BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Power Company for an Increase in Electric Distribution Rates.	)))	Case No. 20-585-EL-AIR
In the Matter of the Application of Ohio Power Company for Tariff Approval.	))	Case No. 20-586-EL-ATA
In the Matter of the Application of Ohio Power Company for Approval to Change Accounting Methods.	)))	Case No. 20-587-EL-AAM

DIRECT TESTIMONY OF JOSEPH HAUGEN ON BEHALF OF INTERSTATE GAS SUPPLY, INC.

April 20, 2021

TABLE OF CONTENTS

EXHIBITS

PJM, "Annual Transmission Revenue Requirements and Rates (2018)"	JH-Exhibit 1
PJM, "Annual Transmission Revenue Requirements and Rates (2019)"	JH-Exhibit 2
PJM, "Annual Transmission Revenue Requirements and Rates (2020)"	JH-Exhibit 3
PJM, "Annual Transmission Revenue Requirements and Rates (2021)"	JH-Exhibit 4
Excerpts of AEP Ohio, "Ohio Choice Market Settlement Polices & Procedures"	JH-Exhibit 5

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Joseph Haugen. My business address is 6100 Emerald Parkway, Dublin, Ohio 43016.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Interstate Gas Supply, Inc. ("IGS Energy" or "IGS").

Q. Please describe your work history and educational background.

A. I began my employment with IGS Energy in February 2013, when I was hired as a Senior Supply Analyst and aided in developing and implementing wholesale risk management hedging and trading strategies. In January 2015, I was promoted to Power Supply Manager where I managed a team of analysts responsible for implementing risk management and trading strategies. In May 2017, I was promoted to my current role, Power Supply Director. In this role, I have responsibilities related to IGS Energy's power supply and risk along with wholesale power market operations. Included in this role is forecasting transmission costs in states where transmission is a bypassable charge and the responsibility of the retail electric provider. I am also responsible for representing IGS in the PJM Interconnection, Inc. ("PJM") stakeholder process.

I graduated from The Ohio State University in 2005 with a B.A. I obtained a Master of Business Administration from Otterbein University in 2009. Prior to working at IGS, I was an energy scheduler for Buckeye Power from 2007 through 2013. I scheduled daily power usage for the 25 cooperatives in Ohio and coordinated generation resources including wind, natural gas, and coal plants in the wholesale markets. I was also responsible for operating the demand response program. Prior to that, I was a Laboratory Manager for CTL Engineering from 2005 to 2007.

Q. Have you previously submitted testimony in any regulatory proceedings?

A. Yes. I have testified before the Public Utilities Commission of Ohio ("Commission") in several cases.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to demonstrate that the Stipulation in this proceeding fails the second and third prong of the Commission's criteria for evaluating the reasonableness of a proposed settlement. Specifically, the limited expansion of the Basic Transmission Cost Recovery ("BTCR") Pilot paired with the continuation of the BTCR's rate design will harm customers and violate the Commission's continued direction to utilize interval data to further cost-causation principles.

My testimony will show that the cost for transmission service, which is paid by customers in the Ohio Power Company ("AEP Ohio") service territory, should mirror the way these costs are set in the wholesale market, PJM. This will allow customers to make decisions more easily that will impact their bill and allow for future savings across the transmission zone by lessening the amount of transmission investment needed. Notably, the AEP Transmission Zone revenue requirement has gone from $1.3 Billion in 2018 to $2.1 Billion in 2021.[1] Our customers have informed us that the increase in this cost has been harmful to their budgets and their bottom lines. Finding ways to control the cost of this service is critical for the success of Ohio's economy.

II. DISCUSSION

Q. How does PJM assess the costs of transmission service?

A. The largest portion of transmission service cost is the Network Integration Transmission Service ("NITS"), which is assessed through a demand charge. The charge is based on the hourly load of the customer during the annual zonal coincidental peak ("1 CP"). By basing it on the zonal peak, PJM can assure the reliability of the transmission grid during times of high use.

Q. Does AEP Ohio use the same billing determinant to pass-through transmission costs to its customers?

A. No.

Q. How does AEP Ohio collect transmission costs from its customers?

A. AEP Ohio uses the non-bypassable Basic BTCR. A majority of demand metered customers will see their demand charge billing determinate change monthly based on their peak the previous month rather than the 1 CP. There is also a monthly usage component. Residential customers are billed based on their monthly usage.

