STATE OF DELAWARE

PUBLIC SERVICE COMMISSION
861 SILVER LAKE BLVD.
CANNON BUILDING, SUITE 100
DOVER, DELAWARE 19904

TELEPHONE: (302) 736-7500
FAX: (302) 739-4849

August 7, 2015

VIA ELECTRONIC DELIVERY

PJM Transmission Owners
Mr. Frank J. Richardson, II (FJRichardson@pplweb.com)
Chairman, Transmission Owners Administrative Committee

Re: **REQUEST OF DELAWARE PUBLIC SERVICE COMMISSION REGARDING THE PJM BOARD OF MANAGERS SELECTION OF THE LS POWER 5A ARTIFICIAL ISLAND PROJECT FOR RESOLUTION OF SYSTEM OPERATING AND RELIABILITY CONCERNS IN NEW JERSEY.**

At its July 29, 2015 meeting, the PJM Board of Managers selected the L.S. Power 5A project as the solution to operating and reliability concerns related to the Artificial Island complex. The Delaware Public Service Commission ("Delaware PSC") appreciates PJM's efforts to resolve these issues but has significant concerns with what appears to be the resulting cost allocation. Given the selection of this project, the Delaware PSC respectfully requests the Transmission Owners ("TOs") to review the cost allocation related to this project and to consider possible alternatives that may be more appropriate in this and other similar circumstances.

As the Transmission Owners within the PJM region, the cost allocation for this project is within the TOs' responsibility as approved by the Federal Energy Regulatory Commission ("FERC") and provided for in the PJM Tariff.[1] It is the Delaware PSC's understanding that the cost of the selected 230KV line, as a low voltage facility, will be based on PJM's Solution Based DFAX which will allocate 99.9 % of the 230KV line cost to the DPL Transmission Zone or approximately 89% of the total project cost, which includes certain 500KV high voltage improvements that are also required. The Delaware PSC considers this cost allocation patently unfair, substantially unrelated to the system benefits provided and neither reasonable nor equitable for the DPL Transmission Zone ratepayers. Unfortunately, that leaves the Delaware PSC with the only alternative of a 206 Complaint Filing at FERC and any further legal recourse that may be required. To avoid a long protracted proceeding related to the proposed cost allocation and to develop a just and reasonable cost allocation, the Delaware PSC urges the TOs to review potential cost allocation alternatives for

[1] PJM Tariff, Schedule 12 § (a)(i)

this and the few other similarly situated circumstances where such allocation creates an unfair burden on transmission ratepayers and is inconsistent with benefits.

Recognizing the need to correct transmission system deficiencies for the benefit of all, the Delaware PSC takes no position at this time regarding the need for the selected project or the selection criteria that PJM presented in the Transmission Expansion Advisory Committee meetings. The Delaware PSC is in no way suggesting that cost allocation should be a determining consideration in the selection of an appropriate project to solve technical system or market efficiency issues. What is being contested is the manner in which the FERC-approved cost allocation is being applied in this circumstance and the inequities that inevitably follow.

As previously noted in the Delaware PSC's letter to PJM and as expressed by other similar letters, there are ways to resolve this cost allocation issue and to avoid unnecessary and protracted proceedings. In the case of the Delaware PSC letter, the Commission urged consideration of three (3) specific factors **that when taken together**, [emphasis added] could support an alternative cost allocation. Upon further reflection, the Delaware PSC suggests the consideration of two additional factors that must also be satisfied to justify a different low voltage cost allocation process.

1. The cost allocation resulting from the Solution Based DFAX would significantly increase transmission rates paid by customers for transmission service;
2. The Solution Based DFAX assigns all (or nearly all) of the costs to a transmission zone which is different than the zone creating the system issue; and
3. The project solution requires new rights-of-way and new transmission equipment.

Additionally:

4. The operating and reliability concerns requiring transmission upgrades were caused by generator deliverability export or transmission limitation issues in one zone with over 50% of costs allocated to a nearby zone; and
5. The cost allocation is greater than or equal to twice (or some other agreed-upon value) the PJM-stated load benefits accruing to a specific transmission zone.

It is important to note that the circumstances under which a variation of the DFAX cost allocation may be appropriate are a key component of the requested review. The Delaware PSC believes the recognition of these five unique, specific and objectively determined circumstances could provide justification for a different cost allocation that more accurately reflects the benefits in relation to the cost. It should be recognized that, ultimately, the FERC[2] and the courts[3] that have addressed this issue have concluded that there must be a reasonable alignment[4] of cost allocation and beneficiaries.

