OCA Cross Exh 1

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A-2017-2640195

February 28, 2014

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

Re: PJM Interconnection, L.L.C., Docket No. ER14-____-000

Dear Secretary Bose:

Pursuant to section 205 of the Federal Power Act,[1] and Part 35 of the regulations of the Federal Energy Regulatory Commission ("Commission"),[2] PJM Interconnection, L.L.C. submits revisions to its economic planning process as set forth in section 1.5.7 of Schedule 6 of the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Schedule 6"). PJM proposes to: (i) revise how the market efficiency benefits are calculated for Regional Facilities, Necessary Lower Voltage and Lower Voltage Facilities; (ii) include generation with an executed Facility Study Agreement ("FSA") in its assumptions; (iii) modify the definition of Production Cost to appropriately account for resources from neighboring RTOs which can be dispatched and are active in PJM's market efficiency models ("dispatchable resources"). These changes appropriately recognize both the present use and broader regional benefits across the PJM region, as well as identifying market efficiency needs due to local congestion. In addition, these changes will ensure that PJM's market efficiency planning standards are better aligned

[1] 16 U.S.C. § 824d.

[2] 18 C.F.R. Part 35 (2013).

with the Commission-accepted cost allocation for PJM market efficiency projects.[3] The remaining changes are enhancements to PJM's analysis to ensure consideration of certain key data inputs relevant to analyzing market efficiency needs in a more robust scenario-based market efficiency planning process. PJM requests an effective date of April 30, 2014 for these revisions, which is 61 days after the date of this filing. This proposal received overwhelming endorsement in PJM's stakeholder process.

## I. Background

On September 8, 2006, PJM filed a proposed modification to its Regional Transmission Expansion Planning Protocol to replace its existing economic planning protocol with a market efficiency process based upon evaluating the economic benefits of accelerating or modifying planned reliability-based transmission upgrades or of constructing new economic-based transmission enhancements or expansions focused on relieving congestion.[4] The Commission modified PJM's initial proposal to base the evaluation on several metrics and directed PJM to file a formulaic approach for selection of economic projects.[5]

On October 9, 2007, to comply with the Commission's directives, PJM submitted a formulaic approach similar to the model adopted by the Midwest Independent Transmission System Operator, Inc. ("MISO") that proposed to use a Benefit/Cost Ratio. The benefit component consists of the sum of two metrics: (i) the Energy Market Benefit and (ii) the

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[3] *PJM Interconnection, L.L.C., et al.*, 142 FERC ¶ 61,214 at 1 (March 22, 2013) (conditionally accepting PJM Transmission Owner's Compliance Filing effective February 1, 2013, subject to further compliance, which was filed by the PJM Transmission Owners on July 22, 2013.) ("March 22 Order"). *See*, PJM Transmission Owners Filing, *Duquesne Light Co., et al.*, Docket No. ER13-90-000 (July 22, 2013).

[4] PJM Initial Filing, *PJM Interconnection, L.L.C.*, Docket No. ER06-1474-000 (Sept. 8, 2006).

[5] *PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,265 at P 31 (2007).

Reliability Pricing Model Benefit.[6] The Energy Market Benefit includes: (i) the change in production cost, weighted at 70 percent, and (ii) the change in net load payments, weighted at 30 percent.[7] The Reliability Pricing Model Benefit includes: (i) the change in capacity costs, weighted at 70 percent, and (ii) the change in net capacity payments, weighted at 30 percent.[8] To be included, a project's benefit/cost ratio had to meet a threshold of at least 1.25 to one. Following a third compliance filing, the Commission accepted PJM's economic transmission planning process.[9] To date, the PJM Board has approved two Lower Voltage Facility market efficiency projects.[10]

On October 11, 2012, the PJM Transmission Owners, acting through the PJM Consolidated Transmission Owners Agreement ("CTOA"),[11] proposed revisions to Schedule 12 of the PJM Open Access Transmission Tariff ("PJM Tariff"), relating to the allocation of costs of transmission system expansions and enhancements approved by PJM in its development of its regional transmission expansion plan ("RTEP").[12] The cost allocation proposed in the

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[6] PJM Compliance Filing, *PJM Interconnection, L.L.C.*, Docket No. ER06-1474-000 (Oct. 9, 2007) ("October 9 Compliance Filing").