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[1] Compare PJM, "Annual Transmission Revenue Requirements and Rates (2018)," available at https://www.pjm.com/-/media/markets-ops/settlements/network-integration-trans-service-2018.ashx (JH-Exhibit 1) with PJM, "Annual Transmission Revenue Requirements and Rates (2021)," available at https://www.pjm.com/-/media/markets-ops/settlements/network-integration-trans-service-mar-2021.ashx (JH-Exhibit 4).

Q. What is the BTCR Pilot Program?

A. The BTCR Pilot Program permits participating customers to have their transmission costs allocated based on the customer's demand during the single zonal transmission peak rather than a customer class allocation. The 1 CP will be updated each January based on the customer's contribution to the single zonal transmission peak during the previous year. This mirrors the methodology by PJM.

Q. Does the Stipulation submitted in these proceedings address the BTCR Pilot Program?

A. Yes, the Stipulation continues the BTCR Pilot Program and expands the eligibility for members of certain customer groups that sign the Stipulation.[2]

Q. Do customers have any alternative to the BTCR for transmission service?

A. No. Aside from the exclusive Pilot, retail customers are functionally barred by AEP-Ohio from securing transmission services directly from PJM or indirectly through a competitive retail electric service ("CRES") provider.

Q. Do AEP Ohio customers excluded from the Pilot have the ability to proactively manage their usage to reduce transmission costs?

A. A customer's monthly peak demand will have little, if any, relationship to the single zonal coincident peak within the PJM zone and thereby eliminate the demand

[2] *See In the Matter of the Application of Ohio Power Company for an Increase in Electric Distribution Rates,* Case Nos. 20-585-EL-AIR, et al., Joint Stipulation and Recommendation (Mar. 12, 2021) ("Stipulation") at 17-18.

response opportunity that is signaled to customers obtaining transmission service, directly or indirectly, through PJM.

A true pass through of transmission service sends a very transparent pricing signal to each customer to reduce demand during peak load conditions and thereby reduce the need for increased transmission investment.

Q. Why has the ability of a customer to have control over transmission costs become increasingly important?

A. Transmission costs have increased every year for at least the last four years in the AEP transmission zone.

Annual Transmission Revenue Requirements and Rates for AEP[3]		
	Annual Transmission Revenue Requirement	Network Integration Transmission Service Rate ($/MW-Year)
2018	$1,295,660,732	$59,818
2019	$1,499,032,942 (+15.7%)	$65,923 (+10.2%)
2020	$1,806,870,058 (+20.5%)	$80,306 (+21.8%)
2021	$2,066,332,706 (+14.4%)	$95,598 (+19.0%)

[3] 2018, JH-Exhibit 1; PJM, "Annual Transmission Revenue Requirements and Rates (2019)," available at https://www.pjm.com/-/media/markets-ops/settlements/network-integration-trans-service-2019.ashx (JH-Exhibit 2); PJM, "Annual Transmission Revenue Requirements and Rates (2020)," available at 2020 - https://www.pjm.com/-/media/markets-ops/settlements/network-integration-trans-service-june-2020.ashx (JH-Exhibit 3); 2021, JH-Exhibit 4.

Similarly, AEP Ohio's BTCR rates have trended upwards:

Historical BTCR Rates[4]			
	Residential	GS-3 Primary	
Effective Date	¢/kWh	$/kW	¢/kWh
April 2021	2.929	$6.72	4.584
April 2020	2.490	$6.12	4.339
April 2019	1.663	$4.51	3.778
June 2018	2.004	$5.32	4.732
April 2018	2.378	$6.02	4.956
Sept. 2017	1.722	$4.84	4.714
Sept. 2016	1.423	$3.83	3.345
Sept. 2015	1.287	$3.44	3.706

Without customers being able to have control over these costs, and therefore the need for more transmission investment, there will continue to be large investments that increase costs for Ohioans.

Q. Based on your review of the Stipulation's treatment of transmission rates, your understanding of the importance of rate design as it affects transmission investment, and the increased burden of transmission rates, do you believe that the treatment of the BTCR pilot in the Stipulation is in the public interest and does not violate any important regulatory principles?

