ELECTRICITY MARKET DESIGN
TRANSMISSION COST ALLOCATION

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New Transmission – Cost Causation & Beneficiary Analysis

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The court has affirmed a cost-benefit standard for transmission evaluation and cost allocation.

"FERC is not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, or benefits that are trivial in relation to the costs sought to be shifted to its members. … Rather desperately FERC's lawyer, and the lawyer for the eastern utilities that intervened in support of [FERC's] ruling, reminded us at argument that Commission has a great deal of experience with issues of reliability and network needs, and they asked us therefore (in effect) to take the soundness of its decision on faith. But we cannot do that because we are not authorized to uphold a regulatory decision that is not supported by substantial evidence on the record as a whole, or to supply reasons for the decision that did not occur to the regulators. … We do not suggest that the Commission has to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars. … ("we have never required a ratemaking agency to allocate costs with exacting precision"); … If it cannot quantify the benefits to the midwestern utilities from new 500 kV lines in the East, even though it does so for 345 kV lines, but it has an articulable and plausible reason to believe that the benefits are at least ***roughly commensurate*** with those utilities' share of total electricity sales in PJM's region, then fine; the Commission can approve PJM's proposed pricing scheme on that basis. For that matter it can presume that new transmission lines benefit the entire network by reducing the likelihood or severity of outages. … But it cannot use the presumption to avoid the duty of "comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party." [1]

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1 *Illinois Commerce Commission v. FERC*, 576 F.3d 470, 476 (7th Cir., August 6, 2009, citations omitted) 9emphasis added).

A transmission infrastructure mandatory cost allocation framework requires a hybrid system that is regional in scope and compatible with the larger market design. FERC Order 1000 proposed principles that are compatible with a larger hybrid system.[2] The broader framework would include:

- **Cost Benefit Framework**
  - Gold Standard: Net Benefits > Total Cost
  - Cost Sharing: Commensurable with Benefits
  - Compatible with Larger Market Design
- **Ex ante Estimation and Allocation**
- **Net Benefits = Change in Expected Social Welfare**
  - Counterfactual without contracts
  - Uncertainty and Expected Present Value
- **Approximations of Benefits**
  - Reliability
  - Economic
  - Public Policy
- **Benefit estimates commensurable across categories for projects**
  - Transmission lines affect all categories of benefits.
  - Transmission costs cannot be separated into distinct buckets.

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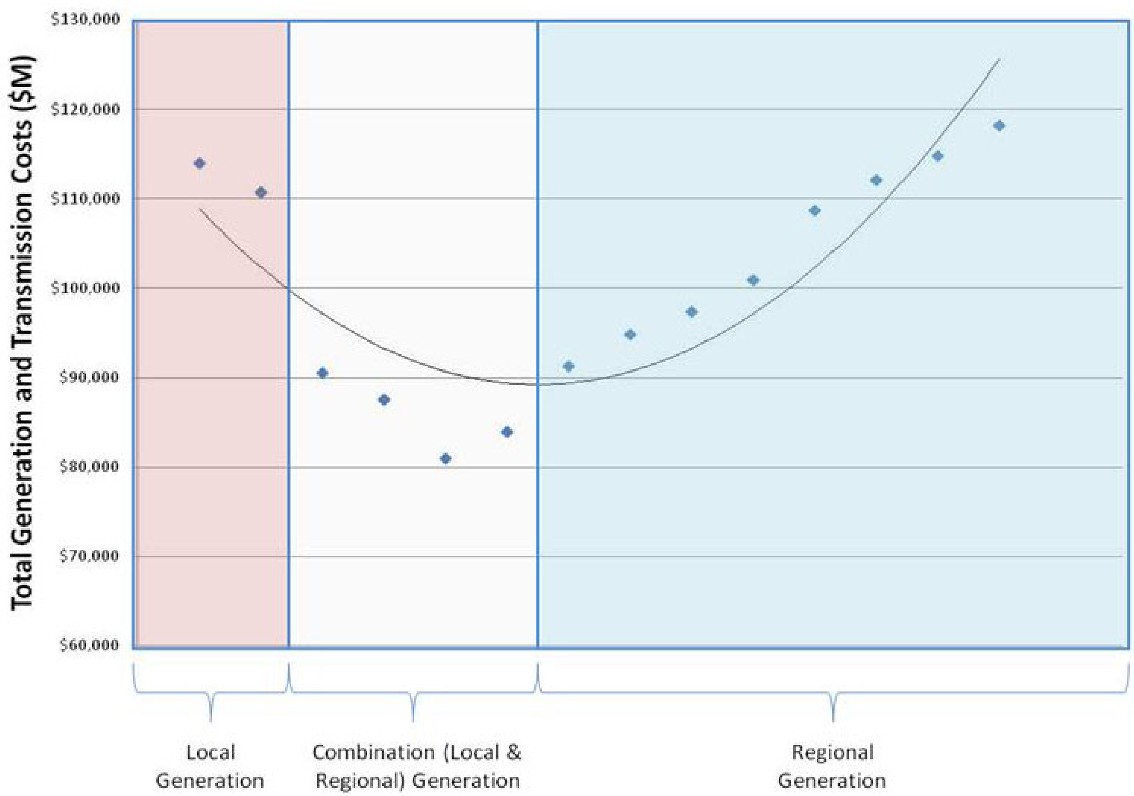
[2] Federal Energy Regulatory Commission, "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities," Docket No. RM10-23-000; Order No. 1000, Washington DC, July 21, 2011.

