sag study on the Findlay Center – Fostoria C	AEP	$0.08		$0.08				
1324	b1420	A sag study will be required to increase the emergency	AEP	$0.10		$0.10				
1325	b1421	Perform a sag study on the Sorenson – McKinley 138 k	AEP	$0.05		$0.05				
1326	b1422	Perform a sag study on John Amos – St. Albans 138 kV	AEP	$0.30		$0.30				
1327	b1423	A sag study will be performed on the Chemical – Capito	AEP	$0.10		$0.10				
1328	b1424	Perform a sag study for Benton Harbor – West Street –	AEP	$0.05		$0.05				
1329	b1425	Perform a sag study for the East Monument – East Dan	AEP	$0.02		$0.02				
1330	b1426	Perform a sag study for the Reusens – Graves 138 kV li	AEP	$0.02		$0.02				
1331	b1427	Perform a sag study on Smith Mountain – Leesville – Al	AEP	$0.18		$0.18				
1332	b1428	Perform a sag study on Smith Mountain – Candlers Mou	AEP	$0.13		$0.13				
1333	b1429	Perform a sag study on Fremont – Clinch River 138 kV	AEP	$0.17		$0.17				
1334	b1430	Install a new 138 kV circuit breaker at Benton Harbor st	AEP	$1.50		$1.50				
1335	b1432	Perform a sag study on the Kenova – Tri State 138 kV li	AEP	$0.05		$0.05				
1336	b1433	Replace risers in the West Huntington Station to increas	AEP	$0.10		$0.10				
1337	b1434	Perform a sag study on the line from Desoto to Madison	AEP	$0.50		$0.50				
1338	b1435	Replace the 2870 MCM ACSR riser at the Sporn station	AEP	$0.30		$0.30				
1339	b1436	Perform a sag study on the Sorenson – Illinois Road 13	AEP	$0.20		$0.20				
1340	b1437	Perform sag study on Rock Cr. – Hummel Cr. 138 kV to	AEP	$0.30		$0.30				
1341	b1438	Replacement of risers at McKinley and Industrial Park s	AEP	$0.15		$0.15				
1342	b1439	By replacing the risers at Lincoln both the Summar Norr	AEP	$0.05		$0.05				
1343	b1440	By replacing the breakers at Lincoln the Summer Emerg	AEP	$0.55		$0.55				
1344	b1441	Replacement of risers at South Side and performance o	AEP	$0.30		$0.30				
1345	b1442	Replacement of 954 ACSR conductor with 1033 ACSR	AEP	$0.50		$0.50				
1346	b1443	Station work at Thelma and Busseyville Stations will be	AEP	$0.20		$0.20				
1347	b1444	Perform electrical clearance studies on Clinch River – C	AEP	$0.10		$0.10				
1348	b1445	Perform a sag study on the Addison (Buckeye CO-OP) -	AEP	$0.08		$0.08				
1349	b1446	Perform a sag study on the Parkersburg (Allegheny Pov	AEP	$0.01		$0.01				
1350	b1447	Dexter – Elliot tap 138 kV sag check	AEP	$0.07		$0.07				
1351	b1448	Dexter – Meigs 138 kV Electrical Clearance Study	AEP	$0.01		$0.01				
1352	b1449	Meigs tap – Rutland 138 kV sag check	AEP	$0.02		$0.02				
1353	b1450	Muskingum – North Muskingum 138 kV sag check	AEP	$0.01		$0.01				
1354	b1451	North Newark – Sharp Road 138 kV sag check	AEP	$0.08		$0.08				
1355	b1452	North Zanesville – Zanesville 138 kV sag check	AEP	$0.02		$0.02				
1356	b1453	North Zanesville – Powelson and Ohio Central – Powels	AEP	$0.13		$0.13				
1357	b1454	Perform an electrical clearance study on the Ross – Del	AEP	$0.06		$0.06				
1358	b1455	Perform a sag check on the Sunny – Canton Central – \	AEP	$0.03		$0.03				
1359	b1456	The Tidd – West Bellaire 345 kV circuit has been de-rat	AEP	$0.08		$0.08				
1360	b1457	The Tiltonsville – Windsor 138 kV circuit has been dera	AEP	$0.02		$0.02				
1361	b1458	Install three new 345 kV breakers at Bixby to separate t	AEP	$0.08		$0.08				
1362	b1459	Several circuits have been de-rated to their normal cond	AEP	$0.01		$0.01				
1363	b1460	Replace 2156 & 2874 risers	AEP	$0.50		$0.50				
1364	b1461	Replace meter, metering CTs and associated equipmen	AEP	$0.40		$0.40				
1365	b1462	Replace relays at both South Cadiz 138 kV and Tidd 13	AEP	$0.50		$0.50				

	A	K	L	M	N	O	P	Q	R	S	T	U	V
8	Upgrade ID	DL	DPL	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL
1275	b1377												
1276	b1378												
1277	b1379												
1278	b1380												
1279	b1381												
1280	b1382												
1281	b1383	$0.81									$0.20		
1282	b1384												
1283	b1385												
1284	b1386											$0.30	
1285	b1387											$0.30	
1286	b1388												
1287	b1389	$4.05											
1288	b1390												
1289	b1391												
1290	b1392												
1291	b1393												
1292	b1395												
1293	b1396												
1294	b1398				$1.96	$1.82	$29.49		$2.71	$117.48		$1.31	
1295	b1398.1												
1296	b1398.2												
1297	b1398.3												
1298	b1398.4												
1299	b1398.5				$0.05	$0.05	$0.76		$0.07	$3.01		$0.03	
1300	b1398.6				$0.01	$0.01	$0.12		$0.01	$0.50		$0.01	
1301	b1398.7				$0.07	$0.06	$1.03		$0.09	$4.09		$0.05	
1302	b1398.8				$0.03	$0.03	$0.51		$0.05	$2.04		$0.02	
1303	b1399												
1304	b1400												
1305	b1401												
1306	b1402												
1307	b1403												
1308	b1404												
1309	b1405												
1310	b1406												
1311	b1407												
1312	b1408												
1313	b1409												
1314	b1410	$0.03	$0.04	$0.20	$0.00		$0.07	$0.03	$0.01	$0.09	$0.03	$0.07	$0.08
1315	b1411	$0.03	$0.04	$0.20	$0.00		$0.07	$0.03	$0.01	$0.09	$0.03	$0.07	$0.08
1316	b1412	$0.03	$0.04	$0.20	$0.00		$0.07	$0.03	$0.01	$0.09	$0.03	$0.07	$0.08
1317	b1413	$0.03	$0.04	$0.20	$0.00		$0.07	$0.03	$0.01	$0.09	$0.03	$0.07	$0.08
1318	b1414	$0.03	$0.04	$0.20	$0.00		$0.07	$0.03	$0.01	$0.09	$0.03	$0.07	$0.08
1319	b1415	$0.03	$0.04	$0.20	$0.00		$0.07	$0.03	$0.01	$0.09	$0.03	$0.07	$0.08
1320	b1416												
1321	b1417												
1322	b1418												
1323	b1419												
1324	b1420												
1325	b1421												
1326	b1422												
1327	b1423												
1328	b1424												
1329	b1425												
1330	b1426												
1331	b1427												
1332	b1428												
1333	b1429												
1334	b1430												
1335	b1432												
1336	b1433												
1337	b1434												
1338	b1435												
1339	b1436												
1340	b1437												
1341	b1438												
1342	b1439												
1343	b1440												
1344	b1441												
1345	b1442												
1346	b1443												
1347	b1444												
1348	b1445												
1349	b1446												
1350	b1447												
1351	b1448												
1352	b1449												
1353	b1450												
1354	b1451												
1355	b1452												
1356	b1453												
1357	b1454												
1358	b1455												
1359	b1456												
1360	b1457												
1361	b1458												
1362	b1459												
1363	b1460												
1364	b1461												
1365	b1462												

	A	W	X	Y
8	Upgrade ID	PSEG	RE	UGI
1275	b1377			
1276	b1378			
1277	b1379			
1278	b1380			
1279	b1381			
1280	b1382			
1281	b1383			
1282	b1384			
1283	b1385			
1284	b1386			
1285	b1387			
1286	b1388			
1287	b1389			
1288	b1390			
1289	b1391			
1290	b1392			
1291	b1393			
1292	b1395			
1293	b1396			
1294	b1398	$72.36	$2.88	
1295	b1398.1			
1296	b1398.2			
1297	b1398.3			
1298	b1398.4			
1299	b1398.5	$1.86	$0.07	
1300	b1398.6	$0.31	$0.01	
1301	b1398.7	$2.52	$0.10	
1302	b1398.8	$1.26	$0.05	
1303	b1399	$72.14	$2.87	
1304	b1400	$3.00		
1305	b1401			
1306	b1402			
1307	b1403			
1308	b1404			
1309	b1405			
1310	b1406			
1311	b1407			
1312	b1408			
1313	b1409			
1314	b1410	$0.11	$0.00	
1315	b1411	$0.11	$0.00	
1316	b1412	$0.11	$0.00	
1317	b1413	$0.11	$0.00	
1318	b1414	$0.11	$0.00	
1319	b1415	$0.11	$0.00	
1320	b1416			
1321	b1417			
1322	b1418			
1323	b1419			
1324	b1420			
1325	b1421			
1326	b1422			
1327	b1423			
1328	b1424			
1329	b1425			
1330	b1426			
1331	b1427			
1332	b1428			
1333	b1429			
1334	b1430			
1335	b1432			
1336	b1433			
1337	b1434			
1338	b1435			
1339	b1436			
1340	b1437			
1341	b1438			
1342	b1439			
1343	b1440			
1344	b1441			
1345	b1442			
1346	b1443			
1347	b1444			
1348	b1445			
1349	b1446			
1350	b1447			
1351	b1448			
1352	b1449			
1353	b1450			
1354	b1451			
1355	b1452			
1356	b1453			
1357	b1454			
1358	b1455			
1359	b1456			
1360	b1457			
1361	b1458			
1362	b1459			
1363	b1460			
1364	b1461			
1365	b1462			

	A	B	C	D	E	F	G	H	I	J
8	Upgrade ID	Description	TO	Cost Estimate	AEC	AEP	APS	BGE	ComEd	Dayton
1366	b1463	Reconductor the Bexley – Groves 138 kV circuit	AEP	$2.90		$2.90				
1367	b1464	Corner 138 kV upgrades	AEP	$0.15		$0.15				
1368	b1465.1	Add a 3rd 2250 MVA 765/345 kV transformer at Sullivar	AEP	$37.00	$0.26	$27.77	$0.46	$0.67	$2.19	$0.32
1369	b1465.2	Replace the 100 MVAR 765 kV shunt reactor bank on R	AEP	$16.00	$0.33	$2.67	$0.96	$0.79	$2.49	$0.39
1370	b1465.3	Transpose the Rockport – Sullivan 765 kV line and the I	AEP	$10.00	$0.21	$1.67	$0.60	$0.49	$1.56	$0.24
1371	b1465.4	Make switching improvements at Sullivan and Jefferson	AEP	$37.00	$0.77	$6.18	$2.23	$1.82	$5.76	$0.89
1372	b1466.1	Create an in and out loop at Adams Station by removing	AEP	$13.50		$13.50				
1373	b1466.2	Upgrade the Adams transformer to 90 MVA	AEP							
1374	b1466.3	At Seaman Station install a new 138 kV bus and two ne	AEP							
1375	b1466.4	Convert South Central Co-op's New Market 69 kV Statio	AEP							
1376	b1466.5	The Seaman – Highland circuit is already built to 138 kV	AEP							
1377	b1466.6	At Highland Station, install a new 138 kV bus, three new	AEP							
1378	b1466.7	Using one of the bays at Highland, build a 138 kV circuit	AEP							
1379	b1467.1	Install a 14.4 MVAr Capacitor Bank at New Buffalo statio	AEP	$3.00		$3.00				
1380	b1467.2	Reconfigure the 138 kV bus at LaPorte Junction station	AEP							
1381	b1468.1	Expand Selma Parker Station and install a 138/69/34.5	AEP	$8.00		$8.00				
1382	b1468.2	Rebuild and convert 34.5 kV line to Winchester to 69 kV	AEP							
1383	b1468.3	Retire the 34.5 kV line from Haymond to Selma Wire	AEP							
1384	b1469.1	Conversion of the Newcomerstown – Cambridge 34.5 kV	AEP	$23.00		$23.00				
1385	b1469.2	Expansion of the Derwent 69 kV Station (including recon	AEP							
1386	b1469.3	Rebuild 11.8 miles of 69 kV line, and convert additional	AEP							
1387	b1470.1	Build a new 138 kV double circuit off the Kanawha – Ba	AEP	$8.50		$8.50				
1388	b1470.2	Install a new 138/46 kV transformer at Skin Fork	AEP							
1389	b1470.3	Replace 5 Moab's on the Kanawha – Baileysville line wi	AEP							
1390	b1471	Perform a sag study on the East Lima – For Lima – Roc	AEP	$0.02		$0.02				
1391	b1472	Perform a sag study on the East Lima – Haviland 138 kV	AEP	$0.14		$0.14				
1392	b1473	Perform a sag study on the East New Concord – Muskin	AEP	$0.15		$0.15				
1393	b1474	Perform a sag study on the Ohio Central – Prep Plant ta	AEP	$0.04		$0.04				
1394	b1475	Perform a sag study on the S73 – North Delphos 138 kV	AEP	$0.08		$0.08				
1395	b1476	Perform a sag study on the S73 – T131 138 kV line to in	AEP	$0.03		$0.03				
1396	b1477	The Natrium – North Martin 138 kV circuit would need a	AEP	$0.10		$0.10				
1397	b1478	Upgrade Strouds Run – Strouds Tap 138 kV relay and r	AEP	$0.06		$0.06				
1398	b1479	West Hebron station upgrades	AEP	$0.05		$0.05				
1399	b1480	Perform upgrades and a sag study on the Corner – Layi	AEP	$0.20		$0.20				
1400	b1481	Perform a sag study on the West Lima – Eastown Road	AEP	$0.07		$0.07				
1401	b1482	Perform a sag study for the Albion – Robison Park 138 k	AEP	$0.09		$0.09				
1402	b1483	Sag study 1 mile of the Clinch River – Saltville 138 kV lin	AEP	$0.22		$0.22				
1403	b1484	Perform a sag study on the Hacienda – Harper 138 kV l	AEP	$0.06		$0.06				
1404	b1485	Perform a sag study on the Jackson Road – Concord 13	AEP	$0.09		$0.09				
1405	b1486	The Matt Funk – Poages Mill – Starkey 138 kV line requ	AEP	$0.03		$0.03				
1406	b1487	Perform a sag study on the New Carlisle – Trail Creek 1	AEP	$0.01		$0.01				
1407	b1488	Perform a sag study on the Olive – LaPorte Junction 13	AEP	$0.01		$0.01				
1408	b1489	A sag study must be performed for the 5.40 mile Tristate	AEP	$0.30		$0.30				
1409	b1490.1	Establish a new 138/69 kV Butler Center station	AEP	$25.00		$25.00				
1410	b1490.2	Build a new 14 mile 138 kV line from Auburn station to V	AEP							
1411	b1490.3	Replace the existing 40 MVA 138/69 kV transformer at A	AEP							
1412	b1490.4	Improve the switching arrangement at Kendallville statio	AEP							
1413	b1491	Replace bus and risers at Thelma and Busseyville statio	AEP	$0.65		$0.65				
1414	b1492	Reconductor 0.65 miles of the Glen Lyn – Wythe 138 kV	AEP	$0.70		$0.70				
1415	b1493	Perform a sag study for the Bellefonte – Grantston 138 k	AEP	$0.07		$0.07				
1416	b1494	Perform a sag study for the North Proctorville – Solida –	AEP	$0.09		$0.09				
1417	b1495	Add an additional 765/345 kV transformer at Baker Stati	AEP	$46.00	$0.19	$40.12		$0.47	$1.55	$0.57
1418	b1496	Replace 138 kV bus and risers at Johnson Mountain Sta	AEP	$0.60		$0.60				
1419	b1497	Replace 138 kV bus and risers at Leesville Station	AEP	$0.60		$0.60				
1420	b1498	Replace 138 kV risers at Wurno Station	AEP	$0.15		$0.15				
1421	b1499	Perform a sag study on Sporn A – Gavin 138 kV to dete	AEP	$0.16		$0.16				
1422	b1500	The North East Canton – Wagenhals 138 kV circuit wou	AEP	$0.02		$0.02				
1423	b1501	The Moseley – Reusens 138 kV circuit requires a sag st	AEP	$0.09		$0.09				
1424	b1502	Reconductor the Conesville East – Conesville Prep Plar	AEP	$2.00		$2.00				
1425	b1507	Rebuild Mt Storm – Doubs 500 kV	Dominion	$370.00	$7.73	$61.79	$22.31	$18.20	$57.65	$8.92
1426	b1508.1	Build a 2nd 230 kV Line Harrisonburg to Endless Cavern	Dominion	$70.00			$25.94			
1427	b1508.2	Install a 3rd 230-115 kV Tx at Endless Caverns	Dominion	$1.70			$0.63			
1428	b1508.3	Upgrade a 115 kV shunt capacitor banks at Merck and I	Dominion	$0.30			$0.11			
1429										
1430	**TOTAL COST ESTIMATE ($M)**			**$15,376.30**	**$314.60**	**$1,523.52**	**$820.51**	**$893.55**	**$1,806.87**	**$227.12**

	A	K	L	M	N	O	P	Q	R	S	T	U	V
8	Upgrade ID	DL	DPL	Dominion	ECP	HTP	JCPL	ME	Neptune	PECO	PENELEC	PEPCO	PPL
1366	b1463												
1367	b1464												
1368	b1465.1	$0.46	$0.35	$1.44	$0.03	$0.03	$0.58		$0.06	$0.77		$0.61	
1369	b1465.2	$0.33	$0.46	$2.18	$0.04		$0.73	$0.33	$0.08	$1.01	$0.34	$0.76	$0.84
1370	b1465.3	$0.21	$0.29	$1.36	$0.02		$0.46	$0.21	$0.05	$0.63	$0.21	$0.47	$0.53
1371	b1465.4	$0.76	$1.07	$5.04	$0.08		$1.69	$0.77	$0.18	$2.33	$0.78	$1.75	$1.95
1372	b1466.1												
1373	b1466.2												
1374	b1466.3												
1375	b1466.4												
1376	b1466.5												
1377	b1466.6												
1378	b1466.7												
1379	b1467.1												
1380	b1467.2												
1381	b1468.1												
1382	b1468.2												
1383	b1468.3												
1384	b1469.1												
1385	b1469.2												
1386	b1469.3												
1387	b1470.1												
1388	b1470.2												
1389	b1470.3												
1390	b1471												
1391	b1472												
1392	b1473												
1393	b1474												
1394	b1475												
1395	b1476												
1396	b1477												
1397	b1478												
1398	b1479												
1399	b1480												
1400	b1481												
1401	b1482												
1402	b1483												
1403	b1484												
1404	b1485												
1405	b1486												
1406	b1487												
1407	b1488												
1408	b1489												
1409	b1490.1												
1410	b1490.2												
1411	b1490.3												
1412	b1490.4												
1413	b1491												
1414	b1492												
1415	b1493												
1416	b1494												
1417	b1495	$0.67	$0.25		$0.02	$0.02	$0.41		$0.04	$0.54		$0.43	
1418	b1496												
1419	b1497												
1420	b1498												
1421	b1499												
1422	b1500												
1423	b1501												
1424	b1502												
1425	b1507	$7.59	$10.66	$50.36	$0.81		$16.87	$7.73	$1.81	$23.31	$7.81	$17.50	$19.50
1426	b1508.1			$44.07									
1427	b1508.2			$1.07									
1428	b1508.3			$0.19									
1429													
1430	**TOTAL COST E**	**$380.30**	**$595.71**	**$2,293.94**	**$35.08**	**$134.93**	**$578.98**	**$167.11**	**$49.33**	**$716.74**	**$208.81**	**$913.54**	**$882.93**

	A	W	X	Y
8	Upgrade ID	PSEG	RE	UGI
1366	b1463			
1367	b1464			
1368	b1465.1	$0.97	$0.04	
1369	b1465.2	$1.22	$0.05	
1370	b1465.3	$0.77	$0.03	
1371	b1465.4	$2.83	$0.11	
1372	b1466.1			
1373	b1466.2			
1374	b1466.3			
1375	b1466.4			
1376	b1466.5			
1377	b1466.6			
1378	b1466.7			
1379	b1467.1			
1380	b1467.2			
1381	b1468.1			
1382	b1468.2			
1383	b1468.3			
1384	b1469.1			
1385	b1469.2			
1386	b1469.3			
1387	b1470.1			
1388	b1470.2			
1389	b1470.3			
1390	b1471			
1391	b1472			
1392	b1473			
1393	b1474			
1394	b1475			
1395	b1476			
1396	b1477			
1397	b1478			
1398	b1479			
1399	b1480			
1400	b1481			
1401	b1482			
1402	b1483			
1403	b1484			
1404	b1485			
1405	b1486			
1406	b1487			
1407	b1488			
1408	b1489			
1409	b1490.1			
1410	b1490.2			
1411	b1490.3			
1412	b1490.4			
1413	b1491			
1414	b1492			
1415	b1493			
1416	b1494			
1417	b1495	$0.68	$0.03	
1418	b1496			
1419	b1497			
1420	b1498			
1421	b1499			
1422	b1500			
1423	b1501			
1424	b1502			
1425	b1507	$28.31	$1.15	
1426	b1508.1			
1427	b1508.2			
1428	b1508.3			
1429				
1430	**TOTAL COST E**	**$2,742.75**	**$90.39**	**$0.10**

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1		**Exhibit DUK-203**													
2	Source: PJM website:		http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx/												
3	Upgrade ID	PJM Required	In Service Date	Location	Task	Equipment	Descriptior	Voltage	Expected R	Last Updated	Trans Own	Study Year	Baseline Re	Driver	Initial TEAC Da
4	b0073	6/1/2008	6/1/2008	Kearny-Tur	Reconductor		605 ft circu	138	293/370	11/18/2009	PSEG	2003	2003	DCTL Conti	5/9/2005
5	b0132.3	6/1/2011	12/1/2011	Portland	Replace	Disconnect	on the Port	230		6/2/2011	ME	2011	2006	NERC Cate	5/23/2006
6	b0160	6/1/2010	6/1/2010	Hudson	Relocate	Circuit	X-2250 from Hudson 1-6 bus to H			11/18/2009	PSEG	2005	2007	Retiremen	5/9/2005
7	b0210.1	6/1/2008	12/31/2012	Orchard - (	Install	Circuit	Second line	230		6/23/2011	AEC	2009	2007	Load Delive	9/22/2005
8	b0267	6/1/2011	6/1/2011	Kittatinny -	Reconductor		(2 mile JCP	230		6/2/2011	JCPL	2011	2008	NERC Cate	5/23/2006
9	b0268	6/1/2011	6/1/2011	Gilbert - Gl	Reconductor		8 mile	230		6/2/2011	JCPL	2011	2006	NERC Cate	5/23/2006
10	b0279.1	6/1/2011	6/1/2011	Glen Gardr	Install	Capacitor	substation	230		5/24/2011	JCPL	2009	2008	Voltage Vic	3/1/2006
11	b0284.1	6/1/2014	6/1/2015	Jacks Mour	Build	Substation	Tap the Ke	500	400 MVAR	5/24/2011	PENELEC		2008	Load Delive	3/1/2006
12	b0284.3	6/1/2013	6/1/2015	Keystone	Replace	Wave Trap	And upgrad	500	2932 / 372	5/24/2011	PENELEC		2008	Load Delive	3/1/2006
13	b0284.4	6/1/2012	6/1/2012	Juniata	Upgrade	Substation	Changes at	500		9/17/2010	PPL				3/1/2006
14	b0285.1	6/1/2014	6/1/2015	Keystone	Replace	Wave Trap	On the Key	500		5/24/2011	PENELEC		2005	Load Delive	3/1/2006
15	b0285.2	6/1/2014	6/1/2015	Conemaug	Replace	Wave Trap	And Relay	500		5/24/2011	PENELEC		2005	Load Delive	3/1/2006
16	b0289	6/1/2010	5/31/2010	Whippany	Install	Dynamic Re	600MVAR	230		7/30/2009	JCPL			Load Delive	3/1/2006
17	b0289.1	6/1/2011	6/1/2011	West Whar	Install	Capacitor	additional	230		5/24/2011	JCPL			Voltage Vic	7/15/2009
18	b0290	6/1/2012	6/1/2012	Branchburg	Install	Capacitor	400MVAR	500		6/1/2010	PSEG		2005	EMAAC Loa	3/1/2006
19	b0319	6/1/2011	6/8/2011	Burches Hi	Add	Transform	2nd	500/230	1000	5/4/2011	PEPCO	2011	2006	Load Delive	5/23/2006
20	b0325	6/1/2011	6/1/2011	Everetts	Install	Transformer		230/115	239.5/247.	5/4/2011	Dominion	2011	2006	NERC Cate	5/23/2006
21	b0328.1	6/1/2011	6/1/2011	Meadow B	Install	Circuit	65 of 81 m	500	3464 / 346	5/4/2011	Dominion	2011	2006	Load Delive	5/23/2006
22	b0328.2	6/1/2011	4/8/2011	Meadow B	Install	Circuit	26 of 81 m	500	3464 / 346	4/13/2011	APS	2011		Load Delive	5/23/2006
23	b0328.3	6/1/2011	6/1/2011	Mount Sto	Upgrade	Substation	add two ne	500		4/19/2011	Dominion	2011	2008	Load Delive	5/23/2006
24	b0328.4	6/1/2011	6/1/2011	Loudoun	Upgrade	Substation		500		4/19/2011	Dominion	2011	2008	Load Delive	5/23/2006
25	b0329	6/1/2011	5/27/2011	Carson-Suf	Construct	Circuit	and Suffolk	500/230	2598 / 259	4/19/2011	Dominion	2011	2006	NERC Cate	5/23/2006
26	b0329.3	6/1/2011	6/1/2011	Chesapeak	Replace	Breaker	breaker '87	115		4/19/2011	Dominion	2014	2009	Short Circu	11/18/2009
27	b0329.4	6/1/2011	6/1/2011	Chesapeak	Replace	Breaker	breaker '16	115		4/19/2011	Dominion	2014	2009	Short Circu	11/18/2009
28	b0329.5	6/1/2011	5/27/2011	Suffolk - Th	Construct	Circuit	Install second Suffolk 500/230 #2			4/19/2011	Dominion	2011		NERC Cate	5/23/2006
29	b0332	6/1/2011	5/30/2013	Chesapeak	Upgrade	Circuit	resag	115	347	3/8/2011	Dominion	2011	2006	NERC Cate	5/23/2006
30	b0334	6/1/2011	6/1/2011	Ironbridge	Uprate	Circuit	Resag	230	706 / 706	6/2/2011	Dominion	2011	2006	NERC Cate	5/23/2006
31	b0335	6/1/2011	6/1/2011	Chase City	Install	Circuit	Chase City-	115	262 / 262	4/19/2011	Dominion	2011	2006	NERC Cate	5/23/2006
32	b0336	6/1/2011	6/1/2011	Chesapeak	Reconductor		One span c	115	239 / 239	4/19/2011	Dominion	2011	2006	Gen Delive	5/23/2006
33	b0344	6/1/2011	6/1/2011	Doubs	Replace	Transform	#3	500/230	585/677	3/9/2011	APS	2011	2006	Load Delive	5/23/2006
34	b0347.1	6/1/2011	5/20/2011	Mount Sto	Build	Circuit	New	500	3464 / 347	4/13/2011	APS	2011	2006	Load Delive	5/23/2006
35	b0347.19	6/1/2011	4/1/2011	Meadow B	Replace	Breaker	Replace M	138		3/9/2011	APS	2011		Short Circu	1/13/2010
36	b0347.2	6/1/2011	5/13/2011	Mount Sto	Build	Circuit	New	500	3464 / 347	4/13/2011	APS	2011		Load Delive	5/23/2006
37	b0347.22	6/1/2011	5/1/2011	Meadow B	Replace	Breaker	Replace M	138		3/9/2011	APS	2011		Short Circu	1/13/2010
38	b0347.25	6/1/2011	5/1/2011	Meadow B	Replace	Breaker	Replace M	138		3/9/2011	APS	2011		Short Circu	1/13/2010
39	b0347.26	6/1/2011	4/1/2011	Meadow B	Replace	Breaker	Replace M	138		3/9/2011	APS	2011		Short Circu	1/13/2010
40	b0347.27	6/1/2011	6/1/2011	Meadow B	Replace	Breaker	Replace M	138		3/9/2011	APS	2011		Short Circu	1/13/2010
41	b0347.29	6/1/2011	6/1/2011	Meadow B	Replace	Breaker	Replace M	138		3/9/2011	APS	2011		Short Circu	1/13/2010
42	b0347.32	6/1/2011	5/1/2011	Meadow B	Replace	Breaker	Replace M	138		3/9/2011	APS	2011		Short Circu	1/13/2010
43	b0347.4	6/1/2011	5/13/2011	Meadow B	Upgrade	Substation		500		3/9/2011	APS	2011		Load Delive	5/23/2006
44	b0355	6/1/2015	6/1/2015	Master - N	Reconductor		Reconduct	230	757N/757E	1/20/2011	PECO	2011	2006	Gen Delive	5/23/2006
45	b0358	6/1/2011	6/1/2011	Buckinghar	Reconductor		(PSEG port	230	760/882	3/9/2011	PSEG	2011	2006	NERC Cate	5/23/2006
46	b0367	6/1/2011	6/19/2011	Dickerson -	Reconductor		circuits 33	230	1117 / 119	6/2/2011	PEPCO	2011	2006	NERC Cate	5/23/2006
47	b0369	6/1/2014	6/1/2015	Jack's Mou	Install	Dynamic R	100 MVAR	500	100 MVAR	5/24/2011	PENELEC	2010	2008	Load Delive	5/23/2006
48	b0370	6/1/2014	6/1/2015	Jack's Mou	Install	Dynamic R	500 MVAR	500	500 MVAR	5/24/2011	PENELEC	2011	2006	Load Delive	5/23/2006
49	b0376	6/1/2014	6/1/2015	Conemaug	Install	Capacitor	250 MVAR	500	250	5/24/2011	PENELEC	2011	2006	Load Delive	5/23/2006
50	b0423.1	6/1/2012	6/1/2012	Readingtor	Upgrade	Terminal e	Upgrade terminal equipment at R			5/24/2011	JCPL			Load Delive	8/11/2010
51	b0427	6/1/2012	6/1/2012	Athenia - S	Reconductor		Athenia (49	230	385/589	3/9/2011	PSEG	2011	2006	Load Delive	10/30/2006
52	b0429	6/1/2011		Kittatinny -	Reconductor		PSEG porti	230	694/854	8/11/2009	PSEG	2011		Gen Delive	10/30/2006
53	b0445	6/1/2012	7/1/2011	Tidd - Mah	Upgrade	Substation	Equipment	138	200/254 - :	3/9/2011	APS	2012	2008	Gen Delive	5/9/2007
54	b0450	6/1/2012	5/31/2012	Fredricksbu	Install	Capacitor	150 MVAR	230		12/28/2010	Dominion	2012	2008	N-2 Voltag	5/9/2007
55	b0451	6/1/2012	5/4/2012	Somerset	Install	Capacitor	25 MVAR	115		12/28/2010	Dominion	2012	2008	N-2 Voltag	5/9/2007
56	b0453.1	6/1/2012	5/4/2012	Remington	Convert	Circuit	115kV to 2	230		12/28/2010	Dominion	2012	2008	N-1	5/9/2007
57	b0453.2	6/1/2012	7/30/2012	Sowego - C	Install	Circuit		230		12/28/2010	Dominion	2012	2008	N-1	5/9/2007
58	b0454	6/1/2012	5/31/2012	Newport N	Reconductor		2.4 miles	230		4/19/2011	Dominion	2012	2008	N-1	5/9/2007
59	b0457	6/1/2012	5/31/2012	Dooms - Le	Replace	Wave Trap	2	500		12/28/2010	Dominion	2012	2008	N-1	5/9/2007
60	b0460	6/1/2012	1/1/2012	Albright - E	Raise	Structures	limiting str	138	175/214	3/9/2011	APS	2012	2008	Gen Delive	5/9/2007
61	b0467.1	6/1/2011	6/1/2011	Dickerson -	Reconductor			230	1118 / 120	4/21/2011	PEPCO	2011	2008	MAAC Loac	5/9/2007
62	b0467.2	6/1/2011	5/31/2011	Dickerson -	Reconductor			230	1118 / 120	4/19/2011	Dominion	2011	2008	MAAC Loac	5/9/2007
63	b0468	6/1/2012	5/31/2012	Middletow	Build	Substation	with two 1	230/69		6/23/2011	PPL	2012	2008	N-2	5/9/2007
64	b0469	6/1/2012	5/31/2012	West Shore	Install	Capacitor	130 MVAR	230		6/23/2011	PPL	2012	2008	N-2	5/9/2007
65	b0472	6/1/2012	6/1/2012	Athenia - S	Upgrade	Cable	Add forced	230	385/589	10/28/2010	PSEG	2012	2008	N-2	5/9/2007
66	b0473	6/1/2013	6/1/2013	Aldene - La	Relocate	Capacitor	Move the :	230		3/9/2011	PSEG	2012	2008	PSEG Load	5/9/2007
67	b0474	6/1/2012	6/1/2012	Waugh Cha	Add	Transform	fourth , tw	230/115	643/686	2/11/2011	BGE	2012	2008	N-2	5/9/2007
68	b0475	6/1/2012	6/1/2012	Northwest	Build	Bus Rings	Two 230 kV	230/115	645/730	5/18/2011	BGE	2012	2008	N-2	5/9/2007
69	b0476	6/1/2012	6/1/2012	High Ridge	Rebuild	Substation	to Breaker	230		5/16/2011	BGE	2012	2008	N-2	5/9/2007
70	b0477	6/1/2012	6/1/2011	Waugh Cha	Replace	Transform	#1 with thr	500/230		3/2/2011	BGE	2012	2008	N-2	5/9/2007
71	b0478	6/1/2012	6/1/2012	Burches Hi	Reconductor		four circuits from Burchess Hill to			4/21/2011	PEPCO	2012	2008	N-2	5/9/2007

	A	P	Q	R	S	T	U	V	W	X	Y
1											
2	Source: PJM v										
3	Upgrade ID	Latest TEAC Date	Status	State	Region	County	Percent Co	Cost Estim	Project ID	In Schedul	Source
4	b0073		UC	NJ	PJM MA		90	0.2	b0073	#N/A	Planned
5	b0132.3		EP	NJ	PJM MA		25	0.1	b0132	b0132	Planned
6	b0160		On Hold	NJ	PJM MA		0	3	b0160	#N/A	Planned
7	b0210.1		UC	NJ	PJM MA		70	0	b0210	b0210	Planned
8	b0267		UC	NJ	PJM MA		75	1.25	b0267	b0267	Planned
9	b0268		UC	NJ	PJM MA		80	7	b0268	b0268	Planned
10	b0279.1		UC	NJ	PJM MA		99	0.99	b0279	b0279	Planned
11	b0284.1		EP	PA	PJM MA		20	25	b0284	b0284	Planned
12	b0284.3		EP	PA	PJM MA		20	0.25	b0284	b0284	Planned
13	b0284.4		EP	PA	PJM MA		0	0.24	b0284	b0284	Planned
14	b0285.1		EP	PA	PJM MA		2	0.2	b0285	b0285	Planned
15	b0285.2		EP	PA	PJM MA		0	0.3	b0285	b0285	Planned
16	b0289		On Hold	NJ	PJM MA		0	35	b0289	b0289	Planned
17	b0289.1		UC	NJ	PJM MA		80	2.36	b0289	b0289	Planned
18	b0290		EP	NJ	PJM MA		20	18	b0290	b0290	Planned
19	b0319		UC	MD	PJM MA		85	36.7	b0319	b0319	Planned
20	b0325		UC	NC	PJM SOUTH		70	5.6	b0325	b0325	Planned
21	b0328.1		UC	VA	PJM SOUTH		90	243	b0328	b0328	Planned
22	b0328.2		UC	VA	PJM WEST		99	119	b0328	b0328	Planned
23	b0328.3		UC	WV	PJM SOUTH		90	10	b0328	b0328	Planned
24	b0328.4		UC	VA	PJM SOUTH		80	10	b0328	b0328	Planned
25	b0329		UC	VA	PJM SOUTH		90	173.49	b0329	b0329	Planned
26	b0329.3		UC	VA	PJM SOUTH		85	0.18	b0329	b0329	Planned
27	b0329.4		UC	VA	PJM SOUTH		90	0.18	b0329	b0329	Planned
28	b0329.5		UC	VA	PJM SOUTH		90	49.02	b0329	b0329	Planned
29	b0332		EP	VA	PJM SOUTH		0	0.7	b0332	b0332	Planned
30	b0334		UC	VA	PJM SOUTH		40	0.7	b0334	b0334	Planned
31	b0335		UC	VA	PJM SOUTH		50	15	b0335	b0335	Planned
32	b0336		EP	VA	PJM SOUTH		0	0.05	b0336	b0336	Planned
33	b0344		UC	MD	PJM WEST		35	5.2	b0344	b0344	Planned
34	b0347.1		UC	MD/PA/W	PJM WEST		99	310	b0347	b0347	Planned
35	b0347.19		UC		PJM WEST		50	0.19	b0347	b0347	Planned
36	b0347.2		UC	WV/VA	PJM WEST		99	308	b0347	b0347	Planned
37	b0347.22		UC		PJM WEST		50	0.19	b0347	b0347	Planned
38	b0347.25		UC		PJM WEST		50	0.19	b0347	b0347	Planned
39	b0347.26		UC		PJM WEST		50	0.19	b0347	b0347	Planned
40	b0347.27		UC		PJM WEST		50	0.19	b0347	b0347	Planned
41	b0347.29		UC		PJM WEST		50	0.19	b0347	b0347	Planned
42	b0347.32		UC		PJM WEST		50	0.19	b0347	b0347	Planned
43	b0347.4		UC	VA	PJM WEST		99	25	b0347	b0347	Planned
44	b0355		EP	PA	PJM MA		15	4.2	b0355	b0355	Planned
45	b0358		EP	NJ	PJM MA		50	3	b0358	b0358	Planned
46	b0367		UC	MD	PJM MA		40	20	b0367	b0367	Planned
47	b0369		EP	PA	PJM MA		20	12	b0369	b0369	Planned
48	b0370		EP	PA	PJM MA		20	32	b0370	b0370	Planned
49	b0376		EP	PA	PJM MA		2	2	b0376	b0376	Planned
50	b0423.1		EP		PJM MA		0	0.1	b0423	b0423	Planned
51	b0427		UC	NJ	PJM MA		90	1.5	b0427	b0427	Planned
52	b0429		On Hold	NJ	PJM MA		0	20	b0429	#N/A	Planned
53	b0445		UC	OH	PJM West		75	0.03	b0445	b0445	Planned
54	b0450		EP	VA	PJM SOUTH		10	1.2	b0450	b0450	Planned
55	b0451		EP	VA	PJM SOUTH		0	0.8	b0451	b0451	Planned
56	b0453.1		EP	VA	PJM SOUTH		20	8.1	b0453	b0453	Planned
57	b0453.2		EP	VA	PJM SOUTH		10	22	b0453	b0453	Planned
58	b0454		EP	VA	PJM SOUTH		10	1.17	b0454	b0454	Planned
59	b0457		EP	VA	PJM SOUTH		0	0.5	b0457	b0457	Planned
60	b0460		UC	PA / WV	PJM WEST		35	0.04	b0460	b0460	Planned
61	b0467.1		UC	MD	PJM MA		40	9	b0467	b0467	Planned
62	b0467.2		UC	MD	PJM MA		50	5	b0467	b0467	Planned
63	b0468		EP	PA	PJM MA		25	24	b0468	b0468	Planned
64	b0469		EP	PA	PJM MA		5	3.4	b0469	b0469	Planned
65	b0472		EP	NJ	PJM MA		0	25	b0472	b0472	Planned
66	b0473		EP	NJ	PJM MA		3	1.5	b0473	b0473	Planned
67	b0474		EP	MD	PJM MA		15	10.3	b0474	b0474	Planned
68	b0475		UC	MD	PJM MA		44	38	b0475	b0475	Planned
69	b0476		UC	MD	PJM MA		27	44	b0476	b0476	Planned
70	b0477		UC	MD	PJM MA		40	29.9	b0477	b0477	Planned
71	b0478		EP	MD	PJM MA		15	16	b0478	b0478	Planned

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
3	Upgrade ID	PJM Required	In Service Date	Location	Task	Equipment	Descriptior	Voltage	Expected R	Last Updated	Trans Own	Study Year	Baseline Re	Driver	Initial TEAC Da
72	b0480	6/1/2012	6/1/2011	Lank - Five	Rebuild	Circuit		69		1/20/2011	DPL	2012	2008	AE Load De	5/9/2007
73	b0483.1	6/1/2009	12/31/2011	Oak Hall - \	Build	Line		138		4/13/2011	DPL	2012	2008	DPL Criteri	5/9/2007
74	b0483.2	6/1/2009	12/31/2011	Wattsville	Install	Transform	New	138/69		4/13/2011	DPL	2012	2008	DPL Criteri	5/9/2007
75	b0483.3	6/1/2009	12/31/2011	Oak Hall	Establish	Bus Position		138		1/20/2011	DPL	2012	2008	DPL Criteri	5/9/2007
76	b0487	6/1/2012	4/24/2015	Susquehan	Construct	Circuit	PPL equip	500	2500 / 300	10/1/2010	PPL	2012	2008	15 Year Loa	5/9/2007
77	b0487.1	6/1/2012	4/24/2015	Lackawann	Install	Transform	and upgrac	500/230	858 / 1165	10/1/2010	PPL	2012	2008	Gen Delive	5/9/2007
78	b0489	6/1/2012	6/1/2015	Susquehan	Construct	Circuit	PSEG equip	500	2500 / 300	3/9/2011	PSEG	2012	2008	15 Year Loa	5/9/2007
79	b0489.1	6/1/2012	6/1/2012	Athenia	Replace	Breaker	31H	230	63kA	3/9/2011	PSEG	2012	2008	Short Circu	8/20/2008
80	b0489.2	6/1/2012	6/1/2013	Bergen	Replace	Breaker	10H	230	63kA	3/9/2011	PSEG	2012	2008	Short Circu	8/20/2008
81	b0489.4	6/1/2012	6/1/2014	Roseland	Construct	Transform	and upgrac	500/230	1200 / 150	3/9/2011	PSEG	2012	2008	15 Year Loa	5/9/2007
82	b0489.7	6/1/2012	2/28/2011	Roseland	Upgrade	Breaker	71H' with 8	230	80 kA	4/13/2011	PSEG			Short Circu	5/20/2009
83	b0489.8	6/1/2012	2/28/2011	Roseland	Upgrade	Breaker	31H' with 8	230	80 kA	3/9/2011	PSEG			Short Circu	5/20/2009
84	b0490	6/1/2015	6/1/2015	Amos - We	Install	Circuit	Amos to W	765	6500 / 700	10/22/2010	AEP	2012	2008	15 Year Loa	5/9/2007
85	b0490.1	6/1/2015	6/1/2015	Welton Spr	Install	Substation	with SVS --	765/500		10/22/2010	AEP	2012	2007	15 Year Loa	5/9/2007
86	b0490.2	6/1/2015	6/1/2015	Amos	Replace	Breaker	breaker 'B'	138		5/31/2011	AEP	2014	2009	Short Circu	11/18/2009
87	b0490.3	6/1/2015	6/1/2015	Amos	Replace	Breaker	breaker 'B1	138		5/31/2011	AEP	2014	2009	Short Circu	11/18/2009
88	b0490.4	6/1/2015	6/1/2015	Amos	Replace	Breaker	breaker 'C'	138		5/31/2011	AEP	2014	2009	Short Circu	11/18/2009
89	b0490.5	6/1/2015	6/1/2015	Amos	Replace	Breaker	breaker 'C1	138		5/31/2011	AEP	2014	2009	Short Circu	11/18/2009
90	b0490.6	6/1/2015	6/1/2015	Amos	Replace	Breaker	breaker 'D'	138		5/31/2011	AEP	2014	2009	Short Circu	11/18/2009
91	b0490.7	6/1/2015	6/1/2015	Amos	Replace	Breaker	breaker 'D1	138		5/31/2011	AEP	2014	2009	Short Circu	11/18/2009
92	b0490.8	6/1/2015	6/1/2015	Amos	Replace	Breaker	breaker 'E'	138		5/31/2011	AEP	2014	2009	Short Circu	11/18/2009
93	b0490.9	6/1/2015	6/1/2015	Amos	Replace	Breaker	breaker 'E2	138		5/31/2011	AEP	2014	2009	Short Circu	11/18/2009
94	b0491	6/1/2015	6/1/2015	Amos - We	Install	Circuit	Amos to W	765	6500 / 700	10/22/2010	APS	2012	2008	15 Year Loa	5/9/2007
95	b0491.1	6/1/2015	6/1/2015	Welton Spr	Install	Substation	with SVS --	765/500		10/22/2010	APS	2012	2007	15 Year Loa	5/9/2007
96	b0492	6/1/2015	6/1/2015	Welton Spr	Install	Circuit	Welton Spr	765		10/22/2010	APS	2012	2008	15 Year Loa	5/9/2007
97	b0492.1	6/1/2015	6/1/2015	Kemptown	Install	Substation	(500 kV po	765/500		2/1/2011	APS	2012	2007	15 Year Loa	5/9/2007
98	b0492.10	6/1/2015	6/1/2014	Mount Sto	Replace	Breaker	G2T554	500		5/25/2011	Dominion	2013	2009	Short Circu	5/20/2009
99	b0492.11	6/1/2015	6/1/2014	Mount Sto	Replace	Breaker	G1T551	500		5/25/2011	Dominion	2013	2009	Short Circu	5/20/2009
100	b0492.12	6/1/2015	6/1/2014	Mount Sto	Upgrade	Breaker	nameplate	500		5/25/2011	Dominion	2013	2009	Short Circu	5/20/2009
101	b0492.6	6/1/2015	6/1/2014	Mount Sto	Replace	Breaker	55072	500		5/25/2011	Dominion	2013	2009	Short Circu	5/20/2009
102	b0492.7	6/1/2015	6/1/2014	Mount Sto	Replace	Breaker	55172	500		5/25/2011	Dominion	2013	2009	Short Circu	5/20/2009
103	b0492.8	6/1/2015	6/1/2014	Mount Sto	Replace	Breaker	H1172-2	500		5/25/2011	Dominion	2013	2009	Short Circu	5/20/2009
104	b0492.9	6/1/2015	6/1/2014	Mount Sto	Replace	Breaker	G2T550	500		5/25/2011	Dominion	2013	2009	Short Circu	5/20/2009
105	b0496	6/1/2013	6/1/2013	Brighton	Replace	Transformer		500/230		11/8/2010	PEPCO	2013	2008	Load Delive	8/22/2007
106	b0497	6/1/2014	6/1/2014	Conastone	Install	Circuit	second circ	230	680/819	4/26/2011	BGE	2012	2008	MAAC Load	8/22/2007
107	b0497.1	6/1/2014	6/1/2014	Conastone	Replace	Breaker	# 4	230		4/26/2011	BGE		2008	Short Circu	3/1/2006
108	b0497.2	6/1/2014	6/1/2014	Conastone	Replace	Breaker	# 7	230		4/26/2011	BGE		2008	Short Circu	3/1/2006
109	b0499	6/1/2013	12/31/2012	Burches Hi	Install	Transform	third	500/230		4/25/2011	PEPCO	2012		Load Delive	8/22/2007
110	b0500.1	6/1/2012	5/31/2012	Conastone	Upgrade	Line	approxima	230		8/11/2009	PPL	2012		Load Delive	8/22/2007
111	b0500.2	6/1/2012		Conastone	Upgrade	Line	and raise C	230		12/30/2010	BGE	2012		Load Delive	8/22/2007
112	b0501	6/1/2012	6/1/2012	Forbes	Construct	Substation	Convert Fo	345/138	350/392	3/9/2011	DL	2012	2008	N-2 Therm	8/22/2007
113	b0502	6/1/2016	6/1/2016	Carson - Br	Construct	Circuit	New Unde	345	540/540, 6	5/2/2011	DL	2012	2008	N-2 Therm	8/22/2007
114	b0502.1	6/1/2013	10/1/2015	Dravosburg	Replace	Breaker	breaker 'Z7	138		3/10/2011	DL	2014	2009	Short Circu	11/18/2009
115	b0502.2	6/1/2013	12/31/2015	Dravosburg	Replace	Breaker	breaker 'Z1	138		3/10/2011	DL	2014	2009	Short Circu	11/18/2009
116	b0502.3	6/1/2013	6/1/2016	Dravosburg	Replace	Breaker	breaker 'Z7	138		3/10/2011	DL	2014	2009	Short Circu	11/18/2009
117	b0502.5	6/1/2013	12/31/2016	Dravosburg	Replace	Breaker	breaker 'N	138		3/10/2011	DL	2014	2009	Short Circu	11/18/2009
118	b0503	6/1/2013	6/1/2012	Carson - O	Loop		Recable &	138	239/272	2/8/2011	DL	2012	2008	N-2 Therm	8/22/2007
119	b0512.1	6/1/2015	12/15/2012	Possum Po	Install	Line	MAPP Proj	500	2250 / 225	4/19/2011	Dominion	2012	2008	Load Delive	8/22/2007
120	b0512.2	6/1/2015	6/1/2013	Possum Po	Install	Line	MAPP Proj	500	2250 / 225	11/22/2010	PEPCO	2012	2008	Load Delive	8/22/2007
121	b0512.30	6/1/2015	12/31/2011	Burches Hi	Install	Line	MAPP Proj	500		12/30/2010	PEPCO	2012		Load Delive	8/22/2007
122	b0512.31	6/1/2015	6/1/2013	Chalk Point	Install	Line	MAPP Project: Install new Chalk F			11/22/2010	PEPCO	2012		Load Delive	8/22/2007
123	b0512.32	6/1/2015	6/1/2013	Hallowing	Install	Line	MAPP Project: Install new Hallow			11/22/2010	PEPCO	2012		Load Delive	8/22/2007
124	b0512.33	6/1/2015	6/1/2013	Hallowing	Install	Line	MAPP Project: Install new Hallow			12/30/2010	BGE	2012		Load Delive	8/22/2007
125	b0512.34	6/1/2015	6/1/2013	Hallowing	Install	Line	MAPP Project: Install new Hallow			11/22/2010	PEPCO	2012		Load Delive	8/22/2007
126	b0512.35	6/1/2015	6/1/2013	Hallowing	Install	Line	MAPP Project: Install new Hallow			11/22/2010	PEPCO	2012		Load Delive	8/22/2007
127	b0512.36	6/1/2015	6/1/2013	Indian Rive	Install	Line	MAPP Project: Install new Indian			11/22/2010	DPL	2012		Load Delive	8/22/2007
128	b0512.37	6/1/2015	6/1/2013	Indian Rive	Reconduct	Line	MAPP Project: Reconductor existi			11/22/2010	DPL	2012		Load Delive	8/22/2007
129	b0512.38	6/1/2015	6/1/2013	Steele - Vie	Reconduto	Line	MAPP Project: Reconductor existi			11/22/2010	DPL	2012		Load Delive	8/22/2007
130	b0512.39	6/1/2015	12/15/2012	Possum Po	Install	Substation	MAPP Project: Possum Point 500			4/19/2011	Dominion	2012		Load Delive	8/22/2007
131	b0512.40	6/1/2015	6/1/2013	Burches Hi	Install	Substation	MAPP Project: Burches Hill 500 k\			11/22/2010	PEPCO	2012		Load Delive	8/22/2007
132	b0512.41	6/1/2015	6/1/2013	Chalk Point	Install	Substation	MAPP Project: Chalk Point 500 kV			11/22/2010	PEPCO	2012		Load Delive	8/22/2007
133	b0512.42	6/1/2015	6/1/2013	Hallowing	Install	Substation	MAPP Project: New Hallowing Po			11/22/2010	PEPCO	2012		Load Delive	8/22/2007
134	b0512.43	6/1/2015	6/1/2013	Calvert Clif	Install	Substation	MAPP Project: Calvert Cliffs 500 k			12/30/2010	BGE	2012		Load Delive	8/22/2007
135	b0512.44	6/1/2015	6/1/2013	Gateway	Install	Substation	MAPP Project: New Gateway 230			11/22/2010	DPL	2012		Load Delive	8/22/2007
136	b0512.45	6/1/2015	6/1/2013	Mission	Install	Substation	MAPP Project: New Mission 230 k			11/22/2010	DPL	2012		Load Delive	8/22/2007
137	b0512.46	6/1/2015	6/1/2013	Vienna	Install	Substation	MAPP Project: Vienna 230 kV sub			11/22/2010	DPL	2012		Load Delive	8/22/2007
138	b0512.47	6/1/2015	6/1/2013	Indian Rive	Install	Substation	MAPP Project: Indian River 230 k\			11/22/2010	DPL	2012		Load Delive	8/22/2007
139	b0512.5	6/1/2013	6/1/2013	Ox	Replace	Breaker	Ox - Replac	230	50 kA	5/13/2011	Dominion	2013	2009	Short Circu	5/20/2009
140	b0512.6	6/1/2011	6/1/2011	Possum Po	Replace	Breaker	Possum Po	230	80 kA	6/2/2011	Dominion	2013	2009	Short Circu	5/20/2009
141	b0513	6/1/2012	6/1/2012	Maridel - C	Rebuild	Circuit	6723-1			9/15/2009	DPL	2012	2008	DPL South	12/19/2007
142	b0526	6/1/2012	6/1/2012	Ritchie - Be	Install	Circuit	Two new c	230		11/8/2010	PEPCO	2012	2008	Load Delive	12/19/2007

	A	P	Q	R	S	T	U	V	W	X	Y
3	Upgrade ID	Latest TEAC Date	Status	State	Region	County	Percent Co	Cost Estim	Project ID	In Schedul	Source
72	b0480		EP	DE	PJM MA		0	1.4	b0480	b0480	Planned
73	b0483.1		EP	MD	PJM MA		40	2.6	b0483	b0483	Planned
74	b0483.2		EP	MD	PJM MA		40	1.4	b0483	b0483	Planned
75	b0483.3		EP	MD	PJM MA		40	0.53	b0483	b0483	Planned
76	b0487		EP	PA	PJM MA		8	427	b0487	b0487	Planned
77	b0487.1		UC	PA	PJM MA		6	59	b0487	b0487	Planned
78	b0489		EP	NJ	PJM MA		15	705	b0489	b0489	Planned
79	b0489.1		EP	NJ	PJM MA		5	0.4	b0489	b0489	Planned
80	b0489.2		EP	NJ	PJM MA		5	0.4	b0489	b0489	Planned
81	b0489.4		UC	NJ	PJM MA		19	45	b0489	b0489	Planned
82	b0489.7		EP	NJ	PJM MA		28	0.8	b0489	b0489	Planned
83	b0489.8		EP	NJ	PJM MA		25	0.8	b0489	b0489	Planned
84	b0490		EP	WV	PJM WEST		3	592.46	b0490	b0490	Planned
85	b0490.1		EP	WV	PJM WEST		5	105.54	b0490	b0490	Planned
86	b0490.2		On Hold		PJM WEST		0	0.8	b0490	b0490	Planned
87	b0490.3		On Hold		PJM WEST		0	0.8	b0490	b0490	Planned
88	b0490.4		On Hold		PJM WEST		0	0.8	b0490	b0490	Planned
89	b0490.5		On Hold		PJM WEST		0	0.8	b0490	b0490	Planned
90	b0490.6		On Hold		PJM WEST		0	0.8	b0490	b0490	Planned
91	b0490.7		On Hold		PJM WEST		0	0.8	b0490	b0490	Planned
92	b0490.8		On Hold		PJM WEST		0	0.8	b0490	b0490	Planned
93	b0490.9		On Hold		PJM WEST		0	0.8	b0490	b0490	Planned
94	b0491		EP	WV	PJM WEST		3	592.46	b0491	b0491	Planned
95	b0491.1		EP	WV	PJM WEST		3	179.63	b0491	b0491	Planned
96	b0492		EP	VA / WV /	PJM WEST		4	448.16	b0492	b0492	Planned
97	b0492.1		EP	MD	PJM MA		3	181.75	b0492	b0492	Planned
98	b0492.10		On Hold		PJM SOUTH		0	0.73	b0492	b0492	Planned
99	b0492.11		On Hold		PJM SOUTH		0	0.73	b0492	b0492	Planned
100	b0492.12		On Hold		PJM SOUTH		0	0.01	b0492	b0492	Planned
101	b0492.6		On Hold		PJM SOUTH		0	0.73	b0492	b0492	Planned
102	b0492.7		On Hold		PJM SOUTH		0	0.73	b0492	b0492	Planned
103	b0492.8		On Hold		PJM SOUTH		0	0.73	b0492	b0492	Planned
104	b0492.9		On Hold		PJM SOUTH		0	0.73	b0492	b0492	Planned
105	b0496		EP	MD	PJM MA		15	18	b0496	b0496	Planned
106	b0497		EP	MD	PJM MA		5	47.8	b0497	b0497	Planned
107	b0497.1		EP	MD	PJM MA		5	0.7	b0497	b0497	Planned
108	b0497.2		EP	MD	PJM MA		5	0.7	b0497	b0497	Planned
109	b0499		EP	MD	PJM MA		20	31	b0499	b0499	Planned
110	b0500.1		On Hold	PA	PJM MA		10	4	b0500	#N/A	Planned
111	b0500.2		On Hold	MD	PJM MA		1	0.38	b0500	#N/A	Planned
112	b0501		UC	PA	PJM WEST		60	82	b0501	b0501	Planned
113	b0502		EP	PA	PJM WEST		3	85.1	b0502	b0502	Planned
114	b0502.1		EP	PA	PJM WEST		0	0.33	b0502	b0502	Planned
115	b0502.2		EP	PA	PJM WEST		0	0.33	b0502	b0502	Planned
116	b0502.3		EP	PA	PJM WEST		0	0.35	b0502	b0502	Planned
117	b0502.5		EP	PA	PJM WEST		0	0.35	b0502	b0502	Planned
118	b0503		EP	PA	PJM WEST		3	18.3	b0503	b0503	Planned
119	b0512.1		EP		PJM MA		0	8.1	b0512	b0512	Planned
120	b0512.2		EP		PJM MA		10	1055	b0512	b0512	Planned
121	b0512.30		EP	MD	PJM MA		0	0	b0512	b0512	Planned
122	b0512.31		EP		PJM MA		0	0	b0512	b0512	Planned
123	b0512.32		EP		PJM MA		0	0	b0512	b0512	Planned
124	b0512.33		EP		PJM MA		10	60.4	b0512	b0512	Planned
125	b0512.34		EP		PJM MA		0	0	b0512	b0512	Planned
126	b0512.35		EP		PJM MA		0	0	b0512	b0512	Planned
127	b0512.36		EP		PJM MA		0	0	b0512	b0512	Planned
128	b0512.37		EP		PJM MA		0	0	b0512	b0512	Planned
129	b0512.38		EP		PJM MA		0	0	b0512	b0512	Planned
130	b0512.39		EP		PJM MA		0	0	b0512	b0512	Planned
131	b0512.40		EP		PJM MA		0	0	b0512	b0512	Planned
132	b0512.41		EP		PJM MA		0	0	b0512	b0512	Planned
133	b0512.42		EP		PJM MA		0	0	b0512	b0512	Planned
134	b0512.43		EP		PJM MA		10	4.6	b0512	b0512	Planned
135	b0512.44		EP		PJM MA		0	0	b0512	b0512	Planned
136	b0512.45		EP		PJM MA		0	0	b0512	b0512	Planned
137	b0512.46		EP		PJM MA		0	0	b0512	b0512	Planned
138	b0512.47		EP		PJM MA		0	0	b0512	b0512	Planned
139	b0512.5		EP	VA	PJM South		0	0.03	b0512	b0512	Planned
140	b0512.6		UC	VA	PJM South		40	0.03	b0512	b0512	Planned
141	b0513		EP	DE	PJM MA		0	2.1	b0513	b0513	Planned
142	b0526		EP	MD	PJM MA		25	71.3	b0526	b0526	Planned