A. No on both counts. Aligning costs and rates is fundamental to effective rate making. In this instance, the failure to move rates toward cost based on the correct

[4] Case No. 21-53-EL-RDR, Revised Tariff (Mar. 4, 2021); Case No. 20-95-EL-RDR, Tariff (Mar. 27, 2020); Case No. 19-133-EL-RDR, Revised Tariff (Mar. 28, 2019); Case No. 18-96-EL-RDR, Revised Tariff (Mar. 28, 2021), Revised Tariff (May 29, 2018); Case No. 17-1462-EL-RDR, Revised Tariff (Aug. 23, 2017); Case No. 16-1409-EL-RDR, Tariff (Jan. 20, 2017); Case No. 15-1105-EL-RDR, Application (June 15, 2015).

cost causation principles will have a tendency to require increased investment since the price signals that would encourage conservation are undermined. Additionally, the Stipulation fails to take advantage of available tools to move transmission rates toward cost. Thus, the BTCR provisions of the Stipulation are not in the public interest and violate important regulatory principles.

III. RECOMMENDATIONS

Q. What do you propose?

A. In AEP Ohio's most recent Electric Security Plan proceeding, the Commission approved a Stipulation that stated, among other things, the subject of transmission rates will be reevaluated at AEP Ohio's next distribution rate case "utilizing the information and experience gained during the pilot program."[5]

Based on our experience with IGS customers participating the Pilot, initial steps could include eliminating the participation allotments and MW caps on the BTCR Pilot.[6] Without these modifications, interested customers are unfairly excluded from participation because of their Supplier's opposition to the Stipulation.

Additionally, AEP Ohio should transition to a rate design for the BTCR that is based upon a customer's individual Service Delivery Identifier ("SDI") transmission tag (also referred to as NSPL tag). According to AEP Ohio's "Ohio Choice Market Settlement Polices & Procedures," individual NSPL tags are calculated annually for each SDI in the AEP Ohio territory based upon the PJM published date and

[5] *In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Case* Nos. 16-1852-EL-SSO, et al., Joint Stipulation and Recommendation (Aug. 25, 2017) at 28.
[6] Stipulation at 17.

time of the PJM AEP Zonal maximum demand from the previous November 1 to October 31 year.[7] For SDIs which are interval metered, the actual hourly usage at that hour provides the at-the-meter NSPL tag component. For non-interval metered customers, their at-the-meter NSPL component is calculated using load profile customer class load shapes. This would bring better transparency and better transmission rate design by aligning costs with how they are incurred from PJM.

Q. Would failing to allocate transmission costs based upon a customer's NSPL value be inconsistent with Commission precedent?

A. Yes. The Commission has consistently promoted the use of a customer's actual interval data for settlement purposes and aligning cost-causation between wholesale costs and billing mechanisms to retail customers. For example, in the 2014 *Retail Market COI Order*, the Commission adopted Staff's recommendation for the implementation of individual network service peak load formulas.[8] Additionally, throughout the Commission's grid modernization proceedings, the Commission has continued to express its desire to utilize the implementation of grid modernization technologies to remove barriers between the wholesale and retail market.[9]

Most recently in 2020, the Commission spoke directly to this issue and further emphasized its importance:

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[7] AEP Ohio, "Ohio Choice Market Settlement Polices & Procedures," May 2018, Page 10, available at https://www.aepohio.com/lib/docs/company/about/choice/OH/2018/AEPOhioSettlementPolicies-Rev-5-2018.pdf (JH-Exhibit 5).

[8] *In the Matter of the Commission's Investigation of Ohio's Retail Electric Service Market,* Case No. 12-3151-EL-COI, Finding and Order (Mar. 26, 2014) at 36.

[9] *See e.g.* PowerForward Roadmap at 31.

> "It continues to be important that EDUs focus on providing consumers and CRES providers with direct and comparable access to meter data and enabling billing mechanisms that properly reflect cost-causation for things like generation capacity and network integration transmission service."[10]

My recommendations advance this desired outcome, and therefore should be adopted by the Commission.

Q. Does this conclude your testimony?

A. Yes, it does. However, I reserve the right to further supplement my testimony.

[10] *In the Matter of the Application of Duke Energy Ohio, Inc., for Approval of its 2021 Energy Efficiency and Demand Side Management Portfolio Programs and Cost Recovery Mechanism*, Case Nos. 20-1013-EL-POR, et al., Entry (June 17, 2020) at ¶ 9.

