COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A GENERAL ADJUSTMENT OF ITS RATES FOR ELECTRIC SERVICE; (2) APPROVAL OF TARIFFS AND RIDERS; (3) APPROVAL OF ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; (4) APPROVAL OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY; AND (5) ALL OTHER REQUIRED APPROVALS AND RELIEF	))))))))))	CASE NO. 2020-00174

NOTICE OF FILING

Notice is given to all parties that the following materials have been filed into the record of this proceeding:

- The digital video recording of the evidentiary hearing conducted on November 17, 2020 in this proceeding;

- Certification of the accuracy and correctness of the digital video recording;

- All exhibits introduced at the evidentiary hearing conducted on November 17, 2020 in this proceeding;

- A written log listing, inter alia, the date and time of where each witness' testimony begins and ends on the digital video recording of the evidentiary hearing conducted on November 17, 2020.

A copy of this Notice, the certification of the digital video record, and hearing log have been served upon all persons listed at the end of this Notice. Parties desiring to view the digital video recording of the hearing may do so at https://youtu.be/zC5eJ6SSULQ.

Parties wishing an annotated digital video recording may submit a written request by electronic mail to pscfilings@ky.gov. A minimal fee will be assessed for a copy of this recording.

Done at Frankfort, Kentucky, this 5th day of March 2021.

Linda C. Bridwell
Executive Director
Public Service Commission of Kentucky

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CERTIFICATION

I, Candace H. Sacre, hereby certify that:

1. The attached DVD contains a digital recording of the Formal Hearing conducted in the above-styled proceeding on November 17, 2020. The Formal Hearing Log, Exhibit List, and Exhibits are included with the recording on November 17, 2020;

2. I am responsible for the preparation of the digital recording;

3. The digital recording accurately and correctly depicts the Formal Hearing of November 17, 2020; and

4. The Formal Hearing Log attached to this Certificate accurately and correctly states the events that occurred at the Formal Hearing of November 17, 2020, and the time at which each occurred.

Signed this 21st day of December, 2020.

Candace H. Sacre
Candace H. Sacre
Administrative Specialist III

Stephanie Schweighardt
Stephanie Schweighardt
Notary Public State at Large
Commission Expires: January 14, 2023
ID#: 614400

Date:	Type:	Location:	Department:
11/17/2020	Public Hearing\Public Comments	Hearing Room 1	Hearing Room 1 (HR 1)

Witness: D. Brett Mattison; Matthew J. Satterwhite
Judge: Kent Chandler; Talina Mathews; Michael Schmitt
Clerk: Candace Sacre

Event Time	Log Event	
9:11:48 AM	Session Started	
9:11:59 AM	Camera Lock Deactivated	
9:12:25 AM	Session Paused	
9:12:46 AM	Session Resumed	
9:13:29 AM	Chairman Schmitt	
	Note: Sacre, Candace	On the record in Case No. 2020-00174, Application of Kentucky Power Company for a General Adjustment of Its Rates for Electric Service, Approval of Tariffs and Riders, Approval of Accounting Practices to Establish Regulatory Assets and Liabilities, Approval of Certificate of Public Convenience and Necessity, and All Other Required Approvals and Relief.
9:14:00 AM	Chairman Schmitt	
	Note: Sacre, Candace	Michael Schmitt, Chairman, presiding today.
9:14:07 AM	Chairman Schmitt	
	Note: Sacre, Candace	Introduction of Vice Chaiman Kent Chandler and Commissioner Talina Mathews, present by videoconferencing.
9:14:15 AM	Chairman Schmitt	
	Note: Sacre, Candace	Videoconferencing and COVID instructions and recommendations.
9:16:26 AM	Chairman Schmitt	
	Note: Sacre, Candace	Hearing today taking evidence on Kentucky Power's request for general rate adjustment, approval of tariffs/riders, certificate of public convenience and necessity, and establishing regulatory assets and liabilities.
9:16:42 AM	Chairman Schmitt	
	Note: Sacre, Candace	Appearance of counsel, also identify witnesses.
9:16:57 AM	Chairman Schmitt	
	Note: Sacre, Candace	Kentucky Power?
9:17:10 AM	Atty Overstreet Kentucky Power	
	Note: Sacre, Candace	Mark Overstreet, Stites and Harbison, 421 West Main St, Frankfort KY, also counsel Katie M. Glass, Stites and Harbison, and Christen M. Blend, American Electric Power, pro hoc vice; Tanner F. Wolffram, AEP, pro hoc vice; and Hector Garcia-Santana, pro hoc vice. Witnesses Brett Mattison, Matt Satterwhite, Kelly Pierce, Kamran Ali, Cynthia Wiseman, Timothy Kerns, Lerah Scott, Heather Whitney, Allyson Keaton, Kim Kaiser, Scott Bishop, Dana Horton, Jason Stegall, Jaclyn Cost, Franz Messner, Adrien McKenzie, Everett Phillips, Stephen Blankenship, Brian West, Alex Vaughan, and Andrew Carlin, if called.

9:18:03 AM	Atty Mark Overstreet Kentucky Power	
	Note: Sacre, Candace	Witnesses are Brett Mattison, Matthew Satterwhite, Kelly Pearce, Kamran Ali, Cynthia Wiseman, Timothy Kerns, Lerah Scott, Heather Whitney, Allyson Keaton, Kim Kaiser, Scott Bishop, Dana Horton, Jason Stegall (quarantine), Jaclyn Cost, Franz Messner, Adrien McKenzie (remotely), Everett Phillips, Steve Blankenship, Brian West, Alex Vaughan, and Andrew Collin, if called.
9:19:07 AM	Chairman Schmitt	
	Note: Sacre, Candace	Attorney General?
9:19:14 AM	Asst Atty General West	
	Note: Sacre, Candace	Mike West, also Larry Cook and John Horne. Witnesses Lane Kollen, Rick Baudino, and Steve Baron.
9:19:39 AM	Chairman Schmitt	
	Note: Sacre, Candace	Kentucky Industrial Utility Customers?
9:19:45 AM	Atty Cohn KIUC	
	Note: Sacre, Candace	Michael Kurtz and Jody Kyler Cohn, Boehm Kurtz and Lowery, 36 East Seventh St, Cincinnati OH 45202. Sharing witnesses with AG.
9:20:03 AM	Chairman Schmitt	
	Note: Sacre, Candace	Walmart?
9:20:06 AM	Atty Grundman Walmart	
	Note: Sacre, Candace	Carrie Harris Grundman, pro hoc vice, joined by Don Parker, Spilman Thomas and Battle, my address is 110 Oakwood Dr Ste 500, Winston-Salem NC 27103. Witness Lisa V. Perry
9:20:29 AM	Chairman Schmitt	
	Note: Sacre, Candace	Kentucky Solar Industries Association?
9:20:33 AM	Atty Spenard KYSEIA	
	Note: Sacre, Candace	David Spenard and Randy Strobo, Strobo Barkley, 239 South Fifth St Ste 917, Louisville KY 40202. Witnesses James Van Nostrand, Benjamin Inskeep, and Justin Barnes.
9:20:57 AM	Chairman Schmitt	
	Note: Sacre, Candace	Mountain Association for Community Economic Development, Kentuckians for the Commonwealth, and Kentucky Solar Energy Society, collectively Joint Intervenors?
9:21:09 AM	Atty Fitzgerald Joint Intervenors	
	Note: Sacre, Candace	Tom Fitzgerald, Kentucky Resources Council, representing Joint Intervenors. Witnesses Andrew McDonald, Joshua Bills, and James Owen.
9:21:39 AM	Chairman Schmitt	
	Note: Sacre, Candace	Sierra Club?
9:21:40 AM	Atty Childers Sierra Club	
	Note: Sacre, Candace	Joe Childers, Childers and Baxter, 201 West Short St Ste 300, Lexington KY, with me Matthew Miller, pro hoc vice. No witnesses.
9:21:57 AM	Chairman Schmitt	
	Note: Sacre, Candace	SWVA Kentucky LLC?
9:22:00 AM	Atty Frye SWVA Kentucky	
	Note: Sacre, Candace	Michael Frye, Jenkins Fenstermaker, PLLC, P O Box 2688, Huntington WV 25726. No witnesses.
9:22:16 AM	Chairman Schmitt	
	Note: Sacre, Candace	Staff?
9:22:18 AM	Asst Gen Counsel Vinsel PSC	
	Note: Sacre, Candace	Nancy Vinsel, note Zach Ripy screen share, also note Sierra Club Childers and Bethany Baxter may be trading off.
9:22:44 AM	Atty Childers Sierra Club	
	Note: Sacre, Candace	Apologize.

9:22:48 AM	Chairman Schmitt	
	Note: Sacre, Candace	Fine, Mr. Childers.
9:22:52 AM	Chairman Schmitt	
	Note: Sacre, Candace	Availability of witnesses. (Click on link for further comments.)
9:23:23 AM	Chairman Schmitt	
	Note: Sacre, Candace	Videoconferencing notes. (Click on link for further comments.)
9:24:30 AM	Chairman Schmitt	
	Note: Sacre, Candace	Public notice given, filed in record, correct?
9:24:40 AM	Atty Overstreet Kentucky Power	
	Note: Sacre, Candace	Correct.
9:24:42 AM	Chairman Schmitt	
	Note: Sacre, Candace	No outstanding motions, correct?
9:24:51 AM	Atty Overstreet Kentucky Power	
	Note: Sacre, Candace	My understanding.
9:25:32 AM	Atty Overstreet Kentucky Power	
	Note: Sacre, Candace	AEP COVID recommendation, quarantined witnesses.
9:26:51 AM	Chairman Schmitt	
	Note: Sacre, Candace	Public comments session normally at this time. On Friday and Monday, vidoeconferencing public comments. This morning, open with public comment separate from this proceeding. Waited, no interest in public comments. Public comments section closed.
9:28:20 AM	Chairman Schmitt	
	Note: Sacre, Candace	Anything to bring to Commission attention?
9:28:34 AM	Atty Overstreet Kentucky Power	
	Note: Sacre, Candace	Nothing.
9:28:37 AM	Asst Gen Counsel Vinsel PSC	
	Note: Sacre, Candace	Unless witness, attorney, or Commissioner, video also be muted. (Click on link for further comments.)
9:30:32 AM	Chairman Schmitt	
	Note: Sacre, Candace	Mr. Overstreet, Commission asked/ordered Kentucky Power witnesses, maybe recalled additional testimony, elaborate. Aware?
9:31:02 AM	Atty Overstreet Kentucky Power	
	Note: Sacre, Candace	Yes, aware, witnesses available.
9:31:13 AM	Chairman Schmitt	
	Note: Sacre, Candace	Mr. Overstreet, first witness?
9:31:23 AM	Atty Overstreet Kentucky Power	
	Note: Sacre, Candace	Brett Mattison, Blend will present.
9:31:44 AM	Chairman Schmitt	
	Note: Sacre, Candace	Witness is sworn.
9:31:59 AM	Chairman Schmitt	
	Note: Sacre, Candace	Ms. Blend?
9:32:09 AM	Atty Blend Kentucky Power - witness Mattison	
	Note: Sacre, Candace	Direct Examination. Name and business address?
9:32:20 AM	Atty Blend Kentucky Power - witness Mattison	
	Note: Sacre, Candace	By whom employed, position?
9:32:26 AM	Atty Blend Kentucky Power - witness Mattison	
	Note: Sacre, Candace	Direct testimony?
9:32:31 AM	Atty Blend Kentucky Power - witness Mattison	
	Note: Sacre, Candace	Rebuttal testimony?
9:32:34 AM	Atty Blend Kentucky Power - witness Mattison	
	Note: Sacre, Candace	Data Responses?
9:32:36 AM	Atty Blend Kentucky Power - witness Mattison	
	Note: Sacre, Candace	Changes, corrections?

9:32:41 AM	Atty Blend Kentucky Power - witness Mattison	
	Note: Sacre, Candace	Asked same questions, answers same?
9:32:46 AM	Atty Blend Kentucky Power	
	Note: Sacre, Candace	Available for cross.
9:32:50 AM	Chairman Schmitt	
	Note: Sacre, Candace	Ms. Vinsel?
9:32:55 AM	Asst Gen Counsel Vinsel PSC - witness Mattison	
	Note: Sacre, Candace	Cross Examination. This case, focus customer relationship, experience. Last rate case, customer growth. Explain shift in thought?
9:34:46 AM	Asst Gen Counsel Vinsel PSC - witness Mattison	
	Note: Sacre, Candace	COSS studies this case, last two rate cases, percentage total operating expenses residential 44 percent; today, over 50 percent, explain increase?
9:36:47 AM	Asst Gen Counsel Vinsel PSC - witness Mattison	
	Note: Sacre, Candace	Vacant positions, reduction contractors. Type of jobs contractors doing?
9:37:24 AM	Asst Gen Counsel Vinsel PSC - witness Mattison	
	Note: Sacre, Candace	COVID impacted vegetation management plan?
9:38:25 AM	Asst Gen Counsel Vinsel PSC - witness Mattison	
	Note: Sacre, Candace	Cost drivers, significant lost revenue lost load, fair statement?
9:38:59 AM	Asst Gen Counsel Vinsel PSC - witness Mattison	
	Note: Sacre, Candace	Lost load revenue $19.5 million?
9:39:19 AM	Asst Gen Counsel Vinsel PSC - witness Mattison	
	Note: Sacre, Candace	Three fourths due to lost industrial load?
9:39:31 AM	Asst Gen Counsel Vinsel PSC - witness Mattison	
	Note: Sacre, Candace	Three large commercial/industrial customers have/are located in Kentucky. Dajcor Aluminum?
9:40:01 AM	Asst Gen Counsel Vinsel PSC - witness Mattison	
	Note: Sacre, Candace	Intuit?
9:40:13 AM	Asst Gen Counsel Vinsel PSC - witness Mattison	
	Note: Sacre, Candace	Sykes Enterprises?
9:41:54 AM	Asst Gen Counsel Vinsel PSC - witness Mattison	
	Note: Sacre, Candace	Kentucky Power proposed three options mitigate rate increase. Capacity charge 2004 rate case, surcharge to recover supplemental annual payments Rockport UPA?
9:42:44 AM	Asst Gen Counsel Vinsel PSC - witness Mattison	
	Note: Sacre, Candace	Within supplemental annual payment, FERC-approved amount in capacity charge?
9:43:16 AM	Asst Gen Counsel Vinsel PSC - witness Mattison	
	Note: Sacre, Candace	$6.2 million, describe proposal?
9:44:29 AM	Asst Gen Counsel Vinsel PSC - witness Mattison	
	Note: Sacre, Candace	Capacity charge, $6.2 million year recovered from ratepayers?
9:44:43 AM	Asst Gen Counsel Vinsel PSC - witness Mattison	
	Note: Sacre, Candace	Rockport UPA to end December 31 2022?
9:44:57 AM	Asst Gen Counsel Vinsel PSC - witness Mattison	
	Note: Sacre, Candace	Capacity charge tariff would end December 31 2022?
9:45:29 AM	Asst Gen Counsel Vinsel PSC - witness Mattison	
	Note: Sacre, Candace	Capacity charge, Kentucky Power offered terminate early condition Commission accept Application as is, still position?
9:46:35 AM	Asst Gen Counsel Vinsel PSC - witness Mattison	
	Note: Sacre, Candace	Excess unprotected ADIT, resulted reduction corporate income tax rate Tax Cut and Jobs Act?
9:47:09 AM	Asst Gen Counsel Vinsel PSC - witness Mattison	
	Note: Sacre, Candace	Balance of account as of filing rate case?

9:47:24 AM	Asst Gen Counsel Vinsel PSC - witness Mattison	
	Note: Sacre, Candace	Kentucky Power proposing return $65 million excess unprotected ADIT?
9:47:40 AM	Asst Gen Counsel Vinsel PSC - witness Mattison	
	Note: Sacre, Candace	2018-00035 Kentucky Power testified amortization period less 18 years result adverse impact credit metrics, familiar?
9:48:17 AM	Asst Gen Counsel Vinsel PSC - witness Mattison	
	Note: Sacre, Candace	Return half ADIT balance, how impact credit metrics?
9:49:57 AM	Asst Gen Counsel Vinsel PSC - witness Mattison	
	Note: Sacre, Candace	$65 million returned over two years, relatively same impact?
9:50:49 AM	Asst Gen Counsel Vinsel PSC - witness Mattison	
	Note: Sacre, Candace	Messner and Vaughan?
9:51:04 AM	Asst Gen Counsel Vinsel PSC - witness Mattison	
	Note: Sacre, Candace	Rate cases expenses payments to Communication Council of America, services provided?
9:51:37 AM	Asst Gen Counsel Vinsel PSC - witness Mattison	
	Note: Sacre, Candace	Helping those new at testifying prepare to testify?
9:51:55 AM	Asst Gen Counsel Vinsel PSC	
	Note: Sacre, Candace	No further.
9:51:59 AM	Chairman Schmitt	
	Note: Sacre, Candace	Attorney General?
9:52:03 AM	Asst Atty General Cook - witness Mattison	
	Note: Sacre, Candace	Cross Examination. Kentucky Power, parent, affiliate financial assistance result COVID-19 crisis?
9:52:30 AM	Asst Atty General Cook - witness Mattison	
	Note: Sacre, Candace	Rebuttal, reaffirm Kentucky Power request use $10.8 million excess accumulated deferred federal income tax eliminate arrearages as of May 28 2020?
9:53:10 AM	Asst Atty General Cook	
	Note: Sacre, Candace	Staff pull up Staff Second Request, Item 42, Response filed July 21 2020, page 617?
9:54:15 AM	Asst Gen Counsel Vinsel PSC	
	Note: Sacre, Candace	Document 16 Index List.
9:55:10 AM	Camera Lock Video Conference Activated	
9:55:41 AM	Asst Atty General Cook - witness Mattison	
	Note: Sacre, Candace	Sponsored Response?
9:55:53 AM	Asst Atty General Cook - witness Mattison	
	Note: Sacre, Candace	Last paragraph Response, agree $104,033 expense from AEPSC Federal Affairs Office lobbying expense included for recovery from ratepayers?
9:56:26 AM	Asst Atty General Cook - witness Mattison	
	Note: Sacre, Candace	Rebuttal made no reference lobbying expense?
9:56:38 AM	Asst Atty General Cook - witness Mattison	
	Note: Sacre, Candace	Aware Commission does not allow lobbying expense recovery from ratepayers?
9:56:52 AM	Asst Atty General Cook - witness Mattison	
	Note: Sacre, Candace	Agree Kentucky Power revenue requirement reduced that sum?
9:57:08 AM	Asst Atty General Cook - witness Mattison	
	Note: Sacre, Candace	Rebuttal, characterize mitigation measures AG\KIUC witness Kollen extending asset offset six months, pages 5-6 Rebuttal?
9:57:59 AM	Asst Atty General Cook - witness Mattison	
	Note: Sacre, Candace	True Kollen proposal extend excess deferred income tax offset 12 months at 50 percent first year offset?

9:58:31 AM	Asst Atty General Cook - witness Mattison	
	Note: Sacre, Candace	AEP parent company made presentation at EEI Conference capital spending projections operating companies next four yuars?
9:58:48 AM	Asst Atty General Cook - witness Mattison	
	Note: Sacre, Candace	Kentucky Power $1 billion cap ex in four years according to presentation?
9:59:13 AM	Atty Blend Kentucky Power	
	Note: Sacre, Candace	Document should be referring?
9:59:22 AM	Asst Atty General Cook	
	Note: Sacre, Candace	On internet.
9:59:41 AM	Asst Atty General Cook - witness Mattison	
	Note: Sacre, Candace	Post-hearing data request provide Kentucky Power projected capital spending next four years?
9:59:44 AM	POST-HEARING DATA REQUEST	
	Note: Sacre, Candace	ASST ATTY GENERAL COOK - WITNESS MATTISON
	Note: Sacre, Candace	KENTUCKY POWER PROJECTED CAPITAL SPENDING NEXT FOUR YEARS
10:00:00 AM	Asst Atty General Cook	
	Note: Sacre, Candace	All have.
10:00:05 AM	Chairman Schmitt	
	Note: Sacre, Candace	Mr. Kurtz?
10:00:32 AM	Camera Lock Deactivated	
10:00:42 AM	Atty Kurtz KIUC	
	Note: Sacre, Candace	Document Cook referring to AG/KIUC Hearing Exhibit 1.
10:02:02 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Cross Examination. Rockport UPAs expire 2022, projected fixed cost savings Kentucky Power?
10:02:30 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Status of decomissioning Big Sandy Unit 2?
10:02:50 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	$21 million decommissioning expense test year, when process be over decommissioning rider trend downward, lower bill for consumers?
10:03:27 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Who correct witness?
10:03:33 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Reference to TCJA settlement between KIUC and Kentucky Power, familiar?
10:03:50 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Tax Cuts and Jobs Act, credit on bills result reduction corporate income tax rate?
10:04:05 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Familiar complaint Kentucky Power filed change settlement agreement mid-year this year use $10.8 million reduction make up past two bills?
10:04:44 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Kentucky Power belief settlement agreements can be modified by Commission?
10:05:06 AM	Atty Blend Kentucky Power	
	Note: Sacre, Candace	Object extent asking for legal opinion.
10:05:14 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Understanding based on complaint, settlement agreements subject to Commission jurisdiction?
10:05:37 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Apply to 2004 settlement agreement?

10:05:52 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	But sure about other settlement agreement?
10:05:59 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Said sure Commission can change tax settlement agreement, not sure about capacity credit settlement agreement?
10:06:23 AM	Atty Kurtz KIUC	
	Note: Sacre, Candace	Series questionsAG/KIUC Exhibit 1, AEP presentation to EEI Financial Conference November 2020, put on screen?
10:07:37 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Generally familiar with corporate activities of AEP?
10:07:38 AM	Camera Lock Video Conference Activated	
10:07:53 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Page 6, EEI Key Themes 5 to 7 percent earnings growth rate 2021 range, what is 5 to 7 percent growth rate?
10:08:35 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Bottom ESG Focus and Transition Towards a Clean Energy Future, what ESG mean?
10:08:49 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Why that important?
10:09:27 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Important factor in stock, credit ratings?
10:09:48 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Page 11, ESG Focus, 42% reduction coal capacity 2030 helps ESG ratings?
10:10:23 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Kentucky Power primarily coal powered, primary generation source Rockport contracts expire two years?
10:10:45 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	260 megawatts Big Sandy?
10:11:00 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Mitchell not scheduled retire 2040?
10:11:14 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Page 25, bottom 5 to 7 percent EPS growth predicated regulated rate base growth, grow earnings growing rate base?
10:11:49 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Also grow earnings cutting costs?
10:12:40 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Regulated utilities grow earnings growing rate base, cooperative utilities not same setup?
10:13:03 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Sales flat/declining as grow rate base, sales flat or negative cost goes up?
10:13:33 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Dilemma grow rate base to grow earnings sales flat/negative, less product cost more, rate increase even higher?
10:14:45 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Page 28, 5.3 percent return on equity just cited?
10:15:08 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Small circle small piece AEP?
10:15:19 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Kentucky Power dragging down overall return?
10:15:48 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	How long in position?
10:15:52 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Kentucky Power always earning lagger?

10:16:07 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Last ten years?
10:16:19 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Authorized Equity Layers, Kentucky Power 42 equity moved up to 43, one percent improvement?
10:16:44 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Why improvement, why AEP more equity capitalization?
10:16:57 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	AEP Transmission 55 percent equity capitalization, Kentucky Transco, Ohio Transco, Indiana Transco?
10:17:22 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	AEP likes high equity capitalization, debt portion pass-through interest expense?
10:18:04 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Page 53, $10.166 billion expenditure five-year period?
10:18:38 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Kentucky Power 5.6 percent of AEP East, PJM footprint?
10:18:53 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Kentucky Power share $10.166 billion five-year cap expend approximately $569 million?
10:19:09 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Includes transmission growth all AEP, Michigan, Indiana, Kentucky, Viginia, West Virginia, Ohio, Tennessee?
10:19:26 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	States enumerated, states in AEP in PJM?
10:19:45 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Investment Categories?
10:19:55 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	How Kentucky ratepayers benefit investments Michigan?
10:21:10 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Not mutually exclusive, Kentucky Power stand-alone PJM same benefits?
10:21:45 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	East Kentucky Power stand-alone member PJM?
10:21:57 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Dayton Power and Light stand-alone member PJM?
10:22:05 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Duke Energy Kentucky and Ohio stand-alone PJM members?
10:22:19 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	As President, Kentucky Power looked at stand-alone membership PJM?
10:22:29 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Joining East Kentucky Power Co-op and not AEP Zone?
10:22:40 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Service territory overlaps East Kentucky?
10:22:46 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Same customer base?
10:23:05 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Page 54, transmission asset statistics?
10:23:42 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Seen statistics Kentucky Power stand-alone basis?
10:23:59 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Aware AG/KIUC recommendation Commission open investigation transmission cost Kentucky Power?

10:24:14 AM	Atty Kurtz - witness Mattison	
	Note: Sacre, Candace	Not aware recommendation in Baron testimony?
10:24:23 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Assume recommendation, Kentucky Power provide statistics Kentucky Power only?
10:24:45 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Page 55, Stable Cost Recovery Framework?
10:24:59 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Still talking transmission?
10:25:07 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Kentucky listed partial T/R recovery?
10:25:16 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Because last rate case 80 percent incremental transmission cost increases through PPA rider Kentucky Power?
10:25:32 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Position should move to 100 percent?
10:25:40 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	AG/KIUC position go back base recovery?
10:25:52 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Why investors like tracker/rider recovery?
10:26:12 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Commission approve 100 percent rider recovery incremental transmission expense, reflective of 10.35 percent ROE FERC authorized, automatically flow through?
10:26:46 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	9.85 base plus 50 basis point RTO added, 10.35 percent ROE FERC authorizes all OCs/transcos?
10:27:15 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Commission right of recovery, passing through ROE higher than asking this case?
10:27:31 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	10.35 percent higher than AG/KIUC recommending 9 percent?
10:27:45 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Equity rate transcos 55 percent, OCs actual cap structure?
10:28:14 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Page 58. (Click on link for further comments.) Capture, AEP wants transmission investments, capture because of rate base, adds to earnings?
10:29:02 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Page 79, CAGR rate 5 percent Kentucky Power through 2025?
10:29:28 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Kentucky Power Projected Rate Base Proxy, increase rate proxy earnings growth?
10:29:45 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Normalized GWh Sales, 6.4 percent reduction 2020, 1.6 percent 2021?
10:30:03 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Grow rate base, grow earnings, sales down, costs up consumers?
10:30:16 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	At job two years, tough service territory, business model make sense depressed economic area Eastern Kentucky?
10:32:37 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Why upsizing shrinking sales environment?
10:33:40 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Contributing to death spiral increasing rate base?

10:34:37 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Difficult situation worse Kentucky Power subsidize transmission investments AEP East system?
10:35:06 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Not have to be AEP zone be member of PJM, current PJM tariff state, rate can be changed?
10:35:23 AM	Atty Blend Kentucky Power	
	Note: Sacre, Candace	Object, asking legal testimony.
10:35:36 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Know regulated, ask changes in tariffs, business reality?
10:36:19 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	AG/KIUC Exhibit 3 AnnualTransmission Revenue Requirements and Rates, this is NITS?
10:37:07 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	PJM costs, essentially return on transmission investment for owner?
10:37:30 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Kentucky Power footprint 1000-1200 megawatts?
10:37:47 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	NITS/AEP average, Indiana, Ohio, Kentucky, Kentucky Transco, Indiana Transco, average $80,306 megawatt year?
10:38:06 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Kentucky Power share $80 million?
10:38:12 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	A thousand megawatts?
10:38:19 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Midway through, East Kentucky Power $23,000, $23,763 a megawatt a year?
10:38:35 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Operate same part Kentucky?
10:38:47 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	NITS transmission charge 25 percent AEP average?
10:39:00 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	Not pay federal/state income tax?
10:39:29 AM	Atty Kurtz KIUC - witness Mattison	
	Note: Sacre, Candace	If rate applied Kentucky Power instead of $80,000, $60 million year differential?
10:39:52 AM	Atty Kurtz KIUC	
	Note: Sacre, Candace	All questions.
10:39:58 AM	Camera Lock Deactivated	
10:40:07 AM	Chairman Schmitt	
	Note: Sacre, Candace	Counsel for Walmart?
10:40:21 AM	Atty Grundman Walmart - witness Mattison	
	Note: Sacre, Candace	Cross Examination. Discussed rate mitigation Kentucky Power proposed ROE?
10:40:47 AM	Atty Grundman Walmart - witness Mattison	
	Note: Sacre, Candace	Rate mitigation measure proposed ROE 30 basis points below suggested by McKenzie?
10:41:01 AM	Atty Grundman Walmart - witness Mattison	
	Note: Sacre, Candace	Value to customers $2.5 million?
10:41:09 AM	Atty Grundman Walmart - witness Mattison	
	Note: Sacre, Candace	Cost to customers authorized ROE $2.5 million, between 9.7 currently and 10.0 seeking?
10:41:51 AM	Atty Grundman Walmart - witness Mattison	
	Note: Sacre, Candace	Who responsible decision seek 10.0 ROE?

10:42:11 AM	Atty Grundman Walmart - witness Mattison	
	Note: Sacre, Candace	You ultimately responsible request of 10.0 ROE?
10:42:20 AM	Atty Grundman Walmart - witness Mattison	
	Note: Sacre, Candace	Nothing have prohibited not seeking increased ROE?
10:42:31 AM	Atty Grundman Walmart - witness Mattison	
	Note: Sacre, Candace	That's correct.
10:42:37 AM	Atty Grundman Walmart - witness Mattison	
	Note: Sacre, Candace	Know McKenzie ROE witness 2017 rate case?
10:42:45 AM	Atty Grundman Walmart - witness Mattison	
	Note: Sacre, Candace	ROE he proposed that rate case?
10:42:57 AM	Atty Grundman Walmart - witness Mattison	
	Note: Sacre, Candace	Subject check, 10.3 sound correct?
10:43:09 AM	Atty Grundman Walmart - witness Mattison	
	Note: Sacre, Candace	Fewer customers asked pay more, fewer available pay cost?
10:43:30 AM	Atty Grundman Walmart - witness Mattison	
	Note: Sacre, Candace	That fact another reason not seek increased ROE?
10:44:54 AM	Atty Grundman Walmart - witness Mattison	
	Note: Sacre, Candace	Talking unemployment numbers now?
10:45:07 AM	Atty Grundman Walmart - witness Mattison	
	Note: Sacre, Candace	Rate mitigation offered set forth months before different unemployment numbers?
10:45:20 AM	Atty Grundman Walmart - witness Mattison	
	Note: Sacre, Candace	10.3 or 10.0 ROE that high compared to ROEs across country?
10:45:38 AM	Atty Grundman Walmart - witness Mattison	
	Note: Sacre, Candace	Not aware?
10:45:46 AM	Atty Grundman Walmart - witness Mattison	
	Note: Sacre, Candace	You aware how would relate ROEs throughout country?
10:46:00 AM	Atty Grundman Walmart - witness Mattison	
	Note: Sacre, Candace	Seen ROEs awarded last 18 months at 10.3?
10:46:10 AM	Atty Grundman Walmart - witness Mattison	
	Note: Sacre, Candace	Believe McKenzie analysis sound and reliable?
10:46:21 AM	Atty Grundman Walmart	
	Note: Sacre, Candace	Not have further.
10:46:23 AM	Chairman Schmitt	
	Note: Sacre, Candace	Kentucky Solar Industries Association?
10:46:43 AM	Atty Spenard KYSEIA	
	Note: Sacre, Candace	Not have questions.
10:46:46 AM	Chairman Schmitt	
	Note: Sacre, Candace	Recess, return 11 o'clock.
10:47:09 AM	Session Paused	
11:03:34 AM	Session Resumed	
11:03:41 AM	Chairman Schmitt	
	Note: Sacre, Candace	Back on record.
11:03:55 AM	Chairman Schmitt	
	Note: Sacre, Candace	Discussion difficulty hearing. (Click on link for further comments.)
11:05:02 AM	Camera Lock Deactivated	
11:06:17 AM	Chairman Schmitt	
	Note: Sacre, Candace	Joint Intervenors?
11:06:33 AM	Atty Fitzgerald Joint Intervenors - witness Mattison	
	Note: Sacre, Candace	Cross Examination. September 30 FERC conference on carbon pricing, wholesale electricity markets, (Reading).(Click on link for further comments.) Recall remarks?

11:08:13 AM	Atty Fitzgerald Joint Intervenors - witness Mattison	
	Note: Sacre, Candace	AEP and subsidiaries believe cleaner generation reduction carbon footprint electrical generation positive goal?
11:08:30 AM	Atty Fitzgerald Joint Intervenors - witness Mattison	
	Note: Sacre, Candace	AEP/subsidiaries own solar generation capacity?
11:08:37 AM	Atty Fitzgerald Joint Intervenors - witness Mattison	
	Note: Sacre, Candace	Any KPC service area?
11:09:27 AM	Atty Fitzgerald Joint Intervenors - witness Mattison	
	Note: Sacre, Candace	Addition wind/solar bring value meeting carbon reduction goals, zero emissions?
11:09:44 AM	Atty Fitzgerald Joint Intervenors - witness Mattison	
	Note: Sacre, Candace	Only utlity-owned solar generation contributes goals or distributed solar contribute to goals?
11:10:04 AM	Atty Fitzgerald Joint Intervenors - witness Mattison	
	Note: Sacre, Candace	Kentucky Power proposal reduce value fed-in electricity rooftop solar encourage/discourage customers taking service under proposed tariff?
11:10:56 AM	Atty Fitzgerald Joint Intervenors - witness Mattison	
	Note: Sacre, Candace	Written remarks noted cost of energy important areas economic hardship such as Kentucky Power territory?
11:11:17 AM	Atty Fitzgerald Joint Intervenors - witness Mattison	
	Note: Sacre, Candace	Kentucky Power/AEP focus always focus end-use customer?
11:11:32 AM	Atty Fitzgerald Joint Intervenors - witness Mattison	
	Note: Sacre, Candace	Eastern Kentucky devastated loss jobs in steel/coal. Disagree Owen testimony impact COVID-19 KPC customer service territory increased job loss, higher unemployment, eviction, utility disconnections, permanently closed businesses, illness, death?
11:13:35 AM	Atty Fitzgerald Joint Intervenors - witness Mattison	
	Note: Sacre, Candace	Kentucky Power believe determining rate is fair, just, reasonable consideration economic circumstances customers appropriate?
11:14:36 AM	Atty Fitzgerald Joint Intervenors - witness Mattison	
	Note: Sacre, Candace	Agree interest shareholders balance keeping rates affordable?
11:15:43 AM	Atty Fitzgerald Joint Intervenors - witness Mattison	
	Note: Sacre, Candace	Always focused on end user?
11:16:02 AM	Atty Fitzgerald Joint Intervenors - witness Mattison	
	Note: Sacre, Candace	Mentioned context comments reduction carbon footprint priority, said not highest for Kentucky Power customers?
11:16:34 AM	Atty Fitzgerald Joint Intervenors - witness Mattison	
	Note: Sacre, Candace	Replacing meters functional AMI fall terms of priorities customers?
11:20:13 AM	Atty Fitzgerald Joint Intervenors - witness Mattison	
	Note: Sacre, Candace	Comments imply elasticity of demand, disproportionate fixed and low-income customers relative other utilities?
11:20:36 AM	Atty Fitzgerald Joint Intervenors - witness Mattison	
	Note: Sacre, Candace	Surveying of customers determine have capacity utilize AMIs ways described?
11:21:15 AM	Atty Fitzgerald Joint Intervenors - witness Mattison	
	Note: Sacre, Candace	Broadband acess/computers allow access to information?
11:22:05 AM	Atty Fitzgerald Joint Intervenors - witness Mattison	
	Note: Sacre, Candace	Agree ROE reasonable one time but become too high or low by changes affecting investment?
11:22:31 AM	Atty Fitzgerald Joint Intervenors - witness Mattison	
	Note: Sacre, Candace	Agree ratepayers not pay for investments made by utility are no benefit them?
11:22:48 AM	Atty Fitzgerald Joint Intervenors - witness Mattison	
	Note: Sacre, Candace	Principle, concur?

11:23:03 AM	Atty Fitzgerald Joint Intervenors - witness Mattison	
	Note: Sacre, Candace	Explain Kentucky Power proposed rate of return significantly higher than granted in most recent fully litigated case at time high unemployment, lower incomes, significant poverty rate?
11:23:38 AM	Atty Fitzgerald Joint Intervenors	
	Note: Sacre, Candace	No further.
11:23:41 AM	Chairman Schmitt	
	Note: Sacre, Candace	Sierra Club?
11:23:54 AM	Atty Miller Sierra Club	
	Note: Sacre, Candace	Does not.
11:24:04 AM	Chairman Schmitt	
	Note: Sacre, Candace	SWVA?
11:24:13 AM	Atty Frye SWVA	
	Note: Sacre, Candace	No.
11:24:18 AM	Chairman Schmitt	
	Note: Sacre, Candace	Kentucky Power, redirect?
11:24:48 AM	Chairman Schmitt	
	Note: Sacre, Candace	Redirect?
11:24:49 AM	Atty Blend Kentucky Power	
	Note: Sacre, Candace	Yes,
11:24:58 AM	Atty Blend Kentucky Power - witness Mattison	
	Note: Sacre, Candace	Redirect Examination. Company Response AG/KIUC Data Request 2 -42, lobbying expense?
11:25:21 AM	Atty Blend Kentucky Power - witness Mattison	
	Note: Sacre, Candace	$104,033 federal lobbying inluded cost of service?
11:25:39 AM	Atty Blend Kentucky Power - witness Mattison	
	Note: Sacre, Candace	If further questions, subject matter expert?
11:25:53 AM	Atty Blend Kentucky Power - witness Mattison	
	Note: Sacre, Candace	AG/KIUC Hearing Exhibit 1, recall questions earnings growth as driver versus O&M reductions driver overall AEP earnings?
11:26:28 AM	Atty Blend Kentucky Power - witness Mattison	
	Note: Sacre, Candace	Page 10, describe what page relates to, how relates earlier testimony?
11:27:31 AM	Atty Blend Kentucky Power - witness Mattison	
	Note: Sacre, Candace	AEP/Kentucky Power making efforts reduce/optimize O&M over more than past year?
11:28:01 AM	Atty Blend Kentucky Power - witness Mattison	
	Note: Sacre, Candace	Slide 33, AG/KIUC Exhibit 1, describe?
11:30:12 AM	Camera Lock Video Conference Activated	
11:31:20 AM	Atty Blend Kentucky Power - witness Mattison	
	Note: Sacre, Candace	Downward trajectory reduction in O&M?
11:31:27 AM	Atty Blend Kentucky Power - witness Mattison	
	Note: Sacre, Candace	Page 53, recall questions?
11:31:50 AM	Atty Blend Kentucky Power - witness Mattison	
	Note: Sacre, Candace	Pie chart upper left-hand corner also investment right-hand side, numbers specific to PJM or total AEP numbers?
11:32:15 AM	Atty Blend Kentucky Power	
	Note: Sacre, Candace	No further.
11:32:19 AM	Chairman Schmitt	
	Note: Sacre, Candace	Vice Chairman Chandler?
11:32:26 AM	Vice Chairman Chandler	
	Note: Sacre, Candace	I do.
11:32:29 AM	Camera Lock Deactivated	

11:32:33 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Examination. AG/KIUC Exhibit 1, page 33, not KP specific graph since billions in O&M. Rate case based on test year ending March 31 2020?
11:33:14 AM	Camera Lock Video Conference Activated	
11:34:03 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Go down in 2020 estimate, go down 2020 estimate revised, expected lower in 2021, O&M doing similar, how reflected in this case?
11:35:01 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Things have changed, test year ended March 31 2020 snapshot of company operations for rates proposing?
11:35:26 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Pro forma adjustments made to snapshot?
11:35:33 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Finalized data April, May, June?
11:35:46 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Reduced contractor costs, reduction in O&M expense on customer's bill?
11:36:06 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Reduced that cost COVID, numbers set prior to reduction, any reduction have or anticipate contractor cost COVID, how included and separate, how reduction in cost O&M expenses customers' bills, currently or interim?
11:37:50 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Mentioned as reduction in expenses, not used calculate rates, no dollar benefit to customers?
11:38:38 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Response earlier reduction contractors impact of COVID not in rate case, no material dollar benefit customers?
11:39:19 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Asked Mitchell retirement 2040?
11:39:38 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	What is today, not answer tomorrow, aware plans to change retirement Mitchell Plant?
11:40:20 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Aware 2040 not accurate expectation?
11:40:39 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Rockport expenses under UPA both expire December two years?
11:41:08 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	25 months from now 195 megawatts each, 390 megawatts, expense falls off books?
11:42:18 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Privy conversations discussions filing rate case effective Jan 1 2023 closing of Rockport?
11:42:29 AM	Camera Lock Deactivated	
11:43:09 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Role earnings expectations play in investment decisions?
11:43:49 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Earnings play role, increasing earnings/rate base on decisions driving earnings?
11:44:09 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Rate base proxy for earnings growth?

11:44:27 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Meeting earnings expectations and return on investment also growth of earnings?
11:44:43 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Growth earnings/rate base role play in investment decisions?
11:45:27 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Distinction between amount earn and increasing total return?
11:45:49 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Earnings growth expectations drive investment decisions?
11:46:06 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Balance with customer expectations?
11:46:55 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Limit on capital for investment?
11:47:23 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Consideration cost to customers?
11:47:51 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Specific to customers invesments/growth of rate base any considerations on customer side?
11:48:14 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Balancing, how implemented in reality?
11:49:24 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	AG's document, chart Kentucky Power compound annual growth rate, rate base earnings growth five years average five percent, remember that?
11:49:55 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Sure customers afford five percent growth rate?
11:51:08 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Best thing KP do for customer invest in smart meters, customer benefit of AMI, remember that?
11:52:10 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Not saying absolute best thing smart meters, answering question go down AMI path?
11:53:00 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Not saying best thing for customers invest smart meters?
11:53:27 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Membership in PJM, aware history Kentucky Power proposal to join PJM as relates KPSC?
11:53:56 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Commission initially denied transfer control transmission system to PJM?
11:54:13 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Initially denied only to ultimately approve?
11:54:25 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Know whether Kentucky Poewr same benefits from PJM as stand-alone member?
11:54:51 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Hypothetical, continued membership in PJM, status quo leads to AEP East, KP net costs, other affiliates benefits expense of KP, how know that?
11:56:45 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Good idea person depending on to tell you be an AEP Service Company?
11:57:30 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Not conflict?

11:57:35 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Conflict person administering all costs?
11:58:22 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Other utilities benefits in excess of costs, KP costs in excess of benefits, other utilities benefits at expense of Kentucky Power?
11:58:59 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	How would you know, ask Kelly Pearce, conflict?
11:59:19 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Read Commission Order 2017 Kentucky Power rate case?
11:59:31 AM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	2017 Order, pg 74, (Reading). (Click on link for further comments.) What done ensure participation PJM aligns interests Kentucky Power and ratepayers?
12:01:01 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Aware LG&E/KU islands, not members RTO?
12:01:12 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	FERC rules require transmission owners provide open access?
12:01:24 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Reality you look at, status quo or blackouts/brownouts not member PJM?
12:02:05 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	What done ensure participation PJM aligns interests of Kentucky Power and ratepayers?
12:02:30 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Any answer response Commission's Order determination participation in PJM aligns with interests Kentucky Power and ratepayers?
12:03:01 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Have you done anything? Horton company witness?
12:03:12 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Provided testimony?
12:03:15 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Aware role Horton played at PJM on behalf AEP?
12:03:23 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Last two years, told Horton Kentucky Power vote differently than other AEP affiliate?
12:03:33 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Conveyed concerns ongoing proceedings to Horton?
12:03:48 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	What Kentucky Power done to recognize must make determination participation in PJM aligns interests Kentucky Power and ratepayers?
12:04:19 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	At what cost? $500 million dollars net cost not answer. $2 net cost understandable answer, some point cost too much?
12:04:50 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	How balancing that?
12:05:41 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Always going to be answer? Reliability of PJM outweigh all costs?
12:06:13 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Commission wanted Kentucky Power three years ago ensure participation PJM aligned, depending on AEP determination and nothing changed over last three years?
12:06:50 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	KP interests not aligned, depending on Horton and Pearce inform such?

12:07:12 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Mitigation proprosals, asked for $70 million increase, net $65 million?
12:07:41 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Proposed accelerate amortization excess ADIT $65 million first year?
12:07:57 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Customer money?
12:08:02 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	First mitigation, give back money faster than agreed KIUC settlement approved three years ago?
12:08:20 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Second mitigation, capacity charge $6.2 million additional money in return Kentucky Power sign PPA instead other generation decision?
12:08:43 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Forego extra money if approved Application as filed?
12:08:57 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Third mitigation,10 percent ROE?
12:09:04 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Ten percent ROE 30 basis points less McKenzie recommended?
12:09:14 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Higher than Commission given last few years?
12:09:22 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Only give up capacity charge to mitigate impact customers if Commission gives everything filed?
12:10:02 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Only agree give up $6.2 million Commission gives everything as filed?
12:10:22 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Apply to proposal for mitigation capacity charge?
12:10:39 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Give up capacity charge next two years if Commission approves Application as filed, Application amended throughout proceeding?
12:10:58 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Company proposal capacity charge now, as amended or as filed?
12:11:13 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Adjustments Vaughan agreed to, responses, and mistakes, Commission ignore and approve as filed?
12:11:39 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Concern as filed, since amended, saying give up $6.2 million as amended or only as initially filed?
12:12:07 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Don't know Vaughan officially speak on behalf of company?
12:12:25 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Changed Application throughout case?
12:12:37 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Things company agrees to, small mistakes, small updates?
12:12:53 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Commission approves everything now proposing, company no longer proposing $6.2 million mitigation?
12:13:23 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Forget the number, offering entire amount if Commission approves Application currently proposed?
12:13:54 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Would include Commission approving 100 percent PPA and grid modernization rider in addition to smart meters?

12:14:13 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Only time offer mitigation, if Commission gives everything?
12:14:30 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	You are in charge there, in charge of whole thing?
12:14:40 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Only if Commission approves all those things, only time offering mitigation capacity rider?
12:15:20 PM	Vice Chairman Chandler - witness Mattison	
	Note: Sacre, Candace	Thank you.
12:15:26 PM	Chairman Schmitt	
	Note: Sacre, Candace	Dr. Mathews?
12:15:31 PM	Commissioner Mathews	
	Note: Sacre, Candace	Yes.
12:15:45 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	Examination. Mitchell and 2040 retirement date, what it is today. Filing due soon CR and ELG, might have bearing on life expectancy of units?
12:16:51 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	Then to Commission environmental compliance plan, involves mitigation impact for CCR and ELG?
12:17:10 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	How much not been fully depreciated?
12:17:33 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	Decison on CCR and ELG, then look at carbon, or those together?
12:18:24 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	No carbon pricing but goal and plan carbon neutral. One hundred percent fossil fuels, from a hundred to zero?
12:18:57 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	Mitchell units coal fired?
12:19:05 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	How play into carbon goals?
12:19:42 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	$600 million mortgage, ballpark how much CPR/ELG cost?
12:20:00 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	Include environmental upgrades since Kentucky Power ownership 50 percent?
12:20:20 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	Factoring in risk, good chance Mitchell not make it 2040?
12:21:05 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	Impact of mortgages left, how much left Big Sandy 2?
12:21:39 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	Big Sandy 1,200-something megawatts?
12:21:51 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	How much used, dispatched often?
12:22:27 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	How much AMI cost per customer?
12:22:59 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	What second, third, fourth year?
12:23:16 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	Must have misunderstood responded Fitzgerald benefits low-income customers, best thing AMI?
12:24:04 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	Life left existing meters?

12:24:26 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	Warehouse some sitting have life expectancy?
12:24:51 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	Benefits AMI involved flex pay, time-of-day rates, more down pike?
12:25:33 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	For some customers, four years?
12:25:46 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	Cost of education necessary, amount in record?
12:26:03 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	Significant some customers?
12:26:25 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	Education component?
12:26:37 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	Caution look Glasgow, Kentucky, before roll out time-of-day rate.
12:26:57 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	Status of what formerly known as Braidy?
12:27:46 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	If go forward, transmission upgrades have to come back for CPCN?
12:28:15 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	Benefits of RTO, no middle ground, AEP being in RTO or not being in an RTO. Discussion about Kentucky Power independently in RTO?
12:29:08 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	Elaborate being an island?
12:29:21 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	Missing middle ground if Kentucky Power member of PJM separate AEP East?
12:30:15 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	Studies released companies belong RTOs continue to self-supply higher cost to customers than if sold plants/not run leaned on market, analysis Kentucky Power benefit from market purchases, less self-supply?
12:31:10 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	Vaughan person to answer?
12:31:31 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	Investment decisions based on expected returns?
12:31:45 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	What degree reliability/safety drive concerns?
12:32:26 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	Further buildout, building something not impact reliability/safety?
12:33:14 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	Aging infrastructure customers paid depreciation, what degree return impact replace infrastructure, how much aging, no longer reliable?
12:34:21 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	Impact expected return affect ability maintain system?
12:35:12 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	As do requirements for reliability/safety imposed by KPSC and NERC?
12:35:28 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	What year AEP carbon free, not renewable goal?
12:36:07 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	AEP carbon-capture equipment Mountaineer Plant, initiative abandoned?

12:36:45 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	By 2050, 80 percent reduction, starting from what?
12:37:08 PM	Commissioner Mathews - witness Mattison	
	Note: Sacre, Candace	Companies use 2005, some 1990 level starting baseline, trying to check.
12:37:23 PM	Commissioner Mathews	
	Note: Sacre, Candace	All have.
12:37:28 PM	Chairman Schmitt	
	Note: Sacre, Candace	Examination schedule, lunch break until 1:30, Mattison additional questions some point.
12:38:41 PM	Session Paused	
1:37:21 PM	Session Resumed	
1:37:29 PM	Chairman Schmitt	
	Note: Sacre, Candace	Back on the record. Ms. Blend, before redirect, Mr. Cook asked question, Mr. Mattison referred to witness no one can recall. Find out from Mr. Mattison? Mr. Cook, recollection of the question resulted in Mattision referring?
1:37:50 PM	Camera Lock Deactivated	
1:38:23 PM	Asst Atty General Cook	
	Note: Sacre, Candace	Questions regarding monies identified in PSC Exhibit 2, lobbying expense, counsel stated another witness but not catch last name identified.
1:39:00 PM	Atty Blend Kentucky Power	
	Note: Sacre, Candace	Which witness best testimony exclusion of federal lobbying expense from cost of service?
1:39:10 PM	Atty Blend Kentucky Power	
	Note: Sacre, Candace	Mr. Mattison referred to Ms. Whitney.
1:39:18 PM	Asst Atty General Cook	
	Note: Sacre, Candace	Yes, PSC 2-42.
1:39:22 PM	Atty Blend Kentucky Power	
	Note: Sacre, Candace	Mattison referred to Company Witness Whitney actual adjustment and cost of service.
1:39:39 PM	Chairman Schmitt	
	Note: Sacre, Candace	Listed witness?
1:39:42 PM	Atty Blend Kentucky Power	
	Note: Sacre, Candace	Yes, Heather M. Whitney, Ms. Whitney.
1:39:49 PM	Chairman Schmitt	
	Note: Sacre, Candace	Redirect?
1:39:59 PM	Atty Blend Kentucky Power	
	Note: Sacre, Candace	No.
1:40:07 PM	Chairman Schmitt	
	Note: Sacre, Candace	Next witness?
1:40:11 PM	Atty Blend Kentucky Power	
	Note: Sacre, Candace	Matthew J. Satterwhite.
1:41:34 PM	Chairman Schmitt	
	Note: Sacre, Candace	Mr. Overstreet?
1:41:39 PM	Atty Overstreet Kentucky Power	
	Note: Sacre, Candace	Matthew J. Satterwhite.
1:41:43 PM	Chairman Schmitt	
	Note: Sacre, Candace	Ms. Vinsel, potential confidential session?
1:41:55 PM	Asst Gen Counsel Vinsel PSC	
	Note: Sacre, Candace	Confidential session twice during Satterwhite testimony, ensure everyone in confidentiality agreement. (Click on link for further comments.)

1:43:27 PM	Asst Gen Counsel Vinsel PSC	
	Note: Sacre, Candace	Resolved issue.
1:43:34 PM	Atty Overstreet Kentucky Power	
	Note: Sacre, Candace	All parties signed except SWVA not signed, does not relate information produced by Kentucky Power and afforded confidential treatment and not used by another party, will be fine except respect SWVA.
1:44:26 PM	Asst Gen Counsel Vinsel PSC	
	Note: Sacre, Candace	Confidential sessions, Frye may remain in hearing.
1:44:38 PM	Chairman Schmitt	
	Note: Sacre, Candace	Witness is sworn.
1:45:07 PM	Atty Overstreet Kentucky Power - witness Satterwhite	
	Note: Sacre, Candace	Direct Examination. Name, employer, position?
1:45:20 PM	Atty Overstreet Kentucky Power - witness Satterwhite	
	Note: Sacre, Candace	Appearing response subpoena?
1:45:26 PM	Atty Overstreet Kentucky Power - witness Satterwhite	
	Note: Sacre, Candace	Subject matter testimony today?
1:45:46 PM	Atty Overstreet Kentucky Power	
	Note: Sacre, Candace	Available for cross.
1:45:49 PM	Chairman Schmitt	
	Note: Sacre, Candace	Ms. Vinsel?
1:45:54 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Cross Examination. Job duties now?
1:47:00 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	In addition FERC and KPSC, ten other regulatory commissions you deal?
1:47:16 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Prior to today, Involvement been this case?
1:48:55 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Prior to that, conversations anyone particularly rebuttal testimony?
1:49:51 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Two weeks ago, AEP announced $37 billion dollar five-year capital plan, renewable expansion/grid investments, familiar?
1:50:12 PM	Asst Gen Counsel Vinsel PSC	
	Note: Sacre, Candace	Brief confidential session.
1:50:17 PM	Chairman Schmitt	
	Note: Sacre, Candace	At this time, confidential session.
1:50:21 PM	Private Mode Activated	
1:50:21 PM	Private Recording Activated	
1:54:09 PM	Camera Lock Video Conference Activated	
1:56:53 PM	Camera Lock Deactivated	
1:57:43 PM	Normal Mode Activated	
1:57:43 PM	Public Recording Activated	
1:57:50 PM	Chairman Schmitt	
	Note: Sacre, Candace	Out of confidential, back into regular open session.
1:58:10 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Cross Examination (cont'd). Regulatory proceedings, team role different state level than FERC level?
1:59:20 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	One way dynamic team parts of AEP, also static team?
2:00:17 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Difference in team participation operating companies versus transmission companies?

2:01:36 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Load-serving entity open-access transmission tariff (LSE OATT), current/previous position at Kentucky Power, did say previous position was?
2:02:33 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Current/previous position, familiar with LSE OATT expense recovery proposed?
2:03:03 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Last rate case 80/20 split tariff PPA, this case Kentucky Power proposes 100 percent costs outside base rates tariff PPA?
2:03:45 PM	Asst Gen Counsel Vinsel PSC	
	Note: Sacre, Candace	Bring up Alex Vaughan Direct Testimony.
2:04:10 PM	Camera Lock Video Conference Activated	
2:04:31 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Read, lines 3-14, Direct testimony, Alex Vaughan into record?
2:06:10 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	When Vaughan says, as expected, PJM owners continued to continue investment, that your experience?
2:06:49 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Eastern grid, particular area?
2:07:39 PM	Camera Lock Deactivated	
2:07:40 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Quotes, Vaughan testimony, first, PJM transmission owners continued increase investment transmission grid, and, second, PJM LSE OATT charges Kentucky Power single largest growing expense, costs allocated by FERC-approved rate schedule.
2:09:42 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Looking at PJM LSE OATT largest single growing expense allocated by FERC-approved rate schedule, familiar with FERC-approved rate schedules?
2:10:18 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Vaughan Direct Testimony, page 33, read lines 6 through 11?
2:11:35 PM	Camera Lock Video Conference Activated	
2:12:05 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	2017-00179 LSE OATT charges grown about $20 million, recall?
2:13:01 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	$96 million PJM LSE OATT charges included base rate test year, remember $96 million.
2:13:31 PM	Camera Lock Deactivated	
2:13:35 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	PSC Exhibit 14, Direct Testimony, last rate case.
2:13:53 PM	Camera Lock Video Conference Activated	
2:15:07 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Page 18, PDF 22, read lines 1 through 9, Direct Testimony, last rate case?
2:16:21 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	What discussed moment ago increase $20 million?
2:16:45 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	PSC Exhibit 13, Rebuttal Testimony, last rate case, page 8, read line 17, through page 9, line 2?
2:16:52 PM	Camera Lock Deactivated	
2:17:10 PM	Camera Lock Video Conference Activated	
2:19:02 PM	Camera Lock Deactivated	

2:19:09 PM	Vice Chairman Chandler	
	Note: Sacre, Candace	Clarification, increase over most recent rate case, reference seems to be 2018 over 2017. Make sure clear.
2:19:48 PM	Asst Gen Counsel Vinsel PSC	
	Note: Sacre, Candace	PSC 13, page 8, line 9, PDF page 11, $17 million above $74.4 million test year PJM LSE OATT expense.
2:20:00 PM	Camera Lock Video Conference Activated	
2:20:37 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Examination. Rebuttal 8 and 9, test year amount, $20.6 million number, increase between 2017 rate case test year and 2014 rate case test year, apples and oranges?
2:21:37 PM	Camera Lock Deactivated	
2:22:23 PM	Camera Lock Video Conference Activated	
2:22:36 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Cross Examination (cont'd). LSE OATT expense reflection of Kentucky Power share costs to rebuild transmission system in region, what region?
2:22:36 PM	Camera Lock Deactivated	
2:22:58 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	AEP East Region or entirety PJM region?
2:23:13 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Kentucky Power provided transmission agreement for AEP East companies, Kentucky Power AEP East Transmission Zone?
2:23:44 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Familiar transmission agreement?
2:23:52 PM	Asst Gen Counsel Vinsel PSC	
	Note: Sacre, Candace	AG/KIUC First Data Request, PDF 1656, recognize this, part of agreement filed part of settlement FERC matter?
2:24:14 PM	Camera Lock Video Conference Activated	
2:25:16 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Letter dated August 4 2020 filing from AEP filing proposed transmission agreement?
2:25:33 PM	Asst Gen Counsel Vinsel PSC	
	Note: Sacre, Candace	PDF page 1660, page 4 of 129, Introduction to transmission agreement, read this, page 2 through 4 your pages?
2:30:17 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Let me have you go down, read last paragraph, begins IURC?
2:32:06 PM	Asst Gen Counsel Vinsel PSC	
	Note: Sacre, Candace	PDF 1724, pg 68 of 129, Appendix 1, agree AEP East operating company both LSEs and transmission owners?
2:33:16 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Appendix 1 transmission agreement, Data Request, page 68 of 129, tell me when there.
2:33:44 PM	Atty Overstreet Kentucky Power	
	Note: Sacre, Candace	Specific Data Request, AG/KIUC 1-41, Attachment 1.
2:34:11 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Chart allocation tranmission related costs/revenues?
2:34:25 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	AEP operating companies as LSE and transmission owners?
2:35:19 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Quotes Vaughan testimony, LSE OATT costs allocated to company by FERC-approved rate schedule, agree transmission agreement lays out significant part allocation process?

2:36:00 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Earlier comment about operating companies, know why chart refers AEP as transmission owner and AEP as LSE rather than operating companies?
2:36:49 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Examination. Ask question on that, AEP load-serving entity itself or LSE through operating companies being LSEs?
2:37:14 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Nexus between AEP and PJM, PJM sees AEP as TO and AEP as LSE?
2:37:43 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Cross Examination (cont'd). Kentucky Power does own transmission system?
2:37:46 PM	Camera Lock Deactivated	
2:38:39 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Kentucky Power is LSE and transmission owner?
2:38:49 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Kentucky Power and AEP distinct entities?
2:39:22 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Kentucky Power needs recover revenue requirement as transmission owner?
2:39:49 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Methodology recover costs covered by transmission agreement?
2:40:08 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Kentucky Power revenue requirement through AEP before PJM?
2:41:03 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Helpful follow up with Vaughan?
2:42:12 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Expenses as an LSE, how Kentucky Power recover transmission expenses?
2:44:17 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Expenses PJM down to AEP and then methodology in agreement down to actual owners operating companies for LSE?
2:45:00 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Kentucky Power invests in transmission in excess allocated costs under FERC schedule?
2:46:09 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Revenues and expenses and allocation in general, Kentucky Power investment in excess of allocated costs through FERC schedule, benefit for Kentucky Power and customers?
2:47:30 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Dollars-and-cents perspective, Kentucky Power investment exceeds cost allocated, benefit to Kentucky Power?
2:48:35 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Quantifying cost and benefits, all generation goes away, way to power service. Ongoing analysis quantifies benefits and cost?
2:51:27 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Commission asks for reporting costs and benefits, may not be one report but parts and pieces?
2:52:25 PM	Asst Gen Counsel Vinsel PSC	
	Note: Sacre, Candace	Vaughan Direct Testimony AEV-5, agree PJM LSE OATT expenses from test year?
2:53:37 PM	Camera Lock Video Conference Activated	
2:54:39 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	End of historic test year this case?

2:54:46 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Line 11, PJM LSE OATT Base Amount $96.896 million, how much PJM LSE OATT expenses reflected in amount are affiliates?
2:55:31 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Vaughan included last rate case expense amounts affiliates/nonaffiliates, items on lines 3, 4, 5, 7, and 8 are affiliates?
2:56:33 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Five lines together over $88 million?
2:57:28 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Surprised five lines compromise 90 percent base amount PJM LSE OATT expenses in test year?
2:57:29 PM	Camera Lock Deactivated	
2:58:22 PM	Asst Gen Counsel Vinsel PSC	
	Note: Sacre, Candace	Like to look at AEP transmission owners specifically, go into confidential session?
2:58:36 PM	Chairman Schmitt	
	Note: Sacre, Candace	Put in Confidential session at this time?
2:58:40 PM	Private Mode Activated	
2:58:40 PM	Private Recording Activated	
2:59:05 PM	Camera Lock Video Conference Activated	
3:05:36 PM	Camera Lock Deactivated	
3:05:53 PM	Camera Lock Video Conference Activated	
3:12:50 PM	Camera Lock Deactivated	
3:18:01 PM	Camera Lock Video Conference Activated	
3:26:34 PM	Asst Gen Counsel Vinsel PSC	
	Note: Sacre, Candace	We can exit confidential session.
3:26:36 PM	Camera Lock Deactivated	
3:26:46 PM	Normal Mode Activated	
3:26:46 PM	Public Recording Activated	
3:27:07 PM	Chairman Schmitt	
	Note: Sacre, Candace	Back in public section.
3:27:18 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Article discussed Commission's June 10 2013 decision, PSC Exhibit 16, Case No. 2011-00042, Order referenced in article, Kentucky transco not regulated by Commission. Page 8, Final Order, (Reading). (Click on link for further comments.)
3:27:59 PM	Camera Lock Video Conference Activated	
3:29:35 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Second paragraph, As noted in the Dissenting Opinion, (Reading). (Click on link for further comments.)
3:30:48 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Aware Kentucky Transmission ever filed application with Kentucky Board on Electric Generation and Transmission Siting?
3:30:48 PM	Camera Lock Deactivated	
3:31:34 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Best of knowledge in your experience?
3:31:42 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	How did Kentucky Transmission get $100 million in rate base?
3:32:13 PM	Asst Gen Counsel Vinsel PSC - witness Satterwhite	
	Note: Sacre, Candace	Don't know how got $100 million in rate base?
3:32:32 PM	Asst Gen Counsel Vinsel PSC	
	Note: Sacre, Candace	Staff has no further.
3:32:35 PM	Chairman Schmitt	
	Note: Sacre, Candace	Recess until 3:45.

3:32:53 PM	Session Paused	
3:50:24 PM	Session Resumed	
3:50:35 PM	Chairman Schmitt	
	Note: Sacre, Candace	Back on the record. Sound test.
3:52:31 PM	Chairman Schmitt	
	Note: Sacre, Candace	AG's Office?
3:52:35 PM	Asst Atty General West	
	Note: Sacre, Candace	No.
3:52:41 PM	Chairman Schmitt	
	Note: Sacre, Candace	Mr. Kurtz?
3:52:49 PM	Camera Lock Deactivated	
3:53:14 PM	Atty Kurtz KIUC - witness Satterwhite	
	Note: Sacre, Candace	Cross Examination. Staff established transmission charges PJM LSE OATT fastest growing?
3:53:35 PM	Atty Kurtz KIUC - witness Satterwhite	
	Note: Sacre, Candace	Vaughan testimony 2014 rate case expense $53.7 million, now $96.89 million?
3:53:53 PM	Atty Kurtz KIUC - witness Satterwhite	
	Note: Sacre, Candace	Over next five years, AEP projected spend $10 billion PJM transmission projects 2021-2025?
3:54:11 PM	Atty Kurtz KIUC - witness Satterwhite	
	Note: Sacre, Candace	EEI report, towards back?
3:54:29 PM	Atty Kurtz KIUC - witness Satterwhite	
	Note: Sacre, Candace	Commission concluded transmission costs expensive, growing, needs cost containment, what do keep expense down?
3:55:34 PM	Atty Kurtz KIUC - witness Satterwhite	
	Note: Sacre, Candace	Preemption doctrine, state commission has to allow recovery FERC-approved transmission expenses?
3:55:46 PM	Atty Kurtz KIUC - witness Satterwhite	
	Note: Sacre, Candace	No requirement recovery through tracker?
3:56:08 PM	Atty Kurtz KIUC - witness Satterwhite	
	Note: Sacre, Candace	Commission go back to base rate recovery/no tracker to keep costs containment?
3:56:54 PM	Atty Kurtz KIUC - witness Satterwhite	
	Note: Sacre, Candace	Automatically flow through real time, how help consumers?
3:58:28 PM	Atty Kurtz KIUC - witness Satterwhite	
	Note: Sacre, Candace	Listen in on AEP earnings calls?
3:58:35 PM	Atty Kurtz KIUC - witness Satterwhite	
	Note: Sacre, Candace	Over what period of time?
3:58:44 PM	Atty Kurtz KIUC - witness Satterwhite	
	Note: Sacre, Candace	Recall analyst ask executives Kentucky Power drag on earnings, doing to sell Kentucky Power, answer "looking at that?"
3:59:36 PM	Atty Kurtz KIUC - witness Satterwhite	
	Note: Sacre, Candace	Regularly look whether Kentucky Power stand-alone entity/merge better for consumers versus AEP family?
4:00:03 PM	Atty Kurtz KIUC - witness Satterwhite	
	Note: Sacre, Candace	Proposing change to transmissioin agreement change to PJM tariff, what Commission ask federal government do?
4:00:58 PM	Atty Kurtz KIUC - witness Satterwhite	
	Note: Sacre, Candace	Tough burden?
4:01:32 PM	Atty Kurtz KIUC - witness Satterwhite	
	Note: Sacre, Candace	Kentucky to FERC, loser under agreement, somebody else like the way agreement works, take it to other guy??

4:02:25 PM	Atty Kurtz KIUC - witness Satterwhite	
	Note: Sacre, Candace	Talking more fundamental to address concern from Kentucky perspective, Kentucky Power stand alone, control own destiny, not reliant on Indiana transco?
4:04:12 PM	Atty Kurtz KIUC - witness Satterwhite	
	Note: Sacre, Candace	Believe Cook example?
4:04:47 PM	Atty Kurtz KIUC - witness Satterwhite	
	Note: Sacre, Candace	Cheapest power in 13-state PJM, not cheapest generation AEP power plants?
4:05:11 PM	Atty Kurtz KIUC - witness Satterwhite	
	Note: Sacre, Candace	Renewables dispatch first, zero energy costs within PJM?
4:05:23 PM	Atty Kurtz KIUC - witness Satterwhite	
	Note: Sacre, Candace	Nuclear next?
4:05:30 PM	Atty Kurtz KIUC - witness Satterwhite	
	Note: Sacre, Candace	Everybody in PJM pays same regardless?
4:05:45 PM	Atty Kurtz KIUC - witness Satterwhite	
	Note: Sacre, Candace	Kentucky benefit from PJM regardless of AEP transmission agreement?
4:06:21 PM	Atty Kurtz KIUC - witness Satterwhite	
	Note: Sacre, Candace	Believe Cook example because wherever nuclear lands in stack, sets marginal clearing price for all PJM?
4:06:50 PM	Atty Kurtz KIUC	
	Note: Sacre, Candace	All questions.
4:06:55 PM	Chairman Schmitt	
	Note: Sacre, Candace	Walmart?
4:07:01 PM	Atty Grundman Walmart	
	Note: Sacre, Candace	No questions.
4:07:03 PM	Chairman Schmitt	
	Note: Sacre, Candace	Kentucky Solar Industries?
4:07:07 PM	Atty Spenard KYSEIA	
	Note: Sacre, Candace	No questions.
4:07:11 PM	Chairman Schmitt	
	Note: Sacre, Candace	Joint Intervenors?
4:07:15 PM	Atty Fitzgerald Joint Intervenors	
	Note: Sacre, Candace	No questions.
4:07:18 PM	Chairman Schmitt	
	Note: Sacre, Candace	Sierra Club?
4:07:23 PM	Atty Miller Sierra Club	
	Note: Sacre, Candace	No quesions
4:07:26 PM	Chairman Schmitt	
	Note: Sacre, Candace	Mr. Frye, SWVA?
4:07:30 PM	Atty Frye SWVA Kentucky	
	Note: Sacre, Candace	No questions.
4:07:33 PM	Chairman Schmitt	
	Note: Sacre, Candace	Vice Chairman Chandler?
4:07:37 PM	Vice Chairman Chandler	
	Note: Sacre, Candace	I do.
4:07:49 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Examination. What past do with schedule or rate just and reasonable?
4:08:18 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Bearing past and history have to do with schedule or rate currently just and reasonable?

4:10:33 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Creating mismatch, expenses allocated Kentucky Power 1 CP basis, reallocating on 12 CP basis, disconnect incurring and being recovered?
4:12:11 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Immaterial fundamental question, agree disconnect between incurring 1 CP basis and allocating 12 CP basis?
4:13:18 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Kentucky Power allocated portion costs 12 CT basis?
4:14:14 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Not how it works, can say how think it works and see if correct?
4:16:39 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Get volatility, trying questions about different, AEP billed as single LSE from PJM 1 CT basis?
4:17:34 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	AEP get one bill 1 CP basis, reallocate to operating companies on 12 CT basis?
4:18:07 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Kentucky paying allocation of entirety of AEP LSE?
4:18:29 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Five and a half, six percent?
4:18:51 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Testimony 2017-00179 rate case, Vinsel asking earlier, remember?
4:19:21 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Talk dollars and cents, agree operating company invest more in transmission than allocated costs, revenue as transmission offset PJM LSE expense allocated?
4:20:21 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	PJM LSE OATT expense, insofar as investments Kentucky Power additional amount offset?
4:20:58 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	PJE LSE OATT expense proposed 100 percent to tariff PPA?
4:21:46 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Very specific, PJM LSE OATT expense, supplemental projects LSE territory, allocated 100 percent to LSE zone?
4:22:31 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Circular, Kentucky Power invests supplemental projects on books transmission investment, recovered, offsetting revenues, flow through/ come back LSE OATT expense?
4:23:21 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	If question Kentucky Transmission Company, same benefit/offset for Kentucky Power customers, not the case?
4:24:05 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	No difference in service, cheaper if operating company makes investment?
4:24:44 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	As Kentucky Power president, wanted invstment Kentucky Power level not Kentucky transco level?
4:24:58 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Benefit to customers?
4:25:32 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Revenues investment at Kentucky Power offset costs?
4:25:52 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Revenues at Kentucky transco level offset no expenses Kentucky Power customers?

4:26:02 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	No benefit to Kentucky Power customers, not offset expenses Kentucky Power level?
4:26:16 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Haven't seen any study to that effect at operating company level?
4:26:38 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	On same page.
4:26:54 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Study operating company level?
4:27:06 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Study specific transmission investments operating company level versus state's transco?
4:27:43 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Filing of FERC formula transmission rates, your group?
4:28:02 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Operating company challenged FERC formula transmission rates, affiliate's FERC transmission rates?
4:28:22 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Allocation costs, passthroughs, offsets revenues, Mr. Pearce next best person to ask?
4:28:37 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	How allocations work, revenues offset between transmission/operating companies, another person know additional information?
4:29:21 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Congestion, driver for supplemental/baseline projects?
4:30:29 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Ali give all the answers, the Mr. Vaughan of transmission?
4:30:45 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Knows what talking about?
4:31:00 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	What benefit Kentucky Power customers get for replacement of 69kV line in Michigan?
4:33:18 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	PJM, bigger than AEP, already takes into account?
4:34:34 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Ever run DFAX AEPSC system if Kentucky Power getting benefits from flow across system?
4:36:03 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Group responsible for maintaining AEP Black Star programs?
4:36:22 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Yes, and filing that with FERC?
4:36:58 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Not come to you until to be filed or in front of regulatory body?
4:37:25 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Rate cases, who determines needed and starts process, your group or operating company level?
4:38:50 PM	Vice Chairman Chandler - witness Satterwhite	
	Note: Sacre, Candace	Decision head of operating companies?
4:39:09 PM	Vice Chairman Chandler	
	Note: Sacre, Candace	Thank you.
4:39:12 PM	Chairman Schmitt	
	Note: Sacre, Candace	Dr. Mathews?

4:39:16 PM	Commissioner Mathews	
	Note: Sacre, Candace	One, maybe two.
4:39:20 PM	Commissioner Mathews - witness Satterwhite	
	Note: Sacre, Candace	Examination. Last rate case, investment in transmission good deal and benefit because paid 6 percent transmission, true?
4:39:50 PM	Commissioner Mathews - witness Satterwhite	
	Note: Sacre, Candace	Also true if transmission investment done by transco?
4:40:14 PM	Camera Lock Video Conference Activated	
4:40:17 PM	Camera Lock Deactivated	
4:40:44 PM	Commissioner Mathews - witness Satterwhite	
	Note: Sacre, Candace	One more time, referring to benefit in Kentucky, talking about ancillary benefits?
4:41:31 PM	Commissioner Mathews - witness Satterwhite	
	Note: Sacre, Candace	Different consideration than putting assets on Kentucky Power base rate, then get some revenue back?
4:42:47 PM	Commissioner Mathews - witness Satterwhite	
	Note: Sacre, Candace	Could spend week talking difference transmission-owning and LSE, way bounce back and forth, but will spare you. With that, finished.
4:43:28 PM	Chairman Schmitt	
	Note: Sacre, Candace	Mr. Overstreet?
4:43:34 PM	Atty Overstreet Kentucky Power	
	Note: Sacre, Candace	Very briefly.
4:43:37 PM	Atty Overstreet Kentucky Power - witness Satterwhite	
	Note: Sacre, Candace	Redirect Examination. Motion to intervene FERC Case ER09-1279-000?
4:44:08 PM	Atty Overstreet Kentucky Power	
	Note: Sacre, Candace	Kentucky Power Exhibit 8?
4:44:36 PM	Camera Lock Video Conference Activated	
4:44:44 PM	Atty Overstreet Kentucky Power - witness Satterwhite	
	Note: Sacre, Candace	Recognize?
4:44:48 PM	Atty Overstreet Kentucky Power - witness Satterwhite	
	Note: Sacre, Candace	Motion to Intervene?
4:44:52 PM	Atty Overstreet Kentucky Power - witness Satterwhite	
	Note: Sacre, Candace	Page 2 of 4, Company Hearing Exhibit 8, read paragraph under Support?
4:45:51 PM	Atty Overstreet Kentucky Power	
	Note: Sacre, Candace	Move admittance.
4:46:03 PM	Camera Lock Deactivated	
4:46:19 PM	Chairman Schmitt	
	Note: Sacre, Candace	Identify as Kentucky Power Hearing Exhibit 1, any objecdtion?
4:46:28 PM	Chairman Schmitt	
	Note: Sacre, Candace	Sustained, let be filed Kentucky Power Hearing Exhibit 1.
4:46:33 PM	KENTUCKY POWER HEARING EXHIBIT 01	
	Note: Sacre, Candace	ATTY OVERSTREET KENTUCKY POWER - WITNESS SATTERWHITE
	Note: Sacre, Candace	MOTION TO INTERVENE FERC CASE ER09-1279-000
4:46:35 PM	Atty Overstreet Kentucky Power	
	Note: Sacre, Candace	No further.
4:46:37 PM	Chairman Schmitt	
	Note: Sacre, Candace	Now about 12 minutes till 5, recess/adjourn. Ms. Vinsel?
4:47:09 PM	Asst Gen Counsel Vinsel PSC	
	Note: Sacre, Candace	Move exhibits, Confidential Exhibits 1 through 4 and Nonconfidential Exhibits into record.
4:47:19 PM	Chairman Schmitt	
	Note: Sacre, Candace	Objection?