[7] *See* PJM's Second Compliance Filing, *PJM Interconnection, L.L.C.*, Docket No. ER06-1474-004 at 4, 7 and 8 (Oct. 9, 2007). The formulaic approach was further amended by way of compliance. *See* PJM's Third Compliance Filing, *PJM Interconnection, L.L.C.*, Docket No. ER06-1474-006 (Jun. 16, 2008).

[8] The reduction in production costs is a standard measure of the economic benefits of an expansion or enhancement. The change in production costs measures the economic benefit of the project to the PJM market, while the load payments measure the extent to which the project will reduce prices to load. Together the evaluation of production cost benefits and direct benefits to load customers were intended as a reasonable formulaic approach to the analysis of the overall benefits of an economic-based enhancement or expansion. *See* October 9 Compliance Filing at 7 and 8.

[9] *PJM Interconnection, L.L.C.*, 126 FERC ¶ 61,152 (Feb. 20, 2009).

[10] Baseline Upgrades: (i) b1153 approved in February 2010; and (ii) b2452, 2452.1 and 2452.3 approved in February 2014.

[11] *PJM Interconnection, L.L.C.*, Consolidated Transmission Owners Agreement, Rate Schedule F.E.R.C. No. 42 (Jun. 19, 2008).

[12] PJM Transmission Owners Filing, *Public Service Electric and Gas Company, et al.*, Docket No. ER13-90-000 (Oct. 11, 2012) ("Transmission Owners' October 11 Filing").

Transmission Owners' October 11 Filing, and accepted by the Commission subject to compliance,[13] was filed as a compromise among the PJM Transmission Owners, as just and reasonable, and not unduly discriminatory or preferential and was intended to satisfy the regional cost allocation principles in Order No. 1000.[14]

The proposed cost allocation distinguished between Regional Facilities, Necessary Lower Voltage Facilities and Lower Voltage Facilities. In the Transmission Owners' October 11 Filing, however, the PJM Transmission Owners proposed to replace the existing postage-stamp rate[15] with use a "hybrid approach" to allocate the cost of Regional Facilities[16] and Necessary Lower Voltage Facilities.[17] Under the hybrid approach, one-half of each project's cost is allocated on a postage-stamp basis. The other half of the cost of Regional Facilities and Necessary Lower Voltage Facilities are allocated to specifically identified beneficiaries of each project. The Transmission Owners' October 11 Filing proposed different methodologies to identify specific beneficiaries of reliability projects and economic projects.

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[13] *PJM Interconnection, L.L.C., et al.*, 142 FERC ¶ 61,214 (Mar. 22, 2013) ("Order on Compliance Filings"); *PJM Interconnection, L.L.C., et al.*, 142 FERC ¶ 61,074 (Jan. 31, 2013) ("Order Conditionally Accepting and Suspending Cost Allocation Filing").

[14] *Transmission Planning and Cost Allocation by Transmission Owners and Operating Public Utilities*, Order No. 1000, III FERC Stats. & Regs., Regs. Preambles ¶ 31,323 (2011), *order on reh'g and clarification*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012) (collectively referred to as "Order No. 1000").

[15] Allocation on a postage-stamp basis means each project is allocated to zones on a load ratio share basis and to merchant transmission facilities in proportion to awarded Firm Transmission Withdrawal Rights. *See Proposed* Schedule 12 § (b)(i)(A)(1).

[16] In the October 11 Filing, the PJM Transmission Owners proposed to revise the definition of Regional Facilities to add double-circuit facilities planned to operate voltages of at least 345 kV but less than 500 kV to the current Commission-approved definition that included all facilities planned to operate at or above 500 kV. *See* October 11Filing at 8.

[17] Necessary Lower Voltage Facilities were defined in the same manner as the current Tariff, *i.e.*, "new facilities or expansions or enhancements to existing Transmission Facilities that are below the applicable voltage limit for a Regional Facility, but that must be constructed or strengthened to support new Regional Facilities. See *Proposed* Schedule 12, § (b)(i)(C).