Annual Transmission Revenue Requirements and Rates		
Transmission Owner (Transmission Zone)	**Annual Transmission Revenue Requirement**	**Network Integration Transmission Service Rate ($/MW-Year)**
AE (AECO)	$136,237,027	$50,960
AEP (AEP) *	$1,295,660,732	$59,818.14
AP (APS)	$128,000,000	$17,895
ATSI (ATSI)	$659,094,666	$54,689.39
BC (BGE)	$216,851,881	$32,851
ComEd, Rochelle (CE)	$728,237,019	$34,392.02
Dayton (DAY)	$40,100,000	$13,295.76
Duke (DEOK)	$106,450,109	$20,055
Duquesne (DLCO)	$133,905,125	$47,891.68
Dominion (DOM)	$1,031,382,000	$52,457.21
DPL, ODEC (DPL)	$135,927,090	$32,938
East Kentucky Power Cooperative (EKPC)	$75,851,112	$26,424
MAIT (METED, PENELEC)	$150,858,703	$26,069.39
JCPL	$135,000,000	$23,597.27
PE (PECO)	$163,823,746	$19,587
PPL, AECoop, UGI (PPL)	$433,895,406	$61,792
PEPCO, SMECO (PEPCO)	$183,228,908	$27,867.40
PS (PSEG)	$1,248,819,352	$130,535.22
Rockland (RECO)	$17,724,263	$44,799
TrAILCo	$272,626,368.81	n/a

*Effective January 1, 2018

Annual Transmission Revenue Requirements and Rates		
Transmission Owner (Transmission Zone)	**Annual Transmission Revenue Requirement**	**Network Integration Transmission Service Rate ($/MW-Year)**
AE (AECO)	$136,237,027	$50,960
AEP (AEP)	$1,295,660,732	$59,818.14
AP (APS)	$128,000,000	$17,895
ATSI (ATSI)	$659,094,666	$54,689.39
BC (BGE)	$216,851,881	$32,851
ComEd, Rochelle (CE)	$728,237,019	$34,392.02
Dayton (DAY)	$40,100,000	$13,295.76
Duke (DEOK)	$106,450,109	$20,055
Duquesne (DLCO)	$133,905,125	$47,891.68
Dominion (DOM)	$1,031,382,000	$52,457.21
DPL, ODEC (DPL)	$135,927,090	$32,938
East Kentucky Power Cooperative (EKPC)	$75,851,112	$26,424
MAIT (METED, PENELEC)	$150,858,703	$26,069.39
JCPL	$135,000,000	$23,597.27
PE (PECO)	$163,823,746	$19,587
PPL, AECoop, UGI (PPL)	$433,895,406	$61,792
PEPCO, SMECO (PEPCO) *	$183,181,005	$28,031.21
PS (PSEG)	$1,248,819,352	$130,535.22
Rockland (RECO)	$17,724,263	$44,799
TrAILCo	$272,626,368.81	n/a

*Effective May 1, 2018

Annual Transmission Revenue Requirements and Rates		
Transmission Owner (Transmission Zone)	**Annual Transmission Revenue Requirement**	**Network Integration Transmission Service Rate ($/MW-Year)**
AE (AECO)	$136,632,319	$53,775
AEP (AEP)	$1,295,660,732	$59,818.14
AP (APS)	$128,000,000	$17,895
ATSI (ATSI)	$659,094,666	$54,689.39
BC (BGE)	$230,595,535	$35,762
ComEd, Rochelle (CE)	$702,431,433	$34,515.60
Dayton (DAY)	$40,100,000	$13,295.76
Duke (DEOK)	$121,250,903	$24,077
Duquesne (DLCO)	$139,341,808	$51,954.44
Dominion (DOM)	$1,031,382,000	$52,457.21
DPL, ODEC (DPL)	$163,224,128	$42,812
East Kentucky Power Cooperative (EKPC)	$83,267,903	$24,441
MAIT (METED, PENELEC)	$150,858,703	$26,069.39
JCPL	$135,000,000	$23,597.27
PE (PECO)	$155,439,100	$19,093
PPL, AECoop, UGI (PPL)	$435,349,329	$58,865
PEPCO, SMECO (PEPCO)	$190,876,083	$31,304.21
PS (PSEG)	$1,248,819,352	$130,535.22
Rockland (RECO)	$17,724,263	$44,799
TrAILCo	$226,652,117.80	n/a