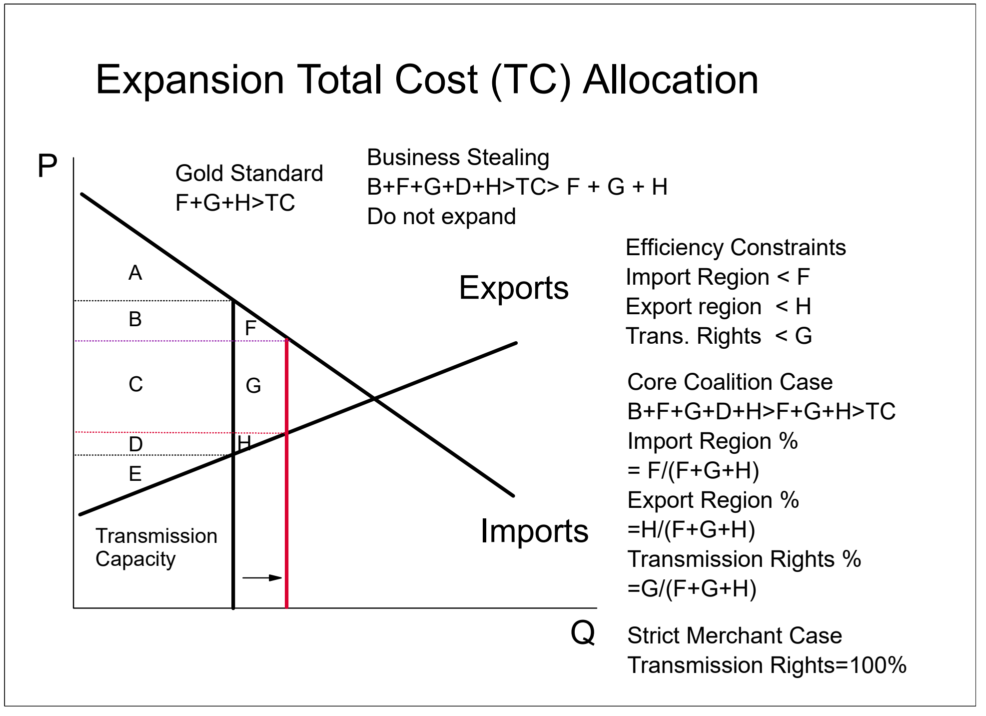
Efficient transmission infrastructure investment interacts with the costs and benefits of types and locations of renewable energy investment.