For new Regional and Necessary Lower Voltage Facilities included in the RTEP as an economic project, the Transmission Owners' October 11 Filing proposed to allocate one-half of each project's costs based on each Zone's load ratio share and one-half of each project's costs to zones with decreases in net load energy payments that result from the new facility. For new Lower Voltage Facilities, the October 11 Filing proposed to allocate the full project costs to zones with decreases in net load energy payments recognizing the more localized benefits such projects provide.[18] Relevant to this filing, the proposed changes to section 1.5.7 of Schedule 6 will more closely align the market efficiency benefit determination with the cost allocation as proposed in the Transmission Owners' October 11 Filing and conditionally accepted by the Commission.[19]

To develop the proposed amendments to section 1.5.7 of Schedule 6, PJM and its stakeholders engaged in an extensive stakeholder process through the Regional Planning Process Task Force ("RPPTF"). PJM and the stakeholders considered various options at four RPPTF meetings and developed a proposal that the majority of the stakeholders could support. The proposed revisions were presented to and endorsed by acclamation by the Markets and Reliability Committee[20] and the Members Committee[21].

## II. Descriptions of Proposed Revisions to Schedule 6

As discussed above, PJM proposes to: (i) revise the proportional measurement used to determine the market efficiency benefits for Regional Facilities and Necessary Lower Voltage

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[18] *See* October 11 Filing at 11.

[19] *See supra* at n. 3.

[20] The proposed changes were endorsed by acclamation: (i) market efficiency - benefit determination with one objection and one abstention; (ii) market efficiency – generation expansion with no objections and two abstentions; and (iii) market efficiency - Cost Production definition with no objections and two abstentions.

[21] The proposed changes were endorsed by acclamation with no objections and no abstention.

Facilities; (ii) revise the benefit metric used for Lower Voltage Facilities; (iii) apply a change in net load payments for Regional Facilities from all zones to zones that benefit, *i.e.*, zones with a decrease in net load payments only; (iv) include generation with an executed Facility Study Agreement, in addition to existing generation and generator units with an interconnection service agreement, to assumptions included in the model to meet future reserve requirements; and (v) modify the definition of Production Cost to better account for dispatchable resources from neighboring RTOs active in our market efficiency models.

### *A. Market Efficiency Benefit Determination*

#### *(1) Change in Benefit Metric Formula for Regional and Necessary Lower Voltage Facilities*

PJM proposes to modify the current weighting for Regional Facilities and Necessary Lower Voltage Facilities between (i) the change in production cost and change in net load payment (for Energy Benefit) and (ii) change in capacity costs and change in net capacity payments (for Capacity Benefit) from the current 70/30 percent split to a 50/50 percent split.[22]

The 70/30 percent weighting was proposed originally by PJM as consistent with the MISO approach approved by the Commission as reasonable.[23] It also seemed to align better with the existing allocation methodology used for Regional and Necessary Lower Voltage Facilities which allocated 100 percent of the costs to zones on a load ratio share. Following the Transmission Owners' October 11 Filing, which proposed to use a hybrid approach to allocate one-half of each project's cost on a postage-stamp basis and the other half to specifically identified beneficiaries for both reliability and economic projects, PJM and its stakeholders re-evaluated the proportional measurement used to determine the market efficiency benefits for

[22] *See* Schedule 6, section 1.5.7(d) *proposed*.

[23] *See Midwest Independent System Operator, Inc.*, 118 FERC ¶ 61,209 at P 131 (2007) ("MISO Order").