Effective June 1, 2018

Annual Transmission Revenue Requirements and Rates		
Transmission Owner (Transmission Zone)	**Annual Transmission Revenue Requirement**	**Network Integration Transmission Service Rate ($/MW-Year)**
AE (AECO)	$136,632,319	$53,775
AEP (AEP)	$1,295,660,732	$59,818.14
AP (APS)	$128,000,000	$17,895
ATSI (ATSI)	$659,094,666	$54,689.39
BC (BGE)	$230,595,535	$35,762
ComEd, Rochelle (CE)	$702,431,433	$34,515.60
Dayton (DAY)	$40,100,000	$13,295.76
Duke (DEOK)	$121,250,903	$24,077
Duquesne (DLCO)	$139,341,808	$51,954.44
Dominion (DOM)	$1,031,382,000	$52,457.21
DPL, ODEC (DPL)	$163,224,128	$42,812
East Kentucky Power Cooperative (EKPC)	$83,267,903	$24,441
MAIT (METED, PENELEC)	$145,431,639	$25,131.56
JCPL	$135,000,000	$23,597.27
PE (PECO)	$155,439,100	$19,093
PPL, AECoop, UGI (PPL)	$435,349,329	$58,865
PEPCO, SMECO (PEPCO)	$190,876,083	$31,304.21
PS (PSEG)	$1,248,819,352	$130,535.22
Rockland (RECO)	$17,724,263	$44,799
TrAILCo	$226,652,117.80	n/a

Effective July 1, 2018

Annual Transmission Revenue Requirements and Rates		
Transmission Owner (Transmission Zone)	**Annual Transmission Revenue Requirement**	**Network Integration Transmission Service Rate ($/MW-Year)**
AE (AECO)	$136,632,319	$53,775
AEP (AEP)	$1,295,660,732	$59,818.14
AP (APS)	$128,000,000	$17,895
ATSI (ATSI)	$659,094,666	$54,689.39
BC (BGE)	$230,595,535	$35,762
ComEd, Rochelle (CE)	$702,431,433	$34,515.60
Dayton (DAY) ***	$37,885,386	$12,561.48
Duke (DEOK)	$121,250,903	$24,077
Duquesne (DLCO)	$139,341,808	$51,954.44
Dominion (DOM) *	$934,439,000	$47,526.56
DPL, ODEC (DPL)	$163,224,128	$42,812
East Kentucky Power Cooperative (EKPC)	$83,267,903	$24,441
MAIT (METED, PENELEC)	$145,431,639	$25,131.56
JCPL	$135,000,000	$23,597.27
OVEC **	$11,256,927	$5,163.73
PE (PECO)	$155,439,100	$19,093
PPL, AECoop, UGI (PPL)	$435,349,329	$58,865
PEPCO, SMECO (PEPCO)	$190,876,083	$31,304.21
PS (PSEG)	$1,248,819,352	$130,535.22
Rockland (RECO) ***	$16,833,707	$42,548
TrAILCo	$226,652,117.80	n/a

* Retroactive to January 1, 2018 to reflect 2017 Tax Cuts and Jobs Act
** Effective December 1, 2018
*** Effective March 21, 2018

Annual Transmission Revenue Requirements and Rates		
Transmission Owner (Transmission Zone)	**Annual Transmission Revenue Requirement**	**Network Integration Transmission Service Rate ($/MW-Year)**
AE (AECO)	$136,632,319	$53,775
AEP (AEP)	$1,499,032,942	$65,923.43
AP (APS)	$128,000,000	$17,895
ATSI (ATSI, AMPT)	$707,792,792	$55,185.23
BC (BGE)	$230,595,535	$35,762
ComEd, Rochelle (CE)	$702,431,433	$34,515.60
Dayton (DAY)	$37,885,386	$12,561.48
Duke (DEOK)	$121,250,903	$24,077
Duquesne (DLCO)	$139,341,808	$51,954.44
Dominion (DOM)	$1,007,914,000	$47,471.44
Dominion Underground (DOM)	$34,420,176	$1,728.93
DPL, ODEC (DPL)	$163,224,128	$42,812
East Kentucky Power Cooperative (EKPC)	$83,267,903	$24,441
MAIT (METED, PENELEC)	$173,323,326	$28,796.22
JCPL	$135,000,000	$22,588.47
OVEC	$11,256,927	$5,163.73
PE (PECO)	$155,439,100	$19,093
PPL, AECoop, UGI (PPL)	$435,349,329	$58,865
PEPCO, SMECO (PEPCO)	$190,876,083	$31,166.72
PS (PSEG)	$1,194,757,707	$119,735.80
Rockland (RECO)	$16,833,707	$42,548
TrAILCo	$226,652,117.80	n/a