RGOS Zone Scenario Generation and Transmission Cost Comparison[3]



[3] Midwest ISO. *Regional Generation Outlet Study*, November 19, 2010, p. 3.

"The cost of 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. … Those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those facilities." (FERC Order 1000, ¶ 622, 637) Cost benefit analysis of transmission expansion inherently provides information about the distribution of benefits for use in cost allocation. (Hogan, 2018)



Developing rules for efficient transmission infrastructure investment may be easier said than done. The initial submissions were "Very Roughly Commensurate."

"Last fall, in early October [2012], utilities across the country began filing tariffs with the Federal Energy Regulatory Commission to explain how they will comply with the commission's Order 1000, issued 18 months ago. That order requires all FERC-jurisdictional transmission service providers to participate in regional grid planning, and forces the planners to take account of state and federal policy governing renewable energy. Costs for projects that pass muster in the regional plan must be allocated in a manner "roughly commensurate" with project benefits." …

"In truth, Order 1000 is proving troublesome even for RTOs. PJM's comply tariff (*FERC Dkt. ER13-198, filed Oct. 25, 2012*) has drawn protests from nearly a dozen state PUCs. But in non-RTO areas, it's harder still. FERC in effect is forcing utilities in non-RTO areas to do many of the same things that RTOs do, but without market pricing or a centralized regional unit dispatch. The comply filings that have come in so far from non-RTO areas raise some key issues:

• ***Active or Passive***: Does Order 1000 require an ex ante assessment of regional needs and solutions, or can planners just sit tight and wait for developers to come forward?

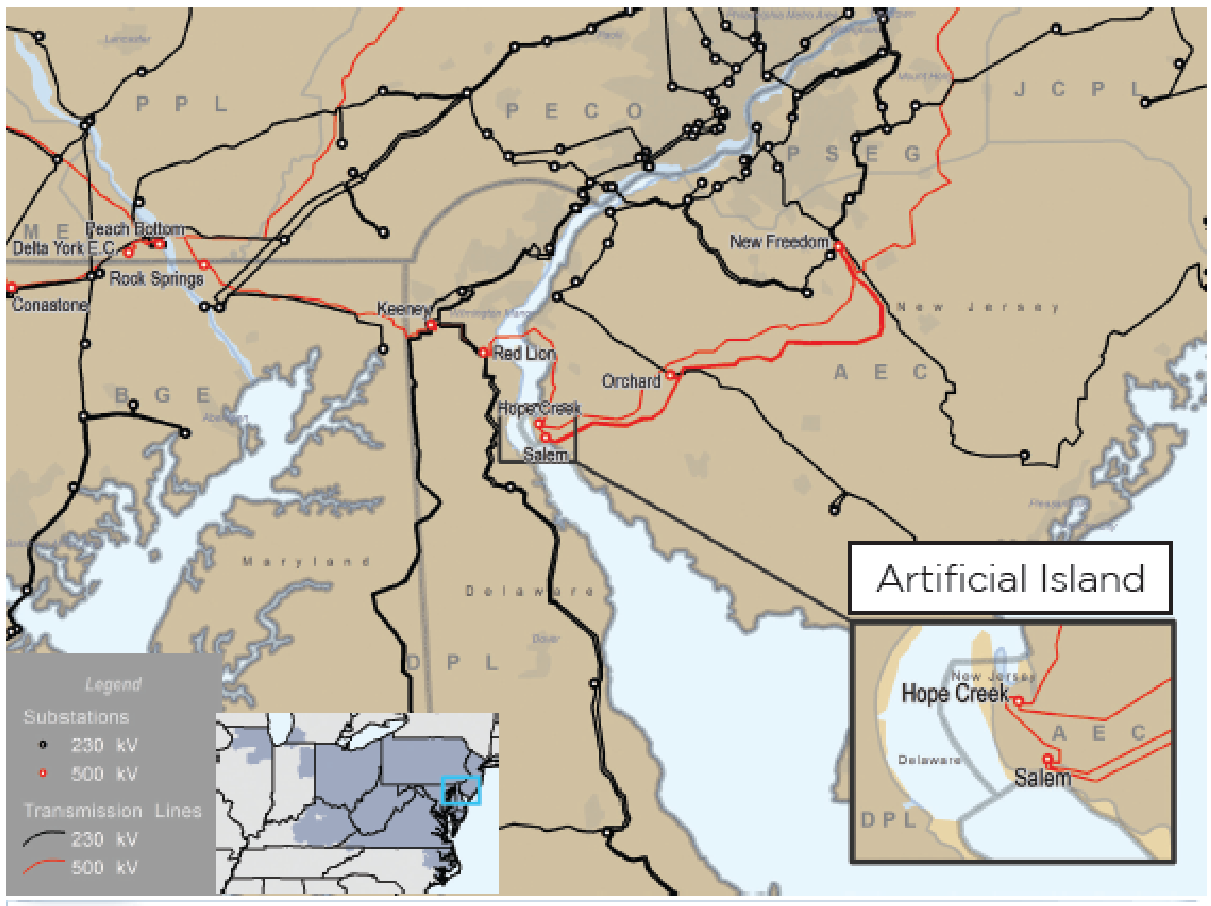
• ***Production Cost Modeling***: Should planners model energy production costs (congestion, fuel use and prices, plant dispatch and capacity factors, etc.) in calculating project benefits?