4:47:25 PM	Atty Overstreet Kentucky Power	
	Note: Sacre, Candace	No.
4:47:26 PM	Chairman Schmitt	
	Note: Sacre, Candace	Admitted as identified by Ms. Vinsel,
4:47:31 PM	PSC HEARING EXHIBITS 1 - 16	
	Note: Sacre, Candace	SEE BELOW FOR COMPLETE LISTING WITH DESCRIPTIONS
4:47:31 PM	Chairman Schmitt	
	Note: Sacre, Candace	Anything else?
4:47:38 PM	Atty Kurtz KIUC	
	Note: Sacre, Candace	Move admission AG/KIUC Hearing Exhibit 1.
4:47:46 PM	Chairman Schmitt	
	Note: Sacre, Candace	Objection?
4:47:48 PM	Chairman Schmitt	
	Note: Sacre, Candace	Hearing none, let be filed.
4:47:49 PM	AG/KIUC HEARING EXHIBIT 01	
	Note: Sacre, Candace	EEI FINANCIAL CONFERENCE NOV 9-10 2020 ADVANCING TOWARDS A CLEAN ENERGY FUTURE
4:47:55 PM	Chairman Schmitt	
	Note: Sacre, Candace	Anything else?
4:47:58 PM	Atty Kurtz KIUC	
	Note: Sacre, Candace	AG/KIUC Hearing Exhibit 3, sorry.
4:48:04 PM	Chairman Schmitt	
	Note: Sacre, Candace	Let AG/KIUC Hearing Exhibit 2 be admitted.
4:48:05 PM	AG/KIUC HEARING EXHIBIT 02	
	Note: Sacre, Candace	PJM INTERCONNECTION APRIL 16 2019 THE BENEFITS OF THE PJM TRANSMISSION SYSTEM
4:48:20 PM	Chairman Schmitt	
	Note: Sacre, Candace	Anything else?
4:48:24 PM	Atty Overstreet Kentucky Power	
	Note: Sacre, Candace	Exhibit 3, no foundation as to provenance, numbers on a spreadsheet.
4:48:41 PM	Atty Kurtz KIUC	
	Note: Sacre, Candace	PJM document, pricing all transmission owners in PJM.
4:48:50 PM	Chairman Schmitt	
	Note: Sacre, Candace	Overruled, let be filed.
4:48:54 PM	Chairman Schmitt	
	Note: Sacre, Candace	Anything further?
4:48:56 PM	AG/KIUC HEARING EXHIBIT 03	
	Note: Sacre, Candace	ANNUAL TRANSMISSION REVENUE REQUIREMENTS AND RATES EFFECTIVE JUNE 1 2002 (REVISED - PECO ZONE UPDATED)
4:48:57 PM	Chairman Schmitt	
	Note: Sacre, Candace	If not, recess until 9 o'clock in the morning.
4:48:58 PM	PSC HEARING EXHIBIT 01	
	Note: Sacre, Candace	FERC FINANCIAL REPORT FERC FORM NO. 1 and FORM 3-Q 2019/Q4
4:48:59 PM	PSC HEARING EXHIBIT 02	
	Note: Sacre, Candace	ATTACHMENT B - 2 TRANSMISSION AGREEMENT AMERICAN ELECTRIC POWER SERVICE CORPORATION APRIL 1984 AS AMENDED
4:49:00 PM	PSC HEARING EXHIBIT 03	
	Note: Sacre, Candace	OFFER OF SETTLEMENT AEPSC FERC DOCKET ER09-1279-000 AUGUST 4 2010
4:49:01 PM	PSC HEARING EXHIBIT 04	
	Note: Sacre, Candace	AMENDMENTS TRANSMISSION AGREEMENT JUNE 5 2009

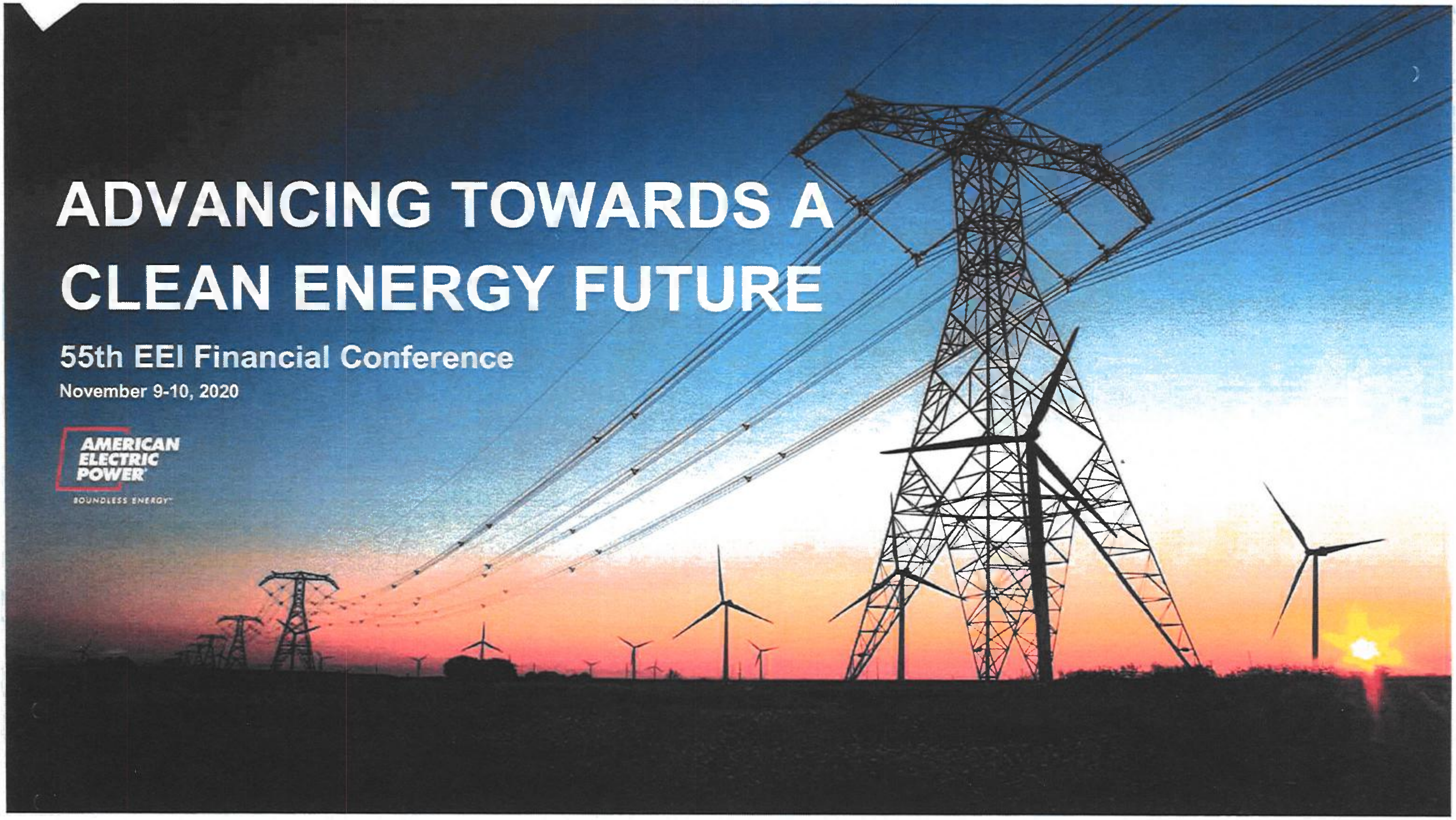
4:49:02 PM	PSC HEARING EXHIBIT 05	
	Note: Sacre, Candace	ATTESTATION FERC DOCKET ER09-____-000 MAY 31 2009
4:49:03 PM	PSC HEARING EXHIBIT 06	
	Note: Sacre, Candace	TRANSMISSION AGREEMENT AEPSC APRIL 1984 AS AMENDED
4:49:04 PM	PSC HEARING EXHIBIT 07	
	Note: Sacre, Candace	DIRECT TESTIMONY J. CRAIG BAKER AEP EAST COMPANIES JUNE 5 2009
4:49:05 PM	PSC HEARING EXHIBIT 08	
	Note: Sacre, Candace	DIRECT TESTIMONY DENNIS W. BETHEL AEP EAST COMPANIES JUNE 5 2009
4:49:06 PM	PSC HEARING EXHIBIT 10	
	Note: Sacre, Candace	TRANSMISSION AGREEMENT DATED APRIL 1984 AS AMENDED COMPOSITE COPY
4:49:06 PM	PSC HEARING EXHIBIT 09	
	Note: Sacre, Candace	AEPSC APRIL 1984 MODIFICATION NO. 1 JANUARY 1 1989 AND SUPPLEMENT A DECEMBER 12 1989
4:49:07 PM	PSC HEARING EXHIBIT 16	
	Note: Sacre, Candace	PSC CASE 2011-00042 APPLICATION OF AEP KENTUCKY TRANSMISSION COMPANY, INC., CPCN
4:49:07 PM	PSC HEARING EXHIBIT 13	
	Note: Sacre, Candace	PSC CASE 2017-00179 REBUTTAL TESTIMONY OF MATTHEW J. SATTERWHITE KENTUCKY POWER COMPANIES
4:49:07 PM	PSC HEARING EXHIBIT 12	
	Note: Sacre, Candace	PSC CASE 2017-00179 DIRECT TESTIMONY OF MATTHEW J. SATTERWHITE KENTUCKY POWER COMPANIES
4:49:07 PM	PSC HEARING EXHIBIT 15	
	Note: Sacre, Candace	SUB REGIONAL RTEP COMMITTEE: WESTERN AEP SUPPLEMENTAL PROJECTS FEBRUARY 21 2020
4:49:07 PM	PSC HEARING EXHIBIT 14	
	Note: Sacre, Candace	PSC CASE 2017-00179 DIRECT TESTIMONY OF SATTERWHITE, BARTSCH, BUCK, CARLIN, CASH KENTUCKY POWER COMPANIES SECTION III VOL 1 OF 4 JUNE 28 2017
4:49:07 PM	PSC HEARING EXHIBIT 11	
	Note: Sacre, Candace	AEP EAST COMPANIES' TRANSMISSION COST OF SERVICE AND COMPARISON OF RETAIL TRANSMISSION RATES PRESENT AND PROPOSED
4:49:07 PM	Session Ended	

Exhibit List Report

2020-00174 17Nov2020

Kentucky Power Company (Kentucky Power)

Name:	Description:
AG/KIUC Hearing Exhibit 1	EEI Financial Conference November 9-10 2020 Advancing Towards a Clean Energy Future
AG/KIUC Hearing Exhibit 2	PJM Interconnection April 16 2019 The Benefits of the PJM Transmission System
AG/KIUC Hearing Exhibit 3	Annual Transmission Revenue Requirements Effective June 1 2020 (Revised - PECO Zone Updated)
Kentucky Power Exhibit 01	Motion to Intervene FERC Case ER09-1279-000
PSC Hearing Exhibit 01	FERC Financial Report FERC Form No. 1 and Form 3-Q 2019/Q4
PSC Hearing Exhibit 02	Attachment B-2 Transmission Agreement American Electric Power Service Corporation April 1984 as Amended
PSC Hearing Exhibit 03	Offer of Settlement AEPSC FERC Docket ER09-1279-000 August 4 2010
PSC Hearing Exhibit 04	Amendments Transmission Agreement June 5 2009
PSC Hearing Exhibit 05	Attestation Docket No. ER09-____-000 May 31 2005
PSC Hearing Exhibit 06	Transmission Agreement AEPSC April 1984 as Amended
PSC Hearing Exhibit 07	Direct Testimony J. Craig Baker AEP East Companies June 5 2009
PSC Hearing Exhibit 08	Direct Testimony Dennis W. Bethel AEP East Companies June 5 2009
PSC Hearing Exhibit 09	Transmission Agreement AEPSC April 1984 Modification No. 1 January 1 1989 and Supplement A December 12 1989
PSC Hearing Exhibit 10	Transmission Agreement Dated April 1984 as Amended Composite Copy
PSC Hearing Exhibit 11	AEP East Companies' Transmission Cost of Service and Comparison of Retail Transmission Rates Present and Proposed
PSC Hearing Exhibit 12	Direct Testimony of Matthew J. Satterwhite Kentucky Power Companies
PSC Hearing Exhibit 13	PSC Case 2017-00179 Rebuttal Testimony of Matthew J. Satterwhite Kentucky Power Companies
PSC Hearing Exhibit 14	PSC Case 2017-00179 Direct Testimony of Satterwhite, Bartsch, Buck, Carlin, Cash Kentucky Power Companies Section III Vol 1 of 4 June 28 2017
PSC Hearing Exhibit 15	Sub Regional RTEP Committee: Western AEP Supplemental Projects February 21 2020
PSC Hearing Exhibit 16	PSC Case 2011-00042 Application of AEP Kentucky Transmission Company, Inc. CPCN



AG/KIUC Hearing Ex. 1

"Safe Harbor" Statement Under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: changes in economic conditions, electric market demand and demographic patterns in AEP service territories, The impact of pandemics, including COVID-19, and any associated disruption of AEP's business operations due to impacts on economic or market conditions, electricity usage, employees, customers, service providers, vendors and suppliers, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability or cost of capital to finance new capital projects and refinance existing debt, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, decreased demand for electricity, weather conditions, including storms and drought conditions, and the ability to recover significant storm restoration costs, the cost of fuel and its transportation, the creditworthiness and performance of fuel suppliers and transporters and the cost of storing and disposing of used fuel, including coal ash and spent nuclear fuel, the availability of fuel and necessary generation capacity and performance of generation plants, the ability to recover fuel and other energy costs through regulated or competitive electric rates, the ability to build or acquire renewable generation, transmission lines and facilities (including the ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs, new legislation, litigation and government regulation, including oversight of nuclear generation, energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances that could impact the continued operation, cost recovery and/or profitability of generation plants and related assets, evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including coal ash and nuclear fuel, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions, including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance, resolution of litigation, the ability to constrain operation and maintenance costs, prices and demand for power generated and sold at wholesale, changes in technology, particularly with respect to energy storage and new, developing, alternative or distributed sources of generation, the ability to recover through rates any remaining unrecovered investment in generation units that may be retired before the end of their previously projected useful lives, volatility and changes in markets for coal and other energy-related commodities, particularly changes in the price of natural gas, changes in utility regulation and the allocation of costs within regional transmission organizations, including ERCOT, PJM and SPP, changes in the creditworthiness of the counterparties with contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, the impact of volatility in the capital markets on the value of the investments held by the pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact of such volatility on future funding requirements, accounting standards periodically issued by accounting standard-setting bodies, and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, naturally occurring and human-caused fires, cyber security threats and other catastrophic events, the ability to attract and retain requisite work force and key personnel.

Darcy Reese, Managing Director

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Tom Scott, Director

Investor Relations
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twscott@aep.com

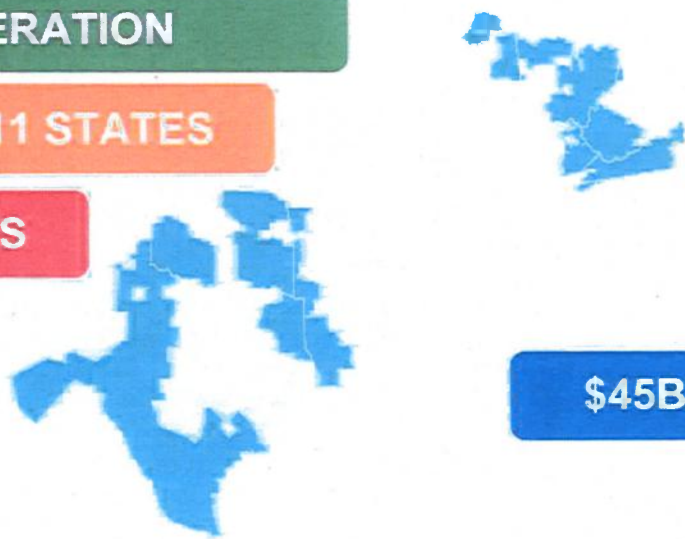
The Premier Regulated Energy Company

16,900 EMPLOYEES

24GW OWNED GENERATION

5.5M CUSTOMERS, 11 STATES

$79B TOTAL ASSETS



40,000 TRANSMISSION MILES

221,000 DISTRIBUTION MILES

$47B RATE BASE

$45B CURRENT MARKET CAPITALIZATION

Statistics as of October 1, 2020 except for rate base as of December 31, 2019 and market capitalization as of November 4, 2020

AEP Leading the Way Forward

Confidence in Steady and Predictable Earnings Growth Rate of 5%-7%	Commitment to Growing Dividend Consistent with Earnings	Well Positioned as a Sustainable Regulated Business	Compelling Portfolio of Premium Investment Opportunities

AEP's Strategic Vision and Execution

EXECUTE STRATEGY	TOP PRIORITIES
Promote clean energy transformation	• Invest in regulated and contracted renewables • Optimize the generation fleet
Enable growth and prosperity for our communities	• Grow top line revenue • Champion economic development • Be good neighbors
Innovate for the benefit of our customers	• Improve customer experience through use of technology and business innovation • Modernize regulatory mechanisms to support customer expectations
Build a modern, secure and resilient grid	• Deploy technologies that enhance grid safety, security and value • Invest in leveraging energy infrastructure
Drive operational excellence	• Achieve Zero Harm • Drive relentless O&M optimization • Implement automation, digitization and process improvements • Be a great place to work

EEI KEY THEMES

Pure Play Electric Utility with Significant Renewables Upside

- 5%-7% Earnings Growth Rate and 2021 Range
- Proven Track Record of TSR and EPS Performance
- Strong Dividend Growth
- O&M Optimization
- ESG Focus and Transition Towards a Clean Energy Future

AMERICAN ELECTRIC POWER

Strong Return Proposition for Investors

TOTAL SHAREHOLDER RETURN

8% - 10%

DIVIDEND YIELD		EPS GROWTH
3%	+	5% - 7%

2021 OPERATING EARNINGS GUIDANCE RANGE

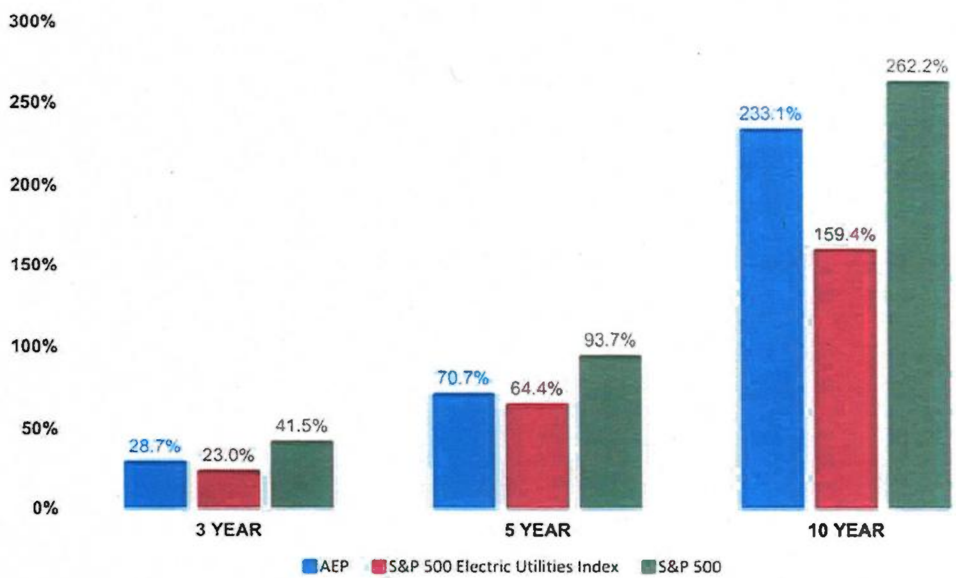
$4.51 - $4.71

2020 EPS MIDPOINT		EPS GROWTH		2021 EPS MIDPOINT
$4.35	+	6%	=	$4.61

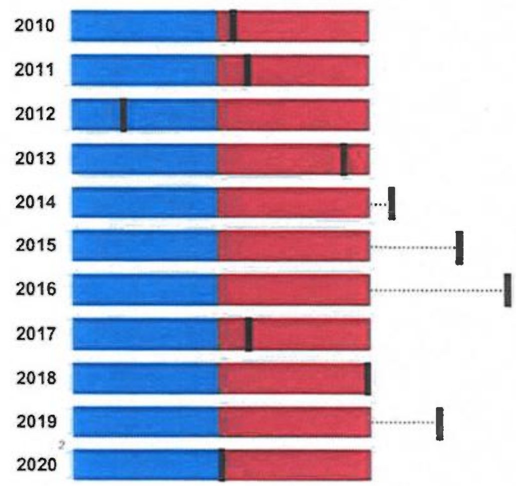
- ✓ STEADY GROWTH
- ✓ CONSISTENT DIVIDENDS
- ✓ LOW RISK, REGULATED ASSETS
- ✓ INVESTMENT PIPELINE
- ✓ INCENTIVE COMPENSATION TIED TO EPS RESULTS

Proven Track Record of Performance

FAVORABLE TOTAL SHAREHOLDER RETURN[1]

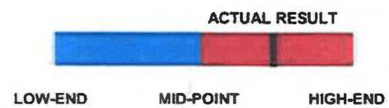


DECADE OF MEETING OR EXCEEDING ORIGINAL OPERATING EPS GUIDANCE



[2] EPS midpoint

KEY



[1] Data as of September 30, 2020

Strong Dividend Growth

- ✓ Targeted payout ratio 60-70% of operating earnings
- ✓ Over 110 years of consecutive quarterly dividends
- ✓ Targeted dividend growth in line with earnings

EPS Growth + Dividend Yield = 8% to 10% Annual Return Opportunity

* Subject to Board approval

O&M Optimization

INITIATIVES	ACTIONS
Achieving Excellence Program	• **Employee based O&M prioritization and optimization effort** • **Driven down costs in 2020 & beyond, initial results imbedded in budgets** • **Program was transitioned from EHS partners to internal resources and will continue annually** • **2021 Program** – New O&M savings ideas, evaluation of further study ideas and Future of Work opportunities • **Future of Work** – Optimization of Value Streams (end-to-end work flow)
Lean Management System Implementation/Continuous Process Improvement	• **Distribution** – Enhanced reliability to reduce O&M and improve storm hardening • **Supply chain** – Optimize the material requisition process to improve material lead times, reducing stock and increasing crew productivity • **Fleet operations** – Reduce the number of vehicle platforms and optimize the acquisition process • **Generation (system productivity)** – Optimize plant systems and operations
Data Analytics	• **Workforce optimization** – Employee/contractor mix • **Hot socket model** – Using AMI data to preemptively identify meters at risk • **Revenue protection** – Detecting meter tampering • **Frequency regulation** – Analysis of PJM bidding strategies
Automation	• **Scrap metal billing and management** • **Service Corp billing allocation factors** • **No-bill workflow assignment process** • **Customer workflow scheduling**
Digital Tools	• **"The Zone"** – Machine learning tool to operate fossil units to minimize O&M and capital, while maintaining improved performance • **Generation Monitoring and Diagnostic Center** – Predictive capabilities that save O&M and capital
Use of Drones	• **Storm damage assessment** • **Real estate and land surveys** • **Transmission facility inspections, construction monitoring and documentation** • **Telecommunication tower inspections** • **Cooling tower and boiler inspections**
Outsourcing	• **Accounting and tax initiative** • **Rapid application and information support** • **Lockbox for customer payments by check**
Workforce Planning	• **Approximately 4,000 employees will retire or leave in the next 5 years**
Strategic Sourcing	• **Reducing cost through procurement category management** – Continuing to mature our Category Management program and aggressively using strategic sourcing opportunities to optimize the value AEP receives from the $6B spent annually on goods and services

ESG Focus

ENVIRONMENTAL

- Dramatic reductions in emissions
- 42% reduction in coal capacity by 2030
- Coal capacity = 15% of rate base
- ~$9B spent on environmental controls since 2000
- Carbon emission reduction goals: 70% by 2030, 80% by 2050, with zero emission aspirations
- Emission reduction strategy tied to long-term incentive compensation

Hg	SO_2	NO_x	CO_2
97%	97%	94%	65%

SOCIAL

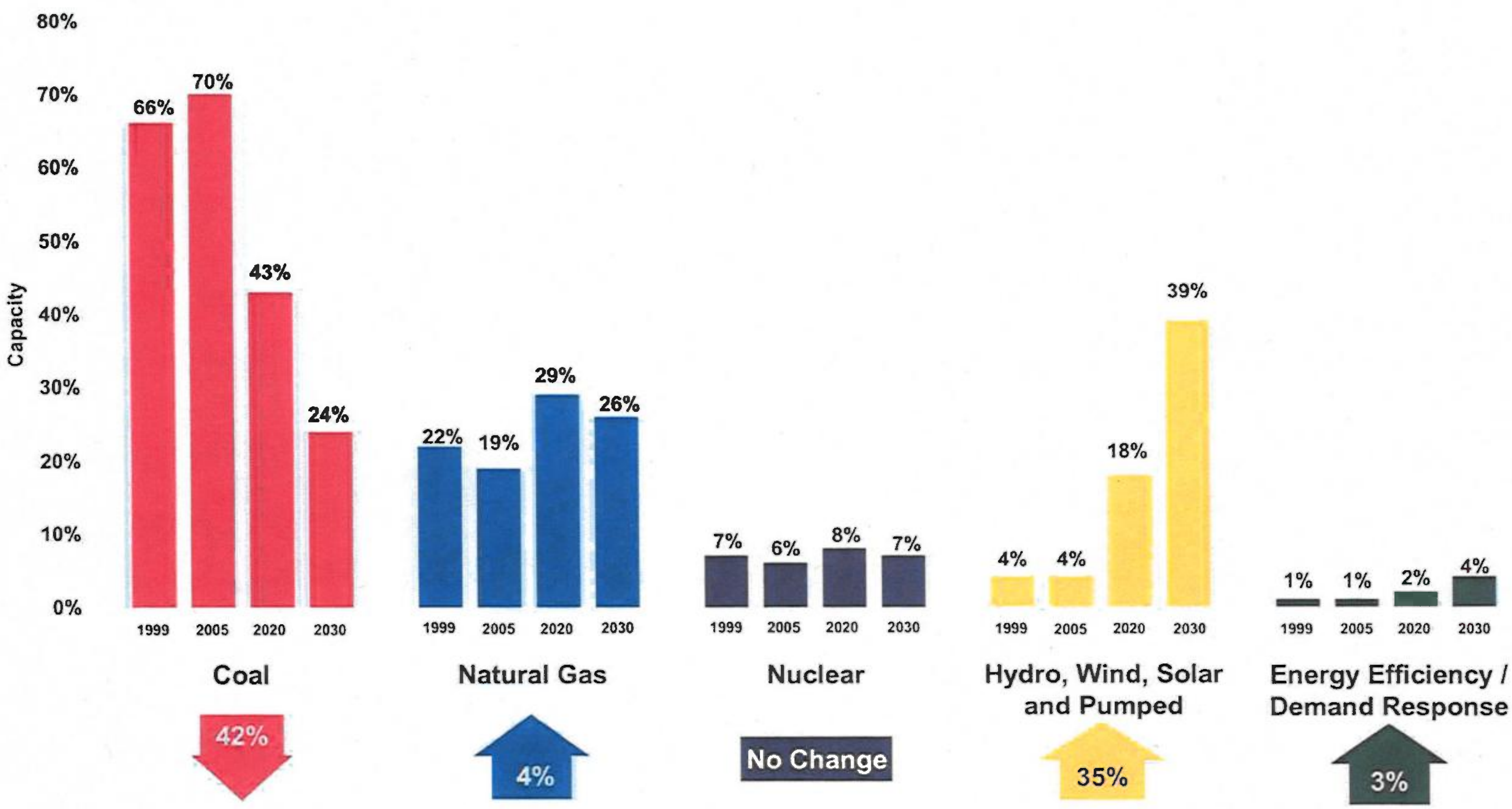
- Diversity and inclusion vision
- Focused on economic and business development in our service territories
- Zero Harm mentality – zero injuries, zero occupational illnesses and zero fatalities

GOVERNANCE

- 13 directors, 12 are independent, 38% diverse with an average tenure of 7 years
- Annual shareholder engagement on strategy and ESG matters with lead independent director participation
- Environmental reports provided at every Board meeting

Note: See "Environmental, Social & Governance section for further information

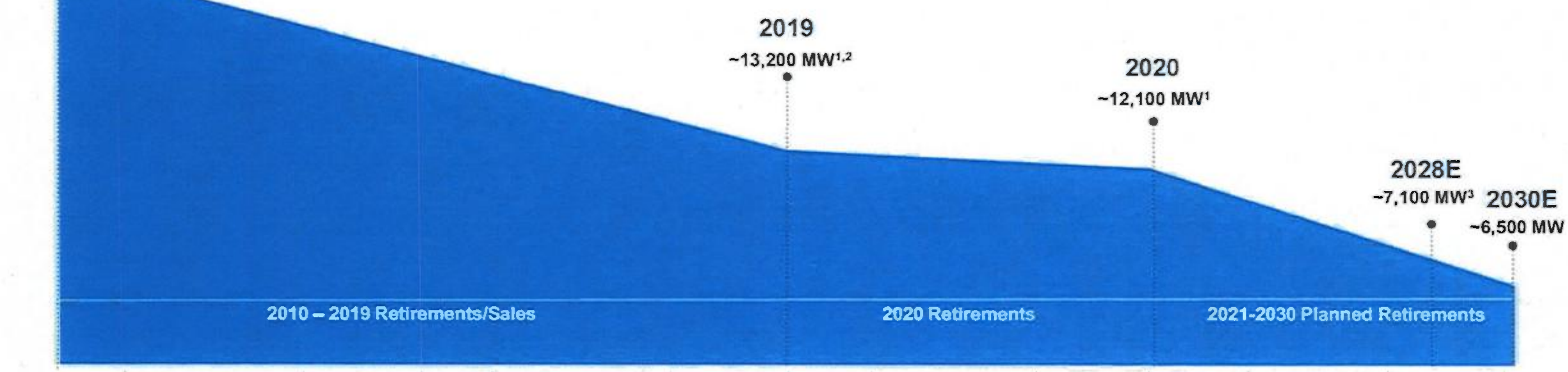
Transforming Our Generation Fleet



2020 data as of 10/1/2020. 2030 includes IRP forecasted additions and retirements as well as subsequent public filings. 2030 does not include wind, solar and natural gas replacement capacity for certain recently announced coal retirements. Energy Efficiency / Demand Response represents avoided capacity rather than physical assets.

Retirement Progress and Plans

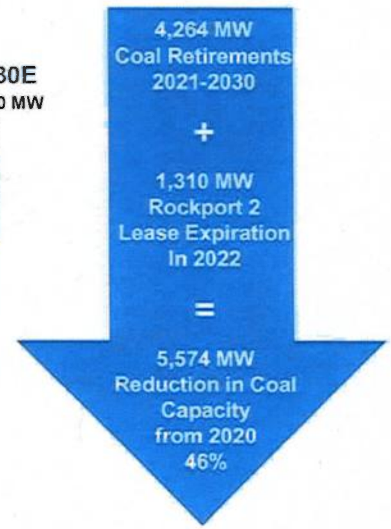
Reduce coal generation by approximately 5,600 MW by 2030 and decrease coal net book value through retirements and depreciation. This creates the opportunity to own replacement wind, solar and natural gas resources.



YEAR	PLANT	CAPACITY	YEAR	PLANT	CAPACITY
2011	Sporn 5	450 MW	2015	Sporn 1-4	600 MW
2012	Conesville 3	165 MW	2015	Tanners Creek 1-4	995 MW
2014	Beckjord	53 MW	2016	Big Sandy 1	278 MW
2015	Big Sandy 2	800 MW	2016	Clinch River 1 & 2	470 MW
2015	Clinch River 3	235 MW	2016	Northeastern 4	470 MW
2015	Glen Lyn 5 & 6	335 MW	2016	Welsh 2	528 MW
2015	Kammer 1-3	630 MW	2017	Gavin 1 & 2	2,640 MW
2015	Kanawha River 1 & 2	400 MW	2017	Zimmer	330 MW
2015	Muskingum River 1-5	1,440 MW	2018	Stuart 1-4	600 MW
2015	Picway 5	100 MW	2019	Conesville 5 & 6	820 MW

YEAR	PLANT	CAPACITY
2020	Conesville 4	651 MW
2020	Oklaunion	460 MW

YEAR	PLANT	CAPACITY
2021	Dolet Hills	257 MW
2023	Pirkey	580 MW
2026	Northeastern 3	469 MW
2028	Rockport 1	1,310 MW
2028	Welsh	1,053 MW
2030	Cardinal	595 MW



[1] Total includes owned coal units and the Rockport 2 lease
[2] Includes 2012 Turk Plant addition and 40% of Conesville 4 that was acquired in conjunction with the sale of Zimmer Plant
[3] Total accounts for the expiration of the Rockport 2 lease

EPA Notice of New Coal Retirements

- **The EPA recently revised requirements of both the Coal Combustion Residual Rule (CCR) and Effluent Limitation Guidelines (ELG), requiring significant dollar investment to utilities' coal-fired generation fleets.**
- **AEP continues to evaluate its fleet on a plant-by-plant basis to determine the economic value to both the customer and the company**
- **AEP plans to file its intentions with the EPA in November 2020**

Plant/Unit	Operating Company	EPA Filing Details	Authority to Operate (current plans)
Rockport 2	AEG/I&M	CCR + ELG Extension, CCR Compliant in 2023	Returning to lessors at the end of lease term (Dec 2022)
Pirkey	SWEPCO	Retirement Extension, Close Ponds by 10/17/2023 Stop Generation in 2023	Retire in 2023
Rockport 1	AEG/I&M	CCR-Only Extension, CCR Compliant in 2023	Full Depreciable Life (2028)
Welsh 1 & 3	SWEPCO	Retirement Extension, Close Ponds by 10/17/2028 Stop generation in 2028	Retire in 2028
Flint Creek	SWEPCO	CCR + ELG Extension, CCR Compliant in 2023	Full Depreciable Life (2038)
Amos 1, 2, & 3	APCo	CCR + ELG Extension, CCR Compliant in 2023	Full Depreciable Life (2040)
Mountaineer	APCo	CCR + ELG Extension, CCR Compliant in 2023	Full Depreciable Life (2040)
Mitchell 1 & 2	KPCo/WPCo	CCR + ELG Extension, CCR Compliant in 2023	Full Depreciable Life (2040)

Advancing Towards a Clean Energy Future

Projected Resource Additions[1]

SOLAR ADDITIONS (MW)			
Company	2021 - 2022	2023 - 2025	2026 - 2030
APCo	110	150	450
I&M	150	300	850
KPCo	20	253	-
PSO	11	300	900
SWEPCO	-	200	100
Totals	291	1,203	2,300

WIND ADDITIONS (MW)			
Company	2021 - 2022	2023 - 2025	2026 - 2030
APCo	-	200	400
I&M	300	150	300
KPCo	-	-	200
PSO	675 [2]	400	200
SWEPCO	810 [2]	600	-
Totals	1,785	1,350	1,100

NATURAL GAS ADDITIONS (MW)			
Company	2021 - 2022	2023 - 2025	2026 - 2030
I&M	18	18	788
PSO	373 [3]	37 [3]	373 [3]
Totals	391	55	1,161

TOTAL PROJECTED RESOURCE ADDITIONS (MW)	
Resource	2021-2030
Solar	3,794
Wind	4,235
Natural Gas	1,607
Totals	9,636

As of 11/2/20

[1] Representative of IRP flings and subsequent public filings or RFPs, as well as projects that have obtained regulatory approval, but have not yet reached commercial operation. Projected resource additions do not include wind, solar and natural gas replacement capacity for certain recently announced future coal retirements.
[2] Represents North Central Wind
[3] To replace expiring PPA

Renewables Progress Update

Company	Structure	Solar (MW)	Wind (MW)	Public Status	Expected In-Service	In 2021-2025 Capital Plan
APCo (VA)	PPA	15	-	Expected COD Q2 2021	2021	N/A
APCo (VA)	PPA	40	-	Expected COD 2021	2021	N/A
APCo (VA)	Owned	105	-	Solar RFP issued in January 2020	2023	Yes
APCo (WV)	Owned	50	-	Solar RFP issued in June 2020	2022	Yes
I&M	Owned	20	-	Approval received (St. Joseph Solar)	2021	Yes
I&M	2/3 Owned & 1/3 PPA	300 [4]	150 [4]	Solar and wind RFP issued November 2020	2023	Yes
PSO	Owned	-	675	Approval received (North Central Wind)	2021/2022	Yes
SWEPCO (AR, LA)	Owned	-	810	Approval received (North Central Wind)	2021/2022	Yes
SWEPCO (LA)	Owned or PPA	200	-	Solar RFP planned for 4Q20 (part of North Central Wind settlement for LA)	2024	No
Total MW		730	1,635			

Total of 2,365 MW of renewable projects in progress

[4] Final solar and wind split to be determined

APCo Virginia Clean Energy Initiative Details

Current & Pending Renewable Resources (MW)

	PPA	Owned	Total	Counts Toward VCEA[1] MW Goal[2]	VCEA Targets[3]	% Progress
Hydro – Current	80	200	280	254	254	100%
Wind – Current	495	-	495	140	2,200	6.4%
Total Current	**575**	**200**	**775**	**394**		
Solar - Pending	55	105	160	160	3,460	4.6%
Total Current & Pending[4]	**630**	**305**	**935**	**554**	**5,914**	**9.4%**

Projected Long Term Resource Additions (MW)

	2021-2025[5]			2026-2030			2031-2050			Total			Counts Toward VCEA MW Goal[2]	VCEA Targets[3]	% Progress
	PPA	Owned	Total	PPA	Owned	Total	PPA	Owned	Total	PPA	Owned	Total			
Wind	-	200	200	-	400	400	-	1,600	1,600	-	2,200	2,200	2,200	2,200	100%
Solar	105	105	210	150	300	450	1,000	1,800	2,800	1,255	2,205	3,460	3,460	3,460	100%
Total	**105**	**305**	**410**	**150**	**700**	**850**	**1,000**	**3,400**	**4,400**	**1,255**	**4,405**	**5,660**	**5,660**	**5,660**	**100%**

[1] Virginia Clean Economy Act
[2] Includes Virginia jurisdictional share of owned and contracted facilities
[3] Targets reflect renewable resources necessary to meet requirements in VCEA through 2050
[4] Does not include an additional 585 MWs of in-service pumped storage owned by APCo
[5] Includes pending solar projects

Additional Clean Energy Initiatives

INDIANA MICHIGAN POWER
An AEP Company

- In November 2020, I&M released a RFP for **450 MW** of combined wind and solar resources projected to be in service by the end of 2023

(MW)	Solar	Wind	Total[1]
PPA	100	50	**150**
Owned	200	100	**300**
Total	300	150	**450**

[1] Final solar and wind split to be determined

- In addition, I&M announced that it will not renew its lease of Rockport Unit 2 which expires in Dec. 2022
- With the previously-announced retirement of Rockport Unit 1, I&M will be coal-free by the end of 2028
  - Does not include I&M's 7.85% contractual share of OVEC
  - Generation fleet will consist of Cook nuclear facility and renewables
- On track to meet 100% of its energy needs from clean resources by 2028

SOUTHWESTERN ELECTRIC POWER COMPANY
An AEP Company

- Over the next 20 years, SWEPCO will generate over **one-third** of its energy from **wind and solar** (9% to 36%)
- Will begin offering large scale solar directly to Arkansas municipal customers in 2021
- Committed to purchasing up to **30 MW** of solar from independent producers in Louisiana through its Renewable Energy Pilot Program tariff

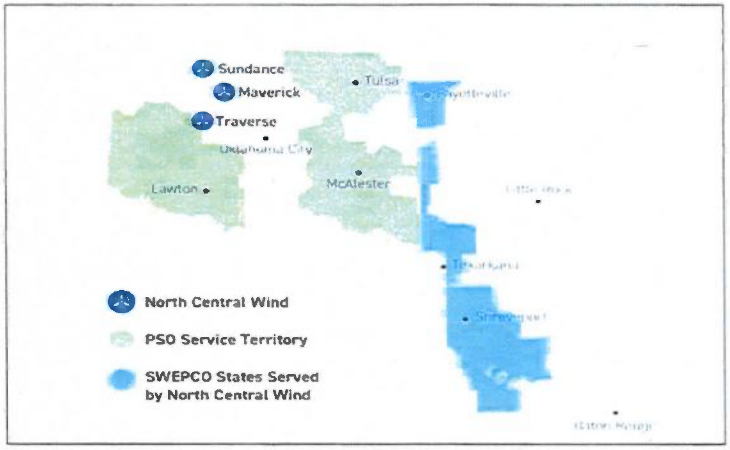
PUBLIC SERVICE COMPANY OF OKLAHOMA
An AEP Company

- In June 2020, PSO signed a 30-year lease with the Army to install an energy resilience project on approximately 81 acres at Fort Sill
- Project includes the construction of **36 MW** of gas-fired generation and **11 MW** of solar panels
- In October 2020, PSO filed for commission approval for $118 million of investment for construction of the gas-fired and solar generation

AEP ENERGY
An AEP Company

- Aggregation where eligible customers within the City of Columbus will be served by 100% clean energy sourced from Ohio renewable assets. The aggregation will tackle social and environmental equity issues, employing Ohio workers and providing job training.
- Customers - 180,000 to 220,000
- Term - June 2021 thru December 2035
- Renewable Supply – Ohio renewable projects such as Emerson Creek Wind Farm **240 MW**, Columbus Solar Park **50 MW**, Atlanta Farms Solar Farm **200 MW**

North Central Wind Overview



SWEPCO AND PSO
REGULATED WIND INVESTMENT

Total Rate Base Investment	~$2 billion (1,485 MW)			
	Name	MW	Investment	Target Date
North Central Wind	Sundance	199	$348M	Mar. 2021 (100% PTC)
	Maverick	287	$402M	Dec. 2021 (80% PTC)
	Traverse	999	$1,235M	Dec. 2021 to Apr. 2022 (80% PTC)
Net Capacity Factor	44.0%			
Customer Savings	~$3 billion (30-year nominal $)			
Developer	Invenergy			
Turbine Supplier	GE			

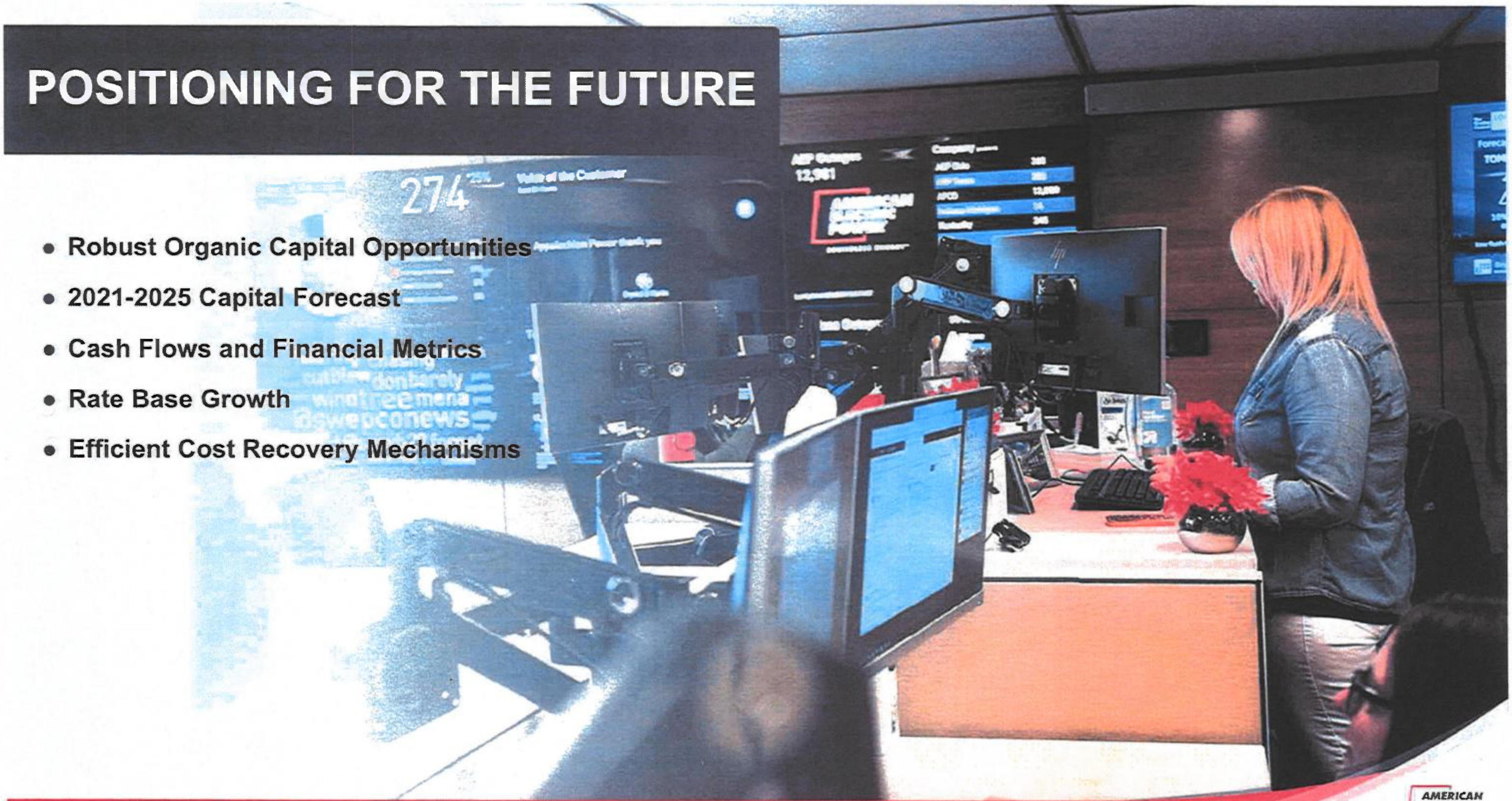
Note: Facilities to be acquired on a fixed cost, turn-key basis at completion

APPROVED MW ALLOCATION

Jurisdiction (Docket #)	MW	% of Project
PSO (PUD 2019-00048)	675	45.5%
SWEPCO – AR (19-035-U)	268	18.1%
SWEPCO – LA (U-35324)	464	31.2%
SWEPCO - FERC	78	5.2%
Total:	1,485	100%

Regulatory approvals achieved in Oklahoma, Louisiana, Arkansas and at FERC

POSITIONING FOR THE FUTURE



- Robust Organic Capital Opportunities
- 2021-2025 Capital Forecast
- Cash Flows and Financial Metrics
- Rate Base Growth
- Efficient Cost Recovery Mechanisms

AMERICAN ELECTRIC POWER

Robust Organic Capital Opportunities

TRANSMISSION

- Grid modernization
- Aging infrastructure
- Physical/cyber security
- Reliability
- Market efficiency
- Economic development projects

DISTRIBUTION

- Grid modernization
- Reliability improvement projects
- Distribution station refurbishment

RENEWABLES

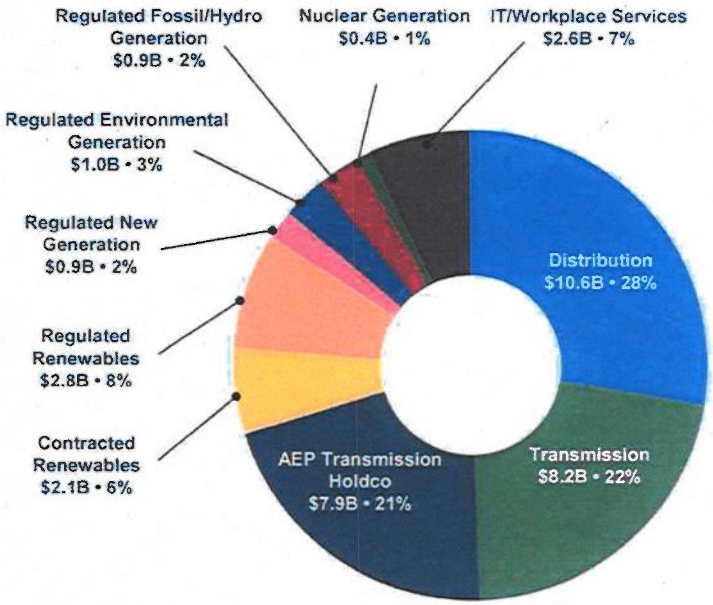
- Regulated renewables supported by integrated resource plans and contracted renewables

TECHNOLOGY

- Digitization
- Automation
- Cyber security
- Enterprise-wide applications

2021 - 2025 Capital Forecast of $37B and Net Plant

2021-2025 Capital Forecast



100%
of capital allocated to regulated businesses and contracted renewables

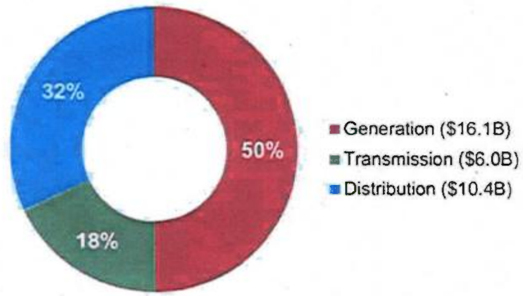
FOCUS ON WIRES & RENEWABLES

71%
allocated to wires

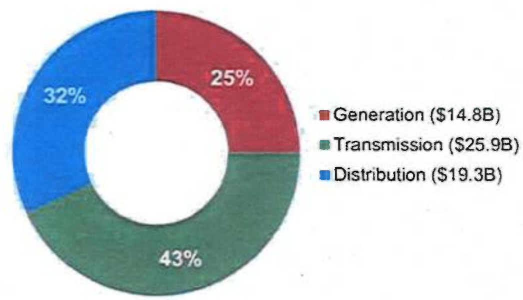
14%
allocated to renewables

Historical Net Plant Profiles

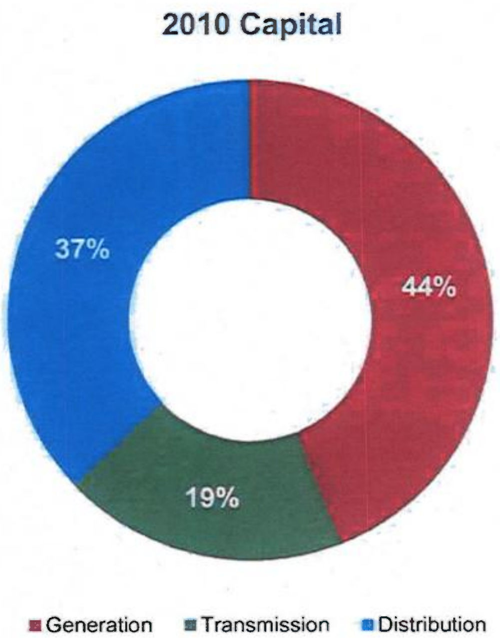
2010 (Total $32.5B)

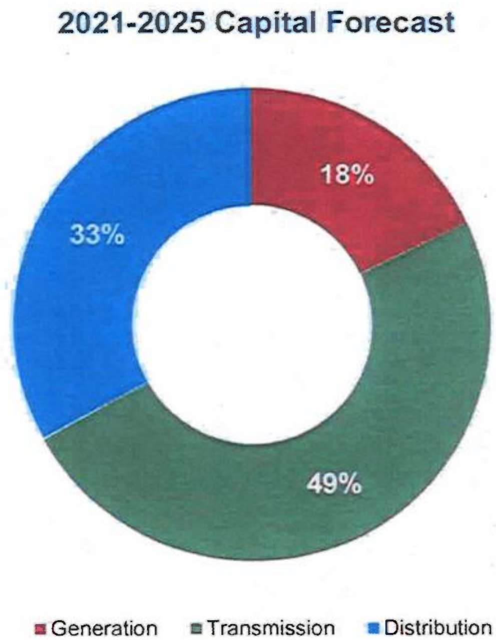


2020 (Total $60B)



Capital Allocation Shifted to Wires





2021-2025 Capital Forecast by Subsidiary

$ in millions (excludes AFUDC)	2021E	2022E	2023E	2024E	2025E	TOTAL
Appalachian Power Company	$ 884	$ 1,163	$ 981	$ 920	$ 1,004	**$ 4,952**
Wheeling Power Company	$ 45	$ 83	$ 37	$ 37	$ 32	**$ 234**
Kingsport Power Company	$ 21	$ 20	$ 19	$ 18	$ 18	**$ 96**
Indiana Michigan Power Company	$ 578	$ 569	$ 937	$ 575	$ 705	**$ 3,364**
Kentucky Power Company	$ 180	$ 235	$ 164	$ 184	$ 231	**$ 994**
AEP Ohio	$ 789	$ 754	$ 802	$ 878	$ 821	**$ 4,044**
Public Service Company of Oklahoma	$ 730	$ 1,105	$ 474	$ 378	$ 921	**$ 3,608**
Southwestern Electric Power Company	$ 872	$ 1,097	$ 537	$ 564	$ 634	**$ 3,704**
AEP Texas Company	$ 1,194	$ 1,091	$ 1,098	$ 1,300	$ 1,388	**$ 6,071**
AEP Generating Company	$ 44	$ 33	$ 12	$ 18	$ 19	**$ 126**
AEP Transmission Holdco	$ 1,597	$ 1,404	$ 1,370	$ 1,647	$ 1,914	**$ 7,932**
Generation & Marketing	$ 501	$ 412	$ 415	$ 418	$ 348	**$ 2,094**
Other	$ 30	$ 22	$ 21	$ 16	$ 2	**$ 91**
Total Capital and Equity Contributions	**$ 7,465**	**$ 7,988**	**$ 6,867**	**$ 6,953**	**$ 8,037**	**$ 37,310**

Capital plans are continuously optimized which may result in redeployment between functions and companies.

Cash Flows and Financial Metrics

$ in millions	2021E	2022E	2023E
Cash from Operations	$ 5,000	$ 5,500	$ 6,000
Capital & JV Equity Contributions[1]	(7,500)	(8,000)	(6,900)
Other Investing Activities	(300)	(300)	(300)
Common Dividends[2]	(1,400)	(1,500)	(1,500)
Required Capital	**$ (4,200)**	**$ (4,300)**	**$ (2,700)**
Financing			
Required Capital	$ (4,200)	$ (4,300)	$ (2,700)
Debt Maturities (Senior Notes, PCRBs)	(2,000)	(3,000)	(1,400)
Securitization Amortizations	(100)	(100)	(100)
Equity Units Conversion	-	805	850
Equity Issuances – Includes DRP[3]	600	1,400	100
Debt Capital Market Needs (New)	**$ (5,700)**	**$ (5,195)**	**$ (3,250)**
Financial Metrics			
Debt to Capitalization (GAAP)		Approximately 60%	
FFO/Total Debt (Moody's)		Low to Mid Teens Reflecting Accelerated Flowback of ADFIT	

[1] Capital expenditures in 2021 include $750M for North Central Wind's Sundance and Maverick projects. Expenditures in 2022 include $1.235B for North Central Wind's Traverse project.

[2] Common dividends increased to $0.74 per share Q4 2020; $2.96/share 2021-2023. Dividends evaluated by Board of Directors each quarter; stated target payout ratio range is 60%-70% of operating earnings. Targeted dividend growth in line with earnings.

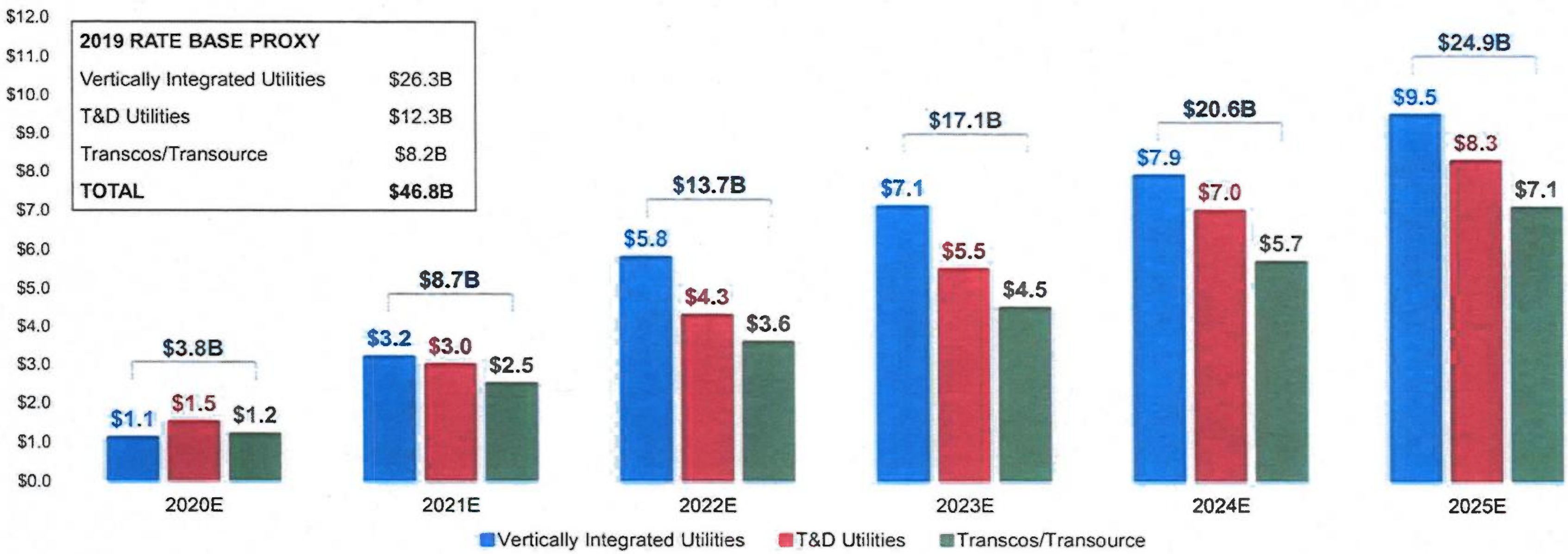
[3] Equity needs in 2021 include $500M for North Central Wind's Sundance and Maverick projects. Equity needs in 2022 include $800M for North Central Wind's Traverse project. Total equity needs for the project are $1.3B.

Actual cash flows will vary by company and jurisdiction based on regulatory outcomes.

7.4% CAGR in Rate Base Growth

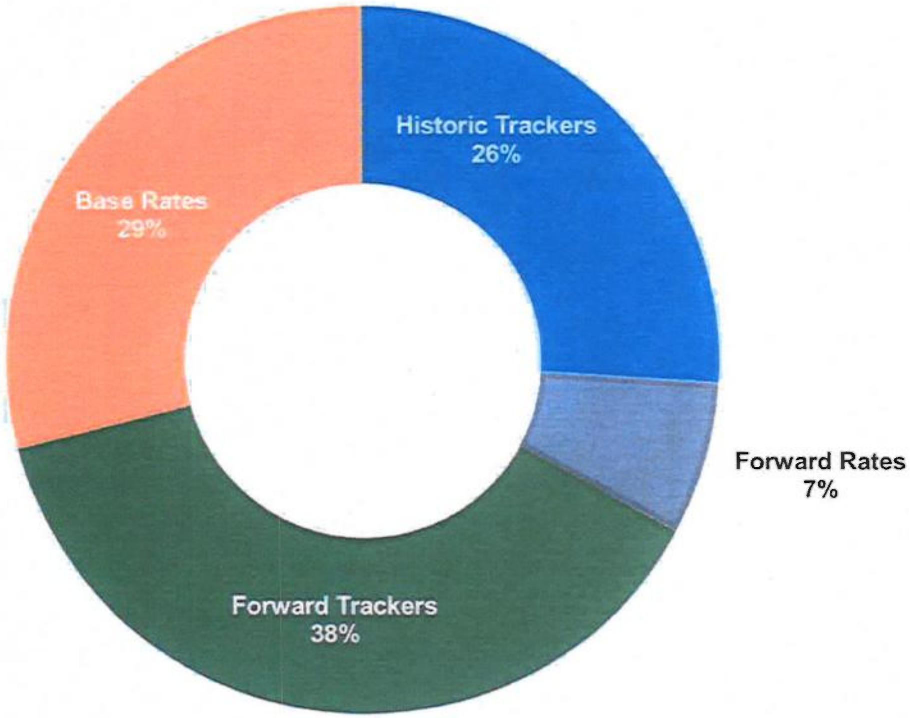
CUMULATIVE CHANGE FROM 2019 BASE

2019 RATE BASE PROXY	
Vertically Integrated Utilities	$26.3B
T&D Utilities	$12.3B
Transcos/Transource	$8.2B
TOTAL	**$46.8B**



5%-7% EPS growth is predicated on regulated rate base growth

Efficient Cost Recovery Mechanisms



More than 70% of 2021-2025 capital plan recovered through reduced lag mechanisms

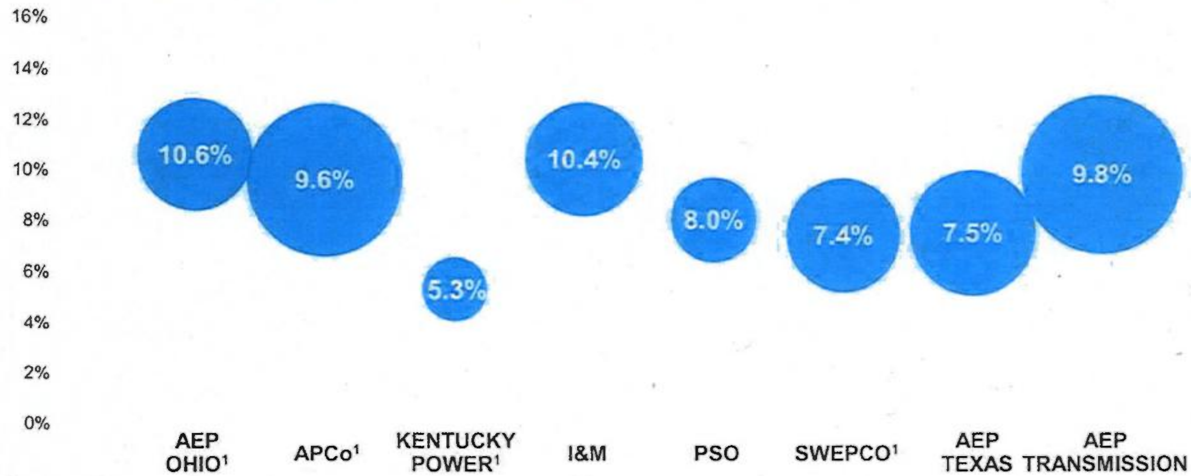
FINANCIAL INFORMATION

- Return on Equity and Authorized Equity Layers
- 2021 Operating Earnings Guidance
- 2021 Guidance Sensitivities and Assumptions
- Current Rate Case Activity
- Bending the O&M Curve
- Normalized Load Trends
- Pension and OPEB Estimates
- Operational and Financing Structure
- 2020 Long-term Debt Financings
- 2021 Debt Issuances and Maturities
- Credit Ratings

AMERICAN ELECTRIC POWER

Return on Equity and Authorized Equity Layers

Twelve Months Ended 9/30/2020 Earned ROE's
(non-GAAP operating earnings, not weather normalized)



2021 Forecasted Regulated ROE is 9.0%

[1] Base rate cases pending

[2] 9/30/20 data represents equity layers as requested in pending base rate case

Sphere size based on each company's relative equity balance

Authorized Equity Layers
(in whole percentages)

Operating Company	12/31/17	9/30/20	Improvement
AEP Ohio[2]	48%	54%	6%
APCo – Virginia[2]	43%	50%	7%
APCo – West Virginia	47%	50%	3%
Kentucky Power[2]	42%	43%	1%
PSO	44%	48%	4%
SWEPCO – Arkansas	46%	48%	2%
AEP Texas	40%	43%	3%
AEP Transmission	50%	55%	5%

Improving Our Authorized Equity Layers Over Time

AMERICAN ELECTRIC POWER

2021 Operating Earnings Guidance

2020E	VERTICALLY INTEGRATED UTILITIES	TRANSMISSION & DISTRIBUTION UTILITIES	AEP TRANSMISSION HOLDCO	GENERATION AND MARKETING	CORPORATE & OTHER	2021E
2021E	$2.16	$1.14	$1.24	$0.36	($0.29)	$4.61

Note: Waterfall components may change based on actual 2020 results.

2021 Key Guidance Sensitivities and Assumptions

	SENSITIVITY		EPS	
Retail Sales			VIU	T&D
Residential	1.0%	+/-	0.030	0.004
Commercial	1.0%	+/-	0.013	0.003
Industrial	1.0%	+/-	0.011	0.001
O&M Expense (excludes O&M with offsets)	1.0%	+/-	0.04	
Interest Expense (floating debt)	25 bps	+/-	0.01	
Interest Expense (new issuances)	25 bps	+/-	0.01	
Regulated ROE	10 bps	+/-	0.05	

A $6.3M change in pretax earnings equals $0.01 per share

ASSUMPTIONS

2021 REGULATED CONNECTED LOAD (BILLED AND ACCRUED)

Residential	59,064 GWh
Commercial	46,193 GWh
Industrial	56,293 GWh

Rate Changes: $199M; $107M secured

Average Shares Outstanding: 499.2M

Note: AFUDC earnings move inversely to interest expense from rate changes

Current Rate Case Activity

AEP OHIO

Docket #	20-0585-EL-AIR
Filing Date	06/01/2020
Requested Rate Base	$3.1B
Requested ROE	10.15%
Cap Structure	45.6%D / 54.4%E
Gross Revenue Increase	$36M (Less $4.5M Depr Decrease)
Net Revenue Increase	$41M
Test Year	11/30/2020

APCo - VIRGINIA

Docket #	PUR-2020-00015
Filing Date	03/31/2020
Requested Rate Base	$2.5B
Requested ROE	9.9%
Cap Structure	50%D / 50%E
Gross Revenue Increase	$65M (Less $27M D&A)
Net Revenue Increase	$38M
Test Year	12/31/2019
Expected Commission Order	11/30/2020
Expected Effective Date	First Quarter 2021

Current Rate Case Activity

KPCo

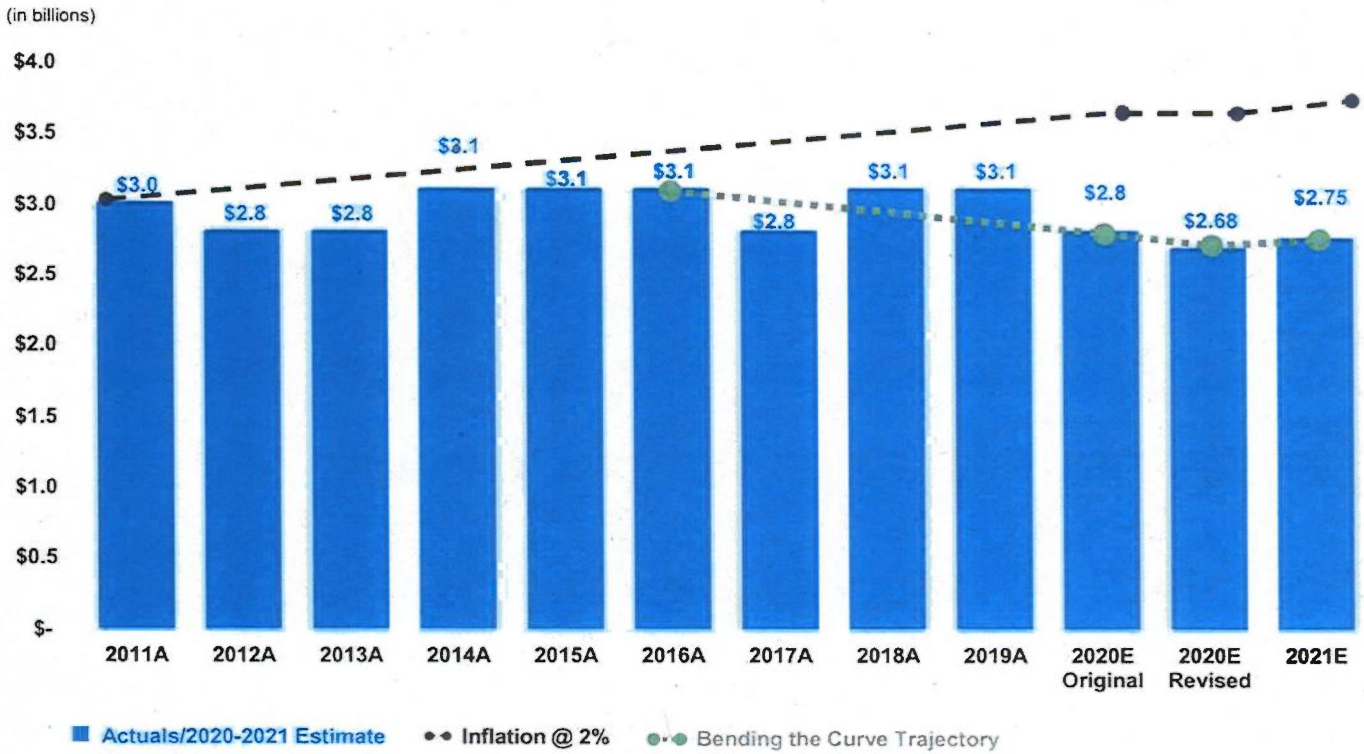
Docket #	2020-00174
Filing Date	06/29/2020
Requested Rate Base	$1.4B
Requested ROE	10%
Cap Structure	53.7%D / 3.0%AR / 43.3%E
Net Revenue Increase	$65M
Test Year	03/31/2020
Procedural Schedule	
Rebuttal Testimony	11/09/2020
Hearing	11/17/2020
Expected Effective Date	January 2021

SWEPCO - Texas

Docket #	51415
Filing Date	10/13/2020
Requested Rate Base	$2.0B
Requested ROE	10.35%
Cap Structure	50.6%D / 49.4%E
Gross Revenue Increase	$90M[1] (Less $17M D&A)
Net Revenue Increase	$73M
Test Year	03/31/2020

[1] Does not include $15M of current riders moving to base rates

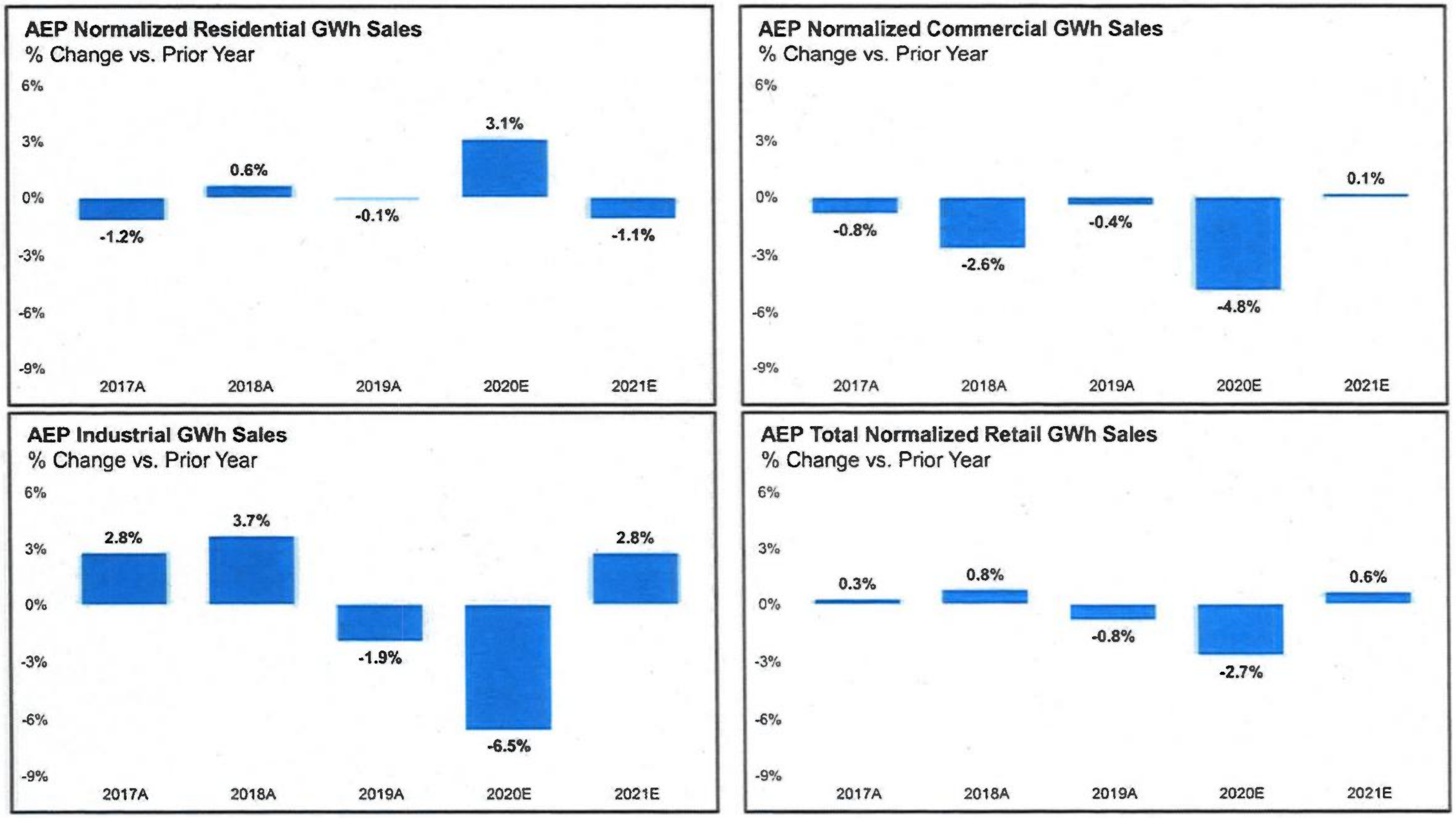
Bending the O&M Curve



O&M focuses on bending the O&M curve down

O&M actual spend represents adjusted spend throughout each year as needed

Normalized Load Trends

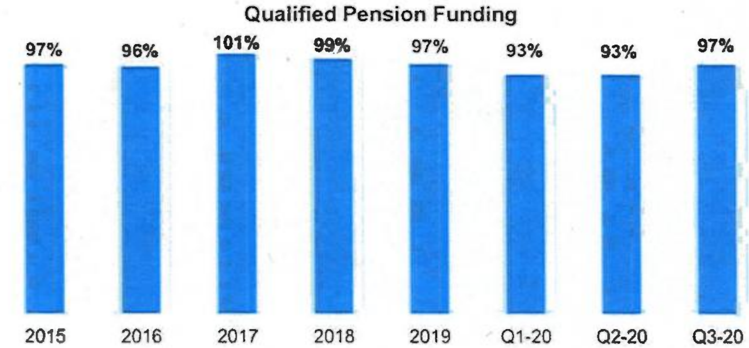


Note: 2020 consists of 9 months weather normalized actual results plus 3 months forecasted values. The 2020 and 2021 comparison may change based on actual 2020 results.

Pension and OPEB Estimates

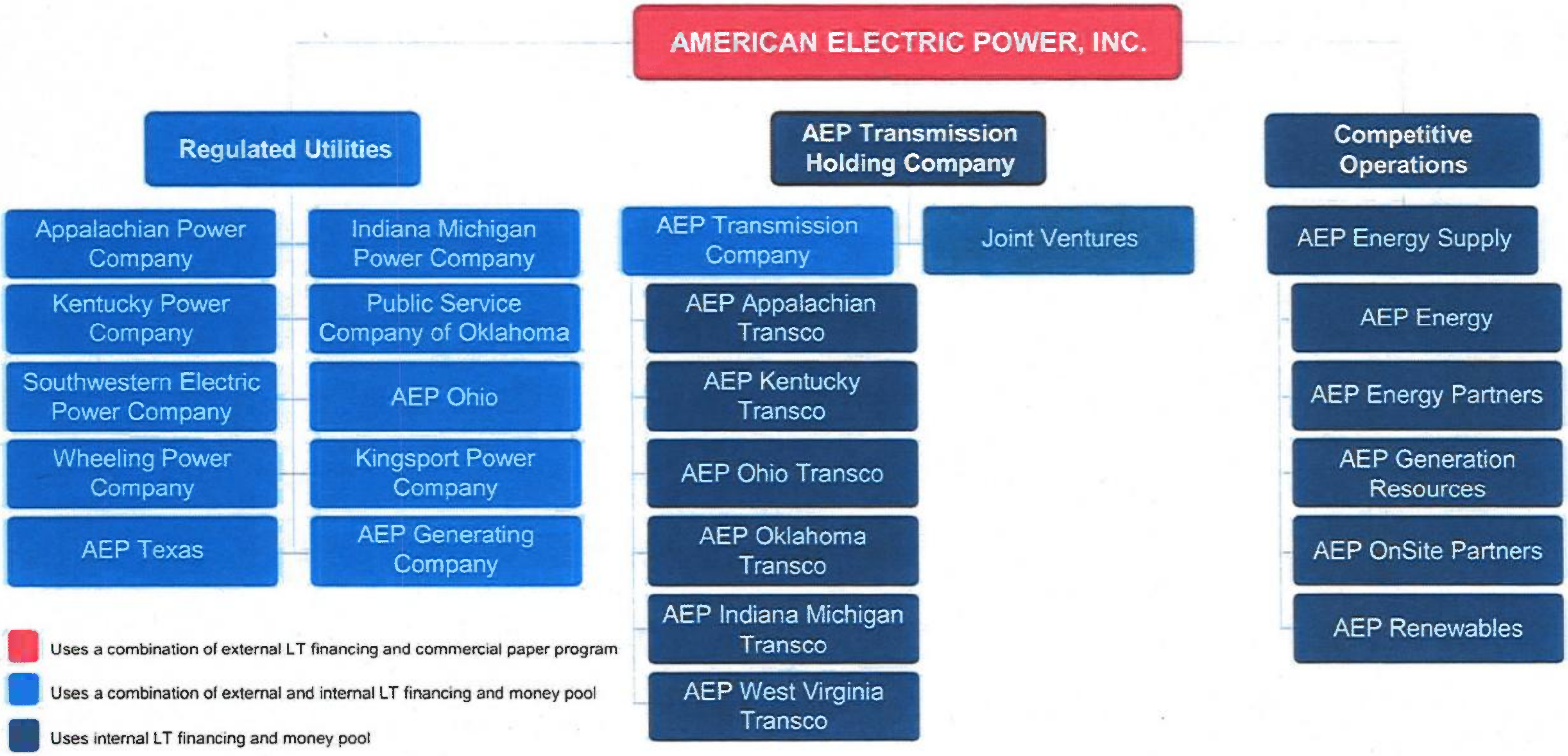
ASSUMPTIONS	2020E	2021E
Pension Discount Rate	3.25%	3.29%
OPEB Discount Rate	3.30%	3.29%
Assumed Long Term Rate of Return on Pension Assets	5.75%	5.75%
Assumed Long Term Rate of Return on OPEB Assets	5.50%	5.50%
Pension/OPEB Funding	$121M	$127M
Pension/OPEB Cost[1]	-	$18M
Pension/OPEB Pre-tax Expense[2]	($50M)	($35M)

[1] Pre-tax expense and pre-capitalization
[2] Recorded in O&M and Non-Service Cost Components of Net Periodic Benefit Cost on the income statement



- YTD pension and OPEB returns were up at 9.4% and 7.2%, respectively, as modest risk seeking asset returns were coupled with strong fixed income gains. Despite these returns, the funded status of both plans decreased as plan liabilities increased more than plan assets due to a falling discount rate.
- We expect combined pension and OPEB costs (pre-tax and including capitalized portion) to increase from 2020 to 2021 due to a falling discount rate, subject to potential changes in investment results, interest rates and actuarial assumptions.
- Pension expense for regulated subsidiaries is recovered through base rates.