Effective January 1, 2019

Annual Transmission Revenue Requirements and Rates		
Transmission Owner (Transmission Zone)	**Annual Transmission Revenue Requirement**	**Network Integration Transmission Service Rate ($/MW-Year)**
AE (AECO)	$145,555,921	$56,171
AEP (AEP)	$1,499,032,942	$65,923.43
AP (APS)	$128,000,000	$17,895
ATSI (ATSI, AMPT)	$707,792,792	$55,185.23
BC (BGE)	$197,870,237	$29,860
ComEd, Rochelle (CE)	$707,009,311	$33,116.34
Dayton (DAY)	$37,885,386	$12,561.48
Duke (DEOK)	$134,316,531	$25,840
Duquesne (DLCO)	$137,514,380	$49,200.14
Dominion (DOM)	$1,007,914,000	$47,471.44
Dominion Underground (DOM)	$34,420,176	$1,728.93
DPL, ODEC (DPL)	$179,314,789	$44,803
East Kentucky Power Cooperative (EKPC)	$92,224,675	$30,251
MAIT (METED, PENELEC)	$173,323,326	$28,796.22
JCPL	$135,000,000	$22,588.47
OVEC	$11,256,927	$5,163.73
PE (PECO)	$162,880,139	$18,922
PPL, AECoop, UGI (PPL)	$522,139,243	$68,031
PEPCO, SMECO (PEPCO)	$217,200,604	$33,873.72
PS (PSEG)	$1,194,757,707	$119,735.80
Rockland (RECO)	$16,833,707	$42,548
TrAILCo	$251,369,162.88	n/a

Effective June 1, 2019

Annual Transmission Revenue Requirements and Rates		
Transmission Owner (Transmission Zone)	**Annual Transmission Revenue Requirement**	**Network Integration Transmission Service Rate ($/MW-Year)**
AE (AECO)	$125,075,638	$45,693
AEP (AEP)	$1,806,870,058	$80,306.41
AP (APS)	$128,000,000	$17,895
ATSI (ATSI, AMPT)	$722,642,824	$57,482.35
BC (BGE)	$209,965,346.90	$31,311
ComEd (CE)	$718,149,481.11	$34,280.85
Dayton (DAY)	$47,109,460**	$14,456.96**
Duke (DEOK)	$159,235,526	$32,143
Duquesne (DLCO)	$141,278,388.40	$53,072.27
Dominion (DOM)	$1,094,470,000	$54,914.33
Dominion Underground (DOM)	$31,431,917	$1,657.90
DPL, ODEC (DPL)	$135,227,058	$33,000
East Kentucky Power Cooperative (EKPC)	$67,129,699	$23,763
MAIT (METED, PENELEC)	$222,281,382	$37,083.18
JCPL	$147,518,299*	$24,354.61*
OVEC	$11,256,927	$5,163.73
PE (PECO)	$135,037,645	$16,022
PPL, AECoop, UGI (PPL)	$596,505,385	$75,204
PEPCO, SMECO (PEPCO)	$173,482,676	$28,022.85
PS (PSEG)	$1,526,297,808	$156,503.24
Rockland (RECO)	$16,833,707	$42,548
TrAILCo	$253,750,977.57	N/A

**JCPL Annual Revenue Requirement accepted by FERC, effective 1/1/20, but subject to refund based on settlement hearing*

***Dayton Annual Revenue Requirement accepted by FERC, effective 5/3/20, but subject to refund based on settlement hearing*

Effective June 1, 2020 (Revised - PECO Zone updated)

JH-Exhibit 4

Annual Transmission Revenue Requirements and Rates		
Transmission Owner (Transmission Zone)	**Annual Transmission Revenue Requirement**	**Network Integration Transmission Service Rate ($/MW-Year)**
AE (AECO)	$125,075,638	$45,693
AEP, AMPT (AEP)	$2,066,332,706	$95,597.51
South FirstEnergy (APS)	$120,322,073^	$13,930.04^
ATSI, AMPT (ATSI)	$831,978,941	$66,744.13
BC (BGE)	$209,965,346.90	$31,311
ComEd (CE)	$718,149,481.11	$34,280.85
Dayton (DAY)	$63,446,423**	$19,175.06**
Duke (DEOK)	$159,235,526	$32,143
Duquesne (DLCO)	$141,278,388.40	$53,072.27
Dominion (DOM)	$1,238,329,019	$61,729.41
Dominion Underground (DOM)	$14,410,946	$744.73
DPL, ODEC (DPL)	$135,227,058	$33,000
East Kentucky Power Cooperative (EKPC)	$67,129,699	$23,763
MAIT (METED, PENELEC)	$295,135,116	$50,128.46
JCPL	$161,318,343*	$27,327.27*
OVEC	$11,256,927	$5,163.73
PE (PECO)	$135,037,645	$16,022
PPL, AECoop, UGI (PPL)	$596,505,385	$75,204
PEPCO, SMECO (PEPCO)	$173,482,676	$28,165.56
PS (PSEG)	$1,645,668,896	$172,189.67
Rockland (RECO)	$16,833,707	$42,548
TrAILCo	$253,750,977.57	N/A
Silver Run	$23,622,243	N/A
Transource WV	$11,055,915	N/A