---

[2] Order No. 1000, 136 FERC ¶ 61,051, FERC Stats. & Regs. ¶ 31,323 (July 21, 2011) at P 622 (Costs of new transmission facilities must be "allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits.")

[3] *KN Energy, Inc. v. FERC,* 968 F.2d 1295, 1300 (D.C. Cir. 1992) ("[A]ll approved rates reflect to some degree the costs actually caused by the customer who must pay them.")

[4] *KN Energy, Inc. v. FERC*, 968 F.2d at 1300-01 (quoting *Alabama Electric Cooperative, Inc v. FERC*, 684 F.2d 20, 27 (D.C. Cir. 1982): "Properly designed rates should produce revenues from each class of customers which match, as closely as practicable, the costs to serve each class or individual customer." (internal footnotes omitted) (emphasis removed))

The final question for the TOs' consideration is how the cost allocation could be developed under these specific circumstances. The Delaware PSC encourages the TOs to examine alternative cost allocation options. The following suggestions can each provide a more just and reasonable cost allocation more closely aligned with benefits.

- With respect to high voltage facilities, transmission ratepayers live in the 50/50 world as filed by the TOs (50% shared on a PJM load ratio basis and 50% on a Solution Based DFAX) that has been approved by the FERC. Under the above mentioned circumstances and as advocated by several Delaware industries in their July 17 letter to the PJM Board, at a minimum, PJM should consider the underlying low voltage line as a regional system requirement or necessary lower voltage facility as permitted by PJM Manual 14B: PJM Region Transmission Planning Process, and allocate the costs of the entire solution on the 50/50 basis

- A second alternative would be to consider a cost allocation based on the economic load benefit to be derived from the selected solution. If this method were employed for this L.S. Power project, and based on PJM's Market Efficiency Study (Exhibit 1) (with which one may or may not agree), under the circumstances assumed in the analysis, the DPL Zone allocation would be approximately 10.1% of the project costs with up to 16.0% allocated to PSEG's New Jersey customers. [5]

- Another option for consideration could be a different combination of alternatives such as perhaps a 40/60 cost allocation under the above limited circumstances (40% shared on a PJM load ratio basis and 60% on a Solution Based DFAX analysis). The 40/60 allocation is a compromise based on the assumption that under the above circumstances, the project, although low voltage, does provide a broader system benefit for which at least some portion of the project should be paid.

Another factor that needs to be considered in this particular cost allocation review is the uprating of the Artificial Island nuclear units that has occurred over the past 15 years. The Delaware industries point out that "past generation interconnection studies concerning up-rates to generation output at the Artificial Island complex performed by, or on behalf of, PJM, including a recent 50 MW up-rate that went in service in 2013, failed to identify the reliability problem for which Delmarva customers are now being asked to shoulder cost responsibility."[6] An equitable cost allocation to relieve generation operational constraints, even if for only the peak 100 hours in the

[5] Other major beneficiaries are: PECO, at 16.8%; and PLGRP, at 12.4% (Exhibit 1). None of the aforementioned zones, each with PJM-calculated annual load payment savings greater than DPL, are currently allocated any cost for the 230KV section of the AI transmission upgrade.

[6] Delaware industries' July 17 Letter to the PJM Board. Their accompanying footnote reads: "A review of the PJM Generation Interconnection Queues indicates that Artificial Island generator output was increased by 95 MW in 2001, by 236 MW in 2007-2008, and by 50 MW as recently as 2013, only a few months after PJM discussed the Artificial Island issue with stakeholders and a few months prior to issuing the Artificial Island RFP in April 2013. In approving the prior up-rates at Artificial Island, PJM appears to have permitted the use of minimum MVAR requirements and complex operating guides **in lieu of requiring the generation owner to reinforce the transmission system to provide adequate stability margins as is now being requested through the Artificial Island Proposal Window RFP**." (Emphasis added)

year, should certainly carry costs in relation to the benefits to be received by the generator. The ability to run at full output during the 100 highest cost hours on the system without "operational difficulties" creates a windfall profit for the generator. It requires Delaware ratepayers to not only pay for the transmission that permits higher system generation levels, but also the windfall profits paid to generators who rely on that transmission for full operation.

The Delaware PSC encourages the TOs to address this and similar cost allocation issues where the use of the Solution Based DFAX allocates costs in an unfair and inequitable manner. A cost allocation process that forces high energy use industries in one transmission zone to absorb the network costs for benefits to competing industries in neighboring zones creates a discriminatory business environment that foretells economic relocations and the related state impacts for industries that rely on lower energy costs to remain competitive.