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
3	Upgrade ID	PJM Required	In Service Date	Location	Task	Equipment	Descriptior	Voltage	Expected R	Last Updated	Trans Own	Study Year	Baseline R	Driver	Initial TEAC Da
143	b0533	6/1/2012	6/1/2012	Powell Mo	Reconductor		with 954 A	138	242/297	3/9/2011	APS	2012	2008	2012 Volta	12/19/2007
144	b0535	6/1/2012	6/1/2011	Dutch Fork	Install	Switched C	Add a 44 M	138		5/4/2011	APS	2012	2008	2012 Volta	12/19/2007
145	b0549	6/1/2012	6/1/2012	Keystone	Install	Capacitor	250 MVAR	500		5/24/2011	PENELEC	2012	2008	Load Delive	12/19/2007
146	b0552	6/1/2012	6/1/2012	Altoona	Install	Capacitor	50 MVAR	230	50	5/24/2011	PENELEC	2012	2008	2012 Load	12/19/2007
147	b0553	6/1/2012	6/1/2012	Raystown	Install	Capacitor	50 MVAR	230		5/24/2011	PENELEC	2012	2008	2012 Load	12/19/2007
148	b0555	6/1/2012	6/1/2015	Johnstown	Install	Capacitor	100 MVAR	230		5/24/2011	PENELEC	2012	2008	2012 Load	12/19/2007
149	b0556	6/1/2012	6/1/2015	Grover	Install	Capacitor	50 MVAR	230		5/24/2011	PENELEC	2012	2008	2012 Load	12/19/2007
150	b0557	6/1/2012	6/1/2012	East Towar	Install	Capacitor	75 MVAR	230		5/24/2011	PENELEC	2012	2008	2012 Load	12/19/2007
151	b0560	6/1/2015	1/1/2013	Kemptown	Install	Capacitor	250 MVAR	500		11/22/2010	APS	2013	2008	Load Delive	12/19/2007
152	b0563	6/1/2012	6/1/2013	Farmers Va	Install	Capacitor	25 MVAR c	115		5/24/2011	PENELEC	2012	2008	Voltage Vic	12/19/2007
153	b0564	6/1/2012	6/1/2013	Ridgway	Install	Capacitor	10 MVAR c	115		5/24/2011	PENELEC	2012	2008	Voltage Vic	12/19/2007
154	b0565	6/1/2012	6/1/2012	Cox's Corn	Install	Capacitor	100 MVAR	230		5/16/2011	PSEG	2012	2008	Voltage Vic	12/19/2007
155	b0566	6/1/2012	6/1/2012	Trappe Tap	Rebuild	Circuit		69		11/19/2009	DPL	2012	2008	Load Delive	12/19/2007
156	b0568	6/1/2011	6/1/2011	Indian Rive	Install	Transform	third trans	230/138		3/30/2011	DPL	2012	2008	Load Delive	12/19/2007
157	b0569.1	6/1/2013	6/1/2013	East Frankf	Add	Transform	2nd	345/138		11/19/2009	ComEd	2012	2008	Gen Delive	9/10/2008
158	b0569.2	6/1/2013	6/1/2012	Country Cl	Reconductor		line 6603	138		3/11/2010	ComEd	2012	2008	Gen Delive	9/10/2008
159	b0570	6/1/2012	6/1/2012	East Side Li	Reconductor		Rebuild the	138	148/192/2	11/17/2010	AEP	2012	2008	Gen Delive	9/17/2008
160	b0572.1	6/1/2011	6/1/2011	Albright - M	Reconductor		with Drake	138		3/9/2011	APS	2011	2008	Gen Delive	9/17/2008
161	b0572.2	6/1/2011	6/1/2013	William - P	Reconductor		with 954 A	138	242/297	3/9/2011	APS	2011	2008	Gen Delive	9/17/2008
162	b0573	6/1/2012	9/1/2011	Cabot - Par	Install	Transmissi	second circ	138		3/30/2011	APS	2012	2008	Gen Delive	9/17/2008
163	b0576	6/1/2013	6/1/2013	Mickleton	Upgrade	Transform	T4	230/69		1/20/2011	AEC		2008	AE Load De	9/17/2008
164	b0583	11/30/2010	11/30/2010	Gosport	Install	Protection	dual prima	115		12/28/2010	Dominion	2010	2009	Stability	9/16/2009
165	b0587	6/1/2013	7/1/2012	Tidd - Carn	Reconductor		AP portion	138		5/16/2011	APS	2011	2008	Thermal O	9/17/2008
166	b0593	5/1/2012	5/31/2012	Eldred-Pine	Rebuild	Line	Part 2: 8 M	69		9/17/2010	PPL		2008	PPL Criteri	9/17/2008
167	b0596	5/1/2011	5/31/2011	Stanton-Pr	Reconductor		#1 & #2 Li	69		9/17/2010	PPL		2008	PPL Criteri	9/17/2008
168	b0597	11/1/2012	11/30/2012	Suburban-I	Reconductor		#1 Line: Re	69		9/17/2010	PPL		2008	PPL Criteri	9/17/2008
169	b0598	11/1/2017	11/30/2017	Suburban T	Reconductor		#1 & #2 Lir	69		9/17/2010	PPL		2008	PPL Criteri	9/17/2008
170	b0600	5/1/2013	5/31/2013	Tripp Park	Reconductor		Tap off Sta	69		11/16/2009	PPL		2008	PPL Criteri	6/11/2008
171	b0604	11/1/2011	5/31/2012	Harwood	Add	Transform	Add 150M	230/138/69		6/23/2011	PPL		2008	PPL Criteri	9/17/2008
172	b0605	5/1/2012	11/30/2017	Tanton-Old	Rebuild	Line	6.4 Miles S	69		6/23/2011	PPL		2008	PPL Criteri	9/17/2008
173	b0610	5/1/2012	5/31/2014	South Farn	Tap	Substation	New Tap o	69		1/20/2011	PPL		2008	PPL Criteri	9/17/2008
174	b0613	5/1/2012	5/30/2012	East Tanne	Tap	Substation	New Tap to	138		9/17/2010	PPL		2008	PPL Criteri	6/11/2008
175	b0614	5/1/2013	5/31/2013	Elroy	Expand	Substation	Expansion	69		6/23/2011	PPL		2008	PPL Criteri	9/17/2008
176	b0614.1	5/1/2013	5/31/2013	Elroy	Install	Transform	Install a se	500/138		5/26/2011	PPL			PPL Criteri	9/17/2008
177	b0614.2	5/1/2013	5/31/2013	Elroy	Install	Transform	Install a ne	138/69		5/26/2011	PPL			PPL Criteri	9/17/2008
178	b0614.3	5/1/2013	5/31/2013	Elroy	Build	Line	Build a nev	138/69		5/26/2011	PPL			PPL Criteri	9/17/2008
179	b0615	12/31/2009	5/31/2012	Seidersville	Reconductor		12 Miles ar	138/69		11/11/2010	PPL			PPL Criteri	9/17/2008
180	b0616	5/1/2011	12/31/2012	New Spring	Install	Substation	and Transn	230/69		9/17/2010	PPL		2008	PPL Criteri	9/17/2008
181	b0623	5/1/2013	5/31/2013	West Shore	Add	Line	New Doub	138/69		6/23/2011	PPL		2008	PPL Criteri	9/17/2008
182	b0625	5/1/2013	5/31/2013	West Shore	Reconductor		#3 & #4 Li	69		9/17/2010	PPL		2008	PPL Criteri	9/17/2008
183	b0629	11/1/2012	11/30/2012	Lincoln	Tap	Substation	Tap to Con	69		11/11/2010	PPL		2008	PPL Criteri	9/17/2008
184	b0630	11/30/2012	9/30/2012	W. Hempfi	Reconductor		Rebuild fro	69		9/15/2009	PPL		2008	PPL Criteri	9/17/2008
185	b0631	11/30/2012	9/30/2012	W. Hempfi	Reconductor		Rebuild to	69		9/15/2009	PPL		2008	PPL Criteri	9/17/2008
186	b0632	11/30/2013		S.Manheim	Terminate	Line	into South	69		9/16/2009	PPL		2008	PPL Criteri	9/17/2008
187	b0634	11/30/2011	11/30/2013	South Man	Rebuild	Line	#1 & #2 do	69		6/23/2011	PPL		2008	PPL Criteri	9/17/2008
188	b0635	11/30/2011	11/30/2013	South Man	Reconductor		#3 Line fro	69		3/18/2011	PPL		2008	PPL Criteri	9/17/2008
189	b0642	6/1/2011	6/1/2011	Oak Grove	Replace	Breaker	7C with 63	230		4/21/2011	PEPCO	2012	2008	Short Circu	8/20/2008
190	b0643	6/1/2011	12/31/2011	Oak Grove	Replace	Breaker	9A with 63	230		4/21/2011	PEPCO	2012	2008	Short Circu	8/20/2008
191	b0644	6/1/2011	12/21/2012	Oak Grove	Replace	Breaker	9B with 63	230		2/23/2011	PEPCO	2012	2008	Short Circu	8/20/2008
192	b0645	6/1/2011	6/1/2011	Oak Grove	Replace	Breaker	9C with 63	230		4/21/2011	PEPCO	2012	2008	Short Circu	8/20/2008
193	b0646	6/1/2011	12/31/2011	Oak Grove	Replace	Breaker	10A with 6	230		4/21/2011	PEPCO	2012	2008	Short Circu	8/20/2008
194	b0647	6/1/2011	12/21/2012	Oak Grove	Replace	Breaker	10C with 6	230		2/23/2011	PEPCO	2012	2008	Short Circu	8/20/2008
195	b0648	6/1/2011	12/21/2012	Oak Grove	Replace	Breaker	13A with 6	230		2/23/2011	PEPCO	2012	2008	Short Circu	8/20/2008
196	b0649	6/1/2011	12/21/2012	Oak Grove	Replace	Breaker	13B with 6	230		2/23/2011	PEPCO	2012	2008	Short Circu	8/20/2008
197	b0653	6/1/2013	6/1/2013	Bernville	Construct	Substation	by tapping	230/69		5/24/2011	ME				9/17/2008
198	b0655	6/1/2010	6/1/2011	Glade	Reconfigur	Substation	and expan	230		5/24/2011	PENELEC		2008	Voltage Vic	9/17/2008
199	b0658	6/1/2009		Morristow	Install	Transformer		230/13.2		8/14/2009	JCPL				9/17/2008
200	b0661	6/1/2014	6/1/2013	Plano	Install	Transform	New	345/138	420 / 480	2/18/2011	ComEd	2013	2008	Load Delive	9/10/2008
201	b0663	6/1/2014	6/1/2013	East Frankf	Reconductor			345	1334 / 172	2/18/2011	ComEd	2013	2008	Load Delive	9/10/2008
202	b0664	6/1/2012	6/1/2012	Branchburg	Reconductor		Upgrade te	230	1308/1485	3/9/2011	PSEG		2008		10/15/2008
203	b0665	6/1/2012	6/1/2012	Somerville	Reconductor		Upgrade w	230	1308/1485	3/9/2011	PSEG		2008		10/15/2008
204	b0668	6/1/2012	6/1/2012	Somerville	Reconductor		with doubl	230	1308/1485	3/9/2011	PSEG		2008		10/15/2008
205	b0671	6/1/2011	6/1/2011	Bridgewate	Replace	Terminal E	Upgrade m	230	734/854	3/9/2011	PSEG		2008		10/15/2008
206	b0673	6/1/2013	6/1/2013	Elko-Carbo	Rebuild	Circuit	to convert	230	482/593	6/1/2010	APS		2009	N-2 Therm	9/16/2009
207	b0674	6/1/2013	6/1/2013	Osage - Wh	Construct	Circuit	line from C	138	242/297	3/9/2011	APS	2013	2008	N-2 Therm	9/17/2008
208	b0674.1	6/1/2011	12/1/2011	Meadow B	Replace	Breaker	Replace Os	138		3/11/2011	APS	2014		Short Circu	1/13/2010
209	b0675.1	6/1/2013	1/1/2012	Monocacy	Convert	Line	138 kV to 2	230	482/593	5/16/2011	APS		2009	N-2 Therm	9/16/2009
210	b0675.2	6/1/2013	6/1/2012	Walkersvill	Convert	Line	138 kV to 2	230	482/593	5/16/2011	APS		2009	N-2 Therm	9/16/2009
211	b0675.3	6/1/2013	6/1/2013	Ringgold &	Convert	Line	138 kV to 2	230	482/593	5/16/2011	APS		2009	N-2 Therm	9/16/2009
212	b0675.4	6/1/2013	1/1/2013	Catoctin &	Convert	Line	138 kV to 2	230	482/593	5/16/2011	APS		2009	N-2 Therm	9/16/2009
213	b0675.5	6/1/2013	6/1/2013	Ringgold	Convert	Substation	a portion o	138/230	230kV	5/18/2011	APS		2009	N-2 Therm	9/16/2009

	A	P	Q	R	S	T	U	V	W	X	Y
3	Upgrade ID	Latest TEAC Date	Status	State	Region	County	Percent Co	Cost Estim	Project ID	In Schedul	Source
143	b0533		UC		PJM WEST		25	7.1	b0533	b0533	Planned
144	b0535		UC		PJM WEST		50	0.5	b0535	b0535	Planned
145	b0549		EP	PA	PJM MA		15	4.5	b0549	b0549	Planned
146	b0552		EP	PA	PJM MA		20	3.75	b0552	b0552	Planned
147	b0553		EP	PA	PJM MA		13	3.75	b0553	b0553	Planned
148	b0555		EP	PA	PJM MA		0	4.5	b0555	b0555	Planned
149	b0556		EP	PA	PJM MA		12	3.75	b0556	b0556	Planned
150	b0557		EP	PA	PJM MA		12	2.25	b0557	b0557	Planned
151	b0560		EP	PA	PJM WEST		0	4	b0560	b0560	Planned
152	b0563		EP	PA	PJM WEST		0	0.8	b0563	b0563	Planned
153	b0564		EP	PA	PJM WEST		0	0.4	b0564	b0564	Planned
154	b0565		EP	NJ	PJM MA		20	9	b0565	b0565	Planned
155	b0566		EP	MD	PJM MA		0	12	b0566	b0566	Planned
156	b0568		UC	MD	PJM MA		30	7.3	b0568	b0568	Planned
157	b0569.1		EP	IL	PJM WEST		0	10	b0569	b0569	Planned
158	b0569.2		EP	IL	PJM WEST		0	1.25	b0569	b0569	Planned
159	b0570	10/28/2010	EP	OH	PJM WEST		0	16.1	b0570	b0570	Planned
160	b0572.1		UC	WV	PJM WEST		70	4.56	b0572	b0572	Planned
161	b0572.2		EP	WV	PJM WEST		25	10.15	b0572	b0572	Planned
162	b0573		UC	WV	PJM WEST		30	1.18	b0573	b0573	Planned
163	b0576		EP	NJ	PJM MA		0	6.88	b0576	b0576	Planned
164	b0583		EP		PJM South		30	0.5	b0583	b0583	Planned
165	b0587		EP	WV	PJM WEST	Brooke & H	20	3.16	b0587	b0587	Planned
166	b0593		EP	PA	PJM MA		10	7.67	b0593	b0593	Planned
167	b0596		UC	PA	PJM MA		35	6.2	b0596	b0596	Planned
168	b0597		EP	PA	PJM MA		10	1.2	b0597	b0597	Planned
169	b0598		EP	PA	PJM MA		0	4.08	b0598	b0598	Planned
170	b0600		EP	PA	PJM MA		0	0.7	b0600	b0600	Planned
171	b0604		EP	PA	PJM MA		35	12.6	b0604	b0604	Planned
172	b0605		EP	PA	PJM MA		0	4.75	b0605	b0605	Planned
173	b0610		EP	PA	PJM MA		0	0.33	b0610	b0610	Planned
174	b0613		EP	PA	PJM MA		0	0.42	b0613	b0613	Planned
175	b0614		EP	PA	PJM MA		0	28.5	b0614	b0614	Planned
176	b0614.1		EP	PA	PJM MA		0	0	b0614	b0614	Planned
177	b0614.2		EP	PA	PJM MA		0	0	b0614	b0614	Planned
178	b0614.3		EP	PA	PJM MA		0	0	b0614	b0614	Planned
179	b0615		UC	PA	PJM MA		60	22.58	b0615	b0615	Planned
180	b0616		EP	PA	PJM MA		10	16.71	b0616	b0616	Planned
181	b0623		EP	PA	PJM MA		0	4.4	b0623	b0623	Planned
182	b0625		EP	PA	PJM MA		0	0.99	b0625	b0625	Planned
183	b0629		EP	PA	PJM MA		0	0.05	b0629	b0629	Planned
184	b0630		EP	PA	PJM MA		0	3.31	b0630	b0630	Planned
185	b0631		EP	PA	PJM MA		0	3.36	b0631	b0631	Planned
186	b0632		EP	PA	PJM MA		0	0.3	b0632	b0632	Planned
187	b0634		EP	PA	PJM MA		5	14	b0634	b0634	Planned
188	b0635		EP	PA	PJM MA		0	3.65	b0635	b0635	Planned
189	b0642	9/8/2010	EP	MD	PJM MA		20	1.5	b0642	b0642	Planned
190	b0643	9/8/2010	EP	MD	PJM MA		10	1.5	b0643	b0643	Planned
191	b0644	9/8/2010	EP	MD	PJM MA		10	1.5	b0644	b0644	Planned
192	b0645	9/8/2010	EP	MD	PJM MA		10	1.5	b0645	b0645	Planned
193	b0646	9/8/2010	EP	MD	PJM MA		5	1.5	b0646	b0646	Planned
194	b0647	9/8/2010	EP	MD	PJM MA		5	1.5	b0647	b0647	Planned
195	b0648	9/8/2010	EP	MD	PJM MA		5	1.5	b0648	b0648	Planned
196	b0649	9/8/2010	EP	MD	PJM MA		5	1.5	b0649	b0649	Planned
197	b0653		EP	PA	PJM MA		15	5.73	b0653	#N/A	Planned
198	b0655		UC	PA	PJM MA		85	5.64	b0655	b0655	Planned
199	b0658		On Hold	PA	PJM MA		23	1.47	b0658	#N/A	Planned
200	b0661		EP	IL	PJM WEST		0	20	b0661	b0661	Planned
201	b0663		EP	IL	PJM WEST		0	15	b0663	b0663	Planned
202	b0664		EP	NJ	PJM MA		5	12	b0664	b0664	Planned
203	b0665		EP	NJ	PJM MA		5	15	b0665	b0665	Planned
204	b0668		EP	NJ	PJM MA		5	9	b0668	b0668	Planned
205	b0671		EP	NJ	PJM MA		20	0.25	b0671	b0671	Planned
206	b0673		EP		PJM WEST		0	7.5	b0673	b0673	Planned
207	b0674		EP		PJM WEST		20	21	b0674	b0674	Planned
208	b0674.1		EP		PJM WEST		5	0.19	b0674	b0674	Planned
209	b0675.1		EP		PJM WEST		15	4.5	b0675	b0675	Planned
210	b0675.2		EP		PJM WEST		5	11.2	b0675	b0675	Planned
211	b0675.3		EP		PJM WEST		2	7.4	b0675	b0675	Planned
212	b0675.4		EP		PJM WEST		2	9.8	b0675	b0675	Planned
213	b0675.5		EP		PJM WEST		5	1.8	b0675	b0675	Planned

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
3	Upgrade ID	PJM Required	In Service Date	Location	Task	Equipment	Descriptior	Voltage	Expected R	Last Updated	Trans Own	Study Year	Baseline R	Driver	Initial TEAC Da
214	b0675.6	6/1/2013	1/1/2013	Catoctin	Convert	Substation	from 138 k	138/230	230kV	5/16/2011	APS		2009	N-2 Therm	9/16/2009
215	b0675.7	6/1/2013	6/1/2013	Carroll	Convert	Substaton	a portion o	138/230	176/202	3/9/2011	APS		2009	N-2 Therm	9/16/2009
216	b0675.8	6/1/2013	1/1/2012	Monocacy	Convert	Substation	from 138 k	138/230	230kV	3/9/2011	APS		2009	N-2 Therm	9/16/2009
217	b0675.9	6/1/2013	6/1/2012	Walkersvill	Convert	Substation	from 138 k	138/230	230kV	3/9/2011	APS		2009	N-2 Therm	9/16/2009
218	b0676.1	6/1/2013	6/1/2013	Doubs & Li	Reconductor		Reconduct	230	1117/1194	8/24/2010	APS		2009	N-2 Therm	9/16/2009
219	b0676.2	6/1/2013	6/1/2013	Doubs & Li	Reconductor		#231	230	1117/1194	8/24/2010	APS		2009	N-2 Therm	9/16/2009
220	b0677	6/1/2013	6/1/2013	Double Tol	Reconductor		with 954 A	138		3/9/2011	APS		2008	N-2 Therm	9/17/2008
221	b0678	6/1/2013	12/1/2012	Glen Falls -	Reconductor		with 954 A	138	242/297	3/9/2011	APS		2009	N-2 Therm	9/16/2009
222	b0679	6/1/2013	6/1/2013	Grand Poir	Reconductor		with 954 A	138		3/9/2011	APS		2008	N-2 Therm	9/17/2008
223	b0680	6/1/2013	6/1/2013	Greene - L	Reconduct	Line	Reconduct	138		3/9/2011	APS		2008	N-2 Therm	9/10/2008
224	b0681	6/1/2013	6/1/2012	Franklin	Replace	Current Transformer		600/5		3/11/2011	APS		2008	N-2 Therm	9/17/2008
225	b0682	6/1/2013	6/1/2012	Whiteley	Replace	Current Transformer		600/5		3/11/2011	APS		2008	N-2 Therm	9/17/2008
226	b0684	6/1/2013	6/1/2013	Guilford - S	Reconductor		with 954 A	138		3/9/2011	APS	2013	2008	Gen Delive	9/17/2008
227	b0685	6/1/2013	6/1/2013	Ringgold	Replace	Transform	#3 with a l	230/138		8/24/2010	APS	2013	2008	Gen Delive	9/17/2008
228	b0686	6/1/2013	6/1/2012	East Frankl	Add	Capacitor	"Red"	138	115.4 MVA	3/12/2010	ComEd	2013	2008	Voltage Vi	9/10/2008
229	b0687	6/1/2013	6/1/2012	Wolfs	Add	Capacitor	"Red"	138	115.4 MVA	3/18/2010	ComEd	2013	2008	Voltage Vi	9/10/2008
230	b0688	6/1/2014	6/1/2014	Plano	Add	Capacitor	"Blue"	138	115.4 MVA	3/18/2010	ComEd	2013	2008	Voltage Vi	9/10/2008
231	b0689	6/1/2013	6/1/2011	Goodings (	Add	Capacitor	"Red"	138	115.4	5/4/2011	ComEd	2013	2008	Voltage Vi	9/10/2008
232	b0690	6/1/2013	6/1/2011	Goodings (	Add	Capacitor	"Blue"	138	115.4	5/4/2011	ComEd	2013	2008	Voltage Vi	9/10/2008
233	b0691	6/1/2013	6/1/2013	Crawford	Add	Capacitor	"Green"	138	115.4 MVA	3/18/2010	ComEd	2013	2008	Voltage Vi	9/10/2008
234	b0692	6/1/2013	6/1/2013	Crawford	Add	Capacitor	"Yellow"	138	115.4 MVA	3/18/2010	ComEd	2013	2008	Voltage Vi	9/10/2008
235	b0693	6/1/2013	6/1/2013	Crawford	Add	Capacitor	"Blue"	138	115.4 MVA	3/18/2010	ComEd	2013	2008	Voltage Vi	9/10/2008
236	b0694	6/1/2013	6/1/2013	Crawford	Add	Capacitor	"Red"	138	115.4 MVA	3/18/2010	ComEd	2013	2008	Voltage Vi	9/10/2008
237	b0701.1	6/1/2012	6/1/2012	Benning	Install	Transform	Install a new 230/69 kV, 250 MVA			4/26/2011	PEPCO		2008	Benn/Buzz	9/17/2008
238	b0701.2	6/1/2012	10/31/2011	Benning	Build	Switching S	Build a new 115 kV Benning switc			4/26/2011	PEPCO		2008	Benn/Buzz	9/17/2008
239	b0702	6/1/2012	6/1/2012	Benning	Install	Shunt Reac	New 50 M\	230		4/21/2011	PEPCO		2008	Benn/Buzz	9/17/2008
240	b0704	6/1/2011	6/1/2011	Cabot	Install	Transform	4th autotra	500/138		4/13/2011	APS		2008	Thermal O	9/17/2008
241	b0707	11/30/2013	11/30/2013	Bohemia -	Install	Line	New 12.5 I	138/69		9/17/2010	PPL		2008	Supplemer	9/17/2008
242	b0708	11/30/2013	11/30/2013	Jackson - L	Install	Line	New Doub	138/69		11/16/2009	PPL		2008	Supplemer	9/17/2008
243	b0709	11/30/2012	11/30/2013	Carlisle - W	Install	Line	New Doub	138/69		6/23/2011	PPL		2008	Supplemer	9/17/2008
244	b0710	5/31/2012	5/31/2013	Reese's Ta	Install	Line	Third Line	138/69		6/23/2011	PPL		2008	Supplemer	9/17/2008
245	b0711	11/30/2013	11/30/2013	West Shor	Install	Line	New Singl	138/69		6/23/2011	PPL		2008	Supplemer	9/17/2008
246	b0715	11/30/2012	11/30/2012	South Akro	Transfer	Line	#1 & #2 frc	138		9/17/2010	PPL		2008	Supplemer	9/17/2008
247	b0716	11/30/2011	5/31/2015	S. Akron - I	Install	Line	Add Secon	69		3/5/2010	PPL		2008	Supplemer	9/17/2008
248	b0717	6/1/2013	5/31/2013	Brunner Isl	Upgrade	Line	Rebuild exi	230		6/23/2011	PPL	2013	2008	N-1-1	8/20/2008
249	b0719	6/1/2013	11/30/2012	Jenkins	Install	Substation	SPS schem	230		3/2/2010	PPL	2013	2008	N-1-1	8/20/2008
250	b0720	6/1/2012	6/1/2012	Quince Orc	Upgrade	Substation	terminal e	230		11/8/2010	PEPCO	2013	2008	N-1-1	8/20/2008
251	b0721	6/1/2013	6/1/2013	Oak Grove	Upgrade	Line	23061	230		11/8/2010	PEPCO	2013	2008	N-1-1	8/20/2008
252	b0722	6/1/2013	6/1/2013	Oak Grove	Upgrade	Line	23058	230		11/8/2010	PEPCO	2013	2008	N-1-1	8/20/2008
253	b0723	6/1/2013	6/1/2013	Oak Grove	Upgrade	Line	23059	230		11/8/2010	PEPCO	2013	2008	N-1-1	8/20/2008
254	b0724	6/1/2013	6/1/2013	Oak Grove	Upgrade	Line	23060	230		11/8/2010	PEPCO	2013	2008	N-1-1	8/20/2008
255	b0725	6/1/2013	6/1/2013	Steele	Install	Transform	3rd transfc	230/138		11/19/2009	DPL	2013	2008	N-1-1	8/20/2008
256	b0726	6/1/2013	6/1/2013	Raritan Riv	Install	Transform	2nd transf	230/115		5/24/2011	JCPL	2013	2008	N-1-1	10/15/2008
257	b0727	6/1/2013	6/1/2013	Bryn Mawr	Rebuild	Transmissi	Line 130-3	138		5/5/2011	PECO	2013	2008	N-1-1	9/17/2008
258	b0729	6/1/2012	6/1/2012	Harford-Pe	Construct	Circuits	Extend twc	115		12/30/2010	BGE	2013	2008	N-1-1	9/17/2008
259	b0730	6/1/2013	6/1/2013	Bells Mill R	Install	Transmissi	Increase th	138		1/20/2011	PEPCO	2013	2008	N-1-1	9/17/2008
260	b0731	6/1/2013	6/1/2013	Bells Mill R	Install	Substation	SPS to autc	34		11/8/2010	PEPCO	2013	2008	N-1-1	9/17/2008
261	b0732	6/1/2013	6/1/2013	Vaugh-Wel	Rebuild	Line		69		11/19/2009	DPL	2013	2008	N-1-1	9/17/2008
262	b0733	6/1/2013	6/1/2012	Harmony	Install	Transform	2nd transf	230/138		11/19/2009	DPL	2013	2008	N-1-1	9/17/2008
263	b0737	6/1/2013	5/31/2013	Indian Rive	Install	Transmissi	Build a nev	138		6/23/2011	DPL	2013	2008	N-1-1	9/17/2008
264	b0738	6/1/2013	6/1/2013	Lombard	Install	capacitor	Add 115.2	138	115.2 MVA	3/18/2010	ComEd	2013	2008	Voltage Vi	9/10/2008
265	b0739	6/1/2013	6/1/2013	Lombard	Install	capacitor	Add 115.2	138	115.2 MVA	3/18/2010	ComEd	2013	2008	Voltage Vi	9/10/2008
266	b0740.1	6/1/2013	6/1/2012	Wolfs	Install	capacitor	Add 57.6 M	138	57.6 MVAR	3/11/2010	ComEd	2013	2008	Voltage Vi	9/10/2008
267	b0740.2	6/1/2014	6/1/2012	Wolfs	Increase	Capacitor I	Add additi	138		10/22/2010	ComEd	2014	2009	Load Deliv	1/13/2010
268	b0744	6/1/2013	5/31/2011	Mill	Upgrade	Strand Bus		138		1/20/2011	AEC		2008	Gen Delive	9/17/2008
269	b0748	12/1/2011	12/1/2011	Canal Roac	Install	Circuit	Establish a	69		3/5/2010	AEP		2008	AEP Criteri	9/17/2008
270	b0749	6/1/2013	6/1/2013	Riverside	Replace	Breaker	and associ	230		12/30/2010	BGE		2008	Gen Delive	7/16/2008
271	b0750	6/1/2015	6/1/2015	Vienna - Lc	Convert	Line	network p	230/138		6/23/2011	DPL		2008	Load Delive	9/17/2008
272	b0751	6/1/2013	12/31/2011	Keeney	Install	Circuit Bre	two additic	500		6/23/2011	DPL		2008	Gen Delive	9/17/2008
273	b0752	6/1/2013	6/1/2013	Reybold - L	Replace	Circuit Bre	two circuit	138		6/1/2010	DPL		2008	Load Delive	9/17/2008
274	b0753	6/1/2015	6/1/2015	Loretto	Install	Transform	second tra	230/138		6/23/2011	DPL		2008	N-1-1	9/17/2008
275	b0754	6/1/2013	6/1/2013	Glasgow - I	Rebuild	Transmissi	10 miles of	138	298/333	2/4/2010	DPL		2008	Load Delive	9/17/2008
276	b0756	6/1/2013	11/29/2013	Chancellor	Install	Transform	(Option D)	500/115		12/28/2010	Dominion		2008	Dominion (	9/17/2008
277	b0756.1	6/1/2013	11/29/2013	Chancellor	Install	Circuit Bre	(Option D)	500		12/28/2010	Dominion			Dominion (	9/17/2008
278	b0757	6/1/2013	5/30/2013	Chesapeak	Reconductor		one mile o	115		1/10/2011	Dominion		2008	Dominion (	9/17/2008
279	b0758	6/1/2013	5/1/2012	Fredericksl	Install	Transform	Install a se	230/115		12/28/2010	Dominion		2008	N-1-1	9/17/2008
280	b0759	6/1/2013	5/1/2012	Dooms - D	Build	Transmissi	Build a sec	115		5/13/2011	Dominion		2008	N-1-1	9/17/2008
281	b0763	6/1/2009	12/31/2010	Yorktown -	Rebuild	Transmissi	17.5 miles	115	260/260	12/28/2010	Dominion		2008	Dominion (	9/17/2008
282	b0764	10/18/2011	10/18/2011	Greenwich	Increase	Rating	on 2.56 mi	230	257	12/28/2010	Dominion			Dominion (	9/17/2008
283	b0768	6/1/2011	6/1/2011	Idylwood -	Loop	Line	#251 into the GIS sub			5/4/2011	Dominion		2008	N-1-1	9/17/2008
284	b0769	6/1/2013	9/1/2013	Garner - La	Retension	Transmissi	15 miles of	115	216	5/13/2011	Dominion		2008	Dominion (	9/17/2008

	A	P	Q	R	S	T	U	V	W	X	Y
3	Upgrade ID	Latest TEAC Date	Status	State	Region	County	Percent Co	Cost Estim	Project ID	In Schedul	Source
214	b0675.6		EP		PJM WEST		5	7.5	b0675	b0675	Planned
215	b0675.7		EP		PJM WEST		3	4.7	b0675	b0675	Planned
216	b0675.8		UC		PJM WEST		45	3.8	b0675	b0675	Planned
217	b0675.9		EP		PJM WEST		5	5	b0675	b0675	Planned
218	b0676.1		EP		PJM WEST		1	3.5	b0676	b0676	Planned
219	b0676.2		EP		PJM WEST		1	3.1	b0676	b0676	Planned
220	b0677		EP		PJM WEST		1	2.7	b0677	b0677	Planned
221	b0678		EP		PJM WEST		1	1	b0678	b0678	Planned
222	b0679		EP		PJM WEST		5	2.1	b0679	b0679	Planned
223	b0680		EP	PA	PJM WEST		2	1.7	b0680	b0680	Planned
224	b0681		EP		PJM WEST		5	0.01	b0681	b0681	Planned
225	b0682		EP		PJM WEST		5	0.01	b0682	b0682	Planned
226	b0684		EP		PJM WEST		2	3.2	b0684	b0684	Planned
227	b0685		EP		PJM WEST		2	5.8	b0685	b0685	Planned
228	b0686		EP	IL	PJM WEST		0	2.9	b0686	b0686	Planned
229	b0687		EP	IL	PJM WEST		0	2.3	b0687	b0687	Planned
230	b0688		EP	IL	PJM WEST		0	2.3	b0688	b0688	Planned
231	b0689		EP	IL	PJM WEST		0	2.3	b0689	b0689	Planned
232	b0690		EP	IL	PJM WEST		0	2.3	b0690	b0690	Planned
233	b0691		EP	IL	PJM WEST		0	2.3	b0691	b0691	Planned
234	b0692		EP	IL	PJM WEST		0	2.3	b0692	b0692	Planned
235	b0693		EP	IL	PJM WEST		0	2.3	b0693	b0693	Planned
236	b0694		EP	IL	PJM WEST		0	2.3	b0694	b0694	Planned
237	b0701.1		EP	MD	PJM MA		20	10.6	b0701	b0701	Planned
238	b0701.2		UC	MD	PJM MA		75	23	b0701	b0701	Planned
239	b0702		UC	MD	PJM MA		50	6.4	b0702	b0702	Planned
240	b0704		UC	PA	PJM WEST	Butler	45	8.07	b0704	#N/A	Planned
241	b0707		EP		PJM MA		10	8.2	b0707	b0707	Planned
242	b0708		EP		PJM MA		0	7.49	b0708	b0708	Planned
243	b0709		EP		PJM MA		0	16.1	b0709	b0709	Planned
244	b0710		EP		PJM MA		0	14	b0710	b0710	Planned
245	b0711		EP		PJM MA		0	3.5	b0711	b0711	Planned
246	b0715		EP		PJM MA		0	2.41	b0715	b0715	Planned
247	b0716		EP		PJM MA		0	0.74	b0716	b0716	Planned
248	b0717		EP	PA	PJM MA		0	27.7	b0717	b0717	Planned
249	b0719		EP	PA	PJM MA		10	0.1	b0719	b0719	Planned
250	b0720		EP	MD	PJM MA		5	1.42	b0720	b0720	Planned
251	b0721		EP	MD	PJM MA		0	3.25	b0721	b0721	Planned
252	b0722		EP	MD	PJM MA		0	3.25	b0722	b0722	Planned
253	b0723		EP	MD	PJM MA		0	3.25	b0723	b0723	Planned
254	b0724		EP	MD	PJM MA		0	3.25	b0724	b0724	Planned
255	b0725		EP	DE	PJM MA		0	8	b0725	b0725	Planned
256	b0726		EP	NJ	PJM MA		0	7.1	b0726	b0726	Planned
257	b0727		EP	PA	PJM MA		10	16.6	b0727	b0727	Planned
258	b0729		EP	MD	PJM MA		0	4.4	b0729	b0729	Planned
259	b0730	1/6/2011	EP	MD	PJM MA		0	15	b0730	b0730	Planned
260	b0731		EP	MD	PJM MA		0	0	b0731	b0731	Planned
261	b0732		EP	DE	PJM MA		0	1.6	b0732	b0732	Planned
262	b0733		EP	DE	PJM MA		0	7.5	b0733	b0733	Planned
263	b0737		EP	DE	PJM MA		0	18	b0737	b0737	Planned
264	b0738		EP	IL	PJM WEST		0	2.3	b0738	b0738	Planned
265	b0739		EP	IL	PJM WEST		0	2.3	b0739	b0739	Planned
266	b0740.1		EP	IL	PJM WEST		0	1.15	b0740	b0740	Planned
267	b0740.2		EP	IL	PJM WEST		0	1.15	b0740	b0740	Planned
268	b0744		UC				40	0.1	b0744	b0744	Planned
269	b0748		EP				0	27	b0748	b0748	Planned
270	b0749		EP				0	1.5	b0749	b0749	Planned
271	b0750		EP				0	40	b0750	b0750	Planned
272	b0751		EP				0	4.5	b0751	b0751	Planned
273	b0752		EP				0	1	b0752	b0752	Planned
274	b0753		EP				0	4.5	b0753	b0753	Planned
275	b0754		EP				0	5.7	b0754	b0754	Planned
276	b0756		EP				0	16	b0756	b0756	Planned
277	b0756.1		EP				0	2	b0756	b0756	Planned
278	b0757		EP				0	1	b0757	b0757	Planned
279	b0758		EP				10	5.5	b0758	b0758	Planned
280	b0759		EP				0	20.5	b0759	b0759	Planned
281	b0763		UC				90	10.2	b0763	b0763	Planned
282	b0764		UC				90	4	b0764	b0764	Planned
283	b0768	10/22/2009	UC				80	22.5	b0768	b0768	Planned
284	b0769	3/3/2011	EP				30	5.8	b0769	b0769	Planned

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
3	Upgrade ID	PJM Required	In Service Date	Location	Task	Equipment	Descriptior	Voltage	Expected R	Last Updated	Trans Own	Study Year	Baseline R	Driver	Initial TEAC Da
285	b0771	11/1/2011	6/30/2011	Chickahom	Build	Line	a parallel li	230		4/26/2011	Dominion		2008	Dominion (	9/17/2008
286	b0774	6/1/2011	6/1/2012	Bremo	Install	Capacitor	33 MVAR c	115		12/28/2010	Dominion		2008	Voltage Vi	9/17/2008
287	b0775	6/1/2011	5/31/2012	Greenwich	Reconductor		line to bring it up to a		261	5/18/2011	Dominion		2008	Dominion (	9/17/2008
288	b0776	6/1/2011	10/13/2011	Trowbridge	Rebuild	Transmission Line		115	398/398 4	6/2/2011	Dominion		2008	N-1-1	9/17/2008
289	b0777	6/1/2011	6/1/2011	Thelma - C	Terminate	Line	the Thelma	230		4/19/2011	Dominion		2008	N-1-1	9/17/2008
290	b0778	5/1/2018	6/1/2012	Lebanon	Install	Capacitor	29.7 MVAR	115		5/24/2010	Dominion		2008	Voltage Vi	9/17/2008
291	b0779	6/1/2012	5/30/2012	Yorktown -	Build	Transmissi	Build a nev	230		5/13/2011	Dominion		2008	Voltage Vi	9/17/2008
292	b0780	6/1/2012	6/1/2012	Chesapeak	Reconductor		Chesapeak	115	239 / 239	5/16/2011	Dominion		2008	Dominion (	9/17/2008
293	b0781	6/1/2012	6/1/2012	Acca statio	Recondcutor		Reconduct	115		4/19/2011	Dominion		2008	Dominion (	9/17/2008
294	b0782	6/1/2013	6/10/2011	Dupont - W	Install	Capacitor	New	115	39.6 MVAR	5/16/2011	Dominion		2008	Dominion (	9/17/2008
295	b0784	6/1/2013	5/30/2013	North Anna	Replace	Wave Trap		500		12/28/2010	Dominion		2008	Gen Delive	9/17/2008
296	b0786	6/1/2011	5/31/2011	Moran DP	Recondcutor			115	258/284	4/19/2011	Dominion		2008	Dominion (	9/17/2008
297	b0787	6/1/2011	5/31/2011	Chase City	Uprate	Transmissi	Chase City-	115	239, 258/2	4/19/2011	Dominion		2008	Dominion (	9/17/2008
298	b0788	6/1/2011	6/1/2012	Farmville -	Reconductor		Reconduct	115	258/284	6/9/2011	Dominion		2008	Dominion (	9/17/2008
299	b0789	6/1/2013	6/1/2013	Bradford -	Replace	Terminal E	Ckt.220-02	230	677/827	4/18/2011	PECO		2008	Gen Delive	9/17/2008
300	b0790	6/1/2013	6/1/2013	Bradford -	Replace	Terminal E	Ckt.220-31	230	677/827	4/18/2011	PECO		2008	Gen Delive	9/17/2008
301	b0791	11/1/2011	11/30/2011	Stanton	Install	Transform	fourth tran	230/69		6/23/2011	PPL		2008		9/17/2008
302	b0792	6/1/2013	6/1/2013	Cecil	Upgrade	Substation	Reconfigur	230/138		11/19/2009	DPL	2013	2008	N-1-1	10/15/2008
303	b0793	6/1/2013	6/1/2013	Possum Po	Rebuild	Line	Close 145T	115	345 / 345	5/18/2011	Dominion		2008		9/17/2008
304	b0794	6/1/2009		Homer City	Upgrade	Breaker	Pierce Roa	230		5/24/2011	PENELEC	2009	2009	Short Circu	5/20/2009
305	b0795	6/1/2012	6/1/2012	Chesaco Pa	Install	Breaker		115		2/11/2011	BGE	2013	2008	N-1-1	10/15/2008
306	b0796	6/1/2013	6/1/2013	Gwynnbro	Install	Breaker	2 breakers	115		12/30/2010	BGE	2013	2008	N-1-1	10/15/2008
307	b0812	6/1/2012	6/1/2011	Kittatinny-	Uprate	Circuit	Increase op	230	732/925	9/15/2009	PSEG	2011	2008	Gen Delive	10/15/2008
308	b0814	6/1/2013	6/1/2012	Essex-Kear	Build	Circuit	New circuit	138		10/28/2010	PSEG	2011	2008	Gen Delive	10/15/2008
309	b0814.1	6/1/2013	6/1/2012	Kearny	Replace	Breaker	1-SHT' with	138		3/9/2011	PSEG		2009	Short Circu	9/16/2009
310	b0814.11	6/1/2013	6/1/2012	Essex	Replace	Breaker	2PM' with	138		3/9/2011	PSEG		2009	Short Circu	9/16/2009
311	b0814.2	6/1/2013	6/1/2012	Kearny	Replace	Breaker	15HF' with	138		3/9/2011	PSEG		2009	Short Circu	9/16/2009
312	b0814.22	6/1/2013		ECRR	Replace	Breaker	903'	138		7/16/2010	PSEG		2009	Short Circu	9/16/2009
313	b0814.3	6/1/2013	6/1/2012	Kearny	Replace	Breaker	14HF' with	138		3/9/2011	PSEG		2009	Short Circu	9/16/2009
314	b0814.4	6/1/2013	6/1/2012	Kearny	Replace	Breaker	10HF' with	138		3/9/2011	PSEG		2009	Short Circu	9/16/2009
315	b0814.5	6/1/2013	6/1/2012	Kearny	Replace	Breaker	2HT' with 8	138		3/9/2011	PSEG		2009	Short Circu	9/16/2009
316	b0814.6	6/1/2013	6/1/2012	Kearny	Replace	Breaker	22HF' with	138		3/9/2011	PSEG		2009	Short Circu	9/16/2009
317	b0814.7	6/1/2013	6/1/2012	Kearny	Replace	Breaker	4HT' with 8	138		3/9/2011	PSEG		2009	Short Circu	9/16/2009
318	b0814.8	6/1/2013	6/1/2012	Kearny	Replace	Breaker	25HF' with	138		3/9/2011	PSEG		2009	Short Circu	9/16/2009
319	b0820	6/1/2011	6/1/2011	Delight-Gw	Remove	Line Drop	limitations	115		6/2/2011	BGE	2011	2008	Gen Delive	11/5/2008
320	b0821	6/1/2011	12/31/2010	Northwest	Remove	Line Drop	limitations	115	335 / 437	4/25/2011	BGE	2011	2008	Gen Delive	11/5/2008
321	b0823	6/1/2011	6/24/2011	Windy Edg	Remove	Line Drop	limitations	115		4/25/2011	BGE	2011	2008	Gen Delive	11/5/2008
322	b0824	6/1/2011	12/31/2010	Granite-Ha	Remove	Line Drop	limitations	115	212 / 262	4/26/2011	BGE	2011	2008	Gen Delive	11/5/2008
323	b0825	6/1/2011	12/31/2010	Harrisonvil	Remove	Line Drop	limitations	115	165 / 250	4/26/2011	BGE	2011	2008	Gen Delive	11/5/2008
324	b0826	6/1/2011	12/31/2010	Riverside-E	Remove	Line Drop	limitations	115	212 /262	4/25/2011	BGE	2011	2008	Gen Delive	11/5/2008
325	b0828	6/1/2011	6/1/2011	Granite-Ha	Disable	Transmissi	HS throwo	115		4/25/2011	BGE	2011	2008	Gen Delive	11/5/2008
326	b0829.1	6/1/2011	6/1/2013	Whitpain	Replace	Breaker	155	230	80 kA	1/20/2011	PECO	2013	2009	Short Circu	5/20/2009
327	b0829.11	6/1/2013	6/1/2013	Branchburg	Replace	Breaker	32H	230	63 kA	6/2/2010	PSEG	2013	2009	Short Circu	5/20/2009
328	b0829.12	6/1/2013	6/1/2013	Branchburg	Replace	Breaker	52H	230	63 kA	6/2/2010	PSEG	2013	2009	Short Circu	5/20/2009
329	b0829.2	6/1/2011	6/1/2013	Whitpain	Replace	Breaker	525	230	80 kA	1/20/2011	PECO	2013	2009	Short Circu	5/20/2009
330	b0829.3	6/1/2011	6/1/2013	Whitpain	Replace	Breaker	175	230	80 kA	1/20/2011	PECO	2013	2009	Short Circu	5/20/2009
331	b0829.4	6/1/2013	6/1/2013	Plymouth M	Replace	Breaker	225	230	63 kA	1/20/2011	PECO	2013	2009	Short Circu	5/20/2009
332	b0829.6	6/1/2013	6/1/2013	Branchburg	Replace	Breaker	91X	500	40 kA	6/2/2010	PSEG	2013	2009	Short Circu	5/20/2009
333	b0829.9	6/1/2013	6/1/2013	Branchburg	Replace	Breaker	102H	230	63 kA	6/2/2010	PSEG	2013	2009	Short Circu	5/20/2009
334	b0830.1	6/1/2012	2/28/2011	Roseland	Upgrade	Breaker	82H with 8	230	80 kA	3/23/2011	PSEG		2009	Short Circu	7/15/2009
335	b0838	6/1/2013	12/31/2014	Hazard Are	Upgrade	Various	and 69 kV l	138		3/10/2011	AEP		2009	N-1-1 Ther	9/16/2009
336	b0840	6/1/2013	6/1/2013	Twin Branc	Install	Transmissi	String a sec	138		6/2/2010	AEP		2009	N-1-1 Ther	9/16/2009
337	b0840.1	6/1/2014	6/1/2014	Twin Branc	Construct	Substation	a new 138/	138/69		6/2/2010	AEP		2009	N-1-1 Ther	9/16/2009
338	b0842	12/16/2011	10/31/2011	Heaton	Install	Transform	2nd XFMR	230/138		5/23/2011	PECO	2013	2009	N-1-1 Volta	7/15/2009
339	b0842.1	6/1/2013	10/31/2011	Heaton	Replace	Breaker	breaker '15	138		5/5/2011	PECO	2014	2009	Short Circu	11/18/2009
340	b0843	6/1/2013	6/1/2013	Llanerch	Install	Capacitor	a 75 MVAR	138		1/20/2011	PECO	2013	2009	N-1-1 Volta	9/16/2009
341	b0844	6/1/2013	6/1/2013	Llanerch	Upgrade	Transform	Move the (	138/69		1/20/2011	PECO	2013	2009	N-1-1 Volta	9/16/2009
342	b0845	6/1/2012	6/1/2011	Chalk Point	Replace	Breaker	Replace Ch	230		6/2/2011	PEPCO	2012		Short Circu	10/28/2010
343	b0846	6/1/2012	6/1/2011	Chalk Point	Replace	Breaker	Replace Ch	230		2/24/2011	PEPCO	2012		Short Circu	10/28/2010
344	b0847	6/1/2012	12/31/2014	Chalk Point	Replace	Breaker	Replace Ch	230		1/20/2011	PEPCO	2012		Short Circu	10/28/2010
345	b0850	6/1/2012	12/31/2011	Chalk Point	Replace	Breaker	Replace Ch	230		4/21/2011	PEPCO	2012		Short Circu	10/28/2010
346	b0851	6/1/2012	12/31/2011	Chalk Point	Replace	Breaker	Replace Ch	230		4/21/2011	PEPCO	2012		Short Circu	10/28/2010
347	b0852	6/1/2012	12/31/2014	Chalk Point	Replace	Breaker	Replace Ch	230		1/20/2011	PEPCO	2012		Short Circu	10/28/2010
348	b0853	6/1/2012	12/31/2014	Chalk Point	Replace	Breaker	Replace Ch	230		1/20/2011	PEPCO	2012		Short Circu	10/28/2010
349	b0854	6/1/2012	12/31/2014	Chalk Point	Replace	Breaker	Replace Ch	230		1/20/2011	PEPCO	2012		Short Circu	10/28/2010
350	b0855	6/1/2012	12/31/2014	Chalk Point	Replace	Breaker	Replace Ch	230		1/20/2011	PEPCO	2012		Short Circu	10/28/2010
351	b0856	6/1/2012	12/31/2014	Chalk Point	Replace	Breaker	Replace Ch	230		1/20/2011	PEPCO	2012		Short Circu	10/28/2010
352	b0857	6/1/2012	12/31/2014	Chalk Point	Replace	Breaker	Replace Ch	230		1/20/2011	PEPCO	2012		Short Circu	10/28/2010
353	b0858	6/1/2012	12/31/2014	Chalk Point	Replace	Breaker	Replace Ch	230		1/20/2011	PEPCO	2012		Short Circu	10/28/2010
354	b0859	6/1/2012	12/31/2014	Chalk Point	Replace	Breaker	Replace Ch	230		1/20/2011	PEPCO	2012		Short Circu	10/28/2010
355	b0860	6/1/2012	12/31/2014	Chalk Point	Replace	Breaker	Replace Ch	230		1/20/2011	PEPCO	2012		Short Circu	10/28/2010

	A	P	Q	R	S	T	U	V	W	X	Y
3	Upgrade ID	Latest TEAC Date	Status	State	Region	County	Percent Co	Cost Estim	Project ID	In Schedule	Source
285	b0771		UC				80	7.7	b0771	b0771	Planned
286	b0774		EP				0	0.6	b0774	b0774	Planned
287	b0775		EP				0	2.1	b0775	b0775	Planned
288	b0776		UC				60	16.4	b0776	b0776	Planned
289	b0777		UC				60	3.5	b0777	b0777	Planned
290	b0778	10/22/2009	EP				0	0.5	b0778	b0778	Planned
291	b0779	3/3/2011	EP				20	74	b0779	b0779	Planned
292	b0780		EP				0	2	b0780	b0780	Planned
293	b0781		UC				100	0.3	b0781	b0781	Planned
294	b0782		EP				10	0.73	b0782	b0782	Planned
295	b0784		EP				0	0.3	b0784	b0784	Planned
296	b0786		UC				90	6	b0786	b0786	Planned
297	b0787		UC				40	7.9	b0787	b0787	Planned
298	b0788		EP				20	9	b0788	b0788	Planned
299	b0789		EP				5	3.7	b0789	b0789	Planned
300	b0790		EP				5	4.6	b0790	b0790	Planned
301	b0791		UC				50	2.4	b0791	b0791	Planned
302	b0792		EP	MD	PJM MA		0	6	b0792	b0792	Planned
303	b0793		EP		PJM SOUTH		0	24	b0793	b0793	Planned
304	b0794		EP	PA	PJM MA		0	0.23	b0794	b0794	Planned
305	b0795		EP	MD	PJM MA		5	2.9	b0795	b0795	Planned
306	b0796		EP	MD	PJM MA		0	1.3	b0796	b0796	Planned
307	b0812		EP	NJ	PJM MA		0	0.1	b0812	b0812	Planned
308	b0814		UC	NJ	PJM MA		2	71.2	b0814	b0814	Planned
309	b0814.1		EP	NJ	PJM MA		5	1	b0814	b0814	Planned
310	b0814.11		EP	NJ	PJM MA		2	0.5	b0814	b0814	Planned
311	b0814.2		EP	NJ	PJM MA		5	1	b0814	b0814	Planned
312	b0814.22		EP	NJ	PJM MA		0	0.5	b0814	b0814	Planned
313	b0814.3		EP	NJ	PJM MA		5	1	b0814	b0814	Planned
314	b0814.4		EP	NJ	PJM MA		5	1	b0814	b0814	Planned
315	b0814.5		EP	NJ	PJM MA		5	1	b0814	b0814	Planned
316	b0814.6		EP	NJ	PJM MA		5	1	b0814	b0814	Planned
317	b0814.7		EP	NJ	PJM MA		5	1	b0814	b0814	Planned
318	b0814.8		EP	NJ	PJM MA		5	1	b0814	b0814	Planned
319	b0820		EP	MD	PJM MA		0	0.4	b0820	b0820	Planned
320	b0821		EP	MD	PJM MA		0	0.1	b0821	b0821	Planned
321	b0823		EP	MD	PJM MA		0	0.1	b0823	b0823	Planned
322	b0824		EP	MD	PJM MA		0	0.1	b0824	b0824	Planned
323	b0825		EP	MD	PJM MA		0	0.1	b0825	b0825	Planned
324	b0826		EP	MD	PJM MA		0	0.1	b0826	b0826	Planned
325	b0828		EP	MD	PJM MA		0	0	b0828	b0828	Planned
326	b0829.1		EP	PA	PJM MA		0	0.5	b0829	b0829	Planned
327	b0829.11		EP	NJ	PJM MA		0	0.5	b0829	b0829	Planned
328	b0829.12		EP	NJ	PJM MA		0	0.5	b0829	b0829	Planned
329	b0829.2		EP	PA	PJM MA		0	0.5	b0829	b0829	Planned
330	b0829.3		EP	PA	PJM MA		0	0.5	b0829	b0829	Planned
331	b0829.4		EP	PA	PJM MA		0	0.5	b0829	b0829	Planned
332	b0829.6		EP	NJ	PJM MA		0	0.8	b0829	b0829	Planned
333	b0829.9		EP	NJ	PJM MA		0	0.5	b0829	b0829	Planned
334	b0830.1		EP	NJ	PJM MA		28	0.8	b0830	b0830	Planned
335	b0838		EP		PJM West		0	44	b0838	b0838	Planned
336	b0840		EP		PJM West		0	6	b0840	b0840	Planned
337	b0840.1		EP		PJM WEST		0	3.5	b0840	b0840	Planned
338	b0842		UC	PA	PJM MA		30	9.5	b0842	b0842	Planned
339	b0842.1		UC	PA	PJM MA		25	0.24	b0842	b0842	Planned
340	b0843		EP	PA	PJM MA		0	2.6	b0843	b0843	Planned
341	b0844		EP	PA	PJM MA		0	0.5	b0844	b0844	Planned
342	b0845		EP	MD	PJM MA		20	2	b0845	b0845	Planned
343	b0846		EP	MD	PJM MA		20	2	b0846	b0846	Planned
344	b0847		EP	MD	PJM MA		0	2	b0847	b0847	Planned
345	b0850		EP	MD	PJM MA		0	2	b0850	b0850	Planned
346	b0851		EP	MD	PJM MA		0	2	b0851	b0851	Planned
347	b0852		EP	MD	PJM MA		0	2	b0852	b0852	Planned
348	b0853		EP	MD	PJM MA		0	2	b0853	b0853	Planned
349	b0854		EP	MD	PJM MA		0	2	b0854	b0854	Planned
350	b0855		EP	MD	PJM MA		0	2	b0855	b0855	Planned
351	b0856		EP	MD	PJM MA		0	2	b0856	b0856	Planned
352	b0857		EP	MD	PJM MA		0	2	b0857	b0857	Planned
353	b0858		EP	MD	PJM MA		0	2	b0858	b0858	Planned
354	b0859		EP	MD	PJM MA		0	2	b0859	b0859	Planned
355	b0860		EP	MD	PJM MA		0	2	b0860	b0860	Planned

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
3	Upgrade ID	PJM Required	In Service Date	Location	Task	Equipment	Descriptior	Voltage	Expected R	Last Updated	Trans Own	Study Year	Baseline R	Driver	Initial TEAC Da
356	b0861	6/1/2012	12/31/2014	Chalk Point	Replace	Breaker	Replace Ch	230		1/20/2011	PEPCO	2012		Short Circu	10/28/2010
357	b0862	6/1/2012	12/31/2014	Chalk Point	Replace	Breaker	Replace Ch	230		1/20/2011	PEPCO	2012		Short Circu	10/28/2010
358	b0864	6/1/2012	12/31/2014	Chalk Point	Replace	Breaker	Replace Ch	230		4/20/2011	GenOn/Mi	2012		Short Circu	3/10/2011
359	b0865	6/1/2012	12/31/2014	Chalk Point	Replace	Breaker	Replace Ch	230		4/20/2011	GenOn/Mi	2012		Short Circu	3/10/2011
360	b0866	6/1/2012	12/31/2014	Chalk Point	Replace	Breaker	Replace Ch	230		4/20/2011	GenOn/Mi	2012		Short Circu	3/10/2011
361	b0867	6/1/2012	12/31/2014	Chalk Point	Replace	Breaker	Replace Ch	230		4/20/2011	GenOn/Mi	2012		Short Circu	3/10/2011
362	b0870	6/1/2013	6/1/2013	Burtonsvill	Rebuild	Circuit	2314 and 2	230		12/30/2010	BGE	2013	2008	Gen Delive	9/17/2008
363	b0871	6/1/2013	6/1/2012	Motts Farn	Install	Capacitor	35 MVAR c	69		1/20/2011	AEC	2013	2009	N-1-1 Volta	9/16/2009
364	b0873	6/1/2013	6/1/2013	Glasgow-M	Install	Line	2nd Glasgc	138		4/26/2010	DPL	2013	2009	N-1-1 Volta	3/13/2009
365	b0874	6/1/2013	6/1/2013	Brandywin	Reconfigur	Substation				4/26/2010	DPL	2013	2009	N-1-1 Volta	3/13/2009
366	b0876	6/1/2013	6/1/2013	138th St.	Install	Substation	Install 75 M	138		1/18/2011	DPL	2013	2009	N-1-1 Volta	3/13/2009
367	b0877	6/1/2014	6/1/2014	Vienna-Ste	Install	Line	2nd line	230		6/1/2010	DPL	2013	2009	N-1-1 Volta	3/13/2009
368	b0879	6/1/2015		Wye Mills-	Install	Line	new line	138		6/8/2011	DPL	2013	2009	N-1-1 Volta	3/13/2009
369	b0879.1	6/1/2013	6/1/2013	Stevensvill	Apply	Load Drop	a special protection scheme (load			4/26/2010	DPL		2009	N-1-1 Volta	11/18/2009
370	b0881	6/1/2012	5/31/2012	Susquehan	Install	Substation	motor ope	230		9/17/2010	PPL	2014	2009	Gen Delive	7/15/2009
371	b0889	6/1/2011	6/1/2013	Bergen	Replace	Breaker	21H'	230	80kA	3/9/2011	PSEG		2009	Short Circu	5/20/2009
372	b0892	6/1/2009	1/30/2011	Chesapeak	Replace	Breaker	SX522	115		12/28/2010	Dominion	2009	2009	Short Circu	9/16/2009
373	b0909	6/1/2013	11/30/2012	Jenkins	Upgrade	Bus	Convert Je	230		9/17/2010	PPL		2009	NERC Cate	5/20/2009
374	b0910	6/1/2013	11/30/2014	Jenkins-Sta	Install	Line	second line	230		9/17/2010	PPL		2009	NERC Cate	5/20/2009
375	b0911	6/1/2011	5/31/2011	Frackville	Install	Disconnect	motor ope	230		9/17/2010	PPL		2009	NERC Cate	5/20/2009
376	b0912	11/1/2011	11/30/2011	Scranton	Install	Capacitors	2, 10.8 MV	69		9/17/2010	PPL		2009		9/16/2009
377	b0913	11/1/2011	11/30/2012	Harwood-J	Upgrade	Line	Extend Car	69		9/17/2010	PPL		2009		9/16/2009
378	b0914	11/1/2012	11/30/2012	Harwood-\	Construct	Line	3rd line frc	69		6/23/2011	PPL		2009		9/16/2009
379	b0915	5/1/2013	5/31/2016	Walnut-Ce	Upgrade	Line		69		6/23/2011	PPL		2009		9/16/2009
380	b0916	5/1/2012	5/31/2012	Sunbury-D	Recondcutor			69		6/23/2011	PPL		2009		9/16/2009
381	b0921	6/1/2011	6/1/2011	Brambleto	Upgrade	Conductor	201 Yukon	230	1057/1057	5/3/2011	Dominion	2011	2009	2011 Basel	7/15/2009
382	b0924	12/31/2010	12/31/2011	Dooms	Install	Reactor	50-100 MV	230		3/30/2011	Dominion		2009	Aging Infra	7/15/2009
383	b0926	5/31/2010	1/30/2011	Hamilton	Install	Reactor	50-100 MV	230		4/19/2011	Dominion		2009	Aging Infra	7/15/2009
384	b0928.1	12/31/2011	6/1/2011	Carolina	Install	Reactors	50-100 MV	230		7/21/2010	Dominion		2009	High Voltag	7/15/2009
385	b0928.2	12/31/2011	7/30/2011	Dooms	Install	Reactor	Install 50-100 MVAR variable reac			3/30/2011	Dominion		2009	High Voltag	7/15/2009
386	b0928.3	12/31/2011	5/30/2011	Everetts	Install	Reactor	Install 50-100 MVAR variable reac			5/16/2011	Dominion		2009	High Voltag	7/15/2009
387	b0928.5	12/31/2011	5/30/2011	N. Alexand	Install	Reactor	Install 50-100 MVAR variable reac			5/16/2011	Dominion		2009	High Voltag	7/15/2009
388	b0928.6	12/31/2011	4/30/2011	N. Anna	Install	Reactor	Install 50-100 MVAR variable reac			5/4/2011	Dominion		2009	High Voltag	7/15/2009
389	b0928.7	12/31/2011	3/30/2011	Suffolk	Install	Reactor	Install 50-100 MVAR variable reac			3/2/2011	Dominion		2009	High Voltag	7/15/2009
390	b0928.8	12/31/2011	8/30/2011	Valley	Install	Reactor	Install 50-100 MVAR variable reac			3/24/2011	Dominion		2009	High Voltag	7/15/2009
391	b0932	6/1/2009	5/20/2011	Brunot Isla	Replace	Breaker	GEN2 69 XI	138		3/9/2011	DL		2009	Short Circu	9/16/2009
392	b0933	6/1/2009	4/21/2011	Dravosburg	Replace	Breaker	Z-91'	138		3/9/2011	DL		2009	Short Circu	9/16/2009
393	b0934	6/1/2009	5/20/2011	Dravosburg	Replace	Breaker	Z-87'	138		3/9/2011	DL		2009	Short Circu	9/16/2009
394	b0935	6/1/2009	3/31/2011	Dravosburg	Replace	Breaker	Z-76'	138		3/9/2011	DL		2009	Short Circu	9/16/2009
395	b0936	6/1/2009	9/23/2011	Dravosburg	Replace	Breaker	Z-77'	138		3/9/2011	DL		2009	Short Circu	9/16/2009
396	b0937	6/1/2009	10/14/2011	Dravosburg	Replace	Breaker	Z-74'	138		3/9/2011	DL		2009	Short Circu	9/16/2009
397	b0938	6/1/2009	4/1/2012	Elrama	Replace	Breaker	#3 SYN BUS	138		4/26/2010	DL		2009	Short Circu	9/16/2009
398	b0939	6/1/2009	12/31/2012	Elrama	Replace	Breaker	#4 SYN REA	138		4/26/2010	DL		2009	Short Circu	9/16/2009
399	b0940	6/1/2009	12/31/2012	Cheswick	Replace	Breaker	2a/2B CAP'	138		4/26/2010	DL		2009	Short Circu	9/16/2009
400	b0941	6/1/2009	12/1/2011	Opequon	Replace	Breaker	breaker 'BU	138	40kA	3/10/2011	APS		2009	Short Circu	9/16/2009
401	b0948	6/1/2009	10/1/2011	Yukon	Replace	Breaker	breaker 'Y-	138	63kA	3/9/2011	APS		2009	Short Circu	9/16/2009
402	b0953	6/1/2009	12/1/2011	Yukon	Replace	Breaker	breaker 'Y-	138	63kA	3/9/2011	APS		2009	Short Circu	9/16/2009
403	b0955	6/1/2009	12/1/2011	Yukon	Replace	Breaker	breaker 'Y-	138	63kA	3/9/2011	APS		2009	Short Circu	9/16/2009
404	b0962	6/1/2009	11/1/2011	Yukon	Replace	Breaker	breaker 'Y-	138	63kA	3/9/2011	APS		2009	Short Circu	9/16/2009
405	b0963	6/1/2009	11/1/2011	Yukon	Replace	Breaker	breaker 'Y-	138	63kA	3/9/2011	APS		2009	Short Circu	9/16/2009
406	b0970	6/1/2013	6/1/2013	Rivesville	Replace	Breaker	breaker '#8	138	40kA	3/9/2011	APS		2009	Short Circu	9/16/2009
407	b0973	6/1/2009	12/1/2011	Springdale	Replace	Breaker	breaker '13	138	63kA	3/9/2011	APS		2009	Short Circu	9/16/2009
408	b0974	6/1/2009	12/1/2011	Springdale	Replace	Breaker	breaker '13	138	63kA	3/9/2011	APS		2009	Short Circu	9/16/2009
409	b0976	6/1/2009	12/1/2011	Springdale	Replace	Breaker	breaker '13	138	63kA	3/9/2011	APS		2009	Short Circu	9/16/2009
410	b0978	6/1/2009	12/1/2011	Springdale	Replace	Breaker	breaker '13	138	63kA	3/9/2011	APS		2009	Short Circu	9/16/2009
411	b0979	6/1/2009	12/1/2011	Springdale	Replace	Breaker	breaker '13	138	63kA	3/9/2011	APS		2009	Short Circu	9/16/2009
412	b0980	6/1/2009	12/1/2011	Springdale	Replace	Breaker	breaker '13	138	63kA	3/9/2011	APS		2009	Short Circu	9/16/2009
413	b0981	6/1/2009	10/1/2011	Yukon	Replace	Breaker	breaker 'Y-	138	63kA	3/9/2011	APS		2009	Short Circu	9/16/2009
414	b0982	6/1/2009	6/1/2011	Yukon	Replace	Breaker	breaker 'Y-	138	63kA	3/9/2011	APS		2009	Short Circu	9/16/2009
415	b0983	6/1/2009	12/31/2011	Yukon	Replace	Breaker	breaker 'Y-	138	63kA	3/9/2011	APS		2009	Short Circu	9/16/2009
416	b0984	6/1/2013	6/1/2013	Rivesville	Replace	Breaker	breaker '#1	138	40kA	3/9/2011	APS		2009	Short Circu	9/16/2009
417	b0986	6/1/2009	6/1/2011	Armstrong	Replace	Breaker	R breaker '	138	40kA	3/10/2011	APS		2009	Short Circu	9/16/2009
418	b0987	6/1/2009	6/1/2011	Yukon	Replace	Breaker	breaker 'Y-	138	63kA	3/9/2011	APS		2009	Short Circu	9/16/2009
419	b0988	6/1/2009	12/1/2011	Springdale	Replace	Breaker	breaker '13	138	63kA	3/9/2011	APS		2009	Short Circu	9/16/2009
420	b0999	6/1/2009	11/1/2011	Redbud	Replace	Breaker	Bus Tie	138		3/9/2011	APS		2009	Short Circu	9/16/2009
421	b1000	6/1/2009	12/31/2011	Portland	Replace	Breaker	95312'	115		6/2/2011	ME		2009	Short Circu	9/16/2009
422	b1001	6/1/2009	12/31/2011	Portland	Replace	Breaker	92712'	115		6/2/2011	ME		2009	Short Circu	9/16/2009
423	b1002	6/1/2009	12/1/2011	Hunterstov	Replace	Breaker	96392'	115		6/2/2011	ME		2009	Short Circu	9/16/2009
424	b1003	6/1/2009	12/1/2011	Hunterstov	Replace	Breaker	96292'	115		5/24/2011	ME		2009	Short Circu	9/16/2009
425	b1004	6/1/2009	12/31/2011	Hunterstov	Replace	Breaker	99192'	115		6/2/2011	ME		2009	Short Circu	9/16/2009
426	b1005	6/1/2009	12/31/2011	Glory	Replace	Breaker	#7 XFMR'	115		6/2/2011	PENELEC		2009	Short Circu	9/16/2009