• ***Sponsor Fitness***: Rules governing capability and qualifications for project developers seem fine, but do they discriminate against non-incumbents?

• ***Public Power Independence***: How to mandate regional cost allocation and yet preserve the FERC-free status of non-jurisdictional participants from the public power sector?" (Radford, 2013)

"PJM opened an RTEP process window on April 29, 2013, seeking proposals to improve operational performance on bulk electric system facilities in the southern New Jersey, Artificial Island area, site of PSE&G's Salem 1 and 2 and Hope Creek 1 nuclear generating plants."

Map 1.1: Artificial Island - New Jersey Area



(PJM, "Artificial Island Project Recommendation," White Paper, July 29, 2015)

The Artificial Island Project is a first instance applying the cost allocation rules identified under Order 1000.

> “After thorough review, the PJM Board of Managers has approved the staff recommendation to accept LS Power’s proposal to build a 230 kV line under the Delaware River. The Board also has approved the designation of Public Service Electric & Gas and Pepco Holdings Inc. for the expansion of interconnection facilities. These projects will resolve the operational performance issues around the Artificial Island area and provide important transmission support for the sub region. …”
>
> “The Board also recognizes the valid concerns raised by Governor Markell, the Delaware Public Service Commission, the Maryland Public Service Commission and others regarding the allocation of costs associated with this project. …”
>
> “This pilot case implementing Order 1000 principles and a competitive solicitation process will continue to be examined for a number of “lessons learned.” The Board thanks the Planning Committee for its thorough review and we urge the adoption of changes that will improve the planning process.” (Terry Boston, ARTIFICIAL ISLAND PROJECT, Letter to PJM Members Committee, July 29, 2015)

The Order 1000 basis of the PJM transmission cost allocation reflects the contradictions of beneficiary pays without basing the allocation on the benefits.

“PJM’s allocation of cost responsibility for RTEP reliability baseline upgrades in accordance with these provisions is beneficiary based. Typically, load growth creates conditions that constitute violations of reliability criteria, which in turn require upgrades for eliminating the violations. The benefit to load from elimination of the violation will differ from the benefit of having the resultant upgrade available for use to deliver PJM generation to serve them. However, the benefit derived by the load in a transmission zone can only be determined by the use of the upgrade to deliver PJM generation to this load zone relative to similar uses of the upgrade by other zonal loads. This quantifiable benefit is then used to determine the relative responsibility for the cost of the system upgrade(s) for each zone. …”