AEP Operational and Financing Structure



- Uses a combination of external LT financing and commercial paper program
- Uses a combination of external and internal LT financing and money pool
- Uses internal LT financing and money pool
- Uses a combination of external and internal LT financing

Note: Does not represent legal structure

2020 Long-Term Debt Financings

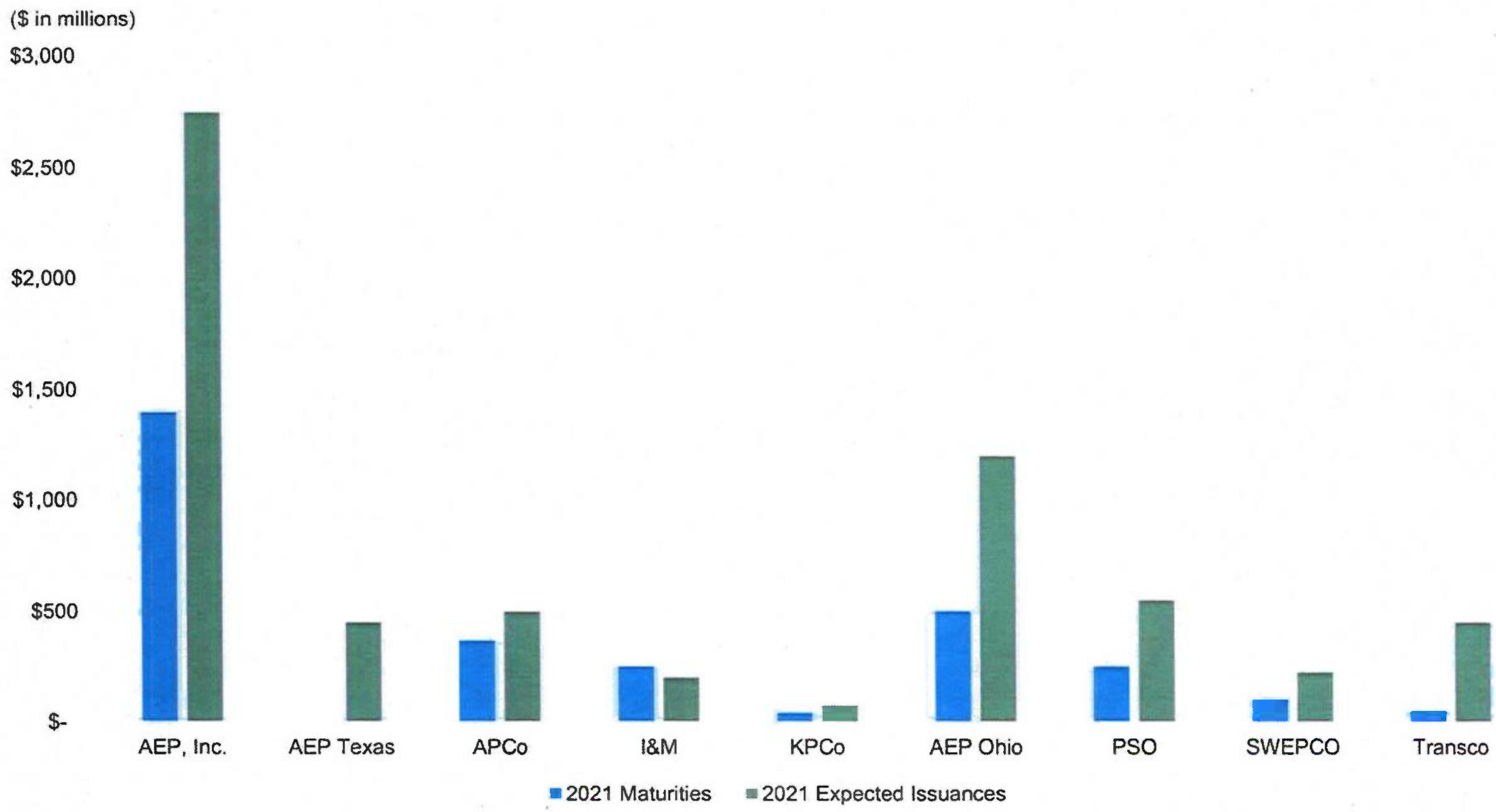
DATE	COMPANY	TYPE	AMOUNT (IN MILLIONS)	RATE	TERM	CREDIT RATINGS (MOODY'S/S&P)[1]
March	AEP, Inc.	Senior Notes	$400	2.30%	10-Year	Baa1/BBB+
March	AEP, Inc.	Senior Notes	$400	3.25%	30-Year	Baa1/BBB+
March	KPCo	Term Loan	$125	Variable	2-Year	N/A
March	AEP Ohio	Senior Notes	$350	2.60%	10-Year	A2/A-
March	AEP, Inc.	Term Loan	$1,000	Variable	364-Day	N/A
April	AEP Transco	Senior Notes	$525	3.65%	30-Year	NA2/A-/A[2]
May	SWEPCO	Term Loan	$100	Variable	18-Month	N/A
May	APCo	Senior Notes	$500	3.70%	30-Year	Baa1/A-
June	KPCo	Pollution Control Bond Direct Loan	$65	2.35%	3-Year	N/A
July	AEP Texas	Senior Notes	$600	2.10%	10-Year	Baa1/A-
August	AEP, Inc.[3]	Mandatory Convertible Equity Units	$850	6.13%	3-Year	Baa3/BBB
September	AEP Texas	Pollution Control Bond Remarketing	$60	0.90%	3-Year	Baa2/A-/A-
September	APCo	Pollution Control Bond Remarketing	$65	1.00%	3-Year	Baa1/A-/A-

[1] Credit ratings assigned to the bonds at time of issuance.

[2] AEP Transmission Company, LLC also received an A rating from Fitch for the April senior notes issuance. AEP Texas and APCo also received A- ratings from Fitch for their respective September pollution control bond remarketings.

[3] Each corporate unit represents a 1/20 undivided beneficial ownership interest in $1,000 principal amount of AEP's 1.30% Junior Subordinated Notes due in 2025 and a forward equity purchase contract which settles after three years in 2023. The Junior Subordinated Notes are expected to be remarketed in 2023, at which time the interest rate will reset at the then current market rate. The interest rate for the forward equity purchase contract which settles in 2023 is 4.825% (not tax deductible).

2021 Debt Issuance and Maturities Overview



Credit Ratings

CURRENT RATINGS FOR AEP, INC. & SUBSIDIARIES (as of 09/30/2020)

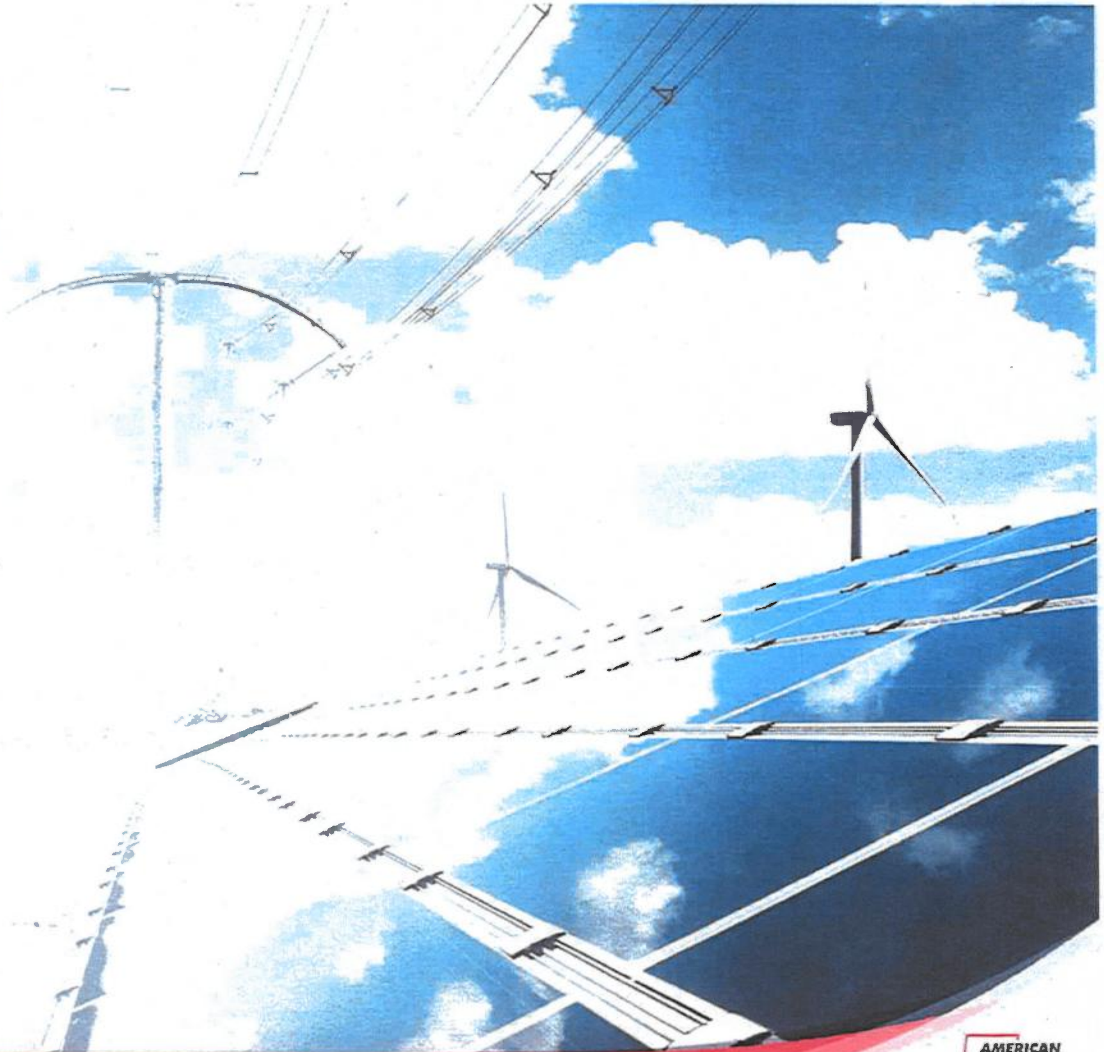
Company	Moody's		S&P		Fitch	
	Senior Unsecured	Outlook	Senior Unsecured	Outlook	Senior Unsecured	Outlook
American Electric Power Company Inc.	Baa2	S	BBB+	S	BBB+	S
AEP, Inc. Short Term Rating	P2	S	A2	S	F2	S
AEP Texas Inc.	Baa2	S	A-	S	A-	S
AEP Transmission Company, LLC	A2	S	A-	S	A	S
Appalachian Power Company[1]	Baa1	S	A-	S	A-	S
Indiana Michigan Power Company[1]	A3	S	A-	S	A-	S
Kentucky Power Company	Baa3	S	A-	S	BBB+	S
AEP Ohio	A3	S	A-	S	A	S
Public Service Company of Oklahoma	Baa1	S	A-	S	A-	S
Southwestern Electric Power Company	Baa2	S	A-	S	BBB+	S
Transource Energy[2]	A2	S	NR	NR	NR	NR

[1] In conjunction with the unenhanced VRDN remarketings, APCo and I&M both received short term credit ratings of A-2/P2 from S&P and Moody's, respectively.

[2] NR stands for Not Rated

ENVIRONMENTAL, SOCIAL AND GOVERNANCE

- Delivering Clean Energy Resources
- Emission Reduction Goals
- Investment in Environmental Controls
- Dramatic Reduction in Emissions
- Electrifying Our Fleet
- Employees and Communities
- Energizing the Talent Pipeline
- Supplier Diversity
- Board and Leadership Composition



Delivering Clean Energy Resources - Environmental

AEP's October 1, 2020 Renewable Portfolio (in MW)

HYDRO, WIND, SOLAR & PUMPED STORAGE	OWNED MW	PPA MW	TOTAL MW
AEP Ohio	-	209	**209**
Appalachian Power Company	785	575	**1,360**
Indiana Michigan Power Company	36	450	**486**
Public Service Company of Oklahoma	-	1,137	**1,137**
Southwestern Electric Power Company	-	469	**469**
Competitive Wind, Solar & Hydro	1,567	101	**1,668**
TOTAL	**2,388**	**2,941**	**5,329**

APPROXIMATELY

11,900 MW

OF RENEWABLE GENERATION INTERCONNECTED ACROSS THE U.S. VIA AEP'S TRANSMISSION SYSTEM TODAY

Emission Reduction Goals - Environmental

AEP's Carbon Emission Reduction Goals

70% by 2030

80% by 2050[1]

(both from a 2000 baseline)

Strategy to Achieve

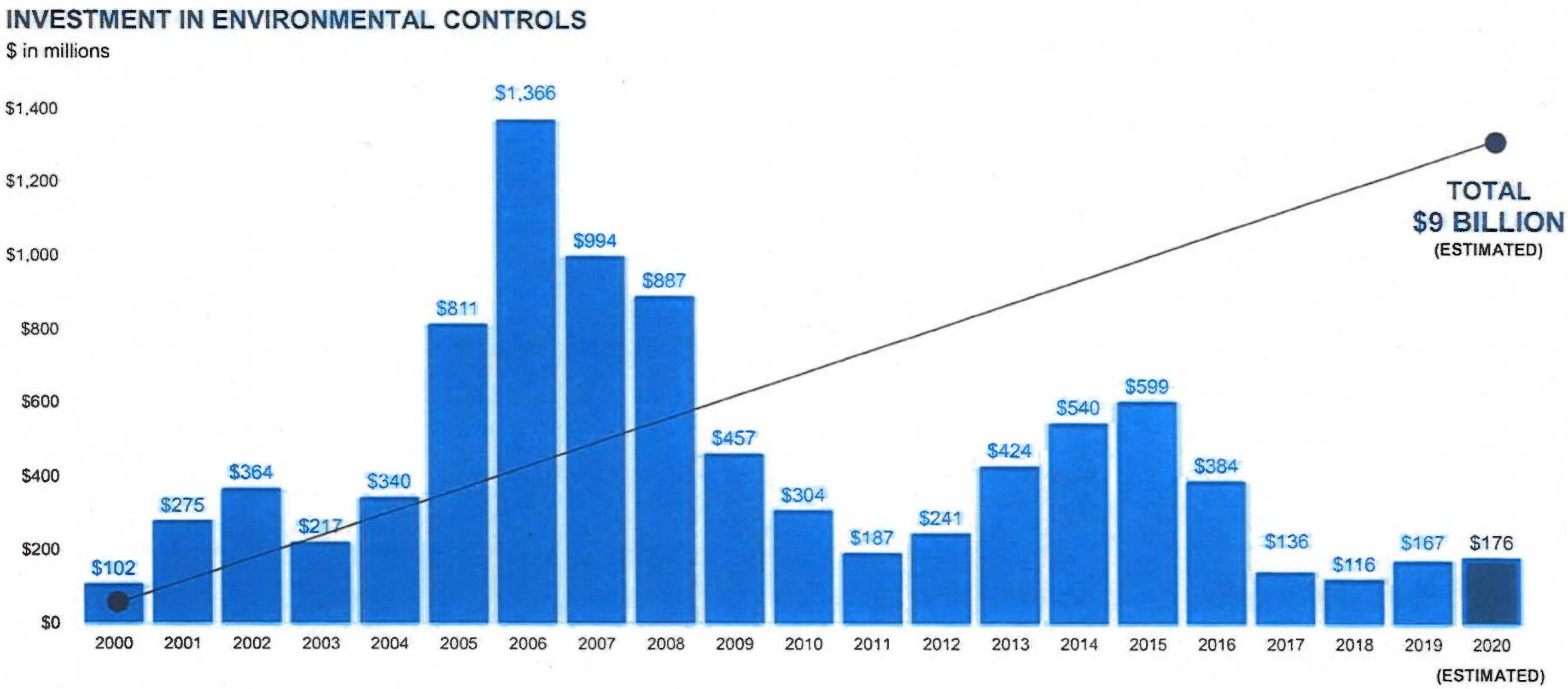
- Investments in renewable energy within and outside of our traditional service territory
- Technology deployment (e.g., energy storage)
- Modernization of the grid with significant investments in transmission and distribution
- Increased use of natural gas
- Optimization of our existing generating fleet
- Electrification

[1] Aspiration is net-zero emissions

AEP's Environmental, Social and Governance (ESG) Reporting:

- Corporate Accountability Report
- Strategic Vision for a Clean Energy Future
- EEI ESG Sustainability Report
- Sustainability Accounting Standards Board (SASB)
- Task Force on Climate-related Financial Disclosure (TCFD)
- CDP Survey Responses
- GRI Report
- AEP also responds to investor-related surveys, including MSCI and Sustainalytics

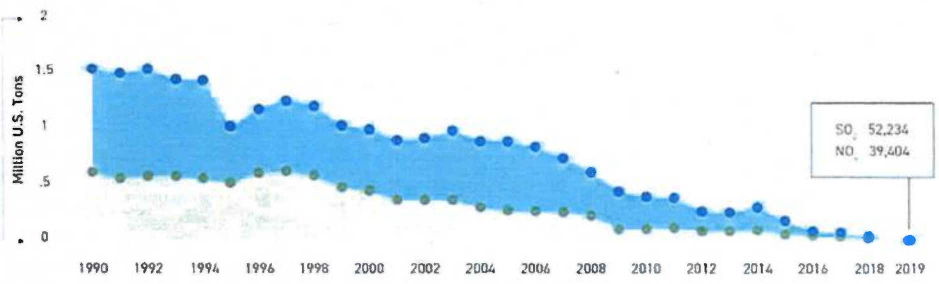
Largest Investment In Environmental Controls - Environmental



AMERICAN ELECTRIC POWER

Dramatic Reductions in Emissions - Environmental

TOTAL AEP SYSTEM NOx & SO_2 EMISSIONS



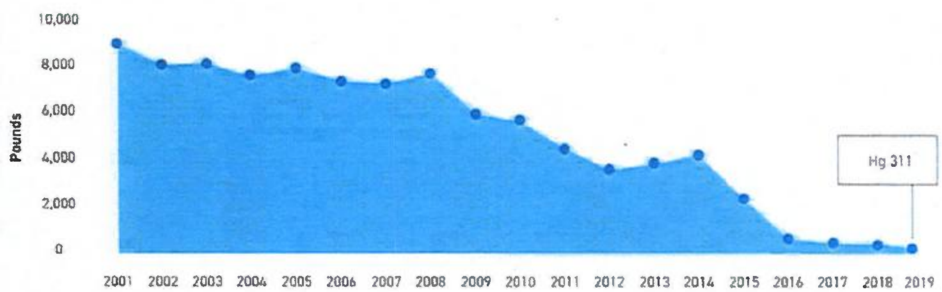
Direct annual emissions of SO_2 and NOx from AEP's ownership share of generation as reported under Title IV of the 1990 Clean Air Act.

1990-2019 ACTUAL

SO_2 97%

NO_x 94%

TOTAL AEP SYSTEM MERCURY AIR EMISSIONS



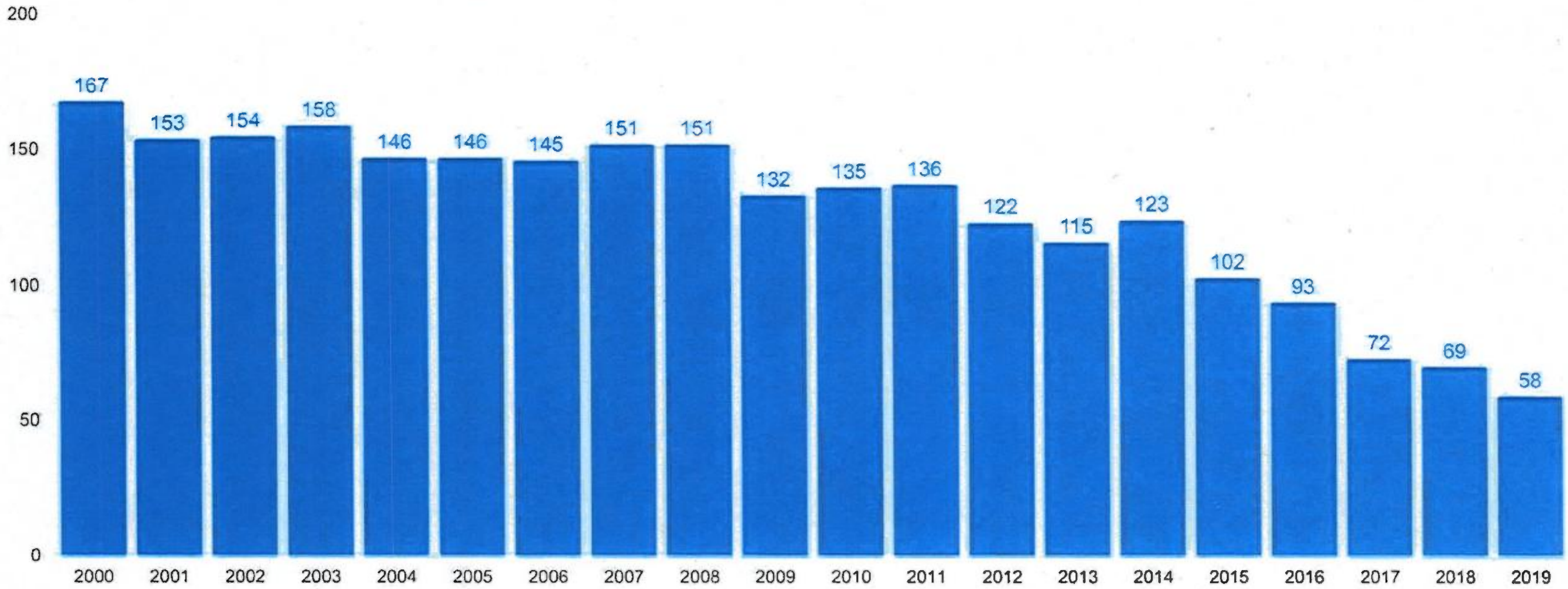
AEP equity share of mercury air emissions from Toxic Release Inventory reporting. 2019 was estimated with MATS program emission monitors.

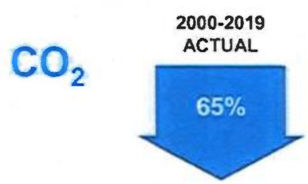
2001-2019 ACTUAL

Hg 97%

Dramatic Reduction in Emissions - Environmental

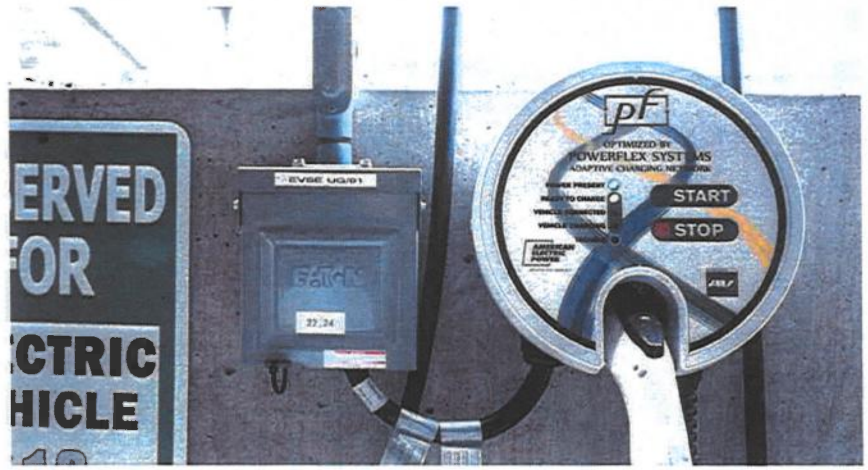
TOTAL AEP SYSTEM – ANNUAL CO_2 EMISSIONS in million metric tons





Electrifying Our Fleet - Environmental

- In 2020, AEP set a new goal to replace 100% of its 2,300 cars and light-duty trucks with EV alternatives by 2030.
- By converting medium- and heavy-duty vehicles as electric or hybrid models become available, AEP will electrify 40% of its entire 8,000-vehicle, on-road fleet in less than 10 years.
- The switch to EVs is estimated to save more than 10 million gallons of fuel, amounting to a $40 million reduction in fuel costs over the life of the vehicles.



AEP is leading by example and encouraging other companies with large fleets to consider EVs or hybrid models, while promoting EV programs and incentives to customers.

Committed to Our Employees and Communities - Social

AMERICA'S MOST JUST COMPANIES

#1 IN UTILITIES

Forbes 2021

DEI BEST PLACE TO WORK FOR DISABILITY INCLUSION 2020

100% DISABILITY EQUALITY INDEX

HUMAN RIGHTS CAMPAIGN

BEST PLACES TO WORK

2020 for LGBTQ Equality

100% CORPORATE EQUALITY INDEX

MILITARY FRIENDLY 2020 EMPLOYER

2020 Bloomberg Gender-Equality Index

2020 GALLUP EXCEPTIONAL WORKPLACE AWARDS

FORTUNE WORLD'S MOST ADMIRED COMPANIES 2020

Energizing the Talent Pipeline - Social

Boundless Energy Career Wheels
"Steering Workforce Development Efforts"

Workforce Development

Expanding diverse community connections, fostering employee creativity and adopting artificial intelligence in the workplace

Trade & Vocational

Assisting individuals in acquiring the skills needed to be successful in post-secondary education, apprenticeships and AEP employment

Education

Training, developing and preparing individuals academically, technically and professionally for positions within AEP

Community Engagement

Proactively improving transparency and educating our customers to build better communities

Employee Development

Experience with a wide variety of business units and leaders throughout the company by gaining cross exposure and visiting locations of technical interest outside of an employee's business unit

Diversity & Inclusion

Committed to a culture where differences are valued and recognized as a significant positive influence on AEP's ability to serve our employees, customers, suppliers and other key stakeholders

Dedicated to Supplier Diversity - Social

AEP'S 2019 DIVERSE SPEND PROFILE

$6.8 billion
Total corporate spend on goods & services in 2019

48 percent
Total corporate spend on locally based suppliers
($3.3 billion)

$882 million
Total corporate spend on goods and services from small businesses
(only Tier 1)

$401 million
Procurement spend on goods and services from diverse suppliers
(includes Tier 1 and Tier 2 spend)

Board and Leadership Composition - Governance

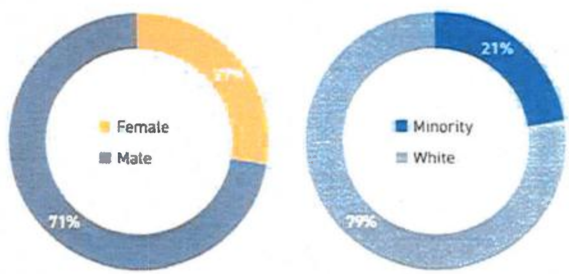
BOARD COMPOSITION

7 YRS
AVERAGE TENURE

92%
INDEPENDENT
(12 of 13 directors are independent)

38%
DIVERSE

2020 LEADERSHIP DIVERSITY



Includes AEP's Board of Directors, AEP Leadership and Regional Utility Presidents as of April 30, 2020.

20% BY 2020
2020
WOMEN ON BOARDS

TRANSMISSION TRANSFORMATION

- AEP Transmission Strategy
- Five-Year Capital Plan
- Investments in Asset Renewal
- Stable Cost Recovery Framework
- Transmission Customer and Shareholder Value
- Enabling an Efficient, Reliable Clean Future
- Transmission's Role in a Clean Energy Future
- Competitive and Off-footprint Transmission
- Holdco Legal Entity Structure

AMERICAN ELECTRIC POWER

AEP Transmission Strategy

AEP Transmission's strategy is to modernize and enhance the reliability, security and efficiency of the transmission network to provide our customers the grid of the future

Diverse 5-year capital investment portfolio of $16.1 billion across AEP's broad geographic footprint of 15 states and 4 regional energy markets

Delivering significant customer benefits:
- ✓ Higher reliability & resilience
- ✓ Lower energy costs
- ✓ Enabling public policies and customer demand for clean energy
- ✓ Economic development

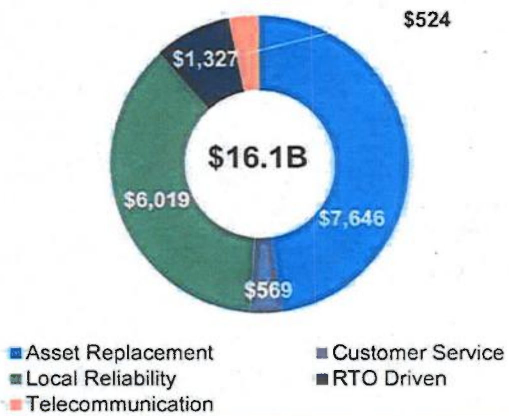
Disciplined execution:
- Low cost, high value solutions
- High speed delivery
- Technological innovation

STABLE COST RECOVERY FRAMEWORK

DELIVER VALUE TO CUSTOMERS & PREDICTABLE EARNINGS GROWTH

Five-Year Transmission Capital Plan

2021-2025 TRANSMISSION INVESTMENT BY CATEGORY ($ MILLIONS)



$16.1 Billion Investment Diversified In Four RTOs

2021-2025 TRANSMISSION INVESTMENT BY RTO ($ MILLIONS)

INVESTMENT CATEGORIES

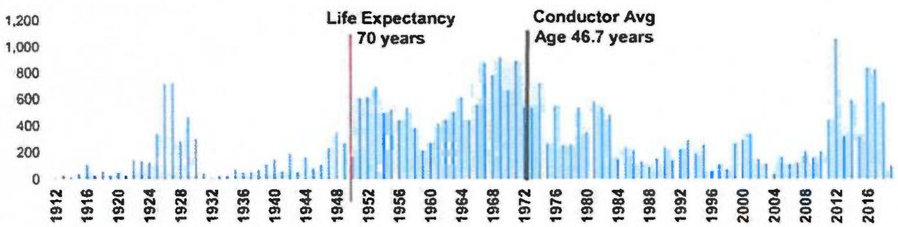
DRIVERS

ASSET REPLACEMENT	LOCAL RELIABILITY	RTO DRIVEN	CUSTOMER SERVICE	TELECOM
• Replacement and rehabilitation investments based on age and performance to reduce customer outages and interruption times	• Upgrades based on AEP standards to address thermal and voltage violations, and contingency conditions	• Upgrades needed to address RTO standards related to thermal voltage overloads and contingency conditions	• Upgrades to connect new customers and enhanced service requests • Facilitates local economic development	• Upgrades to support equipment monitoring, cyber-security requirements, and efficient grid operations

AMERICAN ELECTRIC POWER

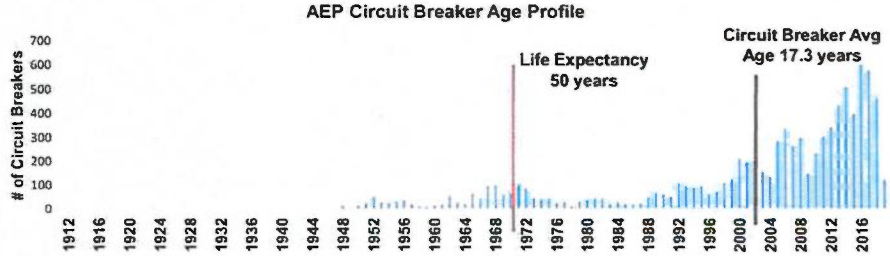
AEP's Investments in Asset Renewal Strengthen and Enable the Grid of the Future

AEP T-Line Age Profile - (Line Mile Age based on oldest conductor age)



AEP Transmission Transformer Age Profile

AEP Circuit Breaker Age Profile



Beyond Life Expectancy Range

- **$2.2 billion** of annual on-system capital investment is required to replace and enhance all assets beyond life expectancy over the next 10 years.
- Asset renewal projects are prioritized based on performance, condition and risk.

AEP Transmission Assets	Line Miles	Transformers	Circuit Breakers
Life Expectancy (Years)	70	60	50
Current Quantity Over Life Expectancy	5,959	209	808
Quantity That Will Exceed Life Expectancy in Next 10 Years	4,732	158	473
Total Replacement Need Over Next 10 Years	10,691	367	1,281
% of AEP System	31%	30%	14%

Average Age (years)	Line Miles	Transformers	Circuit Breakers
2016 Year-End	52.5	36.1	22.9
2019 Year-End	46.7	32.9	17.3

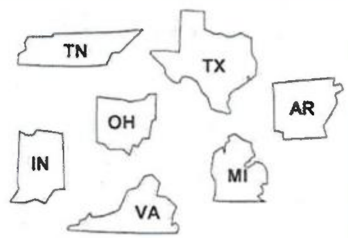
Stable Cost Recovery Framework

Stable and transparent wholesale cost recovery for transmission

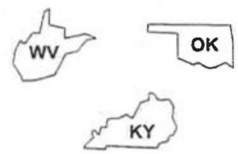
	PJM	SPP	ERCOT
ROE	9.85% Base + 0.50% RTO adder	10.0% Base ROE + 0.50% RTO adder	9.4%
Forward Looking Rates	Yes	Yes	Allowed two updates per year (not forward looking)
Equity Structure	Capped at 55%	No Cap	Capped at 42.5%
Rate Approval Date	May 2019	June 2019	April 2020

~93% of transmission capital investment is recovered through state tracker/rider mechanisms

FULL TRACKER/RIDER (T/R) RECOVERY



PARTIAL (T/R) RECOVERY



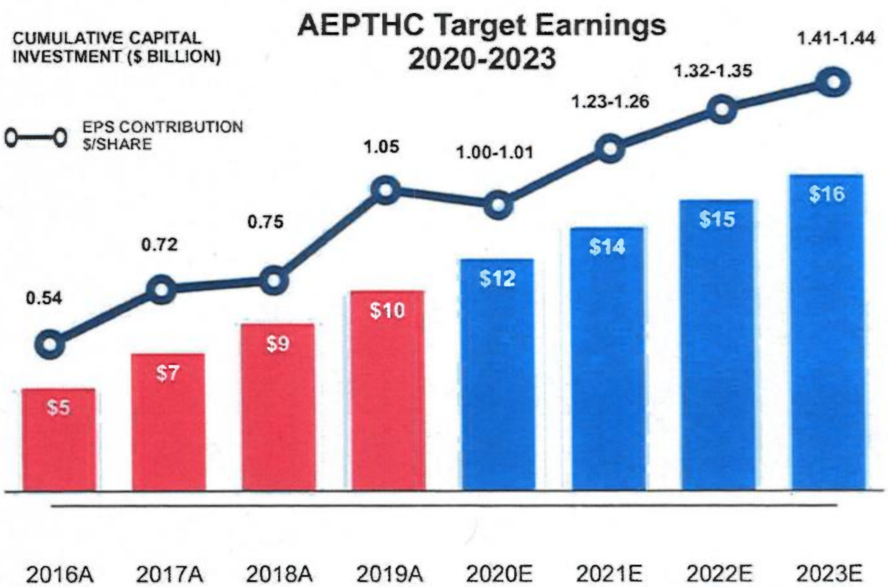
PENDING/FORMULA OR BASE CASE

Note: Arkansas retail formula not currently being utilized

AMERICAN ELECTRIC POWER

Delivering Significant Customer and Shareholder Value

Shareholder Benefits

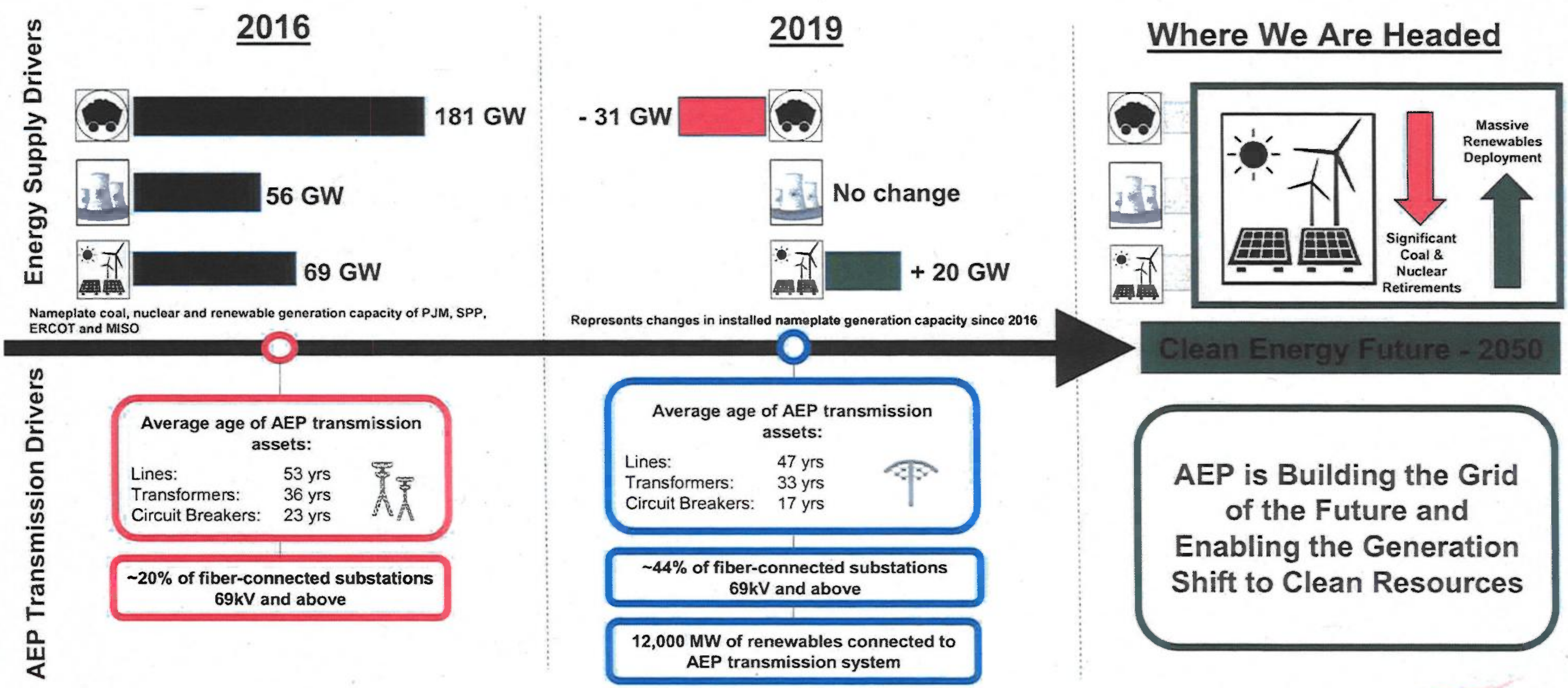


AEPTHC's 2016 – 2023 EPS growth projected at a CAGR of 14.8%

Customer Benefits

Reducing customer costs	Enabling efficient economic dispatch of generation in each of our regions
Driving down emissions	Facilitating the fast and reliable interconnection of renewables to the grid to meet customer demand and public policy goals for clean energy
Improving reliability and security	Keeping the economy productive and connected by powering communications networks and electronics with reduced outages and a storm-hardened system
Creating economic benefits	Supporting economic development through construction projects that deliver community benefits including: ✓ Jobs ✓ State & local taxes ✓ Economic stimulus

Enabling an Efficient, Reliable Clean Future



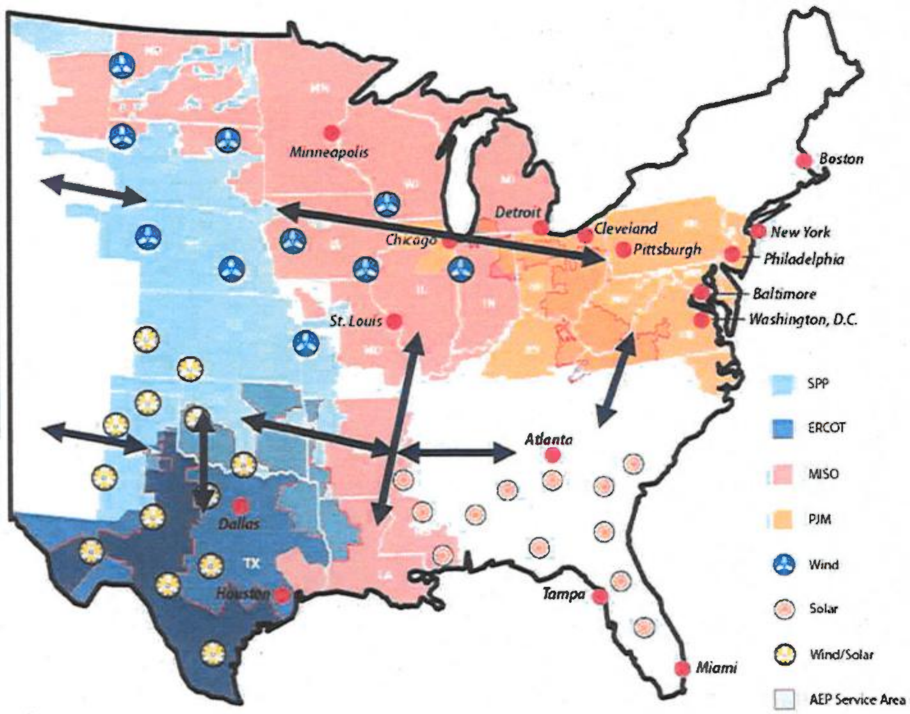
Well Positioned to Capture Potential New Transmission Investment Necessary to Link Clean Resource Rich Areas to Customers

AEP's Competitive Advantage

Scale and Purchasing Power	☑ Largest transmission owner in the U.S.
Investment Opportunities In Grid Of Future	☑ Robust asset renewal program with technology upgrades
Strategically Located	☑ Geographically diverse and located on multiple market seams
Established Competitive Entity With Proven Track Record	☑ Transource is active in four RTOs
Culture Of Innovation	☑ Savings to customers and advantage in competitive solutions

Capturing these new investments provide upside to current investment plan

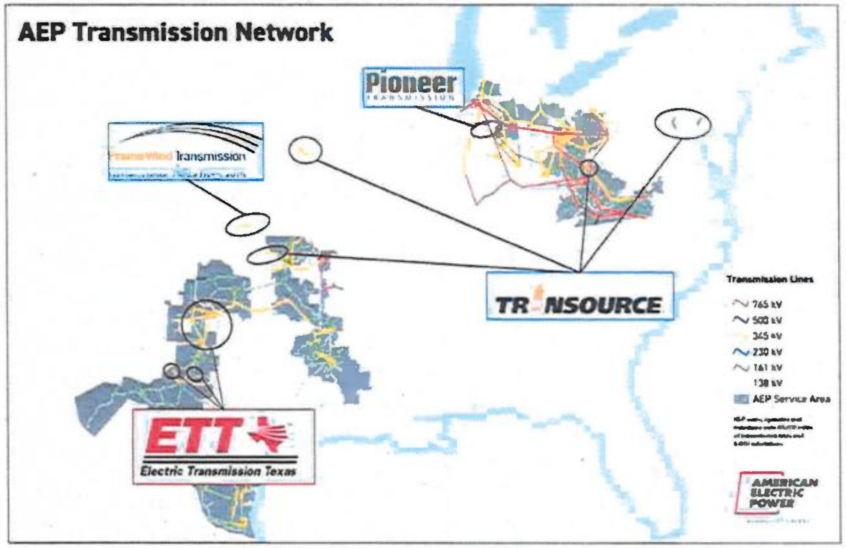
Increasing flows across regional seams will be critical to a cost-effective and efficient clean energy future



AMERICAN ELECTRIC POWER

Competitive & Off-footprint Transmission Investments

AEP is the Largest Developer of Competitive & Off-footprint Transmission in the U.S. and is Well Positioned to Provide Innovative Solutions for Future Grid Investment Opportunities



AEP Joint Venture Company	Total Competitive and Off-footprint Investment ($ in millions)	AEP Ownership ($ in millions)	ROE & Capital Structure (Debt/Equity)
ETT[1]	$ 1,806	$ 903	9.6% ROE 60% / 40%
Transource[2]	$ 776	$ 671	10.75% ROE 46% / 54%
Prairie Wind	$ 158	$ 40	12.8% ROE 45% / 55%
Pioneer	$ 191	$ 96	10.5% ROE 50% / 50%
Total	**$ 2,931**	**$ 1,710**	

[1] ETT investment only includes competitive and off-footprint transmission investment and does not include the legacy AEP investments contributed to the venture

[2] Transource investment includes the total estimated project capex for the awarded projects in PA, MD and OK; Transource ROE and capital structure reflect weighted blend of the operating companies

AEP Transmission Holdco Legal Entity Structure

AEP Transmission Company, LLC ("AEP Transco") is wholly-owned by AEP Transmission Holding Company, LLC ("AEP Trans Holdco")

AEP Trans Holdco is a wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP"), one of the largest utility holding companies in the U.S.

- **AMERICAN ELECTRIC POWER, INC.**
  - **AEP Transmission Holding Co. LLC ("AEP Transmission Holdco")**
    - AEP Transmission Company, LLC ("AEP Transco")[1]
      - AEP Indiana Michigan Transmission Co., Inc. $2,883M Net Plant
      - AEP Appalachian Transmission Co., Inc. $98M Net Plant
      - AEP Kentucky Transmission Co., Inc. $147M Net Plant
      - AEP Oklahoma Transmission Co., Inc. $1,241 Net Plant
      - AEP Ohio Transmission Co., Inc. $4,336M Net Plant
      - AEP West Virginia Transmission Co., Inc. $1,684M Net Plant
      - Total $10,389M Net Plant
    - Pioneer Transmission, LLC
      - $186M Net Plant
    - Electric Transmission America, LLC
      - Prairie Wind Transmission, LLC
      - $138M Net Plant
    - Transource Energy, LLC
      - Transource Missouri, LLC
      - Transource West Virginia, LLC
      - Transource Maryland, LLC
      - Transource Pennsylvania, LLC
      - $434M Net Plant
    - Electric Transmission Texas, LLC
      - $3,144M Net Plant
    - Grid Assurance

Joint Venture

Joint Venture net plant balances are inclusive of non-affiliate share

Net plant totals are as of September 30, 2020, except Pioneer and Prairie Wind, which are as of August 31, 2020

[1] Debt issued at AEP Transco level for transmission companies

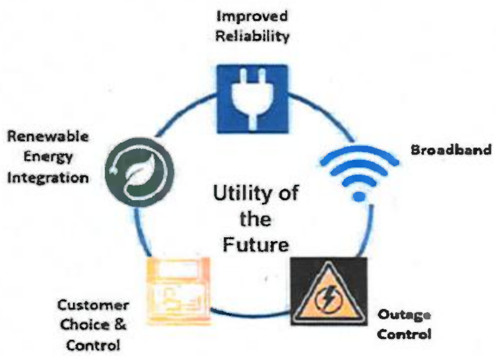
UTILITY TRANSFORMATION

- Expanded Core and Future Investments
- Robust Distribution Capital Expenditure Opportunities
- Key Legislative Initiatives
- Technology and Innovation

Expanded Core and Future Investments

- INCREASE CORE INVESTMENTS IN SYSTEM RELIABILITY
- FULLY ADVANCE METERING INFRASTRUCTURE (AMI) AN DISTRIBUTION AUTOMATION CIRCUIT RECONFIGURATION (DACR) PENETRATION
- LED STREET LIGHT MODERNIZATION

- PROMOTE AN INTERACTIVE, MODERN AND EFFICIENT GRID
- ADAPT GRID TO INTEGRATE MORE DIVERSE ENERGY SOURCES
- BROADBAND AND BEHIND THE METER TECHNOLOGIES TO ALIGN WITH CHANGING CUSTOMER EXPECTATIONS
- ADVANCE ELECTRIFICATION



Positioning to align future investments with customer preferences

Advancing policies and regulatory mechanisms that support timely recovery and diversification of investments

ASSET RENEWAL + GRID MODERNIZATION + NEW PRODUCT LINES = DISTRIBUTION INVESTMENT OPPORTUNITY

Robust Distribution Capital Expenditure Opportunities

Capital Investments in Distribution Modernization are expected to be $8 to $10 billion over the next five years

Distribution Base Investment	Incremental $463 million	$4,207M	Distribution investments for new service, capacity additions, base material and storms
Distribution Grid Resiliency	Incremental $604 million	$3,429M	Asset renewal and reliability investments including pole, conductor, cutout, and station transformer and breaker replacements
Distribution Automation and Technology	Incremental $146 million	$1,124M	Implementation of automated technology including distribution supervisory control and data acquisition, smart switches and reclosers, volt var optimization and sensors. Investments include telecommunication and system components
Advance Metering Infrastructure	Incremental $259 million	$503M	Advanced metering technology for the remaining AEP customers
Distribution – Distributed Energy Resources	Incremental $53 million	$63M	AEP owned energy storage and micro-grid projects connected at distribution voltages
Rural Broadband	Incremental $260 million	$571M	Investment in fiber assets to provide middle mile broadband to rural communities and for company use
Green Technology	Incremental $231 million	$297M	Investments in LED outdoor and streetlights and electric vehicle charging infrastructure, ownership of charging stations if allowed

AEP is committed to making significant grid modernization investments that create win-win solutions for both our customers and our communities

Key: In budget Incremental Opportunities

Key Legislative Initiatives

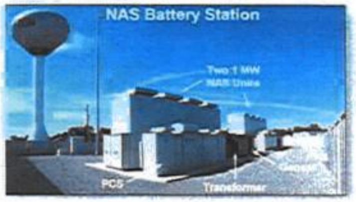
- **Ohio Broadband Deployment (HB13)** – Promotes broadband investment through establishment of residential broadband expansion program.
- **Ohio Bilateral Contracts Bill (HB6)** – Repeal and replace discussions continue; AEP is fully engaged in discussions with legislators and other stakeholders in order to protect customers.
- **Indiana** - 21st Century Energy Policy Development Task Force continues its two-year study of energy policy generally focused around reliability and affordability in Indiana. Recommendations from the legislative Task Force are expected to be submitted for future consideration by December 1, 2020.
- **West Virginia Solar (SB583)** – Allows APCo to build up to 200 MW of solar generation in up to 50 MW increments.
- **Virginia Clean Economy Act (SB851/HB1526)** – Establishes a timeline for electric utilities to attain zero-emissions, creates a mandatory renewable portfolio standard, creates mandatory energy efficiency targets, expands purchase power agreement programs, establishes a percentage of income payment program (PIPP) program and increases net metering program caps.
- **Texas Broadband** – AEP Texas and SWEPCO are working with industry leaders to address broadband needs in rural Texas.

Technology and Innovation

AEP IS AN INDUSTRY LEADER IN DEPLOYING CUTTING-EDGE TECHNOLOGY AND INNOVATIVE SOLUTIONS

Energy Storage & MicroGrids

Currently deploying energy storage solutions such as the 500 KW / 1,000 KWh battery at the Columbus Zoo Microgrid Project

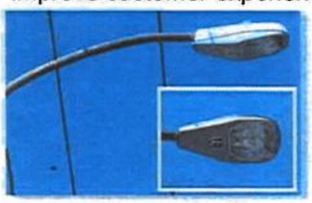


Electric Vehicles

Offering customer rebate programs and off-peak tariffs to promote EV ownership

LED Lighting

Implementing LED street lighting to meet customer demand and improve customer experience



Indoor Agriculture

Exploring innovative solutions at several Operating Companies to promote a sustainable future

Renewables

Exploring innovative solutions at several Operating Companies to promote a sustainable future

Broadband

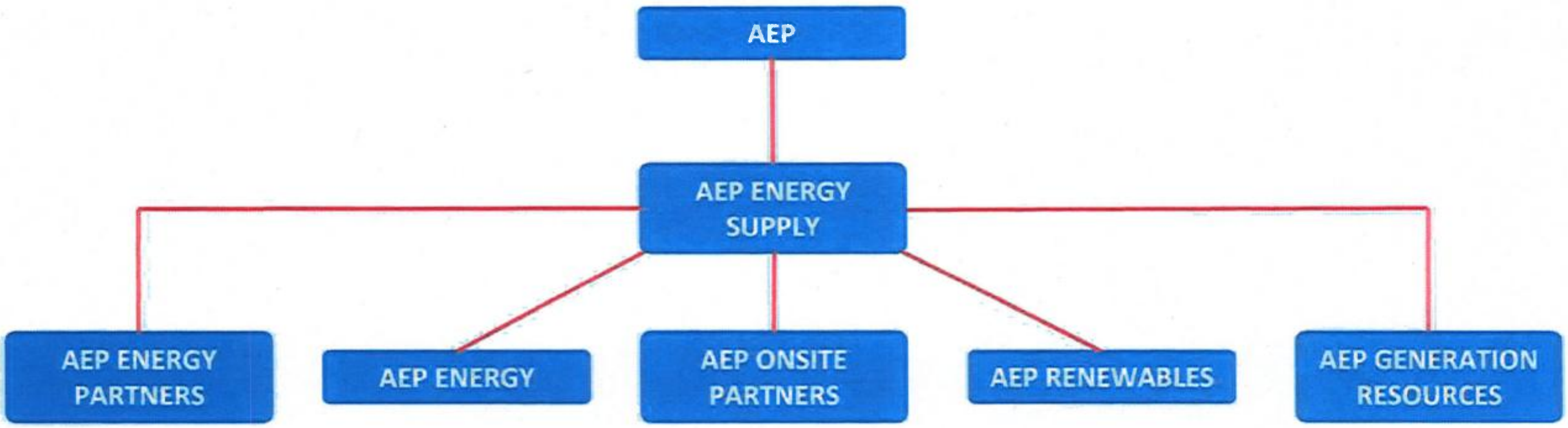
Deploying pilot programs in rural service territory; Promoting broadband programs in regulatory and legislative proceedings

COMPETITIVE BUSINESS

- Organizational Structure
- Strategy and Operations
- Competitive Business Presence
- Customer Energy Solutions
- Universal Scale Renewable Projects
- Development Pipeline and Repower Initiatives

AMERICAN ELECTRIC POWER

Competitive Operations Organizational Structure



Competitive Business Strategy and Operations

$2.1B Capital Allocated 2021-2025

Retail Businesses

AEP ENERGY — An AEP Company

- Provides electricity, natural gas, and demand response to residential, commercial and industrial customers in six states
- Customers: **524,144**
- Electricity: **25.8 TWh**
- Gas: **14.9 Bcf**

AEP ONSITE PARTNERS — An AEP Company

- Build, own, operate and maintain customer solutions utilizing existing and emerging distributed technologies
- Asset Base: Nearly **$370 million**
- **64 projects** in **18 states**

Commodity Businesses

Asset Businesses

AEP ENERGY PARTNERS — An AEP Company

- Transacts commodity hedges for the retail portfolio and engages in wholesale marketing and trading
- Majority of activity is in **PJM** with a smaller presence in **ERCOT, MISO and SPP**
- Active Customers: **84**
- Utility Load Auctions: **10**

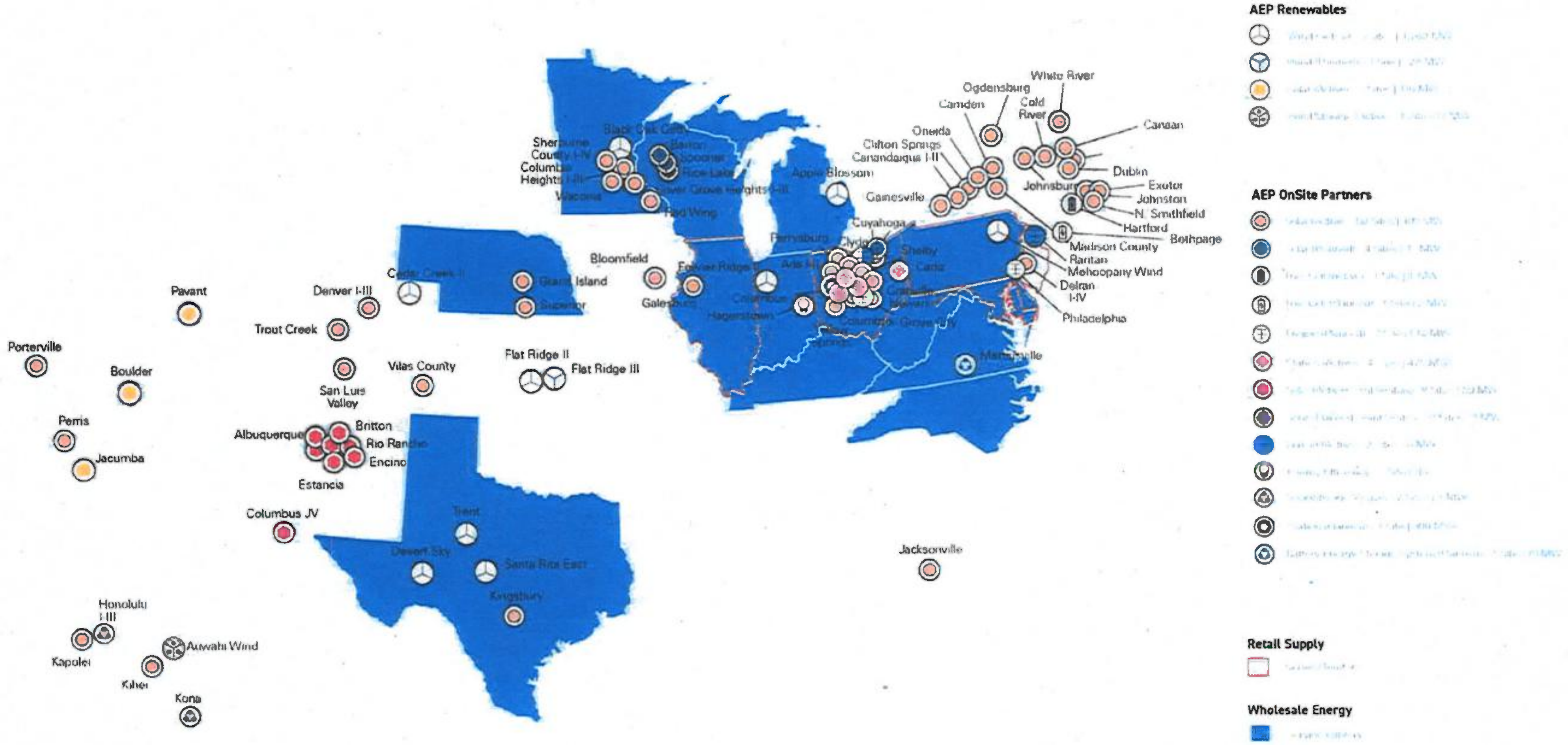
AEP RENEWABLES — An AEP Company

- Develop and/or acquire large scale renewable projects that are backed with long-term contracts with credit-worthy counterparties
- Asset Base: Over **$1.9 billion**
- **13 projects** in **11 states**

Wholesale Businesses

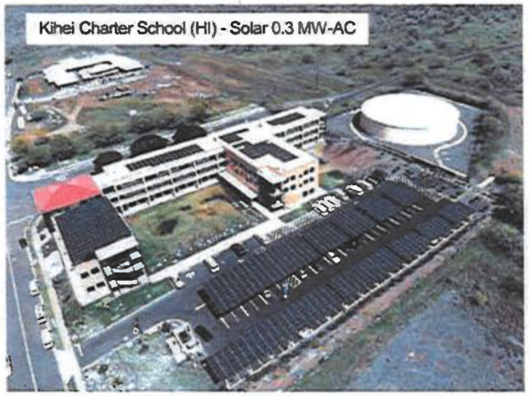
Competitive Business Presence

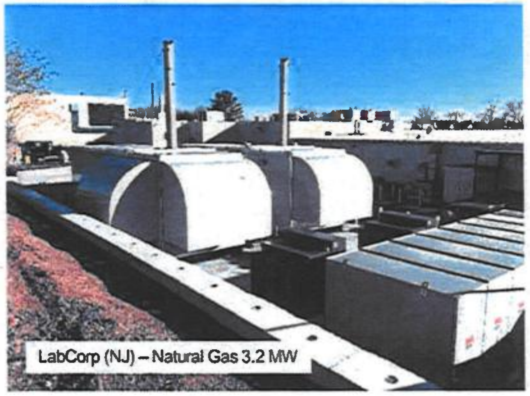
Active in 31 States (7 states overlap with AEP Utilities)



As of 10/01/2020

Customer Energy Solutions





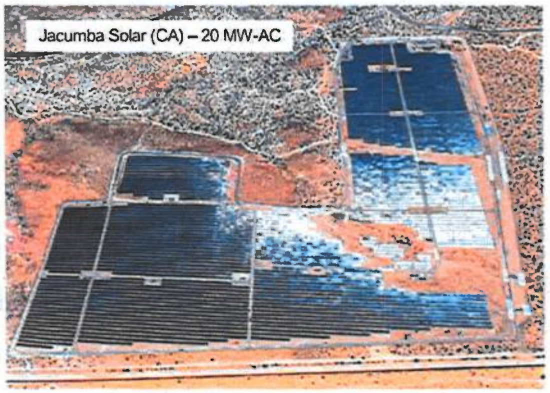
AEP ONSITE PARTNERS

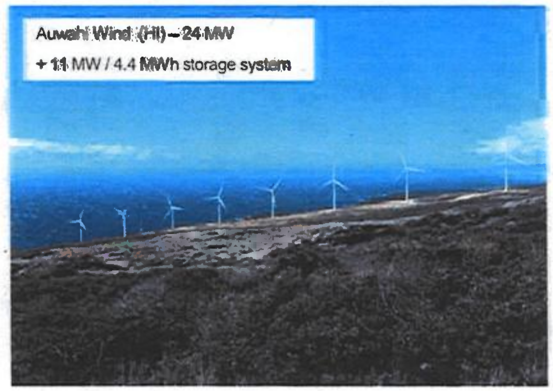
An AEP Company

- Committed to nearly $450 million in energy assets
- Portfolio of 73 operating and under construction projects in 21 different states
- Projects include customer sited solar projects, behind the meter energy storage assets, customer sited substations, peaking generation, energy efficiency projects and fuel cell projects

Universal Scale Renewable Projects

Mehoopany (PA) – 141 MW





AEP RENEWABLES

- Committed to over $2.1 billion in energy assets
- Portfolio of 14 operating projects in 11 different states
- Projects include large scale wind, solar and storage

Development Pipeline and Repower Initiatives

DEVELOPMENT PIPELINE

Progress continues in our development portfolio across three geographically dispersed areas.

The 128 MW Flat Ridge 3 wind project in Kansas is under construction and expected to be placed in-service early 2021 using all of our PTC Safe Harbor equipment (qualifying the plant for 100% PTCs). The project has a long-term power agreement with Evergy for the entire energy output.

The other mid- to late-stage opportunities in our development portfolio possess solid project and market fundamentals, and continue to attract strong interest from utilities, municipalities, cooperatives and corporates.

REPOWER INITIATIVE

Similar to Trent and Desert Sky Wind Farms, we are evaluating our other existing projects for repower.

Review includes Fowler Ridge 2, Cedar Creek 2, Flat Ridge 2 and Mehoopany.

If the repowers were to take place, it would most likely be at 60% PTC level.

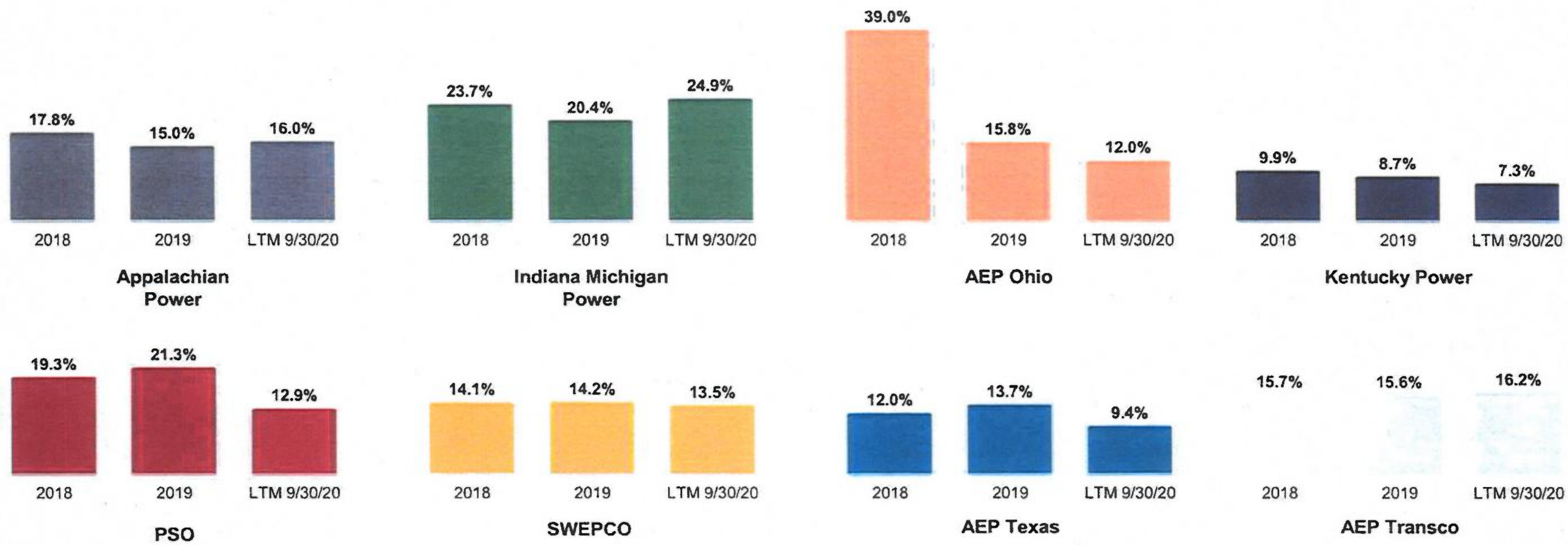
AEP RENEWABLES

WELL-POSITIONED REGULATED BUSINESS

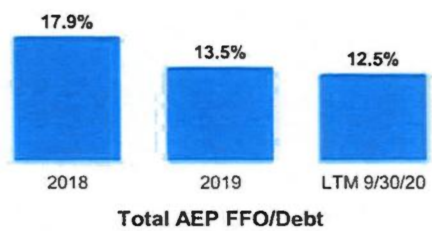
- FFO/Debt by Operating Company
- Composition of Rate Base
- Rate Base, GWH Sales and Capital by Operating Company

AMERICAN ELECTRIC POWER

FFO/Debt[1] By Operating Company

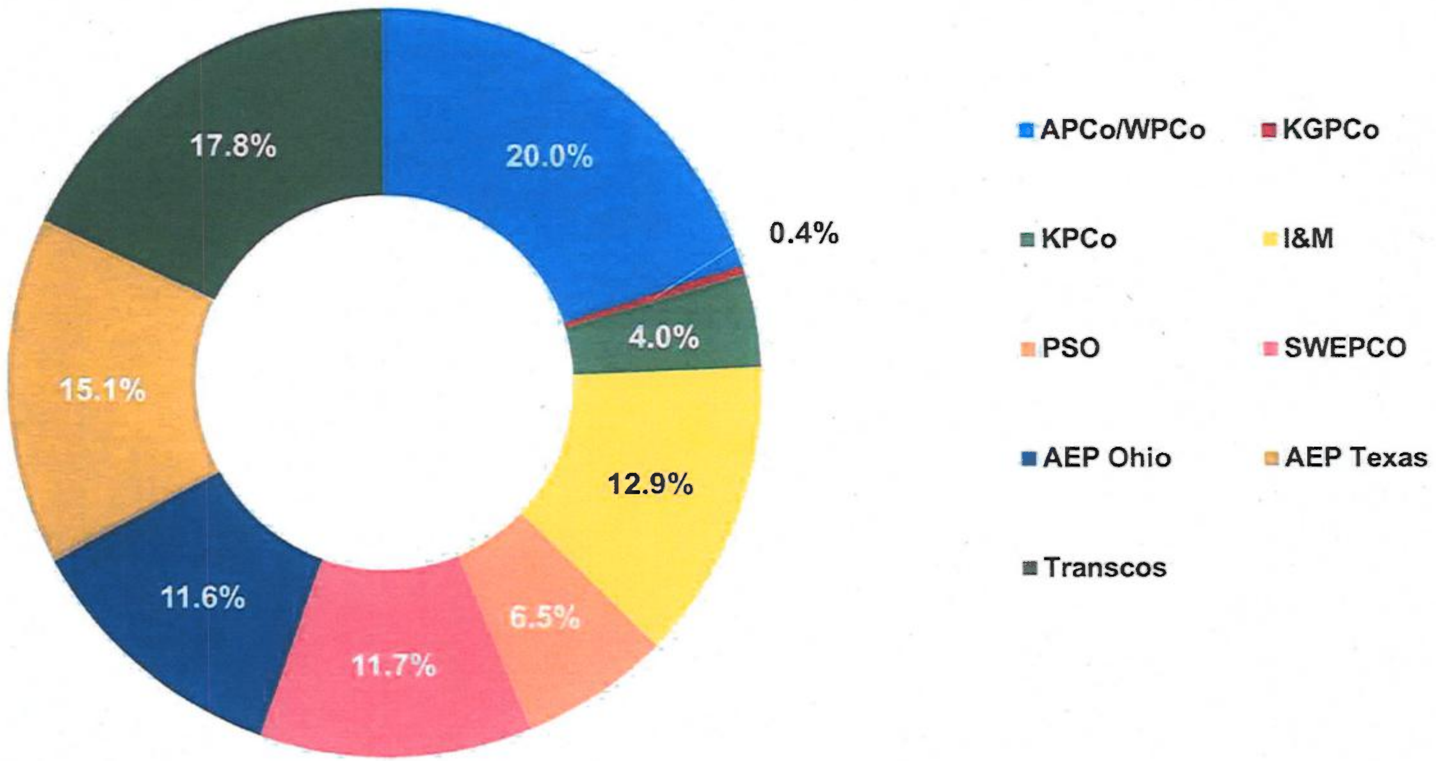


Consolidated FFO to Debt is declining due to elevated capital spend and flow back of ADFIT



[1] FFO/Debt includes capital and operating leases and an adjustment for A/R sold, but excludes securitization and spent nuclear fuel. Ratios reflect AEP view and do not reflect all of the adjustments made by the ratings agencies.

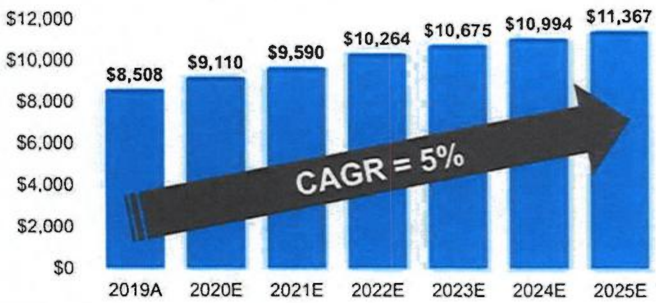
Composition of Rate Base by Operating Company



Appalachian Power and Wheeling Power Companies

APCo Projected Rate Base Proxy

$ in millions

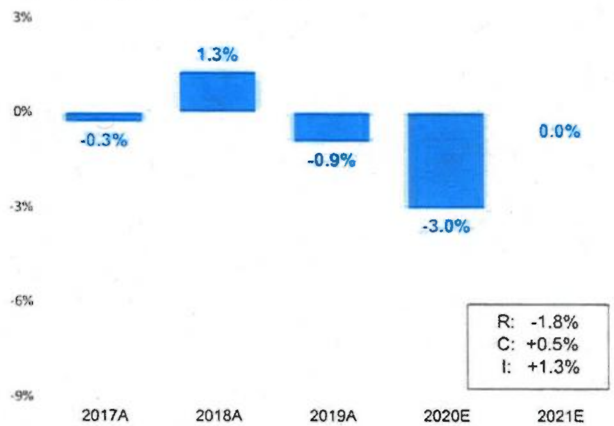


WPCo Projected Rate Base Proxy

$ in millions

APCo/WPCo Normalized GWh Sales

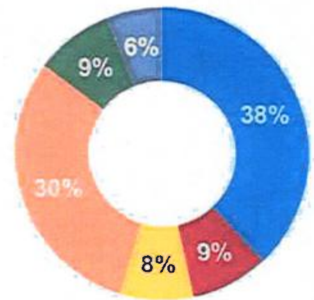
% Change vs. Prior Year



2020 includes 9 months weather normalized actual results plus 3 months forecast

APCo/WPCo 2021-2025 Capital by Function

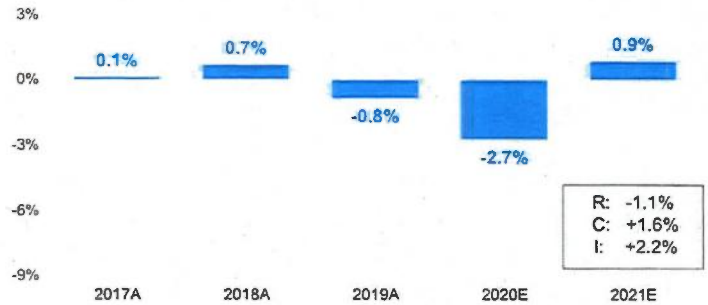
(excludes AFUDC)



- Distribution - $2.0B
- Environmental Generation - $451M
- Fossil/Hydro Generation - $418M
- Transmission - $1.6B
- Corporate/Other - $447M
- Renewables - $316M

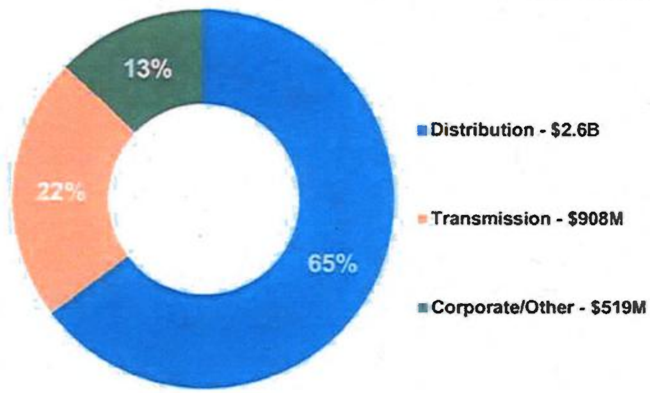
Total $5.2B

AEP Ohio



2020 includes 9 months weather normalized actual results plus 3 months forecast

AEP Ohio 2021-2025 Capital by Function
(excludes AFUDC)



Total $4.0B

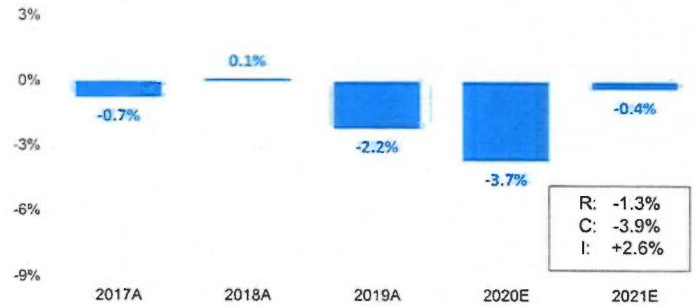
Indiana Michigan Power Company

I&M Projected Rate Base Proxy

$ in millions

I&M Normalized GWh Sales

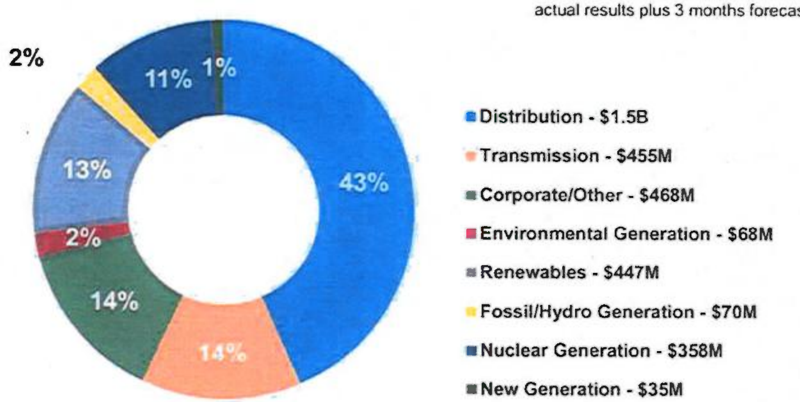
% Change vs. Prior Year



2020 includes 9 months weather normalized actual results plus 3 months forecast

I&M 2021-2025 Capital by Function

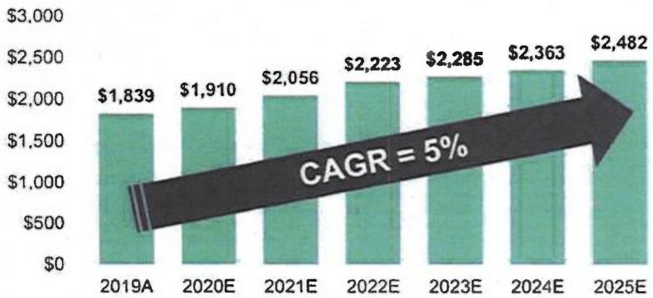
(excludes AFUDC)



Total $3.4B

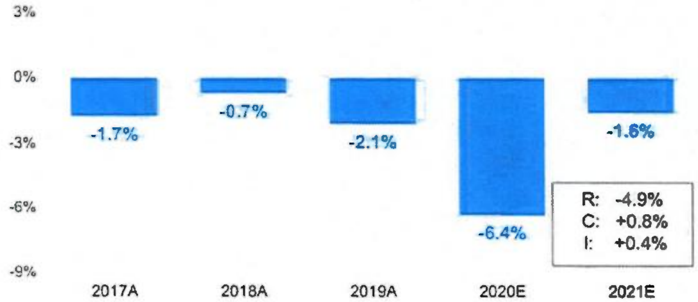
Kentucky Power Company

KPCo Projected Rate Base Proxy



KPCo Normalized GWh Sales

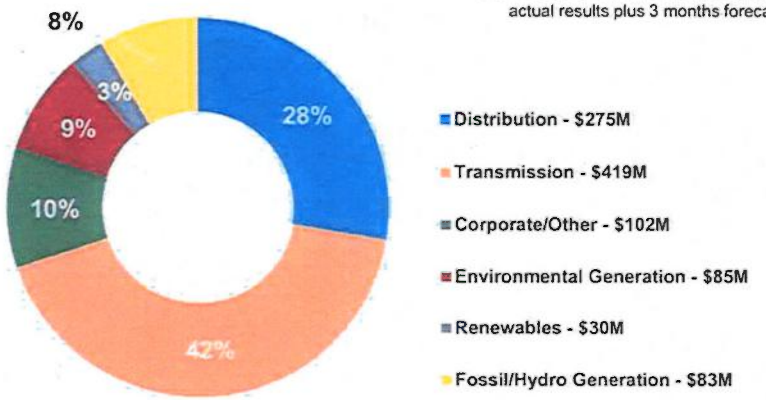
% Change vs. Prior Year



2020 includes 9 months weather normalized actual results plus 3 months forecast

KPCo 2021-2025 Capital by Function

(excludes AFUDC)

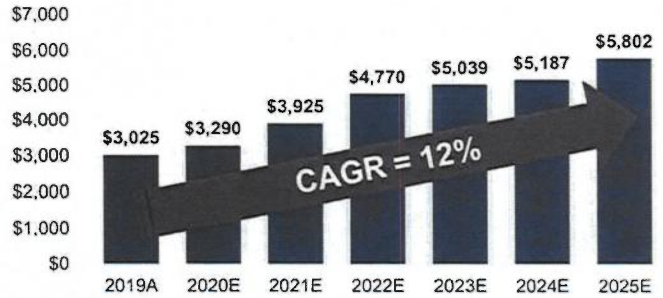


Total $994M

Public Service Company of Oklahoma

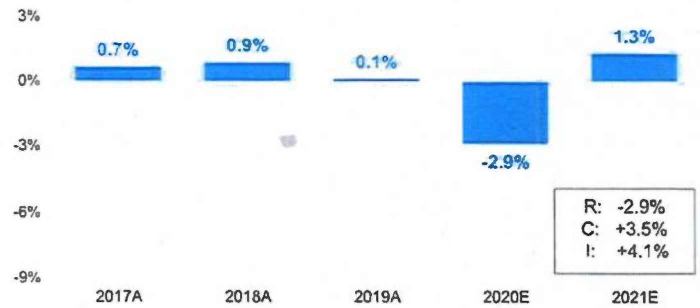
PSO Projected Rate Base Proxy

$ in millions



PSO Normalized GWh Sales

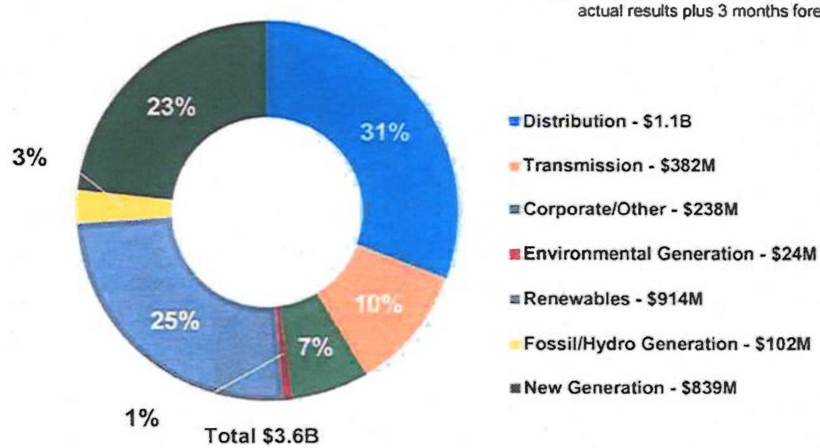
% Change vs. Prior Year



2020 includes 9 months weather normalized actual results plus 3 months forecast

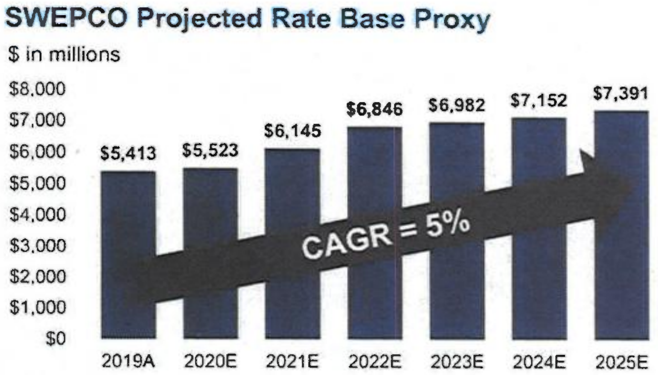
PSO 2021-2025 Capital by Function

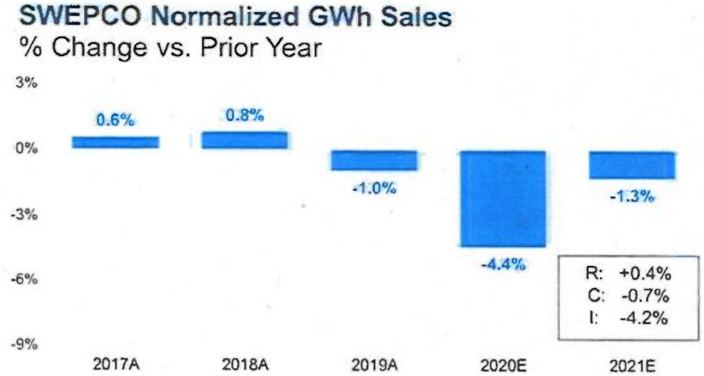
(excludes AFUDC)



AMERICAN ELECTRIC POWER

Southwestern Electric Power Company

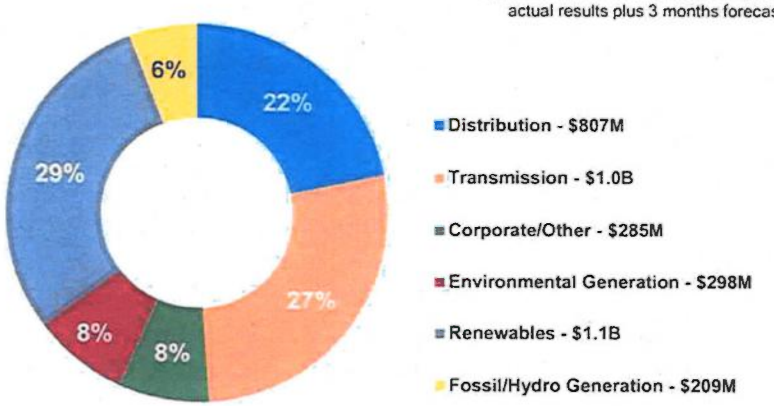




2020 includes 9 months weather normalized actual results plus 3 months forecast

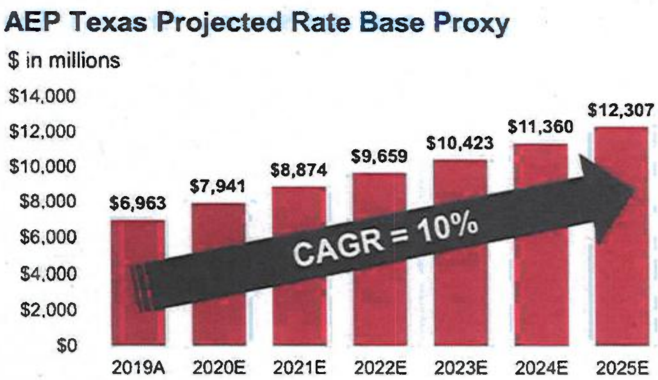
SWEPCO 2021-2025 Capital by Function

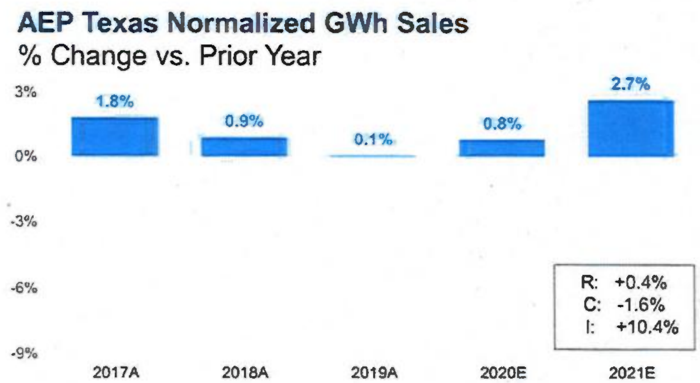
(excludes AFUDC)



Total $3.7B

AEP Texas

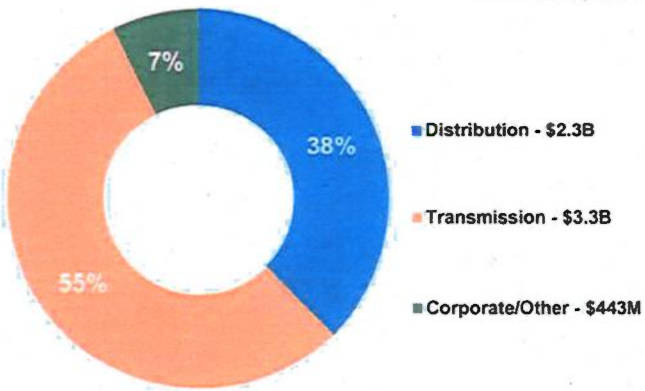




2020 includes 9 months weather normalized actual results plus 3 months forecast

AEP Texas 2021-2025 Capital by Function

(excludes AFUDC)

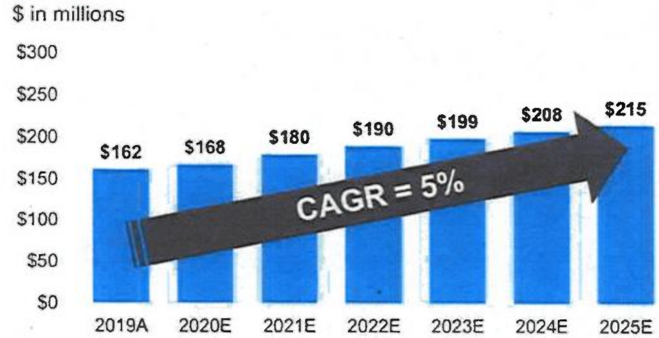


Total $6.1B

Other Utility Subsidiaries

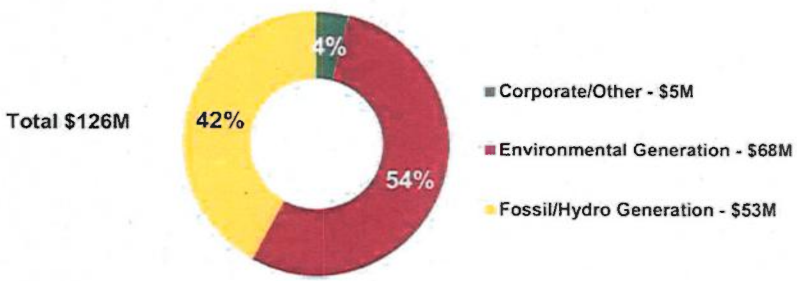
AEP Generating Projected Rate Base Proxy

Kingsport Projected Rate Base Proxy



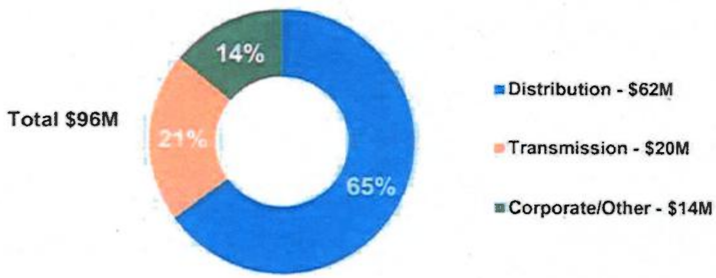
AEP Generating 2021-2025 Capital by Function

(excludes AFUDC)



Kingsport 2021-2025 Capital by Function

(excludes AFUDC)



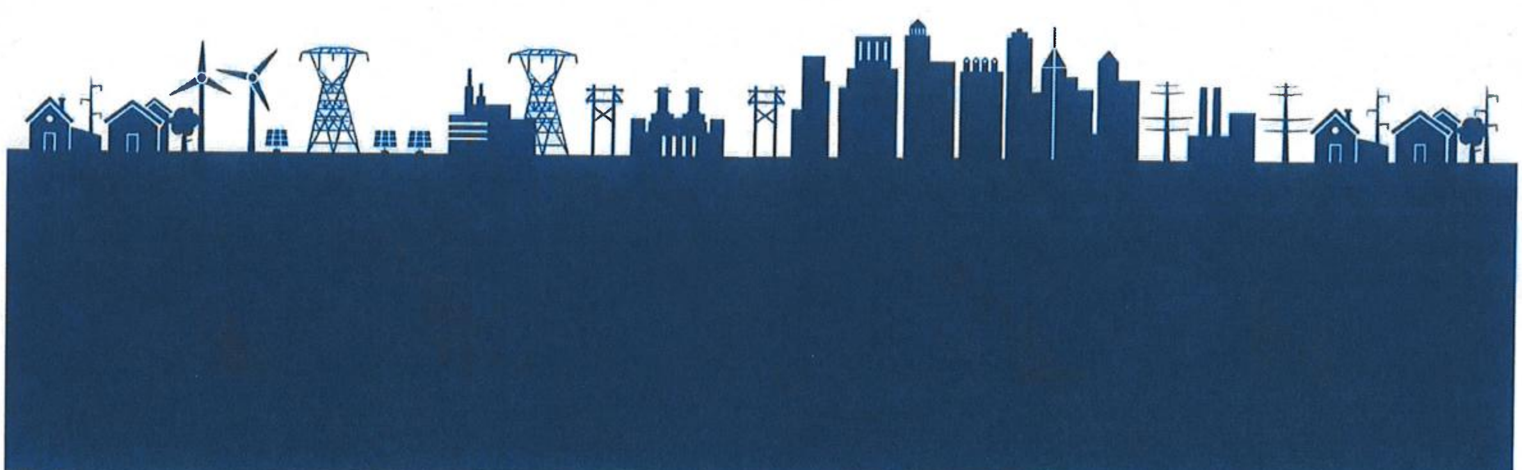
Working to Perfect the Flow of Energy

THE BENEFITS OF THE PJM TRANSMISSION SYSTEM

PJM INTERCONNECTION

April 16, 2019

AG/KIUC Hearing Ex. 2



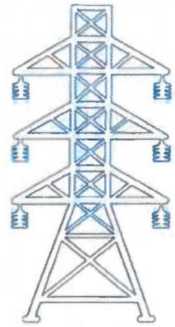


Table of Contents

Errata – April 30, 2019

Apr. 30, 2019:

On page 12, Fig. 4, the “Supplemental” and “Network Upgrades” labels were swapped.