	A	P	Q	R	S	T	U	V	W	X	Y
3	Upgrade ID	Latest TEAC Date	Status	State	Region	County	Percent Co	Cost Estim	Project ID	In Schedul	Source
356	b0861		EP	MD	PJM MA		0	2	b0861	b0861	Planned
357	b0862		EP	MD	PJM MA		0	2	b0862	b0862	Planned
358	b0864		EP	MD	PJM MA		0	2	b0864	#N/A	Planned
359	b0865		EP	MD	PJM MA		0	2	b0865	#N/A	Planned
360	b0866		EP	MD	PJM MA		0	2	b0866	#N/A	Planned
361	b0867		EP	MD	PJM MA		0	2	b0867	#N/A	Planned
362	b0870		EP	MD	PJM MA		0	0.54	b0870	b0870	Planned
363	b0871		EP	NJ	PJM MA		0	2.8	b0871	b0871	Planned
364	b0873		EP		PJM MA		0	16.3	b0873	b0873	Planned
365	b0874		EP		PJM MA		0	10.55	b0874	b0874	Planned
366	b0876	12/8/2010	EP		PJM MA		0	22.8	b0876	b0876	Planned
367	b0877		EP		PJM MA		0	44.61	b0877	b0877	Planned
368	b0879		EP		PJM MA		0	35.36	b0879	b0879	Planned
369	b0879.1		EP		PJM MA		0	0.05	b0879	b0879	Planned
370	b0881		EP	PA	PJM MA		0	0.29	b0881	b0881	Planned
371	b0889		EP	NJ	PJM MA		0	0.5	b0889	b0889	Planned
372	b0892		EP	VA	PJM SOUTH		30	0.2	b0892	b0892	Planned
373	b0909		EP	PA	PJM MA		10	8.74	b0909	b0909	Planned
374	b0910		EP	PA	PJM MA		0	3.81	b0910	b0910	Planned
375	b0911		EP	PA	PJM MA		0	0.45	b0911	b0911	Planned
376	b0912		EP	PA	PJM MA		10	1.61	b0912	b0912	Planned
377	b0913		EP	PA	PJM MA		0	0.81	b0913	b0913	Planned
378	b0914		EP	PA	PJM MA		0	2.4	b0914	b0914	Planned
379	b0915		EP	PA	PJM MA		0	1.5	b0915	b0915	Planned
380	b0916		EP	PA	PJM MA		0	10.3	b0916	b0916	Planned
381	b0921	9/16/2009	UC	VA	PJM South	Warren	95	2.8	b0921	b0921	Planned
382	b0924	9/16/2009	EP	VA	PJM South		10	5.5	b0924	b0924	Planned
383	b0926	9/16/2009	UC	VA	PJM South		95	5.7	b0926	b0926	Planned
384	b0928.1	9/16/2009	EP	VA	PJM SOUTH		30	6	b0928	b0928	Planned
385	b0928.2	9/16/2009	EP	VA	PJM SOUTH		10	6	b0928	b0928	Planned
386	b0928.3	9/16/2009	UC	VA	PJM SOUTH		60	6	b0928	b0928	Planned
387	b0928.5	9/16/2009	UC	VA	PJM SOUTH		60	6	b0928	b0928	Planned
388	b0928.6	9/16/2009	UC	VA	PJM SOUTH		95	6	b0928	b0928	Planned
389	b0928.7	9/16/2009	UC	VA	PJM SOUTH		40	6	b0928	b0928	Planned
390	b0928.8	9/16/2009	EP	VA	PJM SOUTH		10	6	b0928	b0928	Planned
391	b0932		EP	PA	PJM WEST		0	0.3	b0932	b0932	Planned
392	b0933		EP	PA	PJM WEST		0	0.31	b0933	b0933	Planned
393	b0934		EP	PA	PJM WEST		0	0.31	b0934	b0934	Planned
394	b0935		EP	PA	PJM WEST		0	0.31	b0935	b0935	Planned
395	b0936		EP	PA	PJM WEST		0	0.31	b0936	b0936	Planned
396	b0937		EP	PA	PJM WEST		0	0.32	b0937	b0937	Planned
397	b0938		EP	PA	PJM WEST		0	0.32	b0938	b0938	Planned
398	b0939		EP	PA	PJM WEST		0	0.32	b0939	b0939	Planned
399	b0940		EP	PA	PJM WEST		0	0.32	b0940	b0940	Planned
400	b0941		EP		PJM WEST		5	0.14	b0941	#N/A	Planned
401	b0948		EP		PJM WEST		25	0.2	b0948	#N/A	Planned
402	b0953		EP		PJM WEST		25	0.2	b0953	b0953	Planned
403	b0955		EP		PJM WEST		25	0.2	b0955	b0955	Planned
404	b0962		EP		PJM WEST		25	0.2	b0962	b0962	Planned
405	b0963		EP		PJM WEST		25	0.2	b0963	b0963	Planned
406	b0970		EP		PJM WEST		2	0.14	b0970	b0970	Planned
407	b0973		EP		PJM WEST		20	0.2	b0973	b0973	Planned
408	b0974		EP		PJM WEST		20	0.2	b0974	b0974	Planned
409	b0976		EP		PJM WEST		20	0.2	b0976	b0976	Planned
410	b0978		EP		PJM WEST		20	0.2	b0978	b0978	Planned
411	b0979		EP		PJM WEST		20	0.2	b0979	b0979	Planned
412	b0980		EP		PJM WEST		20	0.2	b0980	b0980	Planned
413	b0981		EP		PJM WEST		25	0.2	b0981	b0981	Planned
414	b0982		EP		PJM WEST		30	0.2	b0982	b0982	Planned
415	b0983		EP		PJM WEST		25	0.2	b0983	b0983	Planned
416	b0984		EP		PJM WEST		2	0.14	b0984	b0984	Planned
417	b0986		UC		PJM WEST		35	0.14	b0986	b0986	Planned
418	b0987		EP		PJM WEST		30	0.2	b0987	b0987	Planned
419	b0988		EP		PJM WEST		20	0.2	b0988	b0988	Planned
420	b0999		EP		PJM WEST		5	0.14	b0999	b0999	Planned
421	b1000		EP	PA	PJM MA		0	0.23	b1000	#N/A	Planned
422	b1001		EP	PA	PJM MA		0	0.23	b1001	#N/A	Planned
423	b1002		EP	PA	PJM MA		10	0.23	b1002	b1002	Planned
424	b1003		EP	PA	PJM MA		10	0.23	b1003	b1003	Planned
425	b1004		EP	PA	PJM MA		10	0.23	b1004	b1004	Planned
426	b1005		EP	PA	PJM MA		20	0.23	b1005	b1005	Planned

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
3	Upgrade ID	PJM Required	In Service Date	Location	Task	Equipment	Descriptior	Voltage	Expected R	Last Updated	Trans Own	Study Year	Baseline R	Driver	Initial TEAC Da
427	b1006	6/1/2009	12/31/2011	Shawville	Replace	Breaker	NO.14 XFN	115		6/2/2011	PENELEC		2009	Short Circu	9/16/2009
428	b1007	6/1/2009	12/31/2011	Shawville	Replace	Breaker	NO.15 XFN	115		6/2/2011	PENELEC		2009	Short Circu	9/16/2009
429	b1008	6/1/2009		Shawville	Replace	Breaker	#1B XFMR'	115		5/24/2011	PENELEC		2009	Short Circu	9/16/2009
430	b1009	6/1/2009		Shawville	Replace	Breaker	#2B XFMR'	115		5/24/2011	PENELEC		2009	Short Circu	9/16/2009
431	b1011	6/1/2009	12/31/2011	Shawville	Replace	Breaker	Philipsburg	115		5/24/2011	PENELEC		2009	Short Circu	9/16/2009
432	b1012	6/1/2009	12/31/2011	Shawville	Replace	Breaker	Garman'	115		5/24/2011	PENELEC		2009	Short Circu	9/16/2009
433	b1014.1	6/1/2014	6/1/2014	Eddystone	Replace	Breaker	Station Cal	230	1290N/149	1/20/2011	PECO	2014	2009	Gen Delive	8/2/2009
434	b1014.2	6/1/2014	6/1/2014	Island Rd	Replace	Breaker	Station Cal	230	1290N/149	1/20/2011	PECO	2014	2009	Gen Delive	8/2/2009
435	b1015	6/1/2014	6/1/2014	Printz - Rid	Replace		Increase ra	230	1505E	5/24/2011	PECO	2014	2009	Gen Delive	8/2/2009
436	b1015.1	6/1/2012	6/1/2014	Printz	Replace	Breaker	Replace Br	230	1505E	5/24/2011	PECO	2014	2009	Short Circu	8/2/2009
437	b1015.2	6/1/2012	6/1/2014	Printz	Replace	Breaker	Replace Br	230	1505E	5/24/2011	PECO	2014	2009	Short Circu	8/2/2009
438	b1016	6/1/2014	6/1/2014	Graceton -	Build	Circuit	as double (	230	648N/802E	2/11/2011	BGE	2014	2009	Gen Delive	8/2/2009
439	b1017	6/1/2011	6/1/2011	South Mah	Reconductor		J-3410 circ	345		3/9/2011	PSEG	2011	2009	Gen Delive	8/2/2009
440	b1018	6/1/2011	12/1/2011	South Mah	Reconductor		K-3411 circ	345		6/2/2010	PSEG	2011	2009	Gen Delive	8/2/2009
441	b1019.1	6/1/2011	6/1/2011	Roseland	Replace	Switches	wave trap, line discon		732N/887E	3/1/2011	PSEG	2011	2009	Load Delive	8/2/2009
442	b1019.10	6/1/2011	5/1/2011	Athenia	Replace	Switches	wave trap,	230	732N/887E	3/9/2011	PSEG	2011	2009	Load Delive	8/2/2009
443	b1019.2	6/1/2011	6/1/2011	Roseland	Replace	Switches	wave trap,	230	732N/887E	4/13/2011	PSEG	2011	2009	Load Delive	8/2/2009
444	b1019.3	6/1/2011	4/1/2011	Cedar Grov	Replace	Switches	1-2 and 2-3	230	732N/887E	4/13/2011	PSEG	2011	2009	Load Delive	8/2/2009
445	b1019.4	6/1/2011	3/1/2011	Cedar Grov	Replace	Switches	1-2 and 2-3	230	732N/887E	3/23/2011	PSEG	2011	2009	Load Delive	8/2/2009
446	b1019.5	6/1/2011	4/1/2011	Cedar Grov	Replace	Switches	wave trap,	230	732N/887E	3/9/2011	PSEG	2011	2009	Load Delive	8/2/2009
447	b1019.6	6/1/2011	4/1/2011	Cedar Grov	Replace	Switches	line discon	230	732N/887E	3/9/2011	PSEG	2011	2009	Load Delive	8/2/2009
448	b1019.7	6/1/2011	5/1/2011	Clifton	Replace	Switches	2-4 and 4-5 section dis		732N/887E	3/9/2011	PSEG	2011	2009	Load Delive	8/2/2009
449	b1019.8	6/1/2011	4/1/2011	Clifton	Replace	Switches	1-2 and 2-3 section dis		732N/887E	3/9/2011	PSEG	2011	2009	Load Delive	8/2/2009
450	b1019.9	6/1/2011	5/1/2011	Athenia	Replace	Switches	line, groun	230	732N/887E	3/9/2011	PSEG	2011	2009	Load Delive	8/2/2009
451	b1022.11	6/1/2010	6/1/2011	Elrama	Install	Line	a steel pole	138	223/252	3/10/2011	APS		2009	N-1-1 Cont	6/9/2009
452	b1022.12	6/1/2010	6/1/2011	Bethel Parl	Install	Breaker	at Bethel P	138	223/252	3/10/2011	APS		2009	N-1-1 Cont	6/9/2009
453	b1022.13	6/1/2010	3/31/2011	Elrama	Upgrade	Relaying	at Elrama a	138		3/10/2011	DL		2009	N-1-1 Cont	6/9/2009
454	b1022.14	6/1/2010	4/20/2011	Sonet	Add	Replaying	Incorporat	138		3/10/2011	DL		2009	N-1-1 Cont	6/9/2009
455	b1022.2	6/1/2011	5/5/2011	Woodville	Reconduct	Circuits	2 circuits	138		3/10/2011	DL		2009	N-1-1	6/9/2009
456	b1023.1	6/1/2013	6/1/2013	502 Junctio	Install	Transformer		500/138	418/467	3/9/2011	APS		2009	N-1-1	7/15/2009
457	b1023.2	6/1/2013	6/1/2012	Whiteley-F	Construct	Line	Rebuild as	138	242/297	3/9/2011	APS		2009	N-1-1	7/15/2009
458	b1023.3	6/1/2013	6/1/2013	Osage-Whi	Construct	Circuit	second circ	138	242/297	3/9/2011	APS		2009	N-1-1	7/15/2009
459	b1023.4	6/1/2013	6/1/2013	Braddock	Construct	Substation		138	222/240 - 2	8/24/2010	APS		2009	N-1-1	7/15/2009
460	b1027	6/1/2013	6/1/2011	Enon	Increase	Shunt Capa	Increase th	138	29MVAR	3/9/2011	APS		2009	N-1-1	7/15/2009
461	b1029	6/1/2014	6/1/2014	Wagner	Upgrade	Line	wire sectio	115		2/11/2011	BGE		2009	Gen Delive	9/16/2009
462	b1030	6/1/2011	6/1/2011	Hazelwood	Move	Circuits	substation from circuits		110507/1	6/2/2011	BGE		2009	Gen Delive	9/16/2009
463	b1031	6/1/2011	6/1/2011	Westport -	Replace	Line	wire sectio	115	400 / 487	6/2/2011	BGE		2009	Gen Delive	9/16/2009
464	b1032.1	6/1/2014	6/1/2014	Marquis-Bi	Construct	Substation	New	345/138		6/2/2010	AEP		2009	N-1 Therm	9/16/2009
465	b1032.2	6/1/2014	6/1/2014	Delano	Construct	Line	two 138kV	138		6/2/2010	AEP		2009	N-1 Therm	9/16/2009
466	b1032.3	6/1/2014	6/1/2014	Camp Sher	Convert	Substation	69kV to 13	69/138		9/20/2010	AEP		2009	N-1 Therm	9/16/2009
467	b1032.4	6/1/2014	6/1/2014	Ross - High	Install	Transform	at new stat	138/69		6/2/2010	AEP		2009	N-1 Therm	9/16/2009
468	b1033	6/1/2014	6/1/2014	Danville	Construct	Line	Add a third delivery point from AI			6/2/2010	AEP		2009	N-1 Therm	9/16/2009
469	b1034.1	6/1/2014	6/1/2014	Canton	Construct	Line	new South	138		6/2/2010	AEP		2009	N-1 and N-	9/16/2009
470	b1034.2	6/1/2014	6/1/2014	Canton	Construct	Line	Loop the e	138		6/2/2010	AEP		2009	N-1 and N-	9/16/2009
471	b1034.3	6/1/2014	6/1/2014	Canton Cer	Install	Transformer		345/138	450	6/2/2010	AEP		2009	N-1 and N-	9/16/2009
472	b1034.4	6/1/2014	6/1/2014	Sunnyside	Replace	Line	Rebuild/re	138		6/2/2010	AEP		2009	N-1 and N-	9/16/2009
473	b1034.5	6/1/2014		Torrey	Eliminate	Terminal	Disconnect	138		12/8/2010	AEP			N-1-1 Ther	10/6/2010
474	b1034.6	6/1/2014		South Cant	Replace	Breakers	Replace all	138		11/17/2010	AEP			N-1-1 Ther	10/6/2010
475	b1034.7	6/1/2014		Torrey/We	Replace	Breakers	Replace all	138		11/17/2010	AEP			N-1-1 Ther	10/6/2010
476	b1034.8	6/1/2014		Canton	Install	Breakers	Install addi	138		11/17/2010	AEP			N-1-1 Ther	10/6/2010
477	b1035	6/1/2014	6/1/2014	West Mille	Construct	Breaker str	Establish a	345		6/2/2010	AEP		2009	N-1-1 Ther	9/16/2009
478	b1036	6/1/2014	6/1/2014	Poston	Upgrade	Terminal	and update remote end relays			6/1/2010	AEP		2009	Gen Delive	9/16/2009
479	b1037	6/1/2014	6/1/2014	Bonsack - (	Check Sag	Transmissi	Sag check I	138		6/2/2010	AEP		2009	N-1-1 Ther	9/16/2009
480	b1038	6/1/2014	6/1/2014	Crooksville	Check Sag	Transmissi	and perfor	138		6/1/2010	AEP		2009	Gen Delive	9/16/2009
481	b1039	6/1/2014	6/1/2014	Madison –	Check Sag	Transmissi	and perfor	138		6/2/2010	AEP		2009	N-1-1 Ther	9/16/2009
482	b1040	6/1/2014	6/1/2014	New Carlis	Rebuild	Line	0.065 mile	138		6/2/2010	AEP		2009	N-1-1 Ther	9/16/2009
483	b1041	6/1/2014	6/1/2014	Moseley - I	Check Sag	Transmissi	to increase	138		6/2/2010	AEP		2009	N-1-1 Ther	9/16/2009
484	b1042	6/1/2014	6/1/2014	Amos – Po	Check Sag	Transmissi	to raise the	138		6/2/2010	AEP		2009	N-1-1 Ther	9/16/2009
485	b1043	6/1/2014	6/1/2014	Turner - Ru	Check Sag	Transmissi	to raise the	138		6/2/2010	AEP		2009	N-1-1 Ther	9/16/2009
486	b1044	6/1/2014	6/1/2014	Kenova – S	Check Sag	Transmissi	to raise the	138		6/1/2010	AEP		2009	Gen Delive	9/16/2009
487	b1045	6/1/2014	6/1/2014	Tri State - I	Check Sag	Transmission Line		138		6/2/2010	AEP		2009	N-1-1 Ther	9/16/2009
488	b1046	6/1/2014	6/1/2014	Scottsville	Check Sag	Transmissi	to raise the	138		6/2/2010	AEP		2009	N-1-1 Ther	9/16/2009
489	b1047	6/1/2014	6/1/2014	Otter Switc	Check Sag	Transmissi	to raise the	138		6/2/2010	AEP		2009	N-1-1 Ther	9/16/2009
490	b1048	6/1/2014	6/1/2014	Bixby	Reconductor		Three C - G	138		6/2/2010	AEP		2009	N-1 Therm	9/16/2009
491	b1049	6/1/2014	6/1/2014	Benton Ha	Upgrade	Risers	at the Rive	138		6/2/2010	AEP		2009	N-1 Therm	9/16/2009
492	b1050	6/1/2014	6/1/2014	Bixby	Reconductor		Rebuilding	138		6/2/2010	AEP		2009	N-1-1 Ther	9/16/2009
493	b1051	6/1/2014	6/1/2014	Kenzie Cre	Check Sag	Transmissi	and perfor	138		6/2/2010	AEP		2009	N-1-1 Ther	9/16/2009
494	b1052	6/1/2014	6/1/2014	Hyatt - Saw	Form	Line	Unsix-wire	138		1/3/2011	AEP		2009	N-1-1 Ther	9/16/2009
495	b1052.1	6/1/2014	6/1/2014	Hyatt	Replace	Breaker	Replace the Hyatt 138 kV breaker			1/3/2011	AEP			Short Circu	9/16/2009
496	b1052.2	6/1/2014	6/1/2014	Hyatt	Replace	Breaker	Replace the Hyatt 138 kV breaker			1/3/2011	AEP			Short Circu	9/16/2009
497	b1053	6/1/2014	6/1/2014	Matt Funk	Check Sag	Transmissi	and remediation of 32 miles betw			6/2/2010	AEP		2009	N-1-1 Ther	9/16/2009

	A	P	Q	R	S	T	U	V	W	X	Y
3	Upgrade ID	Latest TEAC Date	Status	State	Region	County	Percent Co	Cost Estima	Project ID	In Schedule	Source
427	b1006		UC	PA	PJM MA		30	0.23	b1006	b1006	Planned
428	b1007		UC	PA	PJM MA		30	0.23	b1007	b1007	Planned
429	b1008		EP	PA	PJM MA		2	0.23	b1008	b1008	Planned
430	b1009		EP	PA	PJM MA		2	0.23	b1009	b1009	Planned
431	b1011		EP	PA	PJM MA		5	0.23	b1011	b1011	Planned
432	b1012		EP	PA	PJM MA		5	0.23	b1012	b1012	Planned
433	b1014.1		EP	PA	PJM MA		0	1	b1014	b1014	Planned
434	b1014.2		EP	PA	PJM MA		0	1	b1014	b1014	Planned
435	b1015		EP	PA	PJM MA		0	1	b1015	b1015	Planned
436	b1015.1		EP	PA	PJM MA		0	0.5	b1015	b1015	Planned
437	b1015.2		EP	PA	PJM MA		0	0.5	b1015	b1015	Planned
438	b1016		EP	MD	PJM MA		0	42.6	b1016	b1016	Planned
439	b1017		UC	NJ	PJM MA		40	11.45	b1017	b1017	Planned
440	b1018		EP	NJ	PJM MA		0	11.45	b1018	b1018	Planned
441	b1019.1		EP	NJ	PJM MA		0	0.35	b1019	b1019	Planned
442	b1019.10		EP	NJ	PJM MA		50	0.35	b1019	b1019	Planned
443	b1019.2		EP	NJ	PJM MA		0	0.35	b1019	b1019	Planned
444	b1019.3		EP	NJ	PJM MA		90	0.35	b1019	b1019	Planned
445	b1019.4		EP	NJ	PJM MA		90	0.35	b1019	b1019	Planned
446	b1019.5		EP	NJ	PJM MA		50	0.35	b1019	b1019	Planned
447	b1019.6		EP	NJ	PJM MA		90	0.35	b1019	b1019	Planned
448	b1019.7		EP	NJ	PJM MA		90	0.35	b1019	b1019	Planned
449	b1019.8		EP	NJ	PJM MA		90	0.35	b1019	b1019	Planned
450	b1019.9		EP	NJ	PJM MA		50	0.35	b1019	b1019	Planned
451	b1022.11	9/16/2009	UC		PJM WEST		60	0.6	b1022	b1022	Planned
452	b1022.12	9/16/2009	UC		PJM WEST		90	1	b1022	b1022	Planned
453	b1022.13	9/16/2009	UC		PJM WEST		50	0.6	b1022	b1022	Planned
454	b1022.14	9/16/2009	UC		PJM WEST		30	0.8	b1022	b1022	Planned
455	b1022.2	9/16/2009	UC	PA	PJM WEST		3	3.1	b1022	b1022	Planned
456	b1023.1	9/16/2009	EP		PJM WEST		2	27.2	b1023	b1023	Planned
457	b1023.2	9/16/2009	EP		PJM WEST		25	13	b1023	b1023	Planned
458	b1023.3	9/16/2009	EP		PJM WEST		20	4.2	b1023	b1023	Planned
459	b1023.4	9/16/2009	EP		PJM WEST		0	15.1	b1023	b1023	Planned
460	b1027	9/16/2009	EP		PJM WEST		20	4.2	b1027	b1027	Planned
461	b1029		EP		PJM MA		0	0.1	b1029	b1029	Planned
462	b1030		EP		PJM MA		0	0.09	b1030	b1030	Planned
463	b1031		EP		PJM MA		0	0.2	b1031	b1031	Planned
464	b1032.1		EP		PJM WEST		0	50	b1032	b1032	Planned
465	b1032.2		EP		PJM WEST		0	0	b1032	b1032	Planned
466	b1032.3		EP		PJM WEST		0	0	b1032	b1032	Planned
467	b1032.4		EP		PJM WEST		0	0	b1032	b1032	Planned
468	b1033		EP		PJM WEST		0	1.6	b1033	b1033	Planned
469	b1034.1		EP		PJM WEST		0	28	b1034	b1034	Planned
470	b1034.2		EP		PJM WEST		0	0	b1034	b1034	Planned
471	b1034.3		EP		PJM WEST		0	0	b1034	b1034	Planned
472	b1034.4		EP		PJM WEST		0	0	b1034	b1034	Planned
473	b1034.5		EP		PJM WEST		0	0	b1034	b1034	Planned
474	b1034.6		EP		PJM WEST		0	0	b1034	b1034	Planned
475	b1034.7		EP		PJM WEST		0	0	b1034	b1034	Planned
476	b1034.8		EP		PJM WEST		0	0	b1034	b1034	Planned
477	b1035		EP		PJM WEST		0	28	b1035	b1035	Planned
478	b1036		EP		PJM WEST		0	1.4	b1036	b1036	Planned
479	b1037		EP		PJM WEST		0	3	b1037	b1037	Planned
480	b1038		EP		PJM WEST		0	1	b1038	b1038	Planned
481	b1039		EP		PJM WEST		0	0.15	b1039	b1039	Planned
482	b1040		EP		PJM WEST		0	1	b1040	b1040	Planned
483	b1041		EP		PJM WEST		0	1.05	b1041	b1041	Planned
484	b1042		EP		PJM WEST		0	0.06	b1042	b1042	Planned
485	b1043		EP		PJM WEST		0	0.02	b1043	b1043	Planned
486	b1044		EP		PJM WEST		0	0.07	b1044	b1044	Planned
487	b1045		EP		PJM WEST		0	0.66	b1045	b1045	Planned
488	b1046		EP		PJM WEST		0	0.35	b1046	b1046	Planned
489	b1047		EP		PJM WEST		0	0.05	b1047	b1047	Planned
490	b1048		EP		PJM WEST		0	5.9	b1048	b1048	Planned
491	b1049		EP		PJM WEST		0	0.1	b1049	b1049	Planned
492	b1050		EP		PJM WEST		0	12.5	b1050	b1050	Planned
493	b1051		EP		PJM WEST		0	0.15	b1051	b1051	Planned
494	b1052		EP		PJM WEST		0	1.5	b1052	b1052	Planned
495	b1052.1		EP		PJM WEST		0	0.8	b1052	b1052	Planned
496	b1052.2		EP		PJM WEST		0	0.8	b1052	b1052	Planned
497	b1053		EP		PJM WEST		0	1.6	b1053	b1053	Planned

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
3	Upgrade ID	PJM Required	In Service Date	Location	Task	Equipment	Descriptior	Voltage	Expected R	Last Updated	Trans Own	Study Year	Baseline R	Driver	Initial TEAC Da
498	b1054	6/1/2014		Byron – W	Change	Relay	settings on	345		4/26/2010	ComEd		2009	Gen Delive	10/22/2009
499	b1055	6/1/2011	12/31/2010	Center – W	Upgrade	Wire Drops	on the Cen	115	296 / 340	4/25/2011	BGE		2009	Gen Delive	10/22/2009
500	b1058	6/1/2014	6/1/2014	Suffolk	Add	Transform	third at sul	230/115		4/26/2010	Dominion		2009	N-1-1	10/22/2009
501	b1058.1	6/1/2014	6/1/2014	Suffolk	Replace	Breaker	Replace Suffolk 115 kV breaker 'T			5/24/2011	Dominion			Short Circu	10/28/2010
502	b1059	6/1/2014	12/31/2011	Hooversvil	Replace	Relay	CRS relay	115		5/24/2011	PENELEC	2014	2009	N-1-1 Ther	10/22/2009
503	b1060	6/1/2014	12/31/2011	Rachel Hill	Replace	Relay	CRS relay	115		5/24/2011	PENELEC	2014	2009	N-1-1 Ther	10/22/2009
504	b1061	6/1/2014	6/1/2011	Yorkana	Replace	Transform	existing tra	230/115		5/24/2011	ME	2014	2009	N-1-1 Ther	10/22/2009
505	b1061.1	6/1/2014	6/1/2011	Yorkana	Replace	Breaker	Replace th	115		5/24/2011	ME			Short Circu	3/2/2011
506	b1061.2	6/1/2014	6/1/2011	Yorkana	Replace	Breaker	Replace th	115		5/24/2011	ME			Short Circu	3/2/2011
507	b1062	6/1/2014	6/1/2014	Shelby	Install	Transform	2nd transf	345/138		1/20/2011	Dayton	2014	2009	N-1-1 Volta	10/22/2009
508	b1065.1	6/1/2014	6/1/2014	Shelby	Install	Transform	New	138/69		1/20/2011	Dayton	2014	2009	N-1-1 Volta	10/22/2009
509	b1065.2	6/1/2014	6/1/2014	Shelby	Install	Line	between S	69		1/20/2011	Dayton	2014	2009	N-1-1 Volta	10/22/2009
510	b1065.3	6/1/2014	6/1/2014	Blue Jacket	Install	Capacitor	New	69	30	1/20/2011	Dayton	2014	2009	N-1-1 Volta	10/22/2009
511	b1067	6/1/2014	6/1/2014	Logan	Install	Capacitor	New shunt	69	30	1/20/2011	Dayton	2014	2009	N-1-1 Volta	10/22/2009
512	b1071	6/1/2014	12/31/2012	Landstown	Replace	Line	Existing co	115		4/19/2011	Dominion		2009	N-1-1 Ther	10/22/2009
513	b1072	6/1/2014	12/31/2011	Cedar	Modify	EMS	Existing EN	230/69		1/20/2011	AEC	2014	2009	N-1-1 Volta	10/22/2009
514	b1073	6/1/2014	6/1/2014	Planebrool	Install	Breaker	2 new on t	230		1/20/2011	PECO	2014	2009	N-1-1 Volta	10/22/2009
515	b1074	6/1/2014		Jenkins	Install	Motor Ope	'2W' discor	230		3/25/2011	PPL	2014	2009	N-1-1 Volta	10/22/2009
516	b1075	12/1/2011	12/1/2011	West Whar	Replace	Line	West Whar	115		5/24/2011	JCPL		2009	Gen Delive	10/22/2009
517	b1076	6/1/2014	6/1/2014	North Anna	Replace	Transform	Existing tra	500/230		12/28/2010	Dominion		2009	Dominion (	9/16/2009
518	b1077	6/1/2014	6/1/2014	East Sidney	Reconductor			138		1/20/2011	Dayton		2009	N-1-1 Ther	10/22/2009
519	b1078	6/1/2014	6/1/2014	Greene - A	Reconductor			138		1/20/2011	Dayton		2009	N-1-1 Ther	10/22/2009
520	b1079	6/1/2014	6/1/2014	Bath - Treb	Perform	Study	sag study t	138		1/20/2011	Dayton		2009	N-1-1 Ther	10/22/2009
521	b1080	6/1/2014	6/1/2014	Arsenal – H	Perform	Study	Restudy ra	138		6/1/2010	DL		2009	N-1-1 Ther	10/22/2009
522	b1081	6/1/2014	6/1/2011	Brunot Isla	Install	Reactors	Install 138l	138		5/31/2011	DL		2009	N-1-1 Ther	10/22/2009
523	b1082	6/1/2014	6/1/2014	Bergen	Install	Transformer		230/138		6/2/2010	PSEG		2009	N-1-1	10/22/2009
524	b1082.1	6/1/2014	6/1/2014	Bergen	Replace	Breaker	Replace Be	138		5/16/2011	PSEG			Short Circu	5/12/2011
525	b1082.2	6/1/2014	6/1/2014	Bergen	Replace	Breaker	Replace Be	138		5/16/2011	PSEG			Short Circu	5/12/2011
526	b1082.3	6/1/2014	6/1/2014	Bergen	Replace	Breaker	Replace Be	138		5/16/2011	PSEG			Short Circu	5/12/2011
527	b1082.4	6/1/2014	6/1/2014	Bergen	Replace	Breaker	Replace Be	138		5/16/2011	PSEG			Short Circu	5/12/2011
528	b1082.5	6/1/2014	6/1/2014	Bergen	Replace	Breaker	Replace Be	138		5/16/2011	PSEG			Short Circu	5/12/2011
529	b1082.6	6/1/2014	6/1/2014	Bergen	Replace	Breaker	Replace Be	230		5/16/2011	PSEG			Short Circu	5/12/2011
530	b1082.7	6/1/2014	6/1/2014	Bergen	Replace	Breaker	Replace Be	230		5/16/2011	PSEG			Short Circu	5/12/2011
531	b1082.8	6/1/2014	6/1/2014	Bergen	Replace	Breaker	Replace Be	230		5/16/2011	PSEG			Short Circu	5/12/2011
532	b1082.9	6/1/2014	6/1/2014	Bergen	Replace	Breaker	Replace Be	230		5/16/2011	PSEG			Short Circu	5/12/2011
533	b1083	6/1/2014	6/1/2014	Mays Chap	Upgrade	Wire	Sections		260/300	2/11/2011	BGE		2009	N-1-1 Ther	10/22/2009
534	b1084	6/1/2014	6/1/2014	Deer Park	Extend	Circuit	Circuit 110570 and other substati			2/11/2011	BGE		2009	N-1-1 Ther	10/22/2009
535	b1085	6/1/2014	6/1/2014	Lipins Corn	Upgrade	Line	Substation wire condu		275/311	2/11/2011	BGE		2009	N-1-1 Ther	10/22/2009
536	b1086	6/1/2014	6/1/2014	Orchard St	Build	Switching S	New statio	115		12/30/2010	BGE		2009	N-1-1 Ther	10/22/2009
537	b1087	6/1/2014	6/1/2014	Cannon Bra	Replace	Transform	with larger	230/115		4/19/2011	Dominion		2009	Dominion (	10/22/2009
538	b1088	6/1/2014	5/31/2012	Radnor He	Install	Line	New, add new underground circu			4/19/2011	Dominion		2009	N-1-1	10/22/2009
539	b1089	6/1/2014	6/1/2014	Burke - Sid	Install	Line	Install 2nd	230		4/19/2011	Dominion		2009	N-1-1 Ther	10/22/2009
540	b1090	6/1/2012	6/1/2012	Northwest	Install	Capacitor	Install a 15	230		12/28/2010	Dominion		2009	N-1-1 Volta	10/22/2009
541	b1091	6/1/2014	6/1/2014	Huffman-Ju	Install	Capacitor	and 43.2 M	138	28.8	6/2/2010	AEP		2009	N-1-1 Volta	10/22/2009
542	b1092	6/1/2014	6/1/2014	Sullivan Ga	Install	Capacitor	and 52.8 M	138	28.8	6/2/2010	AEP		2009	N-1-1 Volta	10/22/2009
543	b1093	6/1/2014	6/1/2014	Morgan Fo	Install	Capacitor	Bank	138	43.2	6/2/2010	AEP		2009	N-1-1 Volta	10/22/2009
544	b1094	6/1/2014	6/1/2014	West Hunt	Install	Capacitor	Bank	138	64.8	6/2/2010	AEP		2009	N-1-1 Volta	10/22/2009
545	b1096	6/1/2013	5/30/2013	Loudoun -	Construct	Line	10 mile do	230		12/28/2010	Dominion		2009	Dominion (	9/16/2009
546	b1097	6/1/2014	6/1/2011	Round Lake	Add	Breaker	Add a 138	138		3/24/2011	ComEd			Gen Delive	1/13/2010
547	b1098	6/1/2014	3/15/2011	Bayway	Reconfigur	Substation	and install	138		3/9/2011	PSEG		2009	Baseline Vo	11/18/2009
548	b1099	6/1/2012	6/1/2012	Aldene - Es	Build	Substation	by tapping	230/26		7/19/2010	PSEG		2009	N-1-1 Ther	11/18/2009
549	b1100	6/1/2013	6/1/2013	Bayonne -	Build	Circuit	Build a nev	138		3/9/2011	PSEG		2009	N-1-1 Ther	11/18/2009
550	b1101	6/1/2012	6/1/2012	Cedar Grov	Reconfigur	Substation	with break	69		4/13/2011	PSEG		2009	N-1-1 Ther	11/18/2009
551	b1104	6/1/2014	6/1/2014	Burtonsvill	Replace	Breaker	1C	230		11/8/2010	PEPCO	2014	2009	Short Circu	11/18/2009
552	b1105	6/1/2014	6/1/2014	Burtonsvill	Replace	Breaker	2C	230		11/8/2010	PEPCO	2014	2009	Short Circu	11/18/2009
553	b1106	6/1/2014	6/1/2014	Burtonsvill	Replace	Breaker	3C	230		11/8/2010	PEPCO	2014	2009	Short Circu	11/18/2009
554	b1107	6/1/2014	6/1/2014	Burtonsvill	Replace	Breaker	4C	230		11/8/2010	PEPCO	2014	2009	Short Circu	11/18/2009
555	b1108	6/1/2014	6/1/2014	Ohio Centr	Replace	Breaker	C2	138		6/2/2010	AEP	2014	2009	Short Circu	11/18/2009
556	b1109	6/1/2014	6/1/2014	Ohio Centr	Replace	Breaker	D1	138		6/2/2010	AEP	2014	2009	Short Circu	11/18/2009
557	b1110	6/1/2014	6/1/2014	Sporn	Replace	Breaker	J	138		6/2/2010	AEP	2014	2009	Short Circu	11/18/2009
558	b1111	6/1/2014	6/1/2014	Sporn	Replace	Breaker	J2	138		6/2/2010	AEP	2014	2009	Short Circu	11/18/2009
559	b1112	6/1/2014	6/1/2014	Sporn	Replace	Breaker	L	138		6/2/2010	AEP	2014	2009	Short Circu	11/18/2009
560	b1113	6/1/2014	6/1/2014	Sporn	Replace	Breaker	L1	138		6/2/2010	AEP	2014	2009	Short Circu	11/18/2009
561	b1114	6/1/2014	6/1/2014	Sporn	Replace	Breaker	L2	138		6/2/2010	AEP	2014	2009	Short Circu	11/18/2009
562	b1115	6/1/2014	6/1/2014	Sporn	Replace	Breaker	N	138		6/2/2010	AEP	2014	2009	Short Circu	11/18/2009
563	b1116	6/1/2014	6/1/2014	Sporn	Replace	Breaker	N2	138		6/2/2010	AEP	2014	2009	Short Circu	11/18/2009
564	b1117	6/1/2011	6/1/2013	Beaver Val	Replace	Breaker	1A & 3A SS	138		8/4/2010	DL	2014	2009	Short Circu	11/18/2009
565	b1118	6/1/2011	10/1/2013	Beaver Val	Replace	Breaker	1B & 3B SS	138		8/4/2010	DL	2014	2009	Short Circu	11/18/2009
566	b1119	6/1/2011	12/31/2013	Beaver Val	Replace	Breaker	2B SS tfmr	138		8/4/2010	DL	2014	2009	Short Circu	11/18/2009
567	b1120	6/1/2011	4/1/2014	Beaver Val	Replace	Breaker	Z30 Midlar	138		8/4/2010	DL	2014	2009	Short Circu	11/18/2009
568	b1122	6/1/2014	10/1/2014	Elywn	Replace	Breaker	Z62 Collier	138		7/14/2010	DL	2014	2009	Short Circu	11/18/2009

	A	P	Q	R	S	T	U	V	W	X	Y
3	Upgrade ID	Latest TEAC Date	Status	State	Region	County	Percent Co	Cost Estim	Project ID	In Schedul	Source
498	b1054		EP		PJM WEST		0	0.01	b1054	b1054	Planned
499	b1055		EP		PJM MA		0	0.2	b1055	b1055	Planned
500	b1058		EP		PJM SOUTH		0	6	b1058	b1058	Planned
501	b1058.1		EP		PJM SOUTH		0	0.17	b1058	b1058	Planned
502	b1059		EP	PA	PJM MA		3	0.07	b1059	b1059	Planned
503	b1060		EP	PA	PJM MA		3	0.07	b1060	b1060	Planned
504	b1061		UC	PA	PJM MA		80	4.2	b1061	b1061	Planned
505	b1061.1		EP	PA	PJM MA		0	0.21	b1061	b1061	Planned
506	b1061.2		EP	PA	PJM MA		0	0.15	b1061	b1061	Planned
507	b1062		EP		PJM WEST		0	7	b1062	b1062	Planned
508	b1065.1		EP		PJM WEST		0	5	b1065	b1065	Planned
509	b1065.2		EP		PJM WEST		0	7.5	b1065	b1065	Planned
510	b1065.3		EP		PJM WEST		0	0.4	b1065	b1065	Planned
511	b1067		EP		PJM WEST		0	0.4	b1067	b1067	Planned
512	b1071		EP		PJM SOUTH		20	38	b1071	b1071	Planned
513	b1072		EP	NJ	PJM MA		0	0.05	b1072	b1072	Planned
514	b1073		EP	PA	PJM MA		0	1.3	b1073	b1073	Planned
515	b1074		EP	PA	PJM MA		0	1.06	b1074	b1074	Planned
516	b1075		UC		PJM MA		65	0.07	b1075	b1075	Planned
517	b1076		EP		PJM SOUTH		0	16	b1076	b1076	Planned
518	b1077		EP		PJM WEST		0	0.53	b1077	b1077	Planned
519	b1078		EP		PJM WEST		0	1.63	b1078	b1078	Planned
520	b1079		EP		PJM WEST		0	0	b1079	b1079	Planned
521	b1080		EP		PJM WEST		0	0	b1080	b1080	Planned
522	b1081		UC		PJM WEST		30	0	b1081	b1081	Planned
523	b1082		EP		PJM MA		0	22.6	b1082	b1082	Planned
524	b1082.1		EP	NJ	PJM MA		0	1.5	b1082	b1082	Planned
525	b1082.2		EP	NJ	PJM MA		0	1.5	b1082	b1082	Planned
526	b1082.3		EP	NJ	PJM MA		0	1.5	b1082	b1082	Planned
527	b1082.4		EP	NJ	PJM MA		0	0.6	b1082	b1082	Planned
528	b1082.5		EP	NJ	PJM MA		0	0.6	b1082	b1082	Planned
529	b1082.6		EP	NJ	PJM MA		0	1.5	b1082	b1082	Planned
530	b1082.7		EP	NJ	PJM MA		0	1.5	b1082	b1082	Planned
531	b1082.8		EP	NJ	PJM MA		0	1.5	b1082	b1082	Planned
532	b1082.9		EP	NJ	PJM MA		0	1.5	b1082	b1082	Planned
533	b1083		EP		PJM MA		0	0.1	b1083	b1083	Planned
534	b1084		EP		PJM MA		0	5	b1084	b1084	Planned
535	b1085		EP		PJM MA		0	1.5	b1085	b1085	Planned
536	b1086		EP		PJM MA		0	26	b1086	b1086	Planned
537	b1087		EP		PJM SOUTH		0	5	b1087	b1087	Planned
538	b1088		EP		PJM SOUTH		20	87.5	b1088	b1088	Planned
539	b1089		EP		PJM SOUTH		10	9	b1089	b1089	Planned
540	b1090		EP		PJM SOUTH		20	1.7	b1090	b1090	Planned
541	b1091		EP		PJM WEST		0	2.4	b1091	b1091	Planned
542	b1092		EP		PJM WEST		0	2	b1092	b1092	Planned
543	b1093		EP		PJM WEST		0	0.8	b1093	b1093	Planned
544	b1094		EP		PJM WEST		0	0.8	b1094	b1094	Planned
545	b1096		EP		PJM SOUTH		10	27.2	b1096	b1096	Planned
546	b1097		EP		PJM WEST		0	4.5	b1097	b1097	Planned
547	b1098		UC		PJM MA		70	15	b1098	b1098	Planned
548	b1099		EP		PJM MA		0	137	b1099	b1099	Planned
549	b1100		EP		PJM MA		2	137	b1100	b1100	Planned
550	b1101		EP		PJM MA		15	76.4	b1101	b1101	Planned
551	b1104		EP	MD	PJM MA		0	1.38	b1104	b1104	Planned
552	b1105		EP	MD	PJM MA		0	1.38	b1105	b1105	Planned
553	b1106		EP	MD	PJM MA		0	1.38	b1106	b1106	Planned
554	b1107		EP	MD	PJM MA		0	1.38	b1107	b1107	Planned
555	b1108		EP		PJM WEST		0	0.8	b1108	b1108	Planned
556	b1109		EP		PJM WEST		0	0.8	b1109	b1109	Planned
557	b1110		EP		PJM WEST		0	0.8	b1110	b1110	Planned
558	b1111		EP		PJM WEST		0	0.8	b1111	b1111	Planned
559	b1112		EP		PJM WEST		0	0.8	b1112	b1112	Planned
560	b1113		EP		PJM WEST		0	0.8	b1113	b1113	Planned
561	b1114		EP		PJM WEST		0	0.8	b1114	b1114	Planned
562	b1115		EP		PJM WEST		0	0.8	b1115	b1115	Planned
563	b1116		EP		PJM WEST		0	0.8	b1116	b1116	Planned
564	b1117		EP	PA	PJM WEST		0	0.4	b1117	b1117	Planned
565	b1118		EP	PA	PJM WEST		0	0.4	b1118	b1118	Planned
566	b1119		EP	PA	PJM WEST		0	0.4	b1119	b1119	Planned
567	b1120		EP	PA	PJM WEST		0	0.4	b1120	b1120	Planned
568	b1122		EP	PA	PJM WEST		0	0.33	b1122	b1122	Planned

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
3	Upgrade ID	PJM Required	In Service Date	Location	Task	Equipment	Descriptior	Voltage	Expected R	Last Updated	Trans Own	Study Year	Baseline R	Driver	Initial TEAC Da
569	b1124	6/1/2014	4/1/2015	Elywn	Replace	Breaker	No.2-3 138	138		4/26/2010	DL	2014	2009	Short Circu	11/18/2009
570	b1125	6/1/2014	6/1/2014	Buzzard Pt	Upgrade	Line	to a 230kV	138/230		2/24/2011	PEPCO		2009	N-1-1 Ther	11/18/2009
571	b1126	6/1/2014	6/1/2014	Buzzard Pt	Upgrade	Line		230		11/8/2010	PEPCO		2009	N-1-1 Ther	11/18/2009
572	b1127	6/1/2013	5/31/2016	Lincoln-Mi	Build	Line	New Line	138		6/23/2011	AEC		2009	N-1-1 Volta	11/18/2009
573	b1128	6/1/2014	6/1/2014	Edgewater	Reconductor		Edgewater	138		3/11/2011	APS	2014	2009	N-1-1 Ther	12/16/2009
574	b1129	6/1/2014	6/1/2014	East Wayn	Reconductor		with 954 A	138		3/11/2011	APS	2014	2009	N-1-1 Ther	12/16/2009
575	b1131	6/1/2014	6/1/2014	Double Tol	Upgrade	Terminal E	Double MDT Terminal Equipment			3/11/2011	APS	2014	2009	N-1-1 Ther	12/16/2009
576	b1132	6/1/2014	6/1/2014	Double Tol	Upgrade	Terminal E	Double MBG terminal Equipment			9/14/2010	APS	2014	2009	N-1-1 Ther	12/16/2009
577	b1133	6/1/2014	6/1/2014	Springdale	Upgrade	Terminal Equipment				9/14/2010	APS	2014	2009	N-1-1 Ther	12/16/2009
578	b1135	6/1/2014	6/1/2013	Bartonville	Reconductor		with high t	138		3/11/2011	APS	2014	2009	N-1-1 Ther	12/16/2009
579	b1137	6/1/2014	6/1/2014	Eastgate –	Reconductor		with 954 A	138		3/11/2011	APS	2014	2009	N-1-1 Ther	12/16/2009
580	b1138	6/1/2014	6/1/2014	King Farm	Reconductor		with 954 A	138		3/11/2011	APS	2014	2009	N-1-1 Ther	12/16/2009
581	b1139	6/1/2014	6/1/2014	Yukon - W	Reconductor		with high t	138		3/11/2011	APS	2014	2009	N-1-1 Ther	12/16/2009
582	b1140	6/1/2014	6/1/2014	Bracken Ju	Reconductor		with 954 A	138		2/1/2011	APS	2014	2009	N-1-1 Ther	12/16/2009
583	b1141	6/1/2014	6/1/2014	Sewickley -	Reconductor		with high t	138		3/11/2011	APS	2014	2009	N-1-1 Ther	12/16/2009
584	b1142	6/1/2014	12/1/2013	Bartonville	Reconductor		and Stonev	138		3/11/2011	APS	2014	2009	N-1-1 Ther	12/16/2009
585	b1143	6/1/2014	6/1/2013	Youngwoo	Reconductor		with high t	138		3/11/2011	APS	2014	2009	N-1-1 Ther	12/16/2009
586	b1144	6/1/2014	6/1/2014	Bull Creek	Reconductor		with high t	138		3/11/2011	APS	2014	2009	N-1-1 Ther	12/16/2009
587	b1145	6/1/2014	6/1/2013	Lawson Jur	Reconductor		with high t	138		3/11/2011	APS	2014	2009	N-1-1 Ther	12/16/2009
588	b1146	6/1/2014	6/1/2014	Layton - Sn	Replace	Structures	to increase	138		9/14/2010	APS	2014	2009	N-1-1 Ther	12/16/2009
589	b1147	6/1/2014	6/1/2014	Smith - Yuk	Replace	Structures	to increase	138		9/14/2010	APS	2014	2009	N-1-1 Ther	12/16/2009
590	b1148	6/1/2014	6/1/2014	Loyalhanna	Reconductor		with 954 A	138		3/11/2011	APS	2014	2009	N-1-1 Ther	12/16/2009
591	b1149	6/1/2014	6/1/2014	Luxor - Sto	Reconductor		with 954 A	138		3/11/2011	APS	2014	2009	N-1-1 Ther	12/16/2009
592	b1150	6/1/2014	6/1/2014	Social Hall	Upgrade	Terminal Equipment				9/14/2010	APS	2014	2009	N-1-1 Ther	12/16/2009
593	b1151	6/1/2014	6/1/2013	Greenwoo	Reconductor		with 954 A	138		3/11/2011	APS	2014	2009	N-1-1 Ther	12/16/2009
594	b1152	6/1/2014	6/1/2013	Grand Poir	Reconductor					3/9/2011	APS	2014	2009	N-1-1 Ther	12/16/2009
595	b1153	6/1/2014	6/1/2014	Conemaug	Upgrade	Transform	and new li	500/230		5/24/2011	PENELEC		2009	Market Eff	11/18/2009
596	b1153.1	6/1/2014	6/1/2014	Shelocta	Revise	Breaker/Re	Revise the	115		5/24/2011	PENELEC			Short Circu	3/2/2011
597	b1154	6/1/2014	6/1/2014	West Oran	Convert	Substation	Convert th	138		5/13/2011	PSEG	2014	2009	N-1-1 Volta	12/16/2009
598	b1154.1	6/1/2014	6/1/2014	Whippany	Upgrade	Breaker	Upgrade th	230		5/24/2011	JCPL			Short Circu	3/10/2011
599	b1155	6/1/2014	6/1/2014	Branchburg	Build	Circuit	Sw. Rack. E	230		1/19/2011	PSEG	2014	2009	N-1-1 Volta	12/16/2009
600	b1155.1	6/1/2014	6/1/2014	Red Oak	Upgrade	Breaker	Upgrade th	230		5/24/2011	JCPL			Short Circu	3/10/2011
601	b1155.2	6/1/2014	6/1/2014	Red Oak	Upgrade	Breaker	Upgrade th	230		5/24/2011	JCPL			Short Circu	3/10/2011
602	b1155.3	6/1/2014	6/1/2014	Branchburg	Replace	Breaker	Replace Br	230		5/16/2011	PSEG			Short Circu	5/12/2011
603	b1155.4	6/1/2014	6/1/2014	Branchburg	Replace	Breaker	Replace Br	230		5/16/2011	PSEG			Short Circu	5/12/2011
604	b1155.5	6/1/2014	6/1/2014	Branchburg	Replace	Breaker	Replace Br	230		5/16/2011	PSEG			Short Circu	5/12/2011
605	b1155.6	6/1/2014	6/1/2014	Branchburg	Replace	Breaker	Replace Br	230		5/16/2011	PSEG			Short Circu	5/12/2011
606	b1156	6/1/2014	6/1/2014	Burlington	Convert	Substation	Convert th	138		5/13/2011	PSEG	2014	2009	N-1-1 Volta	12/16/2009
607	b1156.1	6/1/2014	6/1/2014	Richmond	Upgrade	Breaker	Upgrade Richmond 230 kV breake			1/20/2011	PECO			Short Circu	10/28/2010
608	b1156.10	6/1/2014	6/1/2014	Plymouth I	Replace	Breaker	Replace Plymouth Meeting 230 k'			1/20/2011	PECO			Short Circu	10/28/2010
609	b1156.12	6/1/2014	6/1/2014	Emilie	Replace	Breaker	Replace En	138		5/13/2011	PECO			Short Circu	3/2/2011
610	b1156.13	6/1/2014	6/1/2014	Camden	Replace	Breaker	Replace Ca	230		5/23/2011	PSEG			Short Circu	5/12/2011
611	b1156.14	6/1/2014	6/1/2014	Camden	Replace	Breaker	Replace Ca	230		5/23/2011	PSEG			Short Circu	5/12/2011
612	b1156.15	6/1/2014	6/1/2014	Camden	Replace	Breaker	Replace Ca	230		5/23/2011	PSEG			Short Circu	5/12/2011
613	b1156.16	6/1/2014	6/1/2014	New Freed	Replace	Breaker	Replace Ne	230		5/23/2011	PSEG			Short Circu	5/12/2011
614	b1156.17	6/1/2014	6/1/2014	New Freed	Replace	Breaker	Replace Ne	230		5/23/2011	PSEG			Short Circu	5/12/2011
615	b1156.18	6/1/2014	6/1/2014	New Freed	Replace	Breaker	Replace Ne	230		5/23/2011	PSEG			Short Circu	5/12/2011
616	b1156.19	6/1/2014	6/1/2014	Camden	Upgrade	Breaker	Rebuild Ca	230		5/23/2011	PSEG			Short Circu	5/12/2011
617	b1156.2	6/1/2014	6/1/2014	Richmond	Upgrade	Breaker	Upgrade Richmond 230 kV breake			1/20/2011	PECO			Short Circu	10/28/2010
618	b1156.3	6/1/2014	6/1/2014	Richmond	Upgrade	Breaker	Upgrade Richmond 230 kV breake			1/20/2011	PECO			Short Circu	10/28/2010
619	b1156.4	6/1/2014	6/1/2014	Richmond	Upgrade	Breaker	Upgrade Richmond 230 kV breake			1/20/2011	PECO			Short Circu	10/28/2010
620	b1156.5	6/1/2014	6/1/2014	Richmond	Upgrade	Breaker	Upgrade Richmond 230 kV breake			1/20/2011	PECO			Short Circu	10/28/2010
621	b1156.6	6/1/2014	6/1/2014	Richmond	Upgrade	Breaker	Upgrade Richmond 230 kV breake			1/20/2011	PECO			Short Circu	10/28/2010
622	b1156.7	6/1/2014	6/1/2014	Waneeta	Upgrade	Breaker	Upgrade Waneeta 230 kV breake			1/20/2011	PECO			Short Circu	10/28/2010
623	b1156.8	6/1/2014	6/1/2014	Waneeta	Replace	Breaker	Replace Waneeta 230 kV breaker			1/20/2011	PECO			Short Circu	10/28/2010
624	b1156.9	6/1/2014	6/1/2014	Emilie	Replace	Breaker	Replace Emilie 230 kV breaker '81			1/20/2011	PECO			Short Circu	10/28/2010
625	b1157	6/1/2014	6/1/2013	Lisle	Replace	Bus Tie	CB 2-3	345		4/27/2010	ComEd	2014		Gen Delive	9/16/2009
626	b1158	6/1/2014	6/1/2012	Prospect H	Install	Capacitor	57.6 MVAR capacitor (		57.6	10/22/2010	ComEd	2014		Load Delive	1/13/2010
627	b1159	6/1/2011	6/1/2011	Peters	Replace	Breaker	Bethel P O	138		3/11/2011	APS	2014		Short Circu	1/13/2010
628	b1160	6/1/2011	11/15/2011	Peters	Replace	Breaker	Cecil OCB	138		3/11/2011	APS	2014		Short Circu	1/13/2010
629	b1161	6/1/2011	11/15/2011	Peters	Replace	Breaker	Union JctO	138		3/11/2011	APS	2014		Short Circu	1/13/2010
630	b1162	6/1/2011	12/1/2011	Double Tol	Replace	Breaker	DRB-2	138		3/11/2011	APS	2014		Short Circu	1/13/2010
631	b1163	6/1/2011	12/1/2011	Double Tol	Replace	Breaker	DT 138kv C	138		3/11/2011	APS	2014		Short Circu	1/13/2010
632	b1164	6/1/2014	11/15/2011	Cecil	Replace	Breaker	Enlow OCB	138		3/11/2011	APS	2014		Short Circu	1/13/2010
633	b1165	6/1/2014	11/15/2011	Cecil	Replace	Breaker	SouthFaye	138		3/11/2011	APS	2014		Short Circu	1/13/2010
634	b1166	6/1/2014	12/1/2011	Wylie Ridg	Replace	Breaker	W-9	138		3/11/2011	APS	2014		Short Circu	1/13/2010
635	b1167	6/1/2014	12/1/2011	Reid	Replace	Breaker	RI-2	138		3/11/2011	APS	2014		Short Circu	1/13/2010
636	b1169	6/1/2014	12/31/2014	Shawville	Replace	Breaker	#1A XFMR	115		5/24/2011	PENELEC	2014		Short Circu	1/13/2010
637	b1170	6/1/2014	12/31/2014	Shawville	Replace	Breaker	#2A XFMR	115		5/24/2011	PENELEC	2014		Short Circu	1/13/2010
638	b1171.1	6/1/2013	6/1/2013	Black Oak	Install	Transform	second tra	500/138		3/11/2011	APS	2013		Gen Delive	2/10/2010
639	b1171.3	6/1/2013		Black Oak	Install	Breakers	Install four	500		5/13/2011	APS	2013		Gen Delive	2/10/2010

	A	P	Q	R	S	T	U	V	W	X	Y
3	Upgrade ID	Latest TEAC Date	Status	State	Region	County	Percent Co	Cost Estim	Project ID	In Schedul	Source
569	b1124		EP	PA	PJM WEST		0	0.33	b1124	b1124	Planned
570	b1125		EP		PJM MA		10	56	b1125	b1125	Planned
571	b1126		EP		PJM MA		0	39	b1126	b1126	Planned
572	b1127	1/13/2010	EP	NJ	PJM MA		0	12.5	b1127	b1127	Planned
573	b1128	1/13/2010	EP		PJM WEST		0	2.3	b1128	b1128	Planned
574	b1129	1/13/2010	EP		PJM WEST		0	3	b1129	b1129	Planned
575	b1131	1/13/2010	EP		PJM WEST		0	0.03	b1131	b1131	Planned
576	b1132		EP		PJM WEST		0	0.03	b1132	b1132	Planned
577	b1133		EP		PJM WEST		0	0.02	b1133	b1133	Planned
578	b1135		EP		PJM WEST		0	2.9	b1135	b1135	Planned
579	b1137		EP		PJM WEST		0	5.8	b1137	b1137	Planned
580	b1138		EP		PJM WEST		0	0.7	b1138	b1138	Planned
581	b1139		EP		PJM WEST		0	2	b1139	b1139	Planned
582	b1140		EP		PJM WEST		0	0.8	b1140	b1140	Planned
583	b1141		EP		PJM WEST		0	1	b1141	b1141	Planned
584	b1142		EP		PJM WEST		0	2.3	b1142	b1142	Planned
585	b1143		EP		PJM WEST		0	5.9	b1143	b1143	Planned
586	b1144		EP		PJM WEST		0	1.6	b1144	b1144	Planned
587	b1145		EP		PJM WEST		0	1.6	b1145	b1145	Planned
588	b1146		EP		PJM WEST		0	0.3	b1146	b1146	Planned
589	b1147		EP		PJM WEST		0	0.3	b1147	b1147	Planned
590	b1148		EP		PJM WEST		0	3.2	b1148	b1148	Planned
591	b1149		EP		PJM WEST		0	1.7	b1149	b1149	Planned
592	b1150		EP		PJM WEST		0	0.02	b1150	b1150	Planned
593	b1151		EP		PJM WEST		0	2.7	b1151	b1151	Planned
594	b1152	1/13/2010	EP		PJM WEST		2	2.9	b1152	b1152	Planned
595	b1153		EP		PJM MA		1	29.8	b1153	b1153	Planned
596	b1153.1		EP	PA	PJM MA		0	0	b1153	b1153	Planned
597	b1154	4/15/2011	EP	NJ	PJM MA		1	336	b1154	b1154	Planned
598	b1154.1		EP	NJ	PJM MA		0	0.26	b1154	b1154	Planned
599	b1155		EP		PJM MA		0	125	b1155	b1155	Planned
600	b1155.1		EP	NJ	PJM MA		0	0.16	b1155	b1155	Planned
601	b1155.2		EP	NJ	PJM MA		0	0.1	b1155	b1155	Planned
602	b1155.3		EP	NJ	PJM MA		0	0.6	b1155	b1155	Planned
603	b1155.4		EP	NJ	PJM MA		0	0.6	b1155	b1155	Planned
604	b1155.5		EP	NJ	PJM MA		0	0.6	b1155	b1155	Planned
605	b1155.6		EP	NJ	PJM MA		0	0.6	b1155	b1155	Planned
606	b1156	4/15/2011	EP	NJ	PJM MA		1	381	b1156	b1156	Planned
607	b1156.1		EP	PA	PJM MA		0	0.1	b1156	b1156	Planned
608	b1156.10		EP	PA	PJM MA		0	0.5	b1156	b1156	Planned
609	b1156.12		EP	PA	PJM MA		0	0.5	b1156	b1156	Planned
610	b1156.13		EP	NJ	PJM MA		0	1.5	b1156	b1156	Planned
611	b1156.14		EP	NJ	PJM MA		0	1.5	b1156	b1156	Planned
612	b1156.15		EP	NJ	PJM MA		0	1.5	b1156	b1156	Planned
613	b1156.16		EP	NJ	PJM MA		0	0.6	b1156	b1156	Planned
614	b1156.17		EP	NJ	PJM MA		0	0.6	b1156	b1156	Planned
615	b1156.18		EP	NJ	PJM MA		0	0.6	b1156	b1156	Planned
616	b1156.19		EP	NJ	PJM MA		0	18	b1156	b1156	Planned
617	b1156.2		EP	PA	PJM MA		0	0.1	b1156	b1156	Planned
618	b1156.3		EP	PA	PJM MA		0	0.1	b1156	b1156	Planned
619	b1156.4		EP	PA	PJM MA		0	0.1	b1156	b1156	Planned
620	b1156.5		EP	PA	PJM MA		0	0.1	b1156	b1156	Planned
621	b1156.6		EP	PA	PJM MA		0	0.1	b1156	b1156	Planned
622	b1156.7		EP	PA	PJM MA		0	0.1	b1156	b1156	Planned
623	b1156.8		EP	PA	PJM MA		0	0.5	b1156	b1156	Planned
624	b1156.9		EP	PA	PJM MA		0	0.5	b1156	b1156	Planned
625	b1157		EP		PJM WEST		0	0.01	b1157	b1157	Planned
626	b1158		EP		PJM WEST		0	1.55	b1158	b1158	Planned
627	b1159		UC		PJM WEST		75	0.19	b1159	b1159	Planned
628	b1160		UC		PJM WEST		45	0.19	b1160	b1160	Planned
629	b1161		EP		PJM WEST		20	0.19	b1161	b1161	Planned
630	b1162		EP		PJM WEST		20	0.19	b1162	b1162	Planned
631	b1163		EP		PJM WEST		20	0.19	b1163	b1163	Planned
632	b1164		EP		PJM WEST		5	0.19	b1164	b1164	Planned
633	b1165		EP		PJM WEST		5	0.19	b1165	b1165	Planned
634	b1166		EP		PJM WEST		5	0.22	b1166	b1166	Planned
635	b1167		EP		PJM WEST		5	0.19	b1167	b1167	Planned
636	b1169		EP		PJM WEST		0	0.31	b1169	b1169	Planned
637	b1170		EP		PJM WEST		0	0.31	b1170	b1170	Planned
638	b1171.1		EP	WV	PJM WEST		2	9.11	b1171	b1171	Planned
639	b1171.3	3/2/2011	EP	WV	PJM WEST		2	9.17	b1171	b1171	Planned