“Regional and Necessary Lower Voltage Facilities with estimated costs greater than or equal to $5 million

- 50% of the cost of the upgrade will be assigned annually on a load-ratio share using the PJM Network Transmission Service Peak Load and the applicable load values for Merchant Transmission having Firm Transmission Withdrawal Rights for the 12-month period ending October 31 preceding the calendar year for which the annual cost responsibility allocation is determined
- 50% of the cost of the upgrade will be assigned annually on a directionally-weighted solution-based DFAX methodology

Lower Voltage Facilities (<345kV) with estimated costs greater than or equal to $5 million

- 100% of the cost of the upgrade will be assigned annually on a directionally-weighted solution-based DFAX methodology”

(PJM Manual 14B: PJM Region Transmission Planning Process, Revision: 30, Effective Date: February 26, 2015, pp. 40-41.)

The PJM DFAX methodology tracks "solution flows" for the peak load assuming the source is the aggregate of all PJM generation.

"Calculate the Distribution Factor (DFAX) for each transmission zone and merchant transmission facility with firm withdrawal rights based on its use of the upgrade to deliver PJM generation to serve its load. PJM will use the annual RTEP starting base case to develop all DFAX values for new RTEP upgrades. … A DFAX represents a measure of the use of the upgrade by each MW of a zone's load served by a MW of PJM generation, as determined by power flow analysis. The source used for the DFAX calculation is the aggregate of all PJM generation and the sink is each Transmission Owners peak zonal load or applicable MW values for a merchant transmission with firm withdrawal rights."

Step	Reference	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Total
1. Peak Load (MW)	From PJM Load Report	10,000	6,000	4,000	3,000	2,000	25,000
2. DFAX	From DFAX Analysis	0.050	-0.100	0.009	-0.030	0.100	
2a. Apply DFAX Threshold	Set |DFAX|< 0.01 to 0	0.050	-0.100	0	-0.030	0.100	
2b. Select lowest DFAX		0.050	-0.100	0	-0.030	0.100	
3. Zonal Use of the Upgrade	Line 1 * Line 2b	500	(600)	-	(90)	200	
3a. Zonal Use in [+] Direction		500	-	-	-	200	700
3a. Zonal Use in [-] Direction		-	(600)	-	(90)	-	(690)
3b. % use in [+] Direction	Line 3a / Line 3a Total	71.43%				28.57%	100%
3b. % use in [-] Direction	Line 3a / Line 3a Total	-	86.96%	-	13.04%	-	100%
4a. Weighting Factor in [+] direction	From Production Cost simulation	80%	-	-	-	80%	
4a. Weighting Factor in [-] direction	From Production Cost simulation	-	20%	-	20%	-	
5. Calculate cost allocation Percentage	Line 3b * Line 4a	57.14%	17.39%	-	2.61%	22.86%	100%

(PJM Manual 14B: PJM Region Transmission Planning Process, Revision: 30, Effective Date: February 26, 2015, pp. 42-43.)

The PJM Artificial Island Project raises a challenge to the cost allocation rules under Order 1000.

pjm

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)

(PJM Market Efficiency Study Artificial Island Benefits Requested by Delaware Public Service Commission, July 27, 2105,)

The PJM Artificial Island Project application of the DFAX methodology raises a challenge to the cost allocation rules under Order 1000.

"The Artificial Island Project is a PJM RTEP project that involves the construction of a new 230 kV transmission line under the Delaware River, and construction and installation of certain other facilities, to address certain system stability and related generation operation issues in the Artificial Island area in southern New Jersey. PJM's Board of Managers ("PJM Board") has adopted the use of the solution-based DFAX methodology to allocate the costs of the Artificial Island Project. … The Commission approved the use of solution-based DFAX for purposes of cost allocation of certain PJM-approved transmission projects as part of a comprehensive cost allocation proposal that the PJM Transmission Owners filed to comply with Order No. 1000. … PJM's application of solution-based DFAX to the Artificial Island Project results in the Delmarva Zone, which includes load located within the states of Delaware and Maryland, being assigned approximately 90 percent of the costs of the Artificial Island Project. Other analyses conducted by PJM demonstrate that the Delmarva Zone will receive only 10 percent of the benefits associated with the Project. The result is even more egregious given that the generation issues to be resolved by the Artificial Island Project are not located in the Delmarva Zone. Such disproportionate alignment of benefits and costs is unjust, unreasonable, and wholly inconsistent with cost-causation principles and legal precedent requiring the allocation of transmission project costs to be "roughly commensurate" with the benefits of the project."