By the Numbers...

- PJM's competitive markets, the largest in the world, are enabled by more than 84,200 miles of transmission at 100 kV and above.

- Transmission lines link PJM zones together, allowing them to share capacity and leverage load diversity to reduce the need for additional generation by up to $3.78 billion annually.

- Simulating capacity market auction results without transmission tie lines to adjoining regions yielded an increase in total payments to capacity resources of $1.7 billion in the 2020/2021 auction and $1.3 billion in the 2021/2022 auction. This translates to 15 percent and 19 percent savings, respectively.

- A robust transmission system lowers the net costs of electricity to consumers by allowing the next most-cost-effective megawatt to be dispatched. This reduces overall production costs for generators and the payments that the end users of electricity make.

  PJM transmission assets enable competition among power producers by providing access to PJM's wholesale markets. In 2018 alone, PJM billings totaled $49.8 billion for 806,546 GWh of energy bought and sold within PJM's Energy Market.

  Transmission enhancements in PJM are estimated to reduce costs to customers by more than $280 million a year by alleviating congestion.

  New interregional transmission assets will produce estimated congestion savings of more than $100 million in the first four years of commercial operation alone.

- Some 20 percent of new transmission assets continue to ensure reliability throughout an ongoing, historic and unprecedented generation shift driven by public policy and fuel economics.

  From 2011 through 2018, 31,722 MW of generation has retired, including more than 24,000 MW from 125 coal-fired units, some more than 45 years old.

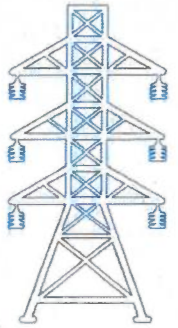
  Retiring units have been replaced by more than 38,000 MW of new resources, including more than 29,500 MW of additional Marcellus and Utica shale natural gas-fired generation and 5,910 MW of renewable wind and solar generation.

  Today, PJM's generation mix is 30 percent less carbon-intensive than 10 years ago. On average, producing one megawatt of power in PJM emits 13 percent less carbon dioxide than 10 years ago and 28 percent less than in 2005.

- At PJM's direction, transmission owners have invested more than $1.3 billion in reactors and static VAR compensators between 2008 and 2018 to reduce the more-expensive generation required to help absorb excess reactive power. This ensures that voltages remain within established limits, typically during periods of low customer demand.

- Transmission helps to maintain reliability across the PJM region – and with neighboring systems – during periods of extreme weather and sudden loss of large generators, when reliable power delivery is needed the most.

- The average operating margin – maneuvering room before hitting a limit – on PJM's 10 internal transfer interfaces more than doubled, from 1,482 MW in 2011 to 3,016 MW in 2018, in part due to new transmission assets.



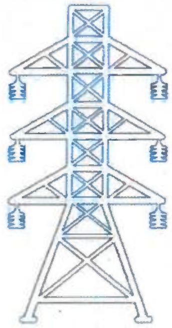
Preface

The goal of this white paper is to quantify the value of new and existing transmission equipment, lines and other assets for PJM Interconnection stakeholders and other engaged parties. This paper is a follow-up to the January 28, 2019, briefing paper, The Value of Transmission, which was a preview of this more expansive treatment of the subject.

The quantitative benefits discussed in this document are based on case studies, analysis and data from across PJM's Planning, Operations and Markets divisions. Each division has provided valuable insights and data to help value the reliability, economic and public policy goals that transmission enables. The majority of this paper focuses on data and narrative about the value of transmission assets.

While PJM's regional planning processes and transmission owner asset management processes are key to transmission development, the focus of this paper is on quantifying the benefit of the assets themselves. Information on these important processes is provided in appendices.

This paper offers observations that summarize transmission value. It does not, and is not intended to, take positions or draw conclusions on issues under discussion in the PJM stakeholder process, at the Federal Regulatory Energy Commission or in state legislatures and utility commissions.



Executive Summary

Transmission Delivers Power and More

"What am I getting for my transmission investment dollars?" In recent years, this question has been on the minds and agendas of state legislatures and utility commissions, consumers and other PJM Interconnection stakeholders. It's a natural question. Today, transmission is constructed and improved for different reasons than 10 years ago. For most of the history of the transmission system, new projects were driven by two things: growth in the demand for electricity from consumers (also called "load") and requests from new generators to connect to the grid, which often require new transmission lines to reach load centers.

The benefits of the transmission system itself and the dollars invested in it extend well beyond delivering power over high-voltage transmission lines. In this paper, PJM quantifies the benefits and drivers of new transmission:

- **Ensuring reliability** - keeping the lights on
- **Keeping costs low** - delivering the lowest cost energy to customers through wholesale markets
- **Supporting public policy** - helping bring to fruition state renewable mandates and federal emission mandates

Load is no longer growing at the 1 percent to 3 percent pace it once was. Now, load growth rates of 0.5 percent and lower are not unusual. Instead of load, transmission investment drivers now include shifting generation resources from coal to gas and renewables, aging infrastructure repair or replacement to maintain reliability, supporting public policy goals (environmental mandates, for example), and ensuring lower-cost energy flows to everyone in PJM by mitigating congestion.

The Value of Transmission

Electricity is a real-time, on-demand commodity used virtually the moment it's created. Like any commodity, it must be delivered from the point of production - a generator - to the point of consumption - our homes and businesses. Transmission lines are the "highway" across which electricity is delivered. The high-voltage transmission network is regionally operated and planned by PJM to ensure reliability at lowest cost. Transmission facilities deliver the power that is vital to our economy, security and overall society. But simply delivering power is not enough. Reliability, resilience and cost effectiveness are equally important. And through preventing loss of power, transmission assets provide the backbone for economic growth and societal well-being, such as access to cleaner, greener generation resources.

Ensuring Reliability at the Lowest Cost

Transmission has enabled the market integration of seven systems into PJM since 2002, increasing reliability and capturing ever larger economies of scale. Load diversity[1] alone across PJM has increased from 1 percent to 3.5 percent since PJM's first market integration in 2002. For perspective, the current load diversity across PJM's original footprint is 1,213 MW whereas as the load diversity across the current PJM footprint is 5,980 MW. This 4,767 MW increase enhances reliability, as it allows zones with excess capacity during periods of peak customer demand to export capacity to zones in need. This reliability benefit is enabled by the 325 inter-zonal transmission lines connecting each transmission owner (TO) zone to adjoining ones.

This benefit, coupled with a generation fleet made up of units with diverse sizes and outage rates, has reduced the capacity reserve levels needed to supply customers. For example, the generation reserves required for the original Mid-Atlantic area of PJM, before all market integrations, were approximately 22 percent. Today the requirement is 15.7 percent. Transmission ties between zones mean that fewer megawatts of generation are needed across PJM to serve load reliably. PJM studies indicate that this has an economic benefit, reducing the need for additional capacity by an estimated $3.78 billion annually, discussed further in **Section 2**.

Equal Access to Lower-Priced Power

Transmission enables the lowest-cost power to reach the greatest number of people. PJM operates the grid by scheduling and directing the lowest-cost power resources to generate electricity first, incrementally adding more expensive resources as they're needed and saving the highest-cost resources for relatively brief periods of peak customer demand.

Transmission assets tie PJM zones together. These assets enable competition among power producers by providing access to PJM's wholesale markets for capacity, energy and ancillary services. In 2018 alone, PJM billings totaled $49.8 billion for 806,546 GWh of energy bought and sold within the PJM Energy Market. A robust transmission system lowers the net costs of electricity to consumers by allowing the next most-cost-effective megawatt to be dispatched. This reduces overall generator production costs and payments made by load.

Since 2002, PJM has added seven transmission zones to its original footprint, enabling the addition of 112,000 MW of generation and 95,000 MW of peak customer demand. This has increased competition in wholesale power markets and provided lower prices to consumers. PJM transmission ties with adjoining power systems provide market access to other adjoining wholesale energy markets such as New York, New England and the Midwest.

Throughout the year, market economics can shift (even from hour to hour) across all 8,760 hours of a year. When the transmission system is constrained and power cannot flow freely, operators must reroute the power flow by dispatching higher-cost generation. This yields less-efficient production of electric power and can increase the cost to consumers. Investing in the transmission system can increase its ability to move more power, decreasing congestion costs and saving consumers money. Transmission enhancements in PJM are expected to reduce costs to customers by more than $288 million a year by alleviating congestion, discussed further in **Section 5**.

Transmission Enables Economic Growth[2]

As many economists and state governmental officials have noted, lower electricity costs drive regional economic growth, making local economies more attractive to industrial and commercial businesses and spurring investment. Lower household electricity bills increase disposable income, which increases the demand for goods and services. Several related recent reports speak to the fundamental links between transmission investment and economic growth.

1 Load diversity is the sum of all zonal non-coincident megawatt annual peaks minus the PJM coincident megawatt annual peak.

2 WIRES. https://wiresgroup.com/new/wires-library/wires-reports.

Enabling Day-to-Day Reliability

At its most fundamental, the PJM transmission system ensures that electricity can be delivered reliably across the grid to customers the instant it is needed.

Operational Flexibility

At every moment, 24 hours a day, 7 days a week, system operators ensure that power continues to flow to customers. The more robust the transmission network is, the greater the system margin.[3] For instance, the average margin in PJM across all ten internal transfer interfaces[4] was 1,482 MW in 2011, which more than doubled to an average margin of 3,016 MW in 2018, in part due to new transmission assets, as discussed in **Section 4**. Drawing a comparison to the interstate highway system, margin gives operators room to maneuver. System margin allows operators to address unexpected system events like loss of generation or loss of another transmission facility.

Solving Aging Infrastructure Issues

Transmission facilities continue to age. Some assets date to the 1960s or even earlier. Two-thirds of all system assets in PJM are more than 40 years old; over one-third are more than 50 years old. Some local, lower-voltage transmission facilities, especially below 230 kV, are approaching 90 years old. Asset owners are identifying serious structural deterioration leading to system enhancements to avoid facility failure and customer service interruptions as discussed in **Section 6**. These replacements have economic benefits as well and have, in certain instances, reduced average annual congestion costs by an order of magnitude or more.

Asset modernization goes beyond simple replacement. Such projects have provided the opportunity to learn from history and adopt new knowledge, capabilities and technologies that did not exist when the original facilities were built, which is discussed further in **Section 6**.

Access to Support in Emergency Conditions

Tie lines with adjoining systems enable neighboring systems to help one another during emergencies. The impact of extreme peak loads during hot summers and frigid winters or the sudden loss of large generators can be minimized by relying on access to generating resources outside of PJM, enabled by interregional agreements and operating procedures with adjoining systems. For instance, established shared generation reserve procedures with the Northeast Power Coordinating Council (NPCC) allow either party to request reserves from the other for a sudden loss of generation greater than 500 MW. PJM and NPCC assisted each other 57 times during 2018 alone, as discussed in **Section 4**.

Grid Resilience

Resilience enables the continuous delivery of electric power to customers through times of unusual and extreme levels of equipment or fuel supply disruptions. These can be caused by a variety of extreme conditions, including weather and fuel delivery system failures. Planning for these events and cost-effectively enhancing system resilience could become a future driver of new transmission investment, as discussed in **Section 6**.

3 Margin, in this context, essentially means the difference between the level of power flowing on one or more transmission facilities at a given instant and the limit of that power flow. Said another way, it's extra room available for additional electricity to flow through the transmission system in case of emergency.

4 PJM's ten internal transfer interfaces, as discussed in **Section 4**, are monitored to ensure that power does not exceed limits that could lead to voltage instability for defined system contingencies.

Ensuring Reliability in a Historic Generation Shift

The grid continues to support a historic and unprecedented generation shift driven by public policy and fuel economics, as discussed in **Section 3.** Coal-fired generation is retiring and being replaced by natural gas-fired and renewable generation. From 2011 through 2018, 258 generating units totaling 31,722 MW across all fuel types retired from service. More than 24,000 MW of those retirements were from 125 coal-fired units, some of them more than 45 years old.

Over the same period, retiring units were replaced by more than 38,500 MW of new generation. Another 16,172 MW is under construction and 87,680 MW is actively under study in PJM's generation interconnection process. Between 2011 and 2018, transmission system enhancements in PJM have enabled the interconnection of more than 29,500 MW of additional natural gas-fired generation and 5,910 MW of renewable wind and solar generation. Today, PJM's generation mix is 30 percent less carbon-intensive than 10 years ago. On average, producing one megawatt of power in PJM emits 13 percent less carbon dioxide than 10 years ago and 28 percent less than in 2005.

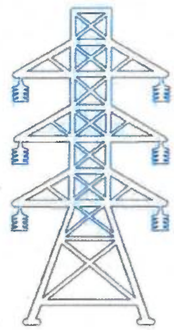
The impact of these changes to PJM cannot be overstated. Neither can the role that transmission has played in allowing this shift occur without compromising reliability:

- A robust transmission system enables new technologies – like wind and solar facilities – to site, configure and operate facilities reliably.
- New transmission assets maintain grid reliability, permitting older generators to retire without causing transmission line overloads or other reliability criteria violations.
- New generation powered by natural gas and renewable fuels relies on new transmission assets in order to sell reliable, economic power into PJM markets.

In addition, the operational flexibility provided by new transmission assets is responsible for encouraging the development of new generation in PJM's footprint, particularly generation fueled by natural gas from the Marcellus and Utica shale. By enabling more generators to compete, the transmission system helps ensure that the lowest-cost generation serves customer load, no matter where it is in the PJM footprint.

Across the Nation

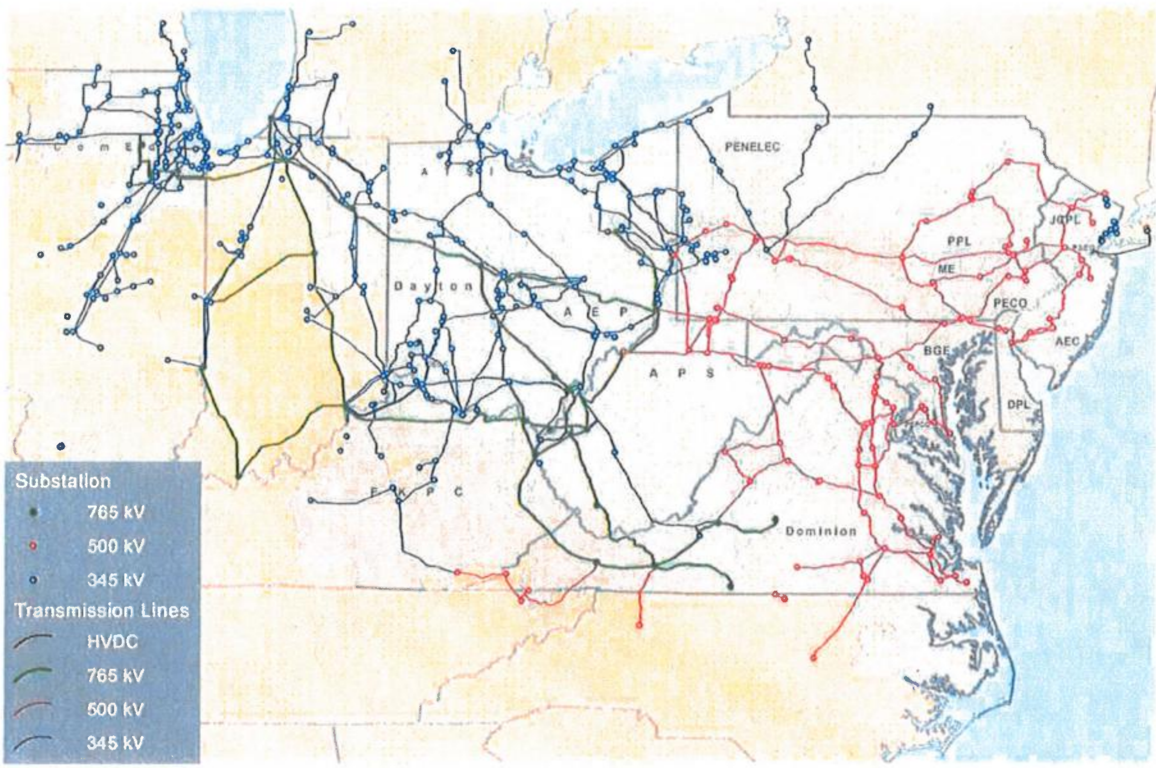
PJM is not alone in its need for new transmission assets, as discussed in **Section 1.** Since 2010, historical and projected transmission investment in the U.S. has continued to grow in independent system operator/regional transmission organization (ISO/RTO) footprints and utilities that are not part of such entities. Available data indicates that, in light of its geographic scope, PJM may outspend other areas of the country in absolute dollar terms, but on a megawatt load-weighted basis, transmission investment in PJM is about average when compared to other ISO/RTOs.



Section 1 Economies of Scale — the Regional Value of Transmission

PJM oversees the round-the-clock generation and delivery of electricity to more than 65 million people in 13 states and the District of Columbia. This requires the careful planning of transmission system enhancements to ensure the reliable delivery of electricity now and in the future. The PJM transmission system that enables power to flow freely throughout PJM is shown in **Map 1**.

Map 1: PJM Backbone Transmission System



PJM directs the operation of more than 84,200 miles of transmission lines across 369,089 square miles of territory, interconnecting with more than 180,000 MW of power generation. Within PJM, 325 transmission tie lines connect each TO zone to adjacent zones, permitting the free flow of power between them. This essential aspect of the PJM grid gives rise to the benefits of shared capacity, power markets and mutual support under stressed system conditions - extreme weather, for example.

Those benefits are amplified when the 212 transmission tie lines between PJM zones and systems adjoining PJM[5] are also considered. While PJM coordinates the flow of electricity on the transmission system, it works cooperatively with the transmission-owning utilities that operate and maintain the equipment that makes up the transmission system, such as high-voltage power lines and substations. PJM is authorized by the Federal Energy Regulatory Commission (FERC) to oversee the grid in its region, bringing independence to operating and planning the infrastructure that is built and owned by the TOs.[6]

The transmission system is similar to the interstate highway system in both the value it brings to society and the cost to build and maintain it. Though building and maintaining such infrastructure can be costly, the result is a system that works around the clock and is designed and maintained to serve the public's demand for safe, reliable electric power at the flip of a switch. Like the interstate highway system, everyone benefits from the transmission system upon which everyone relies for day-to-day livelihoods, crucial goods and services, and emergency services.

PJM's FERC-approved cost allocation procedures[7] reflect this regional "everyone benefits" reality. The cost for new reliability-driven transmission assets - approved by the PJM Board of Managers out of PJM's regional transmission expansion process (RTEP) - that will operate at 765 kV and 500 kV or comprise double-circuit 345 kV construction are allocated 50 percent via load-ratio share across all TO zones and 50 percent via distribution factors based on the impact of a new asset. The socialized component of the allocation acknowledges that a definitive benefit from the elimination of a reliability criteria violation accrues to all consumers of electricity across the PJM footprint. Similarly, Board-approved market-efficiency-driven[8] RTEP projects that will operate at 765 kV and 500 kV, or comprising double-circuit 345 kV construction are allocated 50 percent via load-ratio share and 50 percent via zonal benefit from decreased load payments.

Without continued transmission investment to keep pace with the needs of a growing modern society, new internet, transportation and other technological advancements would be impossible. Customers and generation developers alike rely on investments made in transmission infrastructure. And while initial capital costs can be significant, new transmission infrastructure provides reliability and economic value throughout infrastructure life spans that regularly exceed 50 years.

How Transmission Needs Are Identified

Transmission continues to evolve as grid and consumer needs change. Maintaining a reliable and efficient transmission system in this fluid environment requires extensive planning, coordination, communication and transparency. PJM's comprehensive RTEP process - described in **Appendix A** - identifies the need for changes and additions to the system up to 15 years in the future. The long planning horizon gives the developers who take on these projects time to marshal the necessary resources and gain state and local approvals to build the infrastructure.

5 Including the Midcontinent System Operator (MISO), the New York System Operator (NYISO), TVA, Duke Energy, OVEC and LGE/Kentucky Utilities.

6 This relationship is codified in several organizing agreements: Transmission Owners Agreement (TOA), PJM Operating Agreement (OA) and PJM Open Access Transmission Tariff (OATT or Tariff). These agreements can be found on the PJM website.

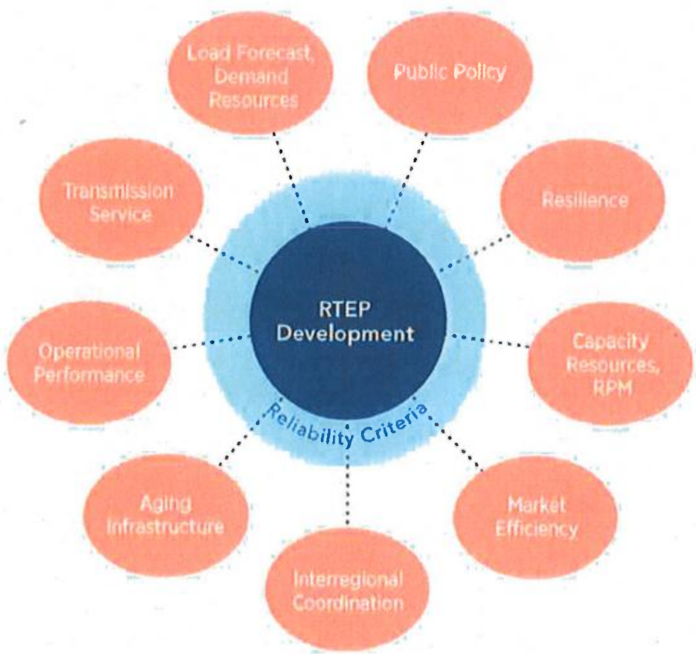
7 Additional details of PJM's RTEP process cost allocation procedure for reliability driven transmission enhancements can be found in Attachment A of PJM Manual 14B: PJM Region Transmission Planning Process: https://www.pjm.com/-/media/documents/manuals/m14b.ashx.

8 Details of PJM's RTEP process cost allocation procedure for market efficiency driven transmission enhancements can be found in Section (b)(v) of Schedule 12 of the OATT and Section 1.5.7(b) of the OA.

PJM's regional scale makes the transmission planning process more efficient by considering the region as a whole, rather than as individual states or separate transmission zones. Transmission system enhancements are driven by a variety of evolving and interrelated industry, market and public policy issues (see **Figure 1**).

The RTEP process ensures that the transmission system complies with national and regional reliability criteria, which are intended to prevent overloaded facilities and potential loss of delivery (also called lost load – in other words, brownouts or blackouts). The North American standards for thermal, reactive, stability short-circuit, and other system requirements are set by the North American Electric Reliability Corporation (NERC), under authorization from FERC.

Figure 1: Transmission System Enhancement Drivers



In order to evaluate the grid for compliance with NERC and regional criteria, PJM has developed and implemented a number of reliability-focused tests with this goal in mind, as described in **Appendix A**. These tests are conducted under simulated emergency conditions in which the grid is stressed to ensure power can be delivered when it is most needed and when local generation is insufficient to provide it.

PJM is required by NERC to plan and operate transmission facilities at 100 kV and above as well as those lower voltage facilities, at the request of the transmission owner. In response to identified regional reliability, market efficiency or public policy needs, PJM staff recommends projects to include in the RTEP, which then must be approved by the PJM Board.

New transmission projects – whether directed by PJM or by TOs as supplemental projects – are built to serve one or more purposes:

- **Increase power-flow capability.** New lines and transformers, existing line reconductoring and bus reconfigurations
- **Provide voltage support and improve generating unit stability.** New devices like shunt capacitors and static VAR compensators
- **Ensure safe transmission line operation.** New substation equipment like circuit breakers, switches, relay protection and control equipment, and instrumentation

Frequently, constructing new facilities to serve one purpose addresses others as well.

For perspective, transmission line capabilities typically have the following ranges:

VOLTAGE CLASS	POWER (MVA)	CURRENT (AMPS)
765 kV	4,000	3,079
	5,400	4,157
500 kV	2,500	2,887
	3,500	4,041
345 kV	1,000	1,673
	2,000	3,347
230 kV	420	1,054
	1,250	3,138

Regional Transmission Investment

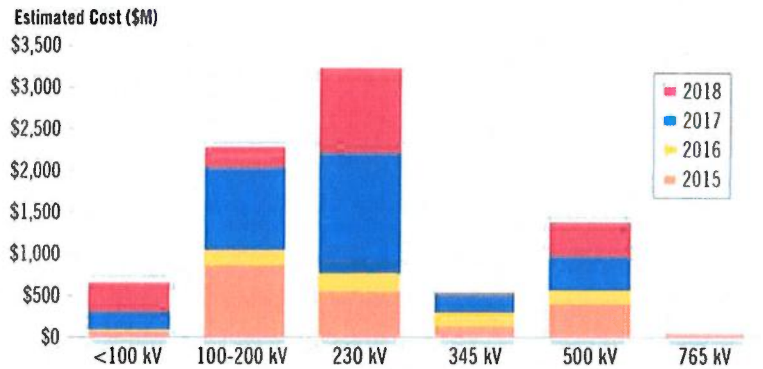
When the RTEP process began in 1997, transmission enhancements ensured that the growth in customer demand could be met and that new generating resources could be interconnected reliably. Customers could be sure enough power could reach them to keep the lights on, and new generation developers could be sure their new resources would not overload existing transmission lines and related facilities. Today, PJM's RTEP process is considerably more robust, and, as noted earlier, studies the interaction of many factors, including those arising out of public policy, market efficiency, interregional coordination and resilience (see **Figure 1**).

The dynamics driving transmission expansion have been shifting more rapidly in recent years. Relatively flat load growth, energy efficiency, security, generation shifts and aging infrastructure repair or replacement - among other issues - continue to move transmission needs away from new large-scale, cross-region backbone projects at higher voltages, as shown in **Figure 2**. Transmission investment in equipment that is 230 kV and below has focused on aging infrastructure replacement as well as upgrades to ensure reliability, improve transfer capability, and comply with local load-serving criteria. Often, system enhancements to solve one issue have helped address one or more other issues as well.

Transmission projects fall into three categories:

- **Baseline projects:** Address reliability criteria violations including thermal, voltage, short-circuit and stability, as well as TO criteria violations,[9] including those violations driven by market efficiency and public policy.
- **Network projects:** Ensure new generation and merchant transmission projects interconnect reliably to the grid as submitted through PJM's interconnection queue.
- **Supplemental projects:** Identified by TOs to address their own local transmission reliability needs. These projects direct repairs or improvements to local transmission lines, equipment, address local operational issues, customer load growth and resilience. Even though the TO develops these projects, PJM reviews them to evaluate their impact on the regional transmission system, to coordinate necessary construction outages, and to implement necessary changes in PJM models and system operations.

Figure 2: Approved Baseline Projects by Voltage (2015-2018)



Roughly 20 percent of all transmission projects approved by PJM since 1999 have enabled or will enable approximately 85,000 MW of new generation to connect to the system without causing transmission line overloads or other reliability criteria violations. Some 80 percent are baseline projects to ensure round-the-clock reliability and market efficiency. Others - known as supplemental projects - are identified by TOs to address local transmission needs. Regardless of how they are categorized, transmission projects that improve reliability can also improve economics and vice versa.

9 Per their respective annual transmission planning and evaluation reports filed with FERC in Form No. 715. Those criteria can be found on PJM's website.

Benefits by the Numbers: Transmission Investment

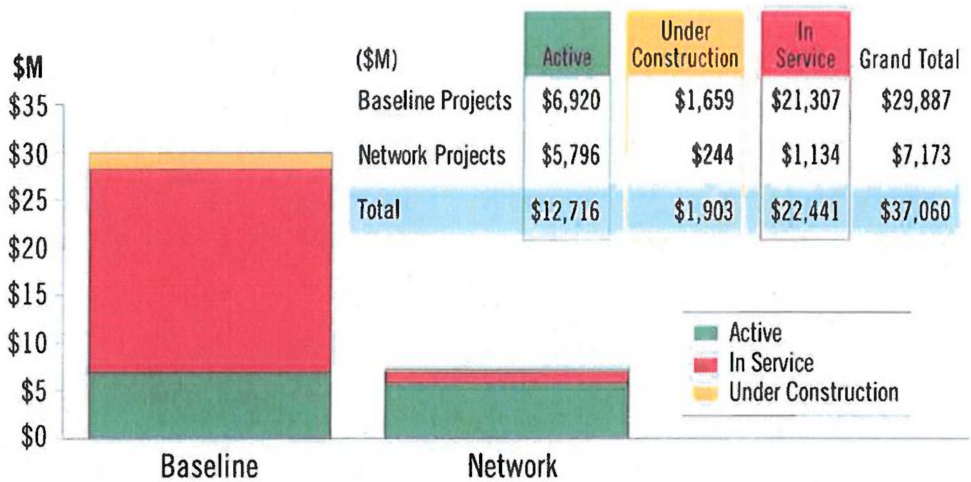
The benefits of the transmission system itself and the dollars invested in it extend well beyond delivering power over high-voltage transmission lines. In this paper, PJM quantifies the benefits and drivers of new transmission in terms of the following:

- **Ensuring reliability** – keeping the lights on
- **Keeping costs low** – delivering lowest-cost energy to customers through wholesale markets
- **Supporting public policy** – helping bring to fruition state renewable mandates and federal emission mandates

Investments in transmission system enhancements approved by the PJM Board since RTEP's inception in 1999 are summarized by their status[10] as of December 31, 2018, in **Figure 3.** The numbers provide a snapshot at a single point in time, as with an end-of-year balance sheet.

- Since 1999, the PJM Board has approved transmission system enhancements totaling $37.1 billion.
- $29.9 billion are baseline projects to ensure compliance with NERC, regional and local TO planning criteria and to address market efficiency congestion relief.
- $7.2 billion are network facilities to enable more than 85,000 MW of new generation to interconnect reliably.

Figure 3: Approved RTEP Projects (1999 - 2018)

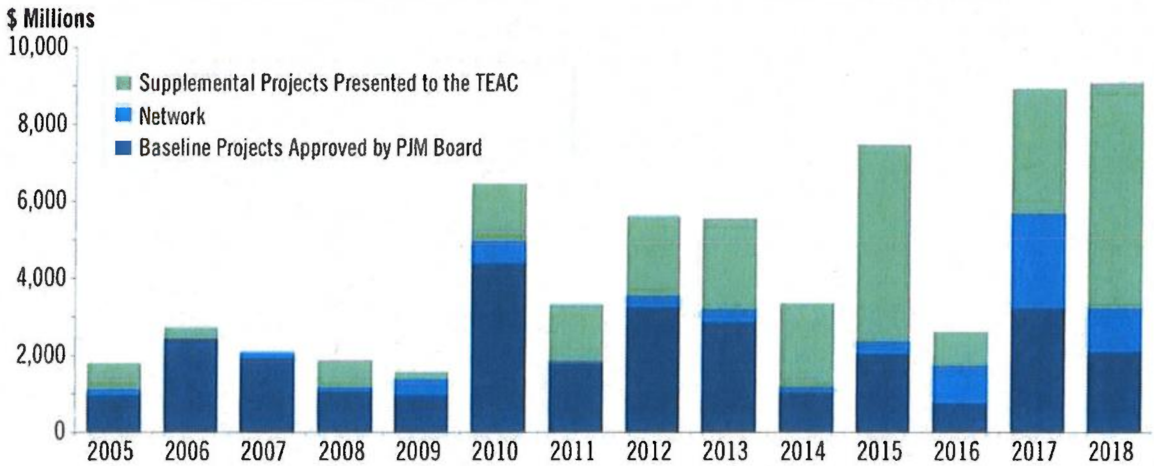


($M)	Active	Under Construction	In Service	Grand Total
Baseline Projects	$6,920	$1,659	$21,307	$29,887
Network Projects	$5,796	$244	$1,134	$7,173
Total	$12,716	$1,903	$22,441	$37,060

The baseline and network transmission investment approved by the PJM Board each year from 2005 through 2018 plus transmission owner supplemental project investment is shown in **Figure 4.**

10 Active baseline status means that the RTEP project has been approved by the PJM Board and awaits construction to begin. Active network projects are those identified in system impact studies and whose construction awaits execution of an Interconnection Service Agreement. Under construction and In-service statuses have their plain meaning for both baseline and network transmission system enhancements.

Figure 4: Annually Approved Baseline and Network Projects Plus Supplementals[11] (2005 - 2018)

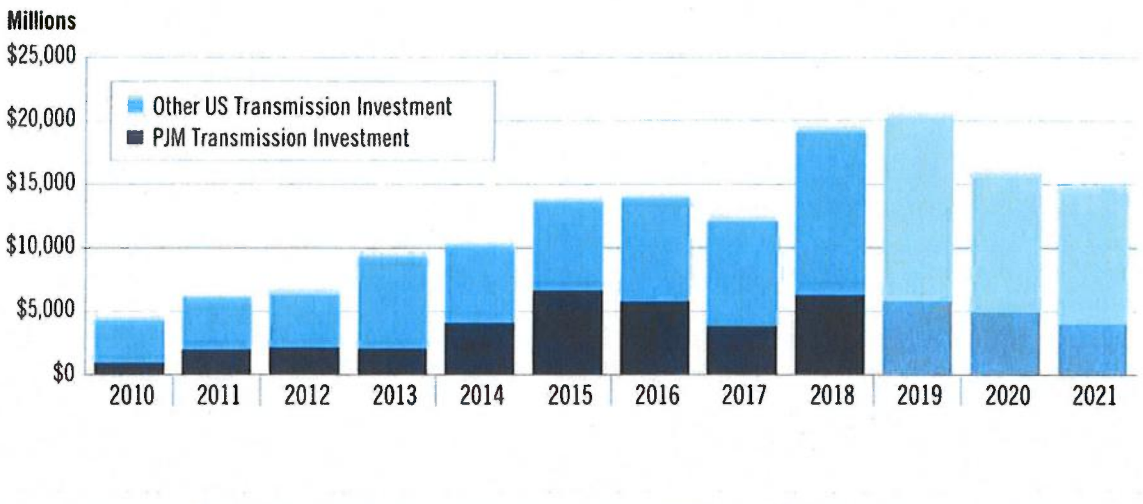


Transmission Investment Nationwide

PJM is not alone in its need for new transmission assets. Other ISOs/RTOs and transmission owners have identified the need for new transmission as well. **Figure 5** provides a summary[12] of historical and projected investment in transmission infrastructure across the U.S. Historical and projected transmission investment in the U.S. has continued to grow since 2010 in ISO/RTO footprints and utilities that are not part of such entities. Available data indicates that, in light of its geographic scope, PJM may outspend other areas of the country in absolute dollar terms, but on a megawatt load-weighted basis, transmission investment in PJM is about average when compared to other ISO/RTOs as shown in **Figure 5**.

> Since 1999, the PJM Board of Managers has approved transmission system enhancements totaling $37.1 billion.

Figure 5: Historical and Projected U.S. Transmission Investment (estimate)

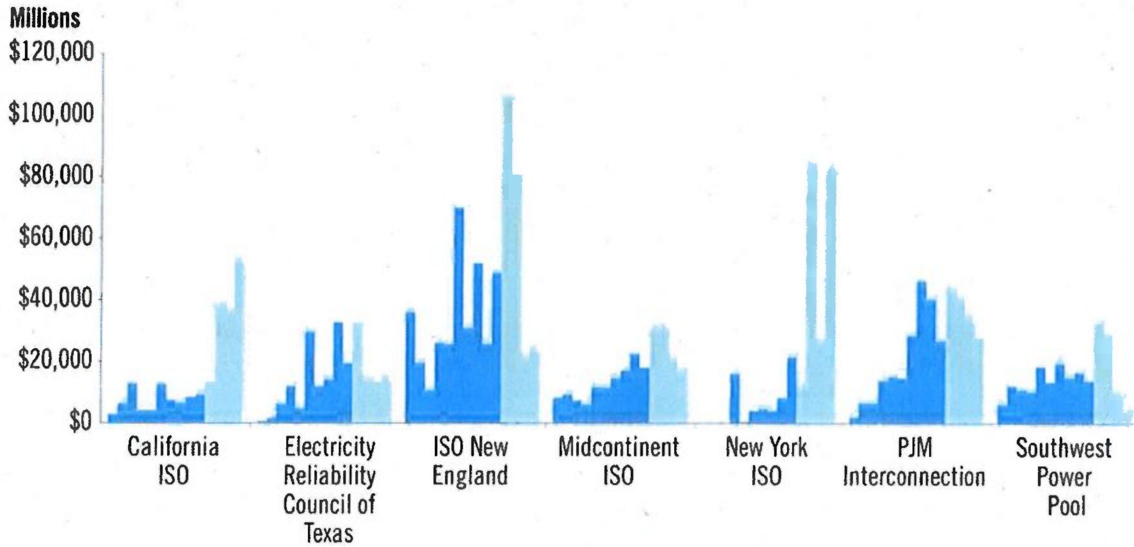


11 **Figure 4** and **Figure 5** include 2015 and 2016 investment numbers that include completion of the Susquehanna-Roseland, PSE&G's Northeast Grid Reliability and TrAIL projects. These accounted for $12.4 billion of the total across the country in those two years.

12 **Figure 5** is based on data provided by a third-party vendor that compiles from a variety of sources and includes data from RTO/ISOs as well as systems outside those footprints. Reporting differences suggest that the national totals are likely measurably higher. As such, the visual is for high-level comparison only.

Figure 6 presents a high-level comparison of RTO/ISO transmission investment from 2008 through 2021 as weighted by 2016 load to provide better perspective across systems of different sizes. Both figures suggest that, despite flattened load growth nationally, transmission investment has continued for a variety of reasons, including aging infrastructure, interconnection of generation powered by renewable fuels and other state policy mandates. PJM notes that both figures show investment numbers in 2015 and 2016 that include completion of the Susquehanna-Roseland, PSE&G's Northeast Grid Reliability and TrAIL projects. These accounted for $12.4 billion of the total $27 billion across the country in those two years.

Figure 6: Load-Weighted Transmission Investment Costs by RTO/ISO (2008 to 2021)



Supplemental Projects

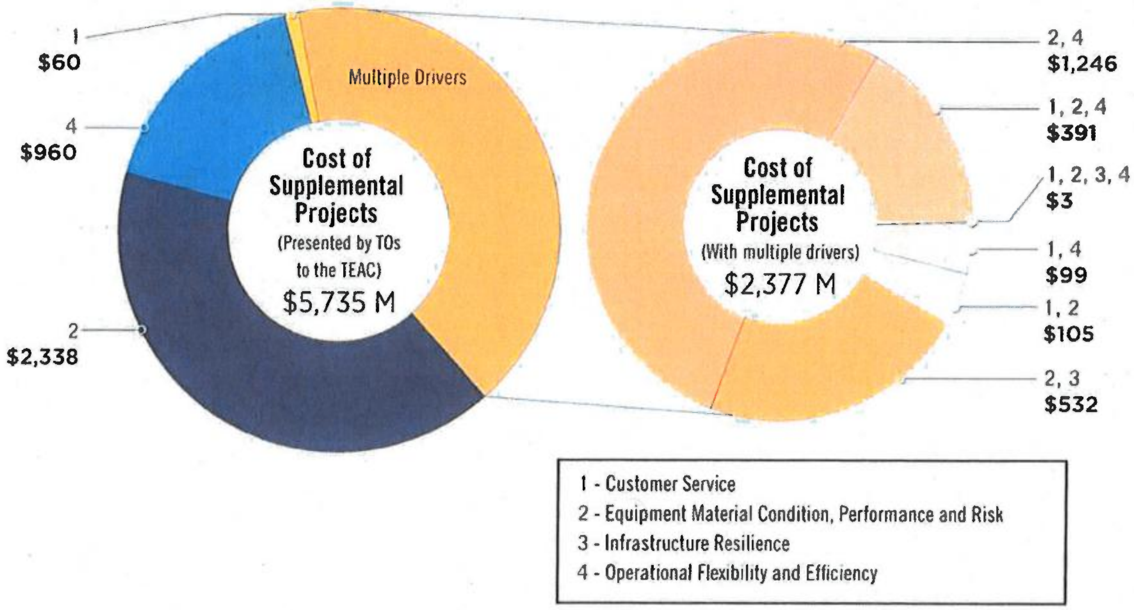
Supplemental projects, known at one time as transmission owner-initiated projects, are not a result of PJM RTEP process studies to ensure compliance with NERC and regional reliability criteria, operational performance, and market-efficiency economic criteria. However, TOs' supplemental projects ensure that issues on lower voltage and local transmission facilities are addressed. PJM reviews supplemental projects to ensure they do not introduce other reliability criteria violations. Supplemental projects are introduced to the PJM regional planning process through PJM's Transmission Expansion Advisory Committee (TEAC) and sub-regional RTEP committees. While not subject to PJM Board approval, they are included in PJM's RTEP models and evaluated to identify any reliability criteria violations requiring solutions.

Supplemental projects are foundational to TO management of their transmission assets and provide significant benefits to customers:

- Planning functions not transferred to PJM (e.g., asset management, load customer connections)
- Continued reliable operation of the local transmission systems, meeting customer needs, fostering economic development opportunities, enhancing grid resilience and security, ensuring public safety, and helping to promote renewable resource integration
- Obligation-to-serve grounded in good utility practice

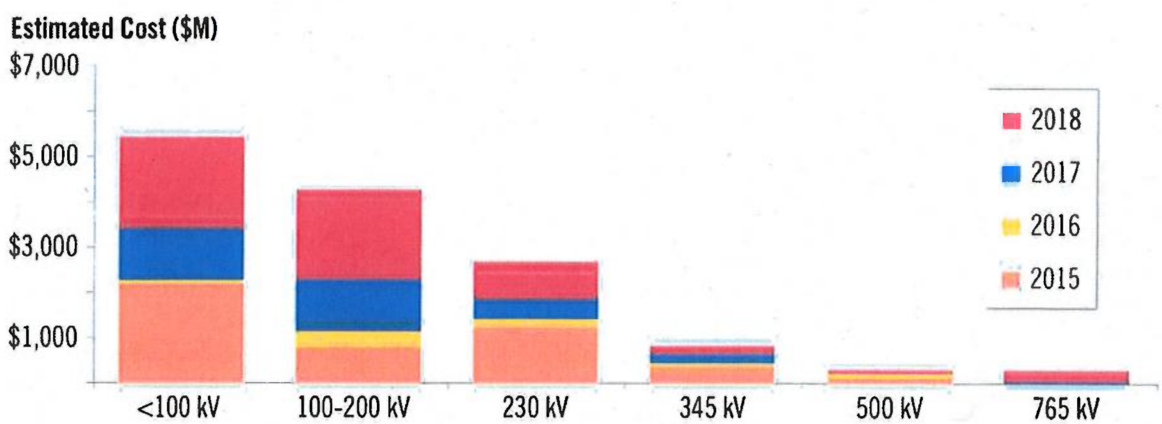
While supplemental projects have a range of drivers, they all improve the TOs' ability to provide reliable service to their customers and enhance system reliability. PJM remains committed to facilitating the process by which stakeholders are able to review the need for these projects to ensure transparency consistent with FERC requirements. In 2018 for example, PJM evaluated TO supplemental projects totaling approximately $6 billion (see **Figure 7**).

Figure 7: PJM Transmission Owner 2018 Supplemental Projects by Driver



As **Figure 7** shows, $2.4 billion of supplemental projects in 2018 had more than one driver. **Figure 8** shows a breakdown by year and voltage for supplemental projects reviewed by PJM from 2015 through 2018.

Figure 8: PJM Transmission Owner Supplemental Projects by Voltage (2015-2018)



A BRIEF HISTORY OF THE TRANSMISSION SYSTEM

Since the beginning of the electric industry, the purpose of transmission has been simple: move power efficiently from a generator to the customers that use it. The evolution of alternating current (AC) power technology in the late 19th century allowed for the development of large centralized power plants, enabling economies of scale that helped (and still help) drive down the cost of electricity for consumers while improving reliability.

In 1896, a 20-mile 11,000-volt (11 kV) AC line was built from a hydroelectric generator at Niagara Falls to power streetlights in Buffalo, N.Y. By 1930, transmission capability had increased up to 240,000 volts (240 kV). In the 1930s, electric service became more common in cities, where population density could support the costs of building generators and transmission lines. However, reaching rural communities was expensive. Fewer customers were located across wider expanses of land. As part of President Franklin Roosevelt's New Deal, high-voltage transmission was built into rural areas to reach the 90 percent of farmers who were without power. Doing so modernized farming and raised the standard of living in many rural communities.

Demand for electricity has continued to grow through the 20th century and beyond, and new, higher-voltage transmission technology has allowed increasingly higher volumes of power to be moved even more efficiently and economically from generation to customer.

A 220 kV Ring: The Landmark Interconnection that Became PJM

As the demand for electric service grew in the 1920s, the Philadelphia Electric Co., Pennsylvania Power & Light Co. and the Public Service Electric & Gas Co. signed an agreement that brought electricity from the Conowingo Dam on the Lower Susquehanna River in Maryland to Philadelphia's burgeoning western suburbs and helped enhance savings and reliability across the three territories. That agreement formed a "power pool," the beginning of PJM.

Savings, Efficiency, Reliability

A 1925 study predicted that by 1935 the creation of the 200-mile, 220 kV transmission ring interconnecting the three territories would result in an average annual savings of at least $3 million ($53 million in 2017 dollars) from "load diversity." Load diversity occurs when different areas experience their highest usage at different hours or even on different days. At those times, extra generation from a lower-demand area can be sent to a higher-demand area where it's needed. This ability to pool resources across service territories via transmission helped reduce costs as well as the need for additional power plants.

Transmission Delivers Distant Generation

Achieving these economies of scale remained a major focus throughout the 20th century. More utilities joined the PJM power pool to develop large generation stations in the coal-rich regions of western Pennsylvania. Having generators close to the source of their fuel cut costs even more. Units 1 and 2 at the Keystone plant in Shelocta, Armstrong County, Pa., began service in 1967 and 1968, respectively.

Units 1 and 2 at the Conemaugh generating station at New Florence, Indiana County, Pa., began in 1970 and 1971. Combined, these coal-fired units – built near the mines from which their fuel came – could produce 3,400 MW.

High-voltage transmission played a key role in the strategy behind these plants. Rather than building them near population centers in the eastern part of PJM, they were built close to the fuel source to spare the cost of shipping coal long distances. Bulk electricity was delivered economically to load centers via newly developed 500 kV extra-high-voltage transmission lines extending from the Keystone to Juniata 500 kV substation in central Pennsylvania, through the Peach Bottom and Whitpain 500 kV substations in southeastern Pennsylvania, and the Branchburg 500 kV substation in central New Jersey. This strategy would be employed throughout the rest of the 20th century and beyond, steadily continuing to save consumers money, increase efficiency and enhance reliability.

In western PJM, American Electric Power (AEP) installed the first 765 kV transmission line in 1969. Doing so enabled the highest utilization of its generating assets and provided much greater operational flexibility to address a wide range of potential contingencies and future uncertainties. AEP's completion of its 765 kV network in the early 1970s allowed it to meet significant load growth and provided it the flexibility to address unforeseen issues in siting and constructing new generation.

Transmission Enables Competition

Transmission lines enabled the evolution of centralized dispatch to deploy power resources in economic order, least-expensive resources first. While not an energy market as it is known today, transmission allowed the introduction of competition to supply consumers with the lowest-cost power.

The Path to Open Access and Competition

A variety of federal legislative and regulatory actions involving transmission were fundamental to opening up wholesale electricity markets to competition. The intention was to provide fair, open and reliable electric service at the lowest-possible cost to consumers.

1935 **The Federal Power Act**
Authorizes the Federal Power Commission to regulate all interstate electricity transmission and wholesale power sales

1978 **Public Utilities Regulatory Policies Act**
PURPA Requires utilities to buy power from on-utility generators and gave independent power producers access to the grid

1992 **Energy Policy Act of 1992**
Requires that competitive generators and utilities be allowed access to the transmission system at rates and terms comparable to what a TO would charge itself

1996 **FERC Order No. 888**
Details how TOs should provide open non-discriminatory access to the transmission system; requires that generation and transmission businesses be separated

FERC Order No. 889
Establishes an Internet-based system for TOs to post available capacity on their lines so companies looking to transport power can see availability

1999 **FERC Order No. 2000**
Encourages transmission-owning utilities to join RTOs and sets minimum standards for those RTOs

2004 **FERC Order No. 2003-A**
Requires TOs to interconnect all generators over 20 MW to the transmission system using a standard set of terms and conditions and a standard process

2005 **Federal Energy Policy Act**
Recognizes need to develop transmission; allows FERC to authorize eminent domain proceedings to complete critical projects

2007 **FERC Order No. 890**
Reforms orders 888 and 889 to ensure transparency and coordination in grid planning

2011 **FERC Order No. 1000**
Requires transmission providers to participate in a regional planning process and seeks to introduce competition to transmission development

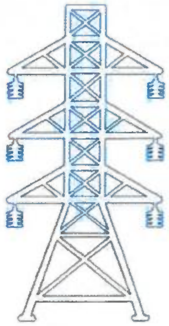
This would be brought into sharper focus in the 1970s. The 1973 OPEC oil embargo caused a sharp increase in U.S. energy prices, which rippled through the electric industry in the form of rate increases. Around the same time, ratepayers also started facing sharply higher prices, called rate shocks, from billion-dollar nuclear power projects. Seeking ways to increase domestic energy production, reduce dependence on foreign oil and keep rates down, Congress passed the Public Utilities Regulatory Policies Act (PURPA) in 1978. This required utilities to buy electricity from independent power producers, which meant these newly emerging generators needed access to the transmission system. PURPA triggered a series of steps introducing competition to the electric industry. The process eventually put transmission at the center of the evolution. No longer were transmission lines just a means for transporting bulk power. They ultimately became the vehicle that enabled competition in wholesale power markets.

The 1990s and Open Access

In the 1990s, Congress and FERC continued to pass additional legislation and regulations to enhance competition and give open access to the transmission system at reasonable rates. FERC also required utilities to separate their generation and transmission businesses to help create a fair and level playing field. FERC has subsequently ordered all RTOs to implement transparent and coordinated regional transmission system expansion planning. This is intended to ensure reliability, encourage development of new transmission and allow for open discussion of needs and solutions.

Continued Evolution

An agreement in 1927 established the power pool that has evolved into today's PJM Interconnection. The reliability and savings promise of the original interconnection has been fulfilled: Today, delivery of electric power over the high-voltage transmission system is more reliable than ever.



Section 2 The Capacity Benefit of Transmission

Ensuring an Adequate Supply of Power

The transmission links that tie PJM areas together ensure the region has enough resources to meet consumers' demand for electricity. Each individual locational deliverability area (LDA)[13] is able to rely on those links to meet consumers' needs more economically and efficiently than if each were to go it alone. The capacity resource requirements for PJM as a whole have decreased with the increase in load and generation diversity that has accompanied the integration of each additional service territory integrated into the PJM region. PJM's capacity auction provides a market for PJM to secure sufficient generating capacity to meet forecasted customer load three years forward. Historically, the capacity market has attracted sufficient capacity investment to meet future needs. Through 2022, PJM has procured 21 percent higher reserves than the forecasted peak electricity demand.

New Transmission's Impact on Individual LDAs

The ability to transmit power across transmission lines into each of the 27 LDAs in PJM – shown on **Map 2** and defined in **Appendix B** – has a direct bearing on reliability and capacity prices in PJM's capacity market auction. The maximum permissible level of this transfer capability (as determined by PJM based on NERC criteria), is called the capacity emergency transfer limit (CETL).

A CETL is the maximum amount of megawatts that an LDA can import before encountering a thermal or voltage reliability criteria violation,[14] as determined by PJM power flow studies. CETL values are affected by transmission system enhancements, load forecasts, generation additions and generation deactivations. New transmission assets increase the transfer capability into an LDA, which is a benefit to the capacity market.

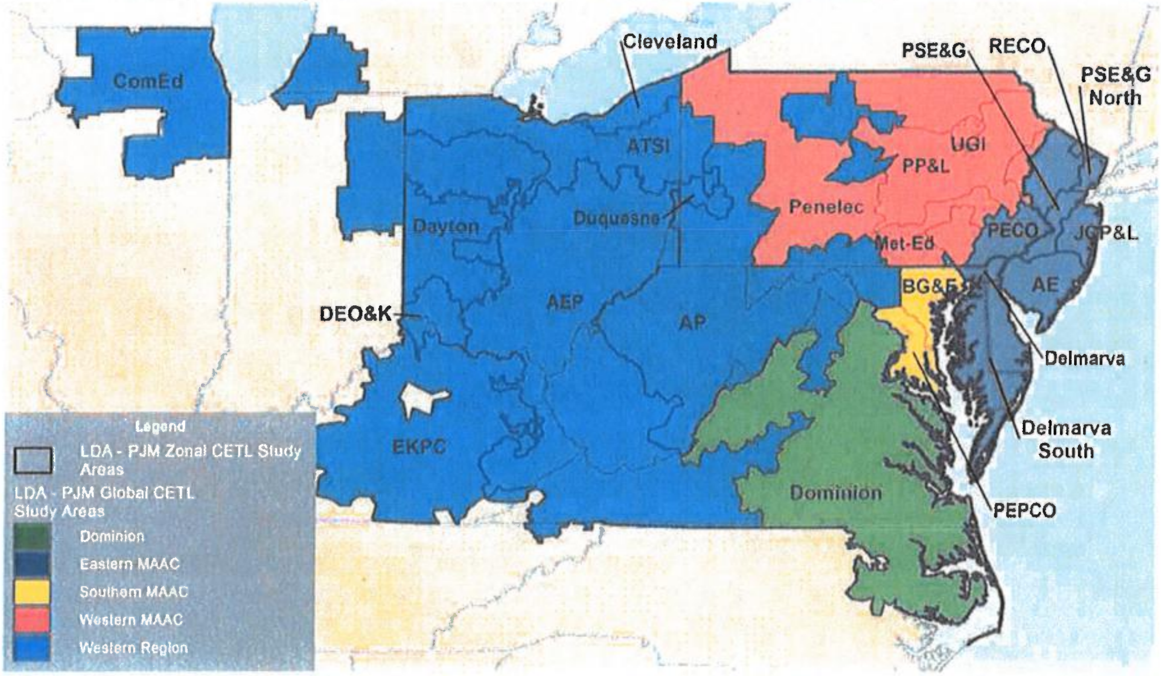
New Transmission Increases Import Capability

PJM's 2021/22 capacity market auction results offer perspective on how much new transmission assets increase import capability. In that auction, the import capability of a number of LDAs increased due to new transmission assets that reached commercial operation from 2013 to 2018. The need for these system enhancements was driven by thermal or voltage reliability criteria violations. One LDA saw increased import capability of 2,450 MW. While not all LDAs increased this much, these types of increased transfer limits are likely to result in a lower capacity auction clearing price for that LDA and, therefore, reduce capacity costs to consumers.

13 Locational deliverability areas are electrically cohesive load areas historically defined by transmission owner service territories and larger geographical zones comprising a number of those service areas, as defined in **Appendix B**.

14 Under defined peak-load test conditions.

Map 2: PJM Locational Deliverability Areas



Increased transfer capability can lower capacity auction clearing prices.

An LDA's CETL value must exceed its capacity emergency transfer objective (CETO). The CETO is the transfer capability required to ensure that available generation will be able to meet customer demand and avoid a customer load interruption event at a risk of no more than once in 25 years. Enough transmission assets ensure that the LDA can continue to serve load. If the CETL value is less than CETO – as determined by power flow analyses – the reliability test fails, which indicates that additional transmission capability is needed. Increasing an LDA's import capability lowers the likelihood of price separation in a capacity auction, driving lower capacity procurement costs to customers in an LDA.

PJM's capacity auction provides a market for PJM to secure sufficient generating capacity to meet forecasted customer load three years forward. Historically, the capacity market has attracted sufficient capacity investment to meet future needs. Through 2022, PJM has procured 21 percent higher reserves than the forecasted peak electricity demand.

Sharing Capacity Resources

Three factors that arise from market integrations provide capacity benefits to load in PJM: increased load diversity, a wider portfolio of generating resources, and transmission ties to neighboring systems. PJM's market integrations have enhanced the value of the transmission assets that link the TO zones. Since 2002, PJM has added seven transmission zones to the PJM footprint. These integrations have enabled the addition of 112,000 MW of generation and 95,000 MW of peak customer demand. The vastly increased generating capacity and electric demand that have resulted from the integrations allows the most-efficient generation dispatch from a much larger fleet of generators. This has also increased competition, which lowers costs to consumers.

Load Diversity

Transmission has enabled seven TO systems to integrate into the PJM region since 2002, increasing reliability and capturing ever larger economies of scale. Load diversity[15] alone across PJM has increased from 1 percent to 3.5 percent since PJM's first market integration in 2002. For perspective, the current load diversity across PJM's original footprint is 1,213 MW whereas as the load diversity across the current PJM footprint is 5,980 MW. This 4,767 MW increase enhances reliability as it allows zones with excess capacity at the time of PJM's peak customer demand to export capacity to zones in need. This reliability benefit is enabled by the 325 inter-zonal transmission lines connecting each TO zone to adjoining zones.

More Generating Resources

Considered holistically, load diversity, together with a generation fleet composed of units with diverse sizes and outage rates has reduced the capacity reserve levels needed to supply customers. For example, the generation reserve requirement for the original Mid-Atlantic area of PJM before any market integrations was approximately 22 percent. Today it is 15.7 percent.

Transmission assets also provide access to capacity and energy in adjoining power markets. Because of its external ties, PJM can carry about 2,500 fewer megawatts of installed reserves, which, in turn, can help reduce costs to consumers.

> Transmission links PJM zones together, allowing them to share capacity, and reducing the need for new generation by $3.78 billion annually.

Meeting Resource Requirements

Resource adequacy is measured in terms of installed reserve margin (IRM). IRM is the level of capacity reserves - typically expressed as a percentage in excess of annual peak demand - needed to satisfy PJM reliability criteria. The criteria state that the available generation resources will be able to meet the demand for electricity and avoid customer load interruption events with a risk of no more than once in 10 years. PJM's capacity market provides the forward-looking market vehicle by which sufficient generation is procured to meet IRM.

Transmission links between LDAs mean that lower levels of capacity are needed to serve the whole system reliably. Recent analysis (see Benefits by the Numbers below) has shown that up to 33,000 fewer megawatts are needed across PJM because of the transmission ties among LDAs. Those facilities have an economic value in PJM as high as an estimated $3.8 billion. Considering the additional operational efficiencies that are gained through internal transmission ties among PJM zones, the overall value is potentially even higher.

Benefits by the Numbers: Capacity Market Results Without Internal LDA Ties or External Ties

The capacity market is key to future reliability. PJM's annual capacity market auctions, which look three years forward, have continued to attract sufficient generation investment to meet consumers' future electricity needs. Through 2022, PJM has been able to procure 21 percent higher reserves than forecasted peak electricity demand, more than the minimum RTO requirement. To quantify the impact of existing transmission on capacity market outcomes, PJM conducted a scenario study in which all transmission lines linking PJM zones to each other and to adjacent systems were "removed." Once isolated from each other, each zone required significantly more generation investment internally to meet reliability requirements.

15 Load diversity is defined as the sum of all zonal non-coincident MW annual peaks minus the RTO coincident MW annual peak.

PJM first computed a "stand-alone" IRM for each individual zone with the assumption that each had no transmission ties to the others or to systems adjoining PJM. Doing so revealed that these "stand-alone" zonal IRMs were generally in the 20 percent to 50 percent range, with smaller zones tending to have higher IRMs. Each stand-alone zonal IRM was converted to a megawatt requirement by multiplying it by the zone's forecasted 2020 summer peak load. Those calculations revealed that five zones were still able to satisfy their stand-alone zonal megawatt requirement. Existing supply capability in each of the remaining 14 zones, however, fell short of meeting respective stand-alone zonal megawatt requirements. As **Table 1** shows, meeting IRM requirements for those 14 zones amounted to an additional 33,000 MW[16] to satisfy the one in 10 loss of load expectation requirement for each. This translates into an annual avoided capacity investment - or savings - of $3.78 billion, assuming a typical new generator start-up cost of $313.62 per megawatt-day as identified for the 2021/22 capacity market base residual auction.

Table 1: Stand-Alone Zonal MW Requirement Analysis - Zones Unable to Meet MW Requirement

Aggregate Zone Data	Zonal MW Requirement
Aggregate "Stand-Alone" Requirement (MW)	150,385
Existing Generation (MW)	116,735
Existing Demand Response Resource (MW)	619
Aggregate Resources (MW) (Generation + Demand Response)	117,354
Additional Capacity Required to Meet Aggregate Stand-Alone Requirement (MW)	33,032

Interregional Tie Lines Provide Capacity Benefits

Transmission assets connecting PJM with neighboring systems support internal reliability and allow external generators to participate in PJM's capacity market, which increases competition by reducing the cost of wholesale power and benefits end-use customers. In other words, external tie lines provide a quantifiable capacity benefit.

Benefits by the Numbers: Recent Base Residual Auction without External Ties

This analysis focused only on the capacity-related benefits of PJM's tie lines to adjoining systems. PJM is examined as a single electrical region with inter-zonal transmission capability but with no interconnection to neighboring systems. PJM looked at the two most recent capacity market auctions and compared those auction results with external ties modeled with results from auction simulations without external ties modeled. The analysis revealed that without external ties:

> Transmission links to neighboring regions saved an estimated $1.7 billion (15 percent) and $1.3 billion (19 percent) in recent annual capacity auctions.

- PJM would be unable to call on external resources in a capacity emergency, which is most likely to occur under peak load conditions. This would require an increase in the IRM and, consequently, the amount of generation resources needed to be procured to satisfy resource adequacy reliability criteria.

16 150,385 MW represents the aggregated megawatt amount required for the 14 stand-alone zones to meet their respective zonal IRMs. The aggregate amount of capacity supply resources available to those 14 zones totaled 117,354 MW: 116,735 MW of existing generation and 619 MW of existing demand response.

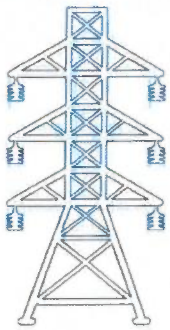
2 External generators would be unable to offer into the PJM capacity market, limiting the number of market players and reducing market liquidity and competition.

Without external tie lines, simulated auction results yielded an increase in total payments to capacity resources of $1.7 billion in the 2020/2021 auction and $1.3 billion in the 2021/2022 auction. This translates to 15 percent and 19 percent savings, respectively (see **Table 2**).

Table 2: Results of Base Residual Auction Scenario Testing[17]

	Base Residual Auction	
	2020-2021	2021-2022
Simulated Payments (Assuming no ties)	$11 billion	$8.3 billion
Existing Payments (With ties)	$9.3 billion	$7.0 billion
Difference in Payments	$1.7 billion savings	$1.3 billion savings
Difference (%)	**15% in savings**	**19% in savings**

17 Note that only these base residual auctions were examined, as prior to Delivery Year 2020/2021, resources offering into the base residual auctions were not subject to capacity performance requirements.



Section 3 Enabling a Reliable Generation Shift

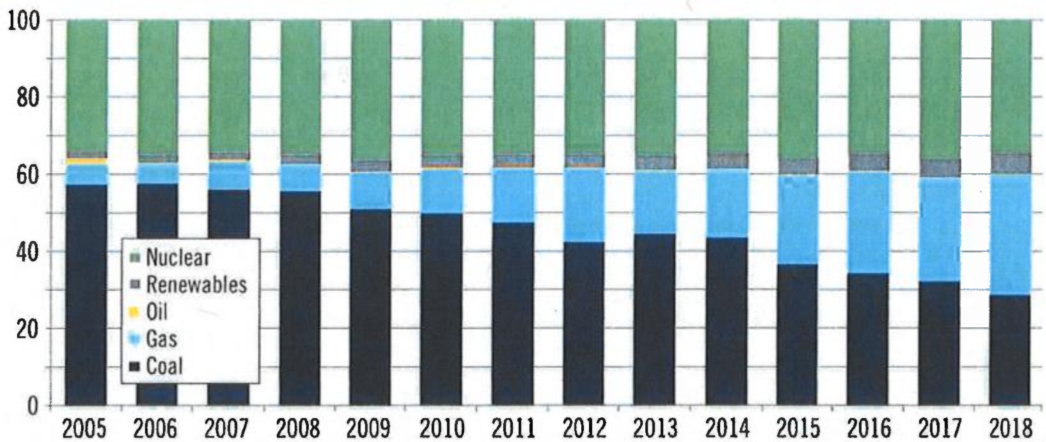
Transmission Supports Unprecedented Generation Shift

Across PJM, as in other areas of the country, the traditional fuel mix of the generation fleet continues to change. Driven by public policy, including renewable portfolio standards and environmental regulations, and the abundant shale gas in the PJM footprint, coal-fired generation is retiring and being replaced largely by natural gas-fired generation and renewable generation (**Figure 9**).

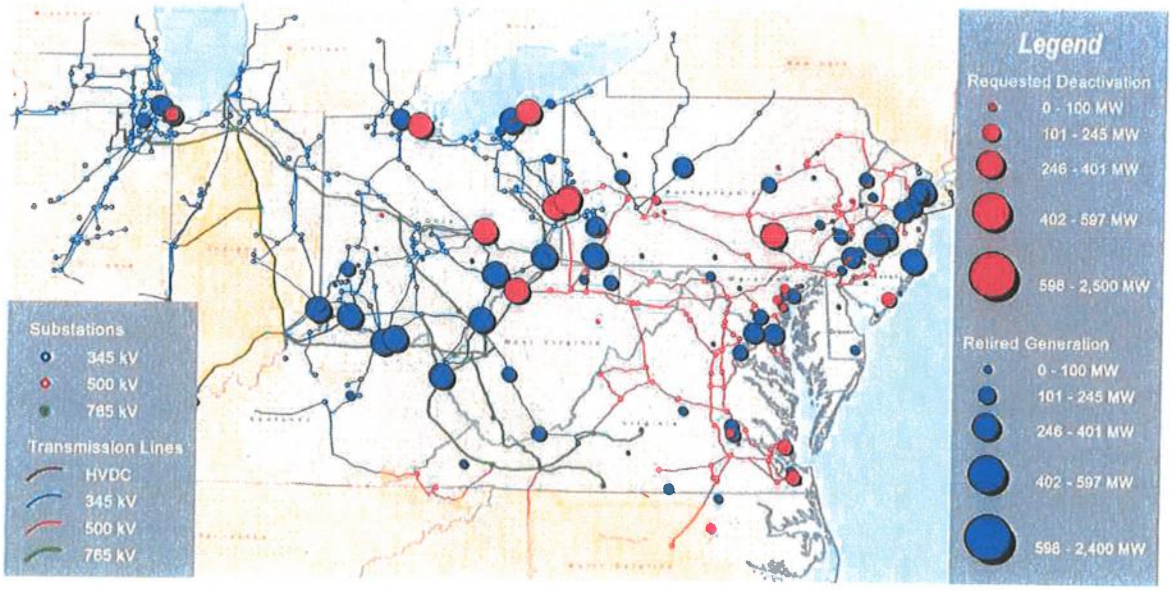
From 2011 through 2018, 258 generating units totaling 31,722 MW - from all fuel types - retired from service, shown in **Map 3**. More than 24,000 MW were represented by 125 coal-fired units, many more than 45 years old. For additional perspective, in 2018, PJM received 63 deactivation notifications totaling 12,279 MW for requested deactivations between April 2018 and June 2022, as shown in **Map 4**.

From 2011 through 2018, 31,722 MW of generation has retired, including more than 24,000 MW powered by coal-fired generation, some more than 45 years old. Retiring units have been replaced by more than 38,514 MW of new resources through December 31, 2018, including more than 29,500 MW of additional natural gas-fired generation and 5,910 MW of renewable wind and solar generation. New transmission assets continue to ensure reliability throughout this ongoing transition and beyond.

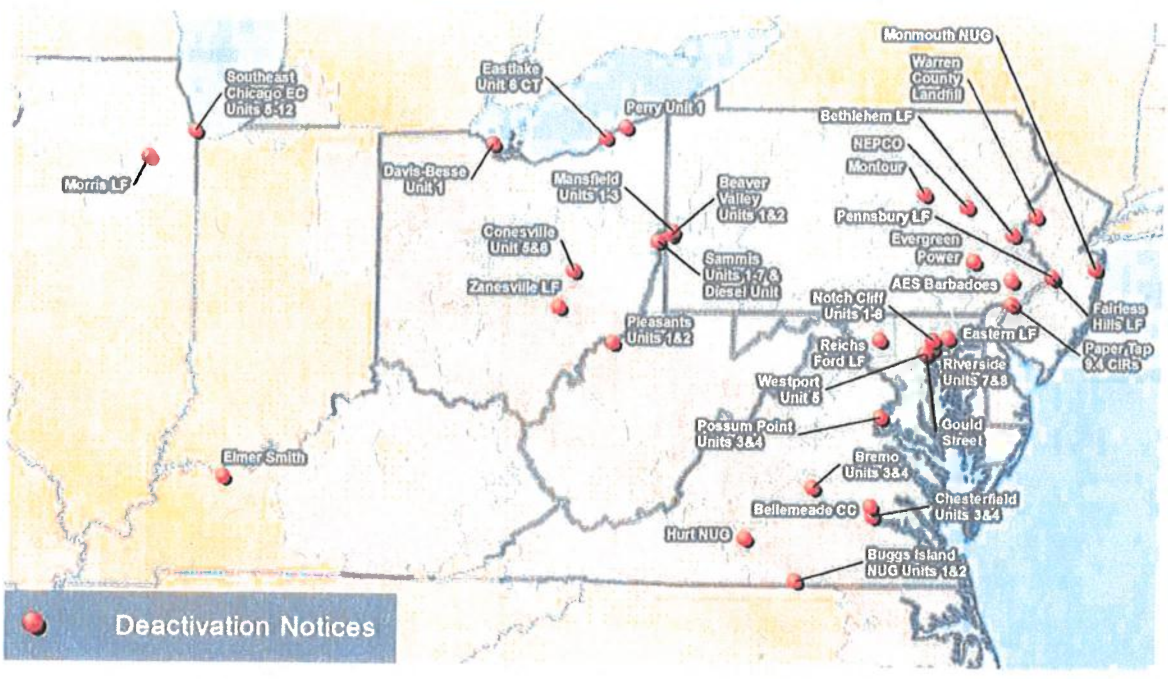
Figure 9: PJM Annual Fuel Mix



Map 3: All Generator Retirements Since 2010



Map 4: PJM Generator Deactivation Notifications Received January 1, 2018 through December 31, 2018



By contrast, PJM received and studied deactivation requests for only 11,000 MW in total during the eight years ending November 1, 2011. Retiring units have been replaced by more than 38,514 MW of new resources through December 31, 2018. Another 16,172 MW are under construction and 87,680 MW are actively under study in PJM's interconnection process. These units are primarily powered by natural gas and renewables like solar, wind and battery storage. A comparison of **Figure 10** and **Figure 11** provides additional detail. In particular, between 2011 and 2018, transmission system enhancements in PJM have enabled the interconnection of more than 29,500 MW of additional natural gas-fired generation and 5,910 MW of renewable wind and solar generation.