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
3	Upgrade ID	PJM Required	In Service Date	Location	Task	Equipment	Descriptior	Voltage	Expected R	Last Updated	Trans Own	Study Year	Baseline Re	Driver	Initial TEAC Da
640	b1172	12/1/2012	6/1/2012	Hopewell -	Build	Line	a 4-6 mile l	230		12/28/2010	Dominion			Dominion (	9/14/2009
641	b1174	5/31/2011	11/4/2011	Collier-Elw	Create	Circuit	a second c	138		3/30/2011	DL			DLCO Crite	5/27/2010
642	b1175	6/1/2014	6/1/2014	Mt. Washir	Apply	SPS Schem	to delay load pick-up for one outa			2/14/2011	BGE	2014		N-1-1 Volta	12/16/2009
643	b1176	6/1/2014	6/1/2014	Mt. Washir	Transfer	Load		6		2/14/2011	BGE	2014		N-1-1 Ther	12/16/2009
644	b1178	4/30/2012	4/30/2012	Chichester	Add	Transform	a second tr	130/138		5/5/2011	PECO			Gen Retire	3/10/2010
645	b1182	6/1/2012	6/1/2012	Chichester	Reconduct	Line	Reconduct	138		5/5/2011	PECO			Gen Retire	3/10/2010
646	b1183	12/31/2011	12/31/2011	Cromby	Replace	Transform	add two 5C	230/69	50	5/5/2011	PECO			Gen Retire	3/10/2010
647	b1184	11/13/2011	11/13/2011	Perkiomen	Install	Breakers	and add a :	138	35	5/5/2011	PECO			Gen Retire	3/10/2010
648	b1188	6/1/2014	5/30/2014	Brambleto	Build	Ring Bus	New Braml	500		5/24/2011	Dominion			Load Delive	9/8/2010
649	b1188.1	6/1/2014	5/30/2014	Loudoun	Replace	Breaker	Replace Loudoun 230 kV breaker			4/19/2011	Dominion			Short Circu	10/28/2010
650	b1188.2	6/1/2014	5/30/2014	Loudoun	Replace	Breaker	Replace Loudoun 230 kV breaker			4/19/2011	Dominion			Short Circu	10/28/2010
651	b1188.3	6/1/2014	5/30/2014	Loudoun	Replace	Breaker	Replace Loudoun 230 kV breaker			4/19/2011	Dominion			Short Circu	10/28/2010
652	b1188.4	6/1/2014	5/30/2014	Loudoun	Replace	Breaker	Replace Loudoun 230 kV breaker			4/19/2011	Dominion			Short Circu	10/28/2010
653	b1188.5	6/1/2014	5/30/2014	Loudoun	Replace	Breaker	Replace Loudoun 230 kV breaker			4/19/2011	Dominion			Short Circu	10/28/2010
654	b1188.6	6/1/2014	5/30/2014	Brambleto	Build	Transform	Install one	500/230		5/24/2011	Dominion			Load Delive	9/8/2010
655	b1190	6/1/2013	6/1/2013	Lemonyne	Reconduct	Line	Reconduct	138		5/24/2011	ATSI	2013		Gen Deliv	5/12/2010
656	b1191	6/1/2013	6/1/2013	Shenango	Replace	Line	Replace th	138		5/24/2011	ATSI	2013		Gen Deliv	5/12/2010
657	b1192	6/1/2013	6/1/2013	Bayshore	Reconduct	Line	Reconduct	138		5/24/2011	ATSI	2013		Gen Deliv	5/12/2010
658	b1194	6/1/2013	6/1/2011	General M	Reconduct	Terminal	Replace su	138		6/6/2011	ATSI	2013		Gen Deliv	5/12/2010
659	b1195.1	5/31/2015	5/1/2011	Corson	Upgrade	Terminal	Upgrade th	138		1/14/2011	AEC			Gen Delive	5/27/2010
660	b1195.2	5/31/2015	5/1/2012	Corson	Upgrade	Terminal	Upgrade the Corson sub T1 termi			1/20/2011	AEC			Gen Delive	5/27/2010
661	b1196	6/1/2013	5/31/2013	Siegfried, I	Reconfigur	Breaker	Remove th	230		3/25/2011	PPL			Gen Delive	5/27/2010
662	b1197	6/1/2015	6/1/2015	Burlington	Reconduct	Line	Reconduct	230		1/20/2011	PECO			Gen Delive	5/27/2010
663	b1197.1	6/1/2015		Burlington	Reconduct	Line	Reconduct	230		12/14/2010	PSEG			Gen Delive	8/11/2010
664	b1198	6/1/2015	6/1/2015	Conowingo	Replace	Terminal E	Replace terminal equipments incl			1/20/2011	PECO			Gen Delive	5/27/2010
665	b1200	6/1/2013	6/1/2013	Double Tol	Reconduct	Line	Reconductor Double Toll Gate - G			3/11/2011	APS			Gen Delive	6/2/2010
666	b1201	5/31/2013	5/31/2013	Hercules Ta	Rebuild	Line	Rebuild the Hercules Tap to Doub			3/25/2011	PPL			PPL Criteria	6/2/2010
667	b1202	5/31/2013	5/31/2013	Mack	Rearrange	Substation	Mack-Macungie Double Tap, Sing			3/25/2011	PPL			PPL Criteria	6/2/2010
668	b1203	11/30/2014	11/30/2014	East Palme	Install	Line	Add the 2nd Circuit to the East Pa			3/25/2011	PPL			PPL Criteria	6/2/2010
669	b1204	5/31/2015	6/1/2015	New Breini	Install	Substation	New Breini	500/138/69		6/23/2011	PPL			PPL Criteria	6/2/2010
670	b1205	5/31/2014	5/31/2014	Siegfried	Install	Transfer Ec	Siegfried-East Palmerton #1 69 k\			3/25/2011	PPL			PPL Criteria	6/2/2010
671	b1206	5/31/2015	5/31/2015	Siegfried	Install	Line	Siegfried-Quarry #1 & #2 69 kV Li			3/25/2011	PPL			PPL Criteria	6/2/2010
672	b1209	11/30/2012	11/30/2012	Neffsville	Convert	Taps	Convert Neffsville Taps from 69k\			3/25/2011	PPL			PPL Criteria	6/2/2010
673	b1210	5/31/2011	5/31/2011	Roseville	Convert	Taps	Convert Roseville Taps from 69kV			3/25/2011	PPL			PPL Criteria	6/2/2010
674	b1211	5/31/2013	5/31/2013	Roseville	Convert	Taps	Convert Roseville Taps from 69kV			3/25/2011	PPL			PPL Criteria	6/2/2010
675	b1212	11/30/2013	11/30/2013	Flory Mill	Install	Taps	New 138kV Taps to Flory Mill 138			3/25/2011	PPL			PPL Criteria	6/2/2010
676	b1213	11/30/2013	11/30/2013	East Peters	Convert	Taps	Convert East Petersburg Taps fro			3/25/2011	PPL			PPL Criteria	6/2/2010
677	b1214	11/30/2013	11/30/2014	South Man	Rearrange	Substation	Terminate South Manheim-Done			3/25/2011	PPL			PPL Criteria	6/2/2010
678	b1215	11/30/2014	11/30/2014	Peckville	Reconduct	Line	Reconductor and rebuild 16 miles			3/25/2011	PPL			PPL Criteria	6/2/2010
679	b1216	11/30/2013	11/30/2013	Kimbles	Install	Line	Build approximately 2.5 miles of r			3/25/2011	PPL			PPL Criteria	6/2/2010
680	b1217	11/30/2012	11/30/2012	Tafton	install	Feed	Provide a “double tap – single fee			3/25/2011	PPL			PPL Criteria	6/2/2010
681	b1221.1	6/1/2014	6/1/2014	Carbon Cer	Convert	Substation	Convert Carbon Center from 138			3/11/2011	APS			Baseline Vo	8/11/2010
682	b1221.2	6/1/2014	12/1/2011	Bear Run	Construct	Substation	Construct Bear Run 230 kV substa			3/11/2011	APS			Baseline Vo	8/11/2010
683	b1221.3	6/1/2014	12/1/2011	Carbon Cer	Loop in	Line	Loop Carbon Center Junction - Wi			3/30/2011	APS			Baseline Vo	8/11/2010
684	b1221.4	6/1/2014	6/1/2014	Carbon Cer	Convert	Substation	Carbon Center - Carbon Center Ju			3/11/2011	APS			Baseline Vo	8/11/2010
685	b1224	6/1/2015	6/1/2015	Clover	Install	Transform	Install 2nd	500/230		5/24/2011	Dominion	2015		Load Delive	5/12/2010
686	b1225	6/1/2011	5/31/2011	Yorktown	Replace	Breaker	Replace Yo	115		5/24/2011	Dominion	2011		Short Circu	9/8/2010
687	b1226	6/1/2011	5/31/2011	Yorktown	Replace	Breaker	Replace Yo	115		5/24/2011	Dominion	2011		Short Circu	9/8/2010
688	b1227	9/6/2010	6/1/2011	Altavista	Perform	Sag Study	Perform a :	138		3/10/2011	AEP			Gen Retire	9/8/2010
689	b1228	6/1/2014		Lawrence	Reconfigur	Substation	Re-configure the Lawrence 230 k\			3/9/2011	PSEG			Gen Delive	9/8/2010
690	b1229	6/1/2013	6/1/2013	Shenango	Replace	Substation	Replace th	138		5/24/2011	ATSI			Common N	9/8/2010
691	b1230	6/1/2013	6/1/2013	Willow - Eu	Reconduct	Line	Reconduct	138		3/11/2011	APS			New Ops P	9/8/2010
692	b1231	6/1/2012	6/1/2012	West Moul	Replace/Re	Transform	Replace th	138/69		2/8/2011	AEP			AEP criteria	8/24/2010
693	b1232	6/1/2015		Nipetown	Reconduct	Line	Reconduct	138		2/8/2011	APS			Gen Delive	9/8/2010
694	b1233.1	6/1/2015		Washingto	Upgrade	Terminal e	Upgrade terminal equipment at V			1/19/2011	APS			Common N	9/8/2010
695	b1234	6/1/2015		Ridgeway	Replace	Structures	Replace str	138		12/14/2010	APS			Common N	9/8/2010
696	b1235	6/1/2013	6/1/2013	Albright	Reconduct	Line	Reconduct	138		3/11/2011	APS			Common N	9/8/2010
697	b1237	6/1/2015		Albright	Upgrade/re	Substation	Upgrade terminal equipment at A			12/14/2010	APS			Common N	9/8/2010
698	b1238	6/1/2015		Edgelawn	Install	Capacitor	Install a 138 kV 44 MVAR capacito			10/22/2010	APS			Baseline Vo	9/8/2010
699	b1239	6/1/2015	6/1/2015	Ridgeway	Install	Capacitor	Install a 13	138		5/13/2011	APS			Baseline Vo	9/8/2010
700	b1240	6/1/2015	6/1/2015	Elko	Install	Capacitor	Install a 13	138		5/13/2011	APS			Baseline Vo	9/8/2010
701	b1241	6/1/2015		Washingto	Upgrade	Terminal e	Upgrade terminal equipment at V			10/22/2010	APS			Baseline th	9/8/2010
702	b1242	6/1/2015		Collins Ferr	Replace	Structures	Replace structures between Collir			10/22/2010	APS			Baseline th	9/8/2010
703	b1243	6/1/2015	6/1/2012	Potter	Install	Capacitor	Install two 12 MVAR 115 kV capa			3/11/2011	APS			Baseline Vo	9/8/2010
704	b1244	5/1/2015	5/1/2014	Peermont	Install	Capacitor	Install 10 N	69		6/23/2011	AEC			Voltage	8/24/2010
705	b1245	5/31/2012	5/31/2012	Newport	Rebuild	Line	Rebuild the Newport-South Millvi			1/20/2011	AEC			Baseline Th	9/8/2010
706	b1246	6/1/2015	5/31/2014	Townsend	Rebuild	Line	Re-build the Townsend - Church 1			6/23/2011	DPL			N-1-1 therr	9/8/2010
707	b1247	6/1/2015	5/31/2015	Glasgow	Rebuild	Line	Re-build the Glasgow - Cecil 138 k			6/23/2011	DPL			Baseline Th	9/8/2010
708	b1248	6/1/2015	5/31/2015	Loretto	Install	Capacitor	Install two 15 MVAR capacitor at			6/23/2011	DPL			Baseline Vo	9/8/2010
709	b1249	6/1/2015	5/31/2014	Sussex	Reconfigur	Capacitor	Reconfigure the existing Sussex 6			6/23/2011	DPL			Baseline Vo	9/8/2010
710	b1250	6/1/2015	5/31/2015	Monroe	Reconduct	Line	Reconductor the Monroe - Glassb			1/20/2011	AEC			N-1-1 Ther	9/8/2010

	A	P	Q	R	S	T	U	V	W	X	Y
3	Upgrade ID	Latest TEAC Date	Status	State	Region	County	Percent Co	Cost Estim	Project ID	In Schedul	Source
640	b1172		EP		PJM SOUTH		20	15.1	b1172	#N/A	Planned
641	b1174		UC		PJM WEST		40	3.88	b1174	b1174	Planned
642	b1175		EP		PJM MA		0	0	b1175	#N/A	Planned
643	b1176		EP		PJM MA		0	0	b1176	#N/A	Planned
644	b1178		EP	PA	PJM MA		25	5.91	b1178	b1178	Planned
645	b1182		EP	PA	PJM MA		25	8.5	b1182	b1182	Planned
646	b1183		EP	PA	PJM MA		20	6.14	b1183	b1183	Planned
647	b1184		UC		PJM MA		35	3.9	b1184	b1184	Planned
648	b1188		EP	VA	PJM SOUTH		0	5.2	b1188	b1188	Planned
649	b1188.1		EP		PJM SOUTH		0	0.22	b1188	b1188	Planned
650	b1188.2		EP		PJM SOUTH		0	0.22	b1188	b1188	Planned
651	b1188.3		EP		PJM SOUTH		0	0.22	b1188	b1188	Planned
652	b1188.4		EP		PJM SOUTH		0	0.22	b1188	b1188	Planned
653	b1188.5		EP		PJM SOUTH		0	0.22	b1188	b1188	Planned
654	b1188.6		EP	VA	PJM SOUTH		0	16.82	b1188	b1188	Planned
655	b1190		EP	OH	PJM WEST		1	4.3	b1190	#N/A	Planned
656	b1191		EP	OH	PJM WEST		0	0.02	b1191	#N/A	Planned
657	b1192		EP	OH	PJM WEST		5	4.3	b1192	#N/A	Planned
658	b1194		EP	OH	PJM WEST		2	0.02	b1194	#N/A	Planned
659	b1195.1		EP		PJM MA		0	0.1	b1195	b1195	Planned
660	b1195.2		EP		PJM MA		0	0.03	b1195	b1195	Planned
661	b1196		EP		PJM MA		0	1	b1196	b1196	Planned
662	b1197		EP		PJM MA		0	1	b1197	b1197	Planned
663	b1197.1		EP		PJM MA		0	3	b1197	b1197	Planned
664	b1198		EP		PJM MA		0	0.5	b1198	b1198	Planned
665	b1200		EP		PJM WEST		0	3	b1200	b1200	Planned
666	b1201		EP		PJM MA		0	1.95	b1201	b1201	Planned
667	b1202		EP		PJM MA		0	0.33	b1202	b1202	Planned
668	b1203		EP	PA	PJM MA		0	12.3	b1203	b1203	Planned
669	b1204	3/2/2011	EP	PA	PJM MA		0	44	b1204	b1204	Planned
670	b1205		EP		PJM MA		0	0.28	b1205	b1205	Planned
671	b1206		EP		PJM MA		0	3.8	b1206	b1206	Planned
672	b1209		EP		PJM MA		0	0	b1209	b1209	Planned
673	b1210		UC		PJM MA		40	1.27	b1210	b1210	Planned
674	b1211		EP		PJM MA		0	0.03	b1211	b1211	Planned
675	b1212		EP		PJM MA		0	0.69	b1212	b1212	Planned
676	b1213		EP	PA	PJM MA		0	0	b1213	b1213	Planned
677	b1214		EP		PJM MA		0	0.08	b1214	b1214	Planned
678	b1215		EP	PA	PJM MA		0	22.4	b1215	b1215	Planned
679	b1216		EP		PJM MA		0	2.69	b1216	b1216	Planned
680	b1217		EP		PJM MA		0	2	b1217	b1217	Planned
681	b1221.1		EP		PJM WEST		0	2	b1221	b1221	Planned
682	b1221.2		EP	PA	PJM WEST		20	6	b1221	b1221	Planned
683	b1221.3		EP		PJM WEST		20	3.2	b1221	b1221	Planned
684	b1221.4		EP		PJM WEST		0	4.3	b1221	b1221	Planned
685	b1224		EP	VA	PJM SOUTH		0	17.1	b1224	b1224	Planned
686	b1225		EP		PJM SOUTH		0	0.2	b1225	b1225	Planned
687	b1226		EP		PJM SOUTH		0	0.2	b1226	b1226	Planned
688	b1227		EP		PJM WEST		0	0.02	b1227	b1227	Planned
689	b1228		EP	NJ	PJM MA		2	9	b1228	b1228	Planned
690	b1229		EP		PJM WEST		0	0.25	b1229	#N/A	Planned
691	b1230		EP		PJM WEST		0	4	b1230	b1230	Planned
692	b1231		EP	OH	PJM WEST		0	11.9	b1231	b1231	Planned
693	b1232		EP	WV	PJM WEST		0	15	b1232	b1232	Planned
694	b1233.1		EP		PJM WEST		0	0.05	b1233	b1233	Planned
695	b1234		EP		PJM WEST		0	0.75	b1234	b1234	Planned
696	b1235		EP	WV	PJM WEST		2	55	b1235	b1235	Planned
697	b1237		EP		PJM WEST		0	0.5	b1237	b1237	Planned
698	b1238		EP		PJM WEST		0	1.2	b1238	b1238	Planned
699	b1239	3/2/2011	EP	PA	PJM WEST		0	1.5	b1239	b1239	Planned
700	b1240	3/2/2011	EP	PA	PJM WEST		0	1.5	b1240	b1240	Planned
701	b1241		EP		PJM WEST		0	0.05	b1241	b1241	Planned
702	b1242		EP		PJM WEST		0	0.35	b1242	b1242	Planned
703	b1243		EP		PJM WEST		0	2.8	b1243	b1243	Planned
704	b1244		EP		PJM MA		0	0.75	b1244	b1244	Planned
705	b1245		EP		PJM MA		0	1.9	b1245	b1245	Planned
706	b1246		EP	MD	PJM MA		0	5.96	b1246	b1246	Planned
707	b1247		EP	MD	PJM MA		0	16	b1247	b1247	Planned
708	b1248		EP		PJM MA		0	1.3	b1248	b1248	Planned
709	b1249		EP		PJM MA		0	0.5	b1249	b1249	Planned
710	b1250		EP		PJM MA		0	1.55	b1250	b1250	Planned

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
3	Upgrade ID	PJM Required	In Service Date	Location	Task	Equipment	Descriptior	Voltage	Expected R	Last Updated	Trans Own	Study Year	Baseline R	Driver	Initial TEAC Da
711	b1251	6/1/2015	6/1/2015	Raphael	Build	Line	Rebuild the	230		4/25/2011	BGE			Common N	8/11/2010
712	b1251.1	6/1/2015	6/1/2015	Raphael	Rebuild	Line	Reconfigur	230		3/31/2011	BGE			Common N	8/11/2010
713	b1252	6/1/2015	6/1/2015	Pumphrey	Replace	Terminal E	Upgrade terminal equipment (rer			2/14/2011	BGE			Cat C Ther	8/11/2010
714	b1253	6/1/2015	6/1/2015	Northeast	Replace	Transform	Replace the existing Northeast 23			2/14/2011	BGE			N-1-1 Ther	9/8/2010
715	b1253.1	6/1/2015	6/1/2015	Northeast	Replace	Breaker	Replace th	230		4/20/2011	BGE			Short Circu	3/10/2011
716	b1253.2	6/1/2015	6/1/2015	Windy Edg	Upgrade	Breaker	Revise recl	115		5/13/2011	BGE			Short Circu	3/2/2011
717	b1253.3	6/1/2015	6/1/2015	Windy Edg	Upgrade	Breaker	Revise recl	115		5/13/2011	BGE			Short Circu	3/2/2011
718	b1253.4	6/1/2015	6/1/2015	Windy Edg	Upgrade	Breaker	Revise recl	115		5/13/2011	BGE			Short Circu	3/2/2011
719	b1254	6/1/2015	6/1/2015	Emory Gro	Build	Substation	Build a nev	500/230		2/14/2011	BGE				9/8/2010
720	b1254.1	6/1/2015		Emory Gro	Rebuild	Line	Rebuild the Emory - North West 2			2/8/2011	BGE				9/8/2010
721	b1255	6/1/2015					Build a new 69 kV substation (Rid			2/8/2011	PSEG				8/24/2010
722	b1256	6/1/2011	6/1/2011	State Line !	Replace	Breaker	Replace th	138		11/8/2010	ComEd	2011		Short Circu	9/8/2010
723	b1257	6/1/2011	6/1/2011	J322	Remove	Breaker	Eliminate t	138		10/22/2010	ComEd	2011		Short Circu	9/8/2010
724	b1260	6/1/2011	6/30/2014	Beaver Val	Replace	Breaker	Replace Beaver Valley 138kV brea			12/29/2010	DL	2011		Short Circu	9/8/2010
725	b1261	6/1/2011	7/1/2011	Butler	Replace	Breaker	Replace Butler 138kV breaker '1-2			3/11/2011	APS	2011		Short Circu	9/8/2010
726	b1263	6/1/2015		Electric Jur	Move	Terminatio	Move line 16703 termination fror			12/14/2010	ComEd			Common N	8/11/2010
727	b1264	6/1/2015		Plano	Replace	Bus ties	Replace 345 kV bus ties 1-2 and 1			10/22/2010	ComEd			Gen Delive	8/11/2010
728	b1265	6/1/2015		Will County	Reconduct	Line	Reconductor approximately 2 mil			10/22/2010	ComEd			Gen Delive	9/8/2010
729	b1266	6/1/2015		Lisle	Replace	Breaker	Normally close 345 kV BT 2-3 at T			10/22/2010	ComEd			Common N	9/8/2010
730	b1266.1	6/1/2015	6/1/2012	DesPlaines	Upgrade	Breaker	Revise recl	138		6/14/2011	ComEd			Short Circu	3/2/2011
731	b1267	6/1/2015	6/1/2015	Erdman	Rebuild	Substation	Rebuild exi	115		2/15/2011	BGE			Baseline Vo	8/24/2010
732	b1267.1	6/1/2015	6/1/2015	Coldspring	Construct	Undergrou	Construct 1	115		2/15/2011	BGE			Baseline Vo	8/24/2010
733	b1267.2	6/1/2015	6/1/2015	Mays Chap	Replace	Breaker	Replace M	115		5/13/2011	BGE			Short Circu	3/2/2011
734	b1267.3	6/1/2015	6/1/2015	Mays Chap	Replace	Breaker	Replace M	115		5/13/2011	BGE			Short Circu	3/2/2011
735	b1268	6/1/2015		Shelby	Reconduct	Line	Reconductor Shelby - Sidney 138k			10/22/2010	Dayton			N-1-1 Ther	8/24/2010
736	b1269	6/1/2015		West Miltc	Reconduct	Line	Reconductor West Milton - Salem			10/22/2010	Dayton			N-1-1 Ther	8/24/2010
737	b1270	6/1/2015		Bath	Reconduct	Line	Reconductor Bath - Trebein 138kV			10/22/2010	Dayton			N-1-1 Ther	8/24/2010
738	b1271	6/1/2015		OHH	Reconduct	Line	Reconductor Underground Sectio			10/22/2010	Dayton			N-1-1 Ther	8/24/2010
739	b1272	6/1/2015		Burdox	Reconduct	Line	Reconductor Burdox - Webster 13			10/22/2010	Dayton			N-1-1 Ther	8/24/2010
740	b1273	6/1/2015		Bath	Install	Transform	Add 2nd Bath 345/138kV Xfr			2/8/2011	Dayton			N-1-1 Ther	8/24/2010
741	b1274	6/1/2015		Trebien	Install	Transform	Add 2nd Trebien 138/69kV Xfr			2/8/2011	Dayton			N-1-1 Ther	8/24/2010
742	b1275	6/1/2015		W. Milton	Install	Transform	Add 2nd W	138/69		2/8/2011	Dayton			N-1-1 Ther	8/24/2010
743	b1276	6/1/2015		W. Milton	Install	Transform	Add 2nd W	345/138		2/8/2011	Dayton			N-1-1 Ther	8/24/2010
744	b1277	6/1/2013	6/1/2013	Osterburg	Build	Line	Build a nev	115		5/24/2011	Penelec			FE planning	8/24/2010
745	b1278	11/1/2012	11/1/2012	Somerset	Install	Capacitor	Install 25 M	115		5/24/2011	Penelec			FE planning	8/24/2010
746	b1279	6/1/2014	6/1/2014	Locks	Increase Ra	Line	Increase ra	115		5/24/2011	Dominion			Category B	8/25/2010
747	b1280	6/1/2011	12/31/2011	Sherman	Replace	Transform	Replace th	138/69		6/23/2011	AEC			Gen Retire	9/8/2010
748	b1280.1	6/1/2012	5/31/2012	Sherman	Replace	Transform	Replace th	138/69		1/20/2011	AEC			Gen Retire	9/8/2010
749	b1281	6/1/2015	6/1/2015	Hayes	Build	Substation	Build new Hayes 345/138 kV subs			5/24/2011	ATSI			Load Deliv	9/8/2010
750	b1282	6/1/2015	6/1/2015	Beaver - Be	Build	Line	Build Beaver - Hayes - Davis - Bes			5/24/2011	ATSI			Load Deliv	9/8/2010
751	b1283	6/1/2015	6/1/2015	Hanna	Loop in	Line	Loop the Chamberlin - Mansfield			5/24/2011	ATSI			Load Deliv	9/8/2010
752	b1284	6/1/2013	6/1/2013	Lime City	Install	Capacitor	Install 50.0 MVAR capacitor bank			5/24/2011	ATSI			N-1-1 Ther	9/8/2010
753	b1285	6/1/2015	6/1/2015	Barberton	Replace	Various	Replace Barberton - Star 138 kV #			5/24/2011	ATSI			N-1-1 Ther	9/8/2010
754	b1286	6/1/2015	6/1/2015	Hanna	Reconduct	Line	Reconductor Hanna - W. Ravenna			5/24/2011	ATSI			N-1-1 Ther	9/8/2010
755	b1287	6/1/2015	6/1/2015	Hanna	Reconduct	Line	Reconductor Hanna - W. Ravenna			5/24/2011	ATSI			N-1-1 Ther	9/8/2010
756	b1288	6/1/2015	6/1/2015	Masury	Replace	Terminal E	Replace Masury - Crossland 138 k			5/24/2011	ATSI			N-1-1 Ther	9/8/2010
757	b1289	6/1/2015	6/1/2015	Evergreen	Reconduct	Line	Reconductor Evergreen - Niles 13			5/24/2011	ATSI			N-1-1 Ther	9/8/2010
758	b1290	6/1/2015	6/1/2015	Niles	Build	Line	Build new Niles - Salt Springs #2 1			5/24/2011	ATSI			N-1-1 Ther	9/8/2010
759	b1291	6/1/2015	6/1/2015	Eastlake	Replace	Substation	Replace substation equipment at			5/24/2011	ATSI			N-1-1 Ther	9/8/2010
760	b1292	6/1/2015	6/1/2015	Eastlake	Replace	Substation	Replace substation equipment at			5/24/2011	ATSI			N-1-1 Ther	9/8/2010
761	b1293	6/1/2015	6/1/2015	Tangy	Replace	Substation	Replace substation equipment at			5/24/2011	ATSI			N-1-1 Ther	9/8/2010
762	b1294	6/1/2011	6/1/2011	Brookside	Modify	CT ratio	Modify the Brookside - Longview			5/24/2011	ATSI			N-1-1 Ther	9/8/2010
763	b1295.1	6/1/2011	6/1/2011	Brookside	Modify	CT ratio	Modify the Brookside - Longview			5/24/2011	ATSI			N-1-1 Ther	9/8/2010
764	b1295.2	6/1/2011	6/1/2011	Brookside	Modify	CT Ratio	Modify the	138		5/24/2011	ATSI			N-1-1 Ther	9/8/2010
765	b1296.1	6/1/2015	6/1/2015	Lemoyne	Reconduct	Exit Condu	Reconductor BG line exit conduct			5/24/2011	ATSI			N-1-1 Ther	9/8/2010
766	b1296.2	6/1/2015	6/1/2015	Lemoyne	Change	CT ratio	Change the	138		5/24/2011	ATSI			N-1-1 Ther	9/8/2010
767	b1297	6/1/2013	6/1/2013	Fulton	Install	Substation	Install a new Fulton 345/138 kV s			5/24/2011	ATSI			N-1-1 Ther	9/8/2010
768	b1299	6/1/2015	6/1/2015	Silica	Add	SCADA con	Add SCADA control and motor op			5/24/2011	ATSI			N-1-1 Ther	9/8/2010
769	b1300	6/1/2015	6/1/2013	East Frankf	Reconduct	Line	Reconduct	345		5/13/2011	ComEd			Load Delive	9/8/2010
770	b1301	6/1/2014	6/1/2014	Garfield	Upgrade	Line	Upgrade b	345		6/14/2011	ComEd			Load Delive	9/8/2010
771	b1302	6/1/2015	6/1/2015	Jackson	Replace	Wave trap	Replace the limiting bus conducto			5/24/2011	ME			N-1-1 ther	9/8/2010
772	b1304.1	6/1/2015		Roseland	Convert	Line	Cinvert the	230		2/8/2011	PSEG				9/8/2010
773	b1304.10	6/1/2015	6/1/2015	South Wat	Replace	Breaker	Replace So	230		5/23/2011	PSEG			Short Circu	5/12/2011
774	b1304.11	6/1/2015	6/1/2015	South Wat	Replace	Breaker	Replace So	230		5/23/2011	PSEG			Short Circu	5/12/2011
775	b1304.12	6/1/2015	6/1/2015	South Wat	Replace	Breaker	Replace So	230		5/23/2011	PSEG			Short Circu	5/12/2011
776	b1304.13	6/1/2015	6/1/2015	South Wat	Replace	Breaker	Replace So	230		5/23/2011	PSEG			Short Circu	5/12/2011
777	b1304.14	6/1/2015	6/1/2015	Essex	Replace	Breaker	Replace Es	230		5/23/2011	PSEG			Short Circu	5/12/2011
778	b1304.15	6/1/2015	6/1/2015	Essex	Replace	Breaker	Replace Es	230		5/23/2011	PSEG			Short Circu	5/12/2011
779	b1304.16	6/1/2015	6/1/2015	Essex	Replace	Breaker	Replace Es	230		5/23/2011	PSEG			Short Circu	5/12/2011
780	b1304.17	6/1/2015	6/1/2015	Essex	Replace	Breaker	Replace Es	230		5/23/2011	PSEG			Short Circu	5/12/2011
781	b1304.18	6/1/2015	6/1/2015	Essex	Replace	Breaker	Replace Es	230		5/23/2011	PSEG			Short Circu	5/12/2011

	A	P	Q	R	S	T	U	V	W	X	Y
3	Upgrade ID	Latest TEAC Date	Status	State	Region	County	Percent Co	Cost Estim	Project ID	In Schedul	Source
711	b1251		EP	MD	PJM MA		0	18	b1251	b1251	Planned
712	b1251.1		EP	MD	PJM MA		0	0	b1251	b1251	Planned
713	b1252		EP		PJM MA		0	0.1	b1252	b1252	Planned
714	b1253		EP	MD	PJM MA		0	10.1	b1253	b1253	Planned
715	b1253.1		EP	MD	PJM MA		0	0.55	b1253	b1253	Planned
716	b1253.2		EP	MD	PJM MA		0	0	b1253	b1253	Planned
717	b1253.3		EP	MD	PJM MA		0	0	b1253	b1253	Planned
718	b1253.4		EP	MD	PJM MA		0	0	b1253	b1253	Planned
719	b1254		EP	MD	PJM MA		0	71	b1254	b1254	Planned
720	b1254.1		EP	MD	PJM MA		0	0	b1254	b1254	Planned
721	b1255		EP	NJ			0	22.5	b1255	b1255	Planned
722	b1256		EP	IL	PJM WEST		0	0.76	b1256	b1256	Planned
723	b1257		EP	IL	PJM WEST		0	0.04	b1257	b1257	Planned
724	b1260		EP	PA	PJM WEST		0	0.4	b1260	b1260	Planned
725	b1261		EP		PJM WEST		5	0.3	b1261	b1261	Planned
726	b1263		EP		PJM WEST		0	3	b1263	b1263	Planned
727	b1264		EP		PJM WEST		0	2	b1264	b1264	Planned
728	b1265		EP		PJM WEST		0	1.5	b1265	b1265	Planned
729	b1266		EP		PJM WEST		0	1	b1266	b1266	Planned
730	b1266.1		EP	IL	PJM WEST		0	0.1	b1266	b1266	Planned
731	b1267		EP	MD	PJM MA		0	7.6	b1267	b1267	Planned
732	b1267.1		EP	MD	PJM MA		0	142	b1267	b1267	Planned
733	b1267.2		EP	MD	PJM MA		0	0.33	b1267	b1267	Planned
734	b1267.3		EP	MD	PJM MA		0	0.33	b1267	b1267	Planned
735	b1268		EP		PJM WEST		0	2.6	b1268	b1268	Planned
736	b1269		EP		PJM WEST		0	4.8	b1269	b1269	Planned
737	b1270		EP		PJM WEST		0	1.3	b1270	b1270	Planned
738	b1271		EP		PJM WEST		0	2.4	b1271	b1271	Planned
739	b1272		EP		PJM WEST		0	1	b1272	b1272	Planned
740	b1273		EP	OH	PJM WEST		0	7	b1273	b1273	Planned
741	b1274		EP	OH	PJM WEST		0	5.3	b1274	b1274	Planned
742	b1275		EP	OH	PJM WEST		0	8.8	b1275	b1275	Planned
743	b1276		EP	OH	PJM WEST		0	5.5	b1276	b1276	Planned
744	b1277		EP		PJM MA		15	3.68	b1277	b1277	Planned
745	b1278		EP		PJM MA		0	0.47	b1278	b1278	Planned
746	b1279		EP	VA	PJM SOUTH		0	9.4	b1279	b1279	Planned
747	b1280		EP		PJM MA		0	3.85	b1280	b1280	Planned
748	b1280.1		EP		PJM MA		0	3.85	b1280	b1280	Planned
749	b1281		EP	OH	PJM WEST		0	33	b1281	#N/A	Planned
750	b1282		EP	OH	PJM WEST		0	34.65	b1282	#N/A	Planned
751	b1283		EP	OH	PJM WEST		1	9.07	b1283	#N/A	Planned
752	b1284		EP		PJM WEST		1	2.35	b1284	#N/A	Planned
753	b1285		EP		PJM WEST		0	0.08	b1285	#N/A	Planned
754	b1286		EP		PJM WEST		0	2.05	b1286	#N/A	Planned
755	b1287		EP		PJM WEST		0	2.05	b1287	#N/A	Planned
756	b1288		EP		PJM WEST		0	0.01	b1288	#N/A	Planned
757	b1289		EP		PJM WEST		0	0.87	b1289	#N/A	Planned
758	b1290		EP		PJM WEST		0	2.89	b1290	#N/A	Planned
759	b1291		EP		PJM WEST		0	0.02	b1291	#N/A	Planned
760	b1292		EP		PJM WEST		0	0.02	b1292	#N/A	Planned
761	b1293		EP		PJM WEST		0	0.01	b1293	#N/A	Planned
762	b1294		UC		PJM WEST		30	0.03	b1294	#N/A	Planned
763	b1295.1		UC		PJM WEST		30	0.03	b1295	#N/A	Planned
764	b1295.2		UC		PJM WEST		30	0.03	b1295	#N/A	Planned
765	b1296.1		EP		PJM WEST		0	0.01	b1296	#N/A	Planned
766	b1296.2		EP		PJM WEST		0	0.01	b1296	#N/A	Planned
767	b1297		EP	OH	PJM WEST		2	23	b1297	#N/A	Planned
768	b1299		EP		PJM WEST		0	0.55	b1299	#N/A	Planned
769	b1300		EP	IL	PJM WEST		0	22	b1300	b1300	Planned
770	b1301	6/9/2011	EP	IL	PJM WEST		0	150	b1301	b1301	Planned
771	b1302		EP		PJM MA		0	0.1	b1302	b1302	Planned
772	b1304.1		EP	NJ	PJM MA		0	650	b1304	b1304	Planned
773	b1304.10		EP	NJ	PJM MA		0	1.5	b1304	b1304	Planned
774	b1304.11		EP	NJ	PJM MA		0	1.5	b1304	b1304	Planned
775	b1304.12		EP	NJ	PJM MA		0	1.5	b1304	b1304	Planned
776	b1304.13		EP	NJ	PJM MA		0	1.5	b1304	b1304	Planned
777	b1304.14		EP	NJ	PJM MA		0	1.5	b1304	b1304	Planned
778	b1304.15		EP	NJ	PJM MA		0	1.5	b1304	b1304	Planned
779	b1304.16		EP	NJ	PJM MA		0	1.5	b1304	b1304	Planned
780	b1304.17		EP	NJ	PJM MA		0	1.5	b1304	b1304	Planned
781	b1304.18		EP	NJ	PJM MA		0	1.5	b1304	b1304	Planned

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
3	Upgrade ID	PJM Required	In Service Date	Location	Task	Equipment	Descriptior	Voltage	Expected R	Last Updated	Trans Own	Study Year	Baseline R	Driver	Initial TEAC Da
782	b1304.19	6/1/2015	6/1/2015	Newport R	Replace	Breaker	Replace Ne	230		5/23/2011	PSEG			Short Circu	5/12/2011
783	b1304.2	6/1/2015		Bergen	Expand	Substation	Expand exi	230		2/8/2011	PSEG				9/8/2010
784	b1304.20	6/1/2015	6/1/2015	Athenia	Upgrade	Breaker	Rebuild Atl	230		5/23/2011	PSEG			Short Circu	5/12/2011
785	b1304.21	6/1/2015	6/1/2015	Bergen	Upgrade	Breaker	Rebuild Be	230		5/23/2011	PSEG			Short Circu	5/12/2011
786	b1304.3	6/1/2015		Bergen	Build	Undergrou	Build secor	230		2/8/2011	PSEG				9/8/2010
787	b1304.4	6/1/2015		Hudson	Build	Undergrou	Build secor	230		2/8/2011	PSEG				9/8/2010
788	b1304.5	6/1/2015	6/1/2015	Athenia	Replace	Breaker	Replace At	230		5/23/2011	PSEG			Short Circu	5/12/2011
789	b1304.6	6/1/2015	6/1/2015	Athenia	Replace	Breaker	Replace At	230		5/23/2011	PSEG			Short Circu	5/12/2011
790	b1304.7	6/1/2015	6/1/2015	South Wat	Replace	Breaker	Replace So	230		5/23/2011	PSEG			Short Circu	5/12/2011
791	b1304.8	6/1/2015	6/1/2015	South Wat	Replace	Breaker	Replace So	230		5/23/2011	PSEG			Short Circu	5/12/2011
792	b1304.9	6/1/2015	6/1/2015	South Wat	Replace	Breaker	Replace So	230		5/23/2011	PSEG			Short Circu	5/12/2011
793	b1306	10/1/2011	10/1/2011	Endless Ca	Reconfigur	Bus	Reconfigure 115kV bus at Endless			5/24/2011	Dominion			Category B	8/25/2010
794	b1308	3/31/2012	3/31/2012	Gordonsvil	Move	Shunts	Improve LSE's power factor factor			5/24/2011	Dominion			Category B	8/25/2010
795	b1309	6/1/2013	5/30/2013	Lakeside/N	Install	Line	Install a 23	230		5/24/2011	Dominion			Category C	8/25/2010
796	b1310	6/1/2013	6/1/2013	Broadnax	Install	Breaker	Install a 11	115		5/24/2011	Dominion			Dominion (	8/25/2010
797	b1311	5/1/2014	5/1/2014	Cranes Cor	Install	Breaker	Install a 23	230		5/24/2011	Dominion			Category C	8/25/2010
798	b1312	6/1/2014	6/1/2014	Hollymead	Loop in/ou	Line	Loop the 2	230		5/13/2011	Dominion			Dominion (	8/25/2010
799	b1313	6/1/2014	6/1/2014	Chesterfiel	Resag	Line	Resag wire to 125C from Chesterf			5/13/2011	Dominion			Category B	8/25/2010
800	b1314	6/1/2014	6/1/2014	Chesterfiel	Rebuild	Line	Rebuild the 6.8 mile line #100 fro			5/24/2011	Dominion			N-1-1 Ther	8/25/2010
801	b1315	6/1/2014	6/1/2014	Trowbridge	Convert	Line	Convert line #64 Trowbridge to W			5/24/2011	Dominion			N-1-1 Volta	8/25/2010
802	b1316	6/1/2014	6/1/2014	Battleboro	Rebuild	Line	Rebuild 10.7 miles of 115 kV line			5/24/2011	Dominion			Category B	8/25/2010
803	b1317	5/1/2015	5/1/2015	Elmont/Fo	Correct	Power Fact	LSE load power factor on the #47			5/24/2011	Dominion			Category B	8/25/2010
804	b1318	5/1/2015	5/1/2015	Acca	Install	Breaker	Install a 115 kV bus tie breaker at			5/24/2011	Dominion			Category C	8/25/2010
805	b1319	5/1/2015	5/1/2015	Northwest	Resag	Line	Resag line #222 to 150 C and upg			5/24/2011	Dominion			N-1-1 Ther	8/25/2010
806	b1320	5/1/2015	5/1/2015	Southwest	Install	Capacitor	Install a 230 kV, 150 MVAR capac			5/24/2011	Dominion			N-1-1	8/25/2010
807	b1321	6/1/2015	6/1/2015	North Anna	Build	Line	Build a nev	230		5/24/2011	Dominion			Cat B and (	8/25/2010
808	b1322	6/1/2015	6/1/2015	Dooms/She	Rebuild	Line	Rebuild the 39 Line (Dooms - She			5/24/2011	Dominion			Category C	8/25/2010
809	b1323	6/1/2013	6/1/2013	Staunton	Install	Transform	Install a 22	230/115		5/24/2011	Dominion			Cat B and (	8/25/2010
810	b1324	6/1/2015	6/1/2015	Oak Ridge	Install	Capacitor	Install a 115 kV capacitor bank at			5/24/2011	Dominion			Cat B and (	8/25/2010
811	b1325	6/1/2015	6/1/2015	Winfall/Eliz	Rebuild	Line	Rebuild 15 miles of line #2020 Wi			5/24/2011	Dominion			N-1-1 Ther	8/25/2010
812	b1326	6/1/2015	6/1/2015	Kitty Hawk	Install	Transform	Install a thi	230/115		5/24/2011	Dominion			Cat B	8/25/2010
813	b1327	6/1/2015	6/1/2015	Kerr Dam/I	Rebuild	Line	Rebuild the 20 mile section of line			5/24/2011	Dominion			Cat B Therı	8/25/2010
814	b1328	5/1/2015	5/1/2015	Possum/Du	Uprate	Line	Uprate the 3.63 mile line section			5/24/2011	Dominion			Cat B	8/25/2010
815	b1329	5/1/2015	5/1/2015	Sterling Pa	Install	Breakers	Install line-tie breakers at Sterling			5/24/2011	Dominion			Cat C	8/25/2010
816	b1330	5/1/2014	5/1/2014	Dulles	Install	Ring Bus	Install a five breaker ring bus at th			5/24/2011	Dominion			Cat C	8/25/2010
817	b1331	6/1/2015	6/1/2015	Shawboro/	Build	Line	Build a 230 kV line from Shawbor			5/24/2011	Dominion			Cat C	8/25/2010
818	b1332	5/31/2018	5/31/2015	Common B	Build	Line	Build Common Branch to Nokesvi			5/24/2011	Dominion			Cat B and (	8/25/2010
819	b1333	6/1/2015	6/1/2015	Possum Po	Replace	Breaker	Advance n1728 (Replace Possum			5/24/2011	Dominion			Short Circu	10/28/2010
820	b1334	6/1/2015	6/1/2015	Ox	Replace	Breaker	Advance n1748 (Replace Ox 230 k			5/24/2011	Dominion			Short Circu	10/28/2010
821	b1335	6/1/2012	6/1/2015	Ox	Replace	Breaker	Advance n1749 (Replace Ox 230 k			5/24/2011	Dominion			Short Circu	10/28/2010
822	b1336	6/1/2015	6/1/2015	Ox	Replace	Breaker	Advance n1750 (Replace Ox 230 k			5/24/2011	Dominion			Short Circu	10/28/2010
823	b1337	6/1/2015	6/1/2015	Ox	Replace	Breaker	Advance n1751 (Replace Ox 230 k			5/24/2011	Dominion			Short Circu	10/28/2010
824	b1338	6/1/2012	6/1/2015	Printz	Replace	Breaker	Replace Printz 230 kV breaker '22			5/17/2011	PECO			Short Circu	10/28/2010
825	b1339	6/1/2012	6/1/2015	Printz	Replace	Breaker	Replace Printz 230 kV breaker '31			5/17/2011	PECO			Short Circu	10/28/2010
826	b1340	6/1/2012	6/1/2015	Printz	Replace	Breaker	Replace Printz 230 kV breaker '21			5/17/2011	PECO			Short Circu	10/28/2010
827	b1341	6/1/2015	6/1/2015	Airpark	Install	Capacitor	Install a 25	138		5/24/2011	ATSI			N-1-1 Volta	10/6/2010
828	b1342	6/1/2015	6/1/2015	Sharon	Install	Capacitor	Install a 50	138		5/24/2011	ATSI			N-1-1 Volta	10/6/2010
829	b1343	6/1/2015	6/1/2015	Collier	Replace	Breaker	Replace Collier 138 kV breaker '2-			1/20/2011	DL			Short Circu	10/28/2010
830	b1344	6/1/2015	6/1/2015	St Joe Resc	Replace	Breaker	Replace St Joe Resources 138 kV I			1/20/2011	DL			Short Circu	10/28/2010
831	b1345	6/1/2012	6/1/2012	Martinsvill	Install	Ring bus	Install Martinsville 4-breaker 34.5			5/24/2011	JCPL			FE Criteria	10/28/2010
832	b1346	6/1/2012	6/1/2012	Franklin/H	Reconduct	Line	Reconductor the Franklin – Humb			5/24/2011	JCPL			FE Criteria	10/28/2010
833	b1348	6/1/2011	6/1/2011	Newton/N	Upgrade	Line	Upgrade the Newton – North Nev			5/24/2011	JCPL			FE Criteria	10/28/2010
834	b1349	6/1/2012	6/1/2012	Newton/W	Reconduct	Line	Reconductor 5.2 miles of the Ne			5/24/2011	JCPL			FE Criteria	10/28/2010
835	b1350	6/1/2011	6/1/2011	East Flemir	Upgrade	Line	Upgrade the East Flemington – Fl			5/24/2011	JCPL			FE Criteria	10/28/2010
836	b1351	6/1/2013	6/1/2013	Larrabee	Add	Breaker	Add 34.5 kV breaker on the Larra			5/24/2011	JCPL			FE Criteria	10/28/2010
837	b1354	6/1/2012	6/1/2011	Rockaway	Add	Breakers	Add four 34.5 kV breakers and re			5/24/2011	JCPL			FE Criteria	10/28/2010
838	b1355	6/1/2012	6/1/2012	Riverdale/I	Build	Line	Build a new second 3.3 miles 34.5			5/24/2011	JCPL			FE Criteria	10/28/2010
839	b1357	6/1/2013	6/1/2013	Larrabee/H	Build	Line	Build 10.2 miles new 34.5 kV line			5/24/2011	JCPL			FE Criteria	10/28/2010
840	b1360	6/1/2012	6/1/2012	Englishtow	Reconduct	Line	Reconductor 0.7 miles of the Eng			5/24/2011	JCPL			FE Criteria	10/28/2010
841	b1361	6/1/2012	6/1/2012	Oceanview	Reconduct	Line	Reconductor the Oceanview – Ne			5/24/2011	JCPL			FE Criteria	10/28/2010
842	b1362	6/1/2011	6/1/2011	Wood Stre	Install	Capacitor	Install 23.8 MVAR capacitor at W			5/24/2011	ME			FE Criteria	10/28/2010
843	b1364	6/1/2011	6/1/2011	South Lena	Upgrade	Bus Condu	Improve the rating of the South L			5/24/2011	ME			FE Criteria	10/28/2010
844	b1365	6/1/2011	6/1/2011	Middletow	Reconduct	Line	Reconductor the Middletown Jun			5/24/2011	ME			FE Criteria	10/28/2010
845	b1366	6/1/2012	6/1/2012	Collins/Cly	Reconduct	Line	Reconductor the Collins –Cly 115			5/24/2011	ME			FE Criteria	10/28/2010
846	b1366.1	6/1/2012	6/1/2012	Cly/Newbe	Reconduct	Line	Reconductor the Cly - Newberry 1			5/24/2011	ME			FE Criteria	10/28/2010
847	b1367	6/1/2011	6/1/2011	Cambria Sl	Replace	Transform	Replace the Cambria Slope 115/4			6/2/2011	Penelec			FE Criteria	10/28/2010
848	b1369	6/1/2011	12/31/2011	Westfall	Replace	Bus Condu	Replace the 4/0 CU substation co			5/24/2011	Penelec			FE Criteria	10/28/2010
849	b1370	6/1/2011	12/31/2011	Westfall	Replace	Transform	Install a 3rd 115/46 kV transform			5/24/2011	Penelec			FE Criteria	10/28/2010
850	b1373	6/1/2012	6/1/2012	Ashtabula	Reconfigur	Substation	Re-configure the Erie West 345 k			5/24/2011	Penelec			FE Criteria	10/28/2010
851	b1374	6/1/2013	6/1/2013	Raritan Riv	Replace	Wave Trap	Replace wave traps at Raritan Riv			5/24/2011	JCPL				10/28/2010
852	b1374.1	6/1/2013	6/1/2013	Deep Run	Replace	Wave Trap	Replace wave traps at Deep Run 1			5/24/2011	JCPL				10/28/2010

	A	P	Q	R	S	T	U	V	W	X	Y
3	Upgrade ID	Latest TEAC Date	Status	State	Region	County	Percent Co	Cost Estima	Project ID	In Schedule	Source
782	b1304.19		EP	NJ	PJM MA		0	0.6	b1304	b1304	Planned
783	b1304.2		EP	NJ	PJM MA		0	0	b1304	b1304	Planned
784	b1304.20		EP	NJ	PJM MA		0	21	b1304	b1304	Planned
785	b1304.21		EP	NJ	PJM MA		0	0	b1304	b1304	Planned
786	b1304.3		EP	NJ	PJM MA		0	0	b1304	b1304	Planned
787	b1304.4		EP	NJ	PJM MA		0	50	b1304	b1304	Planned
788	b1304.5		EP	NJ	PJM MA		0	1.5	b1304	b1304	Planned
789	b1304.6		EP	NJ	PJM MA		0	1.5	b1304	b1304	Planned
790	b1304.7		EP	NJ	PJM MA		0	1.5	b1304	b1304	Planned
791	b1304.8		EP	NJ	PJM MA		0	1.5	b1304	b1304	Planned
792	b1304.9		EP	NJ	PJM MA		0	1.5	b1304	b1304	Planned
793	b1306		EP		PJM SOUTH		0	0.5	b1306	b1306	Planned
794	b1308		EP		PJM SOUTH		0	0.5	b1308	b1308	Planned
795	b1309		EP	VA	PJM SOUTH		0	21	b1309	b1309	Planned
796	b1310		EP		PJM SOUTH		0	0.5	b1310	b1310	Planned
797	b1311		EP		PJM SOUTH		0	1.1	b1311	b1311	Planned
798	b1312	3/3/2011	EP	VA	PJM SOUTH		10	41	b1312	b1312	Planned
799	b1313	3/3/2011	EP		PJM SOUTH		10	8.9	b1313	b1313	Planned
800	b1314		EP	VA	PJM SOUTH		10	8	b1314	b1314	Planned
801	b1315		EP	NC	PJM SOUTH		0	23	b1315	b1315	Planned
802	b1316		EP	NC	PJM SOUTH		0	11	b1316	b1316	Planned
803	b1317		EP		PJM SOUTH		0	0.5	b1317	b1317	Planned
804	b1318		EP		PJM SOUTH		0	0.5	b1318	b1318	Planned
805	b1319		EP		PJM SOUTH		0	1.1	b1319	b1319	Planned
806	b1320		EP		PJM SOUTH		0	1.3	b1320	b1320	Planned
807	b1321		EP	VA	PJM SOUTH		10	70	b1321	b1321	Planned
808	b1322		EP	VA	PJM SOUTH		0	100	b1322	b1322	Planned
809	b1323		EP	VA	PJM SOUTH		0	16.5	b1323	b1323	Planned
810	b1324		EP		PJM SOUTH		0	3	b1324	b1324	Planned
811	b1325		EP	NC	PJM SOUTH		0	18	b1325	b1325	Planned
812	b1326		EP	NC	PJM SOUTH		0	8.1	b1326	b1326	Planned
813	b1327		EP	VA	PJM SOUTH		0	20	b1327	b1327	Planned
814	b1328		EP	VA	PJM SOUTH		0	5.5	b1328	b1328	Planned
815	b1329		EP		PJM SOUTH		0	1	b1329	b1329	Planned
816	b1330		EP	VA	PJM SOUTH		0	6	b1330	b1330	Planned
817	b1331		EP	NC	PJM SOUTH		0	23.3	b1331	b1331	Planned
818	b1332		EP	VA	PJM SOUTH		0	40	b1332	b1332	Planned
819	b1333		EP		PJM SOUTH		0	0.03	b1333	b1333	Planned
820	b1334		EP		PJM SOUTH		0	0.03	b1334	b1334	Planned
821	b1335		EP		PJM SOUTH		0	0.03	b1335	b1335	Planned
822	b1336		EP		PJM SOUTH		0	0.03	b1336	b1336	Planned
823	b1337		EP		PJM SOUTH		0	0.03	b1337	b1337	Planned
824	b1338		EP	PA	PJM MA		0	0.5	b1338	b1338	Planned
825	b1339		EP	PA	PJM MA		0	0.5	b1339	b1339	Planned
826	b1340		EP	PA	PJM MA		0	0.5	b1340	b1340	Planned
827	b1341		EP	OH	PJM WEST		0	1.5	b1341	#N/A	Planned
828	b1342		EP	PA	PJM WEST		0	1.32	b1342	#N/A	Planned
829	b1343		EP		PJM WEST		0	0.36	b1343	b1343	Planned
830	b1344		EP		PJM WEST		0	0.36	b1344	b1344	Planned
831	b1345		EP		PJM MA		13	2.82	b1345	b1345	Planned
832	b1346		EP		PJM MA		10	3.98	b1346	b1346	Planned
833	b1348		UC		PJM MA		50	0.09	b1348	b1348	Planned
834	b1349		EP		PJM MA		0	0.93	b1349	b1349	Planned
835	b1350		UC		PJM MA		50	0.13	b1350	b1350	Planned
836	b1351		EP		PJM MA		1	0.25	b1351	b1351	Planned
837	b1354		UC		PJM MA		80	1.46	b1354	b1354	Planned
838	b1355		EP		PJM MA		10	2.29	b1355	b1355	Planned
839	b1357		EP	NJ	PJM MA		13	9.48	b1357	b1357	Planned
840	b1360		EP		PJM MA		3	0.42	b1360	b1360	Planned
841	b1361		EP		PJM MA		3	0.44	b1361	b1361	Planned
842	b1362		UC		PJM MA		30	0.52	b1362	b1362	Planned
843	b1364		EP		PJM MA		25	0.03	b1364	b1364	Planned
844	b1365		UC		PJM MA		55	0.34	b1365	b1365	Planned
845	b1366		EP		PJM MA		10	2.39	b1366	b1366	Planned
846	b1366.1		EP		PJM MA		0	0	b1366	b1366	Planned
847	b1367		EP		PJM MA		25	1.26	b1367	b1367	Planned
848	b1369		EP		PJM MA		12	0.03	b1369	b1369	Planned
849	b1370		EP		PJM MA		15	3.83	b1370	b1370	Planned
850	b1373		EP		PJM MA		0	0.96	b1373	b1373	Planned
851	b1374		EP				0	0.18	b1374	b1374	Planned
852	b1374.1		EP				0	0	b1374	b1374	Planned

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
3	Upgrade ID	PJM Required	In Service Date	Location	Task	Equipment	Descriptior	Voltage	Expected R	Last Updated	Trans Own	Study Year	Baseline R	Driver	Initial TEAC Da
853	b1374.2	6/1/2013	6/1/2013	Raritan Riv	Replace	Wave Trap	Replace wave traps at Raritan Riv			5/24/2011	JCPL				10/28/2010
854	b1374.3	6/1/2013	6/1/2013	Deep Run	Replace	Wave Trap	Replace wave traps at Deep Run :			5/24/2011	JCPL				10/28/2010
855	b1375	6/1/2011	6/1/2012	Roanoke	Replace	Breaker	Replace Roanoke 138 kV breaker			3/10/2011	AEP			Short Circu	10/28/2010
856	b1376	6/1/2011	6/1/2012	Roanoke	Replace	Breaker	Replace Roanoke 138 kV breaker			3/10/2011	AEP			Short Circu	10/28/2010
857	b1377	6/1/2011	6/1/2012	Roanoke	Replace	Breaker	Replace Roanoke 138 kV breaker			3/10/2011	AEP			Short Circu	10/28/2010
858	b1378	6/1/2011	6/1/2012	Roanoke	Replace	Breaker	Replace Roanoke 138 kV breaker			3/10/2011	AEP			Short Circu	10/28/2010
859	b1379	6/1/2011	6/1/2012	Roanoke	Replace	Breaker	Replace Roanoke 138 kV breaker			3/10/2011	AEP			Short Circu	10/28/2010
860	b1380	6/1/2011	6/1/2012	Roanoke	Replace	Breaker	Replace Roanoke 138 kV breaker			3/10/2011	AEP			Short Circu	10/28/2010
861	b1381	6/1/2011	5/31/2011	Olive	Replace	Breaker	Replace Olive 345 kV breaker 'E'			3/10/2011	AEP			Short Circu	10/28/2010
862	b1382	6/1/2011	5/31/2011	Olive	Replace	Breaker	Replace Olive 138 kV breaker 'R2'			3/10/2011	AEP			Short Circu	10/28/2010
863	b1383	6/1/2015		502 Junctic	Install	Transform	Install 2nd	500/138		2/8/2011	APS			N-1-1 Ther	10/6/2010
864	b1384	6/1/2015		Bedington/	Reconduct	Line	Reconduct	138		12/8/2010	APS			N-1-1 Ther	10/6/2010
865	b1385	6/1/2015		Halfway/Pa	Reconduct	Line	Reconduct	138		12/8/2010	APS			N-1-1 Ther	10/6/2010
866	b1386	6/1/2015		Double Tol	Reconduct	Line	Reconduct	138		2/8/2011	APS			N-1-1 Ther	10/6/2010
867	b1387	6/1/2015		Double Tol	Reconduct	Line	Reconduct	138		2/8/2011	APS			N-1-1 Ther	10/6/2010
868	b1388	6/1/2015		Feagans M	Reconduct	Line	Reconduct	138		12/8/2010	APS			N-1-1 Ther	10/6/2010
869	b1389	6/1/2015		Bens Run/S	Reconduct	Line	Reconduct	138		2/8/2011	APS			N-1-1 Ther	10/6/2010
870	b1390	6/1/2015	12/1/2011	Opequon	Replace	Breaker	Replace Bu	138		3/11/2011	APS			N-1-1 Ther	10/6/2010
871	b1391	6/1/2015		Gore	Replace	Line Trap	Replace Lir	138		12/8/2010	APS			N-1-1 Ther	10/6/2010
872	b1392	6/1/2015		Belmont/T	Replace	Structures	Replace str	138		12/8/2010	APS			N-1-1 Ther	10/6/2010
873	b1393	6/1/2015		Kingwood/	Replace	Structures	Replace str	138		12/8/2010	APS			N-1-1 Ther	10/6/2010
874	b1395	6/1/2015		Kittanning	Upgrade	Terminal E	Upgrade Te	138		12/8/2010	APS			N-1-1 Ther	10/6/2010
875	b1396	6/1/2015	5/31/2015	Lewis	Replace	Breaker	Replace Lewis 138 kV breaker 'L'			1/20/2011	AEC			Short Circu	10/28/2010
876	b1398	6/1/2015					Build two new parallel undergrou			2/8/2011	PSEG				10/28/2010
877	b1398.1	6/1/2015					Install shunt reactor at Glouceste			2/8/2011	PSEG				10/28/2010
878	b1398.12	6/1/2015	6/1/2015	Graysferry	Replace	Breaker	Replace Gr	230		4/20/2011	PECO			Short Circu	3/10/2011
879	b1398.13	6/1/2015	6/1/2015	Peach Bott	Upgrade	Breaker	Upgrade Pe	230		4/20/2011	PECO			Short Circu	3/10/2011
880	b1398.14	6/1/2015	6/1/2015	Whitpain	Replace	Breaker	Replace W	230		4/20/2011	PECO			Short Circu	3/10/2011
881	b1398.15	6/1/2015	6/1/2015	Gloucester	Replace	Breaker	Replace Gl	230		5/23/2011	PSEG			Short Circu	5/12/2011
882	b1398.16	6/1/2015	6/1/2015	Gloucester	Replace	Breaker	Replace Gl	230		5/23/2011	PSEG			Short Circu	5/12/2011
883	b1398.17	6/1/2015	6/1/2015	Gloucester	Replace	Breaker	Replace Gl	230		5/23/2011	PSEG			Short Circu	5/12/2011
884	b1398.18	6/1/2015	6/1/2015	Gloucester	Replace	Breaker	Replace Gl	230		5/23/2011	PSEG			Short Circu	5/12/2011
885	b1398.19	6/1/2015	6/1/2015	Gloucester	Replace	Breaker	Replace Gl	230		5/23/2011	PSEG			Short Circu	5/12/2011
886	b1398.2	6/1/2015					Reconfigure the Cuthbert station			2/8/2011	PSEG				10/28/2010
887	b1398.3	6/1/2015					Build a second 230 kV parallel ove			2/8/2011	PSEG				10/28/2010
888	b1398.4	6/1/2015					Reconductor the existing Mickleto			2/8/2011	PSEG				10/28/2010
889	b1398.5	6/1/2015					Reconductor the existing Mickleto			2/8/2011	AEC				10/28/2010
890	b1398.6	6/1/2015	6/1/2015				Reconductor the Camden – Richr			1/25/2011	PECO				10/28/2010
891	b1398.7	6/1/2015					Reconductor the Camden – Richr			2/8/2011	PSEG				10/28/2010
892	b1398.8	6/1/2015	6/1/2015				Reconductor Richmond – Waneet			1/25/2011	PECO				10/28/2010
893	b1399	6/1/2014					Convert the 138 kV path from Ald			2/8/2011	PSEG			N-1-1 Ther	10/28/2010
894	b1399.1	6/1/2014	6/1/2014	Whippany	Upgrade	Breaker	Upgrade th	230		5/24/2011	JCPL			Short Circu	3/10/2011
895	b1400	6/1/2012					Install 230 kV circuit breakers at E			12/15/2010	PSEG				10/28/2010
896	b1401	6/1/2011		Pruntytow	Revise	Breaker	Change reclosing on Pruntytown			3/10/2011	APS	2011		Short Circu	10/28/2010
897	b1402	6/1/2011		Rivesville	Revise	Breaker	Change reclosing on Rivesville 13			3/10/2011	APS	2011		Short Circu	10/28/2010
898	b1403	6/1/2011		Yukon	Revise	Breaker	Change reclosing on Yukon 138 k			3/10/2011	APS	2011		Short Circu	10/28/2010
899	b1404	6/1/2015		Kiski Valley	Replace	Breaker	Replace the Kiski Valley 138 kV br			12/15/2010	APS	2015		Short Circu	10/28/2010
900	b1405	6/1/2015		Armstrong	Revise	Breaker	Change reclosing on Armstrong 1			12/15/2010	APS	2015		Short Circu	10/28/2010
901	b1406	6/1/2015		Armstrong	Revise	Breaker	Change reclosing on Armstrong 1			12/15/2010	APS	2015		Short Circu	10/28/2010
902	b1407	6/1/2015		Armstrong	Revise	Breaker	Change reclosing on Armstrong 1			12/15/2010	APS	2015		Short Circu	10/28/2010
903	b1408	6/1/2015		Weirton	Replace	Breaker	Replace the Weirton 138 kV brea			12/15/2010	APS	2015		Short Circu	10/28/2010
904	b1409	6/1/2015		Cabot	Replace	Breaker	Replace the Cabot 138 kV breake			6/8/2011	APS	2015		Short Circu	10/28/2010
905	b1410	6/1/2011		Salem	Replace	Breaker	Replace Salem 500 kV 63kA			1/20/2011	PSEG	2011		Short Circu	10/28/2010
906	b1411	6/1/2011		Salem	Replace	Breaker	Replace Salem 500 kV 63kA			1/20/2011	PSEG	2011		Short Circu	10/28/2010
907	b1412	6/1/2011		Salem	Replace	Breaker	Replace Salem 500 kV 63kA			1/20/2011	PSEG	2011		Short Circu	10/28/2010
908	b1413	6/1/2011		Salem	Replace	Breaker	Replace Salem 500 kV 63kA			1/20/2011	PSEG	2011		Short Circu	10/28/2010
909	b1414	6/1/2011		Salem	Replace	Breaker	Replace Salem 500 kV 63kA			1/20/2011	PSEG	2011		Short Circu	10/28/2010
910	b1415	6/1/2011		Salem	Replace	Breaker	Replace Salem 500 kV 63kA			1/24/2011	PSEG	2011		Short Circu	10/28/2010
911	b1416	12/31/2011					Perform a sag study on the Desot			12/8/2010	AEP				10/28/2010
912	b1417	12/31/2011					Perform a sag study on the Delaw			12/8/2010	AEP				10/28/2010
913	b1418	12/31/2011					Perform a sag study on the Rockh			12/8/2010	AEP				10/28/2010
914	b1419	12/31/2011					Perform a sag study on the Findla			12/8/2010	AEP				10/28/2010
915	b1420	12/31/2011		Sorenson/I	Sag Study	Line	A sage stuc	345		12/8/2010	AEP			N-1-1 Ther	10/28/2010
916	b1421	12/31/2011					Perform a sag study on the Soren			12/8/2010	AEP				10/28/2010
917	b1422	12/21/2011					Perform a sag study on John Amo			12/8/2010	AEP				10/28/2010
918	b1423	12/31/2011					A sag study will be performed on			12/8/2010	AEP				10/28/2010
919	b1424	12/31/2011					Perform a sag study for the Bento			12/8/2010	AEP				10/28/2010
920	b1425	12/31/2011					Perform a sag study for the East N			12/8/2010	AEP				10/28/2010
921	b1426	12/31/2011					Perform a sag study for the Reuse			12/8/2010	AEP				10/28/2010
922	b1427	12/31/2011					Perform a sag study on Smith Mo			12/8/2010	AEP				10/28/2010
923	b1428	12/31/2011					Perform a sag study on Smith Mo			12/8/2010	AEP				10/28/2010