Regional Facilities and Necessary Lower Voltage Facilities. After considering numerous proportional variations, the stakeholders agreed the change in the benefit determination for market efficiency projects to a 50/50 split between production cost benefits and direct benefits to load customers better equalizes consideration of market efficiency needs due to overall system conditions and direct impact on load customers.[24] Additionally, such changes should more closely align identification of economic projects with the newly proposed "hybrid approach" cost allocation methodology for Regional and Necessary Lower Voltage Projects.[25]

The table below used in the stakeholder process illustrates the alignment between the existing cost allocation and proposed Market Efficiency formula.

| | Existing Cost Allocation: Market Efficiency Projects. | Proposed Benefit Determination |
|---|---|---|
| Regional Projects | 50% Load Ratio Share and 50% to zones with decreased net load payments | Total Benefit= Energy + Capacity Benefit |
| | | Energy Benefit: 50% change in production costs + 50% change in net load payments (only zones with decrease in net load payments) |
| | | Capacity Benefit: 50% change in capacity costs + 50% change in net capacity payments (only zones with decrease in net capacity payments) |
| Lower Voltage Projects | 100% to zones with decreased net load payments | Total Benefit= Energy + Capacity Benefit |
| | | Energy Benefit: 100% change in net load payments (only zones with decrease in net load payments) |
| | | Capacity Benefit: 100% change in net capacity payments (only zones with decrease in net capacity payments) |

[24] As acknowledged by the PJM Transmission Owners in their October 11 Filing, in western PJM relatively low-voltage transmission facilities serve as the backbone of the transmission network, *e.g.*, mainly 345 kV transmission facilities are preferred. Whereas, in eastern PJM 500 kV and even higher-voltage transmission facilities are preferred.

[25] The "hybrid approach" for Regional and Necessary Lower Voltage Facilities allocates 50 percent of the costs on a postage stamp basis and the other 50 percent using a DFAX methodology. *See* March 22 Order at PP 412 - 426.

### *(2) Change in the Market Efficiency Benefit Calculation for Regional and Necessary Lower Voltage Facilities*

Under the existing market efficiency benefit calculation for Regional and Necessary Lower Voltage Facilities, PJM factored in customers from *all* zones (*i.e.*, customers with projected increases in net load payments and customers with decreases in net load payment). Net load payments are calculated by measuring the gross load payments reduced by the financial transmission credits for each zone. Net capacity payments are calculated by measuring the gross capacity payments reduced by the capacity credits for each zone. Only the customers with projected reductions in payments are deemed to benefit from the new transmission facility. Under the current market efficiency benefit calculation, PJM has not identified one market efficiency project for Regional Facilities.

In this filing, PJM proposes to modify application of the market efficiency benefit calculation from all zones to: (i) only zones with a decrease in net load payments (for Energy Benefit) and (ii) only zones with a decrease in net capacity payments (for Capacity Benefit). It will not apply the market efficiency benefit calculation to zones that would receive an increase in net load payment or net capacity payment. This revision to Regional and Necessary Lower Voltage Facilities conforms to how Lower Voltage Facilities are currently selected, *i.e.*, the cost/benefit analysis applies only to zones with a decrease in net load or net capacity payments. PJM believes this modification to the market efficiency benefit calculation will more appropriately align the benefits with the costs of the facilities by placing the cost of such upgrades on the zones where costs are being reduced. Eliminating from the calculation consideration of zones with an increase in net load or capacity payments should increases the number of projects that could qualify as a market efficiency project.

### *(3) Change in Formula for Lower Voltage Facilities*

PJM proposes to modify the current benefit metric calculation for Lower Voltage Facilities between the change in production cost and change in net load payment (for Energy Benefit) and change in capacity costs and change in net capacity payments (for Capacity Benefit) from the current 70/30 percent split to 100 percent change in net load payments (for Energy Benefit) and 100 percent change in net capacity payments (for Capacity Benefit). PJM and its stakeholders agreed this modification was appropriate as it better addresses the local benefits attributable to Lower Voltage Facilities. PJM proposes these changes are just and reasonable and satisfy the Commission's Order No. 1000 cost allocation principles because they better align the who benefits from the local nature of Lower Voltage Facilities with the cost allocations in a manner that is at least roughly commensurate with the estimated benefits and does not allocate costs to entities with little or no benefit.[26]

### *B. Expansion of Generation Added to the Models to Meet Reserve Requirement*

Section 1.5.7(i)(iv) of Schedule 6 currently identifies the assumptions used in the market efficiency analysis, which includes, among other things, all existing in-service generation and generation with an executed Interconnection Service Agreement ("ISA"), or Interim Interconnection Service Agreement expected to an execute an ISA, less planned generator deactivations.[27] PJM proposes to add generation facilities with a Facility Study Agreement ("FSA").[28]

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[26] Order No. 1000 at PP 559 and 622.