This is an important issue for the Delaware PSC and needs a cooperative approach for resolution. The Delaware Public Service Commission and others would be happy to meet with the TOs to further discuss potential resolutions to this issue. We hope the PJM Transmission Owners can consider a review process and amendment to the current cost allocation process that helps resolve these types of circumstances.

Sincerely,

Dallas Winslow, Chairman
Delaware Public Service Commission

Electronic Copies:
The Honorable Jack Markell, Governor
Commissioners, Delaware Public Service Commission
Mr. David Bonar, Delaware Public Advocate
Ms. Ruth A. Price, Delaware DeputyPublic Advocate
Mr. Robert Howatt, Executive Director, Delaware Public Service Commission
Mr. Matthew Hartigan, Deputy Director, Delaware Public Service Commission
Mr. John Farber, Public Utilities Analyst
Mr. Joe Delosa, Public Utilities Analyst
Mr. Howard Schneider, Chair, PJM Board of Managers
Mr. Craig Glazer, Vice President-Federal Government Policy, PJM
Mr. Michael Kormos, Executive Vice President, PJM
Mr. Steve Herling, PJM Vice President – Planning
Mr. Paul McGlynn, Chair, Transmission Expansion Advisory Committee
Mr. Gregory Carmean, Executive Director, OPSI

ATTACHED EXHIBIT 1

PJM Market Efficiency Study – Artificial Island Benefits
Requested by Delaware Public Service Commission

PJM Market Efficiency Study
Artificial Island Benefits

Requested by Delaware Public Service Commission

Market Efficiency Project Study approach:

- Utilized PJM Market Efficiency Base Case for study year 2019
- Compared LMP and Load Payments between the following scenarios for both a single hour* and annual value:
  - System without Artificial Island solution and one Salem Unit Offline**
  - System with Artificial Island solution and all Salem Units Online

** Single hour derived from RTO* Coincident Peak using 2019 Base Simulation

***Annual assumes one Salem unit offline for entire simulated year.*

Peak Hour Benefits Due To Artificial Island Solution*

LMP Avg. Benefits Due to Artificial sland Solution
(negative value is a benefit, a decrease in LMP)

AECO	(3.4)
AEP	0.3
APS	0.9
BGE	(0.3)
COMED	0.4
DAY	0.3
DEOK	0.3
DOM	1.2
DPL	(3.5)
DUQ	(0.2)
EKPC	0.4
FE-ATSI	(0.1)
JCPL	(3.1)
METED	(4.9)
PECO	(3.2)
PENELEC	(1.3)
PEPCO	1.2
PLGRP	(3.2)
PSEG	(3.0)
RECO	(2.6)

Load Payrnents Benefits Due to Artificial sland SOlution
(Negative value is a benefit, a decrease in Load Payrnents)

AECO	(8,266)
AEP	5,&80
APS	7,557
BGE	(1
COMED	8,530
DAY	770
DEOK	1,501
DOM	23,316
DPL	(13,772)
DUG	(6()2)
EKPC	618
FE-ATSI	(1.770)
JCPL	(18,257)
METED	(14,097)
PECO	(25,998)
PENELEC	(4,050)
PEPCO	7,396
PLGR.P	(2.3,5Q6)
PSEG	(28,942)
RECO	(1,016)

*Simulated RTO coincident peak from 2019 simulation was 155,382 MWs on July 31.

Annual LMP Benefits Due To Artificial Island Solution

- During the peak months of July and August, the market simulation shows an average LMP decrease in DPL Zone of 2.20 $/MWh and 1.90 $/MWh, respectively.
- The annual LMP average across DPL decreases by 0.86 $/MWh.
- The PJM average LMP decreases by 0.52 $/MWh in July, and 0.30 $/MWh in August.