	A	P	Q	R	S	T	U	V	W	X	Y
3	Upgrade ID	Latest TEAC Date	Status	State	Region	County	Percent Co	Cost Estim	Project ID	In Schedul	Source
853	b1374.2		EP				0	0	b1374	b1374	Planned
854	b1374.3		EP				0	0	b1374	b1374	Planned
855	b1375		EP		PJM WEST		0	0.8	b1375	b1375	Planned
856	b1376		EP		PJM WEST		0	0.8	b1376	b1376	Planned
857	b1377		EP		PJM WEST		0	0.8	b1377	b1377	Planned
858	b1378		EP		PJM WEST		0	0.8	b1378	b1378	Planned
859	b1379		EP		PJM WEST		0	0.8	b1379	b1379	Planned
860	b1380		EP		PJM WEST		0	0.8	b1380	b1380	Planned
861	b1381		EP		PJM WEST		0	1	b1381	b1381	Planned
862	b1382		EP		PJM WEST		0	1	b1382	b1382	Planned
863	b1383		EP	PA	PJM WEST		0	15	b1383	b1383	Planned
864	b1384		EP	WV			0	1.75	b1384	b1384	Planned
865	b1385		EP	MA			0	4.75	b1385	b1385	Planned
866	b1386		EP	VA	PJM WEST		0	9	b1386	b1386	Planned
867	b1387		EP	VA	PJM WEST		0	9	b1387	b1387	Planned
868	b1388		EP	WV			0	3.5	b1388	b1388	Planned
869	b1389		EP	WV	WV		0	5.8	b1389	b1389	Planned
870	b1390		EP	WV			5	0.25	b1390	b1390	Planned
871	b1391		EP	WV/MA			0	0.25	b1391	b1391	Planned
872	b1392		EP	WV			0	0.5	b1392	b1392	Planned
873	b1393		EP	WV			0	1	b1393	b1393	Planned
874	b1395		EP	PA			0	0.05	b1395	b1395	Planned
875	b1396		EP	NJ	PJM MA		0	0.4	b1396	b1396	Planned
876	b1398		EP	NJ	PJM MA		0	230	b1398	b1398	Planned
877	b1398.1		EP	NJ	PJM MA		0	0	b1398	b1398	Planned
878	b1398.12		EP	PA	PJM MA		0	0.5	b1398	b1398	Planned
879	b1398.13		EP	PA	PJM MA		0	0.25	b1398	b1398	Planned
880	b1398.14		EP	PA	PJM MA		0	0.5	b1398	b1398	Planned
881	b1398.15		EP	NJ	PJM MA		0	0.6	b1398	b1398	Planned
882	b1398.16		EP	NJ	PJM MA		0	0.6	b1398	b1398	Planned
883	b1398.17		EP	NJ	PJM MA		0	0.6	b1398	b1398	Planned
884	b1398.18		EP	NJ	PJM MA		0	0.6	b1398	b1398	Planned
885	b1398.19		EP	NJ	PJM MA		0	0.6	b1398	b1398	Planned
886	b1398.2		EP	NJ	PJM MA		0	0	b1398	b1398	Planned
887	b1398.3		EP	NJ	PJM MA		0	0	b1398	b1398	Planned
888	b1398.4		EP	NJ	PJM MA		0	0	b1398	b1398	Planned
889	b1398.5		EP	NJ	PJM MA		0	5.9	b1398	b1398	Planned
890	b1398.6		EP				0	0.98	b1398	b1398	Planned
891	b1398.7		EP	NJ	PJM MA		0	8	b1398	b1398	Planned
892	b1398.8		EP				0	4	b1398	b1398	Planned
893	b1399		EP	NJ	PJM MA		0	75	b1399	b1399	Planned
894	b1399.1		EP	NJ	PJM MA		0	0.26	b1399	b1399	Planned
895	b1400		EP				0	3	b1400	b1400	Planned
896	b1401		EP		PJM West		0	0	b1401	b1401	Planned
897	b1402		EP		PJM West		0	0	b1402	b1402	Planned
898	b1403		EP		PJM West		0	0	b1403	b1403	Planned
899	b1404		EP		PJM West		0	0.25	b1404	b1404	Planned
900	b1405		EP		PJM West		0	0	b1405	b1405	Planned
901	b1406		EP		PJM West		0	0	b1406	b1406	Planned
902	b1407		EP		PJM West		0	0	b1407	b1407	Planned
903	b1408		EP		PJM West		0	0.25	b1408	b1408	Planned
904	b1409		EP		PJM West		0	0.3	b1409	b1409	Planned
905	b1410		EP		PJM MA		0	1.5	b1410	b1410	Planned
906	b1411		EP		PJM MA		0	1.5	b1411	b1411	Planned
907	b1412		EP		PJM MA		0	1.5	b1412	b1412	Planned
908	b1413		EP		PJM MA		0	1.5	b1413	b1413	Planned
909	b1414		EP		PJM MA		0	1.5	b1414	b1414	Planned
910	b1415		EP		PJM MA		0	1.5	b1415	b1415	Planned
911	b1416		EP				0	0.12	b1416	b1416	Planned
912	b1417		EP				0	0.07	b1417	b1417	Planned
913	b1418		EP				0	0.02	b1418	b1418	Planned
914	b1419		EP				0	0.08	b1419	b1419	Planned
915	b1420		EP	IN			0	0.1	b1420	b1420	Planned
916	b1421		EP				0	0.05	b1421	b1421	Planned
917	b1422		EP				0	0.3	b1422	b1422	Planned
918	b1423		EP				0	0.1	b1423	b1423	Planned
919	b1424		EP				0	0.05	b1424	b1424	Planned
920	b1425		EP				0	0.02	b1425	b1425	Planned
921	b1426		EP				0	0.02	b1426	b1426	Planned
922	b1427		EP				0	0.18	b1427	b1427	Planned
923	b1428		EP				0	0.13	b1428	b1428	Planned

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
3	Upgrade ID	PJM Required	In Service Date	Location	Task	Equipment	Descriptior	Voltage	Expected R	Last Updated	Trans Own	Study Year	Baseline Re	Driver	Initial TEAC Da
924	b1429	12/31/2011					Perform a sag study on Fremont -			12/8/2010	AEP				10/28/2010
925	b1430	6/1/2015					Install a new 138 kV circuit break			12/15/2010	AEP				10/28/2010
926	b1432	12/31/2011					Perform a sag study on the Kenov			12/8/2010	AEP				10/28/2010
927	b1433	6/1/2015					Replace risers in the West Huntin			12/8/2010	AEP				10/28/2010
928	b1434	12/31/2011					Perform a sag study on the line fr			12/8/2010	AEP				10/28/2010
929	b1435	6/1/2015		Sporn	Replace	Riser	Replace th	345		12/8/2010	AEP			Gen Delive	10/28/2010
930	b1436	12/31/2011					Perform a sag study on the Soren			12/8/2010	AEP				10/28/2010
931	b1437	12/31/2011					Perform sag study on Rock Cr. - H			12/8/2010	AEP				10/28/2010
932	b1438	6/1/2015					Replacement of risers at McKinley			12/8/2010	AEP				10/28/2010
933	b1439	6/1/2015					By replacing the risers at Lincoln l			12/8/2010	AEP				10/28/2010
934	b1440	6/1/2015					By replacing the breaker at Lincol			12/15/2010	AEP				10/28/2010
935	b1441	12/31/2011					Replacement of risers at South Si			12/8/2010	AEP				10/28/2010
936	b1442	12/31/2011					Replacement of 954 ACSR conduc			12/8/2010	AEP				10/28/2010
937	b1443	6/1/2015					Station work at Thelma and Busse			12/8/2010	AEP				10/28/2010
938	b1444	12/31/2012					Perform electrical clearance studi			12/8/2010	AEP				10/28/2010
939	b1445	12/31/2012					Perform a sag study on the Addis			12/8/2010	AEP				10/28/2010
940	b1446	12/31/2012					Perform a sag study on the Parke			12/8/2010	AEP				10/28/2010
941	b1447	12/31/2012					Dexter – Elliot tap 138 kV sag che			12/8/2010	AEP				10/28/2010
942	b1448	12/31/2012					Dexter – Meigs 138 kV Electrical (			12/8/2010	AEP				10/28/2010
943	b1449	12/31/2012					Meigs tap – Rutland 138 kV sag cl			12/8/2010	AEP				10/28/2010
944	b1450	12/31/2012					Muskingum – North Muskingum :			12/8/2010	AEP				10/28/2010
945	b1451	12/31/2012					North Newark – Sharp Road 138 I			12/8/2010	AEP				10/28/2010
946	b1452	12/31/2012					North Zanesville – Zanesville 138			12/8/2010	AEP				10/28/2010
947	b1453	12/31/2012					North Zanesville – Powelson and			12/8/2010	AEP				10/28/2010
948	b1454	12/31/2012					Perform an electrical clearance st			12/8/2010	AEP				10/28/2010
949	b1455	12/31/2012					Perform a sag check on the Sunny			12/8/2010	AEP				10/28/2010
950	b1456	12/31/2012		Tidd/West	Electrical C	Line	The Tidd - '	345		12/8/2010	AEP			Common N	10/28/2010
951	b1457	12/31/2012					The Tiltonsville - Windsor 138 kV			12/8/2010	AEP				10/28/2010
952	b1458	6/1/2015					Install three new 345kV breakers			12/15/2010	AEP				10/28/2010
953	b1459	12/31/2012					Several circuits have been de-rate			12/8/2010	AEP				10/28/2010
954	b1460	6/1/2015	6/1/2015	Muskingun	Replace	Risers	Replace 21	345		1/18/2011	AEP			Gen Delive	10/28/2010
955	b1461	6/1/2015					Replace meter, metering CTs and			12/8/2010	AEP				10/28/2010
956	b1462	6/1/2015					Replace relays at both South Cadi			12/8/2010	AEP				10/28/2010
957	b1463	6/1/2015					Reconductor the Bexley – Groves			12/8/2010	AEP				10/28/2010
958	b1464	6/1/2015					Corner 138 kV upgrades			12/8/2010	AEP				10/28/2010
959	b1465.1	6/1/2015		Sullivan	Install	Transform	Add a 3rd	765/345		2/8/2011	AEP			N-1-1 Ther	10/28/2010
960	b1465.2	6/1/2015		Rockport	Replace	Capacitor	Replace th	765		2/8/2011	AEP			N-1-1 Ther	10/28/2010
961	b1465.3	6/1/2015		Rockport/S	Transpose	Line	Transpose	765		2/8/2011	AEP			N-1-1 Ther	10/28/2010
962	b1465.4	6/1/2015		Sullivan/Je	Improve	Switching	Make switc	765		2/8/2011	AEP			N-1-1 Ther	10/28/2010
963	b1465.5	6/1/2015		Sullivan	Change	Switching	765 kV switching changes at Sulliv			2/8/2011	AEP			N-1-1 Ther	10/28/2010
964	b1466.1	6/1/2015					Create an in and out loop at Adar			2/8/2011	AEP				10/28/2010
965	b1466.2	6/1/2015					Upgrade the Adams transformer			2/8/2011	AEP				10/28/2010
966	b1466.3	6/1/2015					At Seaman Station install a new 1			2/8/2011	AEP				10/28/2010
967	b1466.4	6/1/2015					Convert South Central Co-op's Ne			2/8/2011	AEP				10/28/2010
968	b1466.5	6/1/2015					The Seaman – Highland circuit is a			2/8/2011	AEP				10/28/2010
969	b1466.6	6/1/2015					At Highland Station, install a new			2/8/2011	AEP				10/28/2010
970	b1466.7	6/1/2015					Using one of the bays at Highland			2/8/2011	AEP				10/28/2010
971	b1467.1	6/1/2015					Install a 14.4 MVAr Capacitor Ban			12/8/2010	AEP				10/28/2010
972	b1467.2	6/1/2015					Reconfigure the 138 kV bus at Lal			12/8/2010	AEP				10/28/2010
973	b1468.1	6/1/2015					Expand Selma Parker Station and			2/8/2011	AEP				10/28/2010
974	b1468.2	6/1/2015					Rebuild and convert 34.5 kV line t			2/8/2011	AEP				10/28/2010
975	b1468.3	6/1/2015					Retire the 34.5 kV line from Hayn			2/8/2011	AEP				10/28/2010
976	b1469.1	12/1/2012					Conversion of the Newcomerstov			2/8/2011	AEP				10/28/2010
977	b1469.2	12/1/2012					Expansion of the Derwent 69 kV S			2/8/2011	AEP				10/28/2010
978	b1469.3	12/1/2012					Rebuild 11.8 miles of 69 kV line, a			2/8/2011	AEP				10/28/2010
979	b1470.1	6/1/2015					Build a new 138 kV double circuit			2/8/2011	AEP				10/28/2010
980	b1470.2	6/1/2015					Install a new 138/46 kV transforn			2/8/2011	AEP				10/28/2010
981	b1470.3	6/1/2015					Replace 5 Moab's on the Kanawh			2/8/2011	AEP				10/28/2010
982	b1471	12/31/2012					Perform a sag study on the East L			12/8/2010	AEP				10/28/2010
983	b1472	12/31/2012					Perform a sag study on the East L			12/8/2010	AEP				10/28/2010
984	b1473	12/31/2012					Perform a sag study on the East N			12/8/2010	AEP				10/28/2010
985	b1474	12/31/2012					Perform a sag study on the Ohio (			12/8/2010	AEP				10/28/2010
986	b1475	12/31/2012					Perform a sag study on the S73 –			12/8/2010	AEP				10/28/2010
987	b1476	12/31/2012					Perform a sag study on the S73 –			12/8/2010	AEP				10/28/2010
988	b1477	12/31/2013					The Natrium – North Martin 138 l			12/8/2010	AEP				10/28/2010
989	b1478	6/1/2015					Upgrade Strouds Run – Strouds T			12/8/2010	AEP				10/28/2010
990	b1479	6/1/2015					West Hebron station upgrades			12/8/2010	AEP				10/28/2010
991	b1480	12/31/2013					Perform upgrades and a sag study			12/8/2010	AEP				10/28/2010
992	b1481	12/31/2013					Perform a sag study on the West			12/8/2010	AEP				10/28/2010
993	b1482	12/31/2013					Perform a sag study for the Albior			12/8/2010	AEP				10/28/2010
994	b1483	12/31/2013					Sag Study 1 mile of the Clinch Riv			12/8/2010	AEP				10/28/2010

	A	P	Q	R	S	T	U	V	W	X	Y
3	Upgrade ID	Latest TEAC Date	Status	State	Region	County	Percent Co	Cost Estim	Project ID	In Schedul	Source
924	b1429		EP				0	0.17	b1429	b1429	Planned
925	b1430		EP				0	1.5	b1430	b1430	Planned
926	b1432		EP				0	0.05	b1432	b1432	Planned
927	b1433		EP				0	0.1	b1433	b1433	Planned
928	b1434		EP				0	0.5	b1434	b1434	Planned
929	b1435		EP	WV			0	0.3	b1435	b1435	Planned
930	b1436		EP				0	0.2	b1436	b1436	Planned
931	b1437		EP				0	0.3	b1437	b1437	Planned
932	b1438		EP				0	0.15	b1438	b1438	Planned
933	b1439		EP				0	0.05	b1439	b1439	Planned
934	b1440		EP				0	0.55	b1440	b1440	Planned
935	b1441		EP				0	0.3	b1441	b1441	Planned
936	b1442		EP				0	0.5	b1442	b1442	Planned
937	b1443		EP				0	0.2	b1443	b1443	Planned
938	b1444		EP				0	0.1	b1444	b1444	Planned
939	b1445		EP				0	0.08	b1445	b1445	Planned
940	b1446		EP				0	0.01	b1446	b1446	Planned
941	b1447		EP				0	0.07	b1447	b1447	Planned
942	b1448		EP				0	0.01	b1448	b1448	Planned
943	b1449		EP				0	0.02	b1449	b1449	Planned
944	b1450		EP				0	0.01	b1450	b1450	Planned
945	b1451		EP				0	0.08	b1451	b1451	Planned
946	b1452		EP				0	0.02	b1452	b1452	Planned
947	b1453		EP				0	0.13	b1453	b1453	Planned
948	b1454		EP				0	0.06	b1454	b1454	Planned
949	b1455		EP				0	0.03	b1455	b1455	Planned
950	b1456		EP	WV/OH			0	0.08	b1456	b1456	Planned
951	b1457		EP				0	0.02	b1457	b1457	Planned
952	b1458		EP				0	0.08	b1458	b1458	Planned
953	b1459		EP				0	0.01	b1459	b1459	Planned
954	b1460	1/6/2011	EP	OH			0	0.5	b1460	b1460	Planned
955	b1461		EP				0	0.4	b1461	b1461	Planned
956	b1462		EP				0	0.5	b1462	b1462	Planned
957	b1463		EP				0	2.9	b1463	b1463	Planned
958	b1464		EP				0	0.15	b1464	b1464	Planned
959	b1465.1		EP	IN	PJM WEST		0	37	b1465	b1465	Planned
960	b1465.2		EP	IN	PJM WEST		0	16	b1465	b1465	Planned
961	b1465.3		EP	IN	PJM WEST		0	10	b1465	b1465	Planned
962	b1465.4		EP	IN	PJM WEST		0	7.5	b1465	b1465	Planned
963	b1465.5		EP	IN	PJM WEST		0	29.5	b1465	b1465	Planned
964	b1466.1		EP	OH	PJM WEST		0	13.5	b1466	b1466	Planned
965	b1466.2		EP	OH	PJM WEST		0	0	b1466	b1466	Planned
966	b1466.3		EP	OH	PJM WEST		0	0	b1466	b1466	Planned
967	b1466.4		EP	OH	PJM WEST		0	0	b1466	b1466	Planned
968	b1466.5		EP	OH	PJM WEST		0	0	b1466	b1466	Planned
969	b1466.6		EP	OH	PJM WEST		0	0	b1466	b1466	Planned
970	b1466.7		EP	OH	PJM WEST		0	0	b1466	b1466	Planned
971	b1467.1		EP				0	3	b1467	b1467	Planned
972	b1467.2		EP				0	0	b1467	b1467	Planned
973	b1468.1		EP	IN	PJM WEST		0	8	b1468	b1468	Planned
974	b1468.2		EP	IN	PJM WEST		0	0	b1468	b1468	Planned
975	b1468.3		EP	IN	PJM WEST		0	0	b1468	b1468	Planned
976	b1469.1		EP	OH	PJM WEST		0	23	b1469	b1469	Planned
977	b1469.2		EP	OH	PJM WEST		0	0	b1469	b1469	Planned
978	b1469.3		EP	OH	PJM WEST		0	0	b1469	b1469	Planned
979	b1470.1		EP	WV	PJM WEST		0	8.5	b1470	b1470	Planned
980	b1470.2		EP	WV	PJM WEST		0	0	b1470	b1470	Planned
981	b1470.3		EP	WV	PJM WEST		0	0	b1470	b1470	Planned
982	b1471		EP				0	0.02	b1471	b1471	Planned
983	b1472		EP				0	0.14	b1472	b1472	Planned
984	b1473		EP				0	0.15	b1473	b1473	Planned
985	b1474		EP				0	0.04	b1474	b1474	Planned
986	b1475		EP				0	0.08	b1475	b1475	Planned
987	b1476		EP				0	0.03	b1476	b1476	Planned
988	b1477		EP				0	0.1	b1477	b1477	Planned
989	b1478		EP				0	0.06	b1478	b1478	Planned
990	b1479		EP				0	0.05	b1479	b1479	Planned
991	b1480		EP				0	0.2	b1480	b1480	Planned
992	b1481		EP				0	0.07	b1481	b1481	Planned
993	b1482		EP				0	0.09	b1482	b1482	Planned
994	b1483		EP				0	0.22	b1483	b1483	Planned

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
3	Upgrade ID	PJM Required	In Service Date	Location	Task	Equipment	Descriptior	Voltage	Expected R	Last Updated	Trans Own	Study Year	Baseline Re	Driver	Initial TEAC Da
995	b1484	12/31/2013					Perform a sag study on the Hacie			12/8/2010	AEP				10/28/2010
996	b1485	12/31/2013					Perform a sag study on the Jacksc			12/8/2010	AEP				10/28/2010
997	b1486	12/31/2013					The Matt Funk - Poages Mill – Sta			12/8/2010	AEP				10/28/2010
998	b1487	12/31/2013					Perform a sag study on the New (			12/8/2010	AEP				10/28/2010
999	b1488	12/31/2013					Perform a sag study on the Olive ·			12/8/2010	AEP				10/28/2010
1000	b1489	12/31/2013					A sag study must be performed fc			12/8/2010	AEP				10/28/2010
1001	b1490.1	6/1/2015					Establish a new 138/69 kV Butler			2/8/2011	AEP				10/28/2010
1002	b1490.2	6/1/2015					Build a new 14 mile 138 kV line fr			2/8/2011	AEP				10/28/2010
1003	b1490.3	6/1/2015					Replace the existing 40 MVA 138/			2/8/2011	AEP				10/28/2010
1004	b1490.4	6/1/2015					Improve the switching arrangeme			2/8/2011	AEP				10/28/2010
1005	b1491	12/31/2013					Replace bus and risers at Thelma			12/8/2010	AEP				10/28/2010
1006	b1492	6/1/2015					Reconductor 0.64 miles of the Gle			12/8/2010	AEP				10/28/2010
1007	b1493	12/31/2013					Perform a sag study for the Bellef			12/8/2010	AEP				10/28/2010
1008	b1494	12/31/2013					Perform a sag study for the North			12/8/2010	AEP				10/28/2010
1009	b1495	6/1/2015		Baker	Install	Transform	Add an Ad	765/345		2/8/2011	AEP			N-1-1 Ther	10/28/2010
1010	b1496	6/1/2015					Replace 138 kV bus and risers at J			12/8/2010	AEP				10/28/2010
1011	b1497	6/1/2015					Replace 138 kV bus and risers at I			12/8/2010	AEP				10/28/2010
1012	b1498	6/1/2015					Replace 138 kV risers at Wurno St			12/8/2010	AEP				10/28/2010
1013	b1499	12/31/2013					Perform a sag study on Sporn A -			12/8/2010	AEP				10/28/2010
1014	b1500	12/31/2013					The North East Canton - Wagenha			12/8/2010	AEP				10/28/2010
1015	b1501	12/31/2013					The Moseley - Reusens 138 kV cir			12/8/2010	AEP				10/28/2010
1016	b1502	6/1/2015					Reconductor the Conesville East -			12/8/2010	AEP				10/28/2010
1017	b1503.1	5/1/2013					Network NIVO and Waxpool Subs			2/25/2011	Dominion				10/28/2010
1018	b1503.2	5/1/2013					Construct a 230 kV underground			2/25/2011	Dominion				10/28/2010
1019	b1503.3	5/1/2013					Install a four-breaker, 230 kV ring			2/25/2011	Dominion				10/28/2010
1020	b1503.4	5/1/2013					Network Waxpool Substation by (			2/25/2011	Dominion				10/28/2010
1021	b1504.1	5/1/2013					Re-build Lines #134 and #163 for			12/8/2010	Dominion				10/28/2010
1022	b1504.2	5/1/2013					Install a tie-switch between the li			12/8/2010	Dominion				10/28/2010
1023	b1505	5/1/2013					Loop Line 2095 approximately 20			2/25/2011	Dominion				10/28/2010
1024	b1506.1	5/1/2013					At Gainesville Substation, create t			12/15/2010	Dominion				10/28/2010
1025	b1506.2	5/1/2013					Upgrade Line 124 (radial from Lou			12/8/2010	Dominion				10/28/2010
1026	b1506.3	5/1/2013					Install two additional 230 kV brea			12/15/2010	Dominion				10/28/2010
1027	b1506.4	5/1/2013					Convert NOVEC's Gainesville-Whe			12/8/2010	Dominion				10/28/2010
1028	b1507	6/1/2020	6/1/2015	Mt. Storm	Upgrade	Terminal E	Terminal Equipment upgrade at M			4/21/2011	Dominion			Operationa	10/28/2010
1029	b1507.1	6/1/2020	6/1/2015	Mt. Storm/	Rebuild	Line	Mt Storm - Doubs transmission lir			4/21/2011	Dominion			Operationa	10/28/2010
1030	b1507.2	6/1/2020	6/1/2015	Doubs	Upgrade	Terminal E	Terminal Equipment upgrade at D			3/31/2011	APS			Operationa	10/28/2010
1031	b1507.3	6/1/2020	6/1/2015	Mt. Storm/	Rebuild	Line	Mt Storm - Doubs transmission lir			3/31/2011	APS			Operationa	10/28/2010
1032	b1508.1	6/1/2015	6/1/2015				Build a 2nd 230kV Line Harrisonb			4/21/2011	Dominion				10/28/2010
1033	b1508.2	6/1/2015	6/1/2015				Install a 3rd 230-115kV Tx at Endl			5/24/2011	Dominion				10/28/2010
1034	b1508.3	6/1/2015	6/1/2015				Upgrade 115kV shunt capacitor b			5/24/2011	Dominion				10/28/2010
1035	b1510	6/1/2015	12/1/2011	Waverly	Install	Capacitor	Install 59.4	138		3/11/2011	APS			N-1-1	11/10/2010
1036	b1511	6/1/2014	6/1/2014	Bell Road/(	Reconduct	Line	Reconduct	138		1/20/2011	ComEd			N-1-1 Ther	1/6/2011
1037	b1512	6/1/2014	6/1/2014	Davis Creel	Reconduct	Line	Reconduct	138		1/20/2011	ComEd			N-1-1 Ther	1/6/2011
1038	b1513	6/1/2014	6/1/2014	Davis Creel	Reconduct	Line	Reconduct	138		1/20/2011	ComEd			N-1-1 Ther	1/6/2011
1039	b1514	6/1/2014	6/1/2014	Dresden	Replace	Line Trap	Replace lin	138		1/20/2011	ComEd			N-1-1 Ther	1/6/2011
1040	b1515	6/1/2014	6/1/2014	Frankfort/I	Reconduct	Line	Reconduct	138		1/20/2011	ComEd			N-1-1 Ther	1/6/2011
1041	b1516	6/1/2014	6/1/2014	Frontenac/	Reconduct	Line	Reconduct	138		1/20/2011	ComEd			N-1-1 Ther	1/6/2011
1042	b1517	6/1/2014	6/1/2014	Hanover/T	Replace	Cicuit Swit	Replace cir	138		1/20/2011	ComEd			N-1-1 Ther	1/6/2011
1043	b1518	6/1/2014	6/1/2014	Lisle	Install	Auto Trans	Install a 4tl	345/138		1/20/2011	ComEd			N-1-1 Ther	1/6/2011
1044	b1519.1	6/1/2014	1/1/2012	Crawford-F	Build	Line	New 345 k'	345		5/24/2011	ComEd			N-1-1 Ther	1/6/2011
1045	b1519.2	6/1/2014	1/1/2012	Fisk	Install	Autotransf	Two 345/1	345/138		5/24/2011	ComEd			N-1-1 Ther	1/6/2011
1046	b1519.3	6/1/2014	1/1/2012	Fisk	Install	Cap Bank	Two 138 k\	138		5/24/2011	ComEd			N-1-1 Ther	1/6/2011
1047	b1520	6/1/2013	6/1/2013	Raritan Riv	Upgrade	Breaker	Upgrade oı	230		4/20/2011	GenOn/Reliant			Short Circu	3/10/2011
1048	b1521	6/1/2014	6/1/2014	Bergen	Replace	Breaker	Replace th	230		4/20/2011	PSEG Power			Short Circu	3/10/2011
1049	b1522	6/1/2014	6/1/2014	Bergen	Replace	Breaker	Replace th	230		4/20/2011	PSEG Power			Short Circu	3/10/2011
1050	b1523	6/1/2014	6/1/2014	Bergen	Replace	Breaker	Replace th	230		4/20/2011	PSEG Power			Short Circu	3/10/2011
1051	b1524	11/30/2015	11/30/2015	North Pocc	Build	Substation	Build a nev	230/69		5/13/2011	PPL			PPL Criteria	3/2/2011
1052	b1524.1	11/30/2015	11/30/2015	South Pocc	Build	Line	Build appro	230		5/13/2011	PPL			PPL Criteria	3/2/2011
1053	b1524.2	11/30/2015	11/30/2015	Mt. Pocon	Install	MOLSAB	Install MOI	69		5/13/2011	PPL			PPL Criteria	3/2/2011
1054	b1525	11/30/2015	11/30/2015	West Poco	Build	Substation	Build new '	230/69		5/13/2011	PPL			PPL Criteria	3/2/2011
1055	b1525.1	11/30/2015	11/30/2015	Jenkins - W	Build	Line	Build appro	230		5/13/2011	PPL			PPL Criteria	3/2/2011
1056	b1525.2	11/30/2015	11/30/2015	Jenkins	Install	Breaker	Install Jenk	230		5/13/2011	PPL			PPL Criteria	3/2/2011
1057	b1526	5/31/2016	6/1/2016	Honeybroc	Install	Tie	Install a ne	69/138		5/13/2011	PPL			PPL Criteria	3/2/2011
1058	b1527	5/31/2015	6/1/2015	North Lanc	Build	Substation	Construct a	230/69		5/13/2011	PPL			PPL Criteria	3/2/2011
1059	b1527.1	5/31/2015	6/1/2015	North Lanc	Build	Line	Construct r	69/138		5/13/2011	PPL			PPL Criteria	3/2/2011
1060	b1528	5/31/2015	6/1/2015	East Texas	Install	Switches	Install Mot	69		5/13/2011	PPL			PPL Criteria	3/2/2011
1061	b1529	5/31/2015	6/1/2015	Hosensack	Install	Breaker	Add a douk	230		5/13/2011	PPL			PPL Criteria	3/2/2011
1062	b1530	5/30/2013	6/1/2013	Lock Haver	Reconfigur	Bus	Replace Lo	69		5/13/2011	PPL			PPL Criteria	3/2/2011
1063	b1531	5/31/2012	6/1/2012	Sunbury	Upgrade	Transform	Upgrade Sunbury T22 and T23 tra			5/13/2011	PPL			PPL Criteria	3/2/2011
1064	b1532	5/31/2012	6/1/2012	Sunbury	Install	Capacitor E	Install new 32.4 MVAR capacitor l			5/13/2011	PPL			PPL Criteria	3/2/2011
1065	b1533	5/31/2015	6/1/2015	Lycoming -	Rebuild	Line	Rebuild Lyc	69		5/13/2011	PPL			PPL Criteria	3/2/2011

	A	P	Q	R	S	T	U	V	W	X	Y
3	Upgrade ID	Latest TEAC Date	Status	State	Region	County	Percent Co	Cost Estim	Project ID	In Schedul	Source
995	b1484		EP				0	0.06	b1484	b1484	Planned
996	b1485		EP				0	0.09	b1485	b1485	Planned
997	b1486		EP				0	0.03	b1486	b1486	Planned
998	b1487		EP				0	0.01	b1487	b1487	Planned
999	b1488		EP				0	0.01	b1488	b1488	Planned
1000	b1489		EP				0	0.3	b1489	b1489	Planned
1001	b1490.1		EP	IN	PJM WEST		0	25	b1490	b1490	Planned
1002	b1490.2		EP	IN	PJM WEST		0	0	b1490	b1490	Planned
1003	b1490.3		EP	IN	PJM WEST		0	0	b1490	b1490	Planned
1004	b1490.4		EP	IN	PJM WEST		0	0	b1490	b1490	Planned
1005	b1491		EP				0	0.65	b1491	b1491	Planned
1006	b1492		EP				0	0.7	b1492	b1492	Planned
1007	b1493		EP				0	0.07	b1493	b1493	Planned
1008	b1494		EP				0	0.09	b1494	b1494	Planned
1009	b1495		EP	WV	PJM WEST		0	46	b1495	b1495	Planned
1010	b1496		EP				0	0.6	b1496	b1496	Planned
1011	b1497		EP				0	0.6	b1497	b1497	Planned
1012	b1498		EP				0	0.15	b1498	b1498	Planned
1013	b1499		EP				0	0.16	b1499	b1499	Planned
1014	b1500		EP				0	0.02	b1500	b1500	Planned
1015	b1501		EP				0	0.09	b1501	b1501	Planned
1016	b1502		EP				0	2	b1502	b1502	Planned
1017	b1503.1		Pending				0	30	b1503	#N/A	Planned
1018	b1503.2		Pending				0	0	b1503	#N/A	Planned
1019	b1503.3		Pending				0	0	b1503	#N/A	Planned
1020	b1503.4		Pending				0	0	b1503	#N/A	Planned
1021	b1504.1		Pending				0	3	b1504	#N/A	Planned
1022	b1504.2		Pending				0	0	b1504	#N/A	Planned
1023	b1505		Pending				0	3	b1505	#N/A	Planned
1024	b1506.1		Pending				0	20	b1506	#N/A	Planned
1025	b1506.2		Pending				0	0	b1506	#N/A	Planned
1026	b1506.3		Pending				0	0	b1506	#N/A	Planned
1027	b1506.4		Pending				0	0	b1506	#N/A	Planned
1028	b1507		EP	WV	PJM SOUTH		10	370	b1507	b1507	Planned
1029	b1507.1		EP	WV	PJM SOUTH		0	0	b1507	b1507	Planned
1030	b1507.2		EP	MD	PJM WEST		0	1.18	b1507	b1507	Planned
1031	b1507.3		EP	MD	PJM WEST		0	12.76	b1507	b1507	Planned
1032	b1508.1		EP	VA	PJM SOUTH		0	70	b1508	b1508	Planned
1033	b1508.2		EP	VA	PJM SOUTH		0	1.7	b1508	b1508	Planned
1034	b1508.3		EP	VA	PJM SOUTH		10	0.3	b1508	b1508	Planned
1035	b1510		EP				3	0.82	b1510	#N/A	Planned
1036	b1511		EP				0	0.5	b1511	#N/A	Planned
1037	b1512		EP				0	2.1	b1512	#N/A	Planned
1038	b1513		EP				0	1.5	b1513	#N/A	Planned
1039	b1514		EP				0	0.07	b1514	#N/A	Planned
1040	b1515		EP				0	2.8	b1515	#N/A	Planned
1041	b1516		EP				0	2.1	b1516	#N/A	Planned
1042	b1517		EP				0	0.22	b1517	#N/A	Planned
1043	b1518		EP				0	15	b1518	#N/A	Planned
1044	b1519.1		UC				75	178	b1519	#N/A	Planned
1045	b1519.2		UC				75	0	b1519	#N/A	Planned
1046	b1519.3		UC				75	0	b1519	#N/A	Planned
1047	b1520		EP	NJ	PJM MA		0	0.2	b1520	#N/A	Planned
1048	b1521		EP	NJ	PJM MA		0	1	b1521	#N/A	Planned
1049	b1522		EP	NJ	PJM MA		0	1	b1522	#N/A	Planned
1050	b1523		EP	NJ	PJM MA		0	1	b1523	#N/A	Planned
1051	b1524		EP	PA	PJM MA		0	17.6	b1524	#N/A	Planned
1052	b1524.1		EP	PA	PJM MA		0	28.6	b1524	#N/A	Planned
1053	b1524.2		EP	PA	PJM MA		0	0.38	b1524	#N/A	Planned
1054	b1525		EP	PA	PJM MA		0	18.3	b1525	#N/A	Planned
1055	b1525.1		EP	PA	PJM MA		0	28.5	b1525	#N/A	Planned
1056	b1525.2		EP	PA	PJM MA		0	0.97	b1525	#N/A	Planned
1057	b1526		EP	PA	PJM MA		0	7.63	b1526	#N/A	Planned
1058	b1527		EP	PA	PJM MA		0	7.65	b1527	#N/A	Planned
1059	b1527.1		EP	PA	PJM MA		0	13.64	b1527	#N/A	Planned
1060	b1528		EP	PA	PJM MA		0	0.22	b1528	#N/A	Planned
1061	b1529		EP	PA	PJM MA		0	1.37	b1529	#N/A	Planned
1062	b1530		EP	PA	PJM MA		0	20.5	b1530	#N/A	Planned
1063	b1531		EP	PA	PJM MA		0	8.68	b1531	#N/A	Planned
1064	b1532		EP	PA	PJM MA		0	0.84	b1532	#N/A	Planned
1065	b1533		EP	PA	PJM MA		0	17.74	b1533	#N/A	Planned

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
3	Upgrade ID	PJM Required	In Service Date	Location	Task	Equipment	Descriptior	Voltage	Expected R	Last Updated	Trans Own	Study Year	Baseline R	Driver	Initial TEAC Da
1066	b1534	5/31/2014	6/1/2014	Sunbury - I	Rebuild	Line	Rebuild 1.4	69		5/13/2011	PPL			PPL Criteria	3/2/2011
1067	b1535	12/31/2011	12/31/2011	Gore Junct	Reconduct	Line	Reconduct	115		5/24/2011	PENELEC			FE Criteria	3/2/2011
1068	b1536	6/1/2015	6/1/2015	Ox	Replace	Breaker	Advance n	230		4/20/2011	DOM			Short Circu	3/10/2011
1069	b1537	6/1/2015	6/1/2015	Ox	Replace	Breaker	Advance n	230		4/28/2011	DOM			Short Circu	3/10/2011
1070	b1538	6/1/2015	6/1/2015	Loudoun	Replace	Breaker	Replace Lo	230		4/20/2011	DOM			Short Circu	3/10/2011
1071	b1539	6/1/2015	6/1/2015	Tosco	Replace	Breaker	Replace To	230		5/23/2011	PSEG			Short Circu	5/12/2011
1072	b1540	6/1/2015	6/1/2015	Tosco	Replace	Breaker	Replace To	230		5/23/2011	PSEG			Short Circu	5/12/2011
1073	b1541	6/1/2015	6/1/2015	Hudson	Modify	Bus	Open the H	230		5/23/2011	PSEG			Short Circu	5/12/2011
1074	b1544	6/1/2011	6/1/2011	Pumphrey	Replace	Terminal E	Advance th	230		6/14/2011	BGE			Operationa	4/15/2011
1075	b1545	6/1/2011	6/1/2011	Brandon Sh	Upgrade	Terminal E	Upgrade te	230		6/14/2011	BGE			Operationa	4/15/2011
1076	b1546	6/1/2011	6/1/2011	Graceton	Upgrade	Terminal E	Upgrade te	230		6/14/2011	BGE			Operationa	4/15/2011
1077	b1547	12/31/2012	12/31/2012	Lakeview -	Reconduct	Line	Reconduct	138		5/24/2011	ATSI			Gen Delive	4/15/2011
1078	b1548	12/31/2012	12/31/2012	Ottawa - La	Reconduct	Line	Reconduct	138		5/24/2011	ATSI			Gen Delive	4/15/2011
1079	b1570	6/1/2014	6/1/2014	Marysville	Install	Transform	Add a 345/	345/69		5/13/2011	Dayton			Common M	5/12/2011
1080	b1570.1	6/1/2014	6/1/2014	Marysville	Install	Line	Add Marys	69		5/13/2011	Dayton			Common M	5/12/2011
1081	b1570.2	6/1/2014	6/1/2014	Marysville	Install	Line	Add Marys	69		5/13/2011	Dayton			Common M	5/12/2011
1082	b1570.3	6/1/2014	6/1/2014	Union REA	Reconduct	Line	Reconduct	69		5/13/2011	Dayton			Common M	5/12/2011
1083	b1572	6/1/2014	6/1/2014	West Miltc	Construct	Line	Construct a	138		6/14/2011	Dayton			N-1-1	6/9/2011
1084	b1573	6/1/2014	6/1/2014	Todhunter	Reconfigur	Bus	Reconfigur	345		6/14/2011	DEOK			Common M	6/9/2011
1085	b1574	6/1/2014	6/1/2014	Port Union	Reconduct	Line	Reconduct	138		6/14/2011	DEOK			Common M	6/9/2011
1086	b1575	6/1/2012	6/1/2012	Red Bank-(	Replace	Metering E	Replace th	138		6/14/2011	DEOK			Common M	6/9/2011
1087	b1576	6/1/2013	6/1/2013	Todhunter	Reconduct	Line	Reconduct	138		6/20/2011	DEOK			Common M	6/9/2011
1088	b0024	6/1/2005	6/29/2005	Cardiff - Oy	Construct	Circuit Breaker		230		8/11/2009	AEC	2000		Load Delive	5/9/2005
1089	b0025	6/1/2008	5/23/2008	Bergen-Leo	Convert	Circuit	138kV circu	230	375/557	8/11/2009	PSEG	2000		Contingenc	9/22/2005
1090	b0030	6/1/2005	11/6/2006	Brandon Sh	Construct	Tower Line	to separate	230		8/11/2009	BGE	2000		Multiple Fa	5/9/2005
1091	b0039.1	6/1/2007	6/1/2004	BGE	Upgrade	Reactive				8/11/2009	BGE	2002		Voltage Vio	5/9/2005
1092	b0039.2	6/1/2007	5/31/2005	PEPCO	Upgrade	Reactive				8/6/2009	PEPCO			Voltage Vio	5/9/2005
1093	b0039.5	6/1/2006	6/29/2006	Waugh Cha	Install	Capacitor B	360MVAR (	230		2/18/2010	BGE				5/9/2005
1094	b0040	6/1/2006	12/31/2005	Doubs	Replace	Transform	Transform	500/230		8/14/2009	APS	2002		Gen Delive	5/9/2005
1095	b0042	6/1/2007	6/1/2005	Midd Jct - 2	Upgrade	Transmission Line		115		8/11/2009	ME	2002		Gen Delive	5/9/2005
1096	b0043.1	12/1/2007	6/1/2003	North Phila	Add	Capacitor	in north Philadelphia - Buckingha			8/11/2009	PECO	2002			5/9/2005
1097	b0043.2	12/1/2007	5/14/2004	North Phila	Add	Capacitor	in north Philadelphia - Woodburn			8/11/2009	PECO	2002			5/9/2005
1098	b0043.3	12/1/2007	5/31/2005	North Phila	Add	Capacitor	in north Philadelphia - North Wal			8/11/2009	PECO	2002		Load Delive	5/9/2005
1099	b0052.1	6/1/2005	6/15/2006	Montgome	Add	Capacitor	second 10.	34		8/11/2009	APS	2001		Multiple Fa	5/9/2005
1100	b0052.5	6/1/2006	2/2/2005	McCain	Install	Capacitor	10.2 MVAR	34		8/11/2009	APS	2001		Multiple Fa	5/9/2005
1101	b0053	6/1/2006	8/3/2005	Davis Mill	Add	Capacitor	To obtain a	34		8/11/2009	APS	2001		Multiple Fa	5/9/2005
1102	b0054	6/1/2005	6/30/2005	Ringgold	Add	Capacitor	22 MVAR c	138		8/11/2009	APS	2001		Multiple Fa	5/9/2005
1103	b0055	6/1/2005	5/23/2006	Carroll	Add	Capacitor	44 MVAR c	138		8/11/2009	APS	2001		Multiple Fa	5/9/2005
1104	b0057	6/1/2005	6/9/2006	Lake Nelso	Install	Breaker	two breake	230		8/11/2009	PSEG	2002		DCTL Conti	5/9/2005
1105	b0058	6/1/2007	6/1/2005	Athenia	Replace	Transform	two transfo	230/138		8/28/2009	PSEG	2002			5/9/2005
1106	b0060	4/30/2006	4/7/2006	Deans	Replace	Circuit Bre	#2-10	230		8/11/2009	PSEG	1999		Short Circu	5/9/2005
1107	b0061	4/30/2006	3/24/2006	Deans	Replace	Circuit Bre	#2-8	230		8/11/2009	PSEG	1999		Short Circu	5/9/2005
1108	b0062	4/30/2006	4/21/2006	Deans	Replace	Circuit Bre	#5-6	230		8/11/2009	PSEG	1999		Short Circu	5/9/2005
1109	b0063	4/30/2006	3/10/2006	Deans	Replace	Circuit-Bre	#2-6	230		8/31/2009	PSEG	1999		Short Circu	5/9/2005
1110	b0064	4/30/2006	5/11/2006	Linden	Replace	Breaker	#1-5	230		8/11/2009	PSEG	1999		Short Circu	5/9/2005
1111	b0065	4/30/2006	4/26/2006	Linden	Replace	Breaker	#1-3	230		8/11/2009	PSEG	1999		Short Circu	5/9/2005
1112	b0066	6/1/2007	2/2/2007	Linden	Replace	Breaker	#2-3	230		8/11/2009	PSEG	1999		Short Circu	5/9/2005
1113	b0067	6/1/2008	12/31/2004	Jackson-Ba	Replace	Bus	a section o	115		8/13/2009	ME	2003			5/9/2005
1114	b0069	6/1/2008	4/27/2007	Glory - Dixi	Replace	Disconnect Switch		230	622	8/13/2009	PENELEC	2003		Gen Delive	5/9/2005
1115	b0071	6/1/2008	7/14/2008	Bayway	Loop	Bus	the W-132	138	Bay/Lin 39	4/13/2011	PSEG	2003		Gen Delive	5/9/2005
1116	b0074	6/1/2008	5/2/2008	S. Akron-Be	Rebuild	Double Cir	Upgrade 12 miles of S Akron-Berk			4/13/2011	PPL	2003		N-1-1	5/9/2005
1117	b0077	6/1/2008	5/27/2004	Morris Parl	Replace	Wavetrap		230		8/11/2009	JCPL	2003			5/9/2005
1118	b0078	6/1/2008	5/27/2004	Morris Parl	Replace	Disconnect Switch		230		8/11/2009	JCPL	2003			5/9/2005
1119	b0079	6/1/2008	6/1/2004	Branchburg	Install	SPS				8/11/2009	PSEG	2003			5/9/2005
1120	b0081	6/1/2005	5/14/2005	Des Plaines	Reconductor			138		8/11/2009	ComEd	2003		Load Delive	5/9/2005
1121	b0085	6/30/2005	4/24/2005	Branchburg	Install	Transform	third trans	500/230		8/14/2009	PSEG	2004		Gen Delive	5/9/2005
1122	b0090	6/1/2005	7/14/2005	Camden	Add	Capacitor	150 MVAR	230		8/11/2009	PSEG	2003		Single Cont	5/9/2005
1123	b0091	6/1/2008	5/6/2005	Doubs - Mo	Replace	Wavetrap		230	593	8/12/2009	APS	2003		Tower Out	5/9/2005
1124	b0098	6/1/2005	5/25/2005	Silver Lake	Install	Line	and Transfo	345/138		8/14/2009	ComEd	2003		Gen Delive	5/9/2005
1125	b0099	6/1/2008	3/29/2008	Nelson	Install	Transform	Install third	345/138		4/13/2011	ComEd	2003		Gen Delive	5/9/2005
1126	b0101	6/1/2005	5/25/2005	Waukegan	Install	Auto-close scheme				8/11/2009	ComEd	2003		Load Delive	5/9/2005
1127	b0104	6/1/2008	5/26/2006	East Frankl	Install	Transform	and reconc	345/138		8/14/2009	ComEd	2003		Load Delive	5/9/2005
1128	b0105	6/1/2008	5/27/2006	Electric Jur	Install	Transmissi	line 11107	138		8/11/2009	ComEd	2003		Load Delive	5/9/2005
1129	b0108	4/30/2006	5/5/2006	Deans	Replace	Breaker	#7-8	230		8/11/2009	PSEG	1999		Short Circu	5/9/2005
1130	b0110	6/1/2005	10/22/2005	Doubs		Transform	Purchase s	500/230		8/14/2009	APS			Spare Xfrm	5/9/2005
1131	b0113	6/1/2009	11/8/2007	Roberts Sta	Install	Transform	new transf	345/138		8/14/2009	AEP			Gen Delive	5/9/2005
1132	b0114	6/1/2009	11/14/2010	Don Marqu	Install	Transform	Install new	345/138		1/20/2011	AEP	2003	2007	Gen Delive	5/9/2005
1133	b0115	6/1/2009	7/12/2005	Hyatt - Tre	Install	Series Rea	5% series r	138		8/6/2009	AEP			Gen Delive	5/9/2005
1134	b0116	6/1/2005	6/24/2005	Cook	Replace	Breakers	K, K2, and I	345		8/5/2009	AEP			Short Circu	5/9/2005
1135	b0117	6/1/2005	5/20/2005	Dumont	Replace	Breakers	E, E1, E2, F	345		8/5/2009	AEP			Short Circu	5/9/2005
1136	b0118	6/1/2005	11/11/2004	Tidd	Replace	Breakers	AA and AA	345		8/5/2009	AEP			Short Circu	5/9/2005

	A	P	Q	R	S	T	U	V	W	X	Y
3	Upgrade ID	Latest TEAC Date	Status	State	Region	County	Percent Co	Cost Estim	Project ID	In Schedul	Source
1066	b1534		EP	PA	PJM MA		0	1.8	b1534	#N/A	Planned
1067	b1535		EP	PA	PJM MA		0	0.16	b1535	#N/A	Planned
1068	b1536		EP	VA	PJM SOUTH		0	0.03	b1536	#N/A	Planned
1069	b1537		EP	VA	PJM SOUTH		0	0.03	b1537	#N/A	Planned
1070	b1538		EP	VA	PJM SOUTH		0	0.21	b1538	#N/A	Planned
1071	b1539		EP	NJ	PJM MA		0	0.6	b1539	#N/A	Planned
1072	b1540		EP	NJ	PJM MA		0	0.6	b1540	#N/A	Planned
1073	b1541		EP	NJ	PJM MA		0	0	b1541	#N/A	Planned
1074	b1544		EP	MD	PJM MA		0	0.03	b1544	#N/A	Planned
1075	b1545		EP	MD	PJM MA		0	0.02	b1545	#N/A	Planned
1076	b1546		EP	MD	PJM MA		0	0.01	b1546	#N/A	Planned
1077	b1547		EP	OH	PJM WEST		0	2.8	b1547	#N/A	Planned
1078	b1548		EP	OH	PJM WEST		0	2.1	b1548	#N/A	Planned
1079	b1570		EP	OH	PJM WEST		0	16	b1570	#N/A	Planned
1080	b1570.1		EP	OH	PJM WEST		0	0	b1570	#N/A	Planned
1081	b1570.2		EP	OH	PJM WEST		0	0	b1570	#N/A	Planned
1082	b1570.3		EP	OH	PJM WEST		0	0	b1570	#N/A	Planned
1083	b1572		EP	OH	PJM WEST		0	16	b1572	#N/A	Planned
1084	b1573		EP	OH	PJM WEST		0	1.4	b1573	#N/A	Planned
1085	b1574		EP	OH	PJM WEST		0	3.5	b1574	#N/A	Planned
1086	b1575		EP	OH	PJM WEST		0	0.2	b1575	#N/A	Planned
1087	b1576		EP	OH	PJM WEST		0	0.2	b1576	#N/A	Planned
1088	b0024		IS	NJ	PJM MA	Atlantic	100	58	b0024	#N/A	Post-2005
1089	b0025		IS	NJ	PJM MA	Bergen	100	25	b0025	b0025	Post-2005
1090	b0030		IS	MD	PJM MA	Baltimore	100	4	b0030	#N/A	Post-2005
1091	b0039.1		IS	MD	PJM MA		100	9.12	b0039	#N/A	Post-2005
1092	b0039.2		IS	MD	PJM MA		100	2.64	b0039	#N/A	Post-2005
1093	b0039.5		IS	MD	PJM MA		100	1.7	b0039	#N/A	Post-2005
1094	b0040		IS	MD	PJM WEST	Frederick	100	4.1	b0040	#N/A	Post-2005
1095	b0042		IS	PA	PJM MA	Lancaster	100	0.95	b0042	#N/A	Post-2005
1096	b0043.1		IS	PA	PJM MA	Philadelph	100	1.38	b0043	#N/A	Post-2005
1097	b0043.2		IS	PA	PJM MA	Philadelph	100	1.38	b0043	#N/A	Post-2005
1098	b0043.3		IS	PA	PJM MA	Philadelph	100	1.38	b0043	#N/A	Post-2005
1099	b0052.1		IS	MD	PJM WEST	Howard	100	0.34	b0052	#N/A	Post-2005
1100	b0052.5		IS	MD	PJM WEST		100	0.19	b0052	#N/A	Post-2005
1101	b0053		IS	MD	PJM WEST	Howard	100	0.3	b0053	#N/A	Post-2005
1102	b0054		IS	MD	PJM WEST	Washingto	100	0.17	b0054	#N/A	Post-2005
1103	b0055		IS	MD	PJM WEST	Carroll	100	0.4	b0055	#N/A	Post-2005
1104	b0057		IS	NJ	PJM MA		100	5.2	b0057	#N/A	Post-2005
1105	b0058		IS	NJ	PJM MA		100	6	b0058	#N/A	Post-2005
1106	b0060		IS	NJ	PJM MA		100	0.48	b0060	#N/A	Post-2005
1107	b0061		IS	NJ	PJM MA		100	0.48	b0061	#N/A	Post-2005
1108	b0062		IS	NJ	PJM MA		100	0.48	b0062	#N/A	Post-2005
1109	b0063		IS	NJ	PJM MA		100	0.48	b0063	#N/A	Post-2005
1110	b0064		IS	NJ	PJM MA		100	0.48	b0064	#N/A	Post-2005
1111	b0065		IS	NJ	PJM MA		100	0.48	b0065	#N/A	Post-2005
1112	b0066		IS	NJ	PJM MA		100	0.48	b0066	#N/A	Post-2005
1113	b0067		IS	PA	PJM MA		100	0.02	b0067	#N/A	Post-2005
1114	b0069		IS	PA	PJM MA	Indiana	100	0.1	b0069	#N/A	Post-2005
1115	b0071		IS	NJ	PJM MA		100	4.5	b0071	#N/A	Post-2005
1116	b0074		IS	PA	PJM MA		100	48.27	b0074	b0074	Post-2005
1117	b0077		IS	NJ	PJM MA		100	0	b0077	#N/A	Post-2005
1118	b0078		IS	NJ	PJM MA		100	0	b0078	#N/A	Post-2005
1119	b0079		IS	NJ	PJM MA		100	0	b0079	#N/A	Post-2005
1120	b0081		IS	IL	PJM WEST		100	1.4	b0081	#N/A	Post-2005
1121	b0085		IS	NJ	PJM MA		100	15	b0085	#N/A	Post-2005
1122	b0090		IS	NJ	PJM MA		100	1.25	b0090	b0090	Post-2005
1123	b0091		IS	WV	PJM WEST		100	0.05	b0091	#N/A	Post-2005
1124	b0098		IS	IL	PJM WEST		100	13.5	b0098	#N/A	Post-2005
1125	b0099		IS	IL	PJM WEST		100	5	b0099	#N/A	Post-2005
1126	b0101		IS	IL	PJM WEST		100	0.05	b0101	#N/A	Post-2005
1127	b0104		IS	IL	PJM WEST		100	15	b0104	#N/A	Post-2005
1128	b0105		IS	IL	PJM WEST		100	1.04	b0105	#N/A	Post-2005
1129	b0108		IS	NJ	PJM MA		100	0.48	b0108	#N/A	Post-2005
1130	b0110		IS	MD	PJM WEST		100	0	b0110	#N/A	Post-2005
1131	b0113		IS	OH	PJM WEST		100	14.2	b0113	#N/A	Post-2005
1132	b0114		IS	OH	PJM WEST		100	35.23	b0114	#N/A	Post-2005
1133	b0115		IS	OH	PJM WEST		100	0.9	b0115	#N/A	Post-2005
1134	b0116		IS	MI	PJM WEST		100	4.1	b0116	#N/A	Post-2005
1135	b0117		IS	IN	PJM WEST		100	3.3	b0117	#N/A	Post-2005
1136	b0118		IS	OH	PJM WEST		100	1.3	b0118	#N/A	Post-2005