**JCPL Annual Revenue Requirement accepted by FERC, effective 1/1/20, but subject to refund based on settlement hearing; UPDATE: Effective 3/1/2021, JCPL Annual Revenue Requirement implemented on an interim basis for rate year 2021 pursuant to settlement proceedings in Docket No. ER20-227*

***Dayton Annual Revenue Requirement accepted by FERC, effective 5/3/20, but subject to refund based on settlement hearing*

^South FirstEnergy Annual Revenue Requirement accepted by FERC, effective 1/1/21, but subject to refund based on settlement hearing

Effective March 1, 2021

AEP OHIO®
A unit of American Electric Power

Ohio Choice
Market Settlement
Policies & Procedures

Revised 5/2018

Contents

AEP Ohio Glossary of Settlement Acronyms

Source of acronyms are noted in parenthesis. Those not noted are considered standard industry terms.

AEPCH	AEP Clearing House (AEP)
BTCR	Basic Transmission Cost Recovery Rider (AEP)
CP	Coincident Peak
CRES	Competitive Retail Electric Supplier (Ohio Market)
CSP	Curtailment Service Provider
DOPLSR	Daily Obligation Peak Load Scaling Factor (PJM)
DR	Demand Response
DZF	Daily Zonal Scaling Factor (PJM)
EDC	Electric Distribution Company
EDI	Electronic Data Interchange
EDU	Electric Distribution Utility
FSL	Firm Service Load
FPR	Forecast Pool Requirement (PJM)
FZSF	Final Zonal Scaling Factor (PJM)
LRA	Load Research and Analysis
LMP	Locational Marginal Price (PJM)
LASOR	Load Accounting System of Record (AEP)
LDC	Local Distribution Company
LERS	Load Estimation and Reallocation System (AEP)
LSE	Load Service Entity (PJM)
MACSS	Marketing Accounting and Customer Services System (AEP)
MV90	Multi-Vendor Version 90 (Interval meter interrogation software by Itron)
NEMS	Net Energy Metering Service
NITS	Network Integration Transmission Services (PJM)
NSPL	Network Service Peak Load (PJM)

PIPP	**Percentage of Income Payment Plan (Ohio Market)**
PLC	Peak Load Contribution (PJM)
RPM	Reliability Pricing Model (PJM)
RTO	Regional Transmission Organization
SAS	Statistical Analysis System (business analytics software tool)
SDI	Service Delivery Identifier (AEP)
SOX	Sarbanes-Oxley
SSO	Standard Service Offer (default rate) (Ohio Market)
UFE	Unaccounted For Energy
WNF	Weather Normalization Factor (PJM)

Section Rev. 11/2016

AEP Ohio CRES Transmission Obligation Calculation Process

Overview

Individual Service Delivery Identifier (SDI) transmission tags (also referred to as NSPL tags) are calculated annually for each SDI in the AEP Ohio territory based upon the PJM published date and time of the PJM AEP Zonal maximum demand from the previous November 1 to October 31 year. For SDIs which are interval metered, the actual hourly usage at that hour provides the at-the-meter NSPL tag component. For non-interval metered customers, their at-the-meter NSPL component is calculated using load profile customer class load shapes.

Load Profiling Cumulative Metered SDIs

For SDIs which are not interval metered only total usage and maximum demand over the billing cycle may be known, so the at-the-meter usage at the NSPL hour must be estimated. This estimation is accomplished by performing a load profiling process. In the load profiling process, each SDI is assigned a load_profile_id defining the load characteristic group to which it belongs. Each load_ profile_id has an associated hourly load profile, computed from actual interval metered usage of randomly selected sample customers within each profile_id group. The NSPL tag calculation algorithm then utilizes the individual SDI monthly billing cycle usage spanning the NSPL date/time to scale the hourly profile usage over that time to the appropriate level for the SDI, thus providing a reasonable representation of the hourly usage of each SDI. Once that is accomplished for all hours throughout the billing cycle periods spanning the NSPL date/time, the resulting hourly usage estimates at the NSPL time determines the at-the-meter NSPL component.