Even in the face of this unprecedented shift in fuel mix, the reliability of the system has never wavered. This is in large part due to the flexibility of the transmission system and a planning process that continually looks for and solves violations of established reliability criteria. New transmission has ensured reliable interconnection and delivery of the new resources while keeping the system reliable as units retire.

Figure 10: PJM Installed Capacity (December 31, 2005)

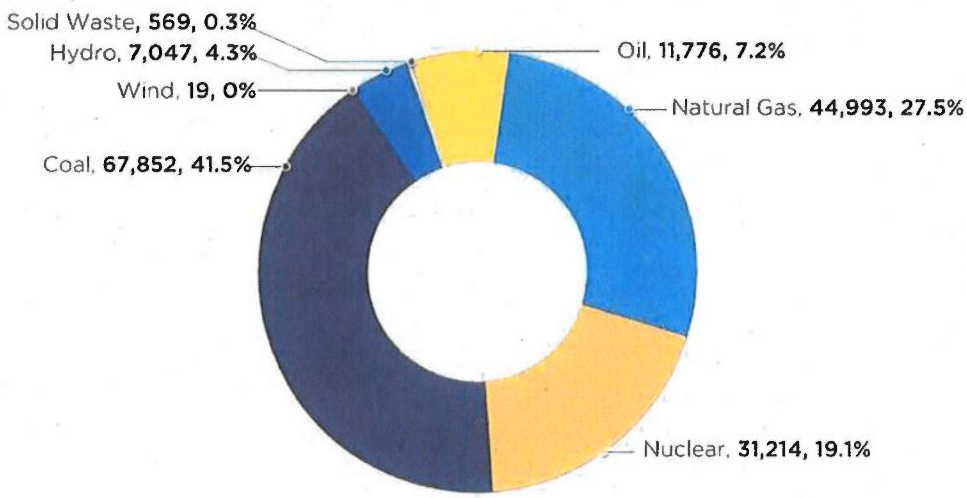
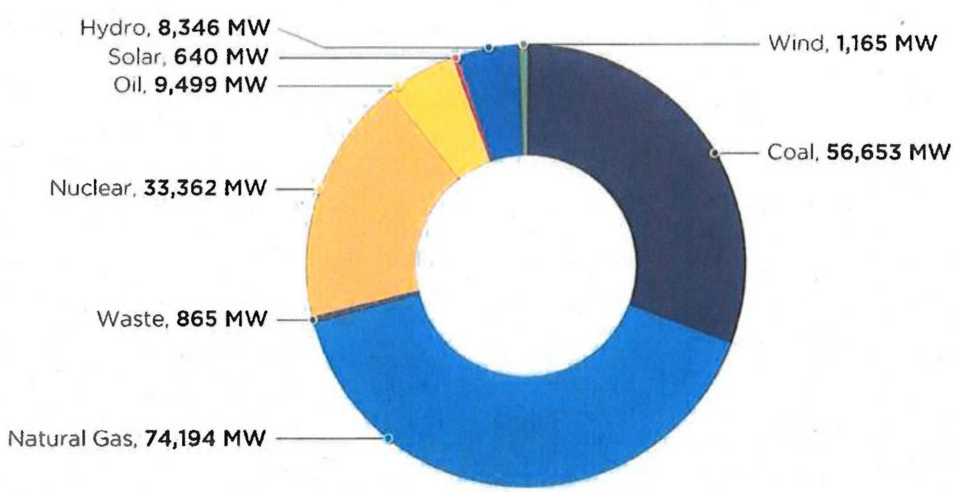


Figure 11: PJM Existing Installed Capacity Mix (December 31, 2018)



Generator Retirements

Transmission expansion continues as grid and consumer needs change. In the PJM region, older generators, particularly coal units, are retiring due to competition from newer technology and low natural gas prices. Such factors are driving the business decisions by generation owners to retire units, over 24,000 MW between 2011 and 2018. Generation owners are required to notify PJM of their intent to deactivate generation.[18] PJM cannot compel unit owners to continue to operate their units.

Unlike time lines associated with requests for interconnection, deactivation may take effect upon 90 days' notice. When PJM has received notice, it has 30 days to complete a reliability study and respond to the generation owner. This mandated time frame and the nature of the baseline system reinforcements required do not allow PJM to conduct an RTEP project proposal window to pursue solutions.

Benefits by the Numbers: Transmission Investment to Ensure Reliable Deactivations

Generator deactivations alter power flows that can cause transmission line overloads and, given reductions in system reactive support from those generators, can undermine voltage control. When PJM receives a formal generator deactivation request, PJM conducts thermal and reactive studies to ensure that remaining generation continues to be deliverable to load. If criteria violations are identified, PJM develops a solution in coordination with affected transmission owners. **Figure 12** shows the transmission enhancements needed since 2012 to allow generators to deactivate reliably.

Figure 12: PJM Transmission Investment Driven by Generator Deactivations

*Note: Cost estimate for baseline transmission enhancements required to allow generators to deactivate reliably

Interconnecting New Generation

Enabling a Diverse Fuel Mix

Transmission enables the development of all forms and sizes of generation, connecting it with consumers across the PJM region. PJM power markets have attracted over 544,000 MW of new interconnection requests since 1999 - shown in **Table 3** - equal to approximately 2.5 times PJM's current installed capacity. Overall, about 15 percent of requested capacity megawatts reach commercial operation. Queue activity reflects ongoing business decisions by developers in response to changing public policy, regulatory, industry, economic and other competitive factors.

Table 3: PJM Generation Interconnection Queue Status Totals (December 31, 2018)

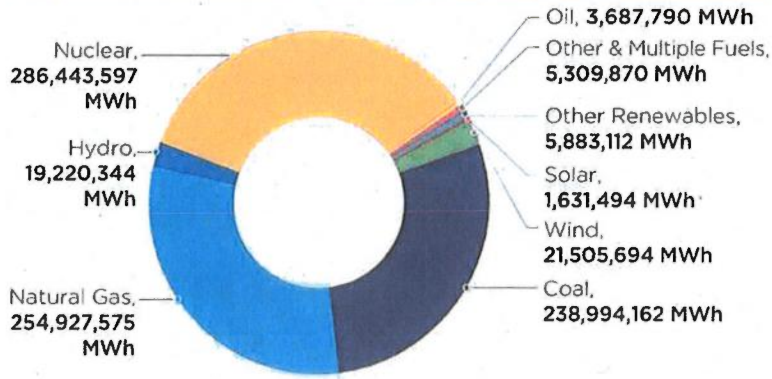
Status	Number of Projects	Requested Capacity Interconnection Rights (MW)	Nameplate Capacity (MW)
Active	663	53,762	85,430.5
In Service	816	51,943	61,128.0
Under Construction	201	17,797	23,433.9
Suspended	72	4,387	6,089.3
Withdrawn	2,508	296,739	368,341.9
Total	4,260	424,627	544,423.5

18 Per Article V of the PJM Open Access Transmission Tariff.

Existing Fuel Mix

A diverse generation portfolio reduces system risk associated with fuel availability and reduces market-price volatility. PJM's 184,724 MW of capacity market-eligible existing installed capacity reflects a fuel mix of about 40 percent natural gas, 31 percent coal and 18 percent nuclear. Hydro, wind, solar, oil and waste fuels constitute the remaining 11 percent. Capacity market-eligible natural gas-fired generation capacity now exceeds that of coal. This diversity is reflected in annual energy production as well, as shown in **Figure 13** for 2018.

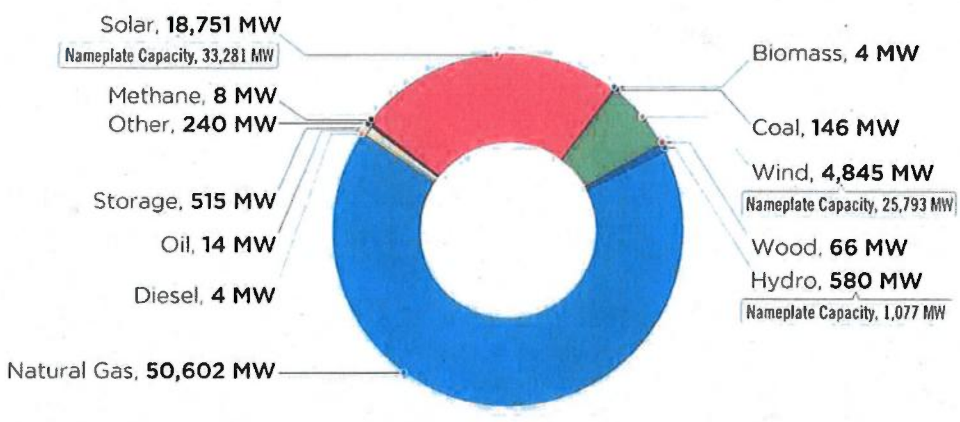
Figure 13: 2018 Energy Production by Fuel Type



Looking Forward

Currently, over 50,000 MW of new capacity powered by natural gas is seeking transmission interconnection to participate in PJM capacity and energy markets, much of it from the Marcellus and Utica shale deposits located in the middle of PJM's geographic region. This is in addition to the more than 74,000 MW already in service. This capacity exceeds that powered by coal, marking an unprecedented shift in PJM's fuel mix. Natural gas powers approximately 30 percent of the generation in PJM's interconnection queue (see **Figure 14**). The figure shows PJM's fuel mix based on requested interconnection capacity rights for generation active, under construction or suspended as of December 31, 2018.

Figure 14: PJM Queued Generation Fuel Mix - Requested Capacity Interconnection Rights (December 31, 2018)



20 percent of all PJM-approved transmission investment since 1999 will enable the interconnection of new generation.

Benefits by the Numbers: Network Upgrades Enable New Generation

As summarized earlier, roughly 20 percent of all PJM-approved transmission projects since 1999 will enable over 85,000 MW of new generation, across all fuel types, to interconnect to the grid reliably. When PJM receives a completed interconnection request, PJM conducts a series of thermal, voltage, short circuit and stability studies to ensure compliance with NERC reliability criteria. If violations are identified, PJM develops a network solution in coordination with affected transmission owners. **Figure 15** shows the network transmission enhancements needed since 2011 to allow all new generators across all fuel types to interconnect reliably. Once those transmission facilities are in place, generators can participate in PJM capacity, energy and ancillary services markets.

Figure 15: Network Transmission Enhancements for New Generation - All Fuel Types

*Note: Cost estimate for network transmission enhancements to allow generation – all fuels – to interconnect reliably

Access to Shale Gas-Fired Generation

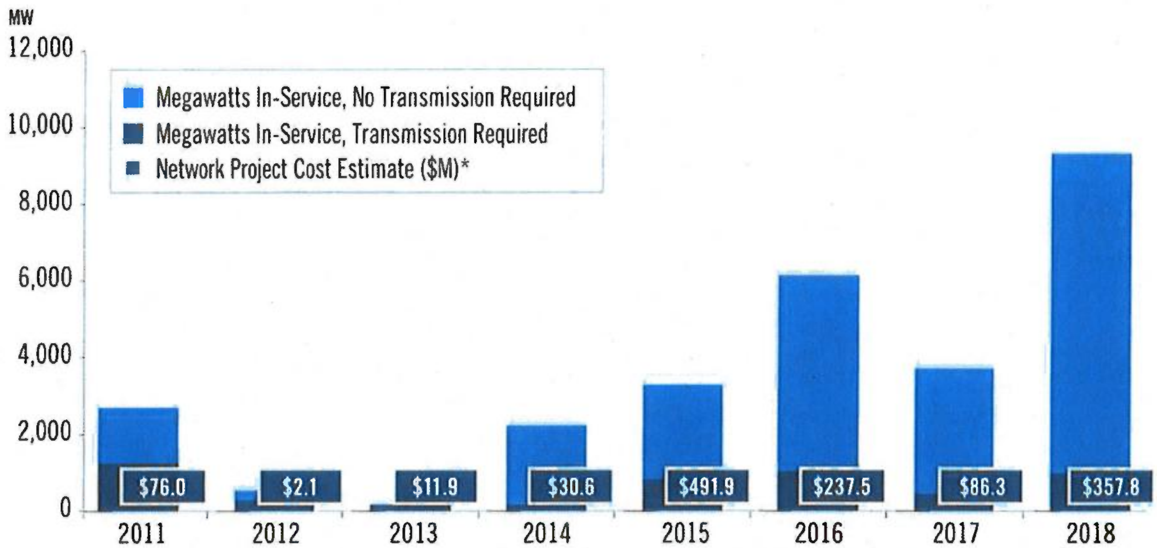
New transmission provides generation powered by the abundant Marcellus shale and Utica shale natural gas found in the PJM footprint access to a broad range of markets via the PJM transmission system. The regional transmission grid provides a market outlet for this generation.

> Robust transmission has enabled a generation shift from coal to natural-gas-fired generation, saving consumers money and helping to reduce emissions.

Benefits by the Numbers: Transmission Enables Shale Gas-Fired Generation

Since 2011, more than 29,500 MW of natural gas-fired generation has been able to interconnect reliably to the PJM transmission grid to reach consumers across the footprint. As with proposed generation of other fuel types, when an interconnection for such generation is received, PJM conducts a body of studies to identify the existence of reliability criteria violations. If violations exist, PJM develops a network solution in coordination with affected transmission owners. **Figure 16** shows the network transmission enhancements needed since 2011 to allow generators powered by natural gas to interconnect reliably.

Figure 16: Network Transmission Enhancements for New Generation - Natural Gas



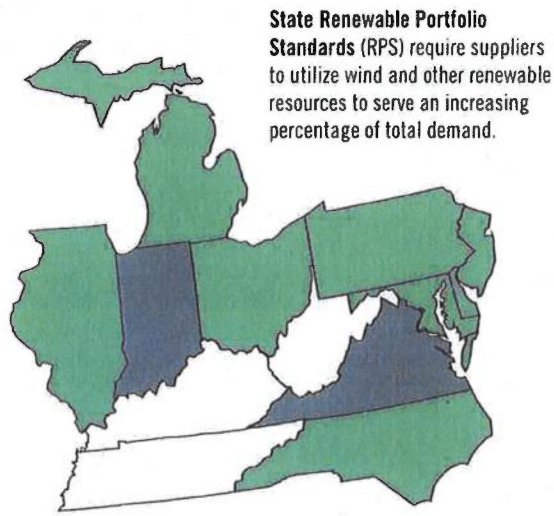
*Note: Cost estimate for network transmission enhancements to allow natural gas-fired generators to interconnect reliably

Transmission Enables Renewables

Transmission enables customer access to renewable power, much of it driven by states' renewable portfolio standard mandates, as shown in **Figure 17**. There has been significant growth in wind- and solar-powered generating plants in PJM. **Figure 18** depicts the growth in wind capacity since 2005; in particular, it shows proposed onshore and offshore wind capacity in comparison to the cumulative amount needed to meet requirements proposed by the states in which PJM operates. Transmission provides the means with which to deliver this renewable energy. **Map 5** shows the wind- and solar-powered generators currently in service on the PJM system.

> Transmission enhancements will enable the interconnection of renewable energy resources such as utility-scale wind and solar plants.

Figure 17: State Renewable Portfolio Standard Targets

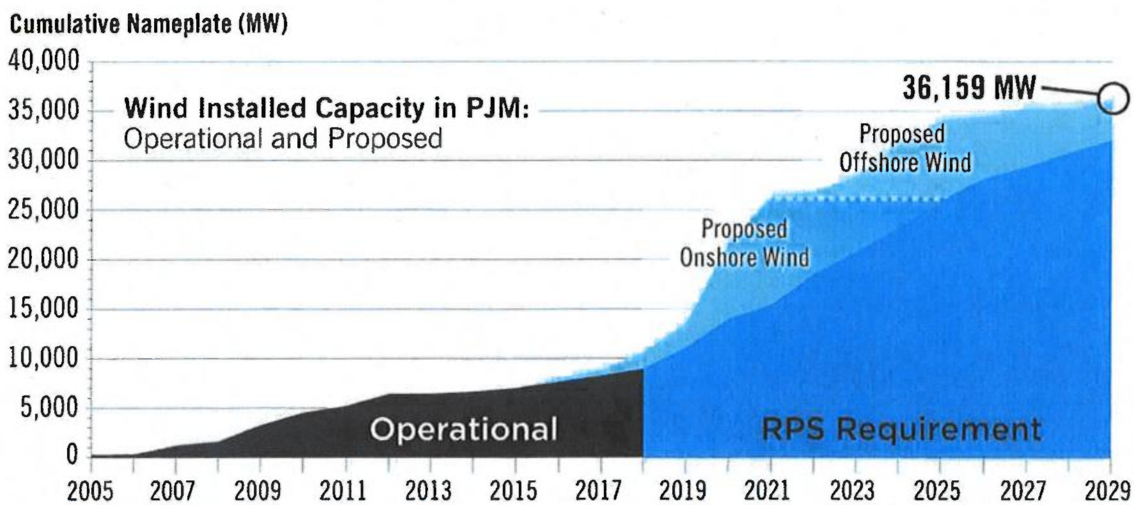


State RPS Targets

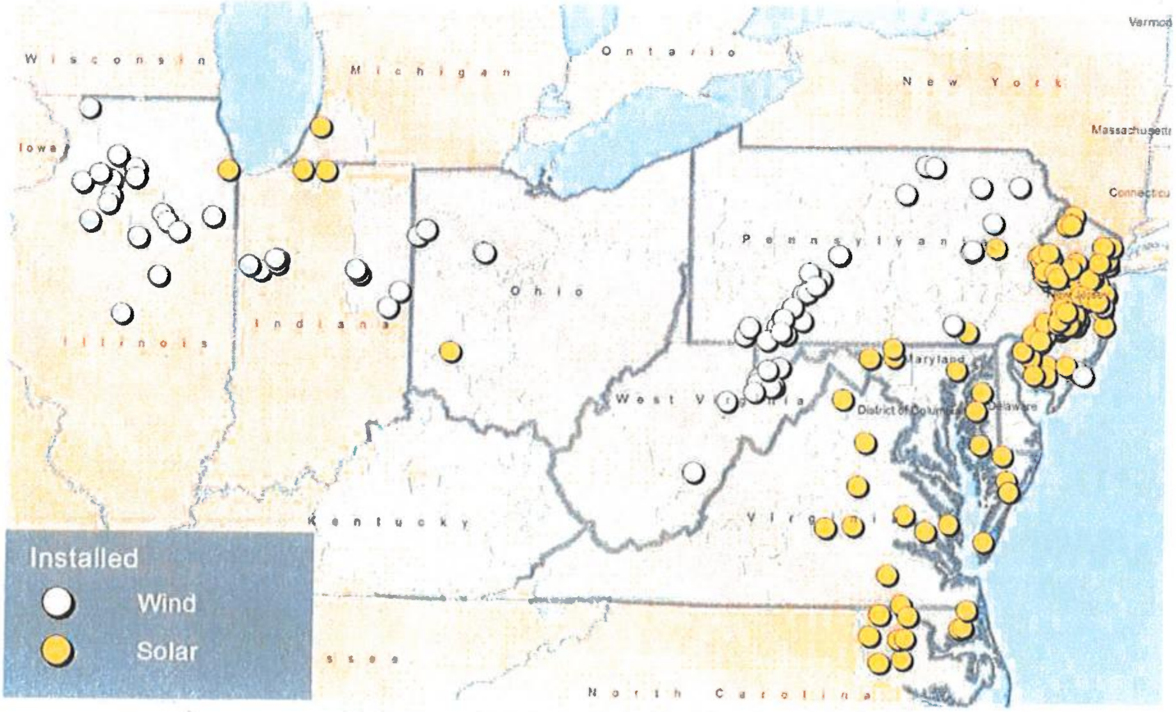
☼ NJ: 50% by 2030	☼ OH: 12.5% by 2026
☼ MD: 25% by 2020	☼ NC: 12.5% by 2021 (IOUs)
☼ DE: 25% by 2026	MI: 15% by 2021
☼ DC: 100% by 2032	VA: 15% by 2025
☼ PA: 18%** by 2021	IN: 10%** by 2025
☼ IL: 25% by 2026	

Source: DSIRE, www.dsireusa.org, January 2019

Figure 18: Wind Capacity in PJM Since 2005



Map 5: Installed Wind- and Solar-Powered Generation in PJM (December 31, 2018)



Benefits by the Numbers: Transmission Enables Renewables

Generators are most economic when they are built at or close to the source of their fuel, such as coal mines, natural gas wells and hydroelectric dams. Wind and solar farms are no exception. They need to be located where the wind blows most or the sun shines most and they need transmission lines to carry their electricity to where it is used.

Between 2011 and 2018, 5,910 MW of wind and solar energy have been able to interconnect reliably to the PJM transmission grid to reach consumers across the region. **Figure 19** and **Figure 20** show the breakdown of existing and queued renewable generation, respectively. Corporate and voluntary purchases of renewable energy are becoming an increasingly significant driver for renewable energy development, facilitated by PJM markets. PJM also estimates that roughly 4,500 MW of distributed solar generation (such as rooftop solar panels) is present on the grid behind the meter.

Figure 19: Existing Installed Capacity - Renewable Fuels (December 31, 2018)

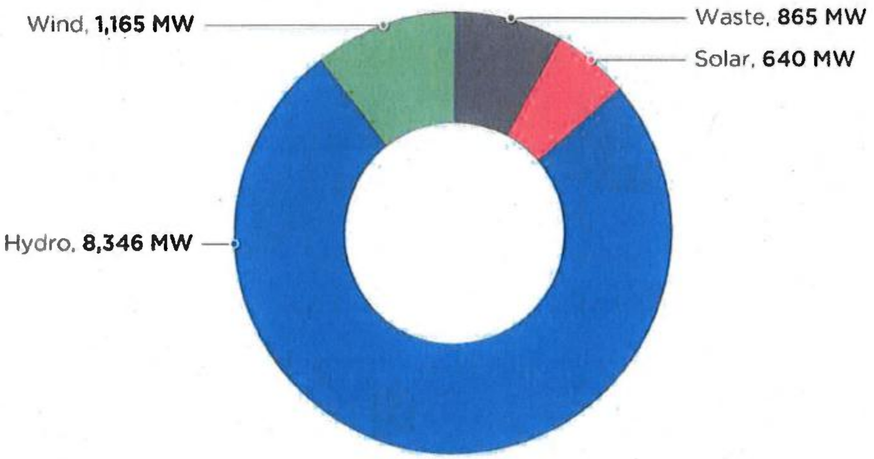
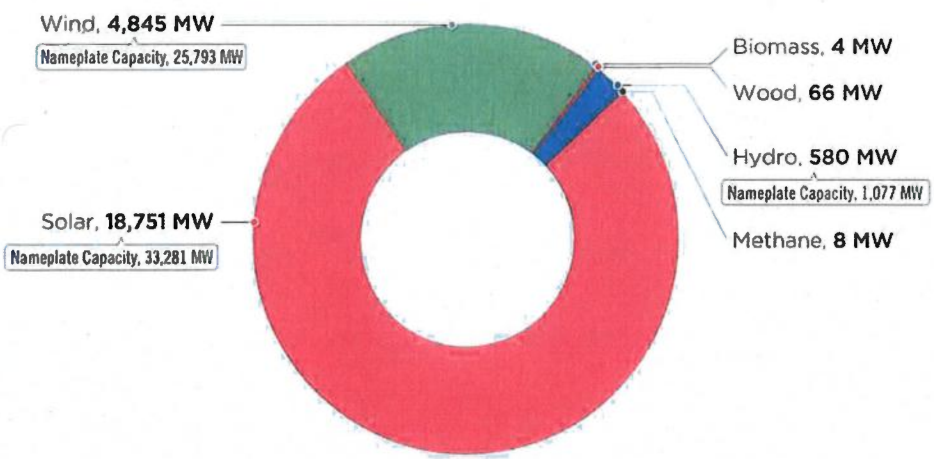
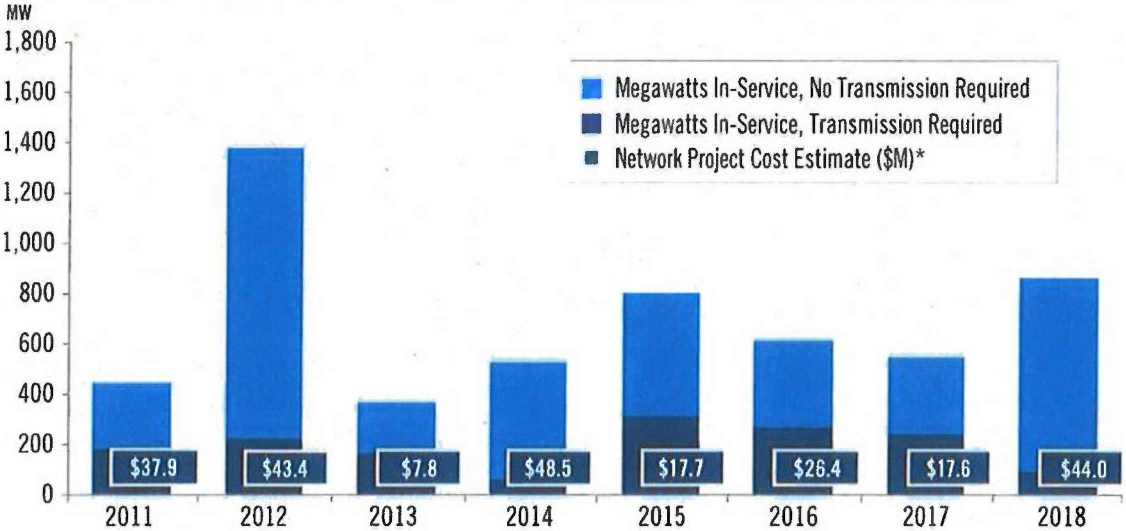


Figure 20: Queued Generation - Renewable Fuels (December 31, 2018)



PJM identifies reliability criteria violations and develops network solutions in coordination with affected transmission owners. **Figure 21** shows the network transmission enhancements needed since 2011 to allow generators powered by renewable fuels to interconnect reliably.

Figure 21: Network Transmission Enhancements for New Generation - Renewable Fuels



*Note: Cost estimate for network transmission enhancements to allow renewable-powered generation to interconnect reliably

Facilitating Emissions Reductions

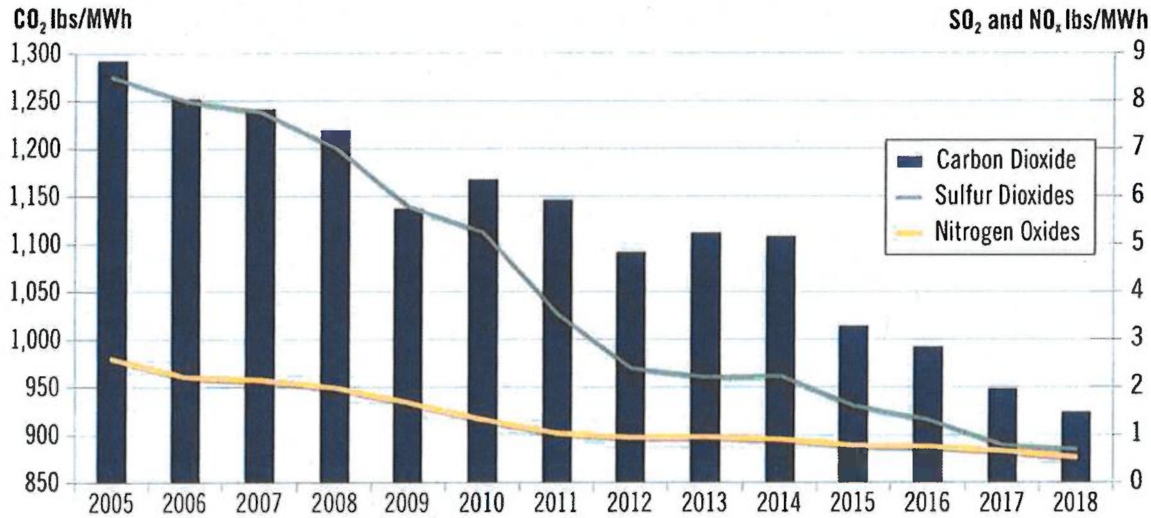
New technologies have improved efficiency with respect to emissions. Emission reductions are largely the result of competitive markets encouraging the entry of new, cleaner, competing technologies. Access to these resources would not be possible without the capability of the transmission system to deliver lower-emissions energy or renewable power.

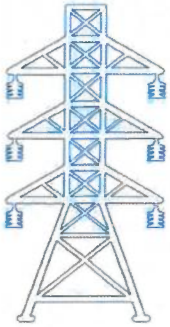
Benefits by the Numbers: Emission Reduction

Today, PJM's generation mix is 30 percent less carbon-intensive than 10 years ago. On average, producing one megawatt of power in PJM emits 13 percent less carbon dioxide than 10 years ago and 28 percent less than in 2005. This reduction has come at zero additional cost to consumers. **Figure 22** shows the reduction in carbon dioxide, sulfur dioxide and nitrogen oxide since 2005.

> Transmission improvements have enabled a 30 percent reduction in carbon emissions over 10 years.

Figure 22: PJM Generation Portfolio Emission Reductions Since 2005





Section 4 Day-to-Day Operations – the Reliability Benefits of Transmission

A primary function of regional transmission organizations like PJM is to ensure that the supply and demand for electricity is reliable and perpetually in balance. PJM operators coordinate the flow of power across the transmission lines that link individual utilities and neighboring grid operators. The transmission assets in place today provide operators with the flexibility to manage the flow of power effectively and efficiently and to reduce the need for emergency procedures up to and including load shed. As discussed throughout this section, a robust transmission system gives grid operators valuable margin, or room to maneuver. This margin allows operators to address unexpected system events like loss of generation or loss of another transmission asset, such as a transmission line, a transformer or a substation.

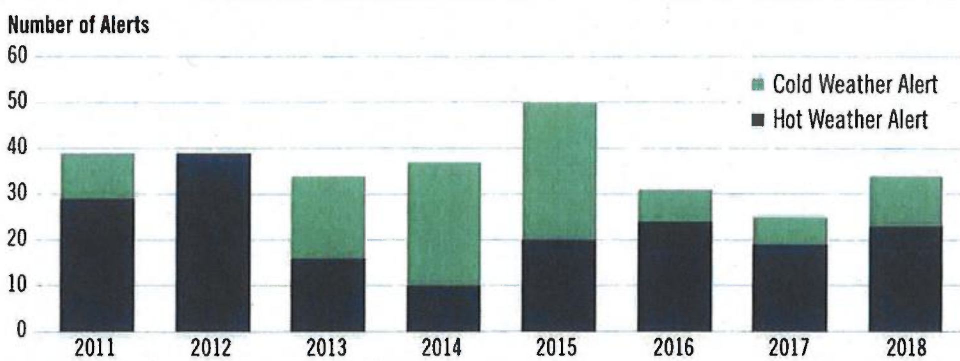
Power Delivery in Extreme Weather

Under emergency conditions in areas of PJM where generating capacity is limited, transmission lines ensure that power can flow freely to where it is needed from resources across the rest of the region. A robust transmission system gives dispatchers the flexibility to respond to system events under critical system conditions such as summer peak load, winter peak load and light load periods.

Cold Weather Alerts and Hot Weather Alerts

Extreme weather conditions can stress the ability of the PJM system to deliver power. Such conditions are frequently characterized by high load and tight operating capacity. **Figure 23** shows the volume of hot and cold weather alerts PJM has issued each year from 2011 through 2018. Even under these stressed conditions, transmission assets in PJM continue to deliver power to both PJM customers and to neighboring systems facing their own extreme weather and peak customer demand.

Figure 23: PJM Extreme Weather Alerts



PJM issues cold weather alerts when forecasts indicate temperatures below 10 degrees Fahrenheit. PJM may also issue a cold weather alert at higher temperatures if it anticipates increased winds or projects that a portion of gas-fired capacity is unable to obtain spot market gas during load pick-up periods.

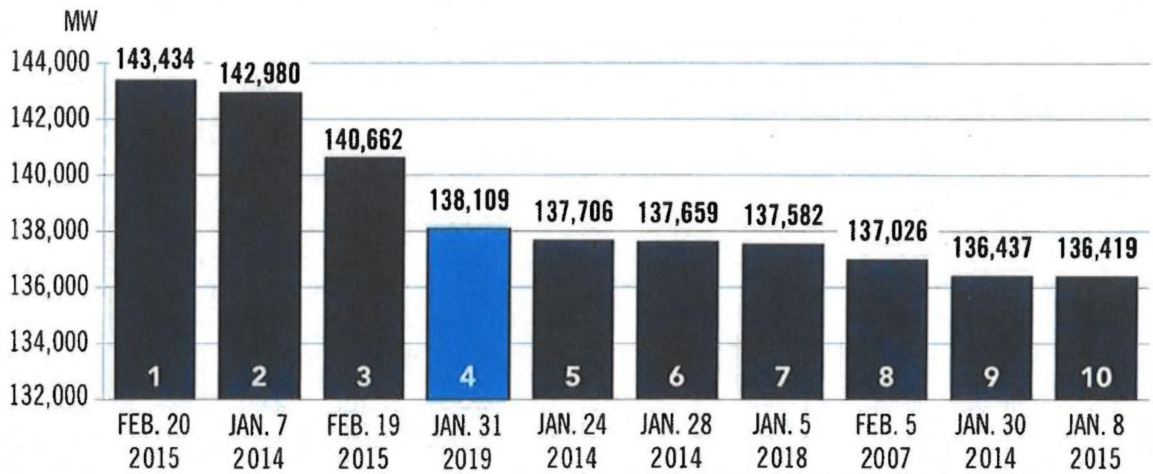
PJM issues hot weather alerts when temperatures are forecast to exceed 90 degrees[19] with high humidity for multiple days. PJM may also issue a hot weather alert at lower temperatures during the spring and fall if there are significant amounts of generation and transmission outages that reduce available generating capacity. These alerts serve to notify PJM members of higher-than-normal demand. During these periods, PJM requests that all available transmission and generation equipment be restored and that any maintenance activities planned during the alert period be deferred.

> Transmission helps to maintain reliability across the PJM region – and between regions – during periods of extreme weather, when reliable power is needed the most.

Benefits by the Numbers: Weathering Extreme Conditions

During the cold snap from December 27, 2017, to January 7, 2018, PJM and its members demonstrated strong coordination and reliable operations. Few transmission concerns emerged, despite PJM experiencing prolonged cold temperatures and one of its top 10 winter peaks, as shown in **Figure 24**. In fact, PJM's robust transmission system was in a position to come to the aid of its southern neighbors. The cold weather was not isolated to the PJM footprint and extended well past PJM's southern border down through the eastern part of the country, extending into Florida. As a result, most external reliability coordinators declared a form of cold weather alert or conservative operations during the cold stretch from January 1 through January 17.

Figure 24: PJM Top 10 Winter Peaks



As of Feb. 28, 2019. This data should not be used as the basis for decision-making.

19 93 degrees in the Dominion and East Kentucky Power Cooperative TO zones.

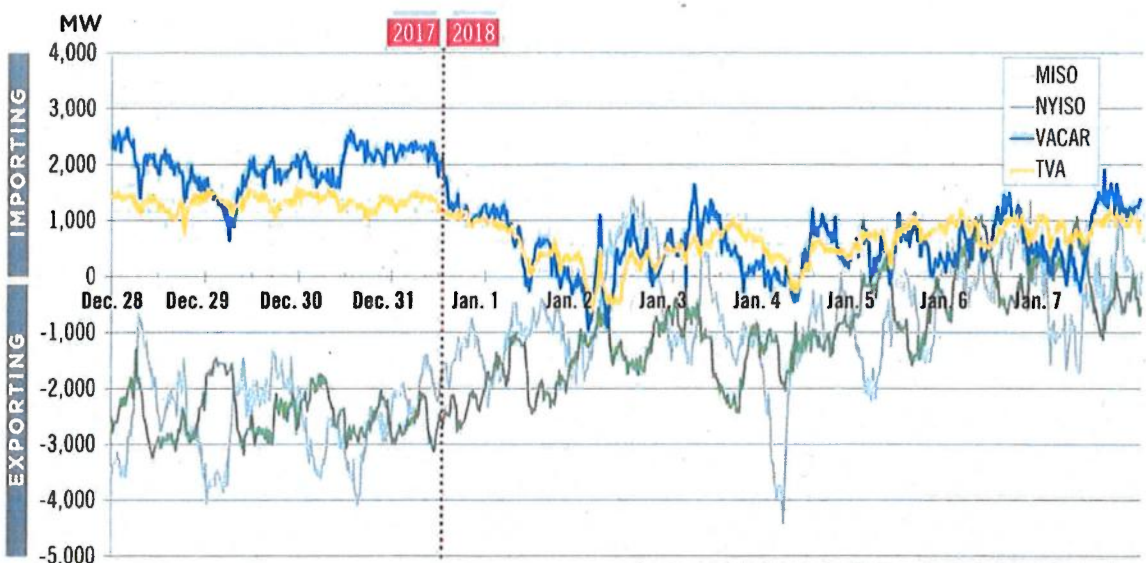
Figure 25 provides a picture of the key role transmission played during the cold snap. At the start of the cold snap, on December 28 and December 31, PJM interchange with other regions remained typical for the time of year, importing power across interregional transmission tie lines from the TVA and VACAR regions[20] to the south and exporting to MISO and NYISO. On January 1, 2018, transactions started to flow more to PJM's southern neighbors, who were experiencing some of their coldest weather and needed assistance to meet load and reserve requirements. This trend ultimately peaked on January 2, 2018, when, opposite usual patterns, PJM exported power to the south. In a corresponding trend, PJM exports to MISO and NYISO decreased.

Over the next several days, flows across interregional transmission tie lines began to return to typical levels, though southern imports had not returned to the same levels seen before the cold snap by January 7. When PJM hit a weekly peak on the evening of January 5, it was importing power from TVA, VACAR and NYISO. During that period, decreased exports and imports with MISO and NYISO were ultimately attributable to economics. PJM prices were elevated, and both MISO and NYISO, who were not in emergency conditions, found it more economical to run more internal generation instead of scheduling transactions supported by more-expensive generation from PJM.

Heavy Load Voltage Schedule Warnings and Actions[21]

In addition to cold weather alerts, PJM issued heavy load voltage schedule warnings and actions on January 4 and 5, 2018. These warnings and actions alerted TOs to energize all capacitors, remove all reactors and optimize voltage schedules to help maximize the power transfer capability of the system. By taking those steps, PJM ensured the system was positioned in the most resilient manner possible, allowing PJM to move power from one area to another if there were major generator or transmission failures. The operational flexibility of PJM's robust transmission system ensured that operational risks during this period were minimized.

Figure 25: PJM Transmission Tie Line Interchange (December 28, 2017, through January 7, 2018)



As of Jan. 31, 2018. This data should not be used as the basis for decision-making.

20 TVA is the Tennessee Valley Regional Authority. VACAR is the Virginia-Carolina region of the Southeastern Electric Reliability Council.
21 These procedures are issued proactively and do not signify any capacity or transmission concerns.

Reducing Power Delivery Constraints

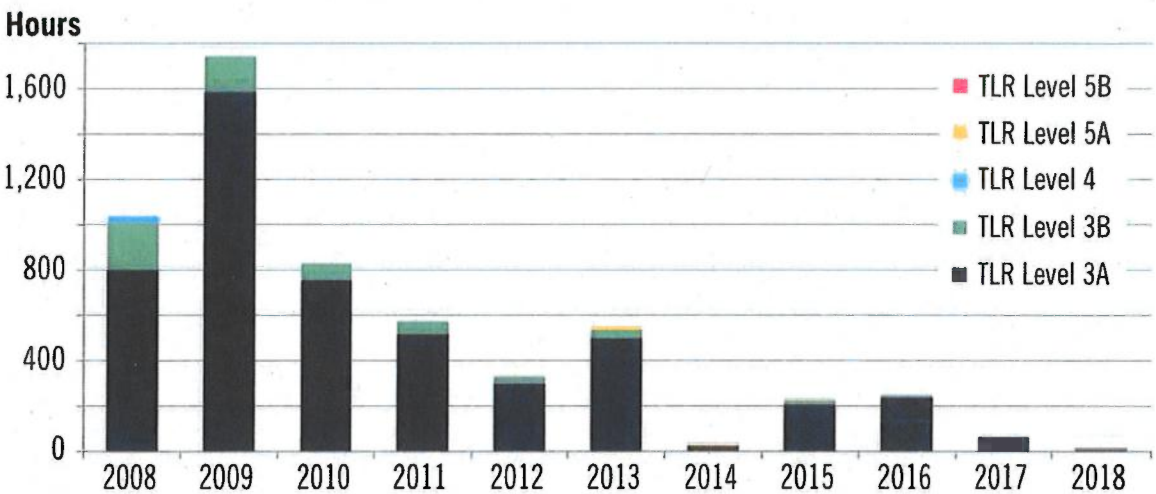
System operators have a number of emergency procedures that help ensure the reliability of the system and avoid interrupting service. A robust and well planned transmission system with new assets improves operational flexibility and efficiency. Since 2011, PJM has observed reductions in a variety of emergency procedures and alerts as well as reductions in operating limits, including interconnection reliability operating limits, remedial action schemes and more robust interchange activity with neighboring systems adjoining PJM.[22]

Benefits by the Numbers: Decreasing Transmission Loading Relief Procedures

Transmission Loading Relief (TLR) procedures[23] curtail power sales between transmission entities to manage cross-border transmission constraints, which are limitations on the ability of the transmission system to move power. PJM prefers to manage constraints by adjusting the output of generators, which is more efficient. Having fewer TLRs preserves PJM customers' interregional power purchases and sales from curtailment, which is an economic benefit. The increasing robustness of the transmission system and continuously improving interregional interoperability allow PJM operators to manage the transmission system using fewer TLR procedures.

Figure 26 makes the point. The number of hours in which PJM issued a TLR peaked in 2009 due to a congestion issue in the Commonwealth Edison (ComEd) TO zone. More than 70 percent of the nearly 1,800 total TLR hours in 2009 were a result of this issue. TLRs have steadily decreased in subsequent years. Between 2009 and 2012, ComEd re-conductored two congested 138 kV transmission lines and one 345 kV transmission line. The re-conductoring increased their emergency ratings an average of 48 percent.

Figure 26: TLR Procedure Hours (2004-2018)



As a result, congestion and TLRs decreased in 2014 and beyond. For the five years from 2014 through 2018, PJM issued TLRs totaling only 604 hours, 75 percent of which were caused by just one PJM-Duke Energy flowgate limit.

22 PJM acknowledges that generation retirement and new generation and fuel sources coming on the system shift power flows across transmission facilities. However, the consistent improvement in these various metrics also indicates that transmission system investments have been a significant contributing factor to bulk electric system robustness.

23 The NERC TLR procedure is used by reliability coordinators like PJM to hold or cut transactions in order to alleviate operating limit violations. The TLR procedure ranges from Level 1 to provide warnings or notifications to Level 6 to invoke emergency procedures. TLR Levels 3 through 5b involve cutting non-firm transactions, reconfiguring the transmission system, and cutting firm transactions, respectively. NERC's TLR procedure can be found on-line: https://www.nerc.com/pa/rrm/TLR/Pages/TLR-Levels.aspx

Controlling Voltage

Voltage on an electric line is similar to water pressure in a hose; it is needed to ensure sufficient flow. Voltage is critical to reliable, on-demand product delivery. NERC standards require that a transmission system remain stable within applicable equipment thermal ratings and within established substation voltage ranges. Both voltage that is too low and voltage that is too high can become a serious issue, depending on the availability of resources - both generation and transmission - to produce or absorb reactive power.[24] In real-time, operators use transmission system equipment to control voltage,[25] including switching transmission lines in and out of service, switching capacitors or reactors, or adjusting voltage set points on static VAR compensators. These operator actions depend on the situation at hand, low voltage or high voltage.

Low Voltage

PJM ensures that the transmission system is able to deliver energy to areas that are experiencing a shortage. Typically, as more power is transferred across a line or set of lines, voltage levels deteriorate. The more abrupt the decline in voltage, the more difficult voltage is to control. Without adequate voltage support, power transfer increases could cause voltages to collapse after a disruption on the system. If voltage level or voltage-drop magnitude violates specified limits, system enhancements must be developed to resolve the violation.

Voltage magnitudes and voltage drop percentages are determined based on operational conditions at each substation. Voltage drop is limited to 5 percent at many 500 kV substations; emergency voltage magnitude is limited to no lower than 97 percent of substation bus voltage. If presented such a situation, system operators would have little time to react and could face the need to take quick, decisive action up to and including interrupting service without warning, an emergency procedure known as load shedding.

High Voltage

High voltage conditions usually occur during light-load system conditions, typically during the fall and spring months when customer usage is down from the peak seasons. PJM has observed load as low as 30 percent of summer peak in some TO zones. PJM's generation dispatch order during low load periods differs markedly from peak load conditions. During the past decade, significant numbers of unit deactivations have also reduced the capability of the system to absorb excess reactive power during light-load conditions.

These factors, coupled with the capacitive effect of more lightly loaded transmission lines, increase bus voltages even further. This trend is not isolated to PJM and has also been observed by neighboring systems, compounding the issue. During light-load conditions, when high voltages can be expected, PJM staff may take actions to control voltage, such as switching out capacitors, switching on shunt reactors, changing transformer tap positions, and other actions up to and including opening transmission lines. Absent such actions, high voltages can damage transmission equipment and jeopardize reliable system operation.

24 Reactive power is the portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers or electrostatic equipment such as capacitors and directly influences electric system voltage. Reactive power is usually expressed as megavolt-ampere reactive (MVAR).

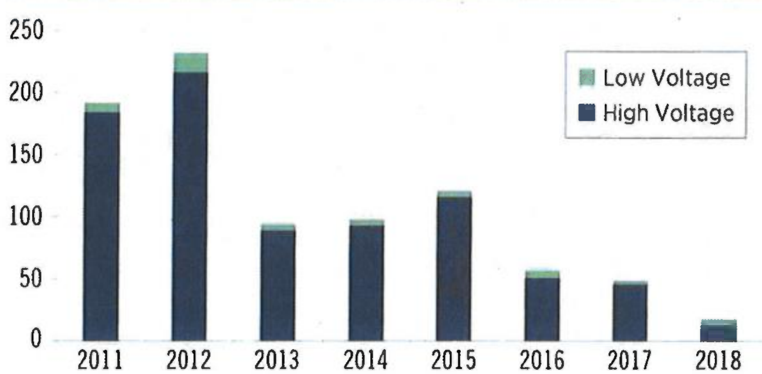
25 Voltage magnitude and voltage drop limits are defined in PJM Manual 3, Transmission Operations: https://www.pjm.com/~/media/documents/manuals/m03.ashx.

Benefits by the Numbers: Transmission Assets to Reduce High-Voltage Conditions

As **Figure 27** shows, transmission system enhancements have reduced the need for operators to implement procedures to control both high- and low-voltage conditions. More specifically, PJM's regional planning process has always included system analysis under peak load conditions, during which low-voltage criteria violations have been identified and solutions implemented over time. Identifying high-voltage conditions has been a much more recent system phenomenon, typically during periods of low customer demand. This has driven the need for new transmission assets to ensure that voltages remain under defined upper limits to prevent equipment damage that could lead to loss of transmission facilities and, ultimately, loss of customer load.

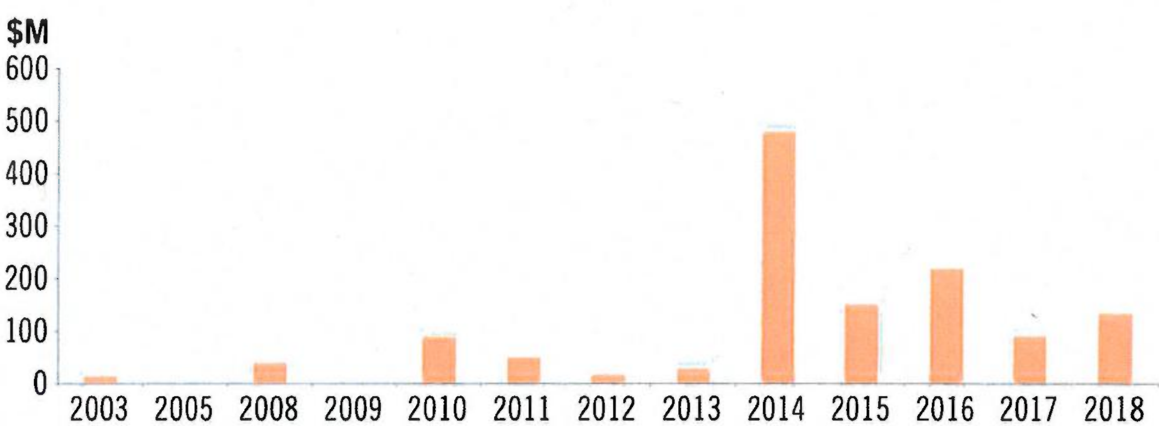
Transmission system enhancements have reduced the number of system operator actions required to ensure voltages remain within established limits.

Figure 27: Voltage Actions (2011 through 2018)

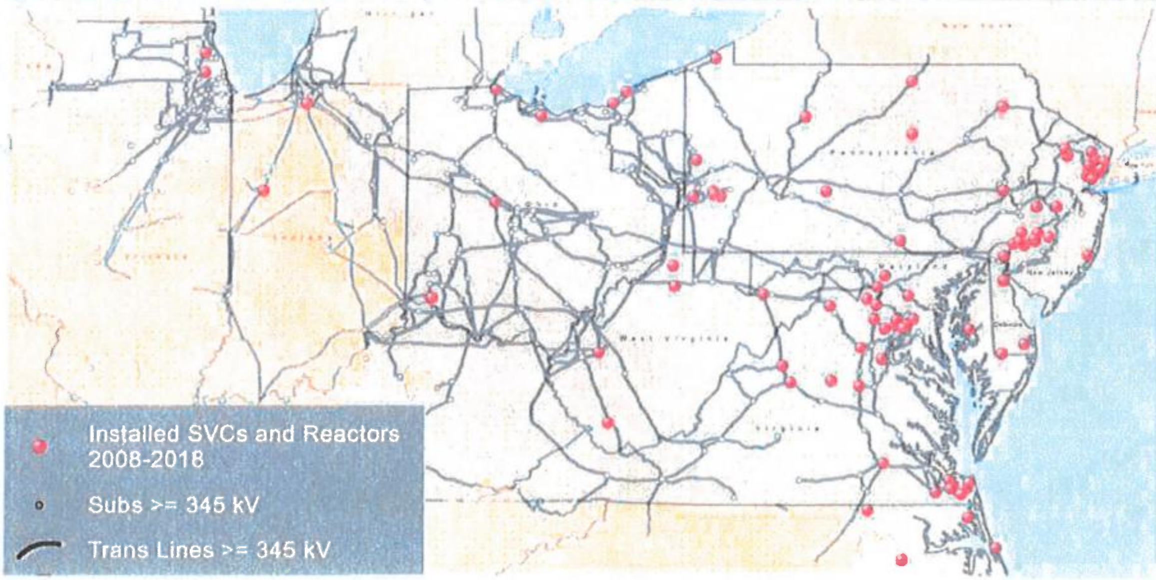


At PJM's direction, transmission owners invested more than $1.3 billion in reactors and static VAR compensators (SVCs) between 2008 and 2018 to help mitigate high-voltage system conditions (**Figure 28**). An SVC device rapidly and continuously provides reactive power required to control dynamic voltage swings under various system conditions, improving power system performance. A reactor is installed on a transmission line to consume excess reactive power when the system is lightly loaded. These devices, described further in **Section 6**, have been installed across PJM (**Map 6**).

Figure 28: PJM SVC and Reactor Investment by In-Service Year



Map 6: Reactors and SVCs Installed in PJM (2008 through 2018)

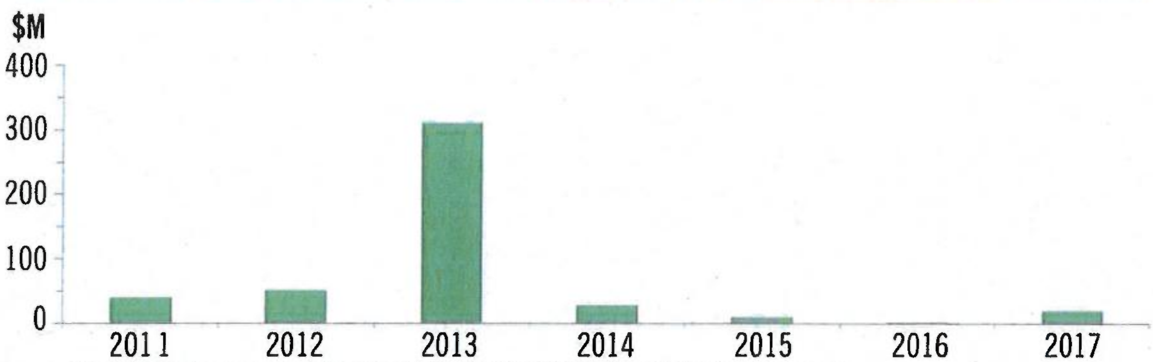


Transmission Enhancements Reduce Uplift Reactive Charges

The installation of additional transmission facilities that absorb reactive power has yielded more economically efficient operations as well. To control voltage violations, PJM operators may dispatch local generation to provide or absorb reactive power. In the case of high voltages, PJM has directed generation to run in order to provide reactive power absorbing capability, incurring operating reserve costs for higher-cost generators. This is reflected in higher "uplift," shown in **Figure 29** for annual reactive charges.[26] Uplift is the amount of money paid to generators to ensure they recover their cleared offer price if not covered fully by the locational marginal price (LMP). Elevated charges driven by generator retirement and associated reactive absorption capability was offset with the installation of reactors and SVCs in 2014 and beyond.

> Transmission system enhancements reduce the number of times more-expensive generation is required to help absorb excess reactive power on the system.

Figure 29: Annual Reactive Services Uplift Charges (2011 through 2018)



PJM notes that for the 2013 Reactive Services uplift, the DPL, PENELEC and ATSI control zones had the three highest reactive local voltage support rates: $2.538, $1.900 and $0.690 per MWh.

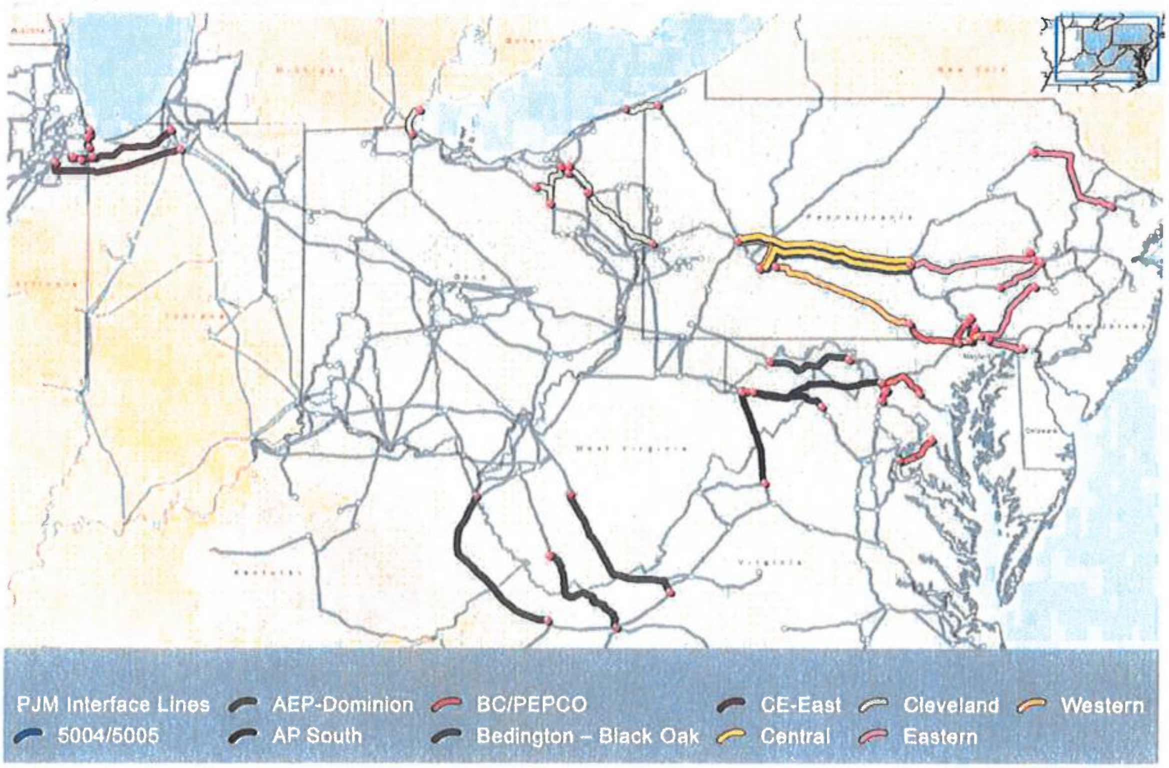
26 Data obtained from Monitoring Analytics 2018 State of the Market Report: https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018.shtml

Greater Transfer Interface Margins

Since 2011, new transmission assets have notably increased the margin on the following reactive transfer interfaces (see **Map 7**):

- Eastern
- Central
- CE East
- AP South
- AEP/Dominion
- Western
- 5004/5005
- Cleveland
- Bedington-Black Oak
- BC/PEPCO

Map 7: PJM Interconnection Reliability Operating Limits



Known as interconnection reliability operating limits (IROLs), each is a group of transmission facilities. The sum of an IROL's flows must remain below a limit defined by operational study so that voltage stability is maintained in real time. In short, for a transfer level above a defined IROL, voltage collapse across the region could occur. PJM monitors IROLs and flows in real-time and studies them in day-ahead simulations to ensure voltage stability is maintained. Development of transfer interface limits is described in **Appendix C**.

Over time, PJM has observed IROL operating margins increase as a result of the additional transfer capability provided by new transmission assets. New transmission assets, by their nature, typically increase the amount of power that can flow into a TO zone to mitigate a capacity deficiency or across a transfer interface. Increasing the ability of an IROL interface to accommodate additional power flow encourages

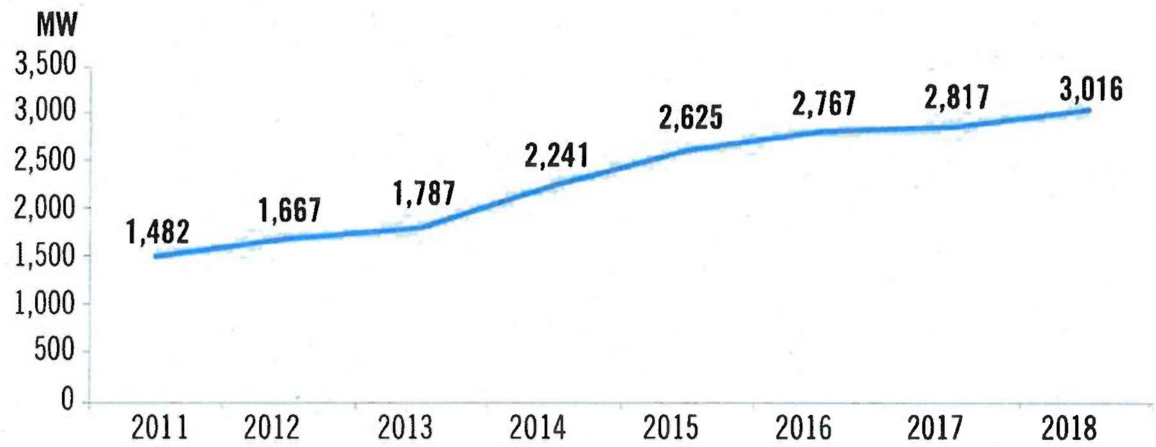
> Transmission system enhancements have increased reactive transfer interface limits, giving the system greater stability and providing customers with greater access to power markets.

generator developers to locate generators where it is less costly (i.e., where transmission will not constrain unit output). Greater transfer capability increases economic efficiency through greater opportunity for bilateral power purchases and sales by participants in PJM markets. This additional capability also reduces congestion otherwise requiring the operation of higher-cost generators.

Benefits by the Numbers: Greater Transfer Interface Margin

The IROL margin is the difference between the reactive transfer interface pre-contingency flow and its IROL limit. The average margin in PJM across all IROL interfaces, as described above, was 1,482 MW in 2011, which more than doubled to an average margin of 3,016 MW in 2018 (see **Figure 30**). While generation patterns shift over time and impact the margin, new transmission enhancements have contributed to this increase as well.

Figure 30: PJM IROL Margin Improvement (2011 through 2018)



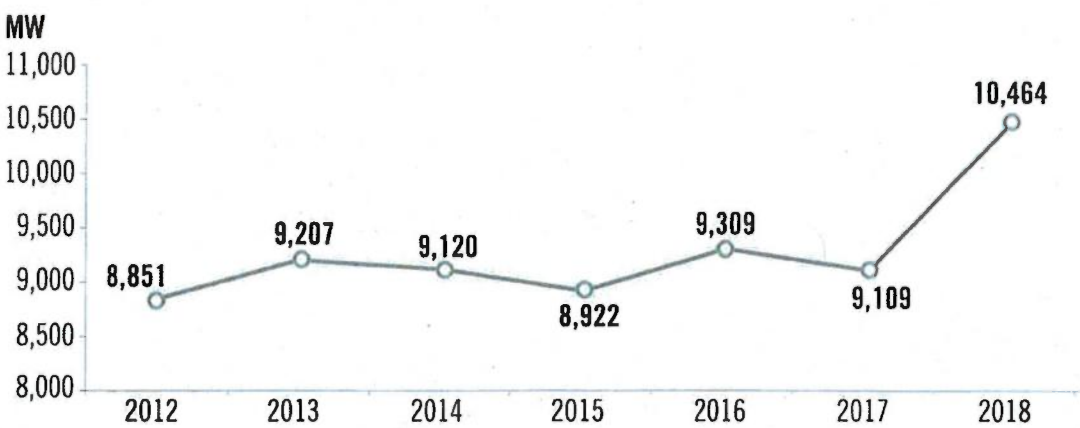
Case Study: Eastern Transfer Interface Limit Margin

PJM's Eastern Interface offers a case study that demonstrates how transmission enhancements have increased the amount of power that can be transferred across it. The ability to transfer power across that interface was boosted by the completion of the Susquehanna-Lackawanna-Hopatcong-Roseland 500 kV transmission line.

- **Hopatcong-Roseland 500 kV line** – energized April 2014
- **Susquehanna-Lackawanna 500 kV line** – energized September 2014
- **Lackawanna-Hopatcong** – energized May 2015 (final project phase)

The completion of the line in May 2015, coupled with other lower-voltage transmission enhancements in eastern PJM, has increased the transfer capability across the Eastern Interface since 2015. Between 2012 and 2018, the maximum annual Eastern Interface IROL transfer capability increased from 8,851 MW to 10,464 MW, as shown in **Figure 31**. Increasing this interface limit improves reactive stability – thereby enhancing reliability – and provides eastern PJM load centers greater access to regional power markets. Overall, the addition of new transmission assets – like Susquehanna-Roseland in this case – also increases the robustness and resilience of the PJM grid.

Figure 31: Maximum Annual Eastern Transfer Interface IROL (2012 through 2018)



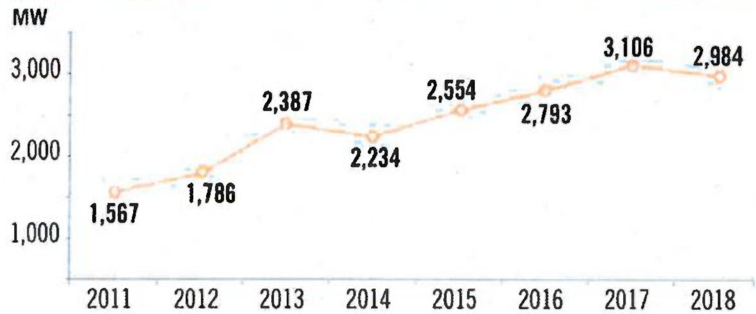
Case Study: Cleveland Transfer Interface Limit Margin

The Cleveland Transfer Interface provides a case study of the benefits of transmission system enhancements. In this instance, the PJM Board-approved RTEP system enhancements shown in **Table 5** and **Map 8** have increased Cleveland Transfer Interface capability as shown in **Figure 32.** As with the Eastern Interface discussed earlier, increasing this interface limit improves reactive stability, thereby enhancing reliability. The additional interface margin alleviates the need for system operators to dispatch generators out of economic merit order to control actual interface power flow, incurring congestion costs. Overall, the addition of new transmission assets like those in **Table 5** increases the robustness and resilience of the PJM grid.

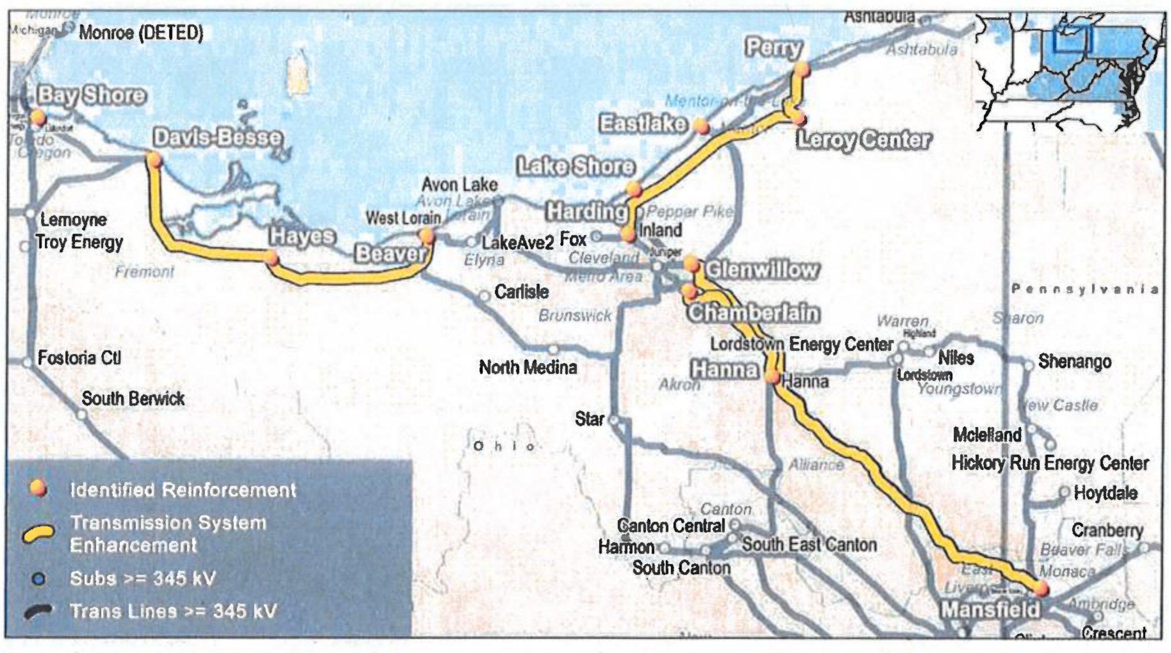
Table 5: Cleveland Transfer Interface Area System Enhancements (2014-2016)

Upgrade	In-Service Date (Month/Year)
Mansfield-Glen Willow 345 kV line	June 2015
Second Davis Besse-Hayes-Beaver 345 kV	June 2014
Mansfield-Chamberlin 345 kV line loop into Hanna	June 2014
A new Leroy Center station splitting the Perry-Harding 345 kV line, with two 345/138 kV transformers installed at Leroy Center	June 2016
Lakeshore SVC	June 2015
Eastlake units converted into synchronous condensers	July 2013-May 2016 (in phases)
Second Bay Shore 345/138 kV transformer	May 2014

Figure 32: Cleveland Transfer Interface Average Annual IROL (2011 through 2018)



Map 8: Cleveland Transfer Interface Area System Enhancements (2014-2016)



Increasing Operational Flexibility

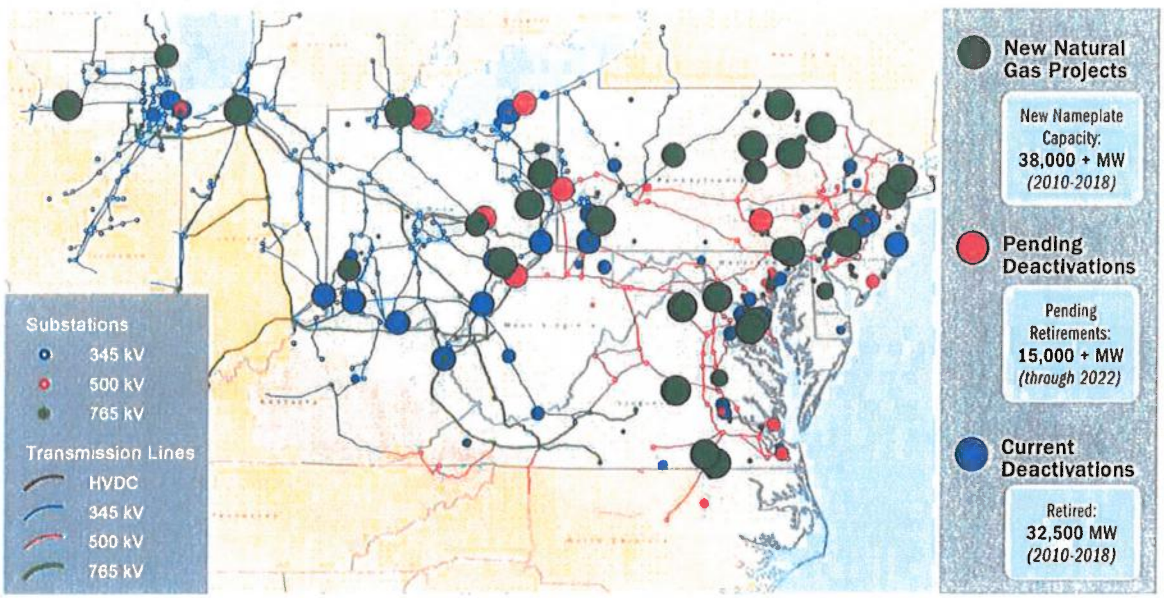
West-to-East Power Flows Are Shifting

> Transmission assets are accommodating a historic fuel shift while keeping the system reliable.

Historically, power flow across PJM transmission lines has generally been from west to east. High-voltage transmission assets were approved to deliver lower-priced western PJM coal-fired generation reliably to eastern PJM load centers. This power flow is changing. The combination of generation retirements across the PJM footprint coupled with the increase of natural gas generation in the east is driving a shift on some transfer interfaces, as shown in **Map 9**. PJM has observed more power flow "push" from east to west.

The operational flexibility of these transmission assets is responsible for encouraging new generation within PJM's footprint, particularly natural gas-fired generation using Marcellus and Utica shale gas. In other words, transmission assets are accommodating a historic fuel shift while keeping the system reliable. Transmission is assisting this shift by allowing more generators to compete so that the lowest-cost generation serves customer load, no matter where it is in the PJM footprint.

Map 9: Generation Entry and Exit Since 2010

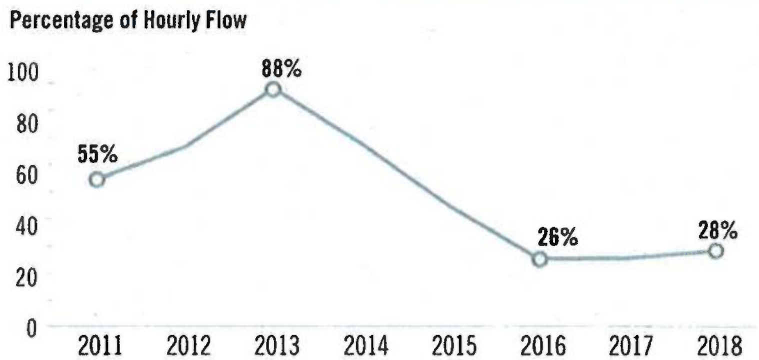


Case Study: Central Interface Operational Flexibility – East-to-West Power Flow

The Central Transfer Interface provides a good example of the shift in flows over time, as shown in **Figure 33**. The average hourly flow from west to east was up to 88 percent of all hours in 2013. By 2018, only 28 percent of hours were west to east. During the other 72 percent, power flowed from east to west.

Removing Need for Remedial Action Schemes

Figure 33: Average Hourly Pre-Contingency West-to-East Power Flow

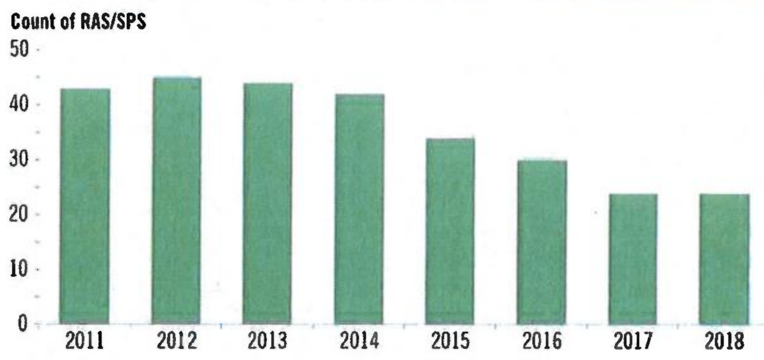


New transmission system enhancements are mitigating the need for Remedial Action Schemes (RAS)[27] across PJM. A RAS device is an assembly of power system protection equipment designed to detect and initiate an automatic action in response to abnormal or pre-defined system conditions, for example, tripping generation for the loss of one or more area transmission lines to prevent generator instability. New transmission assets mean that these schemes can be retired without jeopardizing reliability and without interrupting load or tripping generation. Across the industry, RAS devices have also been subject to misoperation, causing significant system events. PJM periodically evaluates RAS installations to identify which ones may no longer be needed, the result of various reasons including:

- RAS need has been mitigated by an RTEP project that has reached in-service status.
- The reliability issue that the RAS was designed to address no longer exists.
- System changes have mitigated the congestion the RAS was designed to address.
- The RAS has not been activated for several years.

As a result of transmission system enhancements, the number of active RAS devices has been decreasing, as shown in **Figure 34**. From 2012 to 2018, the number of active operational schemes decreased from 45 to 24; 21 schemes were retired or reclassified.

Figure 34: Remedial Action Schemes Across PJM - Year-End Count



27 Formerly known as Special Protection System (SPS), a RAS consists of protection devices such as relays, current transformers, potential transformers, communication interface equipment, communication links, breaker trip and close coils, switch gear auxiliary switches, and all associated connections. A RAS is intended to protect equipment from thermal overload or to protect against system instability stemming primarily from scheduled or forced transmission outages. A number of such systems exist across PJM, originally installed by utilities themselves as a solution to extraordinary transmission outage conditions.

Case Study: Reducing the Need for Remedial Action Schemes

Dominion installed the North Hampton RAS to mitigate potential uncontrolled power interruptions under certain generation and transmission outage conditions. Under this RAS, controlled power interruptions to approximately 950 MW of customer load during peak periods, including over 150,000 customers, would be implemented to maintain grid reliability. With the recent completion of the Skiffes Creek transmission project, the North Hampton RAS can be retired, eliminating the risk of shedding that load.

Interregional transmission ties enable rapid emergency support between PJM and its neighbors.

Interregional Ties Support Reliable Operation

Robust transmission tie lines allow PJM and its neighbors to rely on one another during stressed system operating conditions, which can allow the system to recover from a loss of generation or supply power during peak demand periods.

Case Study: Shared Reserve Activation with NPCC

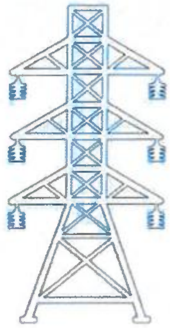
Disturbance recovery is essential for system reliability and meeting NERC standards. Having the ability to transmit power to a neighbor with only a few minutes' notice helps restore system frequency and area control. Transmission makes this possible. PJM participates in reserve-sharing agreements with neighboring systems to assist both PJM and its neighbors with recovery from disturbances, including, in many instances the loss of a generators greater than 500 MW.

PJM's interregional agreement with the Northeast Power Coordinating Council (NPCC) includes provisions for shared reserves to help with disturbance control. This permits PJM to recover from an imbalance between supply and demand faster than with internal reserves alone. The help is reciprocal, and PJM provides NPCC with shared reserves when called upon. **Table 6** shows the number of times per year PJM operators have implemented shared reserve actions, enabled by PJM transmission tie lines with NYISO.

Transmission system enhancements have reduced the number of protective Remedial Action Schemes on the system improving reliability and operating flexibility by removing automatic generation and load trip conditions.

Table 6: NPCC Shared Reserve Activation

Year	No. of Events During Which PJM Received Shared Reserves from NPCC
2011	6
2012	3
2013	4
2014	10
2015	6
2016	4
2017	1
2018	7



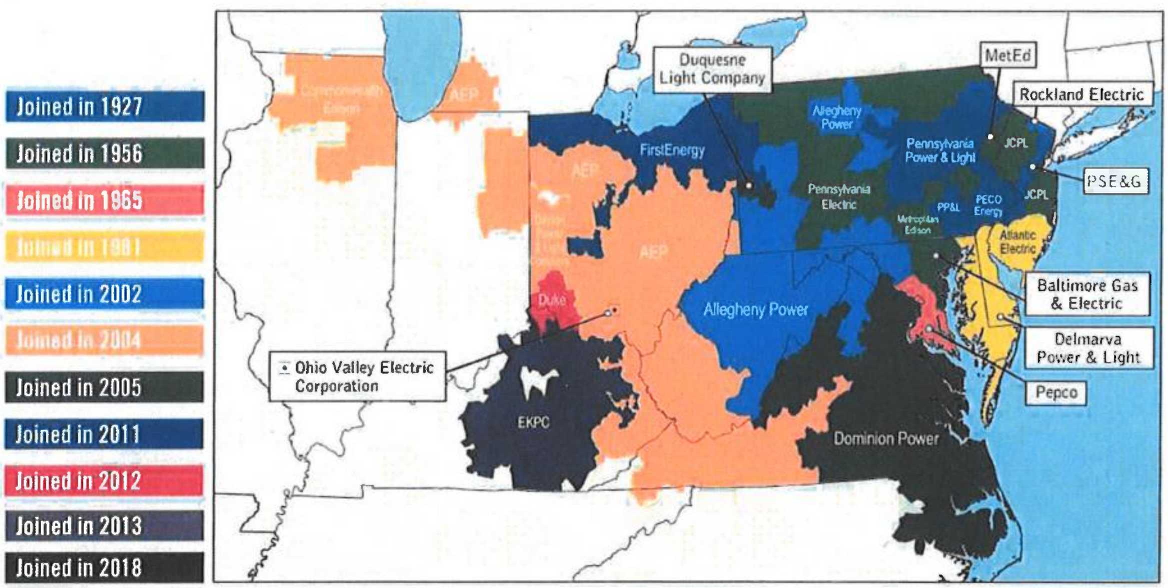
Section 5 Access to Lower-Priced Energy

Transmission enables the lowest-cost power to reach the greatest number of people. PJM is made up of many transmission zones and is interconnected to power systems adjoining PJM. PJM system operators schedule and dispatch the lowest-cost power resources to generate electricity, regardless of which transmission zone or state it comes from, incrementally adding more expensive resources as they're needed and saving the highest-cost resources for relatively brief periods of peak customer demand. This allows low-cost power to flow into, out of and through PJM across transmission lines that allow generation inside and outside of PJM to participate in the wholesale markets, which increases competition, lowering costs.