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
3	Upgrade ID	PJM Required	In Service Date	Location	Task	Equipment	Descriptior	Voltage	Expected R	Last Updated	Trans Own	Study Year	Baseline R	Driver	Initial TEAC Da
1137	b0119	6/1/2005	6/18/2006	Tidd	Replace	Breaker	FF1 and FF	345		8/5/2009	Buckeye Power			Short Circu	5/9/2005
1138	b0121	6/1/2005	7/7/2005	Aldene	Add	Capacitor	150 MVAR	230		8/6/2009	PSEG			Single Cont	5/9/2005
1139	b0122	6/1/2005	5/14/2005	Essex	Bypass	Series Reactor		138		8/6/2009	PSEG			Retiremen	5/9/2005
1140	b0123	6/1/2005	8/1/2005	Various in .	Add	Capacitors	180 MVAR of distribut		180	4/26/2010	JCPL			Retiremen	5/9/2005
1141	b0124.1	6/1/2005	8/10/2005	Kittatinny	Add	Capacitor	72 MVAR	230		8/6/2009	JCPL			Retiremen	5/9/2005
1142	b0124.2	6/1/2006	4/10/2006	Manitou	Add	Capacitor	130 MVAR	230		8/6/2009	JCPL			Retiremen	5/9/2005
1143	b0125	6/1/2005	7/29/2005	Branchbur	Add	Special Pro	at Bridgew	500		8/5/2009	PSEG			Retiremen	5/9/2005
1144	b0126	6/1/2005	5/24/2005	Branchbur	Replace	Wavetrap		230		8/12/2009	PSEG			Retiremen	5/9/2005
1145	b0127	6/1/2005	5/28/2005	Brunswick	Replace	Terminal E	conductor	230		8/3/2009	PSEG			Retiremen	5/9/2005
1146	b0128	6/1/2005	5/12/2005	Electric Jur	Reconductor		500 ft secti	138		8/6/2009	ComEd			Load Delive	5/9/2005
1147	b0129	6/1/2006	5/25/2006	Flagtown –	Replace	Wavetrap	C-2203 line	230		8/3/2009	PSEG			Retiremen	5/9/2005
1148	b0130	6/1/2007	5/19/2006	Branchbur	Replace	Transform	Replace all	500		8/5/2009	PSEG			Gen Delive	5/9/2005
1149	b0132	6/1/2007	5/31/2007	Portland -	Reconductor		With 1590	230		8/11/2009	JCPL				5/9/2005
1150	b0134	6/1/2007	5/15/2007	Kittatinny -	Retension	Circuit	PSEG porti	230		8/3/2009	PSEG			DCTL Conti	5/9/2005
1151	b0135	12/1/2007	12/24/2007	Cumberlan	Install	Circuit	to replace	230		9/10/2009	AEC			Retiremen	5/9/2005
1152	b0136	12/1/2007	2/28/2008	Dennis	Install	Transform	150 MVAR	230		8/6/2009	AEC			Retiremen	5/9/2005
1153	b0137	12/1/2007	12/15/2007	Dennis – C	Install	Circuit	New	138		8/6/2009	AEC			Retiremen	5/9/2005
1154	b0138	12/1/2007	3/31/2008	Cardiff	Install	Transform	and a 50 M	230/138		8/28/2009	AEC			Retiremen	5/9/2005
1155	b0139	12/1/2007	12/24/2007	Cardiff – L	Install	Circuit	New	138		8/6/2009	AEC			Retiremen	5/9/2005
1156	b0140	12/1/2007	1/15/2007	Laurel - W	Reconductor			69		9/24/2009	AEC			Retiremen	5/9/2005
1157	b0141	12/1/2007	3/14/2006	Monroe - I	Reconductor			69		9/24/2009	AEC			Retiremen	5/9/2005
1158	b0142	12/1/2007	4/28/2006	Landis - Mi	Reconductor			138		8/6/2009	AEC			Retiremen	5/9/2005
1159	b0143	12/1/2007	12/15/2007	Beckett - P	Reconductor			69		9/24/2009	AEC			Retiremen	5/9/2005
1160	b0144.1	6/1/2006	6/20/2006	Red Lion –	Build	Circuit		230		8/6/2009	DPL			Load Delive	5/9/2005
1161	b0144.2	6/1/2006	6/20/2006	Indian Rive	Position	Terminal		230		8/11/2009	DPL			DELMARV/	5/9/2005
1162	b0144.3	6/1/2006	11/15/2005	Red Lion S	Position	Terminal		230		8/11/2009	DPL			DELMARV/	5/9/2005
1163	b0144.4	6/1/2006	12/23/2005	Milford Sul	Position	Terminal	2 Terminal	230		8/6/2009	DPL				5/9/2005
1164	b0144.5	6/1/2006	5/26/2006	Indian Rive	Install	Transmissi	for AT-20	138		8/28/2009	DPL				5/9/2005
1165	b0144.6	6/1/2006	4/18/2006	Indian Rive	Install	Transmissi	Undergrou	138/69		8/28/2009	DPL				5/9/2005
1166	b0144.7	6/1/2006	11/11/2006	Indian Rive	Install	Bus Tie	2 bus ties	230		8/6/2009	DPL			Load Delive	5/9/2005
1167	b0145	5/31/2007	6/5/2007	Essex - Ald	Build	Cable	New cable	230		8/3/2009	PSEG			Deliverabil	5/9/2005
1168	b0146.1	6/1/2006	5/19/2006	Quince Orc	Replace	Circuit Bre	line 23029	230		8/6/2009	PEPCO			Short Circu	5/9/2005
1169	b0146.2	6/1/2006	12/19/2006	Quince Orc	Installatior	Circuit Bre	circuits 23(	230		8/6/2009	PEPCO			Short Circu	5/9/2005
1170	b0148	6/1/2005	8/23/2004	Glasgow - I	Re-rate	Line	and North	230		8/6/2009	DPL				5/9/2005
1171	b0149	6/1/2005	12/14/2004	Cheswald -	Complete	Structure	to increase	138		8/28/2009	DPL				5/9/2005
1172	b0150	6/1/2005	6/1/2005	Waugh Ch	Modify	Tap	fixed tap s	500/230		8/14/2009	BGE			Short Circu	5/9/2005
1173	b0152.1	6/1/2005	6/1/2005	High Ridge	Add	Breakers		230		8/3/2009	BGE			Voltage Vic	5/9/2005
1174	b0152.2	6/1/2006	5/15/2006	High Ridge	Install	Breaker	line 2338	230		8/3/2009	BGE			Voltage Vic	5/9/2005
1175	b0153	6/1/2007	3/18/2007	Hudson	Replace	Breaker	BS2-3	230	622	8/12/2009	PSEG			Short Circu	5/9/2005
1176	b0155	6/1/2007	2/28/2007	Linden	Replace	Breaker	BS5-6	230		8/3/2009	PSEG			Short Circu	5/9/2005
1177	b0157	6/1/2007	6/29/2007	West Oran	Add	Capacitor	100MVAR	138		8/11/2009	PSEG	2005		Retiremen	5/9/2005
1178	b0158	6/1/2008	5/21/2009	Sunnymea	Close	Bus Tie	"C" and "F" bus tie			8/11/2009	PSEG	2005		Retiremen	5/9/2005
1179	b0159	6/1/2009	5/29/2009	Bayonne	Installatior	Reactor	Make the Bayonne reactor perma			8/11/2009	PSEG	2005		Retiremen	5/9/2005
1180	b0161	6/1/2009	5/29/2009	Metuchen	Install	Transformer		230/138	340/474	8/28/2009	PSEG	2005		Retiremen	5/9/2005
1181	b0162	6/1/2011	12/1/2008	Edison – M	Upgrade	Circuit	"Q"	138	412/488	8/11/2009	PSEG	2005		Retiremen	5/9/2005
1182	b0163	6/1/2011	4/22/2009	Edison – M	Upgrade	Circuit	"R"	138	412/488	8/11/2009	PSEG	2005		Retiremen	5/9/2005
1183	b0164	6/1/2006	5/13/2006	Wolfs - Os	Upgrade	Transmissi	line 14302	138		8/6/2009	ComEd	2005		Gen Delive	5/9/2005
1184	b0167	6/1/2006	10/14/2005	Oak Grove	Upgrade	Breaker	13C	230		8/6/2009	PEPCO			Short Circu	5/9/2005
1185	b0168	6/1/2006	12/19/2006	Oak Grove	Upgrade	Breaker	5C	230		8/6/2009	PEPCO			Short Circu	5/9/2005
1186	b0169	6/1/2008	5/20/2009	Branchbur	Build	Circuit	to the new	230	850/1000	8/11/2009	PSEG			Load Delive	5/9/2005
1187	b0170	6/1/2008	5/7/2009	Flagtown-S	Reconductor		1590 ACSS	230	850/1000	8/11/2009	PSEG			Load Delive	5/9/2005
1188	b0171.1	6/1/2008	4/18/2008	Elroy - Hos	Replace	Circuit Bre	Two circuit	500		8/5/2009	PECO			Load Delive	5/9/2005
1189	b0171.2	6/1/2008	4/18/2008	Hosensack	Replace	Wave Trap	at substati	500		8/5/2009	PPL			Load Delive	5/9/2005
1190	b0172.1	6/1/2008	5/21/2008	Alburtis	Replace	Wave Trap	at substati	500	2939/3481	8/5/2009	PPL			Load Delive	5/9/2005
1191	b0172.2	6/1/2008	5/20/2008	Branchbur	Replace	Wave Trap	On 5016 lir	500	2939/3481	6/19/2009	PSEG			Load Delive	5/9/2005
1192	b0173	6/1/2008	10/8/2008	Kittatinny	Replace	Line Trap	for the Kitt	230		8/3/2009	JCPL			DCTL Conti	5/9/2005
1193	b0174	6/1/2008	5/7/2008	Portland -	Reconductor		line and up	230		8/6/2009	JCPL			Load Delive	5/9/2005
1194	b0175	6/1/2005	5/31/2005	Whitpain	Upgrade	Circuit Bre	bus breake	230		8/11/2009	PECO			Short Circu	5/9/2005
1195	b0180	6/1/2006	9/15/2006	Whitpain	Replace	Circuit Bre	#165	230		8/3/2009	PECO			Short Circu	5/9/2005
1196	b0181	6/1/2006	12/15/2006	Whitpain	Replace	Circuit Bre	#J105	230		8/3/2009	PECO			Short Circu	5/9/2005
1197	b0182	6/1/2006	12/15/2006	Plymouth I	Upgrade	Circuit Bre	#125	230		8/3/2009	PECO			Short Circu	5/9/2005
1198	b0184	6/1/2009	12/8/2008	Hudson	Replace	Circuit Bre	#1-2	230	622	8/12/2009	PSEG			Short Circu	9/22/2005
1199	b0185	4/30/2006	5/19/2006	Deans	Replace	Circuit Bre	#9-10	230		8/3/2009	PSEG			Short Circu	9/22/2005
1200	b0186	6/1/2009	12/14/2008	Essex	Replace	Circuit Bre	#5-6	230		8/3/2009	PSEG			Short Circu	9/22/2005
1201	b0187	6/1/2006	6/1/2006	Dickerson	Upgrade	Circuit Bre	"D" 1A	230		8/11/2009	PEPCO			Short Circu	9/22/2005
1202	b0188	6/1/2006	6/1/2006	Dickerson	Upgrade	Circuit Bre	"D" 1B	230		8/11/2009	PEPCO			Short Circu	9/22/2005
1203	b0189	6/1/2006	6/1/2006	Dickerson	Upgrade	Circuit Bre	"D" 2A	230		8/11/2009	PEPCO			Short Circu	9/22/2005
1204	b0190	6/1/2006	6/1/2006	Dickerson	Upgrade	Circuit Bre	"D" 2B	230		8/11/2009	PEPCO			Short Circu	9/22/2005
1205	b0191	6/1/2006	6/1/2006	Dickerson	Upgrade	Circuit Bre	"D" 3A	230		8/11/2009	PEPCO			Short Circu	9/22/2005
1206	b0192	6/1/2006	6/1/2006	Dickerson	Upgrade	Circuit Bre	"D" 3B	230		8/11/2009	PEPCO			Short Circu	9/22/2005
1207	b0193	6/1/2006	12/19/2006	Dickerson	Upgrade	Circuit Bre	"D" 5A	230		8/11/2009	PEPCO			Short Circu	9/22/2005

	A	P	Q	R	S	T	U	V	W	X	Y
3	Upgrade ID	Latest TEAC Date	Status	State	Region	County	Percent Co	Cost Estim	Project ID	In Schedul	Source
1137	b0119		IS	OH	PJM WEST		100	1.3	b0119	#N/A	Post-2005
1138	b0121		IS	NJ	PJM MA		100	1.25	b0121	b0121	Post-2005
1139	b0122		IS	NJ	PJM MA		100	0.5	b0122	b0122	Post-2005
1140	b0123		IS	NJ	PJM MA		100	2.7	b0123	b0123	Post-2005
1141	b0124.1		IS	NJ	PJM MA		100	0.8	b0124	b0124	Post-2005
1142	b0124.2		IS	NJ	PJM MA		100	1	b0124	b0124	Post-2005
1143	b0125		IS	NJ	PJM MA		100	0.1	b0125	b0125	Post-2005
1144	b0126		IS	NJ	PJM MA		100	0.5	b0126	b0126	Post-2005
1145	b0127		IS	NJ	PJM MA		100	0.5	b0127	b0127	Post-2005
1146	b0128		IS	IL	PJM WEST		100	0.4	b0128	#N/A	Post-2005
1147	b0129		IS	NJ	PJM MA		100	0.5	b0129	b0129	Post-2005
1148	b0130		IS	NJ	PJM MA		100	20	b0130	b0130	Post-2005
1149	b0132		IS	NJ	PJM MA		100	4.4	b0132	b0132	Post-2005
1150	b0134		IS	NJ	PJM MA		100	20	b0134	b0134	Post-2005
1151	b0135		IS	NJ	PJM MA		100	17.05	b0135	b0135	Post-2005
1152	b0136		IS	NJ	PJM MA		100	27.45	b0136	b0136	Post-2005
1153	b0137		IS	NJ	PJM MA		100	1.16	b0137	b0137	Post-2005
1154	b0138		IS	NJ	PJM MA		100	8.07	b0138	b0138	Post-2005
1155	b0139		IS	NJ	PJM MA		100	3.69	b0139	b0139	Post-2005
1156	b0140		IS	NJ	PJM MA		100	4.99	b0140	b0140	Post-2005
1157	b0141		IS	NJ	PJM MA		100	4.9	b0141	b0141	Post-2005
1158	b0142		IS	NJ	PJM MA		100	1.93	b0142	b0142	Post-2005
1159	b0143		IS	NJ	PJM MA		100	1.63	b0143	b0143	Post-2005
1160	b0144.1		IS	DE	PJM MA		100	44.91	b0144	b0144	Post-2005
1161	b0144.2		IS	DE	PJM MA	Sussex	100	7.46	b0144	b0144	Post-2005
1162	b0144.3		IS	DE	PJM MA	New Castle	100	0.97	b0144	b0144	Post-2005
1163	b0144.4		IS	DE	PJM MA		100	2.1	b0144	b0144	Post-2005
1164	b0144.5		IS	DE	PJM MA		100	0.12	b0144	b0144	Post-2005
1165	b0144.6		IS	DE	PJM MA		100	3.65	b0144	b0144	Post-2005
1166	b0144.7		IS	DE	PJM MA		100	1.23	b0144	b0144	Post-2005
1167	b0145		IS	NJ	PJM MA		100	65	b0145	b0145	Post-2005
1168	b0146.1		IS	MD	PJM MA		100	1.75	b0146	b0146	Post-2005
1169	b0146.2		IS	MD	PJM MA		100	3.04	b0146	b0146	Post-2005
1170	b0148		IS	DE	PJM MA		100	0	b0148	b0148	Post-2005
1171	b0149		IS	DE/MD	PJM MA		100	0	b0149	b0149	Post-2005
1172	b0150		IS	MD	PJM MA		100	0	b0150	#N/A	Post-2005
1173	b0152.1		IS	MD	PJM MA		100	0.59	b0152	b0152	Post-2005
1174	b0152.2		IS	MD	PJM MA		100	0.59	b0152	b0152	Post-2005
1175	b0153		IS	NJ	PJM MA		100	0.48	b0153	#N/A	Post-2005
1176	b0155		IS	NJ	PJM MA		100	0.48	b0155	#N/A	Post-2005
1177	b0157		IS	NJ	PJM MA		100	2	b0157	b0157	Post-2005
1178	b0158		IS	NJ	PJM MA		100	4.63	b0158	b0158	Post-2005
1179	b0159		IS	NJ	PJM MA		100	2	b0159	b0159	Post-2005
1180	b0161		IS	NJ	PJM MA		100	29	b0161	b0161	Post-2005
1181	b0162		IS	NJ	PJM MA		100	1	b0162	b0162	Post-2005
1182	b0163		IS	NJ	PJM MA		100	1	b0163	b0163	Post-2005
1183	b0164		IS	IL	PJM WEST		100	2	b0164	b0164	Post-2005
1184	b0167		IS	MD	PJM MA		100	0.2	b0167	#N/A	Post-2005
1185	b0168		IS	MD	PJM MA		100	0.21	b0168	#N/A	Post-2005
1186	b0169		IS	NJ	PJM MA		100	17	b0169	b0169	Post-2005
1187	b0170		IS	NJ	PJM MA		100	12	b0170	b0170	Post-2005
1188	b0171.1		IS	PA	PJM MA		100	2.2	b0171	b0171	Post-2005
1189	b0171.2		IS	PA	PJM MA	Lehigh	100	0.13	b0171	b0171	Post-2005
1190	b0172.1		IS	PA	PJM MA		100	0.07	b0172	b0172	Post-2005
1191	b0172.2		IS	NJ	PJM MA		100	0.05	b0172	b0172	Post-2005
1192	b0173		IS	NJ	PJM MA		100	0.1	b0173	b0173	Post-2005
1193	b0174		IS	NJ	PJM MA		100	20	b0174	b0174	Post-2005
1194	b0175		IS	PA	PJM MA	Montgome	100	0.5	b0175	#N/A	Post-2005
1195	b0180		IS	PA	PJM MA	Montgome	100	0.25	b0180	b0180	Post-2005
1196	b0181		IS	PA	PJM MA	Montgome	100	0.44	b0181	b0181	Post-2005
1197	b0182		IS	PA	PJM MA	Montgome	100	0.1	b0182	b0182	Post-2005
1198	b0184		IS	NJ	PJM MA	Hudson	100	0.48	b0184	b0184	Post-2005
1199	b0185		IS	NJ	PJM MA	Middlesex	100	0.48	b0185	b0185	Post-2005
1200	b0186		IS	NJ	PJM MA	Essex/Hud	100	0.48	b0186	b0186	Post-2005
1201	b0187		IS	MD	PJM MA	Montgome	100	0.21	b0187	#N/A	Post-2005
1202	b0188		IS	MD	PJM MA	Montgome	100	0.21	b0188	#N/A	Post-2005
1203	b0189		IS	MD	PJM MA	Montgome	100	0.21	b0189	#N/A	Post-2005
1204	b0190		IS	MD	PJM MA	Montgome	100	0.21	b0190	#N/A	Post-2005
1205	b0191		IS	MD	PJM MA	Montgome	100	0.21	b0191	#N/A	Post-2005
1206	b0192		IS	MD	PJM MA	Montgome	100	0.21	b0192	#N/A	Post-2005
1207	b0193		IS	MD	PJM MA	Montgome	100	0.21	b0193	#N/A	Post-2005

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
3	Upgrade ID	PJM Required	In Service Date	Location	Task	Equipment	Descriptior	Voltage	Expected R	Last Updated	Trans Own	Study Year	Baseline R	Driver	Initial TEAC Da
1208	b0194	6/1/2006	12/19/2006	Dickerson	Upgrade	Circuit Bre:	“D” 6C	230		8/11/2009	PEPCO			Short Circu	9/22/2005
1209	b0195	6/1/2006	3/15/2007	Dickerson	Upgrade	Circuit Bre:	“D” 1C	230		8/11/2009	PEPCO			Short Circu	9/22/2005
1210	b0196	6/1/2006	3/15/2007	Dickerson	Upgrade	Circuit Bre:	“D” 2C	230		8/11/2009	PEPCO			Short Circu	9/22/2005
1211	b0197	6/1/2006	3/15/2007	Dickerson	Upgrade	Circuit Bre:	“D” 3C	230		9/10/2009	PEPCO			Short Circu	9/22/2005
1212	b0199	6/1/2008	2/19/2009	Greystone	Change	Tap	of limiting	230		9/23/2009	JCPL			Load Delive	9/22/2005
1213	b0200	6/1/2008	10/8/2008	Greystone	Change	Tap	of limiting	230		8/6/2009	JCPL			Load Delive	9/22/2005
1214	b0201	6/1/2008	5/23/2008	Branchburg	Replace	Wave trap	M-2265	230	653/812	8/3/2009	PSEG			Load Delive	9/22/2005
1215	b0202	6/1/2008	10/8/2008	Kittatinny	Replace	Line Trap	(L2012) 23	230		8/3/2009	JCPL			Load Delive	9/22/2005
1216	b0203	6/1/2008	5/30/2008	Smithburg	Replace	Line Trap	on the East	230		8/3/2009	JCPL			Load Delive	9/22/2005
1217	b0204	6/1/2008	5/31/2006	Cookstowr	Install	Capacitor	Install 72M	230		8/3/2009	JCPL			Load Delive	9/22/2005
1218	b0205	6/1/2008		Planebrool	Install	Capacitor	three 28.8	35		8/5/2009	PECO			Load Delive	9/22/2005
1219	b0206	6/1/2008	5/22/2007	Planebrool	Install	Capacitor	Install 161	230		8/3/2009	PECO			Load Delive	9/22/2005
1220	b0207	6/1/2008	5/25/2008	Newlinville	Install	Capacitor	161Mvar	230		8/3/2009	PECO			Load Delive	9/22/2005
1221	b0208	6/1/2008	4/12/2008	Heaton	Install	Capacitor	161Mvar	230		8/3/2009	PECO			Load Delive	9/22/2005
1222	b0209	6/1/2008	3/27/2008	Chichester	Install	Series Rea	2% series r	230		8/3/2009	PECO			Load Delive	9/22/2005
1223	b0210	6/1/2008	5/7/2008	AE Area, O	Install	Substation	new in AE a	500		8/5/2009	AEC			Load Delive	9/22/2005
1224	b0211	6/1/2008	2/15/2008	Union - Co	Reconductor			138		9/11/2009	AEC			Load Delive	9/22/2005
1225	b0212	6/1/2008	2/28/2008	Corson	Upgrade	Line Trap		138		8/6/2009	AEC			Load Delive	9/22/2005
1226	b0213.1	6/1/2008	4/13/2007	New Freed	Replace	Breaker	BS2-6	230		8/3/2009	PSEG			Short Circu	10/30/2006
1227	b0213.3	6/1/2008	3/29/2007	New Freed	Replace	Breaker	BS2-8	230		8/3/2009	PSEG			Short Circu	10/30/2006
1228	b0214	6/1/2008	2/28/2009	Cardiff	Install	Capacitor	50 MVAR	230		6/19/2009	AEC			Load Delive	9/22/2005
1229	b0215	6/1/2008	6/1/2008	Hunterstov	Install	Dynamic R	and two 1(	230/115		8/14/2009	ME	2008		Gen Delive	9/22/2005
1230	b0216	12/31/2007	12/5/2007	Black Oak	Install	Dynamic R	-100/+525 MVAR		-100/+525	4/26/2010	APS			Voltage Vic	9/22/2005
1231	b0217	6/1/2006	6/3/2006	Mount Sto	Upgrade	Line		500		8/11/2009	Dominion			Gen Delive	9/22/2005
1232	b0218	6/1/2007	12/20/2007	Wylie Ridg	Install	Transform	Third & Fo	500/345		11/19/2009	APS			Operationa	9/22/2005
1233	b0219	6/1/2007	7/1/2007	Palmers Co	Install	Circuits		230		8/3/2009	PEPCO			PJM Rel. Pl	9/22/2005
1234	b0220	6/1/2006	4/18/2006	Wylie Ridg	Upgrade	Coolers	#7	500/345		11/19/2009	APS			Operationa	11/15/2005
1235	b0221	6/1/2006	3/29/2006	Edgewood	Replace	Disconnect	Switch	69		8/5/2009	DPL				11/15/2005
1236	b0222	6/1/2006	5/31/2006	Loudoun	Install	Capacitor	150 MVAR	500		8/11/2009	Dominion				11/15/2005
1237	b0223	6/1/2006	5/31/2006	Ashburn	Install	Capacitor	150 MVAR	230		8/11/2009	Dominion				11/15/2005
1238	b0224	6/1/2006	5/31/2006	Dranesville	Install	Capacitor	150 MVAR	230		8/11/2009	Dominion				11/15/2005
1239	b0225	6/1/2006	5/31/2006	Possum Po	Install	Capacitor	33 MVAR c	115		8/11/2009	Dominion				11/15/2005
1240	b0226	6/30/2006	7/6/2006	Clifton	Install	Transform	150 MVAR	500		10/20/2010	Dominion				11/15/2005
1241	b0227	5/1/2009	6/11/2009	Bristers	Install	Transformer		500/230		8/14/2009	Dominion			Gen Delive	11/15/2005
1242	b0227.1	6/1/2009	2/28/2009	Loudoun	Upgrade	Breakers	6 - 201T2	230		8/11/2009	Dominion	2009		Short Circu	5/23/2006
1243	b0227.2	6/1/2009	6/11/2009	Brister-Gai	Build	Circuit		230		8/11/2009	Dominion			Gen Delive	11/15/2005
1244	b0227.3	6/1/2009	6/26/2006	Loudoun -	Upgrade	Circuit	Two			4/13/2011	Dominion			Gen Delive	11/15/2005
1245	b0228	6/1/2010	11/22/2010	Burtonsvill	Upgrade	Circuit		230	790/941	1/6/2011	PEPCO	2010	2005	Gen Delive	5/23/2006
1246	b0229	6/1/2009	4/23/2009	Bedington	Install	Transform	Fourth	500/138	430/485	4/13/2011	APS			Gen Delive	11/15/2005
1247	b0230	6/1/2008	5/31/2008	Meadow B	Install	Transform	Fourth	500/138	414/465	8/14/2009	APS			Gen Delive	11/15/2005
1248	b0231	6/1/2009	6/1/2009	Suffolk	Install	Breakers	and bus w	500		11/19/2009	Dominion			N-1-1	11/15/2005
1249	b0231.2	6/1/2009	6/1/2009	Suffolk	Install	Transform	Auto Trans	500/230		11/19/2009	Dominion			N-1-1	11/15/2005
1250	b0232	5/31/2006	5/15/2006	Lynnhaven	Install	Capacitor	150 MVAR	230		11/19/2009	Dominion			N-1-1	11/15/2005
1251	b0233	6/1/2009	6/15/2009	Landstown	Install	Capacitor	150 MVAR		150	4/26/2010	Dominion			N-1-1	11/15/2005
1252	b0234	6/1/2009	5/21/2009	Greenwich	Install	Capacitor	150 MVAR	230		11/19/2009	Dominion			N-1-1	11/15/2005
1253	b0235	6/1/2009	5/21/2009	Fentress	Install	Capacitor	150 MVAR	230		11/19/2009	Dominion			N-1-1	11/15/2005
1254	b0236.1	6/1/2008	12/9/2006	West Loop	Install	Substation	New at sub	138		8/6/2009	ComEd			Gen Delive	11/15/2005
1255	b0236.2	6/1/2008	4/26/2008	Crawford -	Install	Line	two new ci	345/138	########	4/13/2011	ComEd			Gen Delive	11/15/2005
1256	b0238	6/1/2009	6/1/2009	Doubs - Di	Reconductor		1200MVA	230	1117/1194	9/24/2009	APS		2007	Gen Delive	3/1/2006
1257	b0238.1	6/1/2009	6/1/2009	Dickerson	Upgrade	Substation	metering e	230		10/30/2009	PEPCO			Gen Delive	8/22/2007
1258	b0240	6/1/2010	1/13/2006	Black Oak		Transform	Open the E	500/138		8/14/2009	APS			Gen Delive	3/1/2006
1259	b0241.2	6/1/2009	6/1/2008	Edge Moor	Replace	Breaker	overstressed breakers			8/6/2009	DPL			Load Delive	3/1/2006
1260	b0241.3	6/1/2009	12/31/2008	Red Lion	Upgrade	Substation		500/230		8/14/2009	DPL			Load Delive	3/1/2006
1261	b0241.5	6/1/2007	12/31/2006	Keeney	Replace	Breaker	233	230		8/3/2009	DPL			Short Circu	3/1/2006
1262	b0241.6	6/1/2008	4/3/2007	Keeney	Replace	Breaker	235	230		8/3/2009	DPL			Short Circu	3/1/2006
1263	b0241.7	6/1/2007	12/31/2007	Keeney	Replace	Breaker	236	230		8/3/2009	DPL			Short Circu	3/1/2006
1264	b0241.8	6/1/2008	12/31/2007	Keeney	Replace	Breaker	237	230		8/3/2009	DPL			Short Circu	3/1/2006
1265	b0241.9	6/1/2008	5/4/2007	Keeney	Replace	Breaker	238	230		8/3/2009	DPL			Short Circu	3/1/2006
1266	b0244	6/1/2008	5/15/2010	Waugh Cha	Install	Transform	4th termin	500/230	1350/1630	7/14/2010	BGE	2008	2007	S MAAC Lo	3/1/2006
1267	b0245	6/1/2009	4/4/2008	Bedington	Replaceme	Conductor	Of the exis	138		6/19/2009	APS			Gen Delive	3/1/2006
1268	b0246	6/1/2009	10/30/2008	Double Tol	Reconductor		with 954 A	138	242/297	8/6/2009	APS			Gen Delive	3/1/2006
1269	b0247	6/1/2006	6/1/2006	Quince Orc	Install	Capacitor	14 MVAR c	69		8/5/2009	PEPCO				5/9/2005
1270	b0248	6/1/2006	6/1/2006	Norbeck	Install	Capacitor	14 MVAR c	69		8/5/2009	PEPCO				5/9/2005
1271	b0249	6/1/2006	12/2/2005	Bells Mill	Install	Capacitor	28 MVAR c	69		8/5/2009	PEPCO				10/30/2006
1272	b0250	6/1/2006	6/1/2006	various loc	Install	Capacitor	108 MVAR of feeder c		108	4/26/2010	PEPCO				5/9/2005
1273	b0251	6/1/2010	4/3/2010	Bells Mill	Install	Capacitor	50 MVAR	230		7/20/2010	PEPCO	2009	2008	Load Delive	5/23/2006
1274	b0251.1	6/1/2010	5/1/2010	Bells Mill	Install	Capacitor	50 MVAR			7/20/2010	PEPCO	2009		Load Delive	5/23/2006
1275	b0252	6/1/2010	8/8/2010	Bells Mill	Install	Capacitor	50 MVAR	230		8/9/2010	PEPCO	2009	2008	Load Delive	5/23/2006
1276	b0252.1	6/1/2010	8/23/2010	Bells Mill	Install	Capacitor	50 MVAR			9/16/2010	PEPCO	2009		Load Delive	5/23/2006
1277	b0253	6/1/2009	1/9/2008	Pine Creek	Convert	Substation	From 69kV	138		8/11/2009	DL	2009		Gen Delive	3/1/2006
1278	b0254	6/1/2009	12/31/2006	North	Convert	Substation	From 69kV	138		6/19/2009	DL			Gen Delive	3/1/2006

	A	P	Q	R	S	T	U	V	W	X	Y
3	Upgrade ID	Latest TEAC Date	Status	State	Region	County	Percent Co	Cost Estim	Project ID	In Schedul	Source
1208	b0194		IS	MD	PJM MA	Montgome	100	0.21	b0194	#N/A	Post-2005
1209	b0195		IS	MD	PJM MA	Montgome	100	0.59	b0195	#N/A	Post-2005
1210	b0196		IS	MD	PJM MA	Montgome	100	0.59	b0196	#N/A	Post-2005
1211	b0197		IS	MD	PJM MA	Montgome	100	0.59	b0197	#N/A	Post-2005
1212	b0199		IS	NJ	PJM MA		100	0.35	b0199	b0199	Post-2005
1213	b0200		IS	NJ	PJM MA		100	0.01	b0200	b0200	Post-2005
1214	b0201		IS	NJ	PJM MA		100	0.5	b0201	b0201	Post-2005
1215	b0202		IS	NJ	PJM MA		100	0.04	b0202	b0202	Post-2005
1216	b0203		IS	NJ	PJM MA		100	0.08	b0203	b0203	Post-2005
1217	b0204		IS	NJ	PJM MA		100	0.96	b0204	b0204	Post-2005
1218	b0205		IS	PA	PJM MA		100	2.2	b0205	b0205	Post-2005
1219	b0206		IS	PA	PJM MA		100	2	b0206	b0206	Post-2005
1220	b0207		IS	PA	PJM MA		100	2	b0207	b0207	Post-2005
1221	b0208		IS	PA	PJM MA		100	2	b0208	b0208	Post-2005
1222	b0209		IS	PA	PJM MA		100	3	b0209	b0209	Post-2005
1223	b0210		IS	NJ	PJM MA		100	52.09	b0210	b0210	Post-2005
1224	b0211		IS	NJ	PJM MA		100	6.22	b0211	b0211	Post-2005
1225	b0212		IS	NJ	PJM MA		100	0.07	b0212	b0212	Post-2005
1226	b0213.1		IS	NJ	PJM MA		100	0.38	b0213	b0213	Post-2005
1227	b0213.3		IS	NJ	PJM MA		100	0.38	b0213	b0213	Post-2005
1228	b0214		IS	NJ	PJM MA		100	2.65	b0214	b0214	Post-2005
1229	b0215		IS	PA	PJM MA		100	10	b0215	b0215	Post-2005
1230	b0216		IS	WV	PJM WEST		100	50	b0216	b0216	Post-2005
1231	b0217		IS	WV/VA/MI	PJM SOUTH		100	1.7	b0217	b0217	Post-2005
1232	b0218		IS	WV	PJM WEST		100	14.5	b0218	b0218	Post-2005
1233	b0219		IS	MD	PJM MA		100	91	b0219	b0219	Post-2005
1234	b0220		IS	WV	PJM WEST		100	0.36	b0220	b0220	Post-2005
1235	b0221		IS	MD	PJM MA		100	0.02	b0221	b0221	Post-2005
1236	b0222		IS	VA	PJM SOUTH		100	1.5	b0222	b0222	Post-2005
1237	b0223		IS	VA	PJM SOUTH		100	1	b0223	b0223	Post-2005
1238	b0224		IS	VA	PJM SOUTH		100	1	b0224	b0224	Post-2005
1239	b0225		IS	VA	PJM SOUTH		100	0.6	b0225	b0225	Post-2005
1240	b0226		IS	VA	PJM SOUTH		100	7.01	b0226	b0226	Post-2005
1241	b0227		IS	VA	PJM SOUTH		100	5.8	b0227	b0227	Post-2005
1242	b0227.1		IS	VA	PJM SOUTH		100	2	b0227	b0227	Post-2005
1243	b0227.2		IS	VA	PJM SOUTH		100	0	b0227	b0227	Post-2005
1244	b0227.3		IS	VA	PJM SOUTH		100	0	b0227	b0227	Post-2005
1245	b0228		IS	MD	PJM MA		100	0.93	b0228	b0228	Post-2005
1246	b0229		IS	WV	PJM WEST		100	7	b0229	b0229	Post-2005
1247	b0230		IS	VA	PJM WEST		100	7	b0230	b0230	Post-2005
1248	b0231		IS	VA	PJM SOUTH		100	5.03	b0231	b0231	Post-2005
1249	b0231.2		IS	VA	PJM SOUTH		100	12.3	b0231	b0231	Post-2005
1250	b0232		IS	VA	PJM SOUTH		100	1	b0232	b0232	Post-2005
1251	b0233		IS	VA	PJM SOUTH		100	1.84	b0233	b0233	Post-2005
1252	b0234		IS	VA	PJM SOUTH		100	1.86	b0234	b0234	Post-2005
1253	b0235		IS	VA	PJM SOUTH		100	1.89	b0235	b0235	Post-2005
1254	b0236.1		IS	IL	PJM WEST		100	61	b0236	b0236	Post-2005
1255	b0236.2		IS	IL	PJM WEST		100	331	b0236	b0236	Post-2005
1256	b0238		IS	MD	PJM WEST		100	9.6	b0238	b0238	Post-2005
1257	b0238.1		IS	MD	PJM WEST		100	1.1	b0238	b0238	Post-2005
1258	b0240		IS	WV	PJM WEST		100	0	b0240	b0240	Post-2005
1259	b0241.2		IS	DE	PJM MA		100	0.83	b0241	b0241	Post-2005
1260	b0241.3		IS	DE	PJM MA		100	12.63	b0241	b0241	Post-2005
1261	b0241.5		IS	DE	PJM MA		100	0.25	b0241	b0241	Post-2005
1262	b0241.6		IS	DE	PJM MA		100	0.25	b0241	b0241	Post-2005
1263	b0241.7		IS	DE	PJM MA		100	0.25	b0241	b0241	Post-2005
1264	b0241.8		IS	DE	PJM MA		100	0.25	b0241	b0241	Post-2005
1265	b0241.9		IS	DE	PJM MA		100	0.25	b0241	b0241	Post-2005
1266	b0244		IS	MD	PJM MA		100	40.4	b0244	b0244	Post-2005
1267	b0245		IS	WV	PJM WEST		100	1.7	b0245	b0245	Post-2005
1268	b0246		IS	VA	PJM WEST		100	1.95	b0246	b0246	Post-2005
1269	b0247		IS	MD	PJM MA		100	0.45	b0247	#N/A	Post-2005
1270	b0248		IS	MD	PJM MA		100	0.45	b0248	#N/A	Post-2005
1271	b0249		IS	MD	PJM MA		100	0.72	b0249	#N/A	Post-2005
1272	b0250		IS	MD	PJM MA		100	2.76	b0250	#N/A	Post-2005
1273	b0251		IS	MD	PJM MA		100	1.95	b0251	b0251	Post-2005
1274	b0251.1		IS	MD	PJM MA		100	1.95	b0251	b0251	Post-2005
1275	b0252		IS	MD	PJM MA		100	1.5	b0252	b0252	Post-2005
1276	b0252.1		IS	MD	PJM MA		100	1.5	b0252	b0252	Post-2005
1277	b0253		IS	PA	PJM WEST	Allegheny	100	5.7	b0253	b0253	Post-2005
1278	b0254		IS	PA	PJM WEST		100	3.9	b0254	b0254	Post-2005

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
3	Upgrade ID	PJM Required	In Service Date	Location	Task	Equipment	Descriptior	Voltage	Expected R	Last Updated	Trans Own	Study Year	Baseline R	Driver	Initial TEAC Da
1279	b0255	6/1/2010	1/6/2010	Highland	Convert	Substation	and Lines t	138	358/419	3/3/2010	DL	2009	2007	Gen Delive	3/1/2006
1280	b0256.1	6/1/2009	2/16/2007	Valley	Convert	Substation	From 69kV	138		6/19/2009	DL			Gen Delive	3/1/2006
1281	b0256.2	6/1/2010	4/6/2010	Valley - Cre	Reconductor		Z-82	138	223/252	7/14/2010	DL	2009	2007	Gen Delive	3/1/2006
1282	b0257.1	6/1/2009	6/1/2007	Wilmerdin	Convert	Substation	From 69kV	138		6/19/2009	DL			Gen Delive	3/1/2006
1283	b0257.2	6/1/2009	12/21/2006	Dravosburg	Convert	Substation	From 69kV	138		6/19/2009	DL			Gen Delive	3/1/2006
1284	b0258	6/1/2010	2/19/2009	Elrama	Replace	Transform	41 MVA tra	138/69	100/112	9/1/2009	DL			Gen Delive	3/1/2006
1285	b0261	6/1/2009	5/13/2009	Red Lion - I	Replace	Disconnect	1200 A	138		9/1/2009	DPL			DPL Load D	3/1/2006
1286	b0262	6/1/2009	11/13/2009	Christiana	Reconductor		0.5 mi	138		11/17/2009	DPL	2009	2007	Gen Delive	3/1/2006
1287	b0263	6/1/2010	5/23/2010	Indian Rive	Replace	Wave trap	1200 A	138		7/15/2010	DPL	2010	2005	Load Delive	3/1/2006
1288	b0264	6/1/2009	1/13/2009	Chichester	Upgrade	Circuit	and the PE	230		8/3/2009	PECO			EMAAC Loa	3/1/2006
1289	b0265	6/1/2009		Delco Tap	Upgrade	Circuit	AE portion	230		8/3/2009	AEC			Load Delive	3/1/2006
1290	b0266	6/1/2009	3/11/2009	Peach Bott	Replace	Wave trap	and amme	230		8/3/2009	PECO			EMAAC Loa	3/1/2006
1291	b0269	6/1/2011	5/3/2011	PECO	Install	Substation	in PECO an	500		6/23/2011	PECO	2010		EMAAC Loa	3/1/2006
1292	b0269.6	6/1/2011	5/3/2011	Whitpain	Add	Breaker	between #	500		6/23/2011	PECO	2010	2005	EMAAC Loa	3/1/2006
1293	b0269.7	6/1/2011	3/4/2011	North Wal	Upgrade	Breaker	105	230		3/17/2011	PECO	2010	2008	Short Circu	5/9/2007
1294	b0269.8	6/1/2011	10/30/2010	Waneeta	Replace	Breaker	285	230		11/9/2010	PECO	2010	2008	Short Circu	5/9/2007
1295	b0274	6/1/2009	5/31/2009	Roseland	Replace	Transform	3 & 4	230/138	606/807	1/20/2010	PSEG	2010		PSEG Load	3/1/2006
1296	b0275	6/1/2010	4/1/2010	Roseland -	Upgrade	Circuits	from Rosel	138	412/488	9/14/2010	PSEG	2010		PSEG Load	3/1/2006
1297	b0276	6/1/2009	5/14/2009	Monroe	Replace	Transform	Two transf	230/69		11/19/2009	AEC			AE Load De	3/1/2006
1298	b0276.1	5/31/2011	5/15/2011	Monroe	Upgrade	Strand bus	Upgrade a strand bus at Monroe			6/23/2011	AEC			NERC Cate	5/27/2010
1299	b0277	6/1/2009	7/1/2009	Cumberlan	Install	Transform	Second tra	230/138		11/19/2009	AEC			AE Load De	3/1/2006
1300	b0278	6/1/2009	5/30/2009	Roseland	Install	Capacitor	228MVAR	230	228 MVAR	7/22/2009	PSEG			EMAAC Loa	3/1/2006
1301	b0279.10	6/1/2009	1/13/2010	Hamburg	Install	Capacitor	6.6MVAR at Q Bus		6.6	4/26/2010	JCPL	2009		Voltage Vio	3/1/2006
1302	b0279.11	6/1/2009	8/25/2009	Newburg	Install	Capacitor	6.6MVAR a	34		9/23/2009	JCPL			Voltage Vio	3/1/2006
1303	b0279.2	6/1/2009	7/27/2007	Kittatinny	Install	Capacitor	100MVAR	230		6/19/2009	JCPL			Voltage Vio	3/1/2006
1304	b0279.4	6/1/2009	6/5/2007	Waretown	Install	Capacitor	6.6MVAR	34		6/19/2009	JCPL			Voltage Vio	3/1/2006
1305	b0279.5	6/1/2009	6/1/2007	Spottswoo	Install	Capacitor	10.8MVAR	34		8/5/2009	JCPL			Voltage Vio	3/1/2006
1306	b0279.6	6/1/2009	5/24/2007	Pequannoc	Install	Capacitor	6.6MVAR	34		6/19/2009	JCPL			Voltage Vio	3/1/2006
1307	b0279.7	6/1/2009	5/24/2007	Haskell	Install	Capacitor	6.6MVAR	34		6/19/2009	JCPL			Voltage Vio	3/1/2006
1308	b0279.9	6/1/2009	12/31/2010	Blairstown	Install	Capacitor	6.6MVAR	34		3/10/2011	JCPL	2009	2008	Voltage Vio	3/1/2006
1309	b0280.1	6/1/2009	3/22/2009	Warringtor	Install	Capacitor	161MVAR	230		8/3/2009	PECO			EMAAC Loa	3/1/2006
1310	b0280.2	6/1/2009	5/15/2009	Bradford	Install	Capacitor	161MVAR	230		8/20/2009	PECO			EMAAC Loa	3/1/2006
1311	b0280.3	6/1/2009	6/1/2007	Warringtor	Install	Capacitor	28.8MVAR	34		8/3/2009	PECO			EMAAC Loa	3/1/2006
1312	b0280.4	6/1/2009	6/1/2007	Waverly	Install	Capacitor	18MVAR	14		8/3/2009	PECO			EMAAC Loa	3/1/2006
1313	b0281.1	6/1/2009	5/15/2009	Lake Ave	Install	Capacitor	35 MVAR	69		7/28/2009	AEC			EMAAC Loa	3/1/2006
1314	b0281.2	6/1/2009	5/24/2010	Shipbottor	Install	Capacitor	15 MVAR	69		7/15/2010	AEC			EMAAC Loa	3/1/2006
1315	b0281.3	6/1/2009	12/31/2008	AE distribu	Install	Capacitor	8 MVAR		8	4/26/2010	AEC			EMAAC Loa	3/1/2006
1316	b0282	6/1/2009	12/31/2008	DPL distrib	Install	Capacitor	46 MVAR		46	4/26/2010	DPL			EMAAC Loa	3/1/2006
1317	b0284.2	6/1/2013	5/31/2009	Juniata	Replace	Wave Trap	Upgrade te	500	2932 / 372	11/14/2010	PPL		2008	EMAAC Loa	3/1/2006
1318	b0286	6/1/2009	11/15/2007	Whippany	Install	Capacitor	130MVAR	230		6/19/2009	JCPL			Voltage Vio	3/1/2006
1319	b0287	6/1/2009	5/29/2009	Elroy	Install	Capacitor	600 MVAR	500		8/5/2009	PECO			EMAAC Loa	3/1/2006
1320	b0288	6/1/2009	6/21/2009	Brighton Su	Add	Transform	2nd 1000 I	500		9/23/2009	PEPCO			Load Delive	3/1/2006
1321	b0291	6/1/2009	5/15/2009	Harmony	Replace	Disconnect	1600A, inc	230		8/3/2009	DPL			Gen Delive	3/1/2006
1322	b0292	6/1/2009	5/22/2009	Atlantic - L	Upgrade	Line Trap	1600A, ter	230		9/23/2009	JCPL		2008	Gen Delive	3/1/2006
1323	b0293.1	6/1/2010	10/22/2010	Martins Cr	Upgrade	Wave Trap	terminal e	230		11/11/2010	PPL	2011	2006	Gen Delive	5/23/2006
1324	b0295	6/1/2009	4/30/2009	North Seaf	Increase	Circuit	Conductor	69		7/21/2009	DPL			DPL South	3/1/2006
1325	b0296	6/1/2008	6/1/2008	Rehoboth	Upgrade	Circuit	6733-2			11/19/2009	DPL			AE Load De	3/1/2006
1326	b0298	6/1/2009	5/20/2009	Conastone	Upgrade	Transform	both trans	500/345	1350/1500	8/24/2009	BGE			S MAAC Lo	3/1/2006
1327	b0298.1	6/1/2008	9/23/2007	Conastone	Replace	Breakers	500-3/232	230		8/3/2009	BGE			Short Circu	8/22/2007
1328	b0299	6/1/2007	4/29/2007	LaSalle Cou	Upgrade	Transmissi	line 0108 v	138		8/6/2009	ComEd			Load Delive	3/1/2006
1329	b0301	6/1/2007	2/22/2007	Wolfs-Osw	Increase	Transmissi	capacity lir	138		8/11/2009	ComEd	2007		Gen Delive	3/1/2006
1330	b0302	6/1/2007	5/12/2007	Dixon-McG	Replace	Conductor	Small piece	138		8/6/2009	ComEd			Load Delive	3/1/2006
1331	b0303	6/1/2008	4/9/2008	Elwood	Install	Circuit Bre	and change	345		4/13/2011	ComEd	2009		Gen Delive	3/1/2006
1332	b0305	6/1/2008	5/1/2008	East Frankl	Normally C	Bus Tie	Red Blue	138		4/13/2011	ComEd	2009		Load Delive	3/1/2006
1333	b0306	6/1/2007	4/7/2007	Electric Jur	Reconductor		Line 11104	0.3 miles		8/11/2009	ComEd	2007		Gen Delive	5/23/2006
							Line #128								
1334	b0307	6/1/2009	6/19/2009	Endless Ca	Reconductor		Line #128	115		8/11/2009	Dominion	2009		Gen Delive	3/1/2006
1335	b0308	6/1/2009	3/15/2007	Endless Ca	Replace	Breaker	L Breaker,	115		8/11/2009	Dominion	2009		Gen Delive	3/1/2006
1336	b0309	6/1/2010	5/31/2007	Carolina	Install	SPS		115		8/11/2009	Dominion	2010		Gen Delive	3/1/2006
1337	b0310	6/1/2010	11/10/2010	Club House	Reconductor			115	347 / 347	11/10/2010	Dominion	2010	2005	Gen Delive	3/1/2006
1338	b0311	6/1/2010	8/11/2010	Idywood -	Reconductor		circuit 251	230	797 / 797	8/12/2010	Dominion	2010		Gen Delive	3/1/2006
1339	b0312	6/1/2010	8/11/2010	Gallows - C	Reconductor			230	851/851	1/20/2011	Dominion	2010	2005	Gen Delive	3/1/2006
1340	b0314	6/1/2009	4/15/2007	Closter	Install	Capacitor	32 MVAR	69		6/19/2009	RECO			Voltage Vio	3/1/2006
1341	b0316	6/1/2009	4/21/2009	Laurel - Mu	Upgrade	Circuit	to increase	69		8/5/2009	DPL			DPL South	3/1/2006
1342	b0318	6/1/2010	6/25/2008	Amos	Install	Transform	New	765		4/13/2011	AEP	2010		NERC Cate	5/23/2006
1343	b0320	6/1/2010	7/5/2010	Milford - Ir	Build	Substation	that splits t	230		7/15/2010	DPL	2010	2005	Load Delive	5/23/2006
1344	b0322	6/1/2011	5/29/2008	Lime Kiln	Convert	Substation		230	482/593	8/11/2009	APS	2011		NERC Cate	5/23/2006
1345	b0323	6/1/2008	5/23/2008	North Sher	Replace	Transformer		138/115	200/224	8/28/2009	APS	2008		NERC Cate	5/23/2006
1346	b0326	6/1/2011	6/18/2009	Remington	Upgrade	Circuit	Line 70	115		8/11/2009	Dominion	2011		NERC Cate	5/23/2006
1347	b0327	6/1/2010	6/11/2010	Harrisonbu	Install	Circuit	2nd	230	721/721	6/15/2010	Dominion	2010	2005	NERC Cate	5/23/2006
1348	b0329.1	6/1/2011	6/10/2009	Thole Stree	Replace	Breaker	breaker '48	115		9/11/2010	Dominion	2014	2009	Short Circu	11/18/2009

	A	P	Q	R	S	T	U	V	W	X	Y
3	Upgrade ID	Latest TEAC Date	Status	State	Region	County	Percent Co	Cost Estim	Project ID	In Schedul	Source
1279	b0255		IS	PA	PJM WEST		100	21.1	b0255	b0255	Post-2005
1280	b0256.1		IS	PA	PJM WEST		100	1.6	b0256	b0256	Post-2005
1281	b0256.2		IS	PA	PJM WEST		100	6.9	b0256	b0256	Post-2005
1282	b0257.1		IS	PA	PJM WEST		100	2.7	b0257	b0257	Post-2005
1283	b0257.2		IS	PA	PJM WEST		100	0.42	b0257	b0257	Post-2005
1284	b0258		IS	PA	PJM WEST		100	2.3	b0258	b0258	Post-2005
1285	b0261		IS	DE	PJM MA		100	0.08	b0261	b0261	Post-2005
1286	b0262		IS	DE	PJM MA		100	0.33	b0262	b0262	Post-2005
1287	b0263		IS	DE	PJM MA		100	0.16	b0263	b0263	Post-2005
1288	b0264		IS	PA	PJM MA		100	4.5	b0264	b0264	Post-2005
1289	b0265		IS	NJ	PJM MA		100	6	b0265	b0265	Post-2005
1290	b0266		IS	PA	PJM MA		100	0.8	b0266	b0266	Post-2005
1291	b0269		IS	PA	PJM MA		100	45.2	b0269	b0269	Post-2005
1292	b0269.6		IS	PA	PJM MA		100	2.5	b0269	b0269	Post-2005
1293	b0269.7		IS	PA	PJM MA		100	0.15	b0269	b0269	Post-2005
1294	b0269.8		IS	PA	PJM MA		100	0.75	b0269	b0269	Post-2005
1295	b0274		IS	NJ	PJM MA		100	15	b0274	b0274	Post-2005
1296	b0275		IS	NJ	PJM MA		100	5	b0275	b0275	Post-2005
1297	b0276		IS	NJ	PJM MA	Gloucester	100	6.88	b0276	b0276	Post-2005
1298	b0276.1		IS		PJM MA		0	0.25	b0276	b0276	Post-2005
1299	b0277		IS	NJ	PJM MA		100	4.9	b0277	b0277	Post-2005
1300	b0278		IS	NJ	PJM MA		100	6	b0278	b0278	Post-2005
1301	b0279.10		IS	NJ	PJM MA		100	0.27	b0279	b0279	Post-2005
1302	b0279.11		IS	NJ	PJM MA		100	0.27	b0279	b0279	Post-2005
1303	b0279.2		IS	NJ	PJM MA		100	0.96	b0279	b0279	Post-2005
1304	b0279.4		IS	NJ	PJM MA		100	0.27	b0279	b0279	Post-2005
1305	b0279.5		IS	NJ	PJM MA		100	0.43	b0279	b0279	Post-2005
1306	b0279.6		IS	NJ	PJM MA		100	0.27	b0279	b0279	Post-2005
1307	b0279.7		IS	NJ	PJM MA		100	0.27	b0279	b0279	Post-2005
1308	b0279.9		IS	NJ	PJM MA		100	0.27	b0279	b0279	Post-2005
1309	b0280.1		IS	PA	PJM MA		100	2.8	b0280	b0280	Post-2005
1310	b0280.2		IS	PA	PJM MA		100	3	b0280	b0280	Post-2005
1311	b0280.3		IS	PA	PJM MA		100	0.75	b0280	b0280	Post-2005
1312	b0280.4		IS	PA	PJM MA		100	0.5	b0280	b0280	Post-2005
1313	b0281.1		IS	NJ	PJM MA		100	2.4	b0281	b0281	Post-2005
1314	b0281.2		IS	NJ	PJM MA		100	1.4	b0281	b0281	Post-2005
1315	b0281.3		IS	NJ	PJM MA		100	0.2	b0281	b0281	Post-2005
1316	b0282		IS	DE/MD	PJM MA		100	1.2	b0282	b0282	Post-2005
1317	b0284.2		IS	PA	PJM MA		100	0.24	b0284	b0284	Post-2005
1318	b0286		IS	NJ	PJM MA		100	1.4	b0286	b0286	Post-2005
1319	b0287		IS	PA	PJM MA		100	10.5	b0287	b0287	Post-2005
1320	b0288		IS	MD	PJM MA		100	33.4	b0288	b0288	Post-2005
1321	b0291		IS	DE	PJM MA		100	0.85	b0291	b0291	Post-2005
1322	b0292		IS	NJ	PJM MA		100	0.1	b0292	b0292	Post-2005
1323	b0293.1		IS	PA	PJM MA		100	0.23	b0293	b0293	Post-2005
1324	b0295		IS	DE	PJM MA		100	0.3	b0295	b0295	Post-2005
1325	b0296		IS	DE	PJM MA		100	1.7	b0296	b0296	Post-2005
1326	b0298		IS	MD	PJM MA		100	55	b0298	b0298	Post-2005
1327	b0298.1		IS	MD	PJM MA		100	1	b0298	b0298	Post-2005
1328	b0299		IS	IL	PJM WEST		100	2.13	b0299	b0299	Post-2005
1329	b0301		IS	IL	PJM WEST	Kendall/W	100	2.13	b0301	b0301	Post-2005
1330	b0302		IS	IL	PJM WEST		100	3.73	b0302	b0302	Post-2005
1331	b0303		IS	IL	PJM WEST		100	2	b0303	b0303	Post-2005
1332	b0305		IS	IL	PJM WEST		100	0	b0305	b0305	Post-2005
1333	b0306		IS	IL	PJM WEST		100	1	b0306	b0306	Post-2005
1334	b0307		IS	VA	PJM SOUTH		90	4.6	b0307	b0307	Post-2005
1335	b0308		IS	VA	PJM SOUTH		100	0.6	b0308	b0308	Post-2005
1336	b0309		IS	NC	PJM SOUTH		100	1	b0309	b0309	Post-2005
1337	b0310		IS	VA	PJM SOUTH		100	20.3	b0310	b0310	Post-2005
1338	b0311		IS	VA	PJM SOUTH		100	3.1	b0311	b0311	Post-2005
1339	b0312		IS	VA	PJM SOUTH		100	5.4	b0312	b0312	Post-2005
1340	b0314		IS	NJ	PJM MA		100	0.38	b0314	b0314	Post-2005
1341	b0316		IS	DE	PJM MA		100	0.8	b0316	#N/A	Post-2005
1342	b0318		IS	WV	PJM WEST		100	13.44	b0318	b0318	Post-2005
1343	b0320		IS	DE	PJM MA		100	15	b0320	b0320	Post-2005
1344	b0322		IS	MD	PJM WEST		100	4.2	b0322	b0322	Post-2005
1345	b0323		IS	VA	PJM WEST		100	2	b0323	b0323	Post-2005
1346	b0326		IS	VA	PJM SOUTH		100	12.8	b0326	b0326	Post-2005
1347	b0327		IS	VA	PJM SOUTH		100	6	b0327	b0327	Post-2005
1348	b0329.1		IS	VA	PJM SOUTH		100	0.16	b0329	b0329	Post-2005

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
3	Upgrade ID	PJM Required	In Service Date	Location	Task	Equipment	Descriptior	Voltage	Expected R	Last Updated	Trans Own	Study Year	Baseline Re	Driver	Initial TEAC Da
1349	b0329.2	6/1/2011	2/10/2011	Chesapeak	Replace	Breaker	breaker 'T2	115		4/19/2011	Dominion	2014	2009	Short Circu	11/18/2009
1350	b0331	6/1/2011	5/21/2009	Shell Bank	Upgrade	Circuit	resag Line	115		8/11/2009	Dominion	2011		NERC Cate	5/23/2006
1351	b0333	6/1/2011	12/14/2007	Elmont	Replace	Wave Trap	#231	230	722/722	9/11/2010	Dominion	2011	2006	NERC Cate	5/23/2006
1352	b0337	6/1/2009	5/14/2009	Lexington	Reconfigur	Bus		230		6/16/2010	Dominion	2009		NERC Cate	5/23/2006
1353	b0338	6/1/2011	5/14/2010	Gordonsvil	Replace	Transform	#1 with a l	230/115	240/240	6/16/2010	Dominion	2011		Gen Delive	5/23/2006
1354	b0339	6/1/2009	3/27/2009	Dooms	Install	Circuit Breaker		230		8/11/2009	Dominion	2009		Short Circu	5/23/2006
1355	b0340	6/1/2010	4/20/2009	Peninsula-I	Reconductor		One span c	115		8/11/2009	Dominion	2010		NERC Cate	5/23/2006
1356	b0341	6/1/2006	4/10/2006	Northern N	Install	Breaker		115		8/11/2009	Dominion	2006		NERC Cate	5/23/2006
1357	b0342	6/1/2010	5/19/2010	Trowbridg	Install	Transform	2nd	230/115	175.1/180.	6/16/2010	Dominion	2010	2005	NERC Cate	5/23/2006
1358	b0343	6/1/2011	11/19/2010	Doubs	Replace	Transform	#2	500/230	585/677	12/30/2010	APS	2011	2006	Load Delive	5/23/2006
1359	b0345	6/1/2011	5/28/2010	Doubs	Replace	Transform	#4	500/230	585/677	8/24/2010	APS	2011	2006	Load Delive	5/23/2006
1360	b0347.10	6/1/2011	6/4/2010	Hatfield	Replace	Breaker	Upgrade (p	500	40558	3/9/2011	APS		2008	Short Circu	7/16/2008
1361	b0347.11	6/1/2011	6/4/2010	Hatfield	Replace	Breaker	Upgrade (p	500	40558	3/9/2011	APS		2008	Short Circu	7/16/2008
1362	b0347.12	6/1/2011	6/4/2010	Hatfield	Replace	Breaker	Upgrade (p	500	40558	3/9/2011	APS		2008	Short Circu	7/16/2008
1363	b0347.13	6/1/2011	6/4/2010	Hatfield	Replace	Breaker	Upgrade (p	500	40558	3/9/2011	APS		2008	Short Circu	7/16/2008
1364	b0347.14	6/1/2011	6/4/2010	Hatfield	Replace	Breaker	Upgrade (p	500	40558	3/9/2011	APS		2008	Short Circu	7/16/2008
1365	b0347.15	6/1/2011	6/4/2010	Hatfield	Replace	Breaker	Upgrade (p	500	40558	3/9/2011	APS		2008	Short Circu	7/16/2008
1366	b0347.16	6/1/2011	4/23/2010	Harrison	Upgrade	Breaker	Upgrade (p	500	50kA	9/14/2010	APS			Short Circu	9/16/2009
1367	b0347.17	6/1/2011	11/12/2010	Meadow B	Replace	Breaker	Replace M	138		1/31/2011	APS	2011		Short Circu	1/13/2010
1368	b0347.18	6/1/2011	1/18/2011	Meadow B	Replace	Breaker	Replace M	138		3/9/2011	APS	2011		Short Circu	1/13/2010
1369	b0347.20	6/1/2011	12/2/2010	Meadow B	Replace	Breaker	Replace M	138		1/31/2011	APS	2011		Short Circu	1/13/2010
1370	b0347.21	6/1/2011	2/9/2011	Meadow B	Replace	Breaker	Replace M	138		3/9/2011	APS	2011		Short Circu	1/13/2010
1371	b0347.23	6/1/2011	11/2/2010	Meadow B	Replace	Breaker	Replace M	138		1/31/2011	APS	2011		Short Circu	1/13/2010
1372	b0347.24	6/1/2011	1/14/2011	Meadow B	Replace	Breaker	Replace M	138		3/9/2011	APS	2011		Short Circu	1/13/2010
1373	b0347.28	6/1/2011	2/23/2011	Meadow B	Replace	Breaker	Replace M	138		3/9/2011	APS	2011		Short Circu	1/13/2010
1374	b0347.3	6/1/2011	4/17/2010	502 Junctic	Build	Substation	New 502	500		9/14/2010	APS	2011	2008	Load Delive	5/23/2006
1375	b0347.30	6/1/2011	1/6/2011	Meadow B	Replace	Breaker	Replace M	138		3/9/2011	APS	2011		Short Circu	1/13/2010
1376	b0347.31	6/1/2011	2/15/2011	Meadow B	Replace	Breaker	Replace M	138		3/9/2011	APS	2011		Short Circu	1/13/2010
1377	b0347.5	6/1/2011	12/11/2007	Harrison	Replace	Breaker	HL-3	500	40474	8/5/2009	APS			Short Circu	7/16/2008
1378	b0347.6	6/1/2011	4/1/2010	Harrison	Replace	Breaker	Upgrade (p	500	40474	3/9/2011	APS		2008	Short Circu	7/16/2008
1379	b0347.7	6/1/2011	4/1/2010	Harrison	Replace	Breaker	Upgrade (p	500	40474	3/9/2011	APS		2008	Short Circu	7/16/2008
1380	b0347.8	6/1/2011	4/1/2010	Harrison	Replace	Breaker	Upgrade (p	500	40474	3/9/2011	APS		2008	Short Circu	7/16/2008
1381	b0347.9	6/1/2011	4/1/2010	Harrison	Replace	Breaker	Upgrade (p	500	40474	3/9/2011	APS		2008	Short Circu	7/16/2008
1382	b0348	6/1/2011	11/12/2010	Stonewall -	Upgrade	Conductor	With 954 A	138	242/297	12/30/2010	APS	2010	2006	NERC Cate	5/23/2006
1383	b0350	5/1/2011	11/19/2007	Glendon - (	Implement		Operating	115		8/11/2009	JCPL	2011		Gen Delive	5/23/2006
1384	b0351	6/1/2011	2/11/2011	Tunnel - Gr	Replace	Terminal E	at Greys Fe	230	1395	3/17/2011	PECO	2011	2008	Gen Delive	5/23/2006
1385	b0352	5/27/2011	5/20/2011	Tunnel - Pa	Reconductor		at Parrish I	230	1395	6/23/2011	PECO	2011	2006	Gen Delive	5/23/2006
1386	b0353.1	6/1/2011	11/19/2010	Eddystone	Install	Reactor	3% series r	138		1/20/2011	PECO	2011	2006	Gen Delive	5/23/2006
1387	b0353.2	6/1/2011	4/27/2011	Plymouth I	Install	Transform	Identical se	230/138		5/5/2011	PECO	2011	2006	Gen Delive	5/23/2006
1388	b0353.3	6/1/2011	5/13/2011	Whitpain	Replace	Breaker	135	230		6/23/2011	PECO	2011	2008	Short Circu	10/15/2008
1389	b0353.4	6/1/2011	2/15/2011	Whitpain	Replace	Breaker	145	230		3/17/2011	PECO	2011	2008	Short Circu	10/15/2008
1390	b0354	6/1/2011	12/10/2010	Eddystone	Upgrade	Terminal E	Eddystone	230	1411	1/20/2011	PECO	2011	2008	Gen Delive	5/23/2006
1391	b0356	5/1/2011	5/5/2008	Portland - (	Replace	Wave Trap		230		8/11/2009	JCPL/ME	2011		NERC Cate	5/23/2006
1392	b0357	6/1/2011	5/16/2011	Buckinghai	Reconductor		(PECO port	230	760/882	6/23/2011	PECO	2011	2006	NERC Cate	5/23/2006
1393	b0361	5/1/2011	1/19/2010	Morristow	Replace	Current Tra	Change tap of limiting CT			1/19/2011	JCPL	2011	2008	NERC Cate	5/23/2006
1394	b0362	5/1/2011	1/19/2010	Pohatcong	Replace	Current Tra	Change tap setting of limiting CT			1/19/2011	JCPL	2011	2008	NERC Cate	5/23/2006
1395	b0363	5/1/2011	1/19/2010	Windsor	Replace	Current Tra	Change tap setting of limiting CT			1/19/2011	JCPL	2011	2008	NERC Cate	5/23/2006
1396	b0364	5/1/2011	1/19/2010	Cookstowr	Replace	Current Tra	Change tap setting of CT			1/19/2011	JCPL	2011	2008	NERC Cate	5/23/2006
1397	b0366	6/1/2011	10/8/2010	Richie	Install	Transform	4th	230/69	252/263.5/	10/22/2010	PEPCO	2011	2008	NERC Cate	5/23/2006
1398	b0371	6/1/2011	2/28/2009	Metuchen	Close	Breaker	Close Tie Breaker 1-3 & replace b			8/11/2009	PSEG	2010		NERC Cate	5/23/2006
1399	b0372	6/1/2011	5/1/2010	Athenia	Close	Breaker	1-2 & replace 2BH (bus 2-3), 5LH			6/1/2010	PSEG	2010	2005	NERC Cate	5/23/2006
1400	b0373	6/1/2011	5/29/2009	Doubs - M	Convert	Line	Facilities tc	230	482/593	8/11/2009	APS	2009		NERC Cate	5/23/2006
1401	b0380	6/1/2010	3/15/2008	Burnham -	Reconductor		17713 from Burnham - Wildwood			8/11/2009	ComEd	2010		NERC Cate	5/23/2006
1402	b0382	6/1/2009	6/1/2007	Cambridge	Close	Substation	Through to Todd Substation			8/11/2009	DPL	2009		DPL Local (	10/30/2006
1403	b0383	6/1/2009	6/6/2006	Wye Mills	Replaceme	Transform	AT-1 and A	138/69		8/28/2009	DPL	2009		DPL Local (	10/30/2006
1404	b0384	6/1/2009	6/12/2006	Indian Rive	Replace	Transform	Indian River AT-20 (40		400	4/26/2010	DPL	2009		DPL Local (	10/30/2006
1405	b0385	6/1/2009	5/31/2008	Oak Hall - I	Upgrades	Circuit	#13765			8/11/2009	DPL	2009		DPL Local (	10/30/2006
1406	b0386	6/1/2009	5/22/2007	Cheswold -	Rebuild	Circuit	#6768			8/11/2009	DPL	2009		DPL Local (	10/30/2006
1407	b0387	6/1/2009	5/31/2008	N. Seaford	Add	Autotransf	2nd Autotr	138/69		8/28/2009	DPL	2009		DPL Local (	10/30/2006
1408	b0388	6/1/2009	12/1/2008	Hallwood -	Upgrade	Transmissi	(6790-2)			8/11/2009	DPL	2009		DPL Local (	10/30/2006
1409	b0389	6/1/2009	10/23/2009	Indian Rive	Replace	Transform	AT-1 and A	138/69		11/16/2009	DPL	2009		DPL Local (	10/30/2006
1410	b0390	6/1/2009	5/25/2006	Rehoboth -	Upgrade	Transmissi	Rehoboth/Lewes (6751-1 & 6751-			8/11/2009	DPL	2009		DPL Local (	10/30/2006
1411	b0392	6/1/2009	6/8/2007	East New N	Construct	Bus	Arrangeme	69		8/11/2009	DPL	2009		DPL Local (	10/30/2006
1412	b0393	6/1/2010	5/1/2008	Harrison - I	Replace	Terminal Equipment		500		8/11/2009	APS	2010		NERC Cate	10/30/2006
1413	b0394	6/1/2010	4/27/2008	Wolfs-Fron	Reconductor		2.8 Miles o	138		8/28/2009	ComEd	2010		NERC Cate	10/30/2006
1414	b0401.1	6/1/2009	10/30/2008	Roseland	Replace	Breaker	BS 6-7	230		8/11/2009	PSEG	2009		Short Circu	10/30/2006
1415	b0401.2	6/1/2009	10/30/2008	Roseland	Replace	Breaker	O-1315	138		8/11/2009	PSEG	2009		Short Circu	10/30/2006
1416	b0401.3	6/1/2009	2/26/2009	Roseland	Replace	Breaker	Breaker S-	138		8/11/2009	PSEG	2009 RTEP Baseline - l		Short Circu	10/30/2006
1417	b0401.4	6/1/2009	1/15/2009	Roseland	Replace	Breaker	Breaker T-	138		8/11/2009	PSEG	2009 RTEP Baseline - l		Short Circu	10/30/2006
1418	b0401.5	6/1/2009	12/31/2008	Roseland	Replace	Breaker	Breaker G-	138		8/11/2009	PSEG	2009 RTEP Baseline - l		Short Circu	10/30/2006
1419	b0401.6	6/1/2009	2/7/2009	Roseland	Replace	Breaker	Breaker P-	138		8/11/2009	PSEG	2009 RTEP Baseline - l		Short Circu	10/30/2006