LMP Avg. Benefits Due to Artificial Island Solution (negative value is a benefit, a decrease in LMP)													
Area	Month												
	1	2	3	4	5	6	7	8	9	10	11	12	Annual Average
AECO	$(0.15)	$(0.26)	$(0.82)	$(0.80)	$(0.18)	$(0.72)	$(1.79)	$(1.27)	$(1.01)	$(0.35)	$(0.48)	$(0.71)	$ (0.77)
AEP	$(0.23)	$(0.32)	$(0.01)	$(0.10)	$ 0.11	$(0.02)	$(0.11)	$(0.01)	$(0.10)	$ 0.25	$(0.19)	$ 0.01	$ (0.06)
APS	$(0.01)	$(0.19)	$(0.35)	$(0.11)	$ 0.38	$(0.07)	$(0.22)	$(0.11)	$(0.24)	$ 0.18	$(0.23)	$(0.06)	$ (0.09)
BGE	$ 0.04	$ 0.14	$(0.47)	$(0.20)	$ 0.20	$(0.12)	$(0.41)	$(0.17)	$(0.47)	$(0.06)	$(0.35)	$(0.28)	$ (0.18)
COMED	$(0.22)	$(0.29)	$ 0.44	$(0.36)	$(0.08)	$ 0.02	$(0.05)	$ 0.08	$ 0.01	$ 0.01	$ 0.48	$ 0.15	$ 0.02
DAY	$(0.31)	$(0.49)	$ 0.16	$(0.05)	$(0.00)	$(0.01)	$(0.09)	$ 0.00	$(0.06)	$ 0.44	$(0.15)	$(0.00)	$ (0.05)
DEOK	$(0.28)	$(0.47)	$ 0.20	$(0.14)	$(0.04)	$(0.02)	$(0.08)	$ 0.00	$(0.05)	$ 0.53	$(0.11)	$(0.01)	$ (0.04)
DOM	$ 0.02	$ 0.28	$(0.33)	$(0.04)	$ 0.31	$ 0.02	$(0.16)	$(0.03)	$(0.09)	$ 0.07	$(0.47)	$(0.16)	$ (0.05)
DPL	$(0.19)	$(0.22)	$(0.85)	$(0.70)	$(0.27)	$(0.77)	$(2.20)	$(1.90)	$(1.05)	$(0.36)	$(0.57)	$(0.77)	$ (0.86)
DUQ	$(0.16)	$(0.10)	$(0.69)	$(0.37)	$ 0.42	$(0.15)	$(0.23)	$(0.12)	$ 0.12	$ 0.70	$(1.04)	$(0.10)	$ (0.14)
EKPC	$(0.22)	$(0.38)	$ 0.11	$ 0.01	$ 0.03	$(0.01)	$(0.06)	$ 0.05	$(0.09)	$ 0.27	$(0.14)	$(0.01)	$ (0.05)
FE-ATSI	$(0.07)	$(0.20)	$(0.30)	$(0.38)	$ 0.22	$(0.15)	$(0.21)	$(0.08)	$(0.04)	$ 0.40	$(0.54)	$(0.07)	$ (0.12)
JCPL	$(0.12)	$(0.28)	$(0.71)	$(0.44)	$ 0.07	$(0.61)	$(1.52)	$(1.02)	$(0.85)	$(0.23)	$(0.41)	$(0.58)	$ (0.59)
METED	$ 0.00	$(0.12)	$(0.78)	$(0.62)	$(0.15)	$(0.62)	$(1.18)	$(0.69)	$(1.15)	$(0.24)	$(0.38)	$(0.46)	$ (0.54)
PECO	$(0.10)	$(0.24)	$(0.68)	$(0.61)	$(0.12)	$(0.63)	$(1.79)	$(1.23)	$(0.91)	$(0.22)	$(0.40)	$(0.63)	$ (0.66)
PENELEC	$ 0.12	$ 0.03	$(0.14)	$(0.51)	$ 0.05	$(0.41)	$(0.64)	$(0.44)	$(0.55)	$(0.16)	$(0.11)	$(0.19)	$ (0.24)
PEPCO	$ 0.03	$ 0.23	$(0.37)	$(0.03)	$ 0.36	$ 0.03	$(0.22)	$(0.05)	$(0.17)	$ 0.01	$(0.37)	$(0.20)	$ (0.06)
PLGRP	$(0.04)	$(0.15)	$(0.69)	$(0.45)	$(0.04)	$(0.56)	$(1.22)	$(0.80)	$(0.79)	$(0.15)	$(0.31)	$(0.50)	$ (0.48)
PSEG	$(0.16)	$(0.28)	$(0.70)	$(0.45)	$ 0.05	$(0.58)	$(1.49)	$(1.00)	$(0.81)	$(0.08)	$(0.59)	$(0.62)	$ (0.59)
RECO	$(0.35)	$(0.88)	$(1.95)	$(0.14)	$ 0.44	$(0.69)	$(0.93)	$(0.71)	$(0.65)	$ 0.09	$(0.81)	$(0.41)	$ (0.59)
PJM	$(0.11)	$(0.15)	$(0.25)	$(0.27)	$ 0.10	$(0.19)	$(0.52)	$(0.30)	$(0.31)	$ 0.09	$(0.25)	$(0.18)	$ (0.20)

Annual Load Payment Savings Due To Artificial Island Solution

- During the peak months of July and August, the market simulation shows a decrease of the monthly load payments across DPL zone of $4.32 million and $3.64 million, respectively.
- The annual total load payments across DPL zone decreases by $17.04 million.
- The PJM annual total load payments decrease by $169.2 million.