[27] Schedule 6 at section 1.5.7(k)(viii).

[28] Schedule 6 at section 1.5.7(i)(iv) and (vii) *proposed*.

Generally, generation is added to models when existing in-service generation and generation with an ISA does not provide enough generation to meet reserve requirements throughout the 15-year planning horizon. Under the current method this additional generation is added by scaling existing generation units, consistent with the makeup of the resources in the interconnection queue, until the reserve requirement is met.[29] In this filing, PJM proposes to include generation with an executed FSA (along with any identified network upgrades that were identified to reliably interconnection the unit with the system) in its assumptions.[30] Including generation with an FSA, as well as any identified network upgrade, will reduce the likelihood of creating congestion due to generation scaling. In addition, this method will allow PJM to consider significantly more generation active in the PJM interconnection queue and should result in minimal or no additional scaling to meet the reserve requirement. However, before including or exempting generation with an executed FSA in its assumptions, PJM will review the list of FSA units with its stakeholders in the Transmission Expansion Advisory Committee when developing assumptions to be included in the analysis. For generation that may significantly impact the results, PJM will determine which FSA units to exclude after reviewing the following factors with its stakeholders: (i) the likelihood of the generation unit coming into service; (ii) the projected in-service date – generation units, such as a large nuclear plant, with an in service date farther out in the planning horizon, the more uncertainty associated with the results; and (ii) the generation unit's potential to influence the results depending on the size of the generation unit

[29] Generation scaling generally means adding additional megawatts to existing generation in the model.

[30] During final stakeholder review of the redline changes to section 1.5.7(i)(iv), PJM inadvertently deleted reference to "executed Interconnection Service Agreement ("ISA")" and "Interim Interconnection Service Agreement ("Interim ISA") for which an ISA is expected to be executed." Those terms are not deleted in these proposed changes as the stakeholders intended to *add* an executed FSA to the assumptions already permitted under this subsection.

and its location.[31] Depending on whether PJM with its stakeholders determine that a generation unit with an FSA may skew the results, PJM may exclude such generation unit from its assumptions.

### *C. Modification of the Definition of Production Costs*

As part of a cleanup initiative, PJM also proposes to revise the definition of Production Costs to allow PJM to account for transactions between neighboring RTOs. Currently, the section 1.5.7 of Schedule 6 limits consideration of the components that make up production costs to consideration of resources within the PJM region and, therefore, does not account for transactions between neighboring RTOs. PJM proposes to amend section 1.5.7(d) to explicitly provide for consideration of dispatchable resources from neighboring RTOs active in our market efficiency models. For example, as part of PJM's existing process, PJM models flow from external regions. This revision will allow PJM to optimize those models by accounting for dispatchable resources from neighboring regions where a neighboring region's dispatchable resources show up in PJM's market efficiency models

## III. Effective Date

PJM requests an effective date of April 30, 2014, which is 61 days after the date of this filing for the proposed modifications to section 1.5.7 to enable PJM to commence its 2-year economic planning cycle under these revised provisions.

## IV. Documents Enclosed

This filing consists of the following documents:

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[31] For example, there are instances where a generation owner may have submitted multiple interconnection requests for the same project and have more than one FSA. PJM would factor in only one of the FSAs for that project. Another example could be that a project is delayed but the date in the FSA was not changed. Also, PJM may have information that a project is not going to move forward but the generation owner has not removed it from the queue hoping that circumstances will change to improve the project's economics.

a. This Transmittal Letter;

b. Attachment A: Proposed revisions to Section 1.5.7 of Schedule 6 of the Amended and Restated Operating Agreement (in redlined format); and

c. Attachment B: Proposed revisions to Section 1.5.7 of Schedule 6 of the Amended and Restated Operating Agreement (in clean format).