(Complaint of the Delaware Public Service Commission and Maryland Public Service Commission, FERC, Docket No. EL15-95-000, August 28, 2015).

The PJM Artificial Island Project cost allocation protests raised an important policy issue. In addition, the evolving conditions raised parallel concerns about cost effectiveness.

"Complainants contend that application of the solution-based DFAX method to the Artificial Island Project in the Delmarva zone results in a disproportionate alignment of benefits and costs that is unjust, unreasonable, and inconsistent with cost causation principles. We disagree. The courts have recognized that no cost allocation method can perfectly assign costs to the beneficiaries of a transmission project, particularly in the case of a transmission grid." (FERC, *Order Denying Complaint and Accepting Cost Allocation Report*, Docket No. EL15-95-000, April 22, 2016).

"I acknowledge that these cases present difficult questions regarding ex ante cost allocation methodologies, and I understand the reasoning and considerations that led the Commission to reject the complaints. Determining an appropriate cost allocation methodology for large transmission projects has been among the most complicated issues presented during my time on the Commission.

Nonetheless, I do not agree with the orders' denial of the complaints. Based on the record, particularly as developed through the technical conference, I am persuaded that the complainants have met their burden to establish that the use of solution-based DFAX to allocate the costs of the Bergen-Linden Corridor Project and the Artificial Island Project is unjust and unreasonable." (Commissioner Fleur Dissent, Docket No. EL15-95-000, April 22, 2016).

PJM Board Suspends Artificial Island Transmission Project

Asks PJM to perform review

(Valley Forge, Pa. – August 5, 2016) – The PJM Interconnection Board has suspended the Artificial Island transmission project and directed PJM to perform a comprehensive analysis to support a future course of action. The announcement came today in a letter to PJM members.

The PJM Artificial Island Project cost allocation debate continued, without much resolution.

FERC OKS PJM CHANGES TO ARTIFICIAL ISLAND COST ALLOCATION

"FERC issued an order last week approving PJM's proposal to update the cost allocation of the Artificial Island project, pending rehearing requests in other dockets. The commission will deal with arguments over the cost allocation of the project in those other cases, it said. …

Along with parties from the Delmarva, Exelon and LS Power challenged the use of the solution-based distribution factor (DFAX) method for the project. They argued it does not work, citing the project having been designed to remedy a generator stability limit. The cost-allocation method may not identify all the beneficiaries and assign cost responsibility commensurate with the benefits received, they added.

PJM came up with some alternatives in a whitepaper and the protesters argued they show the DFAX method does not work for the Artificial Island.

FERC found PJM complied with its tariff in the new design for the Artificial Island and in using the DFAX method to assign its costs.

Protester challenges to the DFAX method are pending in other proceedings, FERC said. Those arguments will be addressed there and FERC saw no need to open an added proceeding on the justness and reasonableness of the DFAX method, it added." (Power Markets Today, October 10, 2017.)

In 2018 PJM developed an alternative cost allocation rule called the "Stability Deviation Method." The approach ignores analysis to identify cost- and-benefits PJM had demonstrated. As of 2019, "The Stability Deviation Method cost allocation for the Artificial Island Project has not been approved by the PJM Board or filed with FERC."[4]

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4 PJM, "Artificial Island Project Cost Allocation Status Update." Transmission Expansion Advisory Committee, October 17, 2019.

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