Transmission assets tie PJM zones together. These assets enable competition among power producers by providing access to PJM's wholesale markets for capacity, energy and ancillary services. For example, billings in 2018 totaled $49.8 billion for energy totaling 806,546 GWh. Markets lower the net costs of electricity to consumers by allowing the lowest-cost megawatts available at any given moment to be dispatched across transmission tie lines for customers to use. Doing so reduces overall production costs and load payments, as discussed later in this section.

> Transmission allows the free flow of electricity between PJM and other regions, enhancing reliability and keeping costs low.

Map 10: PJM Market Integration History



Since 2002, PJM has added seven transmission zones to its original footprint (see **Map 10**). This has enabled the addition of 112,000 MW of generation and 95,000 MW of peak customer demand, increasing competition in wholesale power markets and providing lower wholesale prices to consumers.

Transmission Across PJM Borders

PJM operators coordinate the flow of power across transmission lines that link individual utilities inside PJM and across transmission tie lines to adjoining systems:

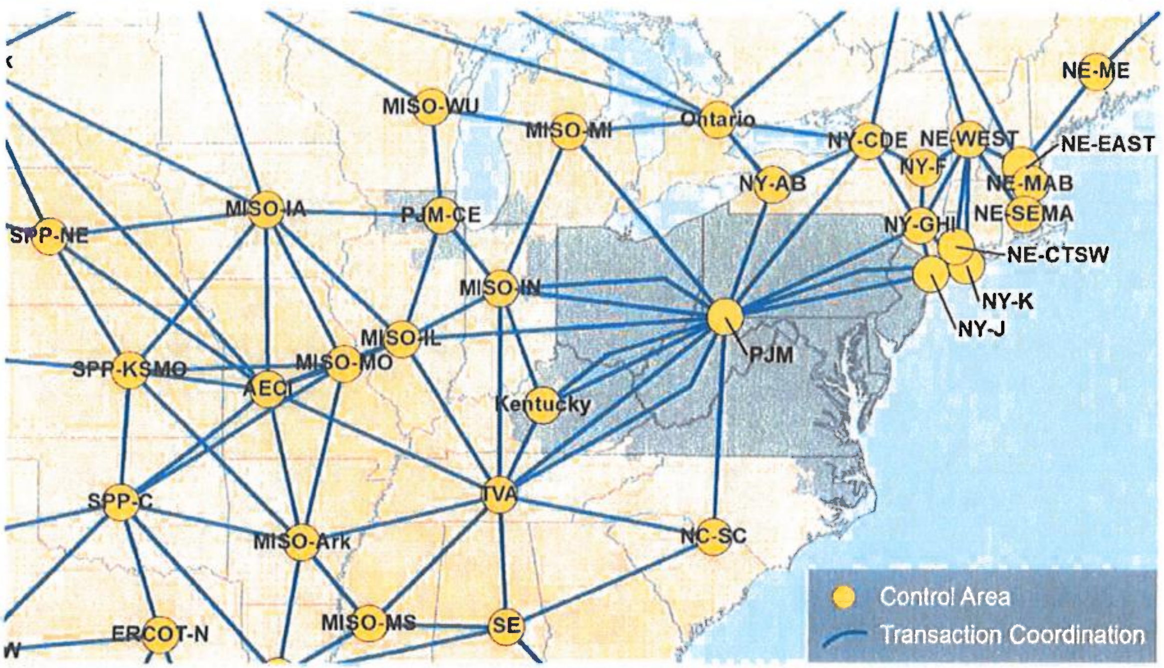
- **North** - New York Independent System Operator (NYISO) and through it, the Independent System Operator of New England (ISO-NE) and Canadian utilities
- **West** - Mid-Continent Independent System Operator (MISO)
- **South** - Tennessee Valley Authority (TVA), Duke Energy Progress of North Carolina, and Louisville Gas and Electric

> Interregional transmission lines improve reliability through access to additional generating capacity.

Coordination agreements between PJM and these systems specify the obligations to which all parties are committed in order to preserve reliability under defined emergency conditions and coordinate economic power transactions for the benefit of respective market participants.

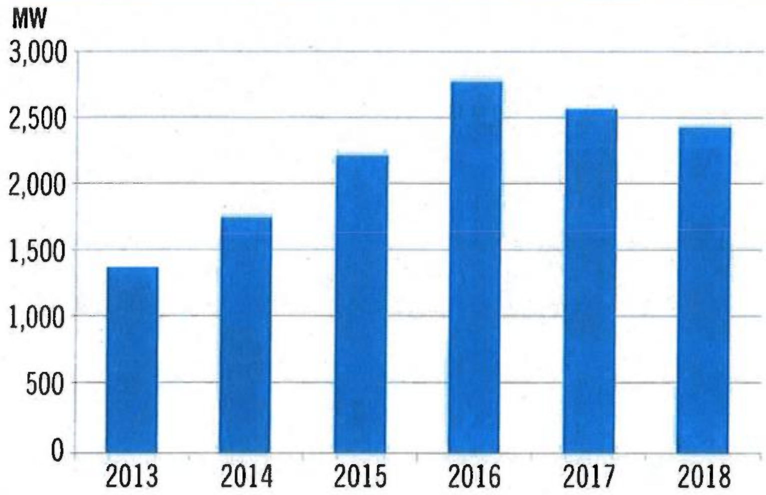
Interregional transmission tie lines allow PJM market participants to buy and sell power with parties outside the PJM control area. The schematic superimposed over PJM and the eastern U.S. in **Map 11** emphasizes the extent to which PJM coordinates these transactions with other control areas in the Eastern Interconnection.

Map 11: Coordinating Interregional Power Sales and Purchases



The ability to schedule power transfers across interregional tie lines promotes economic efficiency. Bilateral transactions, those that occur exclusively between buyers and sellers, allow load-serving entities - and third-party traders - to pursue opportunities from generators outside of PJM. **Figure 35** shows the average hours of scheduled interchange - on a gross basis - from 2013 through 2018. Interregional transmission tie lines permit external generators to be "pseudo-tied" to PJM and participate in PJM's capacity, energy and ancillary services markets as if they were inside PJM's footprint. By doing so, they enhance reliability. Since 2016, PJM has integrated over 5,000 MW of pseudo-tied generation into and out of PJM, accounting for the decrease in scheduled interchange since 2016 shown in **Figure 35**. Operationally, these resources are treated as internal resources. None of this would be possible without the transmission lines that link PJM with adjoining systems.

Figure 35: Average Hourly Scheduled Interchange (Gross)



Enhancing Energy Market Efficiency

A Fluid Market

Transmission enables the lowest-cost power to reach the greatest number of people. PJM operates the grid by scheduling and directing the lowest-cost power resources to generate electricity first, incrementally adding more expensive resources as they are needed and using the highest-cost resources during the relatively brief periods of peak customer demand.

Throughout the year, market economics can shift (even from hour to hour) across all 8,760 hours of a year. Fuel prices fluctuate, generation resources go in and out of service for maintenance, new generation resources are commissioned and old ones retire. The transmission system enables PJM to handle this highly fluid wholesale energy market, transporting the lowest-cost power across the region and giving all generation resources, regardless of fuel type, access to the market.

Impact of Congestion

Ratings on transmission system equipment limit the operation of a facility, whether it be the amount of power flowing on it, the voltage it can support, or the circuit-breaker short-circuit fault current it can interrupt. When the transmission system is constrained, those limits can be reached and operators must reroute power flow by deploying higher-cost generating units to avoid overloads and risk losing transmission equipment. This re-dispatch yields less-efficient production of electric power, which adds congestion costs, which can increase the cost to consumers. Increasing the transmission system's capacity with investment in the system can decrease congestion costs and save consumers money.

Congestion Relief Provided by New Transmission

Congestion reduction is achieved one of two ways:

1. As a major ancillary benefit to transmission projects whose need was justified to prevent overloads
2. Specifically to provide economic benefit that exceeds cost by at least 25 percent

Either way, benefits may include reductions in production cost and load payments:

- Production costs represent the fuel costs, variable operating and maintenance costs, and emission costs of dispatched resources in PJM. Production cost savings represent system-level benefits. New transmission can reduce the variable cost of generation supply to the market.
- Load payments represent the cost, measured by LMPs, for the energy supplied to the consumer. Load payments are directly affected by the quantity of energy and the price.

Transmission enhancements in PJM are estimated to reduce costs to customers by more than $288 million a year by alleviating congestion.

Benefits by the Numbers: Economic Benefit of Approved Transmission Projects

As part of quantifying the value of transmission, PJM conducted a production cost analysis to assess the economic benefit provided by new transmission assets. An energy market simulation tool was used to model the hourly least-cost, security-constrained commitment and dispatch of generation over a future annual period. The general scope and procedure for this analysis is provided in **Appendix D**. A detailed generation, load and 2019 study-year transmission system model was used as input in order to simulate hourly generation commitment and dispatch to meet load, while recognizing the physical limitations of the transmission system.

PJM then compared market simulations with and without RTEP Board-approved transmission projects with in-service dates from 2014 through 2023 that had analytically already yielded congestion reduction over a one-year period. **Table 7** presents annual congestion cost study results for a sample of 10 constraints that yielded significant congestion-cost reduction subsequent to the in-service-year date for each project.

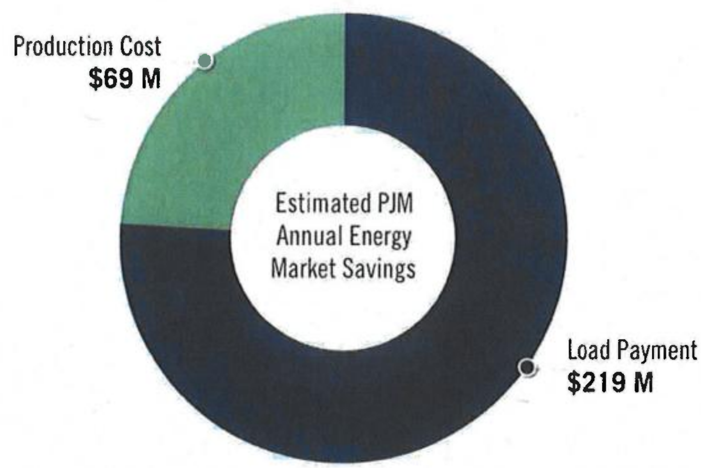
Table 7: Production Costs Analysis Results – Annual Energy Market Savings from New Transmission Assets

Project Description	TO Zone	Project In-Service Year	Annual Congestion ($M)				
			2014	2015	2016	2017	2018
Rebuild Mt Storm-Doubs transmission line	APS, DOM	2014	$5	$0	$0	$0	$0
Construct a Susquehanna-Roseland 500 kV circuit	PPL	2015	$21	$22	$1	$1	$4
Reconductor the Burlington-Croydon circuit	PECO	2015	$11	$2	$0	$0	$0
Convert the Bergen-Marion 138 kV path to double circuit 345 kV	PSE&G	2016	$22	$28	$0	$0	$0
Add two additional 345/138 kV transformers at Kammer	AEP	2016	$3	$8	$9	$1	$1
Upgrade the Mill T2 138/69 kV transformer	AECO	2016	$1	$1	$5	$0	$0
Rebuild Graceton-Bagley 230 kV as double-circuit line	BGE	2017	$107	$104	$144	$7	$11
Construct a new Byron-Wayne 345 kV circuit	ComEd	2017	$16	$8	$18	$8	$0
Loop the TMI-Hosensack 500 kV line into Lauschtown substation	METED	2017	$1	$8	$10	$14	$2
Rebuild the Wattsville-Kenney-Piney Grove 69 kV line	DPL	2018	$13	$4	$8	$14	$0

Congestion cost prior to project in-service dates

The results of this production cost analysis show that in the PJM Energy Market alone, the transmission enhancements approved between 2014 and 2023 are estimated to reduce costs to customers by more than $288 million in combined annual load payments and annual production costs, as shown in **Figure 36**. Transmission enhancements remove market inefficiencies manifested by persistent congestion – as described above – to allow greater access to lower-cost generation.

Figure 36: Energy Market Savings Production Cost Analysis Results

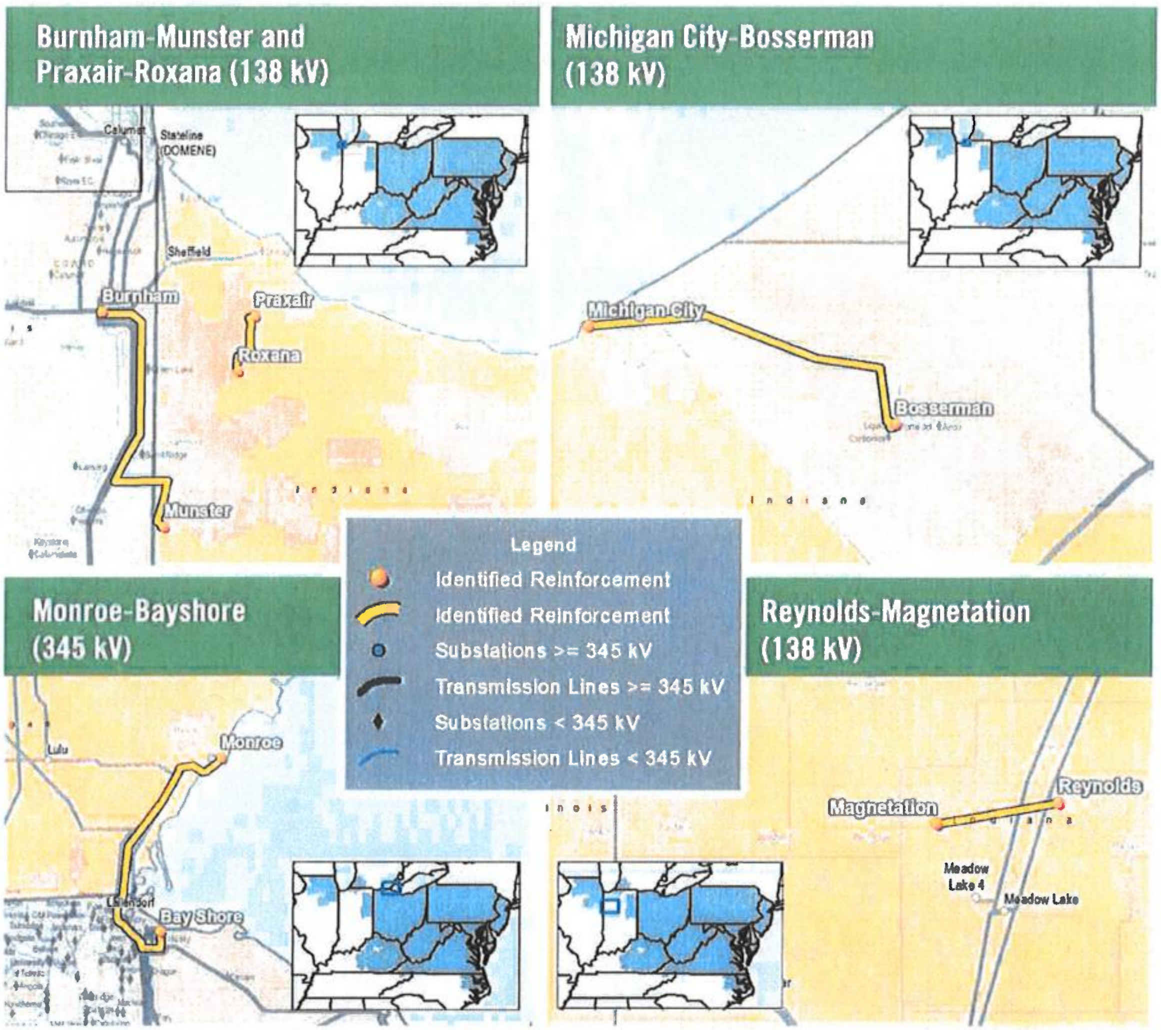


Benefits by the Numbers: PJM/MISO Targeted Market Efficiency Projects

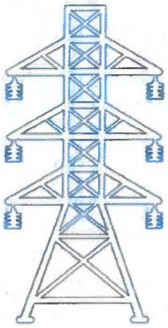
New interregional transmission assets will produce estimated congestion savings of more than $100 million in the first four years alone.

PJM customers also benefit from new transmission assets that reach into neighboring regions. In December 2017, the PJM and MISO Boards approved a portfolio of five targeted market-efficiency projects (TMEPs) to address historical congestion along the PJM/MISO boundary (see **Map 12**). TMEPs are focused on developing low-cost, short lead-time, high-impact projects to address market-to-market congestion. TMEP projects must yield four-year market congestion savings[28] that are equal to or greater than the estimated project capital cost. The total capital cost for the five projects is approximately $20 million, with an estimated congestion savings benefit of $100 million over the first four years of commercial operation.

Map 12: PJM/MISO Approved Targeted Market Efficiency Projects



28 As defined in the PJM/MISO Joint Operating Agreement.



Section 6 Grid Modernization

Modernizing the existing transmission system will provide benefits, including designs that can withstand more extreme events, lower the frequency and shorten the duration of outages, reduce public and employee safety risks, and use advanced technology to improve system operability, efficiency and security. A modernized system will ensure a future characterized by enhanced reliability, cost savings and environmental and societal benefits, whether driven by new technologies, aging infrastructure, asset management processes, resilience, FERC action or other factors.

Asset Management — Aging Infrastructure

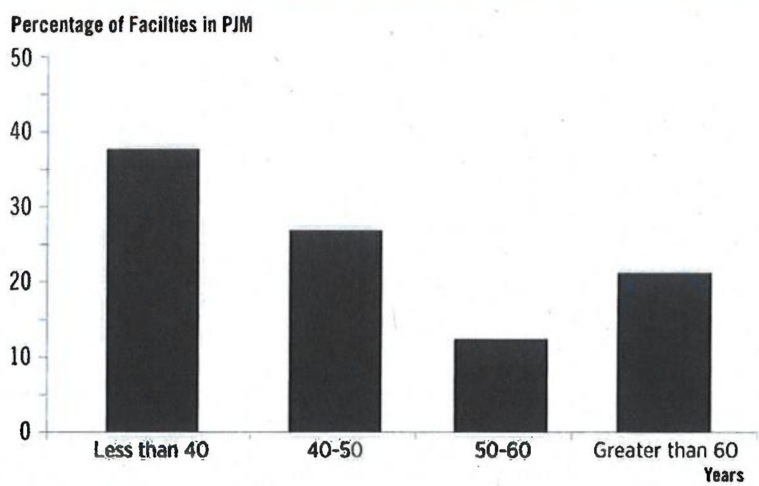
The regional high-voltage transmission system is aging; many facilities were placed in service in the 1960s or earlier. They are deteriorating and reaching the end of their useful lives. Maintaining older equipment means higher costs and greater risk of outages. Addressing this deterioration and the associated costs and risks is part of each transmission owner's broader asset management strategy, as described in **Appendix E.** As equipment continues to age, the approach must shift from simply maintaining assets to replacing and modernizing them. Asset modernization has gone beyond replacement. Replacement projects offer the opportunity to learn from history and adopt new knowledge, capabilities and technologies that did not exist when original facilities were built.

Old transmission equipment deteriorates with age. Two-thirds of transmission in PJM is more than 40 years old and must be replaced to ensure reliability and reduce elevated maintenance costs.

By the Numbers: Aging Infrastructure

Nearly two-thirds of all bulk electric system assets in PJM are more than 40 years old and more than one-third are more than 50 years old (**Figure 37**). Some local, lower-voltage equipment, especially below 230 kV, is approaching 90 years old. Most of this equipment - cable, tower structures and tower foundations, for example - is outdoors and deteriorates with age. Some tower structures - often at 115 kV and 138 kV voltage

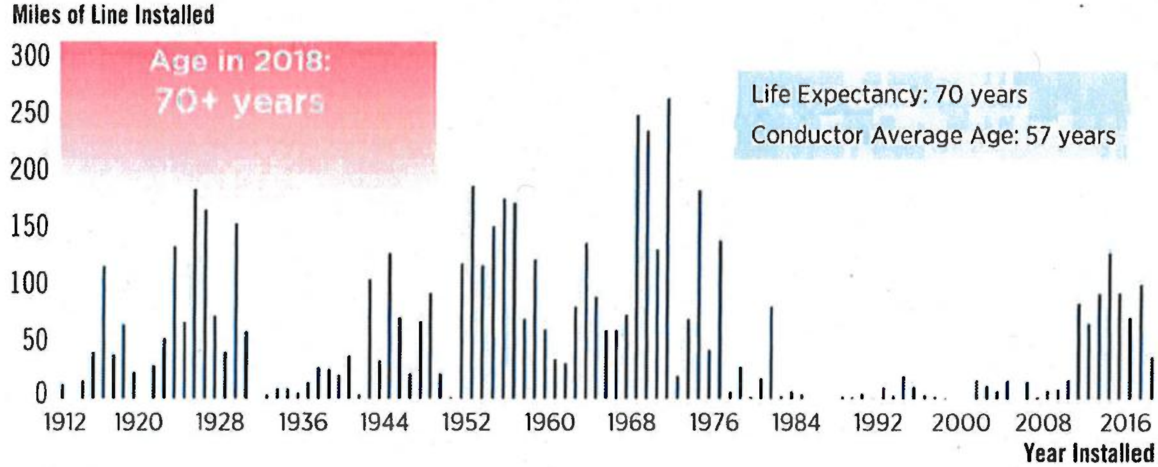
Figure 37: Aging Bulk Electric System Facilities in PJM



levels - were originally constructed of wood and have begun to deteriorate. Other structures originally constructed of iron exhibit significant rusting and degradation. Loss of structural integrity subjects transmission lines to increased maintenance costs and reliability risks.

Figure 38 drives the point home. It shows an example of an aging transmission profile, (in this case, AEP transmission lines in Ohio). Some of these transmission lines date back to 1912. Several thousand miles of transmission lines were built before 1948, which is older than the 70-year life expectancy of a typical line. Overall, a 57.1-year average conductor age demonstrates the growing reliability concerns caused by aging assets, a concern that can be solved by replacement with new transmission assets.

Figure 38: Example Aging Assets Profile - AEP Ohio Footprint in PJM



Enhancing Resilience

Operators of the world's electrical grids are contending with a range of emerging challenges, including extreme weather, cyber and physical attacks, changes in the electric generation fleet driven by cheap and plentiful natural gas, and increased deployment of renewable resources. The pace of those changes has pushed grid operators to prepare for future vulnerabilities for which no set of standards currently exist.

To be resilient, PJM must prepare for, operate through and recover from threats, as depicted in **Figure 39**:

- **Pre-event.** Prepare: Anticipate, evaluate and cost-effectively mitigate risks
- **During an event.** Operate: Manage through a high-impact disruption
- **Post-event.** Recover: Regain essential functions as rapidly as possible

Figure 39: Defining Resilience

PJM's operations, planning, markets, physical security and cybersecurity functions are part of ongoing collaborative, organization-wide efforts to establish processes, develop tools and enhance communications to maximize grid resilience. PJM has initiated efforts to implement planning-process criteria and metrics to enhance grid resilience beyond the measures in place today.

The Role of Transmission in Resilience

For decades, planning criteria has been developed and applied to power systems around the world to ascertain the need for new transmission. This provides a robust grid so that system operators can address various operating scenarios on any given day. Planners test the system under simulated stressed conditions - extreme weather conditions, for example - to understand where reinforcements are needed to make the grid reliable.

NERC planning criteria require that the bulk power system be tested for such contingencies as the loss of a transmission line - a high probability, low impact event - under the assumption that every other transmission facility is in service. Yet in reality, dozens of facilities are out of service on the system on any given day. PJM also simulates more severe, lower-probability events like multiple facility outages. These include the loss of two circuits on a common tower line or a fault on a circuit followed by a breaker failure or two unrelated contingencies, otherwise known as the "n-1-1" test.

NERC standards address resilience to a degree. Planning standards also require examination of the impact of extreme events such as the loss of an entire substation or the loss of an entire right-of-way caused by a landslide, tornado or fire, taking down multiple transmission lines in one corridor. Although an assessment of the impact of these events is required, reinforcement for these low-probability events is not required under current NERC criteria.

Reliability criteria are structured around likely events. Planners must also assess whether the transmission system is sufficiently reinforced to address extreme events such as physical and cybersecurity attacks or extreme weather conditions like hurricanes.

Resilience: Taking Reliability a Step Further

Resilience and reliability both seek to keep the lights on but are not conceptually the same. PJM already complies with established NERC, regional and TO reliability standards. To that end, PJM conducts its planning studies under critical, stressed conditions so that system dispatchers can manage the actual system conditions on any given day in real time. Resilience takes this to another level, addressing challenges and emerging risks that existing reliability standards do not fully capture:

- Maintaining reliability in the face of significant events
- Evaluating threats as part of the TEAC process
- Slowing disruptive events, mitigating their impacts and quickly recovering essential functions
- Protecting essential systems based on assessed risks and hazards
- Improving grid flexibility and control to adapt efficiently and quickly to post-event conditions

PJM has initiated efforts to implement RTEP process criteria and metrics in order to enhance grid resilience beyond that in place today. The NERC CIP-014[29] standard requires TO assessments to identify critical facilities that, if rendered inoperable, would cause instability, uncontrolled separation or cascading outages.

29 https://www.nerc.com/pa/Stand/Reliability%20Standards/CIP-014-1.pdf

PJM experience suggests that developing RTEP projects in response to resilience criteria could be accomplished through three decision-making approaches:

1. **Do no harm,** so that the solution to an identified reliability criteria violation does not introduce new resilience issues.
2. **Leverage project opportunities** already identified under reliability, market-efficiency needs or public policy needs to enhance resilience.
3. **Respond proactively** with new projects to mitigate resilience risks.

Identifying RTEP resilience solutions must balance cost and benefit. All facilities cannot be hardened against all contemplated threats and risks. Defining benefits and values will require comprehensive new RTEP process metrics – both stochastic and deterministic – and the requisite tools to calculate them. Under each approach, metrics are required that assign a resilience score to every transmission facility – substation, line and transformer, based on criticality, for example. System resilience is a key consideration in the evaluation of planning solution alternatives so that PJM can select solutions that enhance resilience as part of addressing other criteria violations or as stand-alone criteria itself.

Resilience vulnerabilities that are significant enough to warrant a transmission system enhancement could be designed to be integrated into PJM's RTEP. For example, this could include building redundancy into black start generation cranking paths, reducing the criticality of substations through transmission line siting and power flow diversity for areas with load congestion or high concentrations of critical restoration generating units.

While PJM continues to pursue formal implementation of these transmission planning approaches, parallel transmission resilience initiatives continue in several areas: spare transformer need, phasor measurement unit implementation and cascading event analysis tool development.

Benefits by the Numbers: Spare Transformers

As the electric transmission system in the U.S. matures, mitigating the risk of high-voltage equipment failures becomes an increasingly important issue for transmission owners and operators. Asset owners must anticipate procurement lead times when planning for emergency or unexpected equipment replacements. Certain equipment, such as power transformers, can take up to 18 months from the time of order until installation. This wait can limit the speed of system restoration. Mitigating this requires transmission owners to develop strategies for monitoring their inventory to maintain reliability and control costs.

> Purchasing and positioning spare transformers ahead of time can sharply reduce restoration time if a major transformer fails.

To address these strategic objectives, in 2006 PJM developed a probabilistic risk assessment (PRA) model for managing the existing 500/230 kV transformer infrastructure. The model couples transformer data provided by asset owners with data from PJM market analyses. This data helps estimate annual likelihood of failure, potential replacement costs and installation time for each transformer. The market analyses provide the expected congestion costs associated with the loss of each transformer. The PRA model combines failure likelihood and congestion information to determine the annual risk, in dollars, to the system for the loss of a transformer. The PJM PRA is performed biennially to minimize transformer fleet risk exposure.

PRA Results

PJM's 2006 assessment found 188 500/230 kV transformers in service and 29 dedicated spares. At the time, more than 50 percent of the 188 transformers were more than 30 years old. PJM's PRA analysis identified the need for seven new spares to be located strategically at six substations, and which needed to be able to be moved to other locations as required.

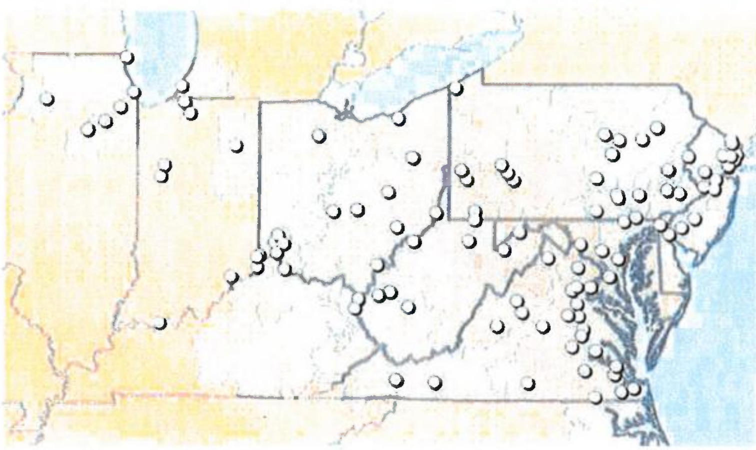
In 2006, these were approved by the PJM Board and were formally included in PJM's RTEP to enhance system reliability and mitigate congestion costs in the event of a transformer failure. PRA analysis identified a congestion risk exposure of $74 million annually that would be mitigated by the deployment of those spare transformers. The PRA also revealed that spares would increase the acceptable risk limit for transformer units in operation, extending their service lives.

System planners and asset owners gain invaluable insight from this process. Knowing and understanding risk has better prepared PJM and its members to proactively and economically address aging transformer infrastructure. Additional analysis has allowed stakeholders to plan proactive transformer replacements, transformer spare purchases and optimal location of spares.

Benefits by the Numbers: Deployment of Phasor Measurement Units

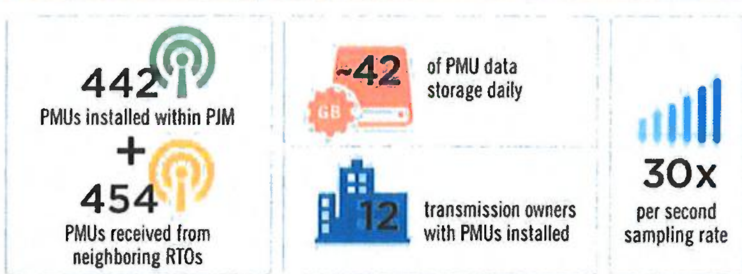
With the aid of a $14 million U.S. Department of Energy stimulus grant, PJM and its member transmission owners have installed more than 400 phasor measurement units (PMUs) in more than 120 substations in 10 states, shown on **Map 13.** PMUs – shown conceptually in **Figure 40** – provide data at a higher resolution and much higher reporting frequency than traditional SCADA (supervisory control and data acquisition) systems, painting a more detailed picture of the status of the grid at any given moment. PJM is developing advanced applications of this technology to improve the efficiency, reliability and resilience of the power system.

Map 13: Location of Phasor Measurement Units Across PJM



> Investment in phasor measurement units across the system help operators detect and address instability before it causes service interruptions.

Figure 40: Using Phasor Measurement Units in PJM



Model validation is a key and novel application of PMUs. Planning, operations and markets rely heavily on models; ensuring that these models accurately represent the physical behavior of the system is critical. PJM is researching other applications, including disturbance detection and location, geomagnetic disturbance monitoring and wide-area controls. In particular, this technology allows PJM to recognize, detect and mitigate electromechanical oscillations, which helps system operators quickly identify potential instability before it has a chance to spread and interrupt service. Overall, further penetration of PMUs promises to revolutionize the practice of evaluating the status of the transmission system, making the process faster and the system more resilient.

Cascading Event Analysis Tool

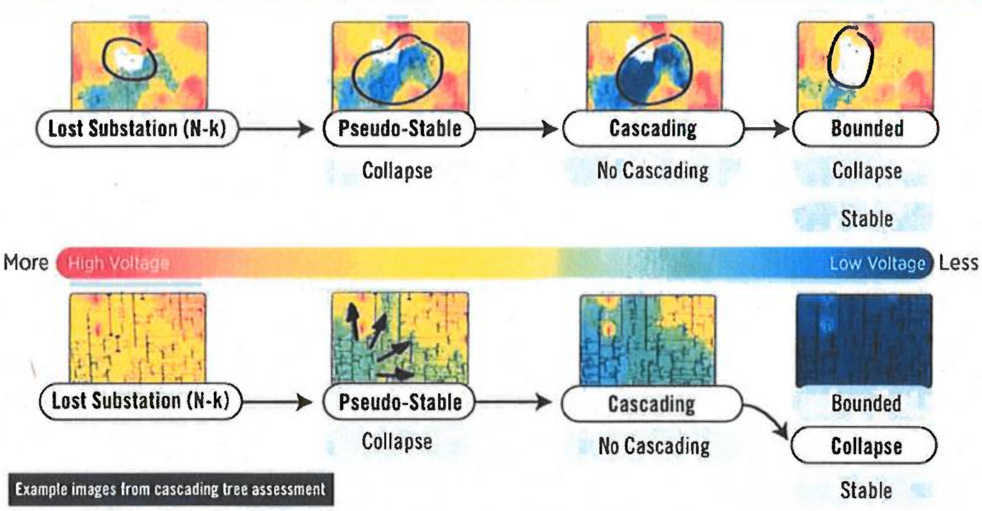
At its most fundamental, a cascading tree evaluates an extreme event that encompasses a risk that may, after some number of additional cascading events, lead to system collapse (i.e., blackout). Major blackouts are usually caused by low-probability, high-consequence events. Since the attacks of 9/11, the power industry has taken a closer look at system contingencies not only driven by naturally occurring events but additional man-made threats as well, including:

- Cyber-attack
- Loss of interdependent systems
- Earthquake
- Physical attack
- Severe terrestrial weather
- Geomagnetic disturbance
- Electromagnetic pulse

Any such initial precipitating event could cause one or more transmission line overloads (on common right-of-way), transformer overload, loss of substation, generator under-voltage, or load under-voltage conditions, among others.

The high-voltage transmission network that crisscrosses the country was planned based on a set of reliability and efficiency criteria. These criteria generally ensure that the transmission system is capable of withstanding a significant outage to one, or a few, critical pieces of equipment. However, these planning criteria do not assess what would happen to the system should a significant disruption of many pieces of equipment occur at once, or in quick succession, as might be triggered by an extreme weather event or a deliberate attack. PJM and transmission owner Dominion Virginia Power have begun developing such an assessment, called "cascading trees," shown conceptually in **Figure 41.** The purpose of this new methodology is to assess the probability and consequence of cascading outages in electric systems. A cascading tree is the set of all likely cascading paths; these, in turn, describe a sequence of potential cascading outages that could reasonably be expected.

Figure 41: Cascading Tree Concept



These possible outages are then classified as shown in **Figure 41** based on whether the propagation of a disturbance can be confined to a certain area or if the exact extent of the cascading cannot be determined. The initial N-k event equates to the complete loss of a substation. Cascading trees quantify the probability of cascading and the extent of associated consequence, leading to a natural ranking of substations. Substations then can be grouped into different tiers, each having a different priority and a discrete set of mitigation actions. Dominion Virginia Power has used this methodology to identify and rank critical substations. The best way to protect a critical substation is to not have one. PJM is currently developing a metric of resilience to complement and enhance a planning process that traditionally has been focused on reliability and efficiency. The intent is to incorporate cascading trees as a weighting factor in the metric of resilience.

Deploying New Transmission Asset Technology

The last five years have brought substantial modernization to system infrastructure. Enhancement of existing equipment, coupled with the application of new tools, has increased efficiency of the equipment and of system operation. Technologies like these are providing PJM with additional tools and operating flexibility to ensure reliability at the lowest cost.

Flexible AC Transmission Systems

> Flexible AC Transmission System (FACTS) technology – developed as a result of key EPRI research since the 1980s – has been deployed in PJM to help regulate voltage, power factor, harmonics and system stability.

A Flexible AC Transmission System (FACTS) is a power system device that takes more conventional power system components - capacitors and reactors - and integrates them in various configurations with intelligent power electronics, high-speed thyristor valve technology and voltage sourced converter (VSC) technology. By doing so, FACTS devices can directly support additional transmission line power flow with reactive power injections at their point-of-interconnection and can indirectly control power flow by modulating transmission line impedances. The most common FACTS devices include static VAR compensators (SVCs) and Static Compensators (STATCOMs). FACTS device technology was developed as a result of key Electric Power Research Institute research conducted since the 1980s and has been deployed in PJM to help regulate voltage power factor, harmonics and system stability.

SVC devices totaling 5,360 MVAR have been deployed in PJM as RTEP projects since 2013, as discussed in **Section 4**. These devices provide system operators with additional operational flexibility to control voltages, particularly during high-voltage conditions overnight when transmission lines are lightly loaded.

Additionally, PJM TOs have installed 525 MVAR of STATCOM technology with another 125 MVAR planned. A STATCOM includes a unique design that incorporates voltage-sourced converters and thyristor valves to yield additional performance, in terms of speed and dynamic range, as compared to SVC devices.

Transmission Tower Configuration Technology

Transmission towers continue to advance technologically. For example, AEP's Sorenson-Robison Park 345 kV/138 kV line - energized in November 2016 - employs a new tubular steel tower configuration that has yielded shorter tower heights and increased capacity within an existing 138 kV right-of-way. This design, coupled with low-impedance bundled conductors, reduces line losses and significantly increases power delivery capability while avoiding the complexities and costs of series compensation. Overall, the design increases line capacity by 50 percent, reduces system losses and maximizes transmission efficiency. Similarly, lines made from composite-core conductors can lower line losses by 25 percent to 40 percent compared to traditional aluminum-conductor steel-reinforced cable. PJM expects that it will continue to see more transmission tower technology innovations in the future.

Energy Storage

FERC, in an order dated January 21, 2010, addressed the classification of energy storage devices on a case-by-case basis. In the same order, FERC ruled that given certain specific criteria being met, storage devices could be treated as transmission facilities and therefore be compensated in the same way as other transmission facilities.

Energy storage units continue to grow in PJM. Efficient grid operations in an era of rapid growth of renewable energy resources will require increased electric system flexibility. PJM's interest in energy storage of all forms reflects this notion. Energy storage helps grid operators keep the power supply stable when wind, solar or other resources are changing their output due to weather conditions or are simply unavailable. It can also improve the efficiency of the transmission system by increasing the utilization factor of existing transmission and distribution networks, as well as existing generation sources. PJM has worked with various companies and national laboratories to advance the use of energy storage and ensure that the PJM wholesale market is capable of allowing all forms of energy storage to participate and compete in the market.

Today, approximately 5,000 MW of pumped storage hydro, 300 MW of battery and flywheel energy storage, and 70 MW of thermal energy storage are qualified to participate in the PJM markets. This includes everything from large central station generation plants connected at transmission to small kilowatt-level behind-the-meter applications. PJM's new services queue includes energy storage capacity totaling 818 MW as of December 31, 2018, which PJM continues to evaluate.

In March 2018, FERC issued a new regulation, Order No. 841, mandating that all ISOs and RTOs create a market-participation model in which energy storage resources can provide all of the market services that they are technically capable of offering. These new rules, which must be implemented by December 2019, are generally seen as a regulatory step that will help enable further growth of energy storage in the U.S.

Unfolding Initiatives

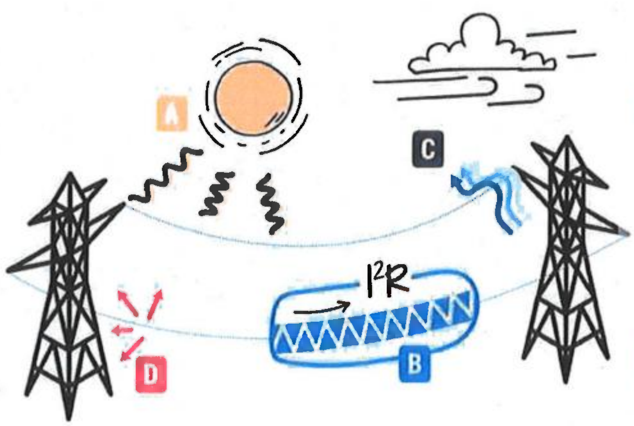
PJM has undertaken a number of initiatives that build on its history of innovation to enhance the reliability and cost-effectiveness of the bulk power system.

Dynamic Line Rating Technology

Dynamic Line Rating (DLR) technology uses advanced sensors and software to monitor real-time conductor temperature along a transmission line. It then uses this data to calculate an actual rating for the line based on environmental conditions, as opposed to modeled scenarios. DLR technology can identify additional capacity on transmission lines that could potentially relieve congestion and create economic efficiencies. Such technology also can contribute to system resilience by providing better monitoring of the real-time capabilities of transmission assets. Every transmission line is designed with a de facto rating that traditionally does not change very often and that is used by PJM and TOs in operating the grid. Introducing DLR technology could allow a more dynamic update of transmission line ratings – for example, hourly, daily, monthly or seasonally – that would improve the reliability and economic efficiency of system operations.

Today, DLR technology - conceptually shown in **Figure 42** - is used in only a select number of locations worldwide. PJM has partnered with transmission owner American Electric Power and DLR technology company LineVision to demonstrate the use of this technology and its potential benefits more widely. To better understand the overall impact of DLR technology, PJM undertook a one-year study of a hypothetical installation on one of its most congested lines. The analysis found that use of the technology could reduce system congestion payments by more than $4 million - providing a rapid, two-month payback of the estimated $500,000 installation cost.

Figure 42: Illustration of DLR



A **Solar heating** – Just as the sun warms the air and the Earth's surface, heat from the sun's rays will raise the temperature at the conductor's surface.

B **Resistive heating** – As current passes through the conductor, heat is generated inside the conductor by electrical losses.

C **Convective cooling** – Nearby wind carries away warm air surrounding the conductor and can cause a dramatic cooling effect along the transmission line.

D **Radiative Cooling** – Even with no wind, transmission lines lose a portion of their heat to cooler ambient air.

Electric Vehicles

PJM continues to pay close attention to U.S. transportation sector electrification and, in particular, the impact of electric vehicles (EV) on transmission system needs. EEI estimates that EVs will grow from 1 million today to 7 million across the country by 2025.[30] The report goes on to cite the Northeast as one of the regions of the country "... with higher concentrations of first adopters of electric vehicles and more immediate, more ambitious policy targets."[31]

EVs would operate essentially in two modes, potentially based on economic signals sent by PJM:

- Charge on-board batteries from electricity purchased from PJM's Energy Market at distributed charging stations
- Discharge power to the grid to earn revenue in PJM markets for energy and related ancillary services, similar to a generation asset

In either mode, PJM must ensure that transmission capability is in place to accommodate the additional flow of power to charging stations, expected to be highly distributed across local and interstate highway systems. The timing of the coincident effect of EVs' charging cycles could also drive the need for additional generating resources and related transmission, particularly during peak load. This transmission need is amplified if the power needed to charge EV batteries is expected to come from wind and natural gas-fired generating resources, often distant from the population centers they serve.

30 "The Coming Electrification of the North American Economy: Why We Need a Robust Transmission Grid" https://wiresgroup.com/new/wp-content/uploads/2019/03/Electrification_BrattleReport_WIRES_FINAL_03062019.pdf

31 Ibid.

Initial PJM Experience

Recently, PJM partnered with companies including BMW North America and General Motors OnStar to demonstrate the potential of aggregated fleets of EVs to respond to certain types of grid signals, such as demand response events, LMPs or the real-time generation profile of renewable energy resources. PJM was an integral partner in one of the world's first successful demonstrations of vehicle-to-grid technology at the University of Delaware, which is continuing to demonstrate the potential for electric vehicles to act as mobile storage devices. As part of this pilot demonstration project, electric BMW Minis charged and discharged in response to the PJM frequency regulation signal and earned approximately $100 per month per car for their services. Given that EVs will be a significant part of future transportation systems, PJM looks forward to playing a role in powering these vehicles and enabling their ability to interact with the grid in innovative ways to maintain reliable and cost-efficient electricity.

Microgrids

Microgrids encompass a combination of increasingly cost-effective distributed generation, environmental motivations and increasing value of highly resilient electric power supply. They are small clusters of energy assets and loads that are controlled to achieve a variety of benefits for the owner/operator. One of the primary benefits of building a microgrid is the ability to provide reliable electric power during significant electric grid disturbances, such as storm outages. PJM works with industry partners, universities and states to better understand how microgrids can impact the grid in a positive way and how they can derive value from the PJM wholesale markets. One such initiative is in PJM's backyard at the Philadelphia Navy Yard, where the Philadelphia Industrial Development Corporation, GE Grid Solutions, The Pennsylvania State University and other partners have created a Microgrid Center of Excellence. The center is demonstrating microgrid control technology coupled with distributed energy assets to improve grid resilience, security, reliability and efficiency, while also incorporating the use of on-site renewable energy.

Distributed Energy Resources

Distributed energy resources continue to introduce another dynamic into PJM's planning process. They can remain on the customer's side of the meter or participate in PJM markets. Distributed energy resources seeking to participate in PJM's wholesale capacity market must do so via PJM's RTEP new services queue process. This ensures that necessary transmission improvements are in place to preserve reliability and that market participation contracts are executed. Distributed energy devices like rooftop solar remain behind the meter and do not participate in PJM capacity markets. Nonetheless, they impact the demand side of PJM resource adequacy. Distributed solar generation acts to offset load, making it lower than it otherwise would be.

Geomagnetic Disturbances

Geomagnetic disturbances, also referred to as solar magnetic disturbances, have the potential to affect the high-voltage transmission system and are of concern to the electricity industry and the government. PJM, which has experienced the impact of such intensified solar activity, has developed specific operating procedures to implement when solar activity is high and could threaten the reliability of the transmission system. Sunspots and other solar phenomena can produce large clouds of plasma (called coronal mass ejections) that can induce electric currents in the Earth and on high-voltage transmission lines. These currents can flow up from the Earth or down into the Earth through grounded grid equipment, mainly transformers. High levels of these ground-induced currents can cause increased reactive power consumption, harmonic currents and hot-spot heating of transformers, the combination of which could result in voltage collapse and blackout.

FERC issued Order No. 779 in 2013 directing NERC to develop reliability standards to address the potential impact of geomagnetic disturbances on reliable system operation. Subsequently, NERC developed reliability standard EOP-010-1 – Geomagnetic Disturbance Operations[32] – and more recently standard TPL-007-1 - Transmission System Planned Performance for Geomagnetic Disturbance Events.[33] The intent of these standards is to mitigate the risk of instability, uncontrolled separation and cascading outages caused by geomagnetic disturbances. FERC issued Order No. 830 in 2016, approving standard TPL-007-1, including a multi-year implementation plan.

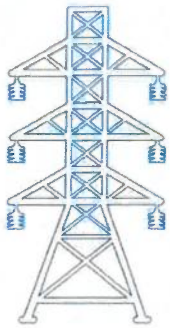
Ocean-Based Wind-Powered Generation

The area off the U.S. Atlantic Coast encompasses a major wind-energy resource that holds the potential to yield thousands of megawatts of power. Efficiently harnessing that energy through the construction of offshore wind farms will require the development of robust transmission to carry the electricity ashore and deliver it to users, particular load centers along the East Coast. Transmission developers are interested in building merchant, non-controllable transmission facilities, AC facilities that eventually will interconnect with future offshore wind-powered generation. Proposed merchant transmission facilities may consist of a single offshore generator lead line or networked offshore transmission facilities. Controllable AC technology, by comparison, allows for the control of the actual amount of power allowed to flow over transmission lines, in particular to other control areas like that between northern New Jersey and New York.

These transmission developers are interested in obtaining capacity interconnection rights to ensure PJM can identify the necessary network upgrades in support of the future generation. This additional process flexibility is expected to accommodate additional wind-powered facilities to participate in PJM's energy and capacity markets. As discussed earlier in **Section 3**, generation powered by renewable fuels like wind provide significant environmental and health benefits.

32 https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-010-1.pdf

33 https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=TPL-007-1&title=Transmission%20System%20Planned%20Performance%20for%20Geomagnetic%20Disturbance%20Events&jurisdiction=United%20States



Conclusion

The benefits of the transmission system itself and the dollars invested in it extend well beyond delivering power over high-voltage transmission lines. The transmission system ensures reliability, keeps costs low and supports public policy initiatives in the states and federally.

Recent reports indicate that the importance and the need for transmission will grow very quickly over the next 10 years. For instance, one report estimates that rapid electrification of industries that were previously powered by fossil fuels will require transmission investment of $30 to $90 billion by 2030.[34]

As the need for this vital infrastructure grows and changes, PJM will continue to play its role to meet those needs: Planning for the future of the grid to keep power flowing wherever and whenever it's needed.

34 The Brattle Group, "The Coming Electrification of the North American Economy: Why We Need a Robust Transmission Grid," March 2019. https://www.brattle.com/11754

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)

AG/KIUC Hearing Ex. 3

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

American Electric Power Service Corporation	Docket No. ER09-1279-000

MOTION OF THE KENTUCKY PUBLIC SERVICE COMMISSION TO INTERVENE OUT-OF-TIME

Comes now the Kentucky Public Service Commission ("KY PSC"), pursuant to Commission Rule 214, 18 C.F.R. § 385.214 and other applicable law, and files this motion to intervene out-of-time in the above-referenced docket regarding American Electric Power Service Corporation's ("AEPSC") June 5, 2009 proposed amendments to its Transmission Agreement by and among such companies and with AEPSC as Agent dated as of April 1, 1984 as amended. The KY PSC requests this late intervention in order to monitor and participate in the above-referenced proceeding, as this case will affect Kentucky ratepayers in AEP's Kentucky service area.

Communications

KY PSC requests that the following name be added to the official service list and that all communications and correspondence regarding these proceedings be directed to:

Richard W. Bertelson, III
Kentucky Public Service Commission
Post Office Box 615
Frankfort, Kentucky 40602
Telephone: 502/564-3940
Telefax: 502/564-7279
e-mail: rick.bertelson@ky.gov

David S. Samford
Kentucky Public Service Commission
Post Office Box 615
Frankfort, Kentucky 40602
Telephone: 502/564-3940
Telefax: 502/564-7279
e-mail: davids.samford@ky.gov

Interest

KY PSC is a regulatory agency of the Commonwealth of Kentucky, established pursuant to Chapter 278 of the Kentucky Revised Statutes and generally responsible for regulating the rates and services of jurisdictional utilities in Kentucky. The jurisdiction of the KY PSC extends to the retail electric rates and service provided by Kentucky Power Company, a subsidiary of AEPSC. The KY PSC has a direct and substantial interest that is not otherwise adequately represented in ensuring that native load customers of Kentucky Power Company are protected from unwarranted costs and that they also receive the benefit of proposals which may reduce their rates. Granting intervention to KY PSC is in the public interest. The KY PSC does not believe that its intervention will prejudice any party, and KY PSC agrees to accept the record as it now stands.

Support

KY PSC supports AEPSC's June 5, 2009 proposed amendments to its Transmission Agreement. KY PSC believes that the proposed amendments will result in transmission rates that are just and reasonable. It appears that under the proposed amendments, Kentucky Power Company's transmission-related costs may actually be lower than at present.

Conclusion

THEREFORE, for the reasons set forth above, KY PSC requests that the Commission grant this motion to intervene in this docket.

Respectfully submitted, this the 5th day of August 2009.

By: /s/Richard W. Bertelson, III

RICHARD W. BERTELSON, III
Post Office Box 615
Frankfort, KY 40602-0615
Telephone: 502/564-3940, Extension 260
Telefax: 502/564-3460
e-mail: rick.bertelson@ky.gov

Counsel for Kentucky Public Service Commission

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused to be served the foregoing document upon each person designated on the official service list as compiled by the Secretary in these proceedings.

By: /s/ Richard W. Bertelson, III

Document Accession #: 20090805-5025   Filed Date: 08/05/2009

Document Content(s)

THIS FILING IS		
Item 1: [X] An Initial (Original) Submission	OR [ ]	Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2022)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2022)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2022)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

PSC Exhibit 1

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
AEP Kentucky Transmission Company, Inc.	**End of** 2019/Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/forms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of ____________ , we have also reviewed schedules ____________________of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/forms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/forms.asp#3Q-gas .

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and” firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and “firm” means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) ’Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent AEP Kentucky Transmission Company, Inc.	02 Year/Period of Report End of 2019/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 1 Riverside Plaza, Columbus, OH 43215-2373	
05 Name of Contact Person Jason M Johnson	06 Title of Contact Person Accountant
07 Address of Contact Person *(Street, City, State, Zip Code)* AEP Service Corp, 1 Riverside Plaza, 26th Flr, Columbus, OH 43215-2373	

08 Telephone of Contact Person, *Including Area Code* (614) 716-1000	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* / /

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name Jeffrey W. Hoersdig 02 Title Assistant Controller	03 Signature Jeffrey W. Hoersdig	04 Date Signed *(Mo, Da, Yr)* 04/17/2020

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	N/A
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	N/A
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	N/A
18	Electric Plant Held for Future Use	214	N/A
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	N/A
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	N/A
24	Extraordinary Property Losses	230	N/A
25	Unrecovered Plant and Regulatory Study Costs	230	N/A
26	Transmission Service and Generation Interconnection Study Costs	231	N/A
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	N/A
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	N/A
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	N/A

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	N/A
68	Transmission Lines Added During the Year	424-425	N/A
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Jeffrey W. Hoersdig
Assistant Controller
1 Riverside Plaza
Columbus, OH 43215

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Kentucky – October 2, 2009

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

None

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Electric – Kentucky

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) [ ] Yes...Enter the date when such independent accountant was initially engaged:
(2) [X] No

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

AEP Transmission Company, LLC, controls 100% of the Respondent as of December 31, 2019. AEP Transmission Holding Company, LLC, controls 100% of AEP Transmission Company, LLC as of December 31, 2019. American Electric Power Company, Inc., a registered holding company, controls 100% of AEP Transmission Holding Company, LLC as of December 31, 2019.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions
1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Not Applicable			
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	See Footnote		
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

Schedule Page: 104 Line No.: 1 Column: a

Summary Compensation Table

The following table provides summary information concerning compensation earned by our Chief Executive Officer, our Chief Financial Officer and the three other most highly compensated executive officers, to whom we refer collectively as the named executive officers.

Name and Principal Position	Year	Salary ($)(1)	Bonus ($)	Stock Awards ($)(2)	Non-Equity Incentive Plan Compensation ($)(3)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)(4)	All Other Compensation ($)(5)	Total ($)
Nicholas K. Akins— Chairman of the Board and Chief Executive Officer	2019	1,475,654	—	8,775,003	3,600,000	530,151	111,628	14,492,436
Brian X. Tierney— Executive Vice President and Chief Financial Officer	2019	793,039	—	4,064,681	1,088,000	470,138	95,560	6,511,418
David M. Feinberg— Executive Vice President, General Counsel and Secretary	2019	677,596	—	1,445,289	865,000	173,983	73,436	3,235,304
Lisa M. Barton— Executive Vice President-Transmission	2019	588,254	—	3,238,802	825,000	173,781	67,799	4,893,636
Lana L. Hillebrand— Executive Vice President-Chief Administrative Officer	2019	615,358	—	1,135,625	800,000	221,245	74,831	2,847,059

(1) Amounts in the salary column are composed of executive salaries earned for the year shown, which include 261 days of pay for 2019. This is one day more than the standard 260 calendar work days and holidays in a year.

(2) The amounts reported in this column reflect the aggregate grant date fair value calculated in accordance with FASB ASC Topic 718 of the performance units and restricted stock units (RSUs) granted under our Long-Term Incentive Plan. See Note 15 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2019 for a discussion of the relevant assumptions used in calculating these amounts. The number of shares realized and the value of these performance shares, if any, will depend on the Company's performance during a 3 year performance period. The potential payout can range from 0 percent to 200 percent of the target number of performance shares, plus any dividend equivalents.

The value of the 2019 performance units will be based on two equally weighted measures: a Board approved cumulative operating earnings per share measure (Cumulative EPS) and a total shareholder return measure (Relative TSR). The grant date fair value of the 2019 performance units that are based on Cumulative EPS was computed in accordance with FASB ASC Topic 718 and was measured based on the closing price of AEP's common stock on the date of grant. The maximum amount payable for the 2019 performance units that are based on Cumulative EPS is equal to: $6,374,972 for Mr. Akins; $1,500,026 for Mr. Tierney; $1,050,010 for Mr. Feinberg; $900,032 for Ms. Barton and $825,042 for Ms. Hillebrand. The grant date fair value of the 2019 performance units that are based on Relative TSR is calculated using a Monte-Carlo model as of the date of grant, in accordance with FASB ASC Top 718. Because the performance shares that are based on Relative TSR are subject to market conditions as defined under FASB ASC Topic 718, they did not have a maximum value on the grant date that differed from the grant date fair values presented in the table. Instead, the maximum value is factored into the calculation of the grant date fair value.

(3) The amounts shown in this column are annual incentive compensation paid for the year shown.

(4) The amounts shown in this column are attributable to the increase in the actuarial values of each of the named executive officer's combined benefits under AEP's qualified and non-qualified defined benefit plans determined using interest rate and mortality assumptions consistent with those used in the Company's financial statements. See Note 8 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2019 for a discussion of the relevant assumptions.

(5) Amounts shown in the All Other Compensation column for 2019 include: (a) Company contributions to the Company's Retirement Savings Plan, (b) Company matching contributions to the Company's Supplemental Retirement Savings Plan and (c) perquisites. The amounts are listed in the following table:

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

Type	Nicholas K. Akins	Brian X. Tierney	David M. Feinberg	Lisa M. Barton	Lana L. Hillebrand
Retirement Savings Plan Match	$ 12,600	$ 12,600	$ 12,600	$ 12,600	$ 12,600
Supplemental Retirement Savings Plan Match	$ 77,400	$ 62,960	$ 47,199	$ 39,613	$ 41,951
Perquisites	$ 21,628	$ 20,000	$ 13,637	$ 15,586	$ 20,280
Total	**$ 111,628**	**$ 95,560**	**$ 73,436**	**$ 67,799**	**$ 74,831**

Perquisites provided in 2019 included: financial counseling and tax preparation services, and, for Mr. Akins, director's group travel accident insurance premium. Executive officers may also have the occasional personal use of event tickets when such tickets are not being used for business purposes, however, there is no associated incremental cost. From time to time executive officers may receive customary gifts from third parties that sponsor sporting events (subject to our policies on conflicts of interest).

Mr. Akins has entered into an Aircraft Time Sharing Agreement that allows him to use our corporate aircraft for personal use for a limited number of hours each year. The Aircraft Time Sharing Agreement requires Mr. Akins to reimburse the Company for the cost of his personal use of corporate aircraft in accordance with limits set forth in Federal Aviation Administration regulations. The incremental costs incurred in connection with personal flights for which Mr. Akins fully reimbursed the Company under the Aircraft Timesharing Agreement include fuel, oil, hangar costs, crew travel expenses, catering, landing fees, and other incremental airport fees. Accordingly, no value is shown for these amounts in the Summary Compensation Table. If the aircraft flies empty before picking up or after dropping off Mr. Akins at a destination on a personal flight, the cost of the empty flight is included in the incremental cost for which Mr. Akins reimburses the Company. Since AEP aircraft are used predominantly for business purposes, we do not include fixed costs that do not change in amount based on usage, such as depreciation and pilot salaries.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Nicholas K. Akins, Chairman of the Board,	Columbus, Ohio
2	and Chief Executive Officer	
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4	Mark C. McCullough, President	Columbus, Ohio
5	and Chief Operating Officer	
6		
7	Wade A. Smith, Vice President	Columbus, Ohio
8		
9	Brian X. Tierney, Vice President	Columbus, Ohio
10	and Chief Financial Officer	
11		
12	David M. Feinberg, Vice President	Columbus, Ohio
13	and Secretary	
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15	Note: Respondent does not have an Executive Committee	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?

[X] Yes

[ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	FERC OATT PJM Interconnections LLC - Attachment H-	ER17-406
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Name of Respondent AEP Kentucky Transmission Company, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2019/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	[X] Yes [ ] No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20191031-5289	10/31/2019	ER17-406	AEP PJM OATT Annual Formula Rate	PJM OATT Attachment H-20
2	20190716-5113	07/16/2019	ER17-406	AEP PJM OATT Annual Formula Rate	PJM OATT Attachment H-20
3	20190528-5200	05/28/2019	ER17-406	AEP PJM OATT Annual Formula Rate	PJM OATT Attachment H-20
4	20190109-5146	01/09/2019	ER17-406	AEP PJM OATT Annual Formula Rate	PJM OATT Attachment H-20
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s).	Schedule	Column	Line No
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

1) None

2) None

3) None

4) None

5) None

6) None

7) None

8) None

9) None

10) None

11) (Reserved)

12) Not Used

13) Mark C. McCullough was elected Director, Jan. 1, 2019
Mark C. McCullough was elected President and Chief Operating Officer, Jan. 1, 2019
Julia A. Sloat was elected Vice President and Treasurer, Jan. 1, 2019
Antonio P. Smyth was elected Vice President, Jan. 29, 2019
Julie Williams resigned as Assistant Controller, Mar. 8, 2019

14) Proprietary capital ratio exceeds 30%

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	124,616,586	111,256,361
3	Construction Work in Progress (107)	200-201	17,135,182	10,055,612
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		141,751,768	121,311,973
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	6,932,886	4,533,125
6	Net Utility Plant (Enter Total of line 4 less 5)		134,818,882	116,778,848
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		134,818,882	116,778,848
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		0	0
19	(Less) Accum. Prov. for Depr. and Amort. (122)		0	0
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	0	0
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		0	0
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		0	0
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		0	0
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		0	0
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		166,246	165,855
41	Other Accounts Receivable (143)		0	0
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		0	0
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		1,048,898	1,953,427
45	Fuel Stock (151)	227	0	0
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	0	0
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

Name of Respondent AEP Kentucky Transmission Company, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2019/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		26,859	16,575
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	3
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		0	0
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		0	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		1,242,003	2,135,860
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		303,693	323,784
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	1,380,935	1,230,677
73	Prelim. Survey and Investigation Charges (Electric) (183)		0	0
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	0
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	734,315	497,513
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		0	0
82	Accumulated Deferred Income Taxes (190)	234	2,185,105	1,778,242
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		4,604,048	3,830,216
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		140,664,933	122,744,924

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [x] An Original (2) [ ] A Resubmission	/ /	end of 2019/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	0	0
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	40,707,500	40,707,500
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	19,854,292	14,447,155
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	0	0
16	Total Proprietary Capital (lines 2 through 15)		60,561,792	55,154,655
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	0	0
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	43,000,000	43,000,000
21	Other Long-Term Debt (224)	256-257	0	0
22	Unamortized Premium on Long-Term Debt (225)		18,833	21,556
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		205,305	213,496
24	Total Long-Term Debt (lines 18 through 23)		42,813,528	42,808,060
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		0	0
29	Accumulated Provision for Pensions and Benefits (228.3)		0	0
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		0	0
35	Total Other Noncurrent Liabilities (lines 26 through 34)		0	0
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		3,446,531	2,560,413
39	Notes Payable to Associated Companies (233)		10,357,607	1,638,163
40	Accounts Payable to Associated Companies (234)		630,303	1,042,921
41	Customer Deposits (235)		0	0
42	Taxes Accrued (236)	262-263	-246,737	-140,727
43	Interest Accrued (237)		0	0
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [x] An Original (2) [ ] A Resubmission	/ /	end of 2019/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		0	0
48	Miscellaneous Current and Accrued Liabilities (242)		199,219	53,562
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		14,386,923	5,154,332
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	0	0
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	97	2,388
60	Other Regulatory Liabilities (254)	278	7,383,604	7,465,583
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		13,681,177	11,058,291
64	Accum. Deferred Income Taxes-Other (283)		1,837,812	1,101,615
65	Total Deferred Credits (lines 56 through 64)		22,902,690	19,627,877
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		140,664,933	122,744,924

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

STATEMENT OF INCOME

Quarterly
1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	12,997,123	11,000,483		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,745,894	1,620,507		
5	Maintenance Expenses (402)	320-323	119,377	98,572		
6	Depreciation Expense (403)	336-337	2,512,078	1,757,120		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	187,920	136,706		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)					
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	251,898	123,783		
15	Income Taxes - Federal (409.1)	262-263	-1,091,087	-114,071		
16	- Other (409.1)	262-263	34,401	-8,427		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	13,065,391	9,218,852		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	10,326,042	7,505,871		
19	Investment Tax Credit Adj. - Net (411.4)	266				
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		6,499,830	5,327,171		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		6,497,293	5,673,312		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
12,997,123	11,000,483					2
						3
1,745,894	1,620,507					4
119,377	98,572					5
2,512,078	1,757,120					6
						7
187,920	136,706					8
						9
						10
						11
						12
						13
251,898	123,783					14
-1,091,087	-114,071					15
34,401	-8,427					16
13,065,391	9,218,852					17
10,326,042	7,505,871					18
						19
						20
						21
						22
						23
						24
6,499,830	5,327,171					25
6,497,293	5,673,312					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		6,497,293	5,673,312		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)					
34	(Less) Expenses of Nonutility Operations (417.1)					
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		3,939	105,295		
38	Allowance for Other Funds Used During Construction (419.1)		617,665	1,254,832		
39	Miscellaneous Nonoperating Income (421)		240	348		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		621,844	1,360,475		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		100,253	1,144		
46	Life Insurance (426.2)					
47	Penalties (426.3)		7	14		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		9,107	9,181		
49	Other Deductions (426.5)		1,471	765		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		110,838	11,104		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	15			
53	Income Taxes-Federal (409.2)	262-263	-22,799	-3,148		
54	Income Taxes-Other (409.2)	262-263	-1,993	1,711		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	15,851	23,315		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	35,215	9,326		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-44,141	12,552		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		555,147	1,336,819		
61	Interest Charges					
62	Interest on Long-Term Debt (427)					
63	Amort. of Debt Disc. and Expense (428)		28,282	28,233		
64	Amortization of Loss on Reaquired Debt (428.1)					
65	(Less) Amort. of Premium on Debt-Credit (429)		2,724	2,722		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		1,777,216	1,618,857		
68	Other Interest Expense (431)		110,151	91,067		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		267,622	393,152		
70	Net Interest Charges (Total of lines 62 thru 69)		1,645,303	1,342,283		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		5,407,137	5,667,848		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		5,407,137	5,667,848		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		14,447,155	8,779,307
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		5,407,137	5,667,848
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31				
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)			
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		19,854,292	14,447,155
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		19,854,292	14,447,155
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	5,407,137	5,667,848
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	2,699,998	1,893,826
5	Amortization of		
6			
7			
8	Deferred Income Taxes (Net)	2,719,985	1,726,970
9	Investment Tax Credit Adjustment (Net)		
10	Net (Increase) Decrease in Receivables	904,141	2,083,224
11	Net (Increase) Decrease in Inventory		
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-204,028	-10,601
14	Net (Increase) Decrease in Other Regulatory Assets		121,694
15	Net Increase (Decrease) in Other Regulatory Liabilities		
16	(Less) Allowance for Other Funds Used During Construction	617,665	1,254,832
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):	-81,613	-765,164
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	10,827,955	9,462,965
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-20,165,064	-29,376,417
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-617,665	-1,254,832
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-19,547,399	-28,121,585
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54			
55	Change in Cash Advances to Affiliates		10,724,323
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-19,547,399	-17,397,262
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Long Term Issuances Costs		-3,866
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68	Notes Payable to Associated Companies	8,719,444	1,638,163
69	Capital Contributions from Parent		6,300,000
70	Cash Provided by Outside Sources (Total 61 thru 69)	8,719,444	7,934,297
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock		
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	8,719,444	7,934,297
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)		
87			
88	Cash and Cash Equivalents at Beginning of Period		
89			
90	Cash and Cash Equivalents at End of period		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

Schedule Page: 120 Line No.: 18 Column: b

		2019 Cash Flow Incr / (Decr)		2018 Cash Flow Incr / (Decr)
Utility Plant, Net	$	(3,452)	$	(988)
Prepayments		(10,284)		(163)
Unamortized Debt Expense		20,091		20,323
Other Deferred Debits, Net		(236,802)		(234,891)
Unamortized Discount/Premium on Long-Term Debt		5,468		5,468
Current and Accrued Liabilities, Net		145,657		(557,301)
Other Deferred Credits, Net		(2,291)		2,388
Total	$	**(81,613)**	$	**(765,164)**

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

INDEX OF NOTES TO FINANCIAL STATEMENTS

GLOSSARY OF TERMS FOR NOTES

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

Term	Meaning
AEP	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and majority owned subsidiaries and affiliates.
AEP East Transmission Companies	APTCo, IMTCo, KTCo, OHTCo and WVTCo.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEP Texas	AEP Texas Inc., an AEP electric utility subsidiary.
AEP Transmission Holdco	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, hedging activities, asset management and commercial and industrial sales in deregulated markets.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEPTCo	AEP Transmission Company, LLC, and its consolidated State Transcos, a subsidiary of AEP Transmission Holdco.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APTCo	AEP Appalachian Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
ARAM	Average Rate Assumption Method, an IRS approved method used to calculate the reversal of Excess ADIT for ratemaking purposes.
ASU	Accounting Standards Update.
ATRR	Annual Transmission Revenue Requirement.
Excess ADIT	Excess accumulated deferred income taxes.
FASB	Financial Accounting Standards Board.
FERC	Federal Energy Regulatory Commission.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IMTCo	AEP Indiana Michigan Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
IRS	Internal Revenue Service.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KTCo	AEP Kentucky Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.

OATT	Open Access Transmission Tariff.
OHTCo	AEP Ohio Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
OKTCo	AEP Oklahoma Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PJM	Pennsylvania - New Jersey - Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
ROE	Return on equity.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SPP	Southwest Power Pool.
State Transcos	Wholly-owned AEPTCo transmission subsidiaries; APTCo, IMTCo, KTCo, OHTCo, OKTCo, SWTCo and WVTCo.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
SWTCo	AEP Southwestern Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
Tax Reform	On December 22, 2017, President Trump signed into law legislation referred to as the “Tax Cuts and Jobs Act” (the TCJA). The TCJA includes significant changes to the Internal Revenue Code of 1986, including a reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018.
Transource Energy	Transource Energy, LLC, a consolidated variable interest entity formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
WVTCo	AEP West Virginia Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

KTCo builds, owns and operates transmission facilities in Kentucky. KTCo is a member of PJM. AEPTCo owns all of KTCo's outstanding equity. Currently, all of KTCo's capital needs are provided by AEPTCo and the Utility Money Pool. AEPSC and other AEP subsidiaries provide services to KTCo through service agreements. KTCo does not have employees.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

KTCo's rates are regulated by the FERC. Historically, the FERC formula rates for KTCo were established each July based on prior calendar year's financial activity and projected plant balances. Effective January 1, 2017, KTCo implemented the modified PJM OATT formula rate calculation which establishes the annual FERC formula rates on a calendar year basis using the projected calendar year's financial activity and projected plant balances. Refer to Note 3 for additional information. The FERC also regulates KTCo's, AEPSC's and AEPTCo's affiliated transactions, including AEPSC's and AEPTCo's billings at cost under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over the issuances and acquisitions of securities of KTCo, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. The FERC is permitted to review and audit the relevant books and records of KTCo.

Basis of Accounting

KTCo's accounting is subject to the requirements of the KPSC and the FERC. The financial statements have been prepared in accordance with the Uniform System of Accounts prescribed by the FERC. The principal differences from GAAP include:

- The requirement to report deferred tax assets and liabilities separately rather than as a single amount.
- The classification of accrued taxes as a single amount rather than as assets and liabilities.
- The classification of accrued non-ARO asset removal costs as accumulated depreciation rather than regulatory liabilities.
- The classification of regulatory assets and liabilities related to the accounting guidance for "Accounting for Income Taxes" as separate assets and liabilities rather than as a single amount.
- The classification of certain nonoperating revenues as miscellaneous nonoperating income instead of as operating revenue.
- The classification of certain nonoperating expenses as miscellaneous nonoperating expense instead of as operating expense.
- The separate classification of income tax expense for operating and nonoperating activities instead of as a single income tax expense.
- The classification of certain other assets and liabilities as noncurrent instead of current.
- The classification of debt issuance costs as noncurrent assets instead of noncurrent liabilities.
- The classification of interest on regulated finance leases as Operating Expense instead of Other Income (Expense).

Accounting for the Effects of Cost-Based Regulation

As a rate-regulated entity, KTCo's financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. Under KTCo's formula rate mechanism and in accordance with accounting guidance for "Regulated Operations," KTCo records regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

Use of Estimates

The preparation of these financial statements requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include, but are not limited to, long-lived asset impairment, the effects of regulation, long-lived asset recovery and the effects of contingencies. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Supplementary Information

		2019		2018
For the Twelve Months Ended December 31,		**(in thousands)**		
Cash Was Paid (Received) for:				
Interest (Net of Capitalized Amounts)	$	1,511	$	1,292
Income Taxes (Net of Refunds)		(534)		254
As of December 31,				
Construction Expenditures Included in Current and Accrued Liabilities		3,127		2,555

Accounts Receivable

Accounts receivable primarily includes receivables from PJM based on the monthly allocation of the tariff rates that were authorized by FERC order and receivables for sales to miscellaneous customers.

Transmission Property

Transmission property is stated at original cost. Additions, major replacements and betterments are added to the property accounts. Under the group composite method of depreciation, continuous interim routine replacements of items such as poles, transformers, etc. result in original cost retirements, less salvage, being charged to accumulated depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. The depreciation rates that are established take into account the past history of interim capital replacements and the amount of salvage received. These rates and the related lives are subject to periodic review. Removal costs are charged to accumulated depreciation. The costs of labor, materials and overhead incurred to operate and maintain the transmission property is included in operation expenses.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held-for-sale criteria under the accounting guidance for “Impairment or Disposal of Long-Lived Assets.” When it becomes probable that an asset in service or an asset under construction will be abandoned and regulatory cost recovery has been disallowed, the cost of that asset shall be removed from plant-in-service or CWIP and charged to expense.

The fair value of an asset or investment is the amount at which that asset or investment could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets or investments in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Allowance for Funds Used During Construction (AFUDC)

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated transmission property.

Valuation of Nonderivative Financial Instruments

The book values of Notes Payable to Associated Companies, accounts receivable and accounts payable approximate fair value because of the short-term maturity of these instruments.

Fair Value Measurements of Assets and Liabilities

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2.

Revenue Recognition

Regulatory Accounting

KTCo's financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses or alternative revenues recognized in accordance with the guidance for "Regulated Operations") and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching revenue with its passage to customers in cost-based regulated rates.

When regulatory assets are probable of recovery through regulated rates, KTCo records them as assets on its balance sheets. KTCo tests for probability of recovery at each balance sheet date or whenever new events occur. Examples of new events include the issuance of a FERC order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, that regulatory asset is derecognized as a charge against income.

Transmission Revenue Accounting

Pursuant to an order approved by the FERC, the AEP East Transmission Companies are included in the OATT administered by PJM. The FERC order implemented an ATRR for each of the AEP East Transmission Companies. Under this requirement, AEPSC, on behalf of the AEP East Transmission Companies, makes annual filings in order to recover prudently incurred costs and an allowed return on plant in service. An annual formula rate filing is made for each calendar year using projected costs, which is used to determine the billings to PJM ratepayers. The annual rate filing is compared to actual costs with any over- or under-recovery being trued-up with interest and recovered in a future year's rates.

In accordance with the accounting guidance for "Regulated Operations-Revenue Recognition", KTCo recognizes revenue related to OATT rate true-ups immediately following the annual FERC filings. Any portion of the true-ups applicable to an affiliated company is recorded as Accounts Receivable from Associated Companies or Accounts Payable to Associated Companies on the balance sheets. Any portion of the true-ups applicable to third parties is recorded as Other Regulatory Assets or Other Regulatory Liabilities on the balance sheets.

Income Taxes

KTCo uses the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which the temporary differences are expected to be recovered or settled.

When the flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

KTCo accounts for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." KTCo classifies interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classifies penalties as Penalties on the statements of income.

Long-term Debt

Debt discount or premium and debt issuance expenses are deferred and amortized generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations. The net amortization expense is included in Amortization of Debt Discount and Expense.

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2019 through February 20, 2020, the date that AEP's Form 10-K was issued, and has updated such evaluation for disclosure purposes through April 17, 2020. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

Coronavirus Outbreak

AEP is responding to the global outbreak (pandemic) of the 2019 novel coronavirus (COVID 19) by taking steps to mitigate the potential risks posed by its spread. AEP provides a critical service to its customers which means that it must keep its employees who operate its businesses safe and minimize unnecessary risk of exposure to the virus. AEP has updated and implemented a company-wide pandemic plan to address specific aspects of the coronavirus pandemic. AEP informed both retail customers and state regulators that disconnections for non-payment will be temporarily suspended. This is a rapidly evolving situation that could lead to extended disruption of economic activity in AEP's markets. AEP has instituted measures to ensure its supply chain remains open; however, there could be global shortages that will impact AEP's maintenance and capital programs that AEP cannot currently estimate. AEP will continue to monitor developments affecting both its workforce and its customers, and will take additional precautions that are determined to be necessary in order to mitigate the impacts. AEP continues to implement strong physical and cyber security measures to ensure that its systems remain functional in order to both serve its operational needs with a remote workforce and keep them running to ensure uninterrupted service to customers. AEP will continue to review and modify its plans as conditions change. Extended disruption of economic activity in AEP's markets may result in accounting and disclosure implications for AEP; however, management cannot estimate the potential impact on AEP's financial statements or results of operations. If any of these costs are not recoverable or a significant write-down of assets occur it could reduce future net income and cash flows and impact financial condition.

2. NEW ACCOUNTING STANDARDS

During the FASB's standard-setting process and upon issuance of final standards, management reviews the new accounting literature to determine its relevance, if any, to KTCo's business. The following standards will impact KTCo's financial statements.

ASU 2016-02 "Accounting for Leases" (ASU 2016-02)

In February 2016, the FASB issued ASU 2016-02 increasing the transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheets and disclosing key information about leasing arrangements. Under the new standard, an entity must recognize an asset and liability for operating leases on the balance sheets. Additionally, capital leases are known as finance leases going forward. Leases with terms of 12 months or longer are also subject to the new requirements. Fundamentally, the criteria used to determine lease classification remains the same, but is more subjective under the new standard.

New leasing standard implementation activities included the identification of the lease population within the AEP System as well as the sampling of representative lease contracts to analyze accounting treatment under the new accounting guidance. Based upon the completed assessments, management also prepared a gap analysis to outline new disclosure compliance requirements.