	A	P	Q	R	S	T	U	V	W	X	Y
3	Upgrade ID	Latest TEAC Date	Status	State	Region	County	Percent Co	Cost Estim	Project ID	In Schedul	Source
1349	b0329.2		IS	VA	PJM SOUTH		100	0.18	b0329	b0329	Post-2005
1350	b0331		IS	VA	PJM SOUTH		100	11	b0331	b0331	Post-2005
1351	b0333		IS	VA	PJM SOUTH		100	0.01	b0333	b0333	Post-2005
1352	b0337		IS	VA	PJM SOUTH		100	6.5	b0337	b0337	Post-2005
1353	b0338		IS	VA	PJM SOUTH		100	3.3	b0338	b0338	Post-2005
1354	b0339		IS	VA	PJM SOUTH		100	2.5	b0339	b0339	Post-2005
1355	b0340		IS	VA	PJM SOUTH		100	0.05	b0340	b0340	Post-2005
1356	b0341		IS	VA	PJM SOUTH		100	0.5	b0341	b0341	Post-2005
1357	b0342		IS	NC	PJM SOUTH		100	3.3	b0342	b0342	Post-2005
1358	b0343		IS	MD	PJM WEST		100	5.2	b0343	b0343	Post-2005
1359	b0345		IS	MD	PJM WEST		100	5.3	b0345	b0345	Post-2005
1360	b0347.10		IS		PJM WEST		100	0.06	b0347	b0347	Post-2005
1361	b0347.11		IS		PJM WEST		100	0.06	b0347	b0347	Post-2005
1362	b0347.12		IS		PJM WEST		100	0.06	b0347	b0347	Post-2005
1363	b0347.13		IS		PJM WEST		100	0.06	b0347	b0347	Post-2005
1364	b0347.14		IS		PJM WEST		100	0.06	b0347	b0347	Post-2005
1365	b0347.15		IS		PJM WEST		100	0.06	b0347	b0347	Post-2005
1366	b0347.16		IS		PJM WEST		100	0.06	b0347	b0347	Post-2005
1367	b0347.17		IS		PJM WEST		100	0.19	b0347	b0347	Post-2005
1368	b0347.18		IS		PJM WEST		100	0.19	b0347	b0347	Post-2005
1369	b0347.20		IS		PJM WEST		100	0.19	b0347	b0347	Post-2005
1370	b0347.21		IS		PJM WEST		100	0.19	b0347	b0347	Post-2005
1371	b0347.23		IS		PJM WEST		100	0.19	b0347	b0347	Post-2005
1372	b0347.24		IS		PJM WEST		100	0.19	b0347	b0347	Post-2005
1373	b0347.28		IS		PJM WEST		100	0.19	b0347	b0347	Post-2005
1374	b0347.3		IS	PA	PJM WEST		100	88	b0347	b0347	Post-2005
1375	b0347.30		IS		PJM WEST		100	0.19	b0347	b0347	Post-2005
1376	b0347.31		IS		PJM WEST		100	0.19	b0347	b0347	Post-2005
1377	b0347.5		IS		PJM WEST		100	0.7	b0347	b0347	Post-2005
1378	b0347.6		IS		PJM WEST		100	0.06	b0347	b0347	Post-2005
1379	b0347.7		IS		PJM WEST		100	0.06	b0347	b0347	Post-2005
1380	b0347.8		IS		PJM WEST		100	0.06	b0347	b0347	Post-2005
1381	b0347.9		IS		PJM WEST		100	0.06	b0347	b0347	Post-2005
1382	b0348		IS	WV/VA	PJM WEST		100	1.6	b0348	b0348	Post-2005
1383	b0350		IS	NJ	PJM MA		100	0.4	b0350	b0350	Post-2005
1384	b0351		IS	PA	PJM MA		100	0.75	b0351	b0351	Post-2005
1385	b0352		IS	PA	PJM MA		100	0.67	b0352	b0352	Post-2005
1386	b0353.1		IS	PA	PJM MA		100	2.1	b0353	b0353	Post-2005
1387	b0353.2		IS	PA	PJM MA		100	8.54	b0353	b0353	Post-2005
1388	b0353.3		IS	PA	PJM MA		100	0.5	b0353	b0353	Post-2005
1389	b0353.4		IS	PA	PJM MA		100	0.5	b0353	b0353	Post-2005
1390	b0354		IS	PA	PJM MA		100	1.1	b0354	b0354	Post-2005
1391	b0356		IS	NJ	PJM MA		100	0.08	b0356	b0356	Post-2005
1392	b0357		IS	PA	PJM MA		100	6.2	b0357	b0357	Post-2005
1393	b0361		IS	NJ	PJM MA		100	0.03	b0361	b0361	Post-2005
1394	b0362		IS	NJ	PJM MA		100	0.03	b0362	b0362	Post-2005
1395	b0363		IS	NJ	PJM MA		100	0.03	b0363	b0363	Post-2005
1396	b0364		IS	NJ	PJM MA		100	0.03	b0364	b0364	Post-2005
1397	b0366		IS	MD	PJM MA		100	13.1	b0366	b0366	Post-2005
1398	b0371		IS	NJ	PJM MA		100	2.25	b0371	b0371	Post-2005
1399	b0372		IS	NJ	PJM MA		100	0.75	b0372	b0372	Post-2005
1400	b0373		IS	MD	PJM WEST		100	9.4	b0373	b0373	Post-2005
1401	b0380		IS	IL	PJM WEST		100	7	b0380	b0380	Post-2005
1402	b0382		IS	DE	PJM MA		100	1.49	b0382	b0382	Post-2005
1403	b0383		IS	DE	PJM MA		100	2.29	b0383	b0383	Post-2005
1404	b0384		IS	DE	PJM MA		100	3.74	b0384	b0384	Post-2005
1405	b0385		IS	MD	PJM MA		100	0.87	b0385	b0385	Post-2005
1406	b0386		IS	DE	PJM MA		100	1.55	b0386	b0386	Post-2005
1407	b0387		IS	DE	PJM MA		100	3.12	b0387	b0387	Post-2005
1408	b0388		IS	MD	PJM MA		100	0.47	b0388	b0388	Post-2005
1409	b0389		IS	DE	PJM MA		100	7.8	b0389	b0389	Post-2005
1410	b0390		IS	DE	PJM MA		100	1.54	b0390	b0390	Post-2005
1411	b0392		IS	MD	PJM MA		100	2.16	b0392	b0392	Post-2005
1412	b0393		IS	WV	PJM WEST		100	0.09	b0393	b0393	Post-2005
1413	b0394		IS	IL	PJM WEST		100	3	b0394	b0394	Post-2005
1414	b0401.1		IS	NJ	PJM MA		100	0.38	b0401	b0401	Post-2005
1415	b0401.2		IS	NJ	PJM MA		100	0.38	b0401	b0401	Post-2005
1416	b0401.3		IS	NJ	PJM MA		100	0.38	b0401	b0401	Post-2005
1417	b0401.4		IS	NJ	PJM MA		100	0.38	b0401	b0401	Post-2005
1418	b0401.5		IS	NJ	PJM MA		100	0.38	b0401	b0401	Post-2005
1419	b0401.6		IS	NJ	PJM MA		100	0.38	b0401	b0401	Post-2005

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
3	Upgrade ID	PJM Required	In Service Date	Location	Task	Equipment	Descriptior	Voltage	Expected R	Last Updated	Trans Own	Study Year	Baseline R	Driver	Initial TEAC Da
1420	b0401.7	6/1/2009	6/16/2009	Roseland	Replace	Breaker	Breaker 2	138		8/11/2009	PSEG	2009 RTEP	Baseline - I	Short Circu	10/30/2006
1421	b0401.8	6/1/2009	5/6/2006	West Oran	Replace	Breaker	Breaker 1	138		8/11/2009	PSEG	2009 RTEP	Baseline - I	Short Circu	10/30/2006
1422	b0403	6/1/2007	5/30/2007	Dooms	Install	Transform	2nd transf	500/230		8/14/2009	Dominion	2007		Gen Delive	10/30/2006
1423	b0404.1	6/1/2007	3/26/2008	South Rea	Replace	Breaker	breaker #1	230		8/11/2009	ME	2007		Short Circu	10/30/2006
1424	b0404.2	6/1/2007	11/3/2009	South Rea	Replace	Breaker	breaker #1	230		8/11/2009	ME	2007		Short Circu	10/30/2006
1425	b0406.1	6/1/2006	6/1/2006	Mitchell	Replace	Breaker	#4 Bank	138		8/28/2009	APS	2006		Short Circu	10/30/2006
1426	b0406.2	6/1/2006	6/1/2006	Mitchell	Replace	Breaker	#5 Bank	138		8/28/2009	APS	2006		Short Circu	10/30/2006
1427	b0406.3	6/1/2007	5/17/2007	Mitchell	Replace	Breaker	#2 Transfo	138		8/28/2009	APS	2007		Short Circu	10/30/2006
1428	b0406.4	6/1/2007	5/17/2007	Mitchell	Replace	Breaker	#3 Bank	138		8/28/2009	APS	2007		Short Circu	10/30/2006
1429	b0406.5	6/1/2007	4/16/2007	Mitchell	Replace	Breaker	Charleroi #	138		8/28/2009	APS	2007		Short Circu	10/30/2006
1430	b0406.6	6/1/2007	5/17/2007	Mitchell	Replace	Breaker	Charleroi #	138		8/28/2009	APS	2007		Short Circu	10/30/2006
1431	b0406.7	6/1/2007	3/14/2008	Mitchell	Replace	Breaker	Shepler Hil	138		8/28/2009	APS	2007		Short Circu	10/30/2006
1432	b0406.8	6/1/2007	11/2/2007	Mitchell	Replace	Breaker	Union Jct	138		8/28/2009	APS	2007		Short Circu	10/30/2006
1433	b0406.9	6/1/2007	10/31/2007	Mitchell	Replace	Breaker	#1-2 bus ti	138		8/28/2009	APS	2007		Short Circu	10/30/2006
1434	b0407.1	6/1/2007	11/7/2008	Marlowe	Replace	Breaker	#1 transfor	138		8/28/2009	APS	2007		Short Circu	10/30/2006
1435	b0407.2	6/1/2007	11/21/2007	Marlowe	Replace	Breaker	"MBO"	138		8/11/2009	APS	2007		Short Circu	10/30/2006
1436	b0407.3	6/1/2008	11/12/2008	Marlowe	Replace	Breaker	"BMA"	138		8/11/2009	APS	2008		Short Circu	10/30/2006
1437	b0407.4	6/1/2008	10/6/2008	Marlowe	Replace	Breaker	"BMR"	138		8/11/2009	APS	2008		Short Circu	10/30/2006
1438	b0407.5	6/1/2008	11/12/2008	Marlowe	Replace	Breaker	"WC-1"	138		8/11/2009	APS	2008		Short Circu	10/30/2006
1439	b0407.6	6/1/2008	11/7/2008	Marlowe	Replace	Breaker	"RI1"	138		8/11/2009	APS	2008		Short Circu	10/30/2006
1440	b0407.7	6/1/2008	5/18/2008	Marlowe	Replace	Breaker	"W"	138		8/11/2009	APS	2008		Short Circu	10/30/2006
1441	b0407.8	6/1/2008	10/4/2008	Marlowe	Replace	Breaker	bus tie	138		9/1/2009	APS	2008		Short Circu	10/30/2006
1442	b0408.1	6/1/2008	12/7/2007	Trissler	Replace	Breaker	"Belmont 6	138		8/11/2009	APS	2008		Short Circu	10/30/2006
1443	b0408.2	6/1/2008	12/31/2007	Trissler	Replace	Breaker	"Edgelawn	138		8/11/2009	APS	2008		Short Circu	10/30/2006
1444	b0409.1	6/1/2006	6/1/2006	Weirton	Replace	Breaker	"Wylie Rid	138		8/11/2009	APS	2006		Short Circu	10/30/2006
1445	b0409.2	12/31/2006	11/6/2006	Weirton	Replace	Breaker	"Wylie Rid	138		8/11/2009	APS	2006		Short Circu	10/30/2006
1446	b0410	6/1/2007	10/12/2007	Glen Falls	Replace	Breaker	"McAlpin 3	138		8/11/2009	APS	2007		Short Circu	10/30/2006
1447	b0411	6/1/2008	11/2/2007	New Freed	Install	Transform	4th transfo	500/230		11/19/2009	PSEG	2008		N-1-1	10/30/2006
1448	b0412	6/1/2010	4/20/2007	Pruntytow	Retension	Line	to a 3502 M	500		8/11/2009	Dominion	2010		Gen Delive	10/30/2006
1449	b0413	6/1/2008	1/31/2008	Chichester	Install	SPS		138		8/11/2009	PECO	2008		Gen Delive	10/30/2006
1450	b0414	6/1/2009	6/19/2009	Christiana -	Upgrade	Circuit		138		9/11/2009	DPL	2009		Gen Delive	10/30/2006
1451	b0415	6/1/2008	12/15/2006	Edgemoore	Increase	Transmissi	the temper	138		9/1/2009	DPL	2008		Gen Delive	10/30/2006
1452	b0417	6/1/2010	5/6/2010	Mitchell - S	Reconductor		With 954 A	138	242/297	8/24/2010	APS	2010	2008	Gen Delive	5/9/2007
1453	b0419	6/1/2010	6/15/2010	Bedington	Install		a breaker f	500		8/24/2010	APS	2010	2005	Gen Delive	10/30/2006
1454	b0420	6/1/2010	6/7/2010	Black Oak	Implement		Operating	500/138		8/24/2010	APS	2010	2008	Gen Delive	10/30/2006
1455	b0423	6/1/2011	11/3/2010	Readingtor	Reconduct	Circuit	Readingtor	230	813/925	3/9/2011	PSEG	2011	2006	Load Delive	10/30/2006
1456	b0424	6/1/2011	11/15/2009	Roseland	Replace	Wave Trap	on Reading	230	671/812	1/19/2010	PSEG	2011	2008	Load Delive	10/30/2006
1457	b0425	6/1/2011	11/15/2010	Linden - To	Reconductor		Linden (49	230	950/1150	3/9/2011	PSEG	2011	2006	Load Delive	10/30/2006
1458	b0426	6/1/2011	1/7/2011	Tosco	Reconductor		Tosco (519	230	950/1150	4/13/2011	PSEG	2011	2008	Load Delive	10/30/2006
1459	b0428	6/1/2011	10/10/2009	Roseland -	Upgrade	Wave Trap	terminal e	138	204/271	1/19/2010	PSEG	2011	2006	Load Delive	10/30/2006
1460	b0430	6/1/2007	2/1/2007	Woodstow	Upgrade	Line Trap		69		8/11/2009	AEC	2007			5/9/2005
1461	b0431	6/1/2010	6/7/2010	Monroe	Upgrade	Strand Bus		230		11/11/2010	AEC	2010	2009		9/16/2009
1462	b0432	6/1/2008	12/31/2008	Monroe	Upgrade	Strand Bus	T3			8/11/2009	AEC	2008			
1463	b0433	6/1/2008	6/1/2008	Union	Upgrade	Terminal		138		4/13/2011	AEC	2008			
1464	b0434	6/1/2010	5/21/2010	Union	Upgrade	Disconect	Switch	138		7/15/2010	AEC	2010			
1465	b0435	6/1/2010	6/2/2010	Corson	Upgrade	Switches		138		7/15/2010	AEC	2010			
1466	b0437	6/1/2008	6/1/2008	Keeney	Spare	Transform	PRA	500/230		8/14/2009	DPL	2008		PRA Analys	10/30/2006
1467	b0438	6/1/2008	6/1/2007	Whitpain	Spare	Transform	PRA	500/230		9/1/2009	PECO	2008		PRA Analys	10/30/2006
1468	b0439	6/1/2008	12/1/2009	Deans		Transform	spare PRA	500/230		1/22/2010	PSEG	2008	2008	PRA Analys	10/30/2006
1469	b0440	6/1/2010	12/31/2010	Juniata		Transform	spare PRA	500/230		1/11/2011	PPL	2008	2008	PRA Analys	10/30/2006
1470	b0441	6/1/2008	6/1/2008	Keeney	Spare	Transform	PRA	500/230		8/14/2009	DPL	2008		PRA Analys	10/30/2006
1471	b0442	6/1/2008	8/30/2010	Keystone		Transform	aquire PRA	500/230		9/8/2010	PENELEC	2008	2008	PRA Analys	10/30/2006
1472	b0443	6/1/2008	6/1/2007	Peach Bott	Spare	Transform	PRA	500/230		8/14/2009	PECO	2008		PRA Analys	10/30/2006
1473	b0446	6/1/2010	12/1/2008	Bayway	Reconfigur	Substation		138		4/13/2011	PSEG			Gen Delive	10/30/2006
1474	b0446.1	6/1/2010	2/9/2008	Bayway	Upgrade	Breaker	Breaker #2	138		6/19/2009	PSEG			Short Circu	8/22/2007
1475	b0446.2	6/1/2010	2/22/2008	Bayway	Upgrade	Breaker	Breaker #3	138		6/19/2009	PSEG			Short Circu	8/22/2007
1476	b0446.3	6/1/2010	6/1/1997	Bayway	Upgrade	Breaker	Breaker #6	138		6/19/2009	PSEG			Short Circu	8/22/2007
1477	b0446.4	6/1/2010	12/28/2009	Linden	Upgrade	Breaker	Breaker as	138		7/22/2009	PSEG			Short Circu	8/22/2007
1478	b0447	6/1/2007	11/20/2008	Cook	Upgrade	Breaker	M2 circuit	345		8/3/2009	AEP			Short Circu	5/9/2007
1479	b0448	6/1/2007	11/2/2009	Cook	Upgrade	Breaker	N2	345		11/10/2009	AEP		2008	Short Circu	5/9/2007
1480	b0453.3	6/1/2012	6/11/2009	Sowego	Install	Transformer		230/115		9/1/2009	Dominion	2012		N-1	5/9/2007
1481	b0455	5/31/2010	5/13/2009	Endless Ca	Install	Transform	2nd	230/115		9/1/2009	Dominion	2010		N-1	5/9/2007
1482	b0456	5/31/2012	10/16/2009	Edinburg -	Reconductor		9.4 miles	115		10/20/2010	Dominion	2012		N-1	5/9/2007
1483	b0461	6/1/2009	5/30/2009	Will County	Install	Capacitor	115.2 MVA	138		4/13/2011	ComEd	2012		Load Delive	5/9/2007
1484	b0462	6/1/2010	4/28/2010	Joliet	Install	Capacitor	115.2 MVA	138		5/20/2010	ComEd	2012	2008	Load Delive	5/9/2007
1485	b0463	6/1/2009	5/30/2009	East Frankl	Install	Capacitor	115.2 MVA	138		11/18/2009	ComEd	2012	2008	Load Delive	5/9/2007
1486	b0465	6/1/2012	5/16/2008	Libertyville	Install	Capacitor	115.2 MVA	138		8/11/2009	ComEd	2012		Load Delive	5/9/2007
1487	b0466	6/1/2012	4/2/2008	Prospect H	Install	Capacitor	57.6 MVAR	138		8/11/2009	ComEd	2012		Load Delive	5/9/2007
1488	b0470	6/1/2012	4/1/2009	Roseland	Install	Breaker	and close t	138		9/1/2009	PSEG	2012		N-2	5/9/2007
1489	b0471	6/1/2012	6/1/2010	Lawrence a	Replace	Wave Trap	Upgrade te	230	653/752	10/28/2010	PSEG	2012	2008	N-2	5/9/2007
1490	b0481	6/1/2012	12/31/2008	Indian Rive	Replace	Wave Trap	on Omar -	138		11/19/2009	DPL	2012		DPL Load D	5/9/2007

	A	P	Q	R	S	T	U	V	W	X	Y
3	Upgrade ID	Latest TEAC Date	Status	State	Region	County	Percent Co	Cost Estim	Project ID	In Schedule	Source
1420	b0401.7		IS	NJ	PJM MA		100	0.38	b0401	b0401	Post-2005
1421	b0401.8		IS	NJ	PJM MA		100	0.38	b0401	b0401	Post-2005
1422	b0403		IS	VA	PJM SOUTH		100	8	b0403	b0403	Post-2005
1423	b0404.1		IS	PA	PJM MA		100	0.23	b0404	b0404	Post-2005
1424	b0404.2		IS	PA	PJM MA		100	0.23	b0404	b0404	Post-2005
1425	b0406.1		IS	PA	PJM WEST	Washingto	100	0.12	b0406	b0406	Post-2005
1426	b0406.2		IS	PA	PJM WEST	Washingto	100	0.12	b0406	b0406	Post-2005
1427	b0406.3		IS	PA	PJM WEST	Washingto	100	0.12	b0406	b0406	Post-2005
1428	b0406.4		IS	PA	PJM WEST	Washingto	100	0.12	b0406	b0406	Post-2005
1429	b0406.5		IS	PA	PJM WEST	Washingto	100	0.12	b0406	b0406	Post-2005
1430	b0406.6		IS	PA	PJM WEST	Washingto	100	0.12	b0406	b0406	Post-2005
1431	b0406.7		IS	PA	PJM WEST	Washingto	100	0.12	b0406	b0406	Post-2005
1432	b0406.8		IS	PA	PJM WEST	Washingto	100	0.12	b0406	b0406	Post-2005
1433	b0406.9		IS	PA	PJM WEST	Washingto	100	0.12	b0406	b0406	Post-2005
1434	b0407.1		IS	WV	PJM WEST	Berkeley	100	0.12	b0407	b0407	Post-2005
1435	b0407.2		IS	WV	PJM WEST	Berkeley	100	0.12	b0407	b0407	Post-2005
1436	b0407.3		IS	WV	PJM WEST	Berkeley	100	0.12	b0407	b0407	Post-2005
1437	b0407.4		IS	WV	PJM WEST	Berkeley	100	0.12	b0407	b0407	Post-2005
1438	b0407.5		IS	WV	PJM WEST	Berkeley	100	0.12	b0407	b0407	Post-2005
1439	b0407.6		IS	WV	PJM WEST	Berkeley	100	0.12	b0407	b0407	Post-2005
1440	b0407.7		IS	WV	PJM WEST	Berkeley	100	0.12	b0407	b0407	Post-2005
1441	b0407.8		IS	WV	PJM WEST	Berkeley	100	0.12	b0407	b0407	Post-2005
1442	b0408.1		IS	WV	PJM WEST	Wood	100	0.12	b0408	b0408	Post-2005
1443	b0408.2		IS	WV	PJM WEST	Wood	100	0.12	b0408	b0408	Post-2005
1444	b0409.1		IS	WV	PJM WEST	Hancock	100	0.12	b0409	b0409	Post-2005
1445	b0409.2		IS	WV	PJM WEST	Hancock	100	0.12	b0409	b0409	Post-2005
1446	b0410		IS	WV	PJM WEST	Harrison	100	0.12	b0410	b0410	Post-2005
1447	b0411		IS	NJ	PJM MA		100	25.24	b0411	b0411	Post-2005
1448	b0412		IS	WV	PJM SOUTH		100	0	b0412	b0412	Post-2005
1449	b0413		IS	PA	PJM MA		100	0.1	b0413	#N/A	Post-2005
1450	b0414		IS	DE	PJM MA		100	0.25	b0414	#N/A	Post-2005
1451	b0415		IS	DE	PJM MA		100	0	b0415	b0415	Post-2005
1452	b0417		IS	PA	PJM WEST		100	3	b0417	b0417	Post-2005
1453	b0419		IS	WV	PJM WEST		100	0	b0419	b0419	Post-2005
1454	b0420		IS	WV	PJM WEST		100	0	b0420	b0420	Post-2005
1455	b0423		IS	NJ	PJM MA		100	7	b0423	b0423	Post-2005
1456	b0424		IS	NJ	PJM MA		100	0.16	b0424	b0424	Post-2005
1457	b0425		IS	NJ	PJM MA		100	2.18	b0425	b0425	Post-2005
1458	b0426		IS	NJ	PJM MA		100	0.61	b0426	b0426	Post-2005
1459	b0428		IS	NJ	PJM MA		100	0.05	b0428	b0428	Post-2005
1460	b0430		IS	NJ	PJM MA		100	0.15	b0430	#N/A	Post-2005
1461	b0431		IS	NJ	PJM MA		100	0.1	b0431	b0431	Post-2005
1462	b0432		IS	NJ	PJM MA		100	0.1	b0432	#N/A	Post-2005
1463	b0433		IS	NJ	PJM MA		100	0.08	b0433	#N/A	Post-2005
1464	b0434		IS	NJ	PJM MA		100	0.1	b0434	#N/A	Post-2005
1465	b0435		IS	NJ	PJM MA		0	0.1	b0435	#N/A	Post-2005
1466	b0437		IS	DE	PJM MA		100	2.5	b0437	b0437	Post-2005
1467	b0438		IS	PA	PJM MA		100	2.5	b0438	b0438	Post-2005
1468	b0439		IS	NJ	PJM MA		100	2.5	b0439	b0439	Post-2005
1469	b0440		IS	PA	PJM MA		100	7.55	b0440	b0440	Post-2005
1470	b0441		IS	DE	PJM MA		100	2.5	b0441	b0441	Post-2005
1471	b0442		IS	PA	PJM MA		100	2.5	b0442	b0442	Post-2005
1472	b0443		IS	PA	PJM MA		100	2.5	b0443	b0443	Post-2005
1473	b0446		IS	NJ	PJM MA		100	3.8	b0446	b0446	Post-2005
1474	b0446.1		IS	NJ	PJM MA		100	0.3	b0446	b0446	Post-2005
1475	b0446.2		IS	NJ	PJM MA		100	0.3	b0446	b0446	Post-2005
1476	b0446.3		IS	NJ	PJM MA		100	0.3	b0446	b0446	Post-2005
1477	b0446.4		IS	NJ	PJM MA		100	0.3	b0446	b0446	Post-2005
1478	b0447		IS	MI	PJM WEST		100	0.8	b0447	b0447	Post-2005
1479	b0448		IS	MI	PJM WEST		100	0.8	b0448	b0448	Post-2005
1480	b0453.3		IS	VA	PJM SOUTH		100	5	b0453	b0453	Post-2005
1481	b0455		IS	VA	PJM SOUTH		100	6	b0455	b0455	Post-2005
1482	b0456		IS	VA	PJM SOUTH		100	7	b0456	b0456	Post-2005
1483	b0461		IS	IL	PJM WEST		100	2.3	b0461	b0461	Post-2005
1484	b0462		IS	IL	PJM WEST		100	2.3	b0462	b0462	Post-2005
1485	b0463		IS	IL	PJM WEST		100	2.3	b0463	b0463	Post-2005
1486	b0465		IS	IL	PJM WEST		100	2.3	b0465	b0465	Post-2005
1487	b0466		IS	IL	PJM WEST		100	1.5	b0466	b0466	Post-2005
1488	b0470		IS	NJ	PJM MA		100	1	b0470	b0470	Post-2005
1489	b0471		IS	NJ	PJM MA		100	0.5	b0471	b0471	Post-2005
1490	b0481		IS	DE	PJM MA		100	0.2	b0481	b0481	Post-2005

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
3	Upgrade ID	PJM Required	In Service Date	Location	Task	Equipment	Descriptior	Voltage	Expected R	Last Updated	Trans Own	Study Year	Baseline R	Driver	Initial TEAC Da
1491	b0482	12/1/2008	12/31/2008	Millsboro -	Rebuild	Circuit		69		8/11/2009	DPL	2012		DPL Criteri	5/9/2007
1492	b0483	6/1/2009	1/14/2010	Church	Replace	Transform	and add tw	138/69		1/22/2010	DPL	2012		DPL Criteri	5/9/2007
1493	b0484	6/1/2010	4/30/2010	Worcester	Re-tension	Circuit	For 125 °C	69		6/1/2010	DPL	2012	2008	DPL Criteri	5/9/2007
1494	b0485	6/1/2010	5/13/2010	Taylor - No	Re-tension	Circuit	Upgrade F	69		7/15/2010	DPL	2012	2008	DPL Criteri	5/9/2007
1495	b0489.3	6/1/2012	10/1/2009	Saddlebroo	Replace	Breaker	21P	230	40kA	1/19/2010	PSEG	2012	2008	Short Circu	8/20/2008
1496	b0489.5	6/1/2012	12/7/2010	Roseland	Upgrade	Breaker	42H' with 8	230	80 kA	3/9/2011	PSEG			Short Circu	5/20/2009
1497	b0489.6	6/1/2012	12/23/2010	Roseland	Upgrade	Breaker	51H' with 8	230	80 kA	3/9/2011	PSEG			Short Circu	5/20/2009
1498	b0489.9	6/1/2012	11/14/2010	Roseland	Upgrade	Breaker	11H'	230	80 kA	4/13/2011	PSEG			Short Circu	5/20/2009
1499	b0493	6/1/2012	5/16/2009	Cheswick -	Reconductor		both circui	138	358/419, 2	11/19/2009	DL	2012		Gen Delive	5/9/2007
1500	b0494.1	6/1/2009	5/13/2009	Red Lion	Install	Transform	2nd transf	230/138		8/14/2009	DPL			DPL Load D	5/9/2007
1501	b0494.2	6/1/2009	5/14/2009	Hares Corn	Upgrade	Relay				8/6/2009	DPL			DPL Load D	5/9/2007
1502	b0494.3	6/1/2009	5/15/2009	Reybold	Upgrade	Relay				8/6/2009	DPL			DPL Load D	5/9/2007
1503	b0494.4	6/1/2009	5/16/2009	New Castle	Upgrade	Relay				8/6/2009	DPL			DPL Load D	5/9/2007
1504	b0495	6/1/2012	10/24/2009	Kammer	Replace	Transform	with a new	765/500	2640 / 304	12/16/2009	APS	2012		Gen Delive	8/22/2007
1505	b0498	6/1/2008	11/12/2008	New Freed	Expand	Circuit	Loop the 5	500		8/5/2009	PSEG			Load Delive	8/22/2007
1506	b0498.1	6/1/2008	9/12/2008	New Freed	Replace	Circuit Bre	20H (5-6)	230		8/3/2009	PSEG			Short Circu	12/19/2007
1507	b0498.2	6/1/2008	9/27/2008	New Freed	Replace	Circuit Bre	22H (1-5)	230		8/3/2009	PSEG			Short Circu	12/19/2007
1508	b0498.3	6/1/2008	6/19/2008	New Freed	Replace	Circuit Bre	30H (7-8)	230		8/3/2009	PSEG			Short Circu	12/19/2007
1509	b0498.4	6/1/2008	6/5/2008	New Freed	Replace	Circuit Bre	32H (1-7)	230		8/3/2009	PSEG			Short Circu	12/19/2007
1510	b0498.5	6/1/2008	10/14/2008	New Freed	Replace	Circuit Bre	40H (9-10)	230		8/3/2009	PSEG			Short Circu	12/19/2007
1511	b0498.6	6/1/2008	5/12/2008	New Freed	Replace	Circuit Bre	42H (1-9)	230		8/3/2009	PSEG			Short Circu	12/19/2007
1512	b0502.4	6/1/2013	8/3/2009	Dravosburg	Replace	Breaker	breaker 'Z7	138		3/10/2011	DL	2014	2009	Short Circu	11/18/2009
1513	b0504	6/1/2009	3/16/2009	Hanging Ro	Add	Circuit Bre	Add two ac	765		8/11/2009	AEP	2009		Operationa	8/22/2007
1514	b0505	6/1/2010	5/22/2010	North Wal	Reconductor		Line 220-1	230		6/4/2010	PECO	2010	2007	EMAAC Loa	8/22/2007
1515	b0506	6/1/2010	1/15/2010	North Wal	Reconductor		Line 220-7	230		1/21/2010	PECO	2010	2008	EMAAC Loa	8/22/2007
1516	b0508.1	5/27/2011	5/19/2011	Warringtor	Replace	Terminal E	station cab	230		6/23/2011	PECO	2011	2009	EMAAC Loa	5/20/2009
1517	b0509	5/27/2011	3/1/2011	Jarrett - He	Reconductor		220-51 line	230		3/17/2011	PECO	2010	2008	EMAAC Loa	8/22/2007
1518	b0510	6/1/2010	12/10/2009	Elmhurst	Install	Capacitor	two 115.3	138		5/20/2010	ComEd	2012	2008	ComED Cri	12/19/2007
1519	b0511	6/1/2009	5/30/2009	Pleasant Va	Reconductor		line L1410	138		11/18/2009	ComEd	2012	2008	N-2	12/19/2007
1520	b0514	6/1/2010	12/1/2009	Shelby	Document		Operating	345/138		3/22/2010	Dayton	2010	2008	Voltage Vio	12/19/2007
1521	b0515	6/1/2008	12/7/2009	Yeagertow	Replace	Breaker	1LY YEAGE	230		1/4/2010	PENELEC	2012	2008	Short Circu	12/19/2007
1522	b0516	6/1/2008	12/7/2009	Yeagertow	Replace	Breaker	2LY YEAGE	230		1/4/2010	PENELEC	2012	2008	Short Circu	12/19/2007
1523	b0517	6/1/2010	10/15/2009	Shawville	Replace	Breaker	BUS SECTIO	230		1/4/2010	PENELEC	2012	2008	Short Circu	12/19/2007
1524	b0518	6/1/2008	10/30/2008	Homer City	Replace	Breaker	201 JOHNS	230		10/12/2009	PENELEC	2012		Short Circu	12/19/2007
1525	b0519	6/1/2008	3/18/2009	Keystone	Replace	Breaker	NO.4XFMR	230		8/11/2009	PENELEC	2012		Short Circu	12/19/2007
1526	b0520	6/1/2008	12/10/2009	Gilbert	Replace	Breaker	12A	230		1/22/2010	JCPL	2012	2008	Short Circu	12/19/2007
1527	b0521	6/1/2008	6/1/2007	Larrabee	Replace	Breaker	BG	230		8/11/2009	JCPL	2012		Short Circu	12/19/2007
1528	b0522	6/1/2008	6/1/2007	Larrabee	Replace	Breaker	GK	230		8/11/2009	JCPL	2012		Short Circu	12/19/2007
1529	b0523	6/1/2008	6/1/2007	Larrabee	Replace	Breaker	K4	230		8/11/2009	JCPL	2012		Short Circu	12/19/2007
1530	b0524	6/1/2008	6/1/2007	Larrabee	Replace	Breaker	CAP3	230		8/11/2009	JCPL	2012		Short Circu	12/19/2007
1531	b0527	6/1/2010	2/28/2010	Bethany	Add	Capacitors	30 MVAR c	69		3/4/2010	DPL	2012	2008	DPL South	12/19/2007
1532	b0528	6/1/2010	7/13/2010	Bethany	Add	Transform	which will	138/12		9/15/2010	DPL	2010	2008	DPL South	12/19/2007
1533	b0529	6/1/2010	11/19/2010	Grasonville	Add	Capacitors	Add anoth	69		1/20/2011	DPL	2010	2008	DPL South	12/19/2007
1534	b0530	6/1/2010	5/10/2010	Wye Mills	Add	Capacitors	30 MVAR c	69		6/1/2010	DPL	2010	2008	DPL South	12/19/2007
1535	b0531	6/1/2010	9/17/2010	Wye Mills	Build	Ring Bus	a 4 breake	138/69		11/11/2010	DPL	2010	2008	DPL South	12/19/2007
1536	b0534	6/1/2012	7/7/2010	Sutton	Install	Switched C	Add a 28.6	138		8/24/2010	APS	2012	2008	2012 Volta	12/19/2007
1537	b0536	6/1/2011	12/19/2008	Doubs	Replace	Breaker	DJ1	230	53815	9/16/2009	APS			Short Circu	12/19/2007
1538	b0537	6/1/2008	5/30/2008	Doubs	Replace	Breaker	DJ7	230		9/16/2009	APS			Short Circu	12/19/2007
1539	b0538	6/1/2008	11/10/2008	Doubs	Replace	Breaker	DJ10	230	66939	9/16/2009	APS			Short Circu	12/19/2007
1540	b0539	6/1/2008	12/4/2009	Doubs	Replace	Breaker	DJ11	230	66939	3/4/2010	APS		2008	Short Circu	12/19/2007
1541	b0540	6/1/2008	11/10/2008	Doubs	Replace	Breaker	DJ12	230	66939	8/3/2009	APS			Short Circu	12/19/2007
1542	b0541	6/1/2008	11/6/2009	Doubs	Replace	Breaker	DJ13	230	66939	3/4/2010	APS		2008	Short Circu	12/19/2007
1543	b0542	6/1/2010	9/22/2008	Doubs	Replace	Breaker	DJ20	230	56902	8/3/2009	APS			Short Circu	12/19/2007
1544	b0543	6/1/2010	6/26/2009	Doubs	Replace	Breaker	DJ21	230	56902	10/28/2009	APS			Short Circu	12/19/2007
1545	b0546	6/1/2012	12/31/2010	Shorewoo	Add	Capacitors	Add 15.6 MVAR of dis		20	2/9/2011	ComEd	2012	2008	Voltage Vio	12/19/2007
1546	b0547	6/1/2012	12/31/2010	Wilmingtor	Add	Capacitors	Add 7.6 MVAR of distr		15	2/9/2011	ComEd	2012	2008	Voltage Vio	12/19/2007
1547	b0548	6/1/2012	5/17/2010	Joliet	Document		Operating	138		5/18/2010	ComEd	2012	2008	Voltage Vio	12/19/2007
1548	b0550	6/1/2012	4/21/2008	Lewis Run	Install	Capacitor	25 MVAR	115		4/13/2011	PENELEC	2012		2012 Load	12/19/2007
1549	b0551	6/1/2012	4/8/2008	Saxton	Install	Capacitor	25 MVAR	115		4/13/2011	PENELEC	2012		2012 Load	12/19/2007
1550	b0559	6/1/2012	10/26/2009	Meadow B	Install	Capacitor	a 200 MVA	500	200MVAR	4/13/2011	APS	2012		2012 Load	12/19/2007
1551	b0567	6/1/2010	6/8/2010	Mt. Pleasa	Rebuild	Circuit		138		7/15/2010	DPL	2012	2008	Load Delive	12/19/2007
1552	b0575.1	6/1/2008	5/7/2008	Hunterstov	Rebuild	Line		115		8/11/2009	ME	2004		FE Criteria	6/11/2008
1553	b0575.2	6/1/2009	4/27/2009	Hunterstov	Upgrade	Line	Texas East	115		9/28/2009	ME	2004	2008	FE Criteria	6/11/2008
1554	b0577	6/1/2011	10/1/2009	Fort Martir	Replace	Breaker	FL-1'	500	46422	10/28/2009	APS		2008	Short Circu	7/16/2008
1555	b0578	6/1/2009	5/15/2009	Essex	Replace	Breaker	4LM (C135	138		8/11/2009	PSEG	2009		Short Circu	8/20/2008
1556	b0579	6/1/2009	5/8/2009	Essex	Replace	Breaker	1LM (220-1	138		8/11/2009	PSEG	2009		Short Circu	8/20/2008
1557	b0580	6/1/2009	4/17/2009	Essex	Replace	Breaker	1BM (BS1-1	138		8/11/2009	PSEG	2009		Short Circu	8/20/2008
1558	b0581	6/1/2009	4/24/2009	Essex	Replace	Breaker	2BM (BS3-4	138		8/11/2009	PSEG	2009		Short Circu	8/20/2008
1559	b0582	6/1/2009	5/23/2009	Linden	Replace	Breaker	3 (132-7 TX	138		8/11/2009	PSEG	2009		Short Circu	8/20/2008
1560	b0584	6/1/2013	5/8/2009	Necessity	Install	Capacitor	33 MVAR C	138		9/1/2009	APS	2009		Voltage Ma	9/17/2008
1561	b0585	6/1/2013	11/29/2009	Cecil	Increase	Capacitor	size to 44 M	138		3/4/2010	APS	2010	2008	Voltage Ma	9/17/2008

	A	P	Q	R	S	T	U	V	W	X	Y
3	Upgrade ID	Latest TEAC Date	Status	State	Region	County	Percent Co	Cost Estim	Project ID	In Schedul	Source
1491	b0482		IS	DE	PJM MA		100	1.8	b0482	b0482	Post-2005
1492	b0483		IS	MD	PJM MA		100	5	b0483	b0483	Post-2005
1493	b0484		IS	MD	PJM MA		20	0.44	b0484	b0484	Post-2005
1494	b0485		IS	MD	PJM MA		100	0.36	b0485	b0485	Post-2005
1495	b0489.3		IS	NJ	PJM MA		100	0.4	b0489	b0489	Post-2005
1496	b0489.5		IS	NJ	PJM MA		100	0.8	b0489	b0489	Post-2005
1497	b0489.6		IS	NJ	PJM MA		100	0.8	b0489	b0489	Post-2005
1498	b0489.9		IS	NJ	PJM MA		100	0.8	b0489	b0489	Post-2005
1499	b0493		IS	PA	PJM WEST		100	2.4	b0493	b0493	Post-2005
1500	b0494.1		IS	DE	PJM MA		100	2.52	b0494	b0494	Post-2005
1501	b0494.2		IS	DE	PJM MA		100	0.8	b0494	b0494	Post-2005
1502	b0494.3		IS	DE	PJM MA		100	0.17	b0494	b0494	Post-2005
1503	b0494.4		IS	DE	PJM MA		100	0.17	b0494	b0494	Post-2005
1504	b0495		IS	OH	PJM WEST		100	42	b0495	b0495	Post-2005
1505	b0498		IS	NJ	PJM MA		100	17	b0498	b0498	Post-2005
1506	b0498.1		IS	NJ	PJM MA		100	0.4	b0498	b0498	Post-2005
1507	b0498.2		IS	NJ	PJM MA		100	0.4	b0498	b0498	Post-2005
1508	b0498.3		IS	NJ	PJM MA		100	0.4	b0498	b0498	Post-2005
1509	b0498.4		IS	NJ	PJM MA		100	0.4	b0498	b0498	Post-2005
1510	b0498.5		IS	NJ	PJM MA		100	0.4	b0498	b0498	Post-2005
1511	b0498.6		IS	NJ	PJM MA		100	0.4	b0498	b0498	Post-2005
1512	b0502.4		IS	PA	PJM WEST		100	0.35	b0502	b0502	Post-2005
1513	b0504		IS	OH	PJM WEST		100	5.17	b0504	b0504	Post-2005
1514	b0505		IS	PA	PJM MA		100	2	b0505	b0505	Post-2005
1515	b0506		IS	PA	PJM MA		100	2.2	b0506	b0506	Post-2005
1516	b0508.1		IS	PA	PJM MA		100	0.38	b0508	b0508	Post-2005
1517	b0509		IS	PA	PJM MA		100	0.53	b0509	b0509	Post-2005
1518	b0510		IS	IL	PJM WEST		100	4.4	b0510	b0510	Post-2005
1519	b0511		IS	IL	PJM WEST		100	3.3	b0511	b0511	Post-2005
1520	b0514		IS	PA	PJM West		100	0	b0514	#N/A	Post-2005
1521	b0515		IS	PA	PJM MA		100	0.4	b0515	b0515	Post-2005
1522	b0516		IS	PA	PJM MA		100	0.4	b0516	b0516	Post-2005
1523	b0517		IS	PA	PJM MA		100	0.31	b0517	b0517	Post-2005
1524	b0518		IS	PA	PJM MA		100	0.31	b0518	b0518	Post-2005
1525	b0519		IS	PA	PJM MA		100	0.31	b0519	b0519	Post-2005
1526	b0520		IS	NJ	PJM MA		100	0.31	b0520	b0520	Post-2005
1527	b0521		IS	NJ	PJM MA		100	0.31	b0521	#N/A	Post-2005
1528	b0522		IS	NJ	PJM MA		100	0.31	b0522	#N/A	Post-2005
1529	b0523		IS	NJ	PJM MA		100	0.31	b0523	#N/A	Post-2005
1530	b0524		IS	NJ	PJM MA		100	0.31	b0524	#N/A	Post-2005
1531	b0527		IS	DE	PJM MA		60	1.76	b0527	b0527	Post-2005
1532	b0528		IS	DE	PJM MA		100	5.3	b0528	b0528	Post-2005
1533	b0529		IS		PJM MA		100	1.3	b0529	b0529	Post-2005
1534	b0530		IS		PJM MA		100	1.8	b0530	b0530	Post-2005
1535	b0531		IS		PJM MA		100	6	b0531	b0531	Post-2005
1536	b0534		IS		PJM WEST		100	1.1	b0534	b0534	Post-2005
1537	b0536		IS	MD	PJM WEST	Frederick	100	0.3	b0536	b0536	Post-2005
1538	b0537		IS	MD	PJM WEST	Frederick	100	0.3	b0537	b0537	Post-2005
1539	b0538		IS	MD	PJM WEST	Frederick	100	0.3	b0538	b0538	Post-2005
1540	b0539		IS	MD	PJM WEST	Frederick	100	0.3	b0539	b0539	Post-2005
1541	b0540		IS	MD	PJM WEST	Frederick	100	0.3	b0540	b0540	Post-2005
1542	b0541		IS	MD	PJM WEST	Frederick	100	0.3	b0541	b0541	Post-2005
1543	b0542		IS	MD	PJM WEST	Frederick	100	0.3	b0542	b0542	Post-2005
1544	b0543		IS	MD	PJM WEST	Frederick	100	0.3	b0543	b0543	Post-2005
1545	b0546		IS	IL	PJM WEST		100	0.4	b0546	b0546	Post-2005
1546	b0547		IS	IL	PJM WEST		100	0.3	b0547	b0547	Post-2005
1547	b0548		IS	IL	PJM WEST		100	0	b0548	#N/A	Post-2005
1548	b0550		IS	PA	PJM MA		100	2.6	b0550	b0550	Post-2005
1549	b0551		IS	PA	PJM MA		100	1.3	b0551	b0551	Post-2005
1550	b0559		IS	PA	PJM WEST		100	3	b0559	b0559	Post-2005
1551	b0567		IS	MD	PJM MA		100	3.92	b0567	b0567	Post-2005
1552	b0575.1		IS	PA	PJM MA		100	2.1	b0575	b0575	Post-2005
1553	b0575.2		IS	PA	PJM MA		100	1.9	b0575	b0575	Post-2005
1554	b0577		IS		PJM WEST		100	0.7	b0577	b0577	Post-2005
1555	b0578		IS	NJ	PJM MA		100	0.4	b0578	b0578	Post-2005
1556	b0579		IS	NJ	PJM MA		100	0.4	b0579	b0579	Post-2005
1557	b0580		IS	NJ	PJM MA		100	0.4	b0580	b0580	Post-2005
1558	b0581		IS	NJ	PJM MA		100	0.4	b0581	b0581	Post-2005
1559	b0582		IS	NJ	PJM MA		100	0.4	b0582	b0582	Post-2005
1560	b0584		IS	PA	PJM WEST	Fayette	100	0.77	b0584	b0584	Post-2005
1561	b0585		IS	PA	PJM WEST	Washingto	100	0.1	b0585	b0585	Post-2005

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
3	Upgrade ID	PJM Required	In Service Date	Location	Task	Equipment	Descriptior	Voltage	Expected R	Last Updated	Trans Own	Study Year	Baseline R	Driver	Initial TEAC Da
1562	b0586	6/1/2013	12/31/2009	Whiteley	Increase	Capacitor	size to 44 I	138		3/4/2010	APS	2010	2008	Voltage Ma	9/17/2008
1563	b0588	6/1/2013	11/16/2010	Grassy Fall	Install	Capacitor	40.8 MVAF	138		12/30/2010	APS	2010	2008	Voltage Ma	9/17/2008
1564	b0590	6/1/2013	10/21/2009	Charleroi	Replace	Breaker	#1 and #2	138		3/4/2010	APS	2009	2008	Short Circu	9/17/2008
1565	b0591	10/1/2010	11/22/2010	Seneca Cav	Install	Capacitor	25.2 MVAF	138		3/10/2011	APS	2010	2008	Voltage Ma	9/17/2008
1566	b0592	6/1/2009	5/24/2009	Metuchen	Replace	Breaker	2-2 transfe	138		8/6/2009	PSEG			Short Circu	8/20/2008
1567	b0594	11/1/2008	11/15/2008	Danville-M	Reconductor		Reconduct	69		8/6/2009	PPL			PPL Criteria	
1568	b0595	11/1/2009	12/31/2009	Lackawann	Rebuild	Line	Lackawann	138/69		1/22/2010	PPL		2008	PPL Criteria	9/17/2008
1569	b0599	11/1/2008	5/15/2008	Peckville-Ja	Reconductor		4/0 Cu segi	69		8/6/2009	PPL			PPL Criteria	
1570	b0603	5/1/2008	5/29/2008	Harwood	Rearrange	Substation		230		8/3/2009	PPL			PPL Criteria	
1571	b0606	11/1/2009	12/31/2009	Bartonsvill	Tap	Substation	New tap of	138		1/22/2010	PPL		2008	PPL Criteria	9/17/2008
1572	b0607	11/1/2010	10/25/2010	Stroudsbur	Tap	Substation	New taps f	138		1/20/2011	PPL		2008	PPL Criteria	9/17/2008
1573	b0608	11/1/2009	7/7/2010	Gilbert	Tap	Substation	New tap of	138		9/17/2010	PPL		2008	PPL Criteria	9/17/2008
1574	b0609	7/1/2008	8/20/2008	Siegfried-Ja	Convert	Communic	DTT to Fibe	138		8/6/2009	PPL			PPL Criteria	
1575	b0611	11/1/2008	10/20/2008	North Cool	Install	Capacitor	7.2 MVAR,	69		8/5/2009	PPL			PPL Criteria	
1576	b0612	5/1/2011	10/22/2010	Siegfried-C	Reconductor		from Siegfr	69		1/20/2011	PPL		2008	PPL Criteria	9/17/2008
1577	b0618	5/1/2008	5/26/2008	Wescosvill	Tap	Substation	New	69		8/5/2009	PPL			PPL Criteria	
1578	b0619	11/1/2008	7/24/2008	McMichae	Tap	Substation	New Tap o	138		8/6/2009	PPL			PPL Criteria	
1579	b0620	11/1/2010	8/26/2010	Monroe	Install	Line	New 138 k'	230/138		9/17/2010	PPL		2008	PPL Criteria	9/17/2008
1580	b0621	11/1/2010	8/26/2010	Jackson	Rearrange	Substation	Upgrades a	138/69		9/17/2010	PPL		2008	PPL Criteria	9/17/2008
1581	b0622	11/1/2010	7/6/2010	Siegfried-Ja	Add	Line	New 138 k'	230/138		9/17/2010	PPL		2008	PPL Criteria	9/17/2008
1582	b0624	12/1/2009	12/31/2009	Cumberlan	Reconductor		Double Cir	69		3/4/2010	PPL		2008	PPL Criteria	9/17/2008
1583	b0626	5/1/2008	5/1/2008	Millersburg	Install	LSAB	LSAB	69		9/1/2009	PPL			PPL Criteria	
1584	b0627	12/31/2010	12/23/2010	Walnut-Ce	Replace	Line	UG Cable from Walnut Substation			1/20/2011	PPL		2008	PPL Criteria	9/17/2008
1585	b0628	5/1/2008	12/6/2007	Berks-Sout	Tap	Substation	New	69		8/5/2009	PPL			PPL Criteria	
1586	b0637	6/1/2011	3/5/2010	Oak Grove	Replace	Breaker	2B with 63	230		9/20/2010	PEPCO	2012	2008	Short Circu	8/20/2008
1587	b0638	6/1/2011	5/4/2010	Oak Grove	Replace	Breaker	4A with 63	230		9/20/2010	PEPCO	2012	2008	Short Circu	8/20/2008
1588	b0639	6/1/2011	6/18/2010	Oak Grove	Replace	Breaker	6A with 63	230		9/20/2010	PEPCO	2012	2008	Short Circu	8/20/2008
1589	b0640	6/1/2011	11/11/2010	Oak Grove	Replace	Breaker	6C with 63	230		2/23/2011	PEPCO	2012	2008	Short Circu	8/20/2008
1590	b0641	6/1/2011	12/21/2010	Oak Grove	Replace	Breaker	7A with 63	230		2/23/2011	PEPCO	2012	2008	Short Circu	8/20/2008
1591	b0650	6/1/2010	6/7/2010	Jackson-JE	Reconductor			115		9/20/2010	ME		2008	Gen Delive	9/17/2008
1592	b0652	6/1/2010	5/28/2010	Yorkana	Install	Breaker	Bus Tie circ	115		9/17/2010	ME			Gen Delive	9/17/2008
1593	b0654	6/1/2010	5/30/2009	Cambria Sl	Reconfigur	Substation	to eliminat	115		10/12/2009	PENELEC		2008	PENELEC C	9/17/2008
1594	b0656	6/1/2010	5/29/2010	Altoona	Install	Breaker	3 breakers	230		8/16/2010	PENELEC		2008	N-2	9/17/2008
1595	b0657	6/1/2011	4/21/2011	Boston Roa	Construct	Substation	7.2 MVAR (	34.5		5/3/2011	JCPL	2008	2008	JCPL Criter	9/17/2008
1596	b0695	6/1/2010	4/30/2010	Elmhurst	Add	SVC	300 MVAR	138	300 MVAR	5/20/2010	ComEd	2013	2008	Voltage Vic	9/10/2008
1597	b0696	6/1/2010	4/30/2010	Elmhurst	Add	SVC	300 MVAR	138	300 MVAR	5/20/2010	ComEd	2013	2008	Voltage Vic	9/10/2008
1598	b0700	6/1/2013	5/3/2011	Goodings C	Install	Transform	third	345/138		5/5/2011	ComEd		2008	Gen and Lc	9/10/2008
1599	b0701	6/1/2012	4/15/2011	Benning	Expand	Substation	Expand Bei	230/69		4/26/2011	PEPCO		2008	Benn/Buzz	9/17/2008
1600	b0703	5/1/2010	10/23/2009	Berks	Upgrade	Line	Modificatio	230		1/26/2010	PPL		2008	N-2	9/17/2008
1601	b0705	11/30/2010	1/17/2011	Derry - Mil	Install	Line	New	69		1/20/2011	PPL		2008	Supplemer	9/17/2008
1602	b0712	11/30/2009	10/26/2009	Strassburg	Install	Line	new #1 Lin	69		3/4/2010	PPL			Supplemer	9/17/2008
1603	b0713	5/31/2010	12/9/2009	Dillersville	Construct	Line	a new Dou	138		3/4/2010	PPL		2008	Supplemer	9/17/2008
1604	b0714	11/30/2010	10/29/2010	Roseville T	Upgrade	Tap	Prepare Rc	138		1/20/2011	PPL		2008	Supplemer	9/17/2008
1605	b0718	6/1/2010		West Shore	Install	Substation	SPS schem	69		7/15/2010	PPL	2013	2008	N-1-1	8/20/2008
1606	b0743	6/1/2009	4/1/2009	Roseland	Install	Breaker	Add a bus t	138		4/13/2011	PSEG	2009		PSEG Load	10/15/2008
1607	b0760	6/1/2009	12/30/2010	Kitty Hawk	Build	Transmissi	Colington (	115		4/19/2011	Dominion		2008	Dominion (	9/17/2008
1608	b0761	6/1/2009	4/30/2009	Possom Po	Install	Transform	second tra	230/115		11/19/2009	Dominion			N-1-1	9/17/2008
1609	b0762	6/1/2010	5/18/2010	Turner - Pr	Build	Substation	new Elko s	230		6/16/2010	Dominion		2008	Dominion (	9/17/2008
1610	b0765	6/1/2009	5/21/2009	Bull Run	Install	Transform	second Bul	230/115		11/19/2009	Dominion			N-1-1	9/17/2008
1611	b0766	6/1/2009	5/20/2009	Loudoun -	Increase	Transmissi	the rating (	115	150	8/10/2010	Dominion			Dominion (	9/17/2008
1612	b0767	11/1/2009	3/2/2011	Old Church	Extend	Line	Extend the	230	797/797	3/30/2011	Dominion		2008	Dominion (	9/17/2008
1613	b0770	6/1/2010	6/4/2010	Lanexa	Install	Transform	second aut	230/115	185.4/191.	6/7/2010	Dominion		2008	Dominion (	9/17/2008
1614	b0770.1	6/1/2010	6/4/2010	Lanexa	Replace	Breaker	breaker '85	115		6/17/2010	Dominion	2014	2009	Short Circu	11/18/2009
1615	b0770.2	6/1/2010	6/4/2010	Lanexa	Replace	Breaker	breaker '92	115		6/17/2010	Dominion	2014	2009	Short Circu	11/18/2009
1616	b0772	6/1/2010	5/20/2010	Elmont	Install	Transform	second aut	230/115	180.4/186	5/20/2010	Dominion		2008	Dominion (	9/17/2008
1617	b0772.1	6/1/2010	2/18/2010	Elmont	Replace	Breaker	breaker '73	115		5/24/2010	Dominion	2014	2009	Short Circu	11/18/2009
1618	b0785	6/1/2011	1/5/2009	Chase City	Rebuild	Transmission Line		115	270 / 294	1/20/2011	Dominion		2008	Dominion (	9/17/2008
1619	b0797	6/1/2009	12/19/2008	Doubs	Replace	Circuit Bre	DJ2 - Advai	230		9/16/2009	APS	2009		Short Circu	10/15/2008
1620	b0798	6/1/2009	3/1/2009	Doubs	Replace	Circuit Bre	DJ3 - Advai	230		9/16/2009	APS	2009		Short Circu	10/15/2008
1621	b0799	6/1/2009	3/1/2009	Doubs	Replace	Circuit Bre	DJ6 - Advai	230		9/16/2009	APS	2009		Short Circu	10/15/2008
1622	b0800	6/1/2009	11/13/2009	Doubs	Replace	Circuit Bre	DJ16 - Adva	230		3/4/2010	APS	2009	2008	Short Circu	10/15/2008
1623	b0802	6/1/2009	10/24/2008	Dickerson !	Upgrade	Circuit Bre	412A - Adv	230		9/16/2009	PEPCO	2009		Short Circu	10/15/2008
1624	b0803	6/1/2009	9/18/2009	Dickerson !	Upgrade	Circuit Bre	42A - Adva	230		10/30/2009	PEPCO	2009	2008	Short Circu	10/15/2008
1625	b0804	6/1/2009	9/25/2009	Dickerson !	Upgrade	Circuit Bre	42C - Adva	230		10/30/2009	PEPCO	2009	2008	Short Circu	10/15/2008
1626	b0805	6/1/2009	12/4/2009	Dickerson !	Upgrade	Circuit Bre	43A - Adva	230		1/21/2010	PEPCO	2009	2008	Short Circu	10/15/2008
1627	b0806	6/1/2009	10/30/2009	Dickerson !	Upgrade	Circuit Bre	44A - Adva	230		11/18/2009	PEPCO	2009	2008	Short Circu	10/15/2008
1628	b0809	6/1/2009	10/27/2008	Dickerson !	Upgrade	Circuit Bre	45B - Adva	230		9/16/2009	PEPCO	2009		Short Circu	10/15/2008
1629	b0810	6/1/2009	11/20/2009	Dickerson !	Upgrade	Circuit Bre	47A - Adva	230		1/21/2010	PEPCO	2009	2008	Short Circu	10/15/2008
1630	b0811	6/1/2009	6/1/2009	Dickerson !	Upgrade	Circuit Bre	SPARE - Ad	230		10/20/2010	PEPCO	2009		Short Circu	10/15/2008
1631	b0813	6/1/2011	12/22/2010	Hudson-So	Reconductor			230	514/790	3/10/2011	PSEG	2011	2008	Gen Delive	10/15/2008
1632	b0814.10	6/1/2013	4/17/2009	Essex	Replace	Breaker	1BT' with 6	138		6/2/2010	PSEG		2009	Short Circu	9/16/2009