Load Payments Savings Due to Artificial Island Solution ($ million, negative value is a benefit, a decrease in load payments)													
Area	Month												
	1	2	3	4	5	6	7	8	9	10	11	12	Annual Total
AECO	$ (0.14)	$ (0.22)	$ (0.67)	$ (0.60)	$ (0.15)	$ (0.70)	$ (2.13)	$ (1.46)	$ (0.91)	$ (0.28)	$ (0.38)	$ (0.64)	$ (8.28)
AEP	$ (2.82)	$ (3.54)	$ (0.13)	$ (0.99)	$ 1.16	$ (0.21)	$ (1.34)	$ (0.17)	$ (1.05)	$ 2.57	$ (1.98)	$ 0.06	$ (8.43)
APS	$ (0.04)	$ (0.84)	$ (1.49)	$ (0.43)	$ 1.48	$ (0.29)	$ (0.97)	$ (0.51)	$ (0.93)	$ 0.73	$ (0.91)	$ (0.28)	$ (4.46)
BGE	$ 0.14	$ 0.39	$ (1.31)	$ (0.50)	$ 0.52	$ (0.35)	$ (1.37)	$ (0.55)	$ (1.29)	$ (0.14)	$ (0.91)	$ (0.83)	$ (6.22)
COMED	$ (2.09)	$ (2.47)	$ 3.78	$ (2.89)	$ (0.71)	$ 0.14	$ (0.49)	$ 0.82	$ 0.08	$ 0.08	$ 4.04	$ 1.41	$ 1.70
DAY	$ (0.52)	$ (0.73)	$ 0.24	$ (0.07)	$ (0.00)	$ (0.02)	$ (0.15)	$ 0.00	$ (0.09)	$ 0.64	$ (0.21)	$ (0.00)	$ (0.92)
DEOK	$ (0.70)	$ (1.04)	$ 0.45	$ (0.28)	$ (0.09)	$ (0.04)	$ (0.22)	$ 0.00	$ (0.10)	$ 1.14	$ (0.24)	$ (0.02)	$ (1.16)
DOM	$ 0.17	$ 2.46	$ (2.86)	$ (0.32)	$ 2.53	$ 0.19	$ (1.58)	$ (0.26)	$ (0.80)	$ 0.57	$ (3.95)	$ (1.49)	$ (5.33)
DPL	$ (0.34)	$ (0.35)	$ (1.35)	$ (0.99)	$ (0.40)	$ (1.30)	$ (4.32)	$ (3.64)	$ (1.66)	$ (0.53)	$ (0.85)	$ (1.32)	$ (17.04)
DUQ	$ (0.22)	$ (0.13)	$ (0.88)	$ (0.43)	$ 0.51	$ (0.21)	$ (0.35)	$ (0.17)	$ 0.15	$ 0.86	$ (1.27)	$ (0.14)	$ (2.26)
EKPC	$ (0.26)	$ (0.39)	$ 0.10	$ 0.01	$ 0.03	$ (0.01)	$ (0.06)	$ 0.05	$ (0.08)	$ 0.23	$ (0.13)	$ (0.01)	$ (0.53)
FE-ATSI	$ (0.44)	$ (1.13)	$ (1.76)	$ (2.03)	$ 1.22	$ (0.89)	$ (1.36)	$ (0.50)	$ (0.23)	$ 2.19	$ (2.96)	$ (0.40)	$ (8.28)
JCPL	$ (0.25)	$ (0.53)	$ (1.37)	$ (0.77)	$ 0.13	$ (1.34)	$ (3.90)	$ (2.52)	$ (1.71)	$ (0.42)	$ (0.75)	$ (1.19)	$ (14.62)
METED	$ 0.00	$ (0.16)	$ (1.08)	$ (0.78)	$ (0.19)	$ (0.88)	$ (1.80)	$ (1.04)	$ (1.53)	$ (0.31)	$ (0.50)	$ (0.68)	$ (8.96)
PECO	$ (0.39)	$ (0.81)	$ (2.38)	$ (1.93)	$ (0.39)	$ (2.36)	$ (7.56)	$ (5.05)	$ (3.20)	$ (0.72)	$ (1.33)	$ (2.32)	$ (28.46)
PENELEC	$ 0.22	$ 0.04	$ (0.24)	$ (0.79)	$ 0.08	$ (0.66)	$ (1.09)	$ (0.76)	$ (0.88)	$ (0.26)	$ (0.18)	$ (0.34)	$ (4.87)
PEPCO	$ 0.08	$ 0.59	$ (0.95)	$ (0.07)	$ 0.91	$ 0.07	$ (0.73)	$ (0.15)	$ (0.45)	$ 0.04	$ (0.89)	$ (0.55)	$ (2.10)
PLGRP	$ (0.15)	$ (0.55)	$ (2.58)	$ (1.49)	$ (0.12)	$ (2.00)	$ (4.72)	$ (3.09)	$ (2.70)	$ (0.50)	$ (1.08)	$ (2.00)	$ (20.97)
PSEG	$ (0.61)	$ (0.96)	$ (2.54)	$ (1.50)	$ 0.20	$ (2.40)	$ (6.98)	$ (4.55)	$ (3.11)	$ (0.28)	$ (2.02)	$ (2.33)	$ (27.10)
RECO	$ (0.04)	$ (0.10)	$ (0.23)	$ (0.02)	$ 0.05	$ (0.10)	$ (0.15)	$ (0.11)	$ (0.09)	$ 0.01	$ (0.09)	$ (0.05)	$ (0.92)
PJM	$ (8.40)	$ (10.46)	$ (17.24)	$ (16.88)	$ 6.77	$ (13.36)	$ (41.29)	$ (23.66)	$ (20.57)	$ 5.61	$ (16.58)	$ (13.13)	$ (169.20)