Management adopted ASU 2016-02 effective January 1, 2019 by means of a cumulative-effect adjustment to the balance sheets. Management elected the following practical expedients upon adoption:

Practical Expedient	Description
Overall Expedients (for leases commenced prior to adoption date and must be adopted as a package)	Do not need to reassess whether any expired or existing contracts are/or contain leases, do not need to reassess the lease classification for any expired or existing leases and do not need to reassess initial direct costs for any existing leases.
Lease and Non-lease Components (elect by class of underlying asset)	Elect as an accounting policy to not separate non-lease components from lease components and instead account for each lease and associated non-lease component as a single lease component.
Short-term Lease (elect by class of underlying asset)	Elect as an accounting policy to not apply the recognition requirements to short-term leases.
Existing and expired land easements not previously accounted for as leases	Elect optional transition practical expedient to not evaluate under Topic 842 existing or expired land easements that were not previously accounted for as leases under the current leases guidance in Topic 840.
Cumulative-effect adjustment in the period of adoption	Elect the optional transition practical expedient to adopt the new lease requirements through a cumulative-effect adjustment on the balance sheets in the period of adoption.

Management concluded that the result of adoption would not materially change the volume of contracts that qualify as leases going forward. The adoption of the new standard did not materially impact results of operations, balance sheets or cash flows.

ASU 2016-13 "Measurement of Credit Losses on Financial Instruments" (ASU 2016-13)

In June 2016, the FASB issued ASU 2016-13 requiring the recognition of an allowance for expected credit losses for financial instruments within its scope. Examples of financial instruments that are in scope include trade receivables, certain financial guarantees, and held-to-maturity debt securities. The allowance for expected credit losses should be based on historical information, current conditions and reasonable and supportable forecasts. Entities are required to evaluate, and if necessary, recognize expected credit losses at the inception or initial acquisition of a financial instrument (or pool of financial instruments that share similar risk characteristics) subject to ASU 2016-13, and subsequently as of each reporting date. The new standard also revises the other-than-temporary impairment model for available-for-sale debt securities.

Management adopted ASU 2016-13 and its related implementation guidance effective January 1, 2020, by means of a cumulative-effect adjustment to the balance sheets. The adoption of the new standard did not have a material impact to financial position, and had no impact on the results of operations or cash flows. Additionally, the adoption of the new standard did not result in any changes to current accounting systems.

Implementation activities included: (1) the identification and evaluation of the population of financial instruments within the AEP system that are subject to the new standard and, (2) the development of supporting valuation models to also contemplate appropriate metrics for current and supportable forecasted information. As required by ASU 2016-13, the financial instruments subject to the new standard were evaluated on a pool-basis to the extent such financial instruments shared similar risk characteristics.

Management continues to develop disclosures to comply with the requirements of ASU 2016-13 that are required in the first quarter of 2020. Management will continue to monitor for any potential industry implementation issues.

3. RATE MATTERS

KTCo is involved in rate and regulatory proceedings at the FERC. This note discusses rate matters and related regulatory proceedings that could have a material effect on KTCo's results of operations, financial position and cash flows.

FERC Rate Matters

FERC Transmission Complaint

In 2016, seven parties filed a complaint at the FERC that alleged the base return on common equity used by AEP's transmission owning subsidiaries within PJM, including KTCo, in calculating formula transmission rates under the PJM OATT is excessive and should be reduced from 10.99% to 8.32%, effective upon the date of the complaint. In March 2018, AEP's transmission owning subsidiaries within PJM and six of the complainants filed a settlement agreement with the FERC (the seventh complainant abstained). The settlement agreement: (a) established a base ROE for AEP's transmission owning subsidiaries within PJM of 9.85% (10.35% inclusive of the RTO incentive adder of 0.5%), effective January 1, 2018, (b) required AEP's transmission owning subsidiaries within PJM to provide a one-time refund of $50 million, attributable from the date of the complaint through December 31, 2017, which was credited to customer bills in the second quarter of 2018 and (c) increased the cap on the equity portion of the capital structure to 55% from 50%. As part of the settlement agreement, AEP's transmission owning subsidiaries within PJM also filed updated transmission formula rates incorporating the reduction in the corporate federal income tax rate due to Tax Reform, effective January 1, 2018 and providing for the amortization of the portion of the excess accumulated deferred income taxes that are not subject to rate normalization requirements over a ten-year period through credits to the federal income tax expense component of the revenue requirement. In May 2019, the FERC approved the settlement agreement.

2016 and 2017 Transmission Rate Filings for AEP East Transmission Companies

The AEP East Transmission Companies, including KTCo, implemented a modified PJM OATT formula rate calculation which established the 2017 calendar year formula rates based on projected 2017 calendar year financial activity and projected plant balances. As accepted by the FERC, KTCo established 2017 calendar year rates based on a projected annual transmission revenue requirement of $10 million and refund of the remaining $101 thousand of 2015 over-recovered revenues included in its 2016 transmission rate filing. The new rates were effective January 2017, subject to refund and true up. In May 2017, AEPSC, on behalf of KTCo, filed its calendar year 2016 annual transmission revenue true up, consisting of an $813 thousand under-recovery of revenues excluding carrying charges, at the FERC and PJM. The 2016 and 2017 true-up of revenues, including carrying charges, were incorporated in the 2018 and 2019 projected transmission revenue requirements, respectively. If the FERC determines that any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Formula Rate

In 2017, AEP's eastern transmission subsidiaries, including KTCo, submitted its 2018 annual transmission revenue requirement with the FERC and PJM, which established the projected KTCo revenue requirement of $14 million. In April 2018, KTCo submitted a revised 2018 annual transmission revenue requirement with the FERC and PJM, which reduced the projected KTCo revenue requirement to $11 million, to reflect the lower federal income tax rate due to tax reform and the 206 settlement impact. The new rates were effective January 2018, subject to refund and true-up. The 2018 true-up of revenues were incorporated in the 2020 projected transmission revenue requirement.

In 2018, AEP's eastern transmission subsidiaries, including KTCo, submitted its 2019 annual transmission revenue requirement with the FERC and PJM. This filing established a projected KTCo revenue requirement of $14.3 million and will refund the remaining $351 thousand of 2017 over-recovered revenues included in its 2017 transmission rate filing. The new rates were effective January 2019, subject to refund and true-up. The 2019 true-up of revenues will be incorporated in the 2021 projected transmission revenue requirement.

In 2019, AEP's eastern transmission subsidiaries, including KTCo, submitted its 2020 annual transmission revenue requirement with the FERC and PJM. This filing established a projected KTCo revenue requirement of $15.2 million and will refund the remaining $1.4 million of 2018 over-recovered revenues included in its 2018 transmission rate filing. The new rates were effective January 2020, subject to refund and true-up.

FERC Transmission ROE Methodology

In November 2019, the FERC issued Opinion No. 569, which adopted a revised methodology for determining whether an existing base ROE is just and reasonable under Federal Power Act and determined the base ROE for Midwest Independent Transmission System Operator's (MISO) transmission-owning members should be reduced to 9.88% (10.38% inclusive of RTO incentive adder of 0.5%). The revised ROE methodology relies on two financial models, which include the discounted cash flow model and the capital asset pricing model, to establish a composite zone of reasonableness. In December 2019, AEP filed multiple requests for rehearing and participated in filing comments and requests for rehearing on behalf of transmission owners and industry organizations. Management believes FERC Opinion No. 569 reverses the expectation of a four-model framework proposed by FERC in 2018 and vetted widely in FERC 2019 Notice of Inquiry regarding base ROE policy. Management does not believe this ruling will have a material impact on financial results for its MISO transmission-owning subsidiaries. In the second quarter of 2019, FERC approved settlement agreements establishing base ROEs of 9.85% (10.35% inclusive of RTO incentive adder of 0.5%) and 10% (10.5% inclusive of RTO incentive adder of 0.5%) for AEP's PJM and SPP transmission-owning subsidiaries, respectively. If FERC makes any changes to its ROE and incentive policies, they would be applied to AEP's PJM and SPP transmission owning subsidiaries on a prospective basis, and could affect future net income and cash flows and impact financial condition.

4. EFFECTS OF REGULATION

Regulatory assets and liabilities are comprised of the following items:

Regulatory Assets:	December 31, 2019	December 31, 2018	Remaining Recovery Period
	(in thousands)		
Regulatory assets approved for recovery:			
Regulatory Assets Currently Not Earning a Return			
Income Tax Assets Subject to Flow Through	$ 1,381	$ 1,231	40 years
Total Regulatory Assets Currently Not Earning a Return	1,381	1,231	
Total Regulatory Assets Approved for Recovery	1,381	1,231	
Total FERC Account 182.3 Regulatory Assets	$ 1,381	$ 1,231	

Regulatory Liabilities:	December 31, 2019	December 31, 2018	Remaining Refund Period
	(in thousands)		
Regulatory liabilities approved for payment:			
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	$ 7,570	$ 7,652	(b)
Excess ADIT that is Not Subject to Rate Normalization Requirements	(186)	(186)	9 years
Total Income Tax Related Regulatory Liabilities	7,384	7,466	
Total Regulatory Liabilities Approved for Payment	7,384	7,466	
Total FERC Account 254 Regulatory Liabilities	$ 7,384	$ 7,466	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See "Federal Tax Reform" section of Note 7 for additional information.

(b) Refunded using ARAM.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

KTCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, KTCo's business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. KTCo accrues contingent liabilities only when management concludes that it is both probable that a liability has been incurred at the date of the financial statements and the amount of loss can be reasonably estimated. When management determines that it is not probable, but rather reasonably possible that a liability has been incurred at the date of the financial statements, KTCo discloses such contingencies and the possible loss or range of loss if such estimate can be made. Any estimated range is based on currently available information and involves elements of judgment and significant uncertainties. Any estimated range of possible loss may not represent the maximum possible loss exposure. Circumstances change over time and actual results may vary significantly from estimates.

For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements.

COMMITMENTS

IMTCo has construction commitments to support its operations and investments. In managing the overall construction program and in the normal course of business, AEPSC provides project development services and IMTCo contractually commits to third-party construction vendors for certain material purchases and other construction services. IMTCo purchases materials, supplies, services and property, plant and equipment under contract as part of its normal course of business. Certain supply contracts contain penalty provisions for early termination.

In accordance with the accounting guidance for "Commitments", IMTCo had no actual contractual commitments as of December 31, 2019.

GUARANTEES

Indemnifications

KTCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. As of December 31, 2019, there were no material liabilities recorded for any indemnifications.

CONTINGENCIES

Insurance and Potential Losses

KTCo maintains property insurance coverage normal and customary for an electric utility, subject to various deductibles. Insurance includes coverage for all risks of physical loss or damage to KTCo property, subject to insurance policy conditions and exclusions. Covered property generally includes substations, facilities and inventories. Excluded property generally includes transmission lines, poles and towers. KTCo's insurance program also generally provides coverage against loss arising from certain claims made by third parties in excess of retentions absorbed by KTCo. Coverage is generally provided by a combination of various industry mutual and/or commercial insurance carriers.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could reduce future net income and cash flows and impact financial condition.

6. FAIR VALUE MEASUREMENTS

Fair Value Measurements of Assets and Liabilities

The accounting guidance for “Fair Value Measurements and Disclosures” establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2.

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities classified as Level 2 measurement inputs. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book value and fair value of Long-term Debt are summarized in the following table:

	December 31, 2019		**December 31, 2018**	
	Book Value	**Fair Value**	**Book Value**	**Fair Value**
	(in thousands)			
Long-term Debt	$ 42,814	$ 47,374	$ 42,808	$ 40,702

7. INCOME TAXES

Income Tax Expense (Credit)

The details of KTCo's income taxes as reported are as follows:

	Years Ended December 31, 2019	2018
	(in thousands)	
Charged (Credited) to Operating Expenses, Net:		
Current	$ (1,056)	$ (123)
Deferred	2,739	1,713
Total	1,683	1,590
Charged (Credited) to Non-Operating Income, Net:		
Current	(25)	(1)
Deferred	(19)	14
Total	(44)	13
Total Income Taxes	$ 1,639	$ 1,603

The following is a reconciliation of the difference between the amount of federal income taxes computed by multiplying book income before income taxes by the federal statutory tax rate and the amount of income taxes reported:

	Years Ended December 31, 2019	2018
	(in thousands)	
Net Income	$ 5,407	$ 5,668
Income Tax Expense	1,639	1,603
Pretax Income	$ 7,046	$ 7,271
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 1,480	$ 1,527
Increase (Decrease) in Income Taxes Resulting from the Following Items:		
Depreciation	11	13
Allowance for Funds Used During Construction	(130)	(264)
State and Local Income Taxes, Net	277	358
Other	1	(31)
Income Tax Expense	$ 1,639	$ 1,603
Effective Income Tax Rate	23.3%	22.0%

The following table shows elements of KTCo's net deferred tax assets (liabilities) and significant temporary differences:

	December 31, 2019	2018
	(in thousands)	
Deferred Tax Assets	$ 2,185	$ 1,778
Deferred Tax Liabilities	(15,519)	(12,160)
Net Deferred Tax Liabilities	$ (13,334)	$ (10,382)
Property Related Temporary Differences	$ (13,980)	$ (11,058)
Amounts Due to Customers for Future Income Taxes	1,842	1,474
Deferred State Income Taxes	(1,253)	(552)
All Other, Net	57	(246)
Net Deferred Tax Liabilities	$ (13,334)	$ (10,382)

AEP System Tax Allocation Agreement

KTCo joins in the filing of a consolidated federal income tax return with its affiliates in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current tax expense. The consolidated net operating loss of the AEP System is allocated to each company in the consolidated group with taxable losses. The tax benefit of the Parent is allocated to its subsidiaries with taxable income. With the exception of the allocation of the consolidated AEP System net operating loss and the loss of the Parent and tax credits, the method of allocation reflects a separate return result for each company in the consolidated group.

Federal and State Income Tax Audit Status

KTCo and other AEP subsidiaries are no longer subject to U.S. federal examination by the IRS for all years through 2015. During the third quarter of 2019, AEP and subsidiaries elected to amend the 2014 and 2015 federal returns and as such the IRS may examine only the amended items on the 2014 and 2015 federal returns.

Federal Tax Reform and Legislation

The IRS has issued new regulations that provide guidance regarding the additional first-year depreciation deduction under Section 168(k). The proposed regulations reflect changes as a result of Tax Reform and affect taxpayers with qualified depreciable property acquired and placed in-service after September 27, 2017. Generally, KTCo's regulated utilities will not be eligible for any bonus depreciation for property acquired and placed in-service after December 31, 2017.

During the fourth quarter of 2018, the IRS proposed new regulations that reflect changes as a result of Tax Reform concerning potential limitations on the deduction of business interest expense. These regulations require an allocation of net interest expense between regulated and competitive businesses within the consolidated tax return. This allocation is based upon net tax basis, and the proposed regulations provide a de minimis test under which all interest is deductible if less than 10% is allocable to the competitive businesses. Management continues to review and evaluate the proposed regulations and at this time expect to be able to deduct materially all business interest expense under this de minimis provision.

State Tax Legislation

In April 2018, the Kentucky legislature enacted House Bill (H.B.) 487. H.B. 487 adopts mandatory unitary combined reporting for state corporate income tax purposes applicable for taxable years beginning on or after January 1, 2019. H.B. 487 also adopts the 80% federal net operating loss (NOL) limitation under Internal Revenue Code Section 172(a) for NOLs generated after January 1, 2018 and the federal unlimited carryforward period for unused NOLs generated after January 1, 2018. In addition, H.B. 366 was also enacted in April 2018, which among other things, replaces the graduated corporate tax rate structure with a flat 5% tax rate for business income and adopts a single-sales factor apportionment formula for apportioning a corporation's business income to Kentucky. In the second quarter of 2018, AEP consolidated recorded an $18 million benefit to Income Tax Expense as a result of remeasuring Kentucky deferred taxes under a unitary filing group. The enacted legislation did not materially impact KTCo's net income.

8. FINANCING ACTIVITIES

Long-term Debt

The following table details Long-term Debt outstanding as follows:

Type of Debt	Maturity	Weighted Average Interest Rate as of December 31, 2019	Interest Rate Ranges as of December 31, 2019	Interest Rate Ranges as of December 31, 2018	Outstanding as of December 31, 2019	Outstanding as of December 31, 2018
					(in thousands)	
Notes Payable - Affiliated	2025 - 2047	3.75%	3.10% - 4.05%	3.10% - 4.05%	$ 43,000	$ 43,000
Unamortized Discount, Net					(186)	(192)
Total Long-term Debt					$ 42,814	$ 42,808

Long-term Debt outstanding as of December 31, 2019 is payable as follows:

	(in thousands)
2020	$ —
2021	—
2022	—
2023	—
2024	—
After 2024	43,000
Principal Amount	43,000
Unamortized Discount, Net	(186)
Total Long-term Debt	$ 42,814

In April 2020, KTCo issued $21 million of Senior Unsecured Notes at an initial rate of 3.65% due in 2050.

Dividend Restrictions

KTCo pays dividends to AEPTCo provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of KTCo to transfer funds to AEPTCo in the form of dividends.

All of the dividends declared by KTCo are subject to a Federal Power Act restriction that prohibits the payment of dividends out of capital accounts without regulatory approval; payment of dividends is allowed out of retained earnings only.

The most restrictive dividend limitation for KTCo is through the Federal Power Act restriction. As of December 31, 2019, the maximum amount of restricted net assets of KTCo that may not be distributed to the AEPTCo in the form of a loan, advance or dividend was $40.7 million.

Corporate Borrowing Program

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC.

KTCo's amounts of outstanding borrowings from the Utility Money Pool as of December 31, 2019 and 2018 are included in Notes Payable to Associated Companies on the balance sheets. KTCo's money pool activity and its corresponding authorized borrowing limits are described in the following table:

Years Ended December 31,	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Borrowings from the Utility Money Pool	Authorized Short-term Borrowing Limit
	(in thousands)					
2019	$ 11,811	$ —	$ 6,760	$ —	$ 10,358	$ 75,000
2018	2,225	12,266	1,194	5,717	1,638	75,000

Maximum, minimum and average interest rates for funds borrowed from and loaned to the Utility Money Pool were as follows:

Years Ended December 31,	Maximum Interest Rate for Funds Borrowed from the Utility Money Pool	Minimum Interest Rate for Funds Borrowed from the Utility Money Pool	Maximum Interest Rate for Funds Loaned to the Utility Money Pool	Minimum Interest Rate for Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2019	3.43%	1.77%	—%	—%	2.41%	—%
2018	2.97%	2.00%	2.52%	1.81%	2.47%	2.18%

Interest expense and interest income related to the direct financing relationship to the Utility Money Pool are included in Interest on Debt to Associated Companies and Interest and Dividend Income, respectively, on IMTCo's statements of income. For amounts borrowed from and advanced to the Utility Money Pool, IMTCo incurred the following amounts of interest expense and earned the following amounts of interest income:

	Years Ended December 31,	
	2019	2018
	(in thousands)	
Interest Expense	$ 165	$ 5
Interest Income	—	105

9. RELATED PARTY TRANSACTIONS

For other related party transactions, also see “AEP System Tax Allocation Agreement” section of Note 7 in addition to “Corporate Borrowing Program” section of Note 8.

Affiliated Transmission Revenues

For the years ended December 31, 2019 and 2018, subsidiaries of AEP that are load serving entities within the PJM region incurred $10.5 million and $8.9 million, respectively, in PJM transmission services related to KTCo that were billed to them in accordance with the OATT and Transmission Agreement. KTCo recorded these affiliated transmission revenues in Operating Revenues.

Services Provided by AEP Subsidiaries

AEPSC provides certain managerial and professional services to AEP’s subsidiaries. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEPSC and its billings are subject to regulation by the FERC.

Other AEP subsidiaries perform certain transmission services for each other when necessary or practical. The costs of these services are billed on a direct-charge basis, whenever possible, or on reasonable basis of proration for services that benefit multiple companies. The billings for services are made at cost and included no compensation for the use of equity capital.

KTCo’s net billings from AEP's subsidiaries were as follows:

	Years Ended December 31,	
Billing Company	**2019**	**2018**
AEP Texas	$ 3	$ 41
AEPEP	1	—
AEPSC	3,210	4,873
APCo	21	(116)
I&M	1	5
KPCo	356	186
OHTCo	12	2
OPCo	100	158
Parent	4	—
PSO	1	—
SWEPCo	(6)	1
Transource Energy	2	1
WVTCo	(1)	—

Purchases of Property

KTCo purchased $222 thousand of transmission property at book value from KPCo during the year ended December 31, 2019. There were no gains or losses recorded on this transaction.

Joint License Agreement

In February 2011, KTCo and KPCo entered into a 50-year joint license agreement allowing either party to occupy the granting party’s facilities or real property. After the expiration of the agreement, the term shall automatically renew for successive one-year terms unless either party provides notice. The joint license billing provides compensation to the granting party for the cost of carrying assets, including depreciation expense, property taxes, interest expense, ROE and income taxes. KTCo recorded costs of $297 thousand and $227 thousand in Operation Expenses for the years ended December 31, 2019 and 2018, respectively.

10. TRANSMISSION PROPERTY

Depreciation

KTCo provides for depreciation of Transmission Property on a straight-line basis over the estimated useful lives of property. KTCo's composite depreciation rates were as follows:

	2019	**2018**
Transmission Property	2.05%	1.60%

Asset Retirement Obligations (ARO)

KTCo has identified, but not recognized, ARO liabilities related to electric transmission assets, as a result of certain easements on property on which assets are owned. Generally, such easements are perpetual and require only the retirement and removal of assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since KTCo plans to use its facilities indefinitely. The retirement obligation would only be recognized if and when KTCo abandons or ceases the use of specific easements, which is not expected.

11. REVENUE FROM CONTRACTS WITH CUSTOMERS

Disaggregated Revenues from Contracts with Customers

KTCo's statements of income represent revenues from contracts with customers by type of revenue. KTCo had $(959) thousand and $(733) thousand of alternative revenues for the years ended December 31, 2019 and 2018, respectively.

Performance Obligations

KTCo has performance obligations as part of its normal course of business. A performance obligation is a promise to transfer a distinct good or service, or a series of distinct goods or services that are substantially the same and have the same pattern of transfer to a customer. The invoice practical expedient within the accounting guidance for "Revenue from Contracts with Customers" allows for the recognition of revenue from performance obligations in the amount of consideration to which there is a right to invoice the customer and when the amount for which there is a right to invoice corresponds directly to the value transferred to the customer.

The purpose of the invoice practical expedient is to depict an entity's measure of progress toward completion of the performance obligation within a contract and can only be applied to performance obligations that are satisfied over time and when the invoice is representative of services provided to date. KTCo elected to apply the invoice practical expedient to recognize revenue for performance obligations satisfied over time as the invoices from the respective revenue streams are representative of services or goods provided to date to the customer. Performance obligations for KTCo are summarized as follows:

Wholesale Revenues - Transmission

KTCo has performance obligations to transmit electricity to wholesale customers through assets owned and operated by KTCo and other AEP subsidiaries. The performance obligation of KTCo to provide transmission services to PJM encompasses a time frame greater than a year. Payments from PJM for transmission services are typically received within one week from the issuance of the invoice, which is issued weekly.

KTCo collects revenues through Transmission Formula Rates charged to affiliates and nonaffiliates. The FERC-approved rates establish the ATRR and transmission service rates for transmission owners. The formula rates establish rates for a one year period and also include a true-up calculation for the prior year's billings, allowing for over/under-recovery of the transmission owner's ATRR. The annual true-ups meet the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations."

Fixed Performance Obligations

The following table represents KTCo's remaining fixed performance obligations satisfied over time as of December 31, 2019. Fixed performance obligations primarily include wholesale transmission services. The amounts below include affiliated and nonaffiliated revenues.

2020	2021-2022	2023-2024	After 2024	Total
		(in thousands)		
$ 13,491	$ —	$ —	$ —	$ 13,491

Contract Assets and Liabilities

Contract assets are recognized when KTCo has a right to consideration that is conditional upon the occurrence of an event other than the passage of time, such as future performance under a contract. KTCo did not have any material contract assets as of December 31, 2019 and 2018.

When KTCo receives consideration, or such consideration is unconditionally due from a customer prior to transferring goods or services to the customer under the terms of a sales contract, they recognize a contract liability on the balance sheet in the amount of that consideration. Revenue for such consideration is subsequently recognized in the period or periods in which the remaining performance obligations in the contract are satisfied. KTCo did not have any material contract liabilities as of December 31, 2019 and 2018.

Accounts Receivable from Contracts with Customers

Accounts receivable from contracts with customers are presented on KTCo's balance sheets within the Customer Accounts Receivable. KTCo's balances for receivables from contracts that are not recognized in accordance with the accounting guidance for "Revenue from Contracts with Customers" included in Customer Accounts Receivable were not material as of December 31, 2019 and 2018.

Amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable from Associated Companies on KTCo's balance sheets were $963 thousand and $793 thousand, respectively, as of December 31, 2019 and 2018.

Name of Respondent AEP Kentucky Transmission Company, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2019/Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)				
5	Balance of Account 219 at End of Preceding Quarter/Year				
6	Balance of Account 219 at Beginning of Current Year				
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				
10	Balance of Account 219 at End of Current Quarter/Year				

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1					
2					
3					
4				5,667,848	5,667,848
5					
6					
7					
8					
9				5,407,137	5,407,137
10					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	82,533,535	82,533,535
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	42,083,051	42,083,051
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	124,616,586	124,616,586
9	Leased to Others		
10	Held for Future Use		
11	Construction Work in Progress	17,135,182	17,135,182
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	141,751,768	141,751,768
14	Accum Prov for Depr, Amort, & Depl	6,932,886	6,932,886
15	Net Utility Plant (13 less 14)	134,818,882	134,818,882
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	6,487,500	6,487,500
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	445,386	445,386
22	Total In Service (18 thru 21)	6,932,886	6,932,886
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	6,932,886	6,932,886

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
					15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication		
3	Nuclear Materials		
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)		
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)		
10	SUBTOTAL (Total 8 & 9)		
11	Spent Nuclear Fuel (120.4)		
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)		
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)		
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents		
4	(303) Miscellaneous Intangible Plant	966,664	453,010
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	966,664	453,010
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights		
9	(311) Structures and Improvements		
10	(312) Boiler Plant Equipment		
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units		
13	(315) Accessory Electric Equipment		
14	(316) Misc. Power Plant Equipment		
15	(317) Asset Retirement Costs for Steam Production		
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)		
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power PLant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)		
36	D. Other Production Plant		
37	(340) Land and Land Rights		
38	(341) Structures and Improvements		
39	(342) Fuel Holders, Products, and Accessories		
40	(343) Prime Movers		
41	(344) Generators		
42	(345) Accessory Electric Equipment		
43	(346) Misc. Power Plant Equipment		
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)		
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)		

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	-35,497	380
49	(352) Structures and Improvements	3,338,680	67,615
50	(353) Station Equipment	105,351,606	1,625,709
51	(354) Towers and Fixtures		
52	(355) Poles and Fixtures		59,129
53	(356) Overhead Conductors and Devices	221,178	10,483,918
54	(357) Underground Conduit	700,240	562,492
55	(358) Underground Conductors and Devices	572	403,336
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	109,576,779	13,202,579
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights		
61	(361) Structures and Improvements		
62	(362) Station Equipment		
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures		
65	(365) Overhead Conductors and Devices		
66	(366) Underground Conduit		
67	(367) Underground Conductors and Devices		
68	(368) Line Transformers		
69	(369) Services		
70	(370) Meters		
71	(371) Installations on Customer Premises		
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems		
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)		
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights		
87	(390) Structures and Improvements		
88	(391) Office Furniture and Equipment		
89	(392) Transportation Equipment		
90	(393) Stores Equipment		
91	(394) Tools, Shop and Garage Equipment		
92	(395) Laboratory Equipment		
93	(396) Power Operated Equipment		
94	(397) Communication Equipment	34,942	1,423
95	(398) Miscellaneous Equipment		
96	SUBTOTAL (Enter Total of lines 86 thru 95)	34,942	1,423
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	34,942	1,423
100	TOTAL (Accounts 101 and 106)	110,578,385	13,657,012
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	110,578,385	13,657,012

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
					3
			1,419,674		4
			1,419,674		5
					6
					7
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ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
		677,976	642,859		48
			3,406,295		49
296,787			106,680,528		50
					51
			59,129		52
			10,705,096		53
			1,262,732		54
			403,908		55
					56
					57
296,787		677,976	123,160,547		58
					59
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			36,365		94
					95
			36,365		96
					97
					98
			36,365		99
296,787		677,976	124,616,586		100
					101
					102
					103
296,787		677,976	124,616,586		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
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46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
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21	Other Property:			
22				
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44				
45				
46				
47	Total			0

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Pikeville Kentucky Transco SC	13,235,397
2	KYTransCo Sta/Line Failures	1,056,862
3	T/KYTC/TransCo Work	1,293,908
4	Other Minor Projects Which is under 5% or $1,000,000	1,549,015
5		
6		
7		
8		
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43	TOTAL	17,135,182

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	4,275,660	4,275,660		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	2,512,078	2,512,078		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	2,512,078	2,512,078		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	296,787	296,787		
13	Cost of Removal	3,451	3,451		
14	Salvage (Credit)				
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	300,238	300,238		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	6,487,500	6,487,500		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production				
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production				
25	Transmission	6,485,001	6,485,001		
26	Distribution				
27	Regional Transmission and Market Operation				
28	General	2,499	2,499		
29	TOTAL (Enter Total of lines 20 thru 28)	6,487,500	6,487,500		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

Schedule Page: 219 Line No.: 13 Column: c

Includes $132 of removal cost in retirement work in progress (RWIP).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1				
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41				
42	Total Cost of Account 123.1 $ 0		TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
				2
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)			
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)			
8	Transmission Plant (Estimated)			
9	Distribution Plant (Estimated)			
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)			
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)			
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2020 No. (d)	2020 Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2021		2022		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
								1
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2020 No. (d)	2020 Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2021		2022		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
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								46

Name of Respondent AEP Kentucky Transmission Company, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2019/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
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19						
20	TOTAL					

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
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48						
49	TOTAL					

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
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21	**Generation Studies**				
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40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets	Balance at Beginning of Current Quarter/Year	Debits	CREDITS Written off During the Quarter/Year Account Charged	CREDITS Written off During the Period Amount	Balance at end of Current Quarter/Year
	(a)	(b)	(c)	(d)	(e)	(f)
1	SFAS 109 Deferred FIT	1,230,677	180,239	282/283	29,981	1,380,935
2						
3						
4						
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44	TOTAL	1,230,677	180,239		29,981	1,380,935

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Deferred Property Taxes	325,000	592,000		325,000	592,000
2						
3	Unamortized Credit Line Fees	124,895		431	52,460	72,435
4	Amortized thru June 2022					
5						
6	Billings and Deferred Projects	44,313	38,801	Footnote	15,122	67,992
7						
8	S-3 Filing Fees	3,305		431	1,417	1,888
9						
10						
11						
12						
13						
14						
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46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	497,513				734,315

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

Schedule Page: 233 Line No.: 6 Column: d

146,426,500,107,163,421

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Provision for Refunds	-14,853	14,403
3	Accrued Book Removal Cost	17,243	2,105
4	DFIT on DSIT	276,981	333,173
5	NOL-State C/F DEF State Tax Asset	25,138	-25,612
6			
7	Other	1	
8	TOTAL Electric (Enter Total of lines 2 thru 7)	304,510	324,069
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Non Utility)	1,473,732	1,861,036
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	1,778,242	2,185,105

Notes

Line 17 Other - Detail	Balance at Beginning of Year	Balance at End of Year
Acc Def Income Taxes		
Non Utility Items-190.2	-	19,365
Sfas 109-Regulatory Assets - 190.3&190.4	1,473,732	1,841,671
Accu Def Income Taxes Pension-OCT		
Total	$1,473,732	$1,861,036

Line 18
Reconciliation of details applicable to Account 190, Line 18, Columns (b) and (c) :

Balance at Beginning of Year	$1,778,242
(Less) Amounts Debited to:	
(a) Account 410.1	(140,267)
(b) Account 410.2	(15,851)
(c) Various	2,479,384
(Plus) Amounts Credited to:	
(a) Account 411.1	159,824
(b) Account 411.2	35,215
(c) Various	(2,111,442)
Balance at End of Year	$2,185,105

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT AS REACQUIRED STOCK (Account 217)		HELD BY RESPONDENT IN SINKING AND OTHER FUNDS		Line No.
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
						2
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						4
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.
(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Account #208 - Donations received from stockholders	
2	Capital Contributions from Parent prior to 2019	40,707,500
3	Capital Contributions from Parent in 2019	
4	Subtotal - Account 208	40,707,500
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40	TOTAL	40,707,500

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1		
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21		
22	TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 221 - None		
2			
3	Account 222 - None		
4			
5	Account 223		
6	Notes Payable Affiliated from AEP Transmission Company, LLC		
7	Senior Notes, Series C, Tranche H, 4.05%	4,000,000	16,785
8	Senior Notes, Series C, Tranche D, 3.66%	5,000,000	20,377
9	Senior Notes, Series C, Tranche E, 3.76%	2,000,000	8,105
10	Senior Notes, Series C, Tranche G, 4.01%	3,000,000	12,157
11	Senior Notes, Series D, Tranche G 3.10%	4,000,000	42,965
12			7,880 D
13	Senior Notes, Series E, Tranche G 4.00%	12,000,000	128,894
14			198,120 D
15	Senior Notes, Series D 3.10%	3,000,000	31,884
16			-24,960 P
17	Senior Notes, Series H 3.75%	10,000,000	106,261
18			24,100 D
19	Subtotal Account 223	43,000,000	572,568
20			
21	Account 224 - None		
22			
23			
24	Account 224 - None		
25			
26			
27			
28			
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31			
32			
33	TOTAL	43,000,000	572,568

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
						4
						5
						6
11/14/14	11/14/34	11/14/14	11/14/34	4,000,000	162,000	7
3/16/15	3/16/25	3/16/15	3/16/25	5,000,000	183,000	8
6/15/15	6/15/25	6/15/15	6/15/25	2,000,000	120,300	9
6/15/15	6/15/30	6/15/15	6/15/30	3,000,000	75,200	10
11/21/16	12/21/26	11/21/16	12/21/26	4,000,000	124,000	11
						12
11/21/16	12/1/46	11/21/16	12/1/46	12,000,000	480,000	13
						14
09/28/2017	12/1/2026	09/28/2017	12/1/2026	3,000,000	93,000	15
						16
9/28/2017	12/1/2047	08/28/2017	12/1/2047	10,000,000	375,000	17
						18
				43,000,000	1,612,500	19
						20
						21
						22
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						32
				43,000,000	1,612,500	33

Schedule Page: 256 Line No.: 19 Column: i

The difference between the total interest on this schedule and the total of account 430 is due to interest on short-term advances from the AEP Money Pool.

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	5,407,137
2		
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	3,656,307
28	Show Computation of Tax:	
29		
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

Schedule Page: 261 Line No.: 28 Column: b

FOOTNOTE DATA

Schedule Page: 261 Line No.: 28 Column: b

		in $ 000's
Net Income for the Year per Page 117		5,407
Federal Income Taxes		1,287
State Income Taxes		351
Pre-Tax Book Income		7,045
AFUDC Interest/ Capitalized		(443)
Excess Tax vs Book Depreciation		(2,823)
Provsion for Revenue Refund		139
Charitable Contribution Carryforward		0
Capitalized Software		0
Other		(253)
Taxable Income before State Taxes		3,665
State & Local Current Tax		8
Federal Taxable Income		3,657
FIT on Current Year Taxable Income		768
Adjustment due to System Consolidation	(a)	-
NOL Deferred Tax Asset		-
Tax Credits		(25)
Audit Settlement Adjustments		-
Alt Min		-
Tax Provision Adjustments		-
Estimated Tax Currently Payable	(b)	743
Adjustments of Prior Year's Accruals		(1,857)
Tax Expense for R/C of Net Operating Loss (Prior Yr)		
Estimated Current Federal Income Taxes		(1,114)

Foot Notes:
(a) Represents the allocation of estimated current year net operating tax loss of American Electric Power Company, Inc.
(b) The Company joins in the filing of a consolidated Federal income tax return with its affiliated companies in the AEP system.
The allocation of the AEP System's consolidated Federal income tax to the System companies allocates the benefit of the current tax losses to the System companies giving rise to them in determining their current tax expense. The tax loss of the System parent company, American Electric Power Company, Inc. is allocated to its subisidiares with taxable income. With exception of the loss of the parent company, the method of allocation approximates a separate return result for each company in the consolidating group.
Instruction 2.
* The tax computation above represents an estimate of the Company's allocated portion of the System consolidated Federal Income Tax.
The computation of actual 2019 System Federal income taxes will not be available until the consolidated

Name of Respondent AEP Kentucky Transmission Company, Inc.	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2019/Q4

FOOTNOTE DATA

Federal Income tax return is filed by October 2020.The actual allocation of the System consolidated Federal income tax to the members of the consolidated group will not be available until after the Consolidated Federal Income Tax Return is filed.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year	Taxes Paid During Year	Adjust- ments
		Taxes Accrued (Account 236)	Prepaid Taxes (Include in Account 165)			
	(a)	(b)	(c)	(d)	(e)	(f)
1	Federal Income	-532,180		-1,113,886	-548,279	
2	FIN 48					
3	State of Kentucky					
4	Income 2015					
5	2016	-540				
6	2017	-83,650				
7	2018				14,518	
8	2019			32,408		
9	Franchise 2017	175				
10	2018	175			175	
11	2019			175		
12	State Lic/Registration Fee					
13	KY ST License Fee 2019			15	15	
14						
15	Real & Personal Property Tax					
16	2017	145,300		45,023	190,323	
17	2018	325,000				
18	2019			592,000		
19						
20	Use Tax - 2017					
21	Use Tax - 2018	4,993		339	5,332	
22	Use Tax -2019			15,372	15,372	
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	-140,727		-428,554	-322,544	

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
-1,097,787		-1,091,087			-22,799	1
						2
						3
						4
-540						5
-83,650						6
-14,518						7
32,408		34,401			-1,993	8
175						9
						10
175		175				11
						12
					15	13
						14
						15
		45,023				16
325,000		206,700			-206,700	17
592,000					592,000	18
						19
						20
					339	21
					15,372	22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
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						40
-246,737		-804,788			376,234	41

Name of Respondent AEP Kentucky Transmission Company, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2019/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6							
7							
8	TOTAL						
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
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48							

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
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			14
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			32
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			43
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			45
			46
			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Green Hat Default	2,388	566	2,291		97
2						
3						
4						
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6						
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8						
9						
10						
11						
12						
13						
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43						
44						
45						
46						
47	TOTAL	2,388		2,291		97

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)			
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS						
		Debits		Credits				
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
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							14
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							19
							20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	15,832,962	11,806,576	8,922,846
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	15,832,962	11,806,576	8,922,846
6	SFAS109	-4,774,671		
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	11,058,291	11,806,576	8,922,846
10	Classification of TOTAL			
11	Federal Income Tax	11,058,291	11,806,576	8,922,846
12	State Income Tax			
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS						
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits: Account Credited (g)	Debits: Amount (h)	Credits: Account Debited (i)	Credits: Amount (j)	Balance at End of Year (k)	Line No.
							1
						18,716,692	2
							3
							4
						18,716,692	5
		1823/ 254	6,667,877	1823/ 254	6,407,033	-5,035,515	6
							7
							8
			6,667,877		6,407,033	13,681,177	9
							10
			6,667,877		6,407,033	13,681,177	11
							12
							13

NOTES (Continued)

Name of Respondent AEP Kentucky Transmission Company, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2019/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Reg Asset-Pre-Formation Costs			
4	DSIT	1,318,959	386,630	119,053
5	Federal DFIT on State NOL Cfwd	5,279		5,279
6	Excess ADIT - Unprotected	-236,120	731,919	1,113,572
7	Other		-1	5,468
8				
9	TOTAL Electric (Total of lines 3 thru 8)	1,088,118	1,118,548	1,243,372
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	SFAS 109	13,497		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	1,101,615	1,118,548	1,243,372
20	Classification of TOTAL			
21	Federal Income Tax	-217,344	731,918	1,124,319
22	State Income Tax	1,318,959	386,630	119,053
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS						
		Debits		Credits				
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
						1,586,536	4
							5
						-617,773	6
						-5,469	7
							8
						963,294	9
							10
							11
							12
							13
							14
							15
							16
							17
		1823/ 25	738,215	1823/ 25	1,599,236	874,518	18
			738,215		1,599,236	1,837,812	19
							20
			738,215		1,599,235	251,275	21
						1,586,536	22
							23

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	SFAS 109 DEFERRED FIT	7,465,583	See footnote	9,937,473	9,855,494	7,383,604
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
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27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	7,465,583		9,937,473	9,855,494	7,383,604

Name of Respondent AEP Kentucky Transmission Company, Inc.	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2019/Q4

FOOTNOTE DATA

Schedule Page: 278 Line No.: 1 Column: c

190.4
282.4
283.4

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales		
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)		
5	Large (or Ind.) (See Instr. 4)		
6	(444) Public Street and Highway Lighting		
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers		
11	(447) Sales for Resale		
12	TOTAL Sales of Electricity		
13	(Less) (449.1) Provision for Rate Refunds	1,295,306	754,911
14	TOTAL Revenues Net of Prov. for Refunds	-1,295,306	-754,911
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues		
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property		
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues		
22	(456.1) Revenues from Transmission of Electricity of Others	14,292,429	11,755,394
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	14,292,429	11,755,394
27	TOTAL Electric Operating Revenues	12,997,123	11,000,483

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
				2
				3
				4
				5
				6
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				10
				11
				12
				13
				14

Line 12, column (b) includes $ 0 of unbilled revenues.
Line 12, column (d) includes 0 MWH relating to unbilled revenues

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

Schedule Page: 300 Line No.: 22 Column: b

See Page 328 for Revenue details

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
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36					
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38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
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16						
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28						
29						
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33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
				0	0	0
				0	0	0
				0	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
0	0	0	0	0	
0	**0**	**0**	**0**	**0**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering		
5	(501) Fuel		
6	(502) Steam Expenses		
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses		
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)		
14	Maintenance		
15	(510) Maintenance Supervision and Engineering		
16	(511) Maintenance of Structures		
17	(512) Maintenance of Boiler Plant		
18	(513) Maintenance of Electric Plant		
19	(514) Maintenance of Miscellaneous Steam Plant		
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)		
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)		
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel		
64	(548) Generation Expenses		
65	(549) Miscellaneous Other Power Generation Expenses		
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)		
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)		
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)		
75	E. Other Power Supply Expenses		
76	(555) Purchased Power		
77	(556) System Control and Load Dispatching		
78	(557) Other Expenses		
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)		
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)		
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	660,089	469,271
84			
85	(561.1) Load Dispatch-Reliability		4
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	94,916	72,204
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	16,073	9,795
90	(561.6) Transmission Service Studies		1
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	36,536	22,917
94	(563) Overhead Lines Expenses	4,596	5,725
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others		
97	(566) Miscellaneous Transmission Expenses	181,089	198,355
98	(567) Rents	297,459	227,492
99	TOTAL Operation (Enter Total of lines 83 thru 98)	1,290,758	1,005,764
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	8,288	5,821
102	(569) Maintenance of Structures	2,016	1,458
103	(569.1) Maintenance of Computer Hardware	1,616	1,419
104	(569.2) Maintenance of Computer Software	28,815	24,200
105	(569.3) Maintenance of Communication Equipment	5,838	1,302
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	46,324	47,782
108	(571) Maintenance of Overhead Lines	1,046	1,673
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	25,412	14,914
111	TOTAL Maintenance (Total of lines 101 thru 110)	119,355	98,569
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	1,410,113	1,104,333

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering		
135	(581) Load Dispatching		
136	(582) Station Expenses		
137	(583) Overhead Line Expenses		
138	(584) Underground Line Expenses		
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses		
141	(587) Customer Installations Expenses		
142	(588) Miscellaneous Expenses		
143	(589) Rents		
144	TOTAL Operation (Enter Total of lines 134 thru 143)		
145	Maintenance		
146	(590) Maintenance Supervision and Engineering		
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment		
149	(593) Maintenance of Overhead Lines		
150	(594) Maintenance of Underground Lines		
151	(595) Maintenance of Line Transformers		
152	(596) Maintenance of Street Lighting and Signal Systems		
153	(597) Maintenance of Meters		
154	(598) Maintenance of Miscellaneous Distribution Plant		
155	TOTAL Maintenance (Total of lines 146 thru 154)		
156	TOTAL Distribution Expenses (Total of lines 144 and 155)		
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses		
161	(903) Customer Records and Collection Expenses		
162	(904) Uncollectible Accounts		
163	(905) Miscellaneous Customer Accounts Expenses		
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses		
169	(909) Informational and Instructional Expenses		
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)		
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)		
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	314,777	291,895
182	(921) Office Supplies and Expenses	24,750	15,093
183	(Less) (922) Administrative Expenses Transferred-Credit	-171	
184	(923) Outside Services Employed	58,336	264,018
185	(924) Property Insurance	35,865	24,807
186	(925) Injuries and Damages	8,242	6,224
187	(926) Employee Pensions and Benefits	610	993
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	3,857	3,404
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	81	80
192	(930.2) Miscellaneous General Expenses	8,125	7,901
193	(931) Rents	322	328
194	TOTAL Operation (Enter Total of lines 181 thru 193)	455,136	614,743
195	Maintenance		
196	(935) Maintenance of General Plant	22	3
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	455,158	614,746
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,865,271	1,719,079

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

Name of Respondent AEP Kentucky Transmission Company, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2019/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	PJM			FNO
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent AEP Kentucky Transmission Company, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2019/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
PJMOATT						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	**0**	**0**	

Name of Respondent AEP Kentucky Transmission Company, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2019/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
		14,292,429	14,292,429	1
				2
				3
				4
				5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
0	**0**	**14,292,429**	**14,292,429**	

Name of Respondent AEP Kentucky Transmission Company, Inc.	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2019/Q4

FOOTNOTE DATA

Schedule Page: 328 Line No.: 1 Column: m

Revenue earned from PJM per the revenue requirement for transmission services filed with FERC.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
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37					
38					
39					
40	TOTAL				

Name of Respondent AEP Kentucky Transmission Company, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2019/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	TRANSFER OF ENERGY Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	1,455
6	Corporate Memberships	3,907
7	Travel Expenses	2,265
8	Trustee Fees	498
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
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46	TOTAL	8,125

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			187,920		187,920
2	Steam Production Plant					
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant					
7	Transmission Plant	2,510,066				2,510,066
8	Distribution Plant					
9	Regional Transmission and Market Operation					
10	General Plant	2,012				2,012
11	Common Plant-Electric					
12	TOTAL	2,512,078		187,920		2,699,998

B. Basis for Amortization Charges

Section A Line 1 Column D represents amortization of capitalized software development costs over a 5 year life and costs associated with the Oracle strategic partnership which are over a 10 year life.

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	TRANSMISSION						
13	350 (Rights)	-35					
14	352	3,401					
15	353	105,591					
16	353.16	103					
17	356	1,264					
18	356.16	9,353					
19	357	1,257					
20	358.16	401					
21	TOTAL TRANSMISSION	121,335					
22							
23	GENERAL PLANT						
24	397	36					
25	TOTAL GENERAL PLANT	36					
26							
27	DEPRECIABLE SUM	121,371					
28							
29							
30							
31							
32							
33							
34							
35							
36							
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

Schedule Page: 336 Line No.: 27 Column: b

The depreciable plant base is the November 30, 2019 total company depreciable plant.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Minor items < 25,000		3,857	3,857	
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
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46	TOTAL		3,857	3,857	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
	928	3,857					1
							2
							3
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							45
		3,857					46

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
 (1) Generation
  a. hydroelectric
   i. Recreation fish and wildlife
   ii Other hydroelectric
  b. Fossil-fuel steam
  c. Internal combustion or gas turbine
  d. Nuclear
  e. Unconventional generation
  f. Siting and heat rejection
 (2) Transmission
  a. Overhead
  b. Underground
 (3) Distribution
 (4) Regional Transmission and Market Operation
 (5) Environment (other than equipment)
 (6) Other (Classify and include items in excess of $50,000.)
 (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
 (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	A(6): Other	3 items under $50,000
2		
3	B: Electric, R, D & D Performed Externally	1 item under $50,000
4		
5	B(1): Research support to the electrical	8 items under $50,000
6	Research Council or the Electric	
7	Power Research Institute	
8		
9	B(4): R&D Support to Others (Classify)	2 item under $50,000
10		
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12		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
749		566	749		1
					2
	161	566	161		3
					4
	977	566	977		5
					6
					7
					8
	837	566	837		9
					10
					11
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Name of Respondent AEP Kentucky Transmission Company, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2019/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production			
4	Transmission			
5	Regional Market			
6	Distribution			
7	Customer Accounts			
8	Customer Service and Informational			
9	Sales			
10	Administrative and General			
11	TOTAL Operation (Enter Total of lines 3 thru 10)			
12	Maintenance			
13	Production			
14	Transmission			
15	Regional Market			
16	Distribution			
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)			
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)			
21	Transmission (Enter Total of lines 4 and 14)			
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)			
24	Customer Accounts (Transcribe from line 7)			
25	Customer Service and Informational (Transcribe from line 8)			
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)			
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)			
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

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Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)			
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant			
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)			
72	Plant Removal (By Utility Departments)			
73	Electric Plant			
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)			
77	Other Accounts (Specify, provide details in footnote):			
78				
79				
80				
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts			
96	TOTAL SALARIES AND WAGES			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
9					
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45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch						
2	Reactive Supply and Voltage						
3	Regulation and Frequency Response						
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	
3	Steam				
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional				
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	
7	Other				
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
10	Purchases		27	Total Energy Losses	
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received				
17	Delivered				
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January				0	
30	February				0	
31	March				0	
32	April				0	
33	May				0	
34	June				0	
35	July				0	
36	August				0	
37	September				0	
38	October				0	
39	November				0	
40	December				0	
41	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
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			33
			34
			35
			36
			37
			38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
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41						
42						
43						
44						
45						
46						

Name of Respondent AEP Kentucky Transmission Company, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2019/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
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						42
						43
						44
						45
						46

Name of Respondent AEP Kentucky Transmission Company, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2019/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
								2
								3
								4
								5
								6
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	NO LINES ADDED						
2							
3							
4							
5							
6							
7							
8							
9							
10							
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42							
43							
44	TOTAL						

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	BAKER 765KV - KY	T	765.00		
2	BAKER 765KV - KY	T	765.00	345.00	34.50
3	BELLEFONTE 138KV - KY	T	138.00	70.50	36.20
4	BREAKS - KY	D	69.00		
5	STANVILLE - KY	T	69.00		
6	STANVILLE - KY	T	138.00	70.50	46.00
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
			REACTOR	4	400	1
7500	10					2
200	1					3
			STATCAP	1	14	4
			STATCAP	1	14	5
208	2					6
						7
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Construction Services	AEPSC	107, 108	1,747,889
3	Transmission Expenses - Operation	AEPSC	See Footnotes	952,834
4	Use of Jointly Owned Facility	KPCo	567	297,457
5	Construction Services	KPCo	107	341,389
6				
7				
8				
9				
10				
11				
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19				
20	**Non-power Goods or Services Provided for Affiliate**			
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
AEP Kentucky Transmission Company, Inc.	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

Schedule Page: 429 Line No.: 3 Column: c

Accounts: 560, 561.2, 561.5, 562, 563, 566, 567, 920, 923

INDEX

INDEX (continued)

Schedule	Page No.

Document Content(s)

PSC Exhibit 2

ATTACHMENT B -2
(Unmarked Version)

TRANSMISSION AGREEMENT

By and among

APPALACHIAN POWER COMPANY

COLUMBUS SOUTHERN POWER COMPANY

INDIANA MICHIGAN POWER COMPANY

KENTUCKY POWER COMPANY

KINGSPORT POWER COMPANY

OHIO POWER COMPANY

WHEELING POWER COMPANY

and with

AMERICAN ELECTRIC POWER SERVICE CORPORATION

AS AGENT

DATED APRIL 1984, AS AMENDED

CONTENTS

0.1 THIS AGREEMENT, made and entered into as of the 1st day of April, 1984, and as subsequently amended, by and among APPALACHIAN POWER COMPANY (Appalachian Company), a Virginia corporation, COLUMBUS AND SOUTHERN POWER COMPANY (Columbus Company), an Ohio corporation, INDIANA MICHIGAN POWER COMPANY (Indiana Company), an Indiana corporation, KENTUCKY POWER COMPANY (Kentucky Company), a Kentucky corporation, OHIO POWER COMPANY (Ohio Company), an Ohio corporation, KINGSPORT POWER COMPANY (Tennessee Company), a Tennessee corporation, and WHEELING POWER COMPANY (Wheeling Company), a West Virginia corporation, said companies (herein sometimes called 'Members' when referred to collectively and 'Member' when referred to individually) being affiliated companies of the integrated public utility electric system known as the American Electric Power SYSTEM (AEP System), and AMERICAN ELECTRIC POWER SERVICE CORPORATION (Agent), a New York corporation, being a service company engaged solely in the business of furnishing essential services to the aforesaid companies and to other affiliated companies.

W I T N E S S E T H,

T H A T:

0.2 WHEREAS, the Members own and operate electric facilities in the states herein indicated, (i) Appalachian Company in Virginia, West Virginia, and Tennessee (ii) Columbus Company in Ohio, (iii) Indiana Company in Indiana and Michigan, (iv) Kentucky Company in Kentucky, (v) Tennessee Company in Tennessee, (vi) Ohio Company in Ohio and West Virginia, and (vii) Wheeling Company in West Virginia; and

0.3 WHEREAS, certain of the Members have entered into an interconnection agreement, dated July 6, 1951, with modification thereto, which provides for certain understandings, conditions, and procedures designed to achieve the full benefits and advantages available through the coordinated operation of their electric power supply facilities; and

0.4 WHEREAS, The Members' electric facilities are now and for many years have been interconnected through their respective transmission facilities at a number of points, forming an integrated transmission network; and

0.5 WHEREAS, the Members have achieved benefits through the coordinated planning and development of a fully integrated Transmission System; and

0.6 WHEREAS, the members believe that an agreement which provides for the equitable sharing among the Members of the costs incurred by the Members in connection with the ownership, operation, and maintenance of their respective portions of the Transmission System would enhance equity among the Members for the continued development of a reliable and economic Transmission System; and

0.7 WHEREAS, effective October 1, 2004 the Members joined the PJM Interconnection, LLC ("PJM"), and placed their respective transmission facilities under the functional control of PJM, a regional transmission operator or "RTO"; and

0.8 WHEREAS, PJM provides transmission service, pursuant to the PJM Open Access Transmission Tariff ("OATT"), to the Members and others who require transmission service over the Transmission System; and

0.9 WHEREAS, the Members believe that benefits and advantages could be best realized if this Agreement were administered by a single clearing agent; and

0.10 WHEREAS, the Members believe that the Agent designated herein for such purpose is qualified to perform such services;

0.11 NOW, THEREFORE, in consideration of the premises and of the mutual covenants and agreements hereinafter contained, the parties hereto hereby agree as follows:

ARTICLE 1

DESCRIPTION OF TRANSMISSION SYSTEM

1.1 The Transmission System covered by this Agreement shall include all the transmission facilities, from time to time, owned by the Members that are included in the costs of service used to determine rates for transmission service under the PJM OATT, or successor open access transmission tariff.

ARTICLE 2

OPERATION

2.1 Each member shall maintain its respective portion of the Bulk Transmission System, together with all associated facilities and appurtenances, in a suitable condition of repair at all times in order that said system will operate in a reliable and satisfactory manner.

ARTICLE 3

TRANSMISSION COMMITTEE

3.1 The Members shall appoint representatives to serve on a Transmission Committee. Such representatives shall have authority to act for the Members in the administration of all matters pertaining to this Agreement.

3.2 Each Member shall designate in writing, delivered to the other Members and Agent, the person who is to act as its representative on said Committee and the person or persons who may serve as alternate whenever such representative is unavailable to act. Agent shall designate in writing delivered to the Members the person who is to act as its representative on said Committee and the person or persons who may serve as alternate whenever such representative is unavailable to act. Such person designated by Agent shall act as chairman of the Transmissions Committee and shall be known as the "Transmission Manager".

ARTICLE 4

AGENTS RESPONSIBILITIES

4.1 For the purpose of carrying out the provisions of this Agreement the Members hereby delegate to Agent, and Agent hereby accepts, the responsibility of administration of this Agreement, and in furtherance thereof Agent hereby agrees:

4.11 To arrange for and conduct such meetings of the Transmission Committee as may be required to insure the effective and efficient carrying out of all matters of procedure essential to the complete performance of the provisions of this Agreement.

4.12 To carry out settlements under this Agreement. Settlements by the Members shall be made for each calendar month through General Ledger accounts (hereby designated and hereinafter called the "TRANSMISSION ACCOUNTS") to be administered by Agent. For the purposes of This Agreement, Transmission Accounts shall be consistent with the accounts listed in the FERC Uniform System of Accounts, and shall include such accounts and sub-accounts as are necessary and proper, directed by the Transmission Committee, and consistent with applicable regulatory requirements.

ARTICLE 5

SETTLEMENTS

5.1 As provided in this Article, following the end of each month, the Members shall effect settlements through the TRANSMISSION ACCOUNTS. Generally, Settlements hereunder will involve the allocation among the Members of transmission-related costs and revenues as incurred and accrued under the PJM OATT,

or successor open access transmission tariff, and the recording of same in the Transmission Accounts of the Members, as specified in Appendix I consistent with the Settlement Agreement approved in FERC Docket No. ER09-1279-000.

5.2 All amounts to be allocated among the Members hereunder shall, to the extent practicable, be included in Settlements for the month in which such cost or revenue is realized or accrued. If necessary in order to implement such timely Settlement, the Agent shall be authorized to effect Settlements on an estimated basis and make such adjustment as is needed in subsequent Settlements that will conform the Settlements to the terms of this Agreement.

5.3 For such time as Member Tennessee Company and/or Wheeling Company (Buyer) purchase power from Members Appalachian Company and Ohio Company (Seller), respectively, under agreements that provide for transmission service and related charges to Buyer from Seller (Purchased Power Agreements or "PPAs"), Seller will be allocated or assigned the costs as described on Appendix I, numbers seven (7) through fifteen (15), that would otherwise have been allocated or assigned to Buyer under this Agreement. The total amount of such allocated or assigned costs will be passed through to Buyer by Seller as the transmission service and related charges provided for in their PPAs. Such transmission and related costs will be the only transmission charges passed through to Buyer under any such PPA. When any such PPA expires or is otherwise modified or superseded, the provisions of the PPA that provide for

transmission service and related charges to Buyer from Seller will be discontinued and Tennessee Company and/or Wheeling Company will receive directly, by allocation or direct assignment, the transmission and related costs pursuant to this agreement, as described on Appendix I, numbers seven (7) through fifteen (15). At such time, Seller shall no longer be allocated or assigned costs which are properly allocable or assignable to Buyer under this Agreement. Further, from the effective date of this Agreement as modified in FERC Docket No. ER09-1279, all the Members, including Tennessee Company and Wheeling Company, will receive direct allocation of revenues as provided herein and described on Appendix I, numbers one (1) though six (6).

ARTICLE 6

TAXES

6.1 If at any time during the duration of this Agreement there should be levied and/or assessed by any governmental authority against any Member any tax related to the receipt of Settlements calculated pursuant to this Agreement (such as sales, excise or similar taxes), such tax expense incurred by such Member that would not have been incurred were the Settlements hereunder not being made, such Member shall be entitled, to the extent permitted by the applicable regulatory authority(ies) to include such tax in its transmission revenue requirement under the PJM or successor OATT when transmission revenue requirements of the Members are next updated, and thereby receive an appropriate level of reimbursement (through cost sharing) for such additional taxes by Members and others receiving service from the Transmission System.

ARTICLE 7

Allocation Principles

7.1 All items of cost and revenue included in Settlements hereunder shall be related to the provision of or receipt of transmission service or a related ("ancillary") service by one or more Members. The allocation methods used to share such costs and revenues, as specified in Appendix I, shall be made pursuant to direction by the Transmission Committee.

7.2 The Transmission Committee may at any time during the Term of This Agreement, upon the recommendation of the Agent or any Member, review any item of cost or revenue, in order to determine whether such item is transmission-related, and whether it should be included in Settlements hereunder. Further, whenever the Transmission Committee determines that any change is needed in Appendix I to add or delete any item of cost or revenue, or to change the allocation or accounting basis of any item, the Transmission Committee shall authorize and direct the Agent to effect such change in Appendix I and in monthly Settlements among the Members and to make any filing with the applicable regulatory authority(ies) to implement such change. pursuant to the PJM OATT or any successor open access transmission tariff.

ARTICLE 8

MODIFICATION

8.1 Any Member, or the Agent, by written notice given to the other Members and Agent, may call for a reconsideration of the terms and conditions herein provided. If such

reconsideration is called for, the Members shall take into account any changed conditions, any results from the application of said terms and conditions, and any other facts that might cause said terms and conditions to result in an inequitable sharing of costs and benefits under this Agreement. Any modification in terms and conditions agreed to by the Members following such reconsideration shall become effective the first day of the month following authorization of such reconsideration by appropriate regulatory authority.

ARTICLE 9

EFFECTIVE DATE AND TERM OF THIS AGREEMENT

9.1 This Agreement shall become effective and shall become a binding obligation of the Parties on the date specified in an Order in such proceeding as this Agreement shall have been filed with, and accepted for filing by the Federal Energy Regulatory Commission (FERC) under the Federal Power Act as a rate schedule.

9.2 This Agreement shall continue in effect for four years from the effective date of the final order in Docket No. ER09-1279-000 for successive periods of one year each until terminated as provided under subsection 9.3 below.

9.3 Any Member upon at least three years' prior written notice to the other Members and Agent may terminate this Agreement at the expiration of such notice period.

ARTICLE 10

REGULATORY AUTHORITIES

10.1 The Members recognize that this Agreement, and any tariff or rate schedule which shall embody or supersede this

Agreement or any part thereof, are in certain respects subject to the jurisdiction of the FERC under the Federal Power Act, and are also subject to such lawful action as any regulatory authority having jurisdiction shall hereafter take with respect thereto. The performance of any obligation of the Members shall be subject to the receipt from time to time as required of such authorizations, approvals or actions of regulatory authorities having jurisdiction as shall be required by law.

10.2 Subject to the terms of the Settlement in Docket NO. ER09-1279-000, it is expressly understood that any Member under this Agreement, as it may hereafter from time to time be modified and supplemented by the Members, shall be entitled, at any time and from time to time, unilaterally to make application to the FERC for a change in rates, charges, classification of service, or any rule, regulation or contract relating thereto, or to make any change in or supersede in whole or in part any provision of this Agreement, under Section 205 of the Federal Power Act and pursuant to the FERC's Rules and Regulations promulgated thereunder.

ARTICLE 11

ASSIGNMENT

11.1 This Agreement shall inure to the benefit of and be binding upon the successors and assigns of the respective parties.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed in their respective corporate names and on their behalf by their proper officers thereunto daily authorized as of the day and year first above written.

Next Page is Signature Page

Transmission Agreement Among:

AMERICAN ELECTRIC POWER SERVICE CORPORATION,

By: ____________________________

Senior Vice President

APPALACHIAN POWER COMPANY,

By: ____________________________

President and Chief Operating Officer

COLUMBUS SOUTHERN POWER COMPANY,

By: ____________________________

President and Chief Operating Officer

INDIANA MICHIGAN POWER COMPANY,

By: ____________________________

KENTUCKY POWER COMPANY,

By: ____________________________

President and Chief Operating Officer

KINGSPORT POWER COMPANY,

By: ____________________________

President and Chief Operating Officer

OHIO POWER COMPANY, and

By: ____________________________

Vice President

WHEELING POWER COMPANY

By: ____________________________

President

Dated as of:

____

Appendix I

AEP Transmission Agreement
Allocation of Transmission Related Costs and Revenues

AEP as Transmission Owner (Revenues)

#	Item	FERC Account*	PJM Billing Basis	AEP Allocation Basis
1	Transmission Owner Scheduling, System Control and Dispatch Service (PJM Schedule 1A)	456.1	NSPL	ARR S1A
2	NITS (AEP LSE)	456.1	NSPL	ATRR
3	NITS (Non-Affiliates)	456.1	NSPL	ATRR
4	Grandfathered PTP (NCEMC)	456.0	Contract	ATRR
5	PJM Expansion Cost Recovery Charge (ECRC)	456.1	NSPL	ARR EC
6	RTO Startup Cost Recovery Charge (SCRC)	456.1	NSPL	ARR SC

AEP as LSE (Expenses)

#	Item	FERC Account*	PJM Billing Basis	AEP Allocation Basis
7	Transmission Owner Scheduling, System Control and Dispatch Service (PJM Schedule 1A)	456.1	MWh	MWh
8	NITS Charges (for AEP Retail Load)	456.1	NSPL	12CP
9	NITS Charges for AEP FR Customers[1/]	447.0	NSPL	DA
10	NITS Reimbursement from AEP FR Customers[1/]	447.0	NSPL	DA
11	Firm Point-to-Point Credits (for AEP Retail Load)	456.1	NSPL	12CP
12	Non-Firm Point-to-Point Credits (AEP Retail Load)	456.1	NSPL	12CP
13	Transmission Enhancement (Schedule 12)	565.0	NSPL	12CP
14	PJM Expansion Cost Recovery Charge (ECRC)	456.1	NSPL	12CP
15	RTO Startup Cost Recovery Charge (SCRC)	456.1	NSPL	12CP

NSPL	PJM Network Service Peak Load
Contract	Pre-OATT FERC Rate Schedules
ARR S1A	Annual Revenue Requirement - Schedule 1A
ATRR	Annual Transmission Revenue Requirement
ARR EC	Annual Revenue Requirement - Expansion Cost Recovery
ARR SC	Annual Revenue Requirement - Startup Cost Recovery
12CP	Average of 12 coincident peaks through 10/31 of prior year
DA	Directly Assigned to Operating Company

* Note: Should the net amount in 456.1 for any Member be negative, e.g. more expense than revenue, the net expense will be recorded in 565.0.

1/ Includes all transmission-related LSE expenses (NITS, Schedule 1A, Point-to-Point Credits, Schedule 12, ECRC, SCRC) which are directly assigned to Operating Company for AEP FR Customers.

Issued By: Richard E. Munczinski
Senior Vice President, Regulatory Services

Effective: first day of the month after the Commission issues a final, non- appealable order accepting the Agreement for filing

Issued On: August 4, 2010

PSC Exhibit 3

ORIGINAL

AMERICAN ELECTRIC POWER

American Electric Power
801 Pennsylvania Avenue N.W.
Suite 320
Washington, DC 20004
AEP.com

FILED
SECRETARY OF THE COMMISSION
2010 AUG -4 A 11: 36
FEDERAL ENERGY REGULATORY COMMISSION

August 4, 2010

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1A
Washington, D.C. 20426

Monique Rowtham-Kennedy
Senior Counsel – Regulatory Services
(202) 383-3436
(202) 383-3459 (F)

Re: **American Electric Power Service Corporation,**
FERC Docket No. ER09-1279-000

Dear Secretary Bose:

Pursuant to Rule 602 of the Federal Energy Regulatory Commission's (the "Commission") Rules of Practice and Procedure, 18 C.F.R.§385.602 (2008), American Electric Power Service Corporation ("AEPSC") on behalf of its affiliates, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company (collectively "AEP" or the "AEP East Companies"), and the following Settling Parties: Public Utilities Commission of Ohio, East Tennessee Energy Consumers, Hoosier Energy Rural Electric Cooperative and the Office of the Ohio Consumers' Counsel, and , (individually, a "Settling Party," and, collectively, the "Settling Parties") submit an original and fourteen copies of an Offer of Settlement intended to resolve without need for evidentiary procedures all issues set for hearing in the captioned proceedings. In addition, this Settlement is supported or not opposed by all parties who have intervened in this proceeding except Steel Dynamics, Inc. and Kentucky Public Service Commission who take no position with respect to the Settlement.[1]

This Offer of Settlement includes the following documents:

1. Explanatory Statement (Appendix A);

[1] In addition to the Settling Parties, the non-opposing parties are Consumer Advocate Division of the Public Service Commission of West Virginia, Virginia State Corporation Commission, Old Dominion Committee for Fair Utility Rates, Public Service Commission of West Virginia, Indiana Utility Regulatory Commission, Indiana Office of Utility Consumer Counsel, and the West Virginia Energy Users Group.

2. Settlement Agreement (Appendix B), and several attachments described below;
3. Draft Order Approving Settlement Agreement (Appendix C), and
4. Service List (Appendix D).

The attachments to the Settlement Agreement, Appendix B, include the following:

1. Attachment A, Settlement Terms and Conditions;
2. Attachment B-1, Revised Rate Schedule language (Blacklined);
3. Attachment B-2, Revised Rate Schedule language (Clean);

All parties in this proceeding and the Commission's Trial Staff have had the opportunity to review and comment on the Offer of Settlement. The Settling Parties expect this Offer of Settlement to be unopposed.

AEP requests that the appropriate number of copies of this filing be transmitted to Presiding Administrative Law Judge David Coffman in accordance with Commission Rule 602(b)(2)(i). In accordance with Rule 602(d), copies of this filing have been served on all participants in this proceeding and on all affected state commissions.

The Settling Parties request that, once the comment period specified in Rule 602(f) has passed, Judge Coffman certify the Settlement Agreement to the Commission, as required by Rule 602(g)(1), as expeditiously as possible.

Respectfully submitted

Monique Rowtham-Kennedy
Senior Counsel
American Electric Power Service Corporation

Enclosures

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

American Electric Power Service Corporation	))	Docket No. ER09-1279-000

EXPLANATORY STATEMENT IN SUPPORT OF SETTLEMENT AGREEMENT

Pursuant to Rule 602 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.602 (2008), American Electric Power Service Corporation ("AEPSC"), on behalf of Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company (collectively "AEP" or the "AEP East Companies") and the following Settling Parties: Public Utilities Commission of Ohio, East Tennessee Energy Consumers, Hoosier Energy Rural Electric Cooperative, and the Office of the Ohio Consumers' Counsel (individually, a "Settling Party," and, collectively, the "Settling Parties") hereby submit this Explanatory Statement in support of the concurrently filed Settlement Agreement, which is intended to resolve all issues in this proceeding. In addition, this Settlement is supported or not opposed by all parties who have intervened in this proceeding, except Steel Dynamics, Inc., and Kentucky Public Service Commission, which take no position with respect to the Settlement. [1]

[1] In addition to the Settling Parties, the non-opposing parties are Consumer Advocate Division of the Public Service Commission of West Virginia, Virginia State Corporation Commission, Old Dominion Committee for Fair Utility Rates, Public Service Commission of West Virginia, Indiana Utility Regulatory Commission, Indiana Office of Utility Consumer Counsel, and the West Virginia Energy Users Group.

I. INTRODUCTION

AEP is a multi-state electric utility holding company system, providing electric service to approximately five million customers in parts of eleven states. AEP represented in its filing in this case that the AEP System is planned and operated on an integrated basis pursuant to various agreements under which the AEP operating companies pool or combine their individual systems to achieve the benefits of integrated operation. This proceeding involves proposed amendments to one such agreement -- the Transmission Agreement entered into in 1984 among five of the AEP East Companies-Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company and Ohio Power Company and administered by AEPSC, as Agent. As approved by the Commission,[2] the Agreement shares the costs of the Members' investments in Extra-High-Voltage (EHV) and high-voltage facilities operated at 138 kilovolts (138 kV) and above.

On June 5, 2009 AEP filed with the Commission proposed amendments to the Transmission Agreement. The proposed amendments, if approved, would effect a comprehensive reallocation of transmission-related costs and revenues among the AEP East Companies including two new Members, Kingsport Power Company and Wheeling Power Company.[3] AEP represented in its filing that the proposed amendments recognize that, pursuant to the PJM Open Access Transmission Tariff ("PJM OATT"), the AEP East Companies, including Kingsport and Wheeling, and other load serving entities in the

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[2] *American Electric Power Service Corp.*, Opinion No. 311, 44 FERC ¶ 61,206 (1987), *reh. denied*, Opinion No. 311-A, 45 FERC ¶ 61,382 (1988).
[3] Kingsport and Wheeling are relatively small operating companies that own no generating facilities but do own transmission facilities.

AEP zone of PJM now receive network transmission service from and share the cost of the AEP East Companies' transmission facilities, including those operated at voltages below 138 kV. The proposed amendment also would change the primary transmission cost allocation methodology under the Transmission Agreement from the current Member Load Ratio ("MLR") basis to a 12-month coincident peak (12-CP) basis. The proposed amendments specify that the allocation of OATT-based transmission and related costs and revenues will include all seven of the AEP East Companies, including Kinsport and Wheeling.

Motions to intervene in this proceedings were filed by the following entities: Public Utilities Commission of Ohio, Public Service Commission of West Virginia, West Virginia Energy Users Group, Virginia State Corporation Commission, Old Dominion Committee for Fair Utility Rates, East Tennessee Energy Consumers, Indiana Utility Regulatory Commission ("IURC"), Steel Dynamics, Inc. ("Steel Dynamics"), Consumer Advocate Division of the Public Service Commission of West Virginia (W.Va. Consumer Advocate"), Hoosier Energy Rural Electric Cooperative, Indiana Office of Utility Consumer Counsel ("IOUCC"), Ohio Consumers' Counsel, and the Kentucky Public Service Commission.

IURC, Steel Dynamics, W. Va Consumer Advocate and IOUCC protested AEP's filing, and AEP answered their protests. On August 3, 2009 the Commission issued an order accepting AEP's proposed amendments to the Transmission Agreement for filing, subject to hearing and settlement judge procedures. The Commission suspended the proposed amendments for a nominal period, making them effective (subject to refund), on the first day of the month after a final Commission order in this proceeding, as requested by AEP. *Order Accepting and Suspending Proposed Transmission Agreement and Establishing Hearing and Settlement Judge Procedures*, 128 FERC ¶ 61,123 (2009).

On August 7, 2009, pursuant to an order of Chief Judge Wagner, the Honorable David Coffman was appointed Settlement Judge. The Chief Judge's August 7, 2009 order also scheduled a settlement conference to convene on August 20, 2009. Settlement negotiations (including informal information gathering and numerous conferences, meetings and telephone conversations) continued since then. The Commission's Trial Staff participated actively in the discussions. Judge Coffman submitted periodic reports to the Commission on the progress of the settlement discussions. Ultimately, the settlement discussions produced the Settlement Agreement submitted in this Docket.

II. SUMMARY OF SETTLEMENT AGREEMENT

The substantive terms of the Settlement Agreement are set forth in three Attachments to the Settlement Agreement, as follows:

A. Settlement Terms and Conditions (Attachment A-1);

B. Revised Rate Schedule language, in Blacklined format, (B-1) that will be incorporated in Transmission Agreement;

C. Revised Rate Schedule language in clean format (B-2);

The following is a summary of each of the Attachments:

A. Settlement Terms and Conditions

The Settlement Terms and Conditions set forth the methodology for implementation of the Revised Transmission Agreement. The Terms and Conditions include a three year phase in of the impacts of the Revised Transmission Agreement for all AEP East Companies, except for Indiana Michigan Power Company, for which the impacts of the Revised Transmission Agreement will be phased in over a four year period The phase in periods would commence on the date of the Commission order approving the Settlement and would end no later than July 31, 2013 for all AEP East Companies except Indiana Michigan Power Company and no later than July 31, 2014 for Indiana Michigan Power Company. The Settlement Terms and Conditions also sets forth the credits and charges to the AEP East Companies to reflect the phased in impacts of the Transmission Agreement pursuant to the terms of the Settlement Agreement. It also provides that all Settling Parties reserve their filing rights under the Federal Power Act, except that a section 206 filing by a Settling Party under the Federal Power Act challenging the terms of the Revised Transmission Agreement or of the Settlement Agreement will render the Settlement Agreement void, and would be subject to the "public interest" standard of review adopted in the *Sierra-Mobile* line of cases.

B. Revised Tariff Sheets

Resolution of the issues as set forth in Attachment A requires certain changes to the Transmission Agreement. Attachments B-1 and B-2 provide the Revised Rate Schedule language, that the Settling Parties have agreed is necessary to implement the Settlement Agreement. Accordingly, these attachments will be incorporated in the Transmission Agreement following Commission approval of the Settlement Agreement.

III. PROCEDURAL ASPECTS OF SETTLEMENT AGREEMENT

The remaining provisions of the Settlement Agreement address procedural aspects of the Settlement Agreement including implementation, non-severability, rights reserved, waiver and amendment, and the scope of review. Specifically, the standard of review for modifications to the Settlement Agreement that are proposed by any Settling Party will be the "public interest" standard adopted in the *Sierra-Mobile* line of cases. The standard of review for modifications to the Settlement Agreement proposed by any non-party to the Settlement Agreement and the Commission acting *sua sponte*, after it is approved by the Commission, will be the most stringent standard permitted by law.

IV. RESPONSES TO REQUIRED QUESTIONS

By order dated October 23, 2003, the Chief Administrative Law Judge requires that five questions be answered as part of every Explanatory Statement submitted in support of a proposed settlement. The questions and specific responses thereto applicable to this Settlement Agreement are as follows:

1. **What are the issues underlying the settlement and what are the major implications?**

The issue raised in this proceeding that underlies the Settlement Agreement is whether the proposed amendments to the Transmission Agreement are just and reasonable.

2. **Whether any of the issues raise policy implications.**

The resolution of the underlying issue does not raise any policy implications.

3. **Whether other pending cases may be affected.**

No other pending cases are affected.

4. **Whether the settlement involves issues of first impression, or if there are any previous reversals on the issues involved?**

There are no issues of first impression presented in this proceeding or resolved by the Settlement Agreement. There are no previous reversals with respect to the Transmission Agreement at issue in this proceeding.

5. Whether the proceeding is subject to the just and reasonable standard or whether there is *Mobile-Sierra* language making it the standard, *i.e.*, the applicable standards of review.

This proceeding on AEP's rate filing is subject to the just and reasonable standard. Section 6.7 of the Settlement Agreement states that, except as specified, a unilateral request by a Settling Party to modify any provision of the Settlement Agreement would be subject to the "public interest" standard adopted in the *Sierra-Mobile* line of cases. As for a unilateral modification request by a non-Settling Party or a proceeding in which the Commission acting *sua sponte* seeks to modify the Settlement Agreement, the standard of review shall be the most stringent standard permitted by applicable law.

V. CONCLUSION

As discussed above, the attached Settlement Agreement resolves all issues in the captioned proceeding, and the Settling Parties urge the Commission to accept the Settlement Agreement without condition or modification. The Settling Parties in this proceeding have authorized counsel for AEP to make this filing on their behalf.

Respectfully submitted,

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Counsel for Hoosier Energy Rural Electric Cooperative

August 4, 2010

CERTIFICATE OF SERVICE

I certify that a copy of the foregoing Settlement filed by American Electric Power Service Corporation was served upon the parties to this proceeding this 4th day of August 2010.

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

American Electric Power Service Corporation	))	Docket No. ER09-1279-000

SETTLEMENT AGREEMENT

Pursuant to Rule 602 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. §385.602 (2008), American Electric Power Service Corporation ("AEPSC"), on behalf of Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company (collectively "AEP" or the "AEP East Companies") and the following Settling Parties: Public Utilities Commission of Ohio, East Tennessee Energy Consumers, Hoosier Energy Rural Electric Cooperative and the Office of the Ohio Consumers' Counsel (individually, a "Settling Party," and, collectively, the "Settling Parties") hereby submit this Settlement Agreement to resolve all issues between and among them in this docket. In addition, this Settlement is supported or not opposed by all parties who have intervened in this proceeding, except Steel Dynamics, Inc. and Kentucky Public Service Commission who take no position with respect to the Settlement.[1]

[1] In addition to the Settling Parties, the non-opposing parties are Consumer Advocate Division of the Public Service Commission of West Virginia, Virginia State Corporation Commission, Old Dominion Committee for Fair Utility Rates, , Public Service Commission of West Virginia, Indiana Utility Regulatory Commission, Indiana Office of Utility Consumer Counsel, and the West Virginia Energy Users Group.