Net Metered Customers

Customers on a net-metered (NEMS) tariff receive benefit from their generation in the NSPL tag calculation process. For NEMS customers with hourly interval metering, any generation they may have had at the time of the peak hour offsets their load (up to zero) for the hour. For non-hourly metered cumulative usage customers, their generation for each month is deducted from their usage, which decreases their cumulative usage at-the-meter amounts for the month. The reduced cumulative usage then follows the Load Profile process above.

Loss Adjustment to At-The-Meter Values

All at-the-meter values are then loss adjusted to the generation level based upon loss factors listed in the Company Tariffs. A check is performed to ensure that the sum of all loss adjusted SDI tags compares closely to the AEP Ohio system load at the NSPL peak hour providing evidence that the tags in total reasonably represent the system total load.

Completion and Availability to Market Participants

The individual SDI tags are then stored for use in the daily CRES NSPL obligation calculations, made available to CRES Providers via the Business Partner Portal and customer enrollment list, and sent via EDI transactions to the customer's assigned CRES. NSPL tags become effective January 1st of every year and the Business Partner Portal will show effective dates where multiple year tags are available. Tags remain unchanged until the next calendar year calculation is performed, even though some SDIs may experience significant load growth or load reduction in the period between the period upon which the tag is based and the days to which it is applied.

New Premise Installs During the Year

There are normally a limited number of new SDIs that were either not active during the NSPL peak hour, or are installed during the year, and which therefore had no interval usage or monthly billing usage for that period. Those SDIs are assigned a default tag, based upon the profile group average value. In the rare instance when new facilities are built for an existing premise resulting in an additional SDI, but with no expected net load change at the combined facilities, the new SDI will receive a tag equivalent to the estimated portion of load delivered through the new service point, rather than a class average. The tag for the original SDI will be accordingly adjusted downward so that the combined transmission tags will match the original load. New SDIs with behind-the-meter generation or on a NEMS tariff will be assigned a default NSPL value.

CRES NSPL Aggregation

CRES daily NSPL obligations are then calculated from the summation of the tags for each of the SDIs for which the CRES has responsibility on the day, with a calibration factor applied by PJM to ensure that the total AEP Ohio load is fully allocated among the AEP Ohio SDIs.

Section continued on next page

<u>Example</u> of Calculation and Aggregation

		NSPL Calculation and Settlement Steps	Value
Calculate Variables	pjm	AEP periodically performs system loss studies, updating transmission and distribution losses for applicable tariffs	Secondary - 1.0932 Primary - 1.0552 Sub-Tran - 1.0341
	AEP	Each year PJM Identifies the Coincident (1CP) Peak	
Calculate Yearly Customer Tags		AEP identifies the 1CP at-the-meter hour load for 'XYZ' customer (customers with-out hourly metering are profiled using sample customer hourly data)	100 MW
		AEP applies transmission and distribution losses to the metered 1CP value to arrive at 'XYZ' Customer's NSPL tag. (e.g. a Sub-Tran customer value of 1.0341)	103.41 MW
		AEP publishes NSPL values via EDI, the customer enrollment list, and the Business Partner Portal	103.41 MW
Daily Settlement		'ABC' CRES' daily customer NSPL tags are aggregated	500 MW
		'ABC' CRES' daily NSPL obligation is submitted to PJM	500 MW
	pjm	PJM applies Daily Zonal Scaling Factor	500.1 MW*
		PJM uses the aggregated NSPL values to calculate appropriate Transmission Charges and Credits for the CRES	$750k*
		PJM posts the CRES Charges and Credits to the CRES' PJM sub-account.	$750k*
		PJM performs a bill-line item transfer for select transmission charges and credits which AEP Ohio is responsible for, transferring to AEP Ohio's PJM sub-account.	$0*
Wires Charge	AEP	AEP Ohio bills customers for transmission under the Basic Transmission Cost Recovery Rider (BTCR).	$750k*

**** Values are for demonstration purposes only***

CERTIFICATE OF SERVICE

I hereby certify that a true copy of the foregoing *Direct Testimony of Joseph Haugen on Behalf of Interstate Gas Supply, Inc.* was filed electronically through the Docketing Information System of the Public Utilities Commission of Ohio on April 20, 2021. The Commission's e-filing system will electronically serve notice of the filing of this document upon the following parties listed below.

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