Distribution Factor Allocations

DFAX ALLOCATIONS WITH AI PROJECT

500 kV Transmission Line	AEC	BGE	DPL	ECP	JCPL	NEPTUNE	HTP	PECO	PENELEC	PEPCO	PSEG	RE
Salem - New Freedom	7.7%	0.0%	0.0%	1.3%	16.7%	1.8%	1.2%	22.5%	0.0%	0.0%	47.0%	1.9%
Salem- Hope Creek	22.8%	1.1%	0.0%	0.0%	41.4%	4.4%	0.0%	0.0%	0.0%	0.0%	29.1%	1.2%
Salem - Orchard	8.2%	0.0%	0.0%	1.3%	16.7%	1.8%	1.2%	22.6%	0.0%	0.0%	46.5%	1.9%
Orchard - New Freedom	0.0%	0.0%	0.0%	1.7%	17.1%	2.0%	1.5%	20.6%	0.0%	0.0%	54.9%	2.2%
Hope Creek- New Freedom	7.7%	0.0%	0.0%	1.3%	16.8%	1.8%	1.2%	22.4%	0.0%	0.0%	47.0%	1.9%
Hope Creek - Red Lion	1.9%	36.0%	29.4%	1.2%	3.2%	0.3%	1.7%	0.0%	0.0%	26.3%	0.0%	0.0%

DFAXALLOCATIONS WITHOUT AI PROJECT

500 kV Transmission Line	AEC	BGE	DPL	ECP	JCPL	NEPTUNE	HTP	PECO	PENELEC	PEPCO	PSEG	RE
Salem -New Freedom	7.6%	0.0%	0.0%	1.3%	16.6%	1.8%	1.2%	22.9%	0.0%	0.0%	46.8%	1.9%
Salem - Hope Creek	21.2%	3.8%	7.7%	0.0%	41.2%	4.4%	0.0%	0.0%	0.0%	0.0%	20.9%	0.9%
Salem - Orchard	8.1%	0.0%	0.0%	1.3%	16.6%	1.8%	1.2%	23.1%	0.0%	0.0%	46.2%	1.9%
Orchard - New Freedom	0.0%	0.0%	0.0%	1.7%	16.9%	2.0%	1.5%	21.0%	0.0%	0.0%	54.7%	2.2%
Hope Creek - New Freed'om	7.6%	0.0%	0.0%	1.3%	16.7%	1.8%	1.2%	22.H%	0.0%	0.0%	46.7%	1.9%
Hope Creek Red Lion	0.6%	26.1%	51.6%	0.9%	1.1%	0.1'%	1.3%	0.0%	0.1%	18.3%	0.0%	0.0%