## V. Correspondence

Correspondence and communications regarding this filing should be sent to the following persons:

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## VI. Service

PJM has served a copy of this filing on all PJM Members and on the affected state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,[32] PJM will post a copy of this filing to the FERC filings section of its internet site, 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 stat utility regulatory commission in the PJM Region[33] alerting them this filing has been made by PJM and is available by following such link. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within twenty-four hours of the filing.

[32] *See* 18 C.F.R. §§ 35.2(e) and 385.201(f)(3).

[33] PJM already maintains, updates, and regularly uses e-mail lists for all PJM Members and affected state commissions.

Also, a copy of this filing will be available on the Commission's eLibrary website at the following link: http:/www.ferc.gov/docs-filing/elibrary.asp in accordance with the Commission's regulations and Order No. 714.

Respectfully submitted,

By: _____

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*Counsel for*
*PJM Interconnection, L.L.C.*

Date: February 28, 2014

OCA Cross Exh. 6
A-2017-2640195 et al.
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**Application of Transource Pennsylvania LLC**
**Independence Energy Connection-East Project and West Project**
**Docket Nos. A-2017-2640195 and A-2017-2640200**

**Interrogatories of the Office of Consumer Advocate**
**Set IV**
**(Responses dated 3/23/2018)**

**Data Request OCA-IV-14:**

Please provide a detailed derivation of the benefit cost ratio as described in Figure 1:

a. Benefits broken out by the Energy Market Benefit (separately reporting the change in total energy production cost and change in load energy payment), the Reliability Pricing Benefit (separately reporting the change in total system capacity cost and change in load capacity payment) and any other benefits PJM included (identify and quantify)

b. Costs broken out by component (e.g., new substation, new transmission, substation upgrades, transmission upgrades, other, etc.)

c. Benefits and costs broken out by utility

d. Benefits and costs broken out by transmission zone

**Response:**

a. All benefits from Project 9A are in the form of load energy payment.

b.

| UPGRADE | | COST ESTIMATE |
|---|---|---|
| RICE | STATION | **$44.5** |
| RINGGOLD | STATION | **$2.7** |
| RICE-RINGGOLD | LINE | **$81.5** |
| R-R STATIONS | LINE WORK | **$4.4** |
| CONASTONE | STATION | **$4.6** |
| FURNACE RUN | STATION | **$49.9** |
| C-FR | LINE | **$44.4** |
| C-FR STATIONS | LINE WORK | **$4.9** |
| C_NW | RECONDUTOR | **$44.7** |
| RINGGOLD | STATION | **$14.1** |
| RINGGOLD-CATOCTIN | RECONDUCTOR | **$44.9** |

| | | |
|---|---|---|
| TOTAL | | **$340.6** |

c. Benefits and costs for the project are not calculated by utility. Please see response to OCA-IV-14(d) below. Regarding costs, the allocation by transmission zone is described in Appendix B of the August 2, 2016 "Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board (Baseline Upgrade IDs: b2743 and b2752), available at: http://www.pjm.com/-/media/committees-groups/committees/teac/20160811/20160811-board-whitepaper-august-2016.ashx. The Company further states that the costs allocated to each transmission zone are for the entire project, regardless of which transmission owners are designated to construct individual specific project components.

d. The following table gives the benefits transmission zones will receive from Project 9A. Project costs are not calculated by transmission zone.

| Change in 15-Year Net Present Value of Net Load Payment Project 9A | |
|---|---|
| PJM ZONE | ($Millions) |
| AEP | 71.38 |
| APS | 96.53 |
| BGE | 218.19 |
| COMED | 23.86 |
| CONABCJK | 4.12 |
| DAY | 6.54 |
| DEOK | 11.25 |
| DOM | 441.33 |
| DUQ | 0.11 |
| EKPC | 5.01 |
| LINDVFT | 63.83 |
| O66HVDC | 15.16 |
| PEPCO | 230.76 |
| Total Benefits | 1188.07 |

Note: This benefit calculation corresponds to the B/C Ratio of 2.48
Presented at the May 12th, 2016 TEAC

**Witness:** Paul F. McGlynn

**Application of Transource Pennsylvania LLC**
**Independence Energy Connection-East Project and West Project**
**Docket Nos. A-2017-2640195 and A-2017-2640200**