	A	P	Q	R	S	T	U	V	W	X	Y
3	Upgrade ID	Latest TEAC Date	Status	State	Region	County	Percent Co	Cost Estim	Project ID	In Schedule	Source
1562	b0586		IS	PA	PJM WEST	Greene	100	0.64	b0586	b0586	Post-2005
1563	b0588		IS	WV	PJM WEST	Nicholas	100	0.5	b0588	b0588	Post-2005
1564	b0590		IS	PA	PJM WEST	Washingto	100	0.45	b0590	b0590	Post-2005
1565	b0591		IS	WV	PJM WEST	Pendleton	100	0.63	b0591	b0591	Post-2005
1566	b0592		IS	NJ	PJM MA		100	0.4	b0592	b0592	Post-2005
1567	b0594		IS	PA	PJM MA		100	2.78	b0594	#N/A	Post-2005
1568	b0595		IS	PA	PJM MA		100	5.09	b0595	b0595	Post-2005
1569	b0599		IS	PA	PJM MA		100	0.38	b0599	#N/A	Post-2005
1570	b0603		IS	PA	PJM MA		100	5.18	b0603	#N/A	Post-2005
1571	b0606		IS	PA	PJM MA		100	0.49	b0606	b0606	Post-2005
1572	b0607		IS	PA	PJM MA		100	0.85	b0607	b0607	Post-2005
1573	b0608		IS	PA	PJM MA		100	0.56	b0608	b0608	Post-2005
1574	b0609		IS	PA	PJM MA		100	0.3	b0609	#N/A	Post-2005
1575	b0611		IS	PA	PJM MA		100	0.67	b0611	#N/A	Post-2005
1576	b0612		IS	PA	PJM MA		100	5.8	b0612	b0612	Post-2005
1577	b0618		IS	PA	PJM MA		100	0.16	b0618	#N/A	Post-2005
1578	b0619		IS	PA	PJM MA		100	0.22	b0619	#N/A	Post-2005
1579	b0620		IS	PA	PJM MA		100	1.32	b0620	b0620	Post-2005
1580	b0621		IS	PA	PJM MA		100	4.24	b0621	b0621	Post-2005
1581	b0622		IS	PA	PJM MA		100	6.08	b0622	b0622	Post-2005
1582	b0624		IS	PA	PJM MA		100	2.87	b0624	b0624	Post-2005
1583	b0626		IS	PA	PJM MA		100	0.09	b0626	#N/A	Post-2005
1584	b0627		IS	PA	PJM MA		100	7.63	b0627	b0627	Post-2005
1585	b0628		IS	PA	PJM MA		100	0.14	b0628	#N/A	Post-2005
1586	b0637	9/8/2010	IS	MD	PJM MA		100	1.5	b0637	b0637	Post-2005
1587	b0638	9/8/2010	IS	MD	PJM MA		100	1.5	b0638	b0638	Post-2005
1588	b0639	9/8/2010	IS	MD	PJM MA		100	1.5	b0639	b0639	Post-2005
1589	b0640	9/8/2010	IS	MD	PJM MA		100	1.5	b0640	b0640	Post-2005
1590	b0641	9/8/2010	IS	MD	PJM MA		100	1.5	b0641	b0641	Post-2005
1591	b0650		IS	PA	PJM MA		100	2.25	b0650	b0650	Post-2005
1592	b0652		IS	PA	PJM MA		100	2.1	b0652	b0652	Post-2005
1593	b0654		IS	PA	PJM MA		100	1.28	b0654	b0654	Post-2005
1594	b0656		IS	PA	PJM MA		100	2.73	b0656	b0656	Post-2005
1595	b0657		IS	PA	PJM MA		100	5.81	b0657	b0657	Post-2005
1596	b0695		IS	IL	PJM WEST		100	32.5	b0695	b0695	Post-2005
1597	b0696		IS	IL	PJM WEST		100	32.5	b0696	b0696	Post-2005
1598	b0700		IS	IL	PJM WEST		100	15	b0700	b0700	Post-2005
1599	b0701		IS	MD	PJM MA		100	22.5	b0701	b0701	Post-2005
1600	b0703		IS	PA	PJM MA		100	0.84	b0703	b0703	Post-2005
1601	b0705		IS		PJM MA		100	6.5	b0705	b0705	Post-2005
1602	b0712		IS		PJM MA		100	1.45	b0712	b0712	Post-2005
1603	b0713		IS		PJM MA		100	0.6	b0713	b0713	Post-2005
1604	b0714		IS		PJM MA		100	1	b0714	b0714	Post-2005
1605	b0718		IS	PA	PJM MA		100	0.37	b0718	b0718	Post-2005
1606	b0743		IS	NJ	PJM MA		100	0.5	b0743	b0743	Post-2005
1607	b0760		IS				100	14.3	b0760	b0760	Post-2005
1608	b0761		IS				100	3.5	b0761	b0761	Post-2005
1609	b0762		IS				100	2.2	b0762	b0762	Post-2005
1610	b0765		IS				100	3	b0765	b0765	Post-2005
1611	b0766		IS				100	0.2	b0766	b0766	Post-2005
1612	b0767		IS				100	39	b0767	b0767	Post-2005
1613	b0770		IS				100	6.19	b0770	b0770	Post-2005
1614	b0770.1		IS	VA	PJM SOUTH		100	0.16	b0770	b0770	Post-2005
1615	b0770.2		IS	VA	PJM SOUTH		100	0.16	b0770	b0770	Post-2005
1616	b0772		IS				100	4.5	b0772	b0772	Post-2005
1617	b0772.1		IS	VA	PJM SOUTH		100	0.16	b0772	b0772	Post-2005
1618	b0785		IS				100	11.17	b0785	b0785	Post-2005
1619	b0797		IS	MD	PJM West		100	0.01	b0797	b0797	Post-2005
1620	b0798		IS	MD	PJM West		100	0.01	b0798	b0798	Post-2005
1621	b0799		IS	MD	PJM West		100	0.01	b0799	b0799	Post-2005
1622	b0800		IS	MD	PJM West		100	0.01	b0800	b0800	Post-2005
1623	b0802		IS	MD	PJM MA		100	0.01	b0802	b0802	Post-2005
1624	b0803		IS	MD	PJM MA		100	0.01	b0803	b0803	Post-2005
1625	b0804		IS	MD	PJM MA		100	0.01	b0804	b0804	Post-2005
1626	b0805		IS	MD	PJM MA		100	0.01	b0805	b0805	Post-2005
1627	b0806		IS	MD	PJM MA		100	0.01	b0806	b0806	Post-2005
1628	b0809		IS	MD	PJM MA		100	0.01	b0809	b0809	Post-2005
1629	b0810		IS	MD	PJM MA		100	0.01	b0810	b0810	Post-2005
1630	b0811		IS	MD	PJM MA		100	0.01	b0811	b0811	Post-2005
1631	b0813		IS	NJ	PJM MA		100	16.5	b0813	b0813	Post-2005
1632	b0814.10		IS	NJ	PJM MA		100	0.5	b0814	b0814	Post-2005

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
3	Upgrade ID	PJM Required	In Service Date	Location	Task	Equipment	Descriptior	Voltage	Expected R	Last Updated	Trans Own	Study Year	Baseline R	Driver	Initial TEAC Da
1633	b0814.12	6/1/2013	10/1/2009	Marion	Replace	Breaker	2HM' with	138		6/2/2010	PSEG		2009	Short Circu	9/16/2009
1634	b0814.13	6/1/2013	10/1/2009	Marion	Replace	Breaker	2LM' with (	138		6/2/2010	PSEG		2009	Short Circu	9/16/2009
1635	b0814.14	6/1/2013	10/1/2009	Marion	Replace	Breaker	1LM' with (	138		6/2/2010	PSEG		2009	Short Circu	9/16/2009
1636	b0814.15	6/1/2013	12/15/2009	Marion	Replace	Breaker	6PM' with	138		6/2/2010	PSEG		2009	Short Circu	9/16/2009
1637	b0814.16	6/1/2013	12/7/2009	Marion	Replace	Breaker	3PM' with	138		6/2/2010	PSEG		2009	Short Circu	9/16/2009
1638	b0814.17	6/1/2013	11/1/2009	Marion	Replace	Breaker	4LM' with (	138		6/2/2010	PSEG		2009	Short Circu	9/16/2009
1639	b0814.18	6/1/2013	10/19/2009	Marion	Replace	Breaker	3LM' with (	138		6/2/2010	PSEG		2009	Short Circu	9/16/2009
1640	b0814.19	6/1/2013	10/11/2009	Marion	Replace	Breaker	1HM' with	138		6/2/2010	PSEG		2009	Short Circu	9/16/2009
1641	b0814.20	6/1/2013	11/7/2009	Marion	Replace	Breaker	2PM3' witl	138		6/2/2010	PSEG		2009	Short Circu	9/16/2009
1642	b0814.21	6/1/2013	11/13/2009	Marion	Replace	Breaker	2PM1' witl	138		6/2/2010	PSEG		2009	Short Circu	9/16/2009
1643	b0814.23	6/1/2013	5/7/2010	Foundry	Replace	Breaker	21P'	138		5/7/2010	PSEG		2009	Short Circu	9/16/2009
1644	b0814.25	6/1/2013	4/24/2009	Essex	Change	Relay	Change the	138		6/2/2010	PSEG		2009	Short Circu	9/16/2009
1645	b0814.26	6/1/2013	4/17/2009	Essex	Change	Relay	Change the	138		6/2/2010	PSEG		2009	Short Circu	9/16/2009
1646	b0814.27	6/1/2013	11/7/2008	Essex	Change	Relay	Change the	138		6/2/2010	PSEG		2009	Short Circu	9/16/2009
1647	b0814.28	6/1/2013	5/15/2009	Essex	Change	Relay	Change the	138		6/2/2010	PSEG		2009	Short Circu	9/16/2009
1648	b0814.29	6/1/2013	10/11/2007	Essex	Change	Relay	Change the	138		6/2/2010	PSEG		2009	Short Circu	9/16/2009
1649	b0814.30	6/1/2013	5/9/2009	Essex	Change	Relay	Change the	138		6/2/2010	PSEG		2009	Short Circu	9/16/2009
1650	b0814.9	6/1/2013	12/20/2008	Essex	Replace	Breaker	2LM' with (	138		6/1/2010	PSEG		2009	Short Circu	9/16/2009
1651	b0815	6/1/2012	7/9/2009	Elmont	Replace	Breaker	22192'	230		9/16/2010	Dominion		2009	Short Circu	5/20/2009
1652	b0816	6/1/2011	3/24/2011	Elmont	Replace	Breaker	21692'	230		4/19/2011	Dominion		2009	Short Circu	5/20/2009
1653	b0817	6/1/2012	8/6/2009	Elmont	Replace	Breaker	200992'	230		9/16/2010	Dominion		2009	Short Circu	5/20/2009
1654	b0818	6/1/2012	10/30/2009	Elmont	Replace	Breaker	2009T2032	230		9/16/2010	Dominion		2009	Short Circu	5/20/2009
1655	b0822	6/1/2009	10/31/2009	Gwynnbro(	Remove	Line Drop	limitations	115		12/15/2009	BGE	2011		Gen Delive	11/5/2008
1656	b0827	6/1/2011	5/27/2011	Texas-May	Install	Protection	for one yea	115		5/31/2011	BGE	2011	2008	Gen Delive	11/5/2008
1657	b0829.5	6/1/2013	10/9/2009	Plymouth I	Replace	Breaker	335	230	63 kA	4/26/2010	PECO	2013	2009	Short Circu	5/20/2009
1658	b0830.2	6/1/2012	11/14/2010	Roseland	Upgrade	Breaker	91H with 8	230	80 kA	3/23/2011	PSEG		2009	Short Circu	7/15/2009
1659	b0830.3	6/1/2012	11/14/2010	Roseland	Upgrade	Breaker	22H with 8	230	80 kA	4/13/2011	PSEG		2009	Short Circu	7/15/2009
1660	b0837	6/1/2013	3/26/2009	Mount Sto	Replace	MOD	existing M(	500		9/1/2009	Dominion	2013		Operationa	10/15/2008
1661	b0839	6/1/2013	6/2/2009	Twin Branc	Replace	Transform(	450 MVA t	345/138		4/26/2010	AEP		2009	N-1-1 Ther	9/16/2009
1662	b0848	6/1/2012	11/22/2009	Chalk Point	Replace	Breaker	Replace Ch	230		2/24/2011	PEPCO	2012		Short Circu	10/28/2010
1663	b0849	6/1/2012	12/3/2010	Chalk Point	Replace	Breaker	Replace Ch	230		2/24/2011	PEPCO	2012		Short Circu	10/28/2010
1664	b0863	6/1/2012	11/13/2010	Chalk Point	Replace	Breaker	Replace Ch	230		2/24/2011	PEPCO	2012		Short Circu	10/28/2010
1665	b0882	6/1/2010	4/26/2010	Hudson	Replace	Breaker	1HA (BS 2-:	230	63kA	6/2/2010	PSEG	2010	2009	Short Circu	5/20/2009
1666	b0883	6/1/2010	9/24/2010	Hudson	Modify	Breaker	2HA (BS 3-·	230	63kA	10/28/2010	PSEG	2010	2009	Short Circu	5/20/2009
1667	b0884	6/1/2010	9/1/2010	Hudson	Modify	Breaker	3HB (BS 7-:	230	63kA	10/28/2010	PSEG	2010	2009	Short Circu	5/20/2009
1668	b0885	6/1/2010	12/15/2010	Hudson	Add	Breaker	4HA (BS 9-	230	63kA	3/9/2011	PSEG	2010	2009	Short Circu	5/20/2009
1669	b0886	6/1/2010	12/15/2010	Hudson	Add	Breaker	4HB (BS 11	230	63kA	3/9/2011	PSEG	2010	2009	Short Circu	5/20/2009
1670	b0888	6/1/2012	4/30/2005	Loudoun	Replace	Breaker	Cap breake	230		4/21/2011	Dominion	2013	2009	Short Circu	5/20/2009
1671	b0893	6/1/2009	9/25/2009	Chesapeak	Replace	Breaker	T202	115		4/26/2010	Dominion	2009	2009	Short Circu	9/16/2009
1672	b0894	6/1/2009	2/24/2009	Possum Po	Replace	Breaker	SX-32	115		4/26/2010	Dominion	2009	2009	Short Circu	9/16/2009
1673	b0895	6/1/2009	5/1/2009	Possum Po	Replace	Breaker	L92-1	115		4/26/2010	Dominion	2009	2009	Short Circu	9/16/2009
1674	b0896	6/1/2009	5/1/2009	Possum Po	Replace	Breaker	L92-2	115		4/26/2010	Dominion	2009	2009	Short Circu	9/16/2009
1675	b0897	6/1/2009	6/22/2009	Suffolk	Replace	Breaker	T202	115		4/26/2010	Dominion	2009	2009	Short Circu	9/16/2009
1676	b0898	6/1/2009	4/9/2009	Peninsula	Replace	Breaker	SC202	115		4/26/2010	Dominion	2009	2009	Short Circu	9/16/2009
1677	b0899	6/1/2009	10/1/2009	ECRR	Replace	Breaker	901	138		6/2/2010	PSEG	2009	2009	Short Circu	9/16/2009
1678	b0900	6/1/2009	10/1/2009	ECRR	Replace	Breaker	902	138		6/2/2010	PSEG	2009	2009	Short Circu	9/16/2009
1679	b0901	6/1/2009	9/21/2010	Greene	Replace	Breaker	GJ-D	138		10/29/2010	Dayton	2009	2009	Short Circu	9/16/2009
1680	b0902	6/1/2009	11/2/2010	Greene	Replace	Breaker	GJ-E	138		11/8/2010	Dayton	2009	2009	Short Circu	9/16/2009
1681	b0903	6/1/2009	11/19/2010	Greene	Replace	Breaker	GJ-F	138		1/4/2011	Dayton	2009	2009	Short Circu	9/16/2009
1682	b0904	6/1/2009	10/9/2010	Greene	Replace	Breaker	GJ-H	138		10/29/2010	Dayton	2009	2009	Short Circu	9/16/2009
1683	b0905	6/1/2009	10/19/2010	Greene	Replace	Breaker	GJ-I	138		11/8/2010	Dayton	2009	2009	Short Circu	9/16/2009
1684	b0906	6/1/2009	3/15/2010	Wagner	Upgrade	Breaker	Increase cc	115		4/26/2010	BGE	2009	2009	Short Circu	9/16/2009
1685	b0907	6/1/2009	3/15/2010	Wagner	Upgrade	Breaker	Increase cc	115		4/26/2010	BGE	2009	2009	Short Circu	9/16/2009
1686	b0908	6/1/2011	12/29/2010	South Akrc	Install	Disconect !	Install mot	230		6/23/2011	PPL		2009	NERC Cate	5/20/2009
1687	b0917	6/1/2009	5/27/2010	Baileysville	Replace	Breaker	P'	138		7/22/2010	AEP		2009	Short Circu	9/16/2009
1688	b0918	6/1/2009	5/28/2010	Riverview	Replace	Breaker	634'	138		7/22/2010	AEP		2009	Short Circu	9/16/2009
1689	b0919	6/1/2009	6/25/2010	Torrey	Replace	Breaker	W'	138		7/22/2010	AEP		2009	Short Circu	9/16/2009
1690	b0920	5/27/2011	4/15/2011	Jarrett & W	Replace	Terminal E	circuit 220·	230		6/23/2011	PECO	2014	2009	N-1-1	7/15/2009
1691	b0923	12/31/2009	5/27/2010	Carson	Install	Reactor	50-100 MV	230		6/17/2010	Dominion		2009	Aging Infra	7/15/2009
1692	b0925	5/31/2010	11/3/2010	Garrisonvil	Install	Reactor	50-100 MV	230		11/5/2010	Dominion		2009	Aging Infra	7/15/2009
1693	b0927	5/31/2010	5/6/2010	Yadkin	Install	Reactor	50-100 MV	230		11/5/2010	Dominion		2009	Aging Infra	7/15/2009
1694	b0928.4	12/31/2011	12/21/2010	Idylwood	Install	Reactor	Install 50-100 MVAR variable reac			1/20/2011	Dominion		2009	High Volta	7/15/2009
1695	b0929	6/1/2009	4/10/2010	Universal	Replace	Breaker	Z-152'	138		7/14/2010	DL		2009	Short Circu	9/16/2009
1696	b0930	6/1/2009	12/31/2010	Universal	Replace	Breaker	Z-154'	138		3/9/2011	DL		2009	Short Circu	9/16/2009
1697	b0931	6/1/2009	12/15/2010	Universal	Replace	Breaker	NO 1-3'	138		3/9/2011	DL		2009	Short Circu	9/16/2009
1698	b0942	6/1/2009	10/29/2010	Butler	Replace	Breaker	breaker '#1	138	40kA	12/30/2010	APS		2009	Short Circu	9/16/2009
1699	b0943	6/1/2009	12/9/2010	Butler	Replace	Breaker	breaker '#2	138	40kA	12/30/2010	APS		2009	Short Circu	9/16/2009
1700	b0944	6/1/2009	8/17/2010	Yukon	Replace	Breaker	breaker 'Y-	138	63kA	12/30/2010	APS		2009	Short Circu	9/16/2009
1701	b0945	6/1/2009	11/9/2010	Yukon	Replace	Breaker	breaker 'Y-	138	63kA	12/30/2010	APS		2009	Short Circu	9/16/2009
1702	b0946	6/1/2009	10/20/2010	Yukon	Replace	Breaker	breaker 'Y-	138	63kA	12/30/2010	APS		2009	Short Circu	9/16/2009
1703	b0947	6/1/2009	9/15/2010	Yukon	Replace	Breaker	breaker 'Y-	138	63kA	12/30/2010	APS		2009	Short Circu	9/16/2009

	A	P	Q	R	S	T	U	V	W	X	Y
3	Upgrade ID	Latest TEAC Date	Status	State	Region	County	Percent Co	Cost Estim	Project ID	In Schedul	Source
1633	b0814.12		IS	NJ	PJM MA		100	0.5	b0814	b0814	Post-2005
1634	b0814.13		IS	NJ	PJM MA		100	0.5	b0814	b0814	Post-2005
1635	b0814.14		IS	NJ	PJM MA		100	0.5	b0814	b0814	Post-2005
1636	b0814.15		IS	NJ	PJM MA		100	0.5	b0814	b0814	Post-2005
1637	b0814.16		IS	NJ	PJM MA		100	0.5	b0814	b0814	Post-2005
1638	b0814.17		IS	NJ	PJM MA		100	0.5	b0814	b0814	Post-2005
1639	b0814.18		IS	NJ	PJM MA		100	0.5	b0814	b0814	Post-2005
1640	b0814.19		IS	NJ	PJM MA		100	0.5	b0814	b0814	Post-2005
1641	b0814.20		IS	NJ	PJM MA		100	0.5	b0814	b0814	Post-2005
1642	b0814.21		IS	NJ	PJM MA		100	0.5	b0814	b0814	Post-2005
1643	b0814.23		IS	NJ	PJM MA		100	0.5	b0814	b0814	Post-2005
1644	b0814.25		IS	NJ	PJM MA		100	0	b0814	b0814	Post-2005
1645	b0814.26		IS	NJ	PJM MA		100	0	b0814	b0814	Post-2005
1646	b0814.27		IS	NJ	PJM MA		100	0	b0814	b0814	Post-2005
1647	b0814.28		IS	NJ	PJM MA		100	0	b0814	b0814	Post-2005
1648	b0814.29		IS	NJ	PJM MA		100	0	b0814	b0814	Post-2005
1649	b0814.30		IS	NJ	PJM MA		100	0	b0814	b0814	Post-2005
1650	b0814.9		IS	NJ	PJM MA		100	0.5	b0814	b0814	Post-2005
1651	b0815		IS	VA	PJM SOUTH		100	0.18	b0815	b0815	Post-2005
1652	b0816		IS	VA	PJM SOUTH		100	0.18	b0816	b0816	Post-2005
1653	b0817		IS	VA	PJM SOUTH		100	0.18	b0817	b0817	Post-2005
1654	b0818		IS	VA	PJM SOUTH		100	0.18	b0818	b0818	Post-2005
1655	b0822		IS	MD	PJM MA		100	0.4	b0822	b0822	Post-2005
1656	b0827		IS	MD	PJM MA		100	0.02	b0827	b0827	Post-2005
1657	b0829.5		IS	PA	PJM MA		100	0.23	b0829	b0829	Post-2005
1658	b0830.2		IS	NJ	PJM MA		100	0.8	b0830	b0830	Post-2005
1659	b0830.3		IS	NJ	PJM MA		100	0.8	b0830	b0830	Post-2005
1660	b0837		IS	WV	PJM West		0	1.5	b0837	b0837	Post-2005
1661	b0839		IS		PJM West		100	8.5	b0839	b0839	Post-2005
1662	b0848		IS	MD	PJM MA		100	2	b0848	b0848	Post-2005
1663	b0849		IS	MD	PJM MA		100	2	b0849	b0849	Post-2005
1664	b0863		IS	MD	PJM MA		100	2	b0863	b0863	Post-2005
1665	b0882		IS	NJ	PJM MA		100	0.8	b0882	b0882	Post-2005
1666	b0883		IS	NJ	PJM MA		100	0.01	b0883	b0883	Post-2005
1667	b0884		IS	NJ	PJM MA		100	0.01	b0884	b0884	Post-2005
1668	b0885		IS	NJ	PJM MA		100	0.16	b0885	b0885	Post-2005
1669	b0886		IS	NJ	PJM MA		100	0.16	b0886	b0886	Post-2005
1670	b0888		IS	VA	PJM SOUTH		100	0.25	b0888	b0888	Post-2005
1671	b0893		IS	VA	PJM SOUTH		100	0.2	b0893	b0893	Post-2005
1672	b0894		IS	VA	PJM SOUTH		100	0.2	b0894	b0894	Post-2005
1673	b0895		IS	VA	PJM SOUTH		100	0.2	b0895	b0895	Post-2005
1674	b0896		IS	VA	PJM SOUTH		100	0.2	b0896	b0896	Post-2005
1675	b0897		IS	VA	PJM SOUTH		100	0.2	b0897	b0897	Post-2005
1676	b0898		IS	VA	PJM SOUTH		100	0.2	b0898	b0898	Post-2005
1677	b0899		IS	NJ	PJM MA		100	0.5	b0899	b0899	Post-2005
1678	b0900		IS	NJ	PJM MA		100	0.5	b0900	b0900	Post-2005
1679	b0901		IS	OH	PJM WEST		100	0.19	b0901	b0901	Post-2005
1680	b0902		IS	OH	PJM WEST		100	0.19	b0902	b0902	Post-2005
1681	b0903		IS	OH	PJM WEST		100	0.19	b0903	b0903	Post-2005
1682	b0904		IS	OH	PJM WEST		100	0.19	b0904	b0904	Post-2005
1683	b0905		IS	OH	PJM WEST		100	0.19	b0905	b0905	Post-2005
1684	b0906		IS	MD	PJM MA		100	0	b0906	b0906	Post-2005
1685	b0907		IS	MD	PJM MA		100	0	b0907	b0907	Post-2005
1686	b0908		IS	PA	PJM MA		100	0.79	b0908	b0908	Post-2005
1687	b0917		IS		PJM WEST		100	0.4	b0917	b0917	Post-2005
1688	b0918		IS		PJM WEST		100	0.4	b0918	b0918	Post-2005
1689	b0919		IS		PJM WEST		100	0.4	b0919	b0919	Post-2005
1690	b0920		IS	PA	PJM MA		100	0.18	b0920	b0920	Post-2005
1691	b0923	9/16/2009	IS	VA	PJM South		100	5.5	b0923	b0923	Post-2005
1692	b0925	9/16/2009	IS	VA	PJM South		100	5.5	b0925	b0925	Post-2005
1693	b0927	9/16/2009	IS	VA	PJM South		100	5.5	b0927	b0927	Post-2005
1694	b0928.4	9/16/2009	IS	VA	PJM SOUTH		100	6	b0928	b0928	Post-2005
1695	b0929		IS	PA	PJM WEST		100	0.3	b0929	b0929	Post-2005
1696	b0930		IS	PA	PJM WEST		100	0.3	b0930	b0930	Post-2005
1697	b0931		IS	PA	PJM WEST		100	0.3	b0931	b0931	Post-2005
1698	b0942		IS		PJM WEST		100	0.14	b0942	#N/A	Post-2005
1699	b0943		IS		PJM WEST		100	0.14	b0943	#N/A	Post-2005
1700	b0944		IS		PJM WEST		100	0.2	b0944	#N/A	Post-2005
1701	b0945		IS		PJM WEST		100	0.2	b0945	#N/A	Post-2005
1702	b0946		IS		PJM WEST		100	0.2	b0946	#N/A	Post-2005
1703	b0947		IS		PJM WEST		100	0.2	b0947	#N/A	Post-2005

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
3	Upgrade ID	PJM Required	In Service Date	Location	Task	Equipment	Descriptior	Voltage	Expected R	Last Updated	Trans Own	Study Year	Baseline R	Driver	Initial TEAC Da
1704	b0949	6/1/2009	10/8/2010	Yukon	Replace	Breaker	breaker 'Y-	138	63kA	3/9/2011	APS		2009	Short Circu	9/16/2009
1705	b0950	6/1/2009	8/31/2010	Yukon	Replace	Breaker	breaker 'Y-	138	63kA	12/30/2010	APS		2009	Short Circu	9/16/2009
1706	b0951	6/1/2009	9/29/2010	Yukon	Replace	Breaker	breaker 'Y-	138	63kA	12/30/2010	APS		2009	Short Circu	9/16/2009
1707	b0952	6/1/2009	10/12/2010	Yukon	Replace	Breaker	breaker 'Y-	138	63kA	12/30/2010	APS		2009	Short Circu	9/16/2009
1708	b0954	6/1/2009	2/15/2010	Charleroi	Replace	Breaker	breaker '#1	138		4/26/2010	APS		2009	Short Circu	9/16/2009
1709	b0956	6/1/2009	5/27/2010	Pruntytow	Replace	Breaker	breaker 'P-	138	63kA	8/24/2010	APS		2009	Short Circu	9/16/2009
1710	b0957	6/1/2009	6/25/2010	Pruntytow	Replace	Breaker	breaker 'P-	138	63kA	8/24/2010	APS		2009	Short Circu	9/16/2009
1711	b0958	6/1/2009	7/29/2010	Pruntytow	Replace	Breaker	breaker 'P-	138	63kA	8/24/2010	APS		2009	Short Circu	9/16/2009
1712	b0959	6/1/2009	4/2/2010	Charleroi	Replace	Breaker	breaker '#2	138	63kA	8/24/2010	APS		2009	Short Circu	9/16/2009
1713	b0960	6/1/2009	4/15/2010	Pruntytow	Replace	Breaker	breaker 'P-	138	63kA	8/24/2010	APS		2009	Short Circu	9/16/2009
1714	b0961	6/1/2009	4/28/2010	Pruntytow	Replace	Breaker	breaker 'P-	138	63kA	8/24/2010	APS		2009	Short Circu	9/16/2009
1715	b0964	6/1/2009	6/10/2010	Pruntytow	Replace	Breaker	breaker 'P-	138		8/24/2010	APS		2009	Short Circu	9/16/2009
1716	b0965	6/1/2009	11/17/2010	Springdale	Replace	Breaker	breaker '13	138	63kA	12/30/2010	APS		2009	Short Circu	9/16/2009
1717	b0966	6/1/2009	5/13/2010	Pruntytow	Replace	Breaker	breaker 'P-	138	63kA	8/24/2010	APS		2009	Short Circu	9/16/2009
1718	b0967	6/1/2009	7/14/2010	Pruntytow	Replace	Breaker	breaker 'P-	138	63kA	8/24/2010	APS		2009	Short Circu	9/16/2009
1719	b0968	6/1/2009	11/22/2010	Ringgold	Replace	Breaker	breaker '#3	138	40kA	12/30/2010	APS		2009	Short Circu	9/16/2009
1720	b0969	6/1/2009	11/17/2010	Springdale	Replace	Breaker	breaker '13	138	63kA	12/30/2010	APS		2009	Short Circu	9/16/2009
1721	b0971	6/1/2009	11/17/2010	Springdale	Replace	Breaker	breaker '13	138	63kA	12/30/2010	APS		2009	Short Circu	9/16/2009
1722	b0972	6/1/2009	6/25/2010	Belmont	Replace	Breaker	breaker 'B-	138	63kA	8/24/2010	APS		2009	Short Circu	9/16/2009
1723	b0975	6/1/2009	10/26/2010	Armstrong	Replace	Breaker	breaker 'BI	138	40kA	12/30/2010	APS		2009	Short Circu	9/16/2009
1724	b0977	6/1/2009	7/14/2010	Belmont	Replace	Breaker	breaker 'B-	138	63kA	8/24/2010	APS		2009	Short Circu	9/16/2009
1725	b0985	6/1/2009	10/24/2010	Belmont	Replace	Breaker	breaker 'B-	138	63kA	12/30/2010	APS		2009	Short Circu	9/16/2009
1726	b0989	6/1/2009	11/11/2010	Edgelawn	Replace	Breaker	breaker 'G(	138	40kA	12/30/2010	APS		2009	Short Circu	9/16/2009
1727	b0990	6/1/2009	8/24/2010	Cabot	Change	Breaker	reclosing o	138	Change Re	9/29/2010	APS		2009	Short Circu	9/16/2009
1728	b0991	6/1/2009	9/9/2010	Belmont	Change	Breaker	reclosing o	138	Change Re	9/29/2010	APS		2009	Short Circu	9/16/2009
1729	b0992	6/1/2009	9/9/2010	Belmont	Change	Breaker	reclosing o	138	Change Re	9/29/2010	APS		2009	Short Circu	9/16/2009
1730	b0993	6/1/2009	9/9/2010	Belmont	Change	Breaker	reclosing o	138	Change Re	9/29/2010	APS		2009	Short Circu	9/16/2009
1731	b0994	6/1/2009	9/9/2010	Belmont	Change	Breaker	reclosing o	138	Change Re	9/29/2010	APS		2009	Short Circu	9/16/2009
1732	b0995	6/1/2009	9/9/2010	Belmont	Change	Breaker	reclosing o	138	Change Re	9/29/2010	APS		2009	Short Circu	9/16/2009
1733	b0996	6/1/2009	8/23/2010	Willow Isla	Change	Breaker	reclosing o	138	Change Re	9/29/2010	APS		2009	Short Circu	9/16/2009
1734	b0997	6/1/2009	8/24/2010	Cabot	Change	Breaker	reclosingoi	138	Change Re	9/29/2010	APS		2009	Short Circu	9/16/2009
1735	b0998	6/1/2009	8/24/2010	Cabot	Change	Breaker	reclosing o	138	Change Re	9/29/2010	APS		2009	Short Circu	9/16/2009
1736	b1010	6/1/2009	9/27/2010	Shawville	Replace	Breaker	Dubois'	115		11/11/2010	PENELEC		2009	Short Circu	9/16/2009
1737	b1013	6/1/2009	6/1/2010	Linden	Replace	Breaker	7PB'	138		9/16/2010	PSEG	2009	2009	Short Circu	9/16/2009
1738	b1020	6/1/2011	4/8/2011	Englishtow	Replace	Wave trap	on the Englishtown - N		501N/727E	5/3/2011	JCPL	2011	2009	Gen Delive	8/2/2009
1739	b1021	6/1/2009	7/22/2009	Wescosvill	Install	Transform	new #4	138/69		4/26/2010	PPL		2009		9/16/2009
1740	b1022.3	6/1/2010	6/21/2010	Smith	Install	Capacitors	Add static	138	100MVAR	3/10/2011	APS		2009	N-1-1	6/9/2009
1741	b1022.4	6/1/2010	12/23/2010	North Faye	Install	Capacitors	Add static	138	100MVAR	3/10/2011	APS		2009	N-1-1	6/9/2009
1742	b1022.5	6/1/2010	9/25/2010	South Faye	Install	Capacitors	Add static	138	100MVAR	3/10/2011	APS		2009	N-1-1	6/9/2009
1743	b1022.6	6/1/2010	6/21/2010	Manifold	Install	Capacitors	Add static	138	100MVAR	3/10/2011	APS		2009	N-1-1	6/9/2009
1744	b1022.7	6/1/2010	11/2/2010	Houston	Install	Capacitors	Add static	138	100MVAR	3/10/2011	APS		2009	N-1-1	6/9/2009
1745	b1028	6/1/2013	1/20/2011	Osage - Co	Reconduct	Line	Reconduct	138	176/214	3/11/2011	APS		2009	N-1-1 Ther	10/6/2010
1746	b1095	6/1/2010	4/16/2010	Chase City	Reconductor		Bus and ad	115		5/25/2010	Dominion		2009		10/22/2009
1747	b1102	6/1/2014	7/11/2009	Bremo	Replace	Breaker	9122	115		9/16/2010	Dominion	2014	2009	Short Circu	11/18/2009
1748	b1103	6/1/2014	11/20/2009	Bremo	Replace	Breaker	822	115		9/16/2010	Dominion	2014	2009	Short Circu	11/18/2009
1749	b1121	6/1/2014	8/5/2009	Beaver Val	Reclose tin	Breaker	on 'Z33 J&I	138	40kA	8/4/2010	DL	2014	2009	Short Circu	11/18/2009
1750	b1123	6/1/2014	1/15/2010	Elywn	Replace	Breaker	No.1-2 138	138		4/26/2010	DL	2014	2009	Short Circu	11/18/2009
1751	b1179	5/27/2011	2/11/2011	Eddystone	Replace	Terminal E	Replace te	230		3/17/2011	PECO			Gen Retire	3/10/2010
1752	b1180.1	5/27/2011	3/31/2011	Chichester	Replace	Terminal Equipment				6/23/2011	PECO			Gen Retire	3/10/2010
1753	b1180.2	5/27/2011	3/31/2011	Chichester	Replace	Terminal E	Replace terminal equipment at Cl			6/23/2011	PECO			Gen Retire	3/10/2010
1754	b1181	6/1/2011	2/11/2011	Eddystone	Install	Transformer		230/138		3/30/2011	PECO			Gen Retire	3/10/2010
1755	b1185	6/1/2010	2/1/2011	Eddystone	Upgrade	Breaker	#365	230		3/17/2011	PECO			Gen Retire	3/10/2010
1756	b1186	6/1/2011	2/1/2011	Eddystone	Upgrade	Breaker	#785	230		3/17/2011	PECO			Gen Retire	3/10/2010
1757	b1189	6/1/2009		Springdale	Replace	Breaker	AE 1 & 2 b	138		2/28/2011	AE SUPPLY	2009		Short Circuit	
1758	b1193	6/1/2013	12/1/2010	Hanna	Reconduct	Line	Replace th	138		1/19/2011	ATSI	2013		Gen Deliv	5/12/2010
1759	b1258	6/1/2011	12/17/2010	Elmhurst	Revise	Breaker	Revise the reclosing on the Elmhu			1/20/2011	ComEd	2011		Short Circu	9/8/2010
1760	b1259	6/1/2011	12/17/2010	Elmhurst	Revise	Breaker	Revise the reclosing on the Elmhu			1/20/2011	ComEd	2011		Short Circu	9/8/2010
1761	b1307	3/31/2011	3/11/2011	Northern N	Install	Transform	Install a 2nd 230/115 kV transfor			5/24/2011	Dominion			Road Main	8/25/2010
1762	b1347	6/1/2011	3/30/2011	Whitesville	Replace	Line	Replace 500 CU substation condu			5/3/2011	JCPL			FE Criteria	10/28/2010
1763	b1352	6/1/2011	3/21/2011	Centerstat	Upgrade	Line	Upgrade the Smithburg - Centers			5/4/2011	JCPL			FE Criteria	10/28/2010
1764	b1353	6/1/2011	4/14/2011	Larrabee/L	Upgrade	Line	Upgrade the Larrabee – Laureltor			5/4/2011	JCPL			FE Criteria	10/28/2010
1765	b1359	6/1/2011	4/14/2011	Montville/'	Reconfigur	Line	Install a Troy Hills 34.5 kV by-pass			5/4/2011	JCPL			FE Criteria	10/28/2010
1766	b1368	6/1/2011	4/15/2011	Claysburg	Replace	Transform	Replace the Claysburg115/46 kV			5/4/2011	Penelec			FE Criteria	10/28/2010
1767	b1371	6/1/2011	4/15/2011	Claysburg	Reconduct	Line	Reconductor 2.6 miles of the Clay			5/4/2011	Penelec			FE Criteria	10/28/2010
1768	b1372	6/1/2011	2/28/2011	Hollidaysb	Replace	Bus Condu	Replace 4/0 CU substation condu			5/4/2011	Penelec			FE Criteria	10/28/2010
1769	b0012	6/1/2004	6/30/2004	South Akro	Install	Capacitors	distributio	230		8/12/2009	PPL	1999			5/9/2005
1770	b0015	6/1/2002	5/31/2002	Athenia	Replace	Breaker	#B-2228-5	230		8/11/2009	PSEG	2000		Short Circu	5/9/2005
1771	b0016	6/1/2002	6/30/2002	Hudson	Replace	Breaker	#BS1-6	230		8/11/2009	PSEG	2000		Short Circu	5/9/2005
1772	b0017	5/1/2004	5/1/2005	Roseland	Replace	Breaker	#BS3-4 #BS	230		4/13/2011	PSEG	2000		Short Circu	5/9/2005
1773	b0018	5/1/2004	1/10/2005	Hudson	Add	Transform	Provide ad	230/138		8/14/2009	PSEG	2000			5/9/2005
1774	b0022	6/1/2003	5/31/2003	Plymouth I	Upgrade	Breaker	#215	230		8/11/2009	PECO	2000		Short Circu	5/9/2005

	A	P	Q	R	S	T	U	V	W	X	Y
3	Upgrade ID	Latest TEAC Date	Status	State	Region	County	Percent Co	Cost Estim	Project ID	In Schedule	Source
1704	b0949		IS		PJM WEST		100	0.2	b0949	#N/A	Post-2005
1705	b0950		IS		PJM WEST		100	0.2	b0950	b0950	Post-2005
1706	b0951		IS		PJM WEST		100	0.2	b0951	b0951	Post-2005
1707	b0952		IS		PJM WEST		100	0.2	b0952	b0952	Post-2005
1708	b0954		IS		PJM WEST		100	0.17	b0954	b0954	Post-2005
1709	b0956		IS		PJM WEST		100	0.2	b0956	b0956	Post-2005
1710	b0957		IS		PJM WEST		100	0.2	b0957	b0957	Post-2005
1711	b0958		IS		PJM WEST		100	0.2	b0958	b0958	Post-2005
1712	b0959		IS		PJM WEST		100	0.17	b0959	b0959	Post-2005
1713	b0960		IS		PJM WEST		100	0.2	b0960	b0960	Post-2005
1714	b0961		IS		PJM WEST		100	0.2	b0961	b0961	Post-2005
1715	b0964		IS		PJM WEST		100	0.2	b0964	b0964	Post-2005
1716	b0965		IS		PJM WEST		100	0.2	b0965	b0965	Post-2005
1717	b0966		IS		PJM WEST		100	0.2	b0966	b0966	Post-2005
1718	b0967		IS		PJM WEST		100	0.2	b0967	b0967	Post-2005
1719	b0968		IS		PJM WEST		100	0.14	b0968	b0968	Post-2005
1720	b0969		IS		PJM WEST		100	0.2	b0969	b0969	Post-2005
1721	b0971		IS		PJM WEST		100	0.2	b0971	b0971	Post-2005
1722	b0972		IS		PJM WEST		100	0.2	b0972	b0972	Post-2005
1723	b0975		IS		PJM WEST		100	0.14	b0975	b0975	Post-2005
1724	b0977		IS		PJM WEST		100	0.2	b0977	b0977	Post-2005
1725	b0985		IS		PJM WEST		100	0.2	b0985	b0985	Post-2005
1726	b0989		IS		PJM WEST		100	0.14	b0989	b0989	Post-2005
1727	b0990		IS		PJM WEST		100	0	b0990	b0990	Post-2005
1728	b0991		IS		PJM WEST		100	0	b0991	b0991	Post-2005
1729	b0992		IS		PJM WEST		100	0	b0992	b0992	Post-2005
1730	b0993		IS		PJM WEST		100	0	b0993	b0993	Post-2005
1731	b0994		IS		PJM WEST		100	0	b0994	b0994	Post-2005
1732	b0995		IS		PJM WEST		100	0	b0995	b0995	Post-2005
1733	b0996		IS		PJM WEST		100	0	b0996	b0996	Post-2005
1734	b0997		IS		PJM WEST		100	0	b0997	b0997	Post-2005
1735	b0998		IS		PJM WEST		100	0	b0998	b0998	Post-2005
1736	b1010		IS	PA	PJM MA		100	0.23	b1010	b1010	Post-2005
1737	b1013		IS	NJ	PJM MA		100	0.5	b1013	b1013	Post-2005
1738	b1020		IS	NJ	PJM MA		100	0.07	b1020	b1020	Post-2005
1739	b1021		IS	PA	PJM MA		100	4.5	b1021	b1021	Post-2005
1740	b1022.3	9/16/2009	IS		PJM WEST		100	0.8	b1022	b1022	Post-2005
1741	b1022.4	9/16/2009	IS		PJM WEST		100	0.9	b1022	b1022	Post-2005
1742	b1022.5	9/16/2009	IS		PJM WEST		100	0.8	b1022	b1022	Post-2005
1743	b1022.6	9/16/2009	IS		PJM WEST		100	0.8	b1022	b1022	Post-2005
1744	b1022.7	9/16/2009	IS		PJM WEST		100	0.8	b1022	b1022	Post-2005
1745	b1028	9/16/2009	IS	WV	PJM WEST		100	2.3	b1028	b1028	Post-2005
1746	b1095		IS		PJM SOUTH		100	2.4	b1095	b1095	Post-2005
1747	b1102		IS	VA	PJM SOUTH		100	0.16	b1102	b1102	Post-2005
1748	b1103		IS	VA	PJM SOUTH		100	0.16	b1103	b1103	Post-2005
1749	b1121		IS	PA	PJM WEST		100	0	b1121	b1121	Post-2005
1750	b1123		IS	PA	PJM WEST		100	0.33	b1123	b1123	Post-2005
1751	b1179		IS		PJM MA		100	3.94	b1179	b1179	Post-2005
1752	b1180.1		IS		PJM MA		100	0.55	b1180	b1180	Post-2005
1753	b1180.2		IS		PJM MA		100	0.55	b1180	b1180	Post-2005
1754	b1181		IS		PJM MA		100	3.6	b1181	b1181	Post-2005
1755	b1185		IS		PJM MA		100	0.13	b1185	b1185	Post-2005
1756	b1186		IS		PJM MA		100	0.13	b1186	b1186	Post-2005
1757	b1189		IS		PJM WEST		0	0.11	b1189	#N/A	Post-2005
1758	b1193		IS	OH	PJM WEST		100	0.05	b1193	#N/A	Post-2005
1759	b1258		IS	IL	PJM WEST		100	0.08	b1258	b1258	Post-2005
1760	b1259		IS	IL	PJM WEST		100	0.08	b1259	b1259	Post-2005
1761	b1307		IS		PJM SOUTH		100	5.1	b1307	b1307	Post-2005
1762	b1347		IS		PJM MA		100	0.02	b1347	b1347	Post-2005
1763	b1352		IS		PJM MA		100	0.09	b1352	b1352	Post-2005
1764	b1353		IS		PJM MA		100	0.09	b1353	b1353	Post-2005
1765	b1359		IS		PJM MA		100	0.03	b1359	b1359	Post-2005
1766	b1368		IS		PJM MA		100	1.49	b1368	b1368	Post-2005
1767	b1371		IS		PJM MA		100	0.63	b1371	b1371	Post-2005
1768	b1372		IS		PJM MA		100	0.04	b1372	b1372	Post-2005
1769	b0012		IS	PA	PJM MA	Lancaster	100	0.41	b0012	#N/A	Pre-2006
1770	b0015		IS	NJ	PJM MA	Essex	100	0.35	b0015	#N/A	Pre-2006
1771	b0016		IS	NJ	PJM MA	Hudson	100	0.35	b0016	#N/A	Pre-2006
1772	b0017		IS	NJ	PJM MA	Essex	100	1.4	b0017	#N/A	Pre-2006
1773	b0018		IS	NJ	PJM MA	Hudson	100	0.1	b0018	#N/A	Pre-2006
1774	b0022		IS	PA	PJM MA	Montgome	100	0.1	b0022	#N/A	Pre-2006

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
3	Upgrade ID	PJM Required	In Service Date	Location	Task	Equipment	Descriptior	Voltage	Expected R	Last Updated	Trans Own	Study Year	Baseline R	Driver	Initial TEAC Da
1775	b0023	6/1/2003	4/24/2003	Cardiff	Construct	Ring Bus	four breaker ring bus and install S			8/11/2009	AEC	2000		Short Circu	5/9/2005
1776	b0026	6/1/2004	11/9/2003	Brunner Isl	Install	Breaker	at Brunner	230		8/11/2009	PPL	2000		Short Circu	5/9/2005
1777	b0027	6/1/2004	5/23/2003	Manor	Replace	Breaker	two Manor	230		8/11/2009	PPL	2000		Short Circu	5/9/2005
1778	b0049	10/1/2003	11/3/2003	Canaan Va	Modify	Structures	21 structur	138		8/11/2009	APS	2001			5/9/2005
1779	b0050.1	10/1/2003	8/1/2003	W. Waynes	Add	Capacitor	5.1 MVAR a	34		8/11/2009	APS	2001			5/9/2005
1780	b0050.2	10/1/2003	8/1/2003	Lime Klin	Add	Capacitor	5.1 MVAR c	34		8/12/2009	APS	2001			5/9/2005
1781	b0050.3	10/1/2003	5/23/2003	Chamber's	Add	Capacitor	2.1 MVAR cap at No. 5		2.1	4/26/2010	APS	2001			5/9/2005
1782	b0051	10/1/2003	8/26/2003	Aqueduct	Add	Capacitor	10.2 MVAR	34		8/11/2009	APS	2001			5/9/2005
1783	b0052.2	6/1/2004	9/16/2004	Boonsboro	Add	Capacitor	5.1 MVAR c	34		8/11/2009	APS	2001			5/9/2005
1784	b0052.3	6/1/2004	10/27/2004	Mt. Airy	Add	Capacitor	second 10.	34		8/11/2009	APS	2001			5/9/2005
1785	b0052.4	6/1/2004	11/1/2004	Antietam	Increase	Capacitor	8.2 MVAr c	34		8/11/2009	APS	2001			5/9/2005
1786	b0059	1/1/2003	1/1/2003	Roxboroug	Add	Breaker	#215	69		8/11/2009	PECO	2002			5/9/2005
1787	b0076	5/31/2004	5/19/2004	Werner	Add	Transformer		230/115		8/28/2009	JCPL	2003			5/9/2005
1788	b0080	6/1/2004	4/16/2004	Dresden "I	Upgrade	Relay		345/138		8/14/2009	ComEd	2003		ComEd	5/9/2005
1789	b0086	6/30/2004	6/30/2004	Cedar	Addition	Capacitor				8/11/2009	AEC	2004			5/9/2005
1790	b0087	6/30/2004	6/29/2004	Motts Farn	Addition	Capacitor				8/11/2009	AEC	2004			5/9/2005
1791	b0088	6/30/2004	4/21/2004	Landis - Mi	Upgrade	Transmission Line		138		8/28/2009	AEC	2004			5/9/2005
1792	b0089	6/30/2004	6/30/2004	Motts Farn	Reconfigur	Load				8/11/2009	AEC	2004			5/9/2005
1793	b0109	9/1/2004	3/31/2005	Wylie Ridg	Install	SPS				11/19/2009	APS			Operationa	5/9/2005
1794															
1795	Source														
1796	PJM ISO website														
1797	http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx/														

	A	P	Q	R	S	T	U	V	W	X	Y
3	Upgrade ID	Latest TEAC Date	Status	State	Region	County	Percent Co	Cost Estim	Project ID	In Schedul	Source
1775	b0023		IS	NJ	PJM MA	Atlantic	100	13.9	b0023	#N/A	Pre-2006
1776	b0026		IS	PA	PJM MA	York	100	0.8	b0026	#N/A	Pre-2006
1777	b0027		IS	PA	PJM MA		100	1	b0027	#N/A	Pre-2006
1778	b0049		IS	WV	PJM WEST	Tucker	100	0.4	b0049	#N/A	Pre-2006
1779	b0050.1		IS	PA	PJM WEST	Franklin	100	0.05	b0050	#N/A	Pre-2006
1780	b0050.2		IS	PA	PJM WEST	Frederick	100	0.05	b0050	#N/A	Pre-2006
1781	b0050.3		IS	PA	PJM WEST	Franklin	100	0.05	b0050	#N/A	Pre-2006
1782	b0051		IS	MD	PJM WEST	Howard	100	0.15	b0051	#N/A	Pre-2006
1783	b0052.2		IS	MD	PJM WEST	Washingto	100	0.34	b0052	#N/A	Pre-2006
1784	b0052.3		IS	MD	PJM WEST	Frederick	100	0.34	b0052	#N/A	Pre-2006
1785	b0052.4		IS	MD	PJM WEST	Washingto	100	0.34	b0052	#N/A	Pre-2006
1786	b0059		IS	PA	PJM MA		100	0.25	b0059	#N/A	Pre-2006
1787	b0076		IS	NJ	PJM MA		100	0	b0076	#N/A	Pre-2006
1788	b0080		IS	IL	PJM WEST		100	0.1	b0080	#N/A	Pre-2006
1789	b0086		IS	NJ	PJM MA		100	0.07	b0086	#N/A	Pre-2006
1790	b0087		IS	NJ	PJM MA		100	0.76	b0087	#N/A	Pre-2006
1791	b0088		IS	NJ	PJM MA		100	0.08	b0088	#N/A	Pre-2006
1792	b0089		IS	NJ	PJM MA		100	0	b0089	#N/A	Pre-2006
1793	b0109		IS	WV	PJM WEST		100	0	b0109	#N/A	Pre-2006
1794											
1795	Source										
1796	PJM ISO webs										
1797	http://www.p										

Exhibit DUK-203

Appendix A-1: Preliminary MTEP11 Appendix A Baseline Reliability and Generation Interconnection Project Cost Allocations by Pricing Zones Subject to Approval for Appendix A

Values shown below are subject to change depending on actual project costs [1]

Project ID	Project Type	Region	ISD	Zone	Total Shared Cost2	AMIL	AMMO	ATC	BREC	CWLD	CWLP	DEM
2306	BRP	Central	6/1/2016	AMMO	30,751,000	1,051,903	26,723,064	454,291	63,516	12,115	13,507	453,570
				Central Total	30,751,000	1,051,903	26,723,064	454,291	63,516	12,115	13,507	453,570
1809	BRP	East	12/31/2013	METC	32,600,000							
2812	BRP	East	5/31/2012	METC	43,300,000							
3303	BRP	East	6/1/2015	METC	11,400,000							
3304	BRP	East	12/31/2013	METC	26,600,000							
3516	GIP	East	9/1/2011	ITC	242,500							
3517	GIP	East	12/31/2012	METC	5,829,500							
3518	GIP	East	6/1/2012	METC	32,000							
				East Total	120,004,000	-	-	-	-	-	-	-
1950	BRP	West	6/1/2011	ATC	17,697,000			17,697,000				
2634	BRP	West	12/1/2014	GRE/MP	25,233,333							
3191	GIP	West	2/28/2011	ITCM	4,074,000	74,771	73,159	101,798	14,233	2,715	3,027	101,636
3192	GIP	West	12/31/2011	ITCM	29,400							
3193	GIP	West	12/31/2011	ITCM	111,942							
3194	GIP	West	7/31/2010	ITCM	211,332							
3195	GIP	West	10/1/2010	ITCM	1,758,082							
3196	GIP	West	7/1/2011	ITCM	831,141							
3206	GIP	West	6/1/2018	ATC	86,539,748	$ 1,277,327	$ 1,249,795	$ 71,415,397	$ 243,141	$ 46,375	$ 51,705	$ 1,736,269
3312	BRP	West	6/1/2014	NSP	13,660,000							
3317	BRP	West	6/1/2014	NSP	6,000,000							
3373	BRP	West	12/30/2012	MP	8,000,000			653,494				
3397	BRP	West	6/1/2014	DPC	18,000,000			885,926				
3481	BRP	West	12/31/2014	OTP	14,000,000							
				West Total	196,145,978	1,352,097	1,322,955	90,753,615	257,374	49,089	54,732	1,837,905
				MISO Total	346,900,978	2,404,000	28,046,018	91,207,905	320,890	61,204	68,239	2,291,475
												1.47%
												2.49%
												2.01%
												42.12%
												0.62%
												1.05%
												0.85%

Notes:

(1) The allocations shown above are estimates which are based on current estimates of project costs and projected in-service dates.The actual allocation amounts will vary depending on the actual project costs and actual in-service dates.

(2) Total Shared Cost reflects the Project cost subject to sharing and allocated to pricing zones in MISO. This does not include 50% or 90% of the Network Upgrade cost of the Generator Interconnection Projects (GIP) assgined to the Generators .

(3) Total Project Cost with 100% GIP includes the total network upgrade costs for GIPs including the 50% or 90% assigned to the generators. This does not take into account those GIPs with agreements for Transmission Owners to reimburse the generators for 100% of their Network Upgrade costs.

Source: MTEP11 Appendices A1 A2 A3
As posted 9/23/11

: DUK-203

dix A-1: Pr

Values sho

	Pricing Zone													
Project ID	**DPC**	**GRE**	**HE**	**IPL**	**ITC**	**ITCM**	**MDU**	**MEC**	**METC**	**MICH13A**	**MP**	**MPW**	**NIPS**	**NSP**
2306	44,337	43,626	26,053	114,164	378,475	132,889	28,721	174,720	299,986	28,278	75,274	5,671	130,011	368,724
	44,337	43,626	26,053	114,164	378,475	132,889	28,721	174,720	299,986	28,278	75,274	5,671	130,011	368,724
1809									32,600,000					
2812									43,300,000					
3303					42,530				11,357,470					
3304									26,600,000					
3516					242,500									
3517									5,829,500					
3518									32,000					
	-	-	-	-	285,030	-	-	-	119,718,970	-	-	-	-	-
1950														
2634		220,023									22,746,133			2,085,492
3191	9,935	9,776	5,838	25,582	84,809	3,288,978	6,436	39,151	67,221	6,336	16,867	1,271	29,133	82,624
3192						29,400								
3193						111,942								
3194						211,332								
3195						1,758,082								
3196						831,141								
3206	$ 209,442	$ 167,001	$ 99,731	$ 437,020	$ 1,448,806	$ 1,449,164	$ 109,944	$ 1,007,504	$ 1,148,348	$ 108,247	$ 391,837	$ 21,707	$ 497,683	$ 2,932,912
3312		1,545,669												9,026,660
3317														6,000,000
3373	85,801	91,225									6,276,961			843,029
3397	8,491,279	87,065				2,150,057								6,385,673
3481		101,251					8,455				134,575			252,515
	8,796,457	2,222,010	105,568	462,601	1,533,614	9,830,095	124,835	1,046,656	1,215,569	114,584	29,566,373	22,978	526,816	27,608,905
	8,840,794	2,265,636	131,621	576,765	2,197,119	9,962,983	153,556	1,221,376	121,234,525	142,861	29,641,647	28,649	656,827	27,977,629

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Average In-service Date for projects with DUK Share:

8/31/2017

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Percent of DUK zone charged to DEOK on 12CP basis

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Source: MT
As posted 9.

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Project ID	OTP	SIPC	SMMPA	VECT	Total	Total Project Cost with 100% GIP3
2306	54,212	17,913	11,144	44,838	30,751,000	30,751,000
	54,212	17,913	11,144	44,838	30,751,000	30,751,000
1809					32,600,000	32,600,000
2812					43,300,000	43,300,000
3303					11,400,000	11,400,000
3304					26,600,000	26,600,000
3516					242,500	485,000
3517					5,829,500	11,659,000
3518					32,000	64,000
	-	-	-	-	120,004,000	126,108,000
1950					17,697,000	17,697,000
2634	181,686				25,233,333	25,233,333
3191	12,148	4,014	2,497	10,047	4,074,000	8,148,000
3192					29,400	58,800
3193					111,942	223,884
3194					211,332	422,664
3195					1,758,082	3,516,163
3196					831,141	1,662,281
3206	$ 207,525	$ 68,570	$ 42,661	$ 171,639	86,539,748	173,079,497
3312	3,087,671				13,660,000	13,660,000
3317					6,000,000	6,000,000
3373	49,489				8,000,000	8,000,000
3397					18,000,000	18,000,000
3481	13,503,204				14,000,000	14,000,000
	17,041,723	72,584	45,158	181,686	196,145,978	289,701,622
	17,095,935	90,496	56,303	226,524	346,900,978	446,560,622

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Source: MT
As posted 9.

Exhibit DUK-203

Appendix A-2.1. *Indicative* Schedule 26 Annual Charges by MISO Pricing Zone for new MTEP 11 Approved Baseline Reliability Projects and Generation Interconnection Projects

Values shown below (in 2011$) are subject to change depending on actual project costs including Construction Work in Progress, actual In-service Dates, and actual Annual Charge Rates for Transmission Owners

	Year									
Pricing Zone	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
AMIL	18,468	18,173	28,123	48,320	99,253	333,744	381,871	431,193	424,328	417,462
AMMO	18,070	17,781	27,517	47,278	97,114	4,810,148	4,788,672	4,768,367	4,693,085	4,617,802
ATC	3,306,603	3,402,261	3,920,281	5,146,542	7,954,466	10,841,665	13,648,377	16,521,956	16,254,068	15,986,180
BREC	3,515	3,459	5,353	9,198	18,893	39,672	49,198	58,951	58,009	57,067
CWLD	671	660	1,021	1,754	3,603	7,567	9,384	11,244	11,064	10,884
CWLP	748	736	1,138	1,956	4,018	8,436	10,462	12,536	12,336	12,136
DPC	2,454	21,872	23,214	1,324,018	1,318,159	1,320,037	1,314,060	1,308,279	1,293,285	1,278,291
DUK	25,104	24,702	38,228	65,681	134,915	283,297	351,320	420,969	414,242	407,515
GRE	2,415	23,064	24,047	379,268	379,861	388,066	388,543	389,175	382,462	375,748
HE	1,442	1,419	2,196	3,773	7,749	16,272	20,180	24,180	23,794	23,407
IPL	6,319	6,218	9,622	16,532	33,958	71,306	88,427	105,958	104,265	102,572
ITC	88,192	86,745	96,919	118,714	187,077	309,608	365,084	421,917	415,019	408,122
ITCM	1,531,233	1,506,629	1,493,650	1,820,903	1,850,895	1,904,076	1,933,713	1,964,708	1,931,955	1,899,203
MDU	1,590	1,564	2,421	6,040	10,396	19,764	24,043	28,425	27,971	27,517
MEC	9,670	9,516	17,442	33,451	73,703	144,445	184,231	224,960	221,371	217,782
METC	16,603	13,544,878	29,645,680	29,224,907	31,957,180	31,570,383	31,130,437	30,691,567	30,202,183	29,712,799
MICH13A	1,565	1,540	2,383	4,095	8,411	17,662	21,903	26,245	25,826	25,406
MP	4,166	1,427,585	1,408,769	6,581,382	6,495,360	6,422,472	6,336,249	6,250,392	6,147,299	6,044,206
MPW	314	309	478	821	1,687	3,542	4,392	5,263	5,179	5,095
NIPS	7,196	7,081	10,958	18,827	38,672	81,204	100,702	120,666	118,738	116,810
NSP	20,408	211,263	231,522	4,377,802	4,429,811	4,546,162	4,597,187	4,650,958	4,575,714	4,500,470
OTP	3,000	14,176	15,620	3,597,185	3,550,890	3,514,054	3,467,613	3,421,367	3,365,992	3,310,618
SIPC	991	976	1,510	2,594	5,328	11,188	13,875	16,625	16,360	16,094
SMMPA	617	607	939	1,614	3,315	6,961	8,632	10,343	10,178	10,013
VECT	2,482	2,442	3,779	6,493	13,337	28,005	34,730	41,615	40,950	40,285
MISO Total	$ 5,073,835	$ 20,335,655	$ 37,012,811	$ 52,839,146	$ 58,678,049	$ 66,699,735	$ 69,273,285	$ 71,927,862	$ 70,775,673	$ 69,623,483

Notes:

1) Indicative Schedule 26 annual charges not intended to be used for rate making purposes.

2) The indicative annual charges shown only reflect new MTEP 11 projects and would be additive to the indicative annual Schedule 26 charges shown in the posted spreadsheet at the following link on the MISO website under the MTEP Status Report and Cost Allocation section:
https://www.misoenergy.org/PLANNING/TRANSMISSIONEXPANSIONPLANNING/Pages/TransmissionExpansionPlanning.aspx

3) Annual Revenue Requirement calculated using an estimated Annual Charge Rate for each constructing Transmission Owner based on the methodology described in Attachment GG. Annual Charge Rate estimated using Transmission Owner's Attachment O data as of January 2011 and assumes 40-year straight-line depreciation.

4) For approved projects with recovery for Construction Work in Progress, charges are phased-in based on an assumed schedule. For example a project with an in-service date five-years out, CWIP charges are phased in as follows: 1 Year from In-Service Date (ISD) = 75% of estimated project cost; 2 Years from ISD = 45%; 3 Years from ISD = 20%; 4 Years from ISD = 7.5%.

5) For approved projects without approval for Construction Work in Progress recovery, charges start based on the estimated in-service date and whether the constructing Transmission Owner uses forward-looking or historic recovery mechanisms. For example, if a project is expected to go in-service in June 2012 and the constructing Transmission Owner uses forward-looking then the charges are assumed to start in 2012, and if the Transmision Owner uses historic the charges for this project would start in 2013.

Source: MTEP11 Appendices A1 A2 A3
As posted 9/23/11

Exhibit DUK-203

Appendix A-2.2. *Indicative* MTEP 06 through MTEP 11 Cost Allocation Summary for Baseline Reliability, Generation Interconnection, and Market Effficiency Projects

Pricing Zone	Total Cost Shared Approved Transmision Investment	Costs allocated for projects located outside Pricing Zone	Costs for projects located in the Pricing Zone	Total Project Cost Allocated to Pricing Zone
[1]	[2]	[3]	[4]	[5] = [3] + [4]
AMIL	$150,901,748	32,189,497	124,225,956	$156,415,453
AMMO	$74,232,100	25,534,161	68,799,775	$94,333,936
ATC	$684,196,645	71,197,425	550,149,646	$621,347,071
BREC	$0	320,890	-	$320,890
CWLD	$0	813,458	-	$813,458
CWLP	$0	1,398,167	-	$1,398,167
DPC	$18,000,000	607,901	8,491,279	$9,099,180
DUK	$42,719,762	78,533,640	39,799,859	$118,333,499
GRE	$179,205,420	27,691,765	9,322,330	$37,014,094
HE	$0	10,432,502	-	$10,432,502
IPL	$15,400,000	13,749,996	3,875,701	$17,625,697
ITC	$85,332,101	33,318,503	78,567,534	$111,886,037
ITCM	$82,691,614	64,011,172	74,649,280	$138,660,452
MDU	$11,000,000	8,619,445	10,756,475	$19,375,921
MEC	$0	1,431,658	-	$1,431,658
METC	$379,483,053	69,949,782	367,324,160	$437,273,943
MICH13A	$0	5,184,234	-	$5,184,234
MP	$161,718,208	83,050,043	59,029,213	$142,079,256
MPW	$0	29,202	-	$29,202
NIPS	$20,645,686	14,495,479	19,319,177	$33,814,656
NSP	$604,210,564	242,668,673	327,149,322	$569,817,995
OTP	$182,095,007	114,131,638	52,849,946	$166,981,584
SIPC	$0	1,453,606	-	$1,453,606
SMMPA	$0	20,987,479	-	$20,987,479
VECT	$114,757,364	4,864,381	50,434,703	$55,299,084
MISO Total	$2,806,589,271	$926,664,697	$1,844,744,355	$2,771,409,052

Note: The difference in the MISO Total of columns 2 and 5 represents the portion of project cost allocated to First Energy who is no longer part of the MISO footprint.

Source: MTEP11 Appendices A1 A2 A3
As posted 9/23/11

Attachment E

Attachment A to the
Consolidated Transmission Owners Agreement
Signature Pages

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Duke Energy Kentucky, Inc.

By: ______________________________

Name: Julia S. Janson

Title: President

Date: September 27, 2011

IN WITNESS WHEREOF, the Parties and PJM have caused this Agreement to be executed by their duly authorized representatives.

Duke Energy Ohio, Inc. f/k/a The Cincinnati Gas & Electric Company

By: Julia S. Janson

Name: Julia S. Janson

Title: President

Date: September 27, 2011