**Interrogatories of the Office of Consumer Advocate**
**Set IV**
**(Responses dated 3/23/2018)**

**Data Request OCA-IV-16:**

Please provide a detailed derivation of each benefit cost ratio, if any, calculated in addition to those Mr. McGlynn referenced on pages 29 and 33 of his testimony:

a. Benefits broken out by the Energy Market Benefit (separately reporting the change in total energy production cost and change in load energy payment), the Reliability Pricing Benefit (separately reporting the change in total system capacity cost and change in load capacity payment) and any other benefits PJM included (identify and quantify)

b. Costs broken out by component (e.g., new substation, new transmission, substation upgrades, transmission upgrades, other, etc.)

c. Benefits and costs broken out by utility

d. Benefits and costs broken out by transmission zone

**Response:**

a. All benefits from Project 9A are in the form of load energy payment.
b. Please see response to OCA-IV-14b. The cost estimates have not changed.
c. Please see response to OCA-IV-14c.
d. The following table gives the benefits transmission zones will receive from Project 9A. Project costs are not calculated by transmission zone.

| Change in 15-Year Net Present Value of Net Load Payment Project 9A | |
|---|---|
| PJM ZONE | ($) |
| AEP | 52,089,668 |
| APS | 85,590,533 |
| BGE | 44,930,925 |
| COMED | 11,700,983 |
| DAY | 5,378,001 |

| | |
|---|---|
| DEOK | 6,824,715 |
| DOM | 274,155,876 |
| DUQ | 2,844,756 |
| EKPC | 4,184,839 |
| PEPCO | 123,784,114 |
| Total Benefits | 611,484,411 |

Note: This benefits calculation is from the workbook used to calculate the BC ratio of 1.32 presented at Feb 9th 2018 TEAC

**Witness:** Paul F. McGlynn

Change in 15-Year Net Present Value of Net Load Payment
Project 9A

| PJM ZONE | ($million) |
|---|---|
| AECO | 17.90 |
| AEP | 5.32 |
| APS | -4.74 |
| BGE | -158.44 |
| COMED | 67.47 |
| DAY | 1.67 |
| DEOK | 17.19 |
| DOM | -382.05 |
| DPL | 30.42 |
| DUQ | 4.23 |
| EKPC | -0.36 |
| FE-ATSI | 55.32 |
| JCPL | 52.66 |
| LINDVFT | 5.32 |
| METED | 62.15 |
| NEPTHVDC | 9.97 |
| O66HVDC | 5.11 |
| PECO | 83.00 |
| PENELEC | 31.63 |
| PEPCO | -161.71 |
| PLGRP | 164.91 |
| PSEG | 72.97 |
| RECO | 2.99 |
| Total PJM Change | -17.05 |
| Zones that decrease | -707.29 |
| Zones that increase | 690.24 |

Change in 15-Year Net Present Value of Net Load Payment
Project 9A

| PJM ZONE | | NLP NPV ($) |
|---|---|---|
| AECO | $ | 17,903,639 |
| AEP | $ | 5,318,294 |
| APS | $ | (4,738,473) |
| BGE | $ | (158,435,444) |
| COMED | $ | 67,467,567 |
| DAY | $ | 1,670,667 |
| DEOK | $ | 17,188,314 |
| DOM | $ | (382,049,485) |
| DPL | $ | 30,415,129 |
| DUQ | $ | 4,232,346 |
| EKPC | $ | (357,204) |
| FE-ATSI | $ | 55,324,876 |
| JCPL | $ | 52,659,515 |
| LINDVFT | $ | 5,322,364 |
| METED | $ | 62,147,589 |
| NEPTHVDC | $ | 9,969,764 |
| O66HVDC | $ | 5,107,620 |
| PECO | $ | 83,000,950 |
| PENELEC | $ | 31,631,372 |
| PEPCO | $ | (161,710,391) |
| PLGRP | $ | 164,913,851 |
| PSEG | $ | 72,968,290 |
| RECO | $ | 2,994,278 |
| Total PJM Change | $ | (17,054,570) |
| Zones that decrease | $ | (707,290,998) |
| Zones that increase | $ | 690,236,427 |