ARTICLE I

INTRODUCTION

AEP is a multi-state electric utility holding company system, whose operating companies provide electric service to approximately five million customers in parts of eleven states. Prior to 2000, when AEP merged with the former Central and South West System, AEP consisted of seven electric utility operating companies. The five largest companies operate generation, transmission and distribution facilities and are parties to the Transmission Agreement. The two smaller companies – Kingsport Power Company ("Kingsport") and Wheeling Power Company ("Wheeling") operate only transmission and distribution facilities. These seven AEP East operating companies provide electric service to customers in parts of seven states – Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia and West Virginia. AEPSC provides management and professional services at cost to these companies and others in the AEP System.

AEP represented in its filing in this case that the AEP System is planned and operated on an integrated basis pursuant to various agreements under which the AEP operating companies pool or combine their individual systems to achieve the benefits of integrated operation. This proceeding involves proposed amendments to one such agreement -- the Transmission Agreement entered into in 1984 among five of the AEP East Companies- Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company and Ohio Power

Company, and administered by AEPSC, as Agent. As approved by the Commission,[2] the Agreement provides for the sharing of the costs of the Members' investments in Extra-High-Voltage (EHV) and high-voltage facilities operated at 138 kilovolts (138 kV) and above.

On June 5, 2009 AEP filed with the Commission proposed amendments to the Transmission Agreement. The proposed amendments to the Transmission Agreement , if approved, would effect a comprehensive reallocation of transmission-related costs and revenues among the AEP East Companies including two new Members, Kingsport Power Company and Wheeling Power Company. AEP represented in the filing that the proposed amendments recognized that, pursuant to the PJM Open Access Transmission Tariff ("PJM OATT"), the AEP East Companies, including Kingsport and Wheeling, and other load serving entities in the AEP zone of PJM now share the cost of all the AEP East Companies transmission facilities, including those operated at voltages below 138 kV. The proposed amendments also would change the primary transmission cost allocation methodology under the Transmission Agreement from the current Member Load Ratio ("MLR") basis to a 12-month coincident peak (12-CP) basis. The proposed amendments specify that the allocation of OATT-based transmission and related costs and revenues will include all seven of the AEP East Companies, including Kingsport and Wheeling. Motions to intervene in this proceedings were filed by the following entities: Public Utilities Commission of Ohio, Public Service Commission of West Virginia, West Virginia Energy Users Group, Virginia State Corporation Commission, Old Dominion Committee for Fair Utility Rates, East Tennessee Energy Consumers, Indiana Utility

[2] *American Electric Power Service Corp.*, Opinion No. 311, 44 FERC ¶ 61,206 (1987), *reh. denied*, Opinion No. 311-A, 45 FERC ¶ 61,382 (1988)

Regulatory Commission ("IURC"), Steel Dynamics, Inc. ("Steel Dynamics"), Consumer Advocate Division of the Public Service Commission of West Virginia (W.Va. Consumer Advocate"), Hoosier Energy Rural Electric Cooperative, Indiana Office of Utility Consumer Counsel ("IOUCC"), Ohio Consumers' Counsel, and the Kentucky Public Service Commission.

IURC, Steel Dynamics, W. Va. Consumer Advocate and IOUCC protested AEP's filing, and AEP answered their protests. On August 3, 2009 the Commission issued an order accepting AEP's proposed amendments to the Transmission Agreement for filing, subject to hearing and settlement judge procedures. The Commission suspended the proposed amendments for a nominal period, making them effective (subject to refund), on the first day of the month after a final Commission order in this proceeding, as requested by AEP. *Order Accepting and Suspending Proposed Transmission Agreement and Establishing Hearing and Settlement Judge Procedures*, 128 FERC ¶ 61,123 (2009).

On August 7, 2009, pursuant to an order of Chief Judge Wagner, the Honorable David Coffman was appointed Settlement Judge. The Chief Judge's August 7, 2009 order also scheduled a settlement conference to convene on August 20, 2009. Settlement negotiations (including informal information gathering and numerous conferences, meetings and telephone conversations) continued since then. The Commission's Trial Staff participated actively in the discussions. Judge Coffman submitted periodic reports to the Commission on the progress of the settlement discussions. Ultimately, the settlement discussions produced this Settlement Agreement.

ARTICLE II
SCOPE OF SETTLEMENT AGREEMENT

The Settling Parties hereby settle and resolve all issues between them arising from AEP's submittals in Docket No. ER09-1279-000, on the terms set forth in the following Article III and Attachments A, B-1 and B-2. Attachments A, B-1 and B-2 are incorporated by reference in and made a part of this Settlement Agreement, and all references herein to the Settlement Agreement shall be deemed to encompass the listed Attachments.

ARTICLE III
TERMS OF THE SETTLEMENT AGREEMENT

3.1 The Settlement Terms and Conditions set forth in Attachment A describe the agreement of the Settling Parties regarding the implementation of the Revised Transmission Agreement.

3.2 Revised provisions for the Transmission Agreement are set forth in Attachment B-1 (Blacklined) and B-2 (Clean) to this Settlement Agreement. The provisions submitted herewith shall be substituted for the tariff pages accepted for filing, subject to refund, in the Commission's August 3, 2009 Order in this Docket. The Settling Parties request that the Commission accept the Rate Schedule pages set forth in Attachment B-2 for filing without suspension, investigation, change or condition.

ARTICLE IV
IMPLEMENTATION

4.1 This Settlement Agreement shall be binding as among the Settling Parties upon the execution hereof. The revised tariff sheets and other provisions set forth in the Attachments hereto shall become effective on the date the Commission specifies as the effective date for the agreed-upon rates and charges in its order approving or accepting the Settlement Agreement. The Settling Parties shall request that the Commission permit the agreed-upon rates and charges to become effective on the first day of the month after a final Commission order in this proceeding.

4.2 This Settlement Agreement shall be null and void and shall not become effective unless: (i) the Commission approves it without condition or modification as a complete settlement of the issues described herein, or (ii) the Settling Parties are willing to accept all such conditions and modifications as the Commission may require. Any Settling Party that does not notify the other Settling Parties, within 15 days of a Commission order imposing any condition or modification to the Settlement Agreement, that it may or will seek rehearing or reconsideration of the order shall be deemed to have waived all objections thereto.

ARTICLE V
NON-SEVERABILITY

5.1 This Settlement Agreement and its Attachments establish rights and obligations that are interrelated and interdependent. No Settling Party shall be deemed to have agreed to any term of the Settlement Agreement in isolation from any other term. For these reasons, the provisions of this Settlement Agreement are not severable.

ARTICLE VI
RESERVATIONS

6.1 The provisions of this Settlement Agreement are intended to govern only the specific matters addressed herein. No Settling Party waives any claim or right that it may have with respect to matters not addressed in this Settlement Agreement.

6.2 No Settling Party shall be bound or prejudiced by this Settlement Agreement unless it is approved and made effective pursuant to its terms.

6.3 Nothing in this Settlement Agreement shall constitute an admission by any Settling Party of the correctness or applicability of any claim, defense, rule, or interpretation of law, allegation of fact, principle, or method of ratemaking or cost-of-service determination. The Settlement Agreement is made upon the explicit understanding that it constitutes a negotiated agreement with respect to the rates, terms, and conditions at issue in these proceedings. The Settling Parties shall not be deemed to have conceded the applicability of any principle, or any method of ratemaking or cost-of-service determination, rate design or rate schedule, or terms and conditions of service; or the application of any rule or interpretation of law that may underlie, or be thought to underlie, this Settlement Agreement. The Settlement Terms and Conditions contained in Attachment A are principles that the Settling Parties shall be deemed to have accepted solely for purposes of resolving the issues in this docket, and their inclusion as part of this Settlement Agreement shall not (i) constitute an admission by any Settling Party of the correctness of any principle therein, or (ii) establish any precedent binding on a Settling Party in any other proceeding. In any further negotiation or proceedings whatsoever (other than a proceeding involving the honoring, enforcement or construction hereof, as applicable as set forth herein), the Settling Parties shall not be bound or prejudiced by this Settlement Agreement.

6.4 The Commission's approval of this Settlement Agreement shall not constitute approval of, or precedent regarding, any principle or issue in this proceeding. Nothing herein shall be deemed to constitute or establish a "settled practice" as the Court interpreted that term in *Public Service Comm'n of New York v. FERC*, 642 F.2d 1335 (D.C. Cir. 1980).

6.5 This Settlement Agreement is expressly contingent upon the following further conditions: (i) all Settling Parties shall provide reasonable cooperation in seeking the Commission's acceptance and approval hereof; (ii) no Settling Party shall seek or request additional terms or conditions of settlement beyond those contained herein; and (iii) the Commission approves or accepts this Settlement Agreement without modification. If the Commission requires any modification(s) of this Settlement Agreement and if such modification(s) is (are) not fulfilled, then: (i) this Settlement Agreement shall not be binding on any Settling Party; (ii) the Settling Parties shall not be obligated to negotiate further, other than to discuss in good faith whether the modification(s) required by the Commission is (are) acceptable to them; (iii) all Settling Parties shall be deemed to have reserved all of their respective rights and remedies with respect to the issues in this proceeding; and (iv) this Settlement Agreement shall not be part of the record in any subsequent proceedings, and all discussions and negotiations related hereto shall be privileged.

6.6 The titles and headings of the various articles of this Settlement Agreement: (i) are for reference and convenience purposes only; (ii) are not to be construed or taken into account in interpreting the Settlement Agreement; and (iii) do not qualify, modify, or explain the effects of the Settlement Agreement.

6.7 This Settlement Agreement may be amended only by a written instrument duly executed by all Settling Parties. The standard of review for any modification to this Settlement Agreement sought by a Settling Party that is not agreed to by all other Settling Parties shall be the "public interest" standard adopted in the *Sierra-Mobile* line of cases

A Settling Party or Settling Parties seeking to modify the Settlement Agreement in any respect shall bear the applicable burden under the FPA.

6.8 The standard of review for any modifications to this Settlement Agreement requested by an intervenor or other interested entity that is not a Settling Party or that is sought in a proceeding initiated by the Commission acting *sua sponte* will be the most stringent standard permissible under applicable law. For purposes of the application of sections 6.7 and 6.8, all parties who have formally represented in writing, by their respective authorized representative, that they did not object to the Agreement shall be treated as "Settling Parties."

6.9 This Settlement Agreement is submitted pursuant to Rule 602 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §385.602 (2008). Unless and until the Settlement Agreement becomes effective pursuant to its terms, the Settlement Agreement shall be privileged and of no effect and shall not be admissible in evidence or in any way described or discussed in any proceeding before any court or regulatory body (except in comments on the Settlement Agreement in this proceeding).

American Electric Power Service
Corporation as agent for
Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company

By:______________________________

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The following undersigned entities are not parties to the Settlement Agreement, however the undersigned indicate by their signature below that they do not object to this Settlement Agreement:

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The following undersigned entities are not parties to the Settlement Agreement, however the undersigned indicate by their signature below that they do not object to this Settlement Agreement:

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Indiana Office of Utility Consumer Counsel,

By:______________________________

Robert G. Mork
Deputy Consumer Counselor for Federal Affairs
Indiana Attorney No. 19146-49
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
115 West Washington Street, Suite 1500 South
Indianapolis, Indiana 46204
phone: (317) 233-3234
facsimile: (317) 232-5923
rmork@oucc.IN.gov

The following undersigned entities are not parties to the Settlement Agreement, however the undersigned indicate by their signature below that they do not object to this Settlement Agreement:

Public Service Commission of West Virginia,

By:______________________________

Richard E. Hitt, General Counsel
Public Service Commission of West Virginia
Post Office Box 812
Charleston, West Virginia 25323
Phone: (304) 340-0450
Fax: (304) 340-0840
e-mail:rhitt@psc.state.wv.us

West Virginia Energy Users Group,

By:______________________________

Robert A. Weishaar, Jr.
McNees Wallace & Nurick LLC
777 North Capitol Street, N.E.
Suite 401
Washington, DC 20002-4292
Office: 202.898.5700
Cell: 202.409.4170
FAX: 717.260.1765
rweishaa@mwn.com

Indiana Office of Utility Consumer Counsel,

By:______________________________

Robert G. Mork
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rmork@oucc.IN.gov

Indiana Utility Regulatory Commission - Does not oppose or object to Settlement. in FERC Docket No. ER09-1229

By: Beth Krogel Roads

Beth Krogel Roads Legal Counsel, RTO/FERC Issues
Scott R. Storms GENERAL COUNSEL
Indiana Utility Regulatory Commission
101 W. Washington Street, Suite 1500 E
Indianapolis, Indiana 46024
Phone: 317-232-2092

ATTACHMENT A

American Electric Power Service Corporation
Docket No. ER09-1279-000

Transmission Agreement Settlement For Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company (collectively "AEP" or "the AEP East Companies")

Settlement Terms and Conditions

The following terms and conditions are a part of the Settlement Agreement being filed August 4, 2010 in Docket No. ER09-1279 ("the Settlement"):

1. AEP's proposal as originally filed in the captioned docket and accepted and suspended subject to hearing and settlement judge procedures pursuant to *American Elec. Power Serv. Corp*, 128 FERC ¶ 61,123 (2009) (hereinafter referred to as the "Revised Transmission Agreement") will be implemented upon approval of the Settlement, subject to the terms and conditions contained herein.

2. Impacts of the Revised Transmission Agreement will for retail rate making purposes be moderated as described in paragraphs 3 and 4 below, for a three (3) year period commencing on the date of the Commission order approving the Settlement and ending no later than July 31, 2013 for all of the AEP East Companies except Indiana Michigan Power Company.

3. Credits will be applied to Ohio Power Company, Columbus Southern Power Company and Appalachian Power Company -West Virginia to reduce impacts of the Revised Transmission Agreement by 75% in year 1, by 50% in year 2 and by 25% in year 3.

4. Charges will be applied to Kentucky Power Company, Kingsport Power Company and Wheeling Power Company to reduce the decrease in transmission cost allocation under the Revised Transmission Agreement by 75% in year 1, by 50% in year 2 and by 25% in year 3.

5. Impacts of the Revised Transmission Agreement on Indiana Michigan Power Company will be phased in over a four year period commencing

on the date of the Commission order approving the Settlement and ending no later than July 1, 2014.

6. Credits to Indiana Michigan will reduce impacts of the Revised Transmission Agreement by 80% in year 1, 60% in year 2, 40% in year 3 and 20% in year 4.

7. All parties to the Settlement reserve their respective rights under sections 205, 206 and 306 of the Federal Power act, however, the Settlement will be voided if a filing is made under 206 challenging the Revised Transmission Agreement or this Settlement. In addition, while the Settlement is in effect, AEP will not modify Appendix I of the Revised Transmission Agreement unless such 206 filing is made by a non-AEP settling party.

8. AEP shall not seek recovery of any shortfall of revenues resulting from the application of the terms and conditions of this Settlement Agreement in any Ohio state regulatory proceeding, except as provided for in the Settlement.

9. The Transmission Agreement will be modified as provided in Attachment B.

10. The credits and charges pursuant to paragraphs 3, 4 and 6 above shall be as follows:

	Year 1	Year 2	Year 3	Year 4
	(Dollars in Millions)			
APCo WV	(6.9)	(4.6)	(2.3)	0
CSP	(2.4)	(1.6)	(0.8)	0
I&M	(24.1)	(18.1)	(12.1)	(6.0)
KPCo	3.1	2.1	1.1	0
KgPCo	3.0	2.0	1.0	0
OPCo	(10.9)	(7.3)	(3.6)	0
WPCo	1.9	1.2	0.6	0

ATTACHMENT B -1
(Marked Version)

TRANSMISSION AGREEMENT

By and among

APPALACHIAN POWER COMPANY

COLUMBUS SOUTHERN POWER COMPANY

INDIANA MICHIGAN POWER COMPANY

KENTUCKY POWER COMPANY

KINGSPORT POWER COMPANY

OHIO POWER COMPANY

WHEELING POWER COMPANY

and with

AMERICAN ELECTRIC POWER SERVICE CORPORATION

AS AGENT

DATED APRIL 1984, AS AMENDED

CONTENTS

0.1 THIS AGREEMENT, made and entered into as of the 1st day of April, 1984, and as subsequently amended, by and among APPALACHIAN POWER COMPANY (Appalachian Company), a Virginia corporation, COLUMBUS AND SOUTHERN POWER COMPANY (Columbus Company), an Ohio corporation, INDIANA MICHIGAN POWER COMPANY (Indiana Company), an Indiana corporation, KENTUCKY POWER COMPANY (Kentucky Company), a Kentucky corporation, OHIO POWER COMPANY (Ohio Company), an Ohio corporation, KINGSPORT POWER COMPANY (Tennessee Company), a Tennessee corporation, and WHEELING POWER COMPANY (Wheeling Company), a West Virginia corporation, said companies (herein sometimes called 'Members' when referred to collectively and 'Member' when referred to individually) being affiliated companies of the integrated public utility electric system known as the American Electric Power SYSTEM (AEP System), and AMERICAN ELECTRIC POWER SERVICE CORPORATION (Agent), a New York corporation, being a service company engaged solely in the business of furnishing essential services to the aforesaid companies and to other affiliated companies.

W I T N E S S E T H,

T H A T:

0.2 WHEREAS, the Members own and operate electric facilities in the states herein indicated, (i) Appalachian Company in Virginia, West Virginia, and Tennessee (ii) Columbus Company in Ohio, (iii) Indiana Company in Indiana and Michigan, (iv) Kentucky Company in Kentucky, (v) Tennessee Company in Tennessee, (vi) Ohio Company in Ohio and West Virginia, and (vii) Wheeling Company in West Virginia; and

0.3 WHEREAS, certain of the Members have entered into an interconnection agreement, dated July 6, 1951, with modification thereto, which provides for certain understandings, conditions, and procedures designed to achieve the full benefits and advantages available through the coordinated operation of their electric power supply facilities; and

0.4 WHEREAS, The Members' electric facilities are now and for many years have been interconnected through their respective transmission facilities at a number of points, forming an integrated transmission network; and

0.5 WHEREAS, the Members have achieved benefits through the coordinated planning and development of a fully integrated Transmission System; and

0.6 WHEREAS, the members believe that an agreement which provides for the equitable sharing among the Members of the costs incurred by the Members in connection with the ownership, operation, and maintenance of their respective portions of the Transmission System would enhance equity among the Members for the continued development of a reliable and economic Transmission System; and

0.7 WHEREAS, effective October 1, 2004 the Members joined the PJM Interconnection, LLC ("PJM"), and placed their respective transmission facilities under the functional control of PJM, a regional transmission operator or "RTO"; and

0.8 WHEREAS, PJM provides transmission service, pursuant to the PJM Open Access Transmission Tariff ("OATT"), to the Members and others who require transmission service over the Transmission System; and

0.9 WHEREAS, the Members believe that benefits and advantages could be best realized if this Agreement were administered by a single clearing agent; and

0.10 WHEREAS, the Members believe that the Agent designated herein for such purpose is qualified to perform such services;

0.11 NOW, THEREFORE, in consideration of the premises and of the mutual covenants and agreements hereinafter contained, the parties hereto hereby agree as follows:

ARTICLE 1

DESCRIPTION OF TRANSMISSION SYSTEM

1.1 The Transmission System covered by this Agreement shall include all the transmission facilities, from time to time, owned by the Members that are included in the costs of service used to determine rates for transmission service under the PJM OATT, ~~including without limitation, (i) All Member transmission lines; (ii) all facilities such as transformers, buses, switchgear, and associated facilities located at Member transmission substations, and (iii) any other transmission lines and associated substation facilities at any voltage designated by the Transmission Committee as having been, installed or leased for the mutual benefit of all Members and/or others who receive transmission service from PJM or a successor RTO or other successor transmission service provider~~or successor open access transmission tariff.

ARTICLE 2

OPERATION

2.1 Each member shall maintain its respective portion of the Bulk Transmission System, together with all associated facilities and appurtenances, in a suitable condition of repair at all times in order that said system will operate in a reliable and satisfactory manner.

ARTICLE 3

TRANSMISSION COMMITTEE

3.1 The Members shall appoint representatives to serve on a Transmission Committee. Such representatives shall have authority to act for the Members in the administration of all matters pertaining to this Agreement.

3.2 Each Member shall designate in writing, delivered to the other Members and Agent, the person who is to act as its representative on said Committee and the person or persons who may serve as alternate whenever such representative is unavailable to act. Agent shall designate in writing delivered to the Members the person who is to act as its representative on said Committee and the person or persons who may serve as alternate whenever such representative is unavailable to act. Such person designated by Agent shall act as chairman of the Transmissions Committee and shall be known as the "Transmission Manager".

ARTICLE 4

AGENTS RESPONSIBILITIES

4.1 For the purpose of carrying out the provisions of this Agreement the Members hereby delegate to Agent, and Agent hereby accepts, the responsibility of administration of this Agreement, and in furtherance thereof Agent hereby agrees:

4.11 To arrange for and conduct such meetings of the Transmission Committee as may be required to insure the effective and efficient carrying out of all matters of procedure essential to the complete performance of the provisions of this Agreement.

4.12 To carry out settlements under this Agreement. Settlements by the Members shall be made for each calendar month through General Ledger accounts (hereby designated and hereinafter called the "TRANSMISSION ACCOUNTS") to be administered by Agent. For the purposes of This Agreement, Transmission Accounts shall be consistent with the accounts listed in the FERC Uniform System of Accounts, and shall include such accounts and sub-accounts as are necessary and proper, directed by the Transmission Committee, and consistent with applicable regulatory requirements.

ARTICLE 5

SETTLEMENTS

5.1 As provided in this Article, following the end of each month, the Members shall effect settlements through the TRANSMISSION ACCOUNTS. Generally, Settlements hereunder will involve the allocation among the Members of transmission-related costs and revenues as incurred and accrued under the PJM OATT,

or successor open access transmission tariff ~~among the Members~~, and the recording of same in the Transmission Accounts of the Members, as specified in Appendix I consistent with the Settlement Agreement approved in FERC Docket No. ER09-1279-000.

5.2 All amounts to be allocated among the Members hereunder shall, to the extent practicable, be included in Settlements for the month in which such cost or revenue is realized or accrued. If necessary in order to implement such timely Settlement, the Agent shall be authorized to effect Settlements on an estimated basis and make such adjustment as is needed in subsequent Settlements that will conform the Settlements to the terms of this Agreement.

5.3 For such time as Member Tennessee Company and/or Wheeling Company (Buyer) purchase power from Members Appalachian Company and Ohio Company (Seller), respectively, under agreements that provide for transmission service and related charges to Buyer from Seller (Purchased Power Agreements or "PPAs"), Seller will be allocated or assigned the costs as described on Appendix I, numbers seven (7) through fifteen (15), that would otherwise have been allocated or assigned to Buyer under this Agreement. The total amount of such allocated or assigned costs will be passed through to Buyer by Seller as the transmission service and related charges provided for in their PPAs. Such transmission and related costs will be the only transmission charges passed through to Buyer under any such PPA. When any such PPA expires or is otherwise modified or superseded, the provisions of the PPA that provide for transmission service and related charges to Buyer from Seller will be discontinued and Tennessee Company and/or Wheeling Company will receive directly, by allocation or direct assignment, the transmission and related costs pursuant to this agreement, as described on Appendix I, numbers seven (7) through fifteen (15). At such time, Seller shall no longer be allocated or assigned costs which are properly allocable or assignable to Buyer under this Agreement. Further, from the effective date of this Agreement as modified in FERC Docket No. ER09-1279, all the Members, including Tennessee Company and Wheeling Company, will receive direct allocation of revenues as provided herein and described on Appendix I, numbers one (1) though six (6).

ARTICLE 6

TAXES

6.1 If at any time during the duration of this Agreement there should be levied and/or assessed by any governmental authority against any Member any tax related to the receipt of Settlements calculated pursuant to this Agreement (such as sales, excise or similar taxes), such tax expense incurred by such Member that would not have been incurred were the Settlements hereunder not being made, such Member shall be entitled, to the extent permitted by the applicable regulatory authority(ies) to include such tax in its transmission revenue requirement under the PJM or successor OATT when transmission revenue requirements of the Members are next updated, and thereby receive an appropriate level of reimbursement (through cost sharing) for such additional taxes by Members and others receiving service from the Transmission System.

ARTICLE 7

Allocation Principles

7.1 All items of cost and revenue included in Settlements hereunder shall be related to the provision of or receipt of transmission service or a related ("ancillary") service by one or more Members~~on behalf of one or more of the Members~~. The allocation methods used to share such costs and revenues, as specified in Appendix I, shall be made pursuant to direction by the Transmission Committee.

7.2 The Transmission Committee may at any time during the Term of This Agreement, upon the recommendation of the Agent or any Member, review any item of cost or revenue, in order to determine whether such item is transmission-related, and whether it should be included in Settlements hereunder. Further, whenever the Transmission Committee determines that any change is needed in Appendix I to add or delete any item of cost or revenue, or to change the allocation or accounting basis of any item, the Transmission Committee shall authorize and direct the Agent ~~when and how~~to effect such change in Appendix I and in monthly Settlements among the Members and to make any filing with the applicable regulatory authority(ies) to implement such change. pursuant to the PJM OATT or any successor open access transmission tariff.

~~7.3 Allocations of costs shall, to the extent practicable, be based on measurable cost indicators that will effect a sharing of costs among the Members consistent with the use of such service, and will be sufficiently stable, over time, so as~~

~~not to cause undue or objectionable variability in the costs of the Members.~~

~~7.4 Allocations of revenues shall, to the extent practicable, be based on measurable indicators of the cost incurred by each Member in providing the service that gave rise to the revenue~~

ARTICLE 8

MODIFICATION

8.1 Any Member, or the Agent, by written notice given to the other Members and Agent, may call for a reconsideration of the terms and conditions herein provided. If such reconsideration is called for, the Members shall take into account any changed conditions, any results from the application of said terms and conditions, and any other facts that might cause said terms and conditions to result in an inequitable sharing of costs and benefits under this Agreement. Any modification in terms and conditions agreed to by the Members following such reconsideration shall become effective the first day of the month following authorization of such reconsideration by appropriate regulatory authority.

ARTICLE 9

EFFECTIVE DATE AND TERM OF THIS AGREEMENT

9.1 This Agreement shall become effective and shall become a binding obligation of the Parties on the date specified in an Order in such proceeding as this Agreement shall have been filed with, and accepted for filing by the Federal Energy Regulatory Commission (FERC) under the Federal Power Act as a rate schedule.

9.2 This Agreement shall continue in effect for four years from the effective date of the final order in Docket No. ER09-1279-000 ~~for an initial period from the Effective Date to December 31, 1990, and thereafter~~for successive periods of one year each until terminated as provided under subsection 9.3 below.

9.3 Any Member upon at least three years' prior written notice to the other Members and Agent may terminate this Agreement at the expiration ~~of said initial period or at the expiration of any successive period of one yea~~such notice period~~r~~.

ARTICLE 10

REGULATORY AUTHORITIES

10.1 The Members recognize that this Agreement, and any tariff or rate schedule which shall embody or supersede this Agreement or any part thereof, are in certain respects subject to the jurisdiction of the FERC under the Federal Power Act, and are also subject to such lawful action as any regulatory authority having jurisdiction shall hereafter take with respect thereto. The performance of any obligation of the Members shall be subject to the receipt from time to time as required of such authorizations, approvals or actions of regulatory authorities having jurisdiction as shall be required by law.

10.2 Subject to the terms of the Settlement in Docket NO. ER09-1279-000, ~~I~~it is expressly understood that any Member under this Agreement, as it may hereafter from time to time be modified and supplemented by the Members, shall be entitled, at any time and from time to time, unilaterally to make application to the FERC for a change in rates, charges, classification of service, or any rule, regulation or contract relating thereto, or to make any change in or supersede in whole or in part any provision of this Agreement, under Section 205 of the Federal Power Act and pursuant to the FERC's Rules and Regulations promulgated thereunder.

ARTICLE 11

ASSIGNMENT

11.1 This Agreement shall inure to the benefit of and be binding upon the successors and assigns of the respective parties.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed in their respective corporate names and on their behalf by their proper officers thereunto daily authorized as of the day and year first above written.

Next Page is Signature Page

Transmission Agreement Among:

AMERICAN ELECTRIC POWER SERVICE CORPORATION,

By:________________________

~~Michael Heyeck~~
Senior Vice President

APPALACHIAN POWER COMPANY,

By:________________________

~~Dana E. Waldo~~
President and Chief Operating Officer

COLUMBUS SOUTHERN POWER COMPANY,

By:________________________

~~Joseph Hamrock~~
President and Chief Operating Officer

INDIANA MICHIGAN POWER COMPANY,

By:________________________

~~Helen J. Murray~~
President and Chief Operating Officer

KENTUCKY POWER COMPANY,

By:________________________

~~Timothy C. Mosher~~
President and Chief Operating Officer

KINGSPORT POWER COMPANY,

By:________________________

~~Dana E. Waldo~~
President and Chief Operating Officer

OHIO POWER COMPANY, and

By:________________________

~~Brian X. Tierney~~
Vice President

WHEELING POWER COMPANY

By:________________________

~~Dana E. Waldo~~
President

Dated as of: ______________________

Appalachian Power Company
20
First Revised Rate Schedule FERC No. 34

Original Sheet No.

Appendix I

AEP Transmission Agreement
Allocation of Transmission Related Costs and Revenues

AEP as Transmission Owner (Revenues)

#	Item	FERC Account*	PJM Billing Basis	AEP Allocation Basis
1	Transmission Owner Scheduling, System Control and Dispatch Service (PJM Schedule 1A)	456.1	NSPL	ARR S1A
2	NITS (AEP LSE)	456.1	NSPL	ATRR
3	NITS (Non-Affiliates)	456.1	NSPL	ATRR
4	Grandfathered PTP (NCEMC)	456.0	Contract	ATRR
5	PJM Expansion Cost Recovery Charge (ECRC)	456.1	NSPL	ARR EC
6	RTO Startup Cost Recovery Charge (SCRC)	456.1	NSPL	ARR SC

AEP as LSE (Expenses)

#	Item	FERC Account*	PJM Billing Basis	AEP Allocation Basis
7	Transmission Owner Scheduling, System Control and Dispatch Service (PJM Schedule 1A)	456.1	MWh	MWh
8	NITS Charges (for AEP Retail Load)	456.1	NSPL	12CP
9	NITS Charges for AEP FR Customers[1/]	447.0	NSPL	DA
10	NITS Reimbursement from AEP FR Customers[1/]	447.0	NSPL	DA
~~11~~	~~Schedule 1A Charge for AEP FR Customers~~	~~447.0~~	~~NSPL~~	~~DA~~
~~12~~	~~Schedule 1A Reimbursement from AEP FR Customers~~	~~447.0~~	~~NSPL~~	~~DA~~
11	Firm Point-to-Point Credits (for AEP Retail Load)	456.1	NSPL	12CP
12	Non-Firm Point-to-Point Credits (AEP Retail Load)	456.1	NSPL	12CP
13	Transmission Enhancement (Schedule 12)	565.0	NSPL	12CP
14	PJM Expansion Cost Recovery Charge (ECRC)	456.1	NSPL	12CP
15	RTO Startup Cost Recovery Charge (SCRC)	456.1	NSPL	12CP

NSPL	PJM Network Service Peak Load
Contract	Pre-OATT FERC Rate Schedules
ARR S1A	Annual Revenue Requirement - Schedule 1A
ATRR	Annual Transmission Revenue Requirement
ARR EC	Annual Revenue Requirement - Expansion Cost Recovery
ARR SC	Annual Revenue Requirement - Startup Cost Recovery
12CP	Average of 12 coincident peaks through 10/31 of prior year
DA	Directly Assigned to Operating Company

* Note: Should the net amount in 456.1 for any Member be negative, e.g. more expense than revenue, the net expense will be recorded in 565.0.

Issued By: Richard E. Munczinski
Senior Vice President, Regulatory Services

Effective: first day of the month after the Commission issues a final, non- appealable order accepting the Agreement for filing

Issued On: August 4, 2010

1/ Includes all transmission-related LSE expenses (NITS, Schedule 1A, Point-to-Point Credits, Schedule 12, ECRC, SCRC) which are directly assigned to Operating Company for AEP FR Customers.

ATTACHMENT B -2
(Unmarked Version)

TRANSMISSION AGREEMENT

By and among

APPALACHIAN POWER COMPANY

COLUMBUS SOUTHERN POWER COMPANY

INDIANA MICHIGAN POWER COMPANY

KENTUCKY POWER COMPANY

KINGSPORT POWER COMPANY

OHIO POWER COMPANY

WHEELING POWER COMPANY

and with

AMERICAN ELECTRIC POWER SERVICE CORPORATION

AS AGENT

DATED APRIL 1984, AS AMENDED

CONTENTS

0.1 THIS AGREEMENT, made and entered into as of the 1st day of April, 1984, and as subsequently amended, by and among APPALACHIAN POWER COMPANY (Appalachian Company), a Virginia corporation, COLUMBUS AND SOUTHERN POWER COMPANY (Columbus Company), an Ohio corporation, INDIANA MICHIGAN POWER COMPANY (Indiana Company), an Indiana corporation, KENTUCKY POWER COMPANY (Kentucky Company), a Kentucky corporation, OHIO POWER COMPANY (Ohio Company), an Ohio corporation, KINGSPORT POWER COMPANY (Tennessee Company), a Tennessee corporation, and WHEELING POWER COMPANY (Wheeling Company), a West Virginia corporation, said companies (herein sometimes called 'Members' when referred to collectively and 'Member' when referred to individually) being affiliated companies of the integrated public utility electric system known as the American Electric Power SYSTEM (AEP System), and AMERICAN ELECTRIC POWER SERVICE CORPORATION (Agent), a New York corporation, being a service company engaged solely in the business of furnishing essential services to the aforesaid companies and to other affiliated companies.

W I T N E S S E T H,

T H A T:

0.2 WHEREAS, the Members own and operate electric facilities in the states herein indicated, (i) Appalachian Company in Virginia, West Virginia, and Tennessee (ii) Columbus Company in Ohio, (iii) Indiana Company in Indiana and Michigan, (iv) Kentucky Company in Kentucky, (v) Tennessee Company in Tennessee, (vi) Ohio Company in Ohio and West Virginia, and (vii) Wheeling Company in West Virginia; and

0.3 WHEREAS, certain of the Members have entered into an interconnection agreement, dated July 6, 1951, with modification

thereto, which provides for certain understandings, conditions, and procedures designed to achieve the full benefits and advantages available through the coordinated operation of their electric power supply facilities; and

0.4 WHEREAS, The Members' electric facilities are now and for many years have been interconnected through their respective transmission facilities at a number of points, forming an integrated transmission network; and

0.5 WHEREAS, the Members have achieved benefits through the coordinated planning and development of a fully integrated Transmission System; and

0.6 WHEREAS, the members believe that an agreement which provides for the equitable sharing among the Members of the costs incurred by the Members in connection with the ownership, operation, and maintenance of their respective portions of the Transmission System would enhance equity among the Members for the continued development of a reliable and economic Transmission System; and

0.7 WHEREAS, effective October 1, 2004 the Members joined the PJM Interconnection, LLC ("PJM"), and placed their respective transmission facilities under the functional control of PJM, a regional transmission operator or "RTO"; and

0.8 WHEREAS, PJM provides transmission service, pursuant to the PJM Open Access Transmission Tariff ("OATT"), to the Members and others who require transmission service over the Transmission System; and

0.9 WHEREAS, the Members believe that benefits and advantages could be best realized if this Agreement were administered by a single clearing agent; and

0.10 WHEREAS, the Members believe that the Agent designated herein for such purpose is qualified to perform such services;

0.11 NOW, THEREFORE, in consideration of the premises and of the mutual covenants and agreements hereinafter contained, the parties hereto hereby agree as follows:

ARTICLE 1

DESCRIPTION OF TRANSMISSION SYSTEM

1.1 The Transmission System covered by this Agreement shall include all the transmission facilities, from time to time, owned by the Members that are included in the costs of service used to determine rates for transmission service under the PJM OATT, or successor open access transmission tariff.

ARTICLE 2

OPERATION

2.1 Each member shall maintain its respective portion of the Bulk Transmission System, together with all associated facilities and appurtenances, in a suitable condition of repair at all times in order that said system will operate in a reliable and satisfactory manner.

ARTICLE 3

TRANSMISSION COMMITTEE

3.1 The Members shall appoint representatives to serve on a Transmission Committee. Such representatives shall have authority to act for the Members in the administration of all matters pertaining to this Agreement.

3.2 Each Member shall designate in writing, delivered to the other Members and Agent, the person who is to act as its representative on said Committee and the person or persons who may serve as alternate whenever such representative is unavailable to act. Agent shall designate in writing delivered to the Members the person who is to act as its representative on said Committee and the person or persons who may serve as alternate whenever such representative is unavailable to act. Such person designated by Agent shall act as chairman of the Transmissions Committee and shall be known as the "Transmission Manager".

ARTICLE 4

AGENTS RESPONSIBILITIES

4.1 For the purpose of carrying out the provisions of this Agreement the Members hereby delegate to Agent, and Agent hereby accepts, the responsibility of administration of this Agreement, and in furtherance thereof Agent hereby agrees:

4.11 To arrange for and conduct such meetings of the Transmission Committee as may be required to insure the effective and efficient carrying out of all matters of procedure essential to the complete performance of the provisions of this Agreement.

4.12 To carry out settlements under this Agreement. Settlements by the Members shall be made for each calendar month through General Ledger accounts (hereby designated and hereinafter called the "TRANSMISSION ACCOUNTS") to be administered by Agent. For the purposes of This Agreement, Transmission Accounts shall be consistent with the accounts listed in the FERC Uniform System of Accounts, and shall include such accounts and sub-accounts as are necessary and proper, directed by the Transmission Committee, and consistent with applicable regulatory requirements.

ARTICLE 5

SETTLEMENTS

5.1 As provided in this Article, following the end of each month, the Members shall effect settlements through the TRANSMISSION ACCOUNTS. Generally, Settlements hereunder will involve the allocation among the Members of transmission-related costs and revenues as incurred and accrued under the PJM OATT,

or successor open access transmission tariff, and the recording of same in the Transmission Accounts of the Members, as specified in Appendix I consistent with the Settlement Agreement approved in FERC Docket No. ER09-1279-000.

5.2 All amounts to be allocated among the Members hereunder shall, to the extent practicable, be included in Settlements for the month in which such cost or revenue is realized or accrued. If necessary in order to implement such timely Settlement, the Agent shall be authorized to effect Settlements on an estimated basis and make such adjustment as is needed in subsequent Settlements that will conform the Settlements to the terms of this Agreement.

5.3 For such time as Member Tennessee Company and/or Wheeling Company (Buyer) purchase power from Members Appalachian Company and Ohio Company (Seller), respectively, under agreements that provide for transmission service and related charges to Buyer from Seller (Purchased Power Agreements or "PPAs"), Seller will be allocated or assigned the costs as described on Appendix I, numbers seven (7) through fifteen (15), that would otherwise have been allocated or assigned to Buyer under this Agreement. The total amount of such allocated or assigned costs will be passed through to Buyer by Seller as the transmission service and related charges provided for in their PPAs. Such transmission and related costs will be the only transmission charges passed through to Buyer under any such PPA. When any such PPA expires or is otherwise modified or superseded, the provisions of the PPA that provide for

transmission service and related charges to Buyer from Seller will be discontinued and Tennessee Company and/or Wheeling Company will receive directly, by allocation or direct assignment, the transmission and related costs pursuant to this agreement, as described on Appendix I, numbers seven (7) through fifteen (15). At such time, Seller shall no longer be allocated or assigned costs which are properly allocable or assignable to Buyer under this Agreement. Further, from the effective date of this Agreement as modified in FERC Docket No. ER09-1279, all the Members, including Tennessee Company and Wheeling Company, will receive direct allocation of revenues as provided herein and described on Appendix I, numbers one (1) though six (6).

ARTICLE 6

TAXES

6.1 If at any time during the duration of this Agreement there should be levied and/or assessed by any governmental authority against any Member any tax related to the receipt of Settlements calculated pursuant to this Agreement (such as sales, excise or similar taxes), such tax expense incurred by such Member that would not have been incurred were the Settlements hereunder not being made, such Member shall be entitled, to the extent permitted by the applicable regulatory authority(ies) to include such tax in its transmission revenue requirement under the PJM or successor OATT when transmission revenue requirements of the Members are next updated, and thereby receive an appropriate level of reimbursement (through cost sharing) for such additional taxes by Members and others receiving service from the Transmission System.

ARTICLE 7

Allocation Principles

7.1 All items of cost and revenue included in Settlements hereunder shall be related to the provision of or receipt of transmission service or a related ("ancillary") service by one or more Members. The allocation methods used to share such costs and revenues, as specified in Appendix I, shall be made pursuant to direction by the Transmission Committee.

7.2 The Transmission Committee may at any time during the Term of This Agreement, upon the recommendation of the Agent or any Member, review any item of cost or revenue, in order to determine whether such item is transmission-related, and whether it should be included in Settlements hereunder. Further, whenever the Transmission Committee determines that any change is needed in Appendix I to add or delete any item of cost or revenue, or to change the allocation or accounting basis of any item, the Transmission Committee shall authorize and direct the Agent to effect such change in Appendix I and in monthly Settlements among the Members and to make any filing with the applicable regulatory authority(ies) to implement such change. pursuant to the PJM OATT or any successor open access transmission tariff.

ARTICLE 8

MODIFICATION

8.1 Any Member, or the Agent, by written notice given to the other Members and Agent, may call for a reconsideration of the terms and conditions herein provided. If such

reconsideration is called for, the Members shall take into account any changed conditions, any results from the application of said terms and conditions, and any other facts that might cause said terms and conditions to result in an inequitable sharing of costs and benefits under this Agreement. Any modification in terms and conditions agreed to by the Members following such reconsideration shall become effective the first day of the month following authorization of such reconsideration by appropriate regulatory authority.

ARTICLE 9

EFFECTIVE DATE AND TERM OF THIS AGREEMENT

9.1 This Agreement shall become effective and shall become a binding obligation of the Parties on the date specified in an Order in such proceeding as this Agreement shall have been filed with, and accepted for filing by the Federal Energy Regulatory Commission (FERC) under the Federal Power Act as a rate schedule.

9.2 This Agreement shall continue in effect for four years from the effective date of the final order in Docket No. ER09-1279-000 for successive periods of one year each until terminated as provided under subsection 9.3 below.

9.3 Any Member upon at least three years' prior written notice to the other Members and Agent may terminate this Agreement at the expiration of such notice period.

ARTICLE 10

REGULATORY AUTHORITIES

10.1 The Members recognize that this Agreement, and any tariff or rate schedule which shall embody or supersede this

Agreement or any part thereof, are in certain respects subject to the jurisdiction of the FERC under the Federal Power Act, and are also subject to such lawful action as any regulatory authority having jurisdiction shall hereafter take with respect thereto. The performance of any obligation of the Members shall be subject to the receipt from time to time as required of such authorizations, approvals or actions of regulatory authorities having jurisdiction as shall be required by law.

10.2 Subject to the terms of the Settlement in Docket NO. ER09-1279-000, it is expressly understood that any Member under this Agreement, as it may hereafter from time to time be modified and supplemented by the Members, shall be entitled, at any time and from time to time, unilaterally to make application to the FERC for a change in rates, charges, classification of service, or any rule, regulation or contract relating thereto, or to make any change in or supersede in whole or in part any provision of this Agreement, under Section 205 of the Federal Power Act and pursuant to the FERC's Rules and Regulations promulgated thereunder.

ARTICLE 11

ASSIGNMENT

11.1 This Agreement shall inure to the benefit of and be binding upon the successors and assigns of the respective parties.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed in their respective corporate names and on their behalf by their proper officers thereunto daily authorized as of the day and year first above written.

Next Page is Signature Page

Transmission Agreement Among:

AMERICAN ELECTRIC POWER
SERVICE CORPORATION,

By:_________________________

Senior Vice President

APPALACHIAN POWER COMPANY,

By:_________________________

President and Chief Operating
Officer

COLUMBUS SOUTHERN POWER
COMPANY,

By:_________________________

President and Chief Operating
Officer

INDIANA MICHIGAN POWER
COMPANY,

By:_________________________

KENTUCKY POWER COMPANY,

By:_________________________

President and Chief Operating
Officer

KINGSPORT POWER COMPANY,

By:_________________________

President and Chief Operating
Officer

OHIO POWER COMPANY, and

By:_________________________

Vice President

WHEELING POWER COMPANY

By:_________________________

President

Dated as of:

____

Appalachian Power Company Original Sheet No. 36
First Revised Rate Schedule FERC No. 34

Appendix I

AEP Transmission Agreement
Allocation of Transmission Related Costs and Revenues

AEP as Transmission Owner (Revenues)

#	Item	FERC Account*	PJM Billing Basis	AEP Allocation Basis
1	Transmission Owner Scheduling, System Control and Dispatch Service (PJM Schedule 1A)	456.1	NSPL	ARR S1A
2	NITS (AEP LSE)	456.1	NSPL	ATRR
3	NITS (Non-Affiliates)	456.1	NSPL	ATRR
4	Grandfathered PTP (NCEMC)	456.0	Contract	ATRR
5	PJM Expansion Cost Recovery Charge (ECRC)	456.1	NSPL	ARR EC
6	RTO Startup Cost Recovery Charge (SCRC)	456.1	NSPL	ARR SC

AEP as LSE (Expenses)

#	Item	FERC Account*	PJM Billing Basis	AEP Allocation Basis
7	Transmission Owner Scheduling, System Control and Dispatch Service (PJM Schedule 1A)	456.1	MWh	MWh
8	NITS Charges (for AEP Retail Load)	456.1	NSPL	12CP
9	NITS Charges for AEP FR Customers[1/]	447.0	NSPL	DA
10	NITS Reimbursement from AEP FR Customers[1/]	447.0	NSPL	DA
11	Firm Point-to-Point Credits (for AEP Retail Load)	456.1	NSPL	12CP
12	Non-Firm Point-to-Point Credits (AEP Retail Load)	456.1	NSPL	12CP
13	Transmission Enhancement (Schedule 12)	565.0	NSPL	12CP
14	PJM Expansion Cost Recovery Charge (ECRC)	456.1	NSPL	12CP
15	RTO Startup Cost Recovery Charge (SCRC)	456.1	NSPL	12CP

NSPL PJM Network Service Peak Load
Contract Pre-OATT FERC Rate Schedules
ARR S1A Annual Revenue Requirement - Schedule 1A
ATRR Annual Transmission Revenue Requirement
ARR EC Annual Revenue Requirement - Expansion Cost Recovery
ARR SC Annual Revenue Requirement - Startup Cost Recovery
12CP Average of 12 coincident peaks through 10/31 of prior year
DA Directly Assigned to Operating Company

* Note: Should the net amount in 456.1 for any Member be negative, e.g. more expense than revenue, the net expense will be recorded in 565.0.

1/ Includes all transmission-related LSE expenses (NITS, Schedule 1A, Point-to-Point Credits, Schedule 12, ECRC, SCRC) which are directly assigned to Operating Company for AEP FR Customers.

Issued By: Richard E. Munczinski
Senior Vice President, Regulatory Services

Effective: first day of the month after the Commission issues a final, non- appealable order accepting the Agreement for filing

Issued On: August 4, 2010

August 4, 2010

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1A
Washington, D.C. 20426

Monique Rowtham-Kennedy
Senior Counsel -
Regulatory Services
(202) 383-3436
(202) 383-3459 (F)

Re: **American Electric Power Service Corporation,**
FERC Docket No. ER09-1279-000

Dear Secretary Bose:

Pursuant to Rule 602 of the Federal Energy Regulatory Commission's (the "Commission") Rules of Practice and Procedure, 18 C.F.R.§385.602 (2008), American Electric Power Service Corporation ("AEPSC") on behalf of its affiliates, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company (collectively "AEP" or the "AEP East Companies"), and the following Settling Parties: Public Utilities Commission of Ohio, East Tennessee Energy Consumers, Hoosier Energy Rural Electric Cooperative and the Office of the Ohio Consumers' Counsel, and , (individually, a "Settling Party," and, collectively, the "Settling Parties") submit an original and fourteen copies of an Offer of Settlement intended to resolve without need for evidentiary procedures all issues set for hearing in the captioned proceedings. In addition, this Settlement is supported or not opposed by all parties who have intervened in this proceeding except Steel Dynamics, Inc. and Kentucky Public Service Commission who take no position with respect to the Settlement.[1]

This Offer of Settlement includes the following documents:

1. Explanatory Statement (Appendix A);
2. Settlement Agreement (Appendix B), and several attachments described below;
3. Draft Order Approving Settlement Agreement (Appendix C), and

[1] In addition to the Settling Parties, the non-opposing parties are Consumer Advocate Division of the Public Service Commission of West Virginia, Virginia State Corporation Commission, Old Dominion Committee for Fair Utility Rates, Public Service Commission of West Virginia, Indiana Utility Regulatory Commission, Indiana Office of Utility Consumer Counsel, and the West Virginia Energy Users Group.

4. Service List (Appendix D).

The attachments to the Settlement Agreement, Appendix B, include the following:

1. Attachment A, Settlement Terms and Conditions;
2. Attachment B-1, Revised Rate Schedule language (Blacklined);
3. Attachment B-2, Revised Rate Schedule language (Clean);

All parties in this proceeding and the Commission's Trial Staff have had the opportunity to review and comment on the Offer of Settlement. The Settling Parties expect this Offer of Settlement to be unopposed.

AEP requests that the appropriate number of copies of this filing be transmitted to Presiding Administrative Law Judge David Coffman in accordance with Commission Rule 602(b)(2)(i). In accordance with Rule 602(d), copies of this filing have been served on all participants in this proceeding and on all affected state commissions.

The Settling Parties request that, once the comment period specified in Rule 602(f) has passed, Judge Coffman certify the Settlement Agreement to the Commission, as required by Rule 602(g)(1), as expeditiously as possible.

Respectfully submitted

Monique Rowtham-Kennedy
Senior Counsel
American Electric Power Service Corporation

Enclosures

Docket No. ER09-1279-000

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

American Electric Power Service Corporation	))	Docket No. ER09-1279-000

EXPLANATORY STATEMENT
IN SUPPORT OF SETTLEMENT AGREEMENT

Pursuant to Rule 602 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.602 (2008), American Electric Power Service Corporation ("AEPSC"), on behalf of Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company (collectively "AEP" or the "AEP East Companies") and the following Settling Parties: Public Utilities Commission of Ohio, East Tennessee Energy Consumers, Hoosier Energy Rural Electric Cooperative, and the Office of the Ohio Consumers' Counsel (individually, a "Settling Party," and, collectively, the "Settling Parties") hereby submit this Explanatory Statement in support of the concurrently filed Settlement Agreement, which is intended to resolve all issues in this proceeding. In addition, this Settlement is supported or not opposed by all parties who have intervened in this proceeding, except Steel Dynamics, Inc., and Kentucky Public Service Commission, which take no position with respect to the Settlement. [1]

[1] In addition to the Settling Parties, the non-opposing parties are Consumer Advocate Division of the Public Service Commission of West Virginia, Virginia State Corporation Commission, Old Dominion Committee for Fair Utility Rates, Public Service Commission of West Virginia, Indiana Utility Regulatory Commission, Indiana Office of Utility Consumer Counsel, and the West Virginia Energy Users Group.

I. INTRODUCTION

AEP is a multi-state electric utility holding company system, providing electric service to approximately five million customers in parts of eleven states. AEP represented in its filing in this case that the AEP System is planned and operated on an integrated basis pursuant to various agreements under which the AEP operating companies pool or combine their individual systems to achieve the benefits of integrated operation. This proceeding involves proposed amendments to one such agreement -- the Transmission Agreement entered into in 1984 among five of the AEP East Companies-Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company and Ohio Power Company and administered by AEPSC, as Agent. As approved by the Commission,[2] the Agreement shares the costs of the Members' investments in Extra-High-Voltage (EHV) and high-voltage facilities operated at 138 kilovolts (138 kV) and above.

On June 5, 2009 AEP filed with the Commission proposed amendments to the Transmission Agreement. The proposed amendments, if approved, would effect a comprehensive reallocation of transmission-related costs and revenues among the AEP East Companies including two new Members, Kingsport Power Company and Wheeling Power Company.[3] AEP represented in its filing that the proposed amendments recognize that, pursuant to the PJM Open Access Transmission Tariff ("PJM OATT"), the AEP East Companies, including Kingsport and Wheeling, and other load serving entities in the

[2] *American Electric Power Service Corp.*, Opinion No. 311, 44 FERC ¶ 61,206 (1987), *reh. denied*, Opinion No. 311-A, 45 FERC ¶ 61,382 (1988).
[3] Kingsport and Wheeling are relatively small operating companies that own no generating facilities but do own transmission facilities.

AEP zone of PJM now receive network transmission service from and share the cost of the AEP East Companies' transmission facilities, including those operated at voltages below 138 kV. The proposed amendment also would change the primary transmission cost allocation methodology under the Transmission Agreement from the current Member Load Ratio ("MLR") basis to a 12-month coincident peak (12-CP) basis. The proposed amendments specify that the allocation of OATT-based transmission and related costs and revenues will include all seven of the AEP East Companies, including Kinsport and Wheeling.

Motions to intervene in this proceedings were filed by the following entities: Public Utilities Commission of Ohio, Public Service Commission of West Virginia, West Virginia Energy Users Group, Virginia State Corporation Commission, Old Dominion Committee for Fair Utility Rates, East Tennessee Energy Consumers, Indiana Utility Regulatory Commission ("IURC"), Steel Dynamics, Inc. ("Steel Dynamics"), Consumer Advocate Division of the Public Service Commission of West Virginia (W.Va. Consumer Advocate"), Hoosier Energy Rural Electric Cooperative, Indiana Office of Utility Consumer Counsel ("IOUCC"), Ohio Consumers' Counsel, and the Kentucky Public Service Commission.

IURC, Steel Dynamics, W. Va Consumer Advocate and IOUCC protested AEP's filing, and AEP answered their protests. On August 3, 2009 the Commission issued an order accepting AEP's proposed amendments to the Transmission Agreement for filing, subject to hearing and settlement judge procedures. The Commission suspended the proposed amendments for a nominal period, making them effective (subject to refund), on the first day of the month after a final Commission order in this proceeding, as requested by AEP. *Order Accepting and Suspending Proposed Transmission Agreement and Establishing Hearing and Settlement Judge Procedures*, 128 FERC ¶ 61,123 (2009).

On August 7, 2009, pursuant to an order of Chief Judge Wagner, the Honorable David Coffman was appointed Settlement Judge. The Chief Judge's August 7, 2009 order also scheduled a settlement conference to convene on August 20, 2009. Settlement negotiations (including informal information gathering and numerous conferences, meetings and telephone conversations) continued since then. The Commission's Trial Staff participated actively in the discussions. Judge Coffman submitted periodic reports to the Commission on the progress of the settlement discussions. Ultimately, the settlement discussions produced the Settlement Agreement submitted in this Docket.

II. SUMMARY OF SETTLEMENT AGREEMENT

The substantive terms of the Settlement Agreement are set forth in three Attachments to the Settlement Agreement, as follows:

A. Settlement Terms and Conditions (Attachment A-1);

B. Revised Rate Schedule language, in Blacklined format, (B-1) that will be incorporated in Transmission Agreement;

C. Revised Rate Schedule language in clean format (B-2);

The following is a summary of each of the Attachments:

A. Settlement Terms and Conditions

The Settlement Terms and Conditions set forth the methodology for implementation of the Revised Transmission Agreement. The Terms and Conditions include a three year phase in of the impacts of the Revised Transmission Agreement for all AEP East Companies, except for Indiana Michigan Power Company, for which the impacts of the Revised Transmission Agreement will be phased in over a four year period The phase in periods would commence on the date of the Commission order approving the Settlement and would end no later than July 31, 2013 for all AEP East Companies except Indiana Michigan Power Company and no later than July 31, 2014 for Indiana Michigan Power Company. The Settlement Terms and Conditions also sets forth the credits and charges to the AEP East Companies to reflect the phased in impacts of the Transmission Agreement pursuant to the terms of the Settlement Agreement. It also provides that all Settling Parties reserve their filing rights under the Federal Power Act, except that a section 206 filing by a Settling Party under the Federal Power Act challenging the terms of the Revised Transmission Agreement or of the Settlement Agreement will render the Settlement Agreement void, and would be subject to the "public interest" standard of review adopted in the *Sierra-Mobile* line of cases.

B. Revised Tariff Sheets

Resolution of the issues as set forth in Attachment A requires certain changes to the Transmission Agreement. Attachments B-1 and B-2 provide the Revised Rate Schedule language, that the Settling Parties have agreed is necessary to implement the Settlement Agreement. Accordingly, these attachments will be incorporated in the Transmission Agreement following Commission approval of the Settlement Agreement.

III. PROCEDURAL ASPECTS OF SETTLEMENT AGREEMENT

The remaining provisions of the Settlement Agreement address procedural aspects of the Settlement Agreement including implementation, non-severability, rights reserved, waiver and amendment, and the scope of review. Specifically, the standard of review for modifications to the Settlement Agreement that are proposed by any Settling Party will be the "public interest" standard adopted in the *Sierra-Mobile* line of cases. The standard of review for modifications to the Settlement Agreement proposed by any non-party to the Settlement Agreement and the Commission acting *sua sponte*, after it is approved by the Commission, will be the most stringent standard permitted by law.

IV. RESPONSES TO REQUIRED QUESTIONS

By order dated October 23, 2003, the Chief Administrative Law Judge requires that five questions be answered as part of every Explanatory Statement submitted in support of a proposed settlement. The questions and specific responses thereto applicable to this Settlement Agreement are as follows:

1. **What are the issues underlying the settlement and what are the major implications?**

The issue raised in this proceeding that underlies the Settlement Agreement is whether the proposed amendments to the Transmission Agreement are just and reasonable.

2. **Whether any of the issues raise policy implications.**

The resolution of the underlying issue does not raise any policy implications.

3. **Whether other pending cases may be affected.**

No other pending cases are affected.

4. **Whether the settlement involves issues of first impression, or if there are any previous reversals on the issues involved?**

There are no issues of first impression presented in this proceeding or resolved by the Settlement Agreement. There are no previous reversals with respect to the Transmission Agreement at issue in this proceeding.

5. Whether the proceeding is subject to the just and reasonable standard or whether there is *Mobile-Sierra* language making it the standard, *i.e.,* the applicable standards of review.

This proceeding on AEP's rate filing is subject to the just and reasonable standard. Section 6.7 of the Settlement Agreement states that, except as specified, a unilateral request by a Settling Party to modify any provision of the Settlement Agreement would be subject to the "public interest" standard adopted in the *Sierra-Mobile* line of cases. As for a unilateral modification request by a non-Settling Party or a proceeding in which the Commission acting *sua sponte* seeks to modify the Settlement Agreement, the standard of review shall be the most stringent standard permitted by applicable law.

V. CONCLUSION

As discussed above, the attached Settlement Agreement resolves all issues in the captioned proceeding, and the Settling Parties urge the Commission to accept the Settlement Agreement without condition or modification. The Settling Parties in this proceeding have authorized counsel for AEP to make this filing on their behalf.

Respectfully submitted,

____
Monique Rowtham-Kennedy
American Electric Power Service Corporation
801 Pennsylvania Avenue, N.W.
Suite 320
Washington, D.C. 20004-2684
Telephone: 202-383-3436
Fax: 202-383-3459
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1015 15th St., NW, 12th Floor
Washington, D.C. 20005
(202) 296-2960
(202) 296-0166 fax

Counsel for Hoosier Energy Rural Electric
Cooperative

August 4, 2010

CERTIFICATE OF SERVICE

I certify that a copy of the foregoing Settlement filed by American Electric Power Service Corporation was served upon the parties to this proceeding this 4th day of August 2010.

Monique Rowtham-Kennedy
American Electric Power Service Corporation
801 Pennsylvania Avenue, N.W.
Suite 320
Washington, D.C. 20004-2684
Telephone: 202-383-3436
Fax: 202-383-3459

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

American Electric Power Service Corporation	))	Docket No. ER09-1279-000

SETTLEMENT AGREEMENT

Pursuant to Rule 602 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. §385.602 (2008), American Electric Power Service Corporation ("AEPSC"), on behalf of Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company (collectively "AEP" or the "AEP East Companies") and the following Settling Parties: Public Utilities Commission of Ohio, East Tennessee Energy Consumers, Hoosier Energy Rural Electric Cooperative and the Office of the Ohio Consumers' Counsel (individually, a "Settling Party," and, collectively, the "Settling Parties") hereby submit this Settlement Agreement to resolve all issues between and among them in this docket. In addition, this Settlement is supported or not opposed by all parties who have intervened in this proceeding, except Steel Dynamics, Inc. and Kentucky Public Service Commission who take no position with respect to the Settlement.[1]

[1] In addition to the Settling Parties, the non-opposing parties are Consumer Advocate Division of the Public Service Commission of West Virginia, Virginia State Corporation Commission, Old Dominion Committee for Fair Utility Rates, , Public Service Commission of West Virginia, Indiana Utility Regulatory Commission, Indiana Office of Utility Consumer Counsel, and the West Virginia Energy Users Group.

ARTICLE I

INTRODUCTION

AEP is a multi-state electric utility holding company system, whose operating companies provide electric service to approximately five million customers in parts of eleven states. Prior to 2000, when AEP merged with the former Central and South West System, AEP consisted of seven electric utility operating companies. The five largest companies operate generation, transmission and distribution facilities and are parties to the Transmission Agreement. The two smaller companies – Kingsport Power Company ("Kingsport") and Wheeling Power Company ("Wheeling") operate only transmission and distribution facilities. These seven AEP East operating companies provide electric service to customers in parts of seven states – Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia and West Virginia. AEPSC provides management and professional services at cost to these companies and others in the AEP System.

AEP represented in its filing in this case that the AEP System is planned and operated on an integrated basis pursuant to various agreements under which the AEP operating companies pool or combine their individual systems to achieve the benefits of integrated operation. This proceeding involves proposed amendments to one such agreement -- the Transmission Agreement entered into in 1984 among five of the AEP East Companies- Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company and Ohio Power

Company, and administered by AEPSC, as Agent. As approved by the Commission,[2] the Agreement provides for the sharing of the costs of the Members' investments in Extra-High-Voltage (EHV) and high-voltage facilities operated at 138 kilovolts (138 kV) and above.

On June 5, 2009 AEP filed with the Commission proposed amendments to the Transmission Agreement. The proposed amendments to the Transmission Agreement , if approved, would effect a comprehensive reallocation of transmission-related costs and revenues among the AEP East Companies including two new Members, Kingsport Power Company and Wheeling Power Company. AEP represented in the filing that the proposed amendments recognized that, pursuant to the PJM Open Access Transmission Tariff ("PJM OATT"), the AEP East Companies, including Kingsport and Wheeling, and other load serving entities in the AEP zone of PJM now share the cost of all the AEP East Companies transmission facilities, including those operated at voltages below 138 kV. The proposed amendments also would change the primary transmission cost allocation methodology under the Transmission Agreement from the current Member Load Ratio ("MLR") basis to a 12-month coincident peak (12-CP) basis. The proposed amendments specify that the allocation of OATT-based transmission and related costs and revenues will include all seven of the AEP East Companies, including Kingsport and Wheeling. Motions to intervene in this proceedings were filed by the following entities: Public Utilities Commission of Ohio, Public Service Commission of West Virginia, West Virginia Energy Users Group, Virginia State Corporation Commission, Old Dominion Committee for Fair Utility Rates, East Tennessee Energy Consumers, Indiana Utility

[2] *American Electric Power Service Corp.*, Opinion No. 311, 44 FERC ¶ 61,206 (1987), *reh. denied,* Opinion No. 311-A, 45 FERC ¶ 61,382 (1988)

Regulatory Commission ("IURC"), Steel Dynamics, Inc. ("Steel Dynamics"), Consumer Advocate Division of the Public Service Commission of West Virginia (W.Va. Consumer Advocate"), Hoosier Energy Rural Electric Cooperative, Indiana Office of Utility Consumer Counsel ("IOUCC"), Ohio Consumers' Counsel, and the Kentucky Public Service Commission.

IURC, Steel Dynamics, W. Va. Consumer Advocate and IOUCC protested AEP's filing, and AEP answered their protests. On August 3, 2009 the Commission issued an order accepting AEP's proposed amendments to the Transmission Agreement for filing, subject to hearing and settlement judge procedures. The Commission suspended the proposed amendments for a nominal period, making them effective (subject to refund), on the first day of the month after a final Commission order in this proceeding, as requested by AEP. *Order Accepting and Suspending Proposed Transmission Agreement and Establishing Hearing and Settlement Judge Procedures*, 128 FERC ¶ 61,123 (2009).

On August 7, 2009, pursuant to an order of Chief Judge Wagner, the Honorable David Coffman was appointed Settlement Judge. The Chief Judge's August 7, 2009 order also scheduled a settlement conference to convene on August 20, 2009. Settlement negotiations (including informal information gathering and numerous conferences, meetings and telephone conversations) continued since then. The Commission's Trial Staff participated actively in the discussions. Judge Coffman submitted periodic reports to the Commission on the progress of the settlement discussions. Ultimately, the settlement discussions produced this Settlement Agreement.

ARTICLE II
SCOPE OF SETTLEMENT AGREEMENT

The Settling Parties hereby settle and resolve all issues between them arising from AEP's submittals in Docket No. ER09-1279-000, on the terms set forth in the following Article III and Attachments A, B-1 and B-2. Attachments A, B-1 and B-2 are incorporated by reference in and made a part of this Settlement Agreement, and all references herein to the Settlement Agreement shall be deemed to encompass the listed Attachments.

ARTICLE III
TERMS OF THE SETTLEMENT AGREEMENT

3.1 The Settlement Terms and Conditions set forth in Attachment A describe the agreement of the Settling Parties regarding the implementation of the Revised Transmission Agreement.

3.2 Revised provisions for the Transmission Agreement are set forth in Attachment B-1 (Blacklined) and B-2 (Clean) to this Settlement Agreement. The provisions submitted herewith shall be substituted for the tariff pages accepted for filing, subject to refund, in the Commission's August 3, 2009 Order in this Docket. The Settling Parties request that the Commission accept the Rate Schedule pages set forth in Attachment B-2 for filing without suspension, investigation, change or condition.

ARTICLE IV
IMPLEMENTATION

4.1 This Settlement Agreement shall be binding as among the Settling Parties upon the execution hereof. The revised tariff sheets and other provisions set forth in the Attachments hereto shall become effective on the date the Commission specifies as the effective date for the agreed-upon rates and charges in its order approving or accepting the Settlement Agreement. The Settling Parties shall request that the Commission permit the agreed-upon rates and charges to become effective on the first day of the month after a final Commission order in this proceeding.

4.2 This Settlement Agreement shall be null and void and shall not become effective unless: (i) the Commission approves it without condition or modification as a complete settlement of the issues described herein, or (ii) the Settling Parties are willing to accept all such conditions and modifications as the Commission may require. Any Settling Party that does not notify the other Settling Parties, within 15 days of a Commission order imposing any condition or modification to the Settlement Agreement, that it may or will seek rehearing or reconsideration of the order shall be deemed to have waived all objections thereto.

ARTICLE V
NON-SEVERABILITY

5.1 This Settlement Agreement and its Attachments establish rights and obligations that are interrelated and interdependent. No Settling Party shall be deemed to have agreed to any term of the Settlement Agreement in isolation from any other term. For these reasons, the provisions of this Settlement Agreement are not severable.

ARTICLE VI
RESERVATIONS

6.1 The provisions of this Settlement Agreement are intended to govern only the specific matters addressed herein. No Settling Party waives any claim or right that it may have with respect to matters not addressed in this Settlement Agreement.

6.2 No Settling Party shall be bound or prejudiced by this Settlement Agreement unless it is approved and made effective pursuant to its terms.

6.3 Nothing in this Settlement Agreement shall constitute an admission by any Settling Party of the correctness or applicability of any claim, defense, rule, or interpretation of law, allegation of fact, principle, or method of ratemaking or cost-of-service determination. The Settlement Agreement is made upon the explicit understanding that it constitutes a negotiated agreement with respect to the rates, terms, and conditions at issue in these proceedings. The Settling Parties shall not be deemed to have conceded the applicability of any principle, or any method of ratemaking or cost-of-service determination, rate design or rate schedule, or terms and conditions of service; or the application of any rule or interpretation of law that may underlie, or be thought to underlie, this Settlement Agreement. The Settlement Terms and Conditions contained in Attachment A are principles that the Settling Parties shall be deemed to have accepted solely for purposes of resolving the issues in this docket, and their inclusion as part of this Settlement Agreement shall not (i) constitute an admission by any Settling Party of the correctness of any principle therein, or (ii) establish any precedent binding on a Settling Party in any other proceeding. In any further negotiation or proceedings whatsoever (other than a proceeding involving the honoring, enforcement or construction hereof, as applicable as set forth herein), the Settling Parties shall not be bound or prejudiced by this Settlement Agreement.

6.4 The Commission's approval of this Settlement Agreement shall not constitute approval of, or precedent regarding, any principle or issue in this proceeding. Nothing herein shall be deemed to constitute or establish a "settled practice" as the Court interpreted that term in *Public Service Comm'n of New York v. FERC*, 642 F.2d 1335 (D.C. Cir. 1980).

6.5 This Settlement Agreement is expressly contingent upon the following further conditions: (i) all Settling Parties shall provide reasonable cooperation in seeking the Commission's acceptance and approval hereof; (ii) no Settling Party shall seek or request additional terms or conditions of settlement beyond those contained herein; and (iii) the Commission approves or accepts this Settlement Agreement without modification. If the Commission requires any modification(s) of this Settlement Agreement and if such modification(s) is (are) not fulfilled, then: (i) this Settlement Agreement shall not be binding on any Settling Party; (ii) the Settling Parties shall not be obligated to negotiate further, other than to discuss in good faith whether the modification(s) required by the Commission is (are) acceptable to them; (iii) all Settling Parties shall be deemed to have reserved all of their respective rights and remedies with respect to the issues in this proceeding; and (iv) this Settlement Agreement shall not be part of the record in any subsequent proceedings, and all discussions and negotiations related hereto shall be privileged.

6.6 The titles and headings of the various articles of this Settlement Agreement: (i) are for reference and convenience purposes only; (ii) are not to be construed or taken into account in interpreting the Settlement Agreement; and (iii) do not qualify, modify, or explain the effects of the Settlement Agreement.

6.7 This Settlement Agreement may be amended only by a written instrument duly executed by all Settling Parties. The standard of review for any modification to this Settlement Agreement sought by a Settling Party that is not agreed to by all other Settling Parties shall be the "public interest" standard adopted in the *Sierra-Mobile* line of cases

A Settling Party or Settling Parties seeking to modify the Settlement Agreement in any respect shall bear the applicable burden under the FPA.

6.8 The standard of review for any modifications to this Settlement Agreement requested by an intervenor or other interested entity that is not a Settling Party or that is sought in a proceeding initiated by the Commission acting *sua sponte* will be the most stringent standard permissible under applicable law. For purposes of the application of sections 6.7 and 6.8, all parties who have formally represented in writing, by their respective authorized representative, that they did not object to the Agreement shall be treated as "Settling Parties."

6.9 This Settlement Agreement is submitted pursuant to Rule 602 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §385.602 (2008). Unless and until the Settlement Agreement becomes effective pursuant to its terms, the Settlement Agreement shall be privileged and of no effect and shall not be admissible in evidence or in any way described or discussed in any proceeding before any court or regulatory body (except in comments on the Settlement Agreement in this proceeding).

American Electric Power Service
Corporation as agent for
Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company

By:______________________________

Monique Rowtham-Kennedy
American Electric Power Service Corporation
801 Pennsylvania Avenue, N.W.
Suite 320
Washington, D.C. 20004-2684
Telephone: 202-383-3436
Fax: 202-383-3459

Counsel for American Electric Power Service Corporation

By:______________________________________

Jody Kyler
Assistant Consumers' Counsel
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Counsel for the Office of the Ohio Consumers' Counsel

By:______________________________________

Stephen Reilly
Thomas G. Lindgren
Assistant Attorney General
Public Utilities Section
Ohio Attorney General's Office
180 East Broad St.
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Counsel for the Ohio Public Utilities Commission

By:________________________________

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Counsel for East Tennessee Energy Consumers

____

Barry Cohen
Miller, Balis & O'Neil, P.C.
1015 15th St., NW, 12th Floor
Washington, D.C. 20005
(202) 296-2960
(202) 296-0166 fax

Counsel for Hoosier Energy Rural Electric Cooperative

The following undersigned entities are not parties to the Settlement Agreement, however the undersigned indicate by their signature below that they do not object to this Settlement Agreement:

Public Service Commission of West Virginia,

By:___________________________________

Richard E. Hitt, General Counsel
Public Service Commission of West Virginia
Post Office Box 812
Charleston, West Virginia 25323
Phone: (304) 340-0450
Fax: (304) 340-0840
e-mail:rhitt@psc.state.wv.us

West Virginia Energy Users Group,

By:___________________________________

Robert A. Weishaar, Jr.
McNees Wallace & Nurick LLC
777 North Capitol Street, N.E.
Suite 401
Washington, DC 20002-4292
Office: 202.898.5700
Cell: 202.409.4170
FAX: 717.260.1765
rweishaa@mwn.com

Indiana Office of Utility Consumer Counsel,

By:___________________________________

Robert G. Mork
Deputy Consumer Counselor for Federal Affairs
Indiana Attorney No. 19146-49
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
115 West Washington Street, Suite 1500 South
Indianapolis, Indiana 46204
phone: (317) 233-3234
facsimile: (317) 232-5923
rmork@oucc.IN.gov

Indiana Utility Regulatory Commission

By:____________________________________

Beth Krogel Roads Legal Counsel, RTO/FERC Issues
Scott R. Storms GENERAL COUNSEL
Indiana Utility Regulatory Commission
101 W. Washington Street, Suite 1500 E
Indianapolis, Indiana 46024
Phone: 317-232-2092

ATTACHMENT A

American Electric Power Service Corporation
Docket No. ER09-1279-000

Transmission Agreement Settlement
For
Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company
(collectively "AEP" or "the AEP East Companies")

Settlement Terms and Conditions

The following terms and conditions are a part of the Settlement Agreement being filed August 4, 2010 in Docket No. ER09-1279 ("the Settlement"):

1. AEP's proposal as originally filed in the captioned docket and accepted and suspended subject to hearing and settlement judge procedures pursuant to *American Elec. Power Serv. Corp*, 128 FERC ¶ 61,123 (2009) (hereinafter referred to as the "Revised Transmission Agreement") will be implemented upon approval of the Settlement, subject to the terms and conditions contained herein.

2. Impacts of the Revised Transmission Agreement will for retail rate making purposes be moderated as described in paragraphs 3 and 4 below, for a three (3) year period commencing on the date of the Commission order approving the Settlement and ending no later than July 31, 2013 for all of the AEP East Companies except Indiana Michigan Power Company.

3. Credits will be applied to Ohio Power Company, Columbus Southern Power Company and Appalachian Power Company -West Virginia to reduce impacts of the Revised Transmission Agreement by 75% in year 1, by 50% in year 2 and by 25% in year 3.

4. Charges will be applied to Kentucky Power Company, Kingsport Power Company and Wheeling Power Company to reduce the decrease in transmission cost allocation under the Revised Transmission Agreement by 75% in year 1, by 50% in year 2 and by 25% in year 3.

5. Impacts of the Revised Transmission Agreement on Indiana Michigan Power Company will be phased in over a four year period commencing

on the date of the Commission order approving the Settlement and ending no later than July 1, 2014.

6. Credits to Indiana Michigan will reduce impacts of the Revised Transmission Agreement by 80% in year 1, 60% in year 2, 40% in year 3 and 20% in year 4.

7. All parties to the Settlement reserve their respective rights under sections 205, 206 and 306 of the Federal Power act, however, the Settlement will be voided if a filing is made under 206 challenging the Revised Transmission Agreement or this Settlement. In addition, while the Settlement is in effect, AEP will not modify Appendix I of the Revised Transmission Agreement unless such 206 filing is made by a non-AEP settling party.

8. AEP shall not seek recovery of any shortfall of revenues resulting from the application of the terms and conditions of this Settlement Agreement in any Ohio state regulatory proceeding, except as provided for in the Settlement.

9. The Transmission Agreement will be modified as provided in Attachment B.

10. The credits and charges pursuant to paragraphs 3, 4 and 6 above shall be as follows:

	Year 1	Year 2	Year 3	Year 4
	(Dollars in Millions)			
APCo WV	(6.9)	(4.6)	(2.3)	0
CSP	(2.4)	(1.6)	(0.8)	0
I&M	(24.1)	(18.1)	(12.1)	(6.0)
KPCo	3.1	2.1	1.1	0
KgPCo	3.0	2.0	1.0	0
OPCo	(10.9)	(7.3)	(3.6)	0
WPCo	1.9	1.2	0.6	0

ATTACHMENT B -1
(Marked Version)

TRANSMISSION AGREEMENT

By and among

APPALACHIAN POWER COMPANY

COLUMBUS SOUTHERN POWER COMPANY

INDIANA MICHIGAN POWER COMPANY

KENTUCKY POWER COMPANY

KINGSPORT POWER COMPANY

OHIO POWER COMPANY

WHEELING POWER COMPANY

and with

AMERICAN ELECTRIC POWER SERVICE CORPORATION

AS AGENT

DATED APRIL 1984, AS AMENDED

CONTENTS

0.1 THIS AGREEMENT, made and entered into as of the 1st day of April, 1984, and as subsequently amended, by and among APPALACHIAN POWER COMPANY (Appalachian Company), a Virginia corporation, COLUMBUS AND SOUTHERN POWER COMPANY (Columbus Company), an Ohio corporation, INDIANA MICHIGAN POWER COMPANY (Indiana Company), an Indiana corporation, KENTUCKY POWER COMPANY (Kentucky Company), a Kentucky corporation, OHIO POWER COMPANY (Ohio Company), an Ohio corporation, KINGSPORT POWER COMPANY (Tennessee Company), a Tennessee corporation, and WHEELING POWER COMPANY (Wheeling Company), a West Virginia corporation, said companies (herein sometimes called 'Members' when referred to collectively and 'Member' when referred to individually) being affiliated companies of the integrated public utility electric system known as the American Electric Power SYSTEM (AEP System), and AMERICAN ELECTRIC POWER SERVICE CORPORATION (Agent), a New York corporation, being a service company engaged solely in the business of furnishing essential services to the aforesaid companies and to other affiliated companies.

W I T N E S S E T H,

T H A T:

0.2 WHEREAS, the Members own and operate electric facilities in the states herein indicated, (i) Appalachian Company in Virginia, West Virginia, and Tennessee (ii) Columbus Company in Ohio, (iii) Indiana Company in Indiana and Michigan, (iv) Kentucky Company in Kentucky, (v) Tennessee Company in Tennessee, (vi) Ohio Company in Ohio and West Virginia, and (vii) Wheeling Company in West Virginia; and

0.3 WHEREAS, certain of the Members have entered into an interconnection agreement, dated July 6, 1951, with modification

thereto, which provides for certain understandings, conditions, and procedures designed to achieve the full benefits and advantages available through the coordinated operation of their electric power supply facilities; and

0.4 WHEREAS, The Members' electric facilities are now and for many years have been interconnected through their respective transmission facilities at a number of points, forming an integrated transmission network; and

0.5 WHEREAS, the Members have achieved benefits through the coordinated planning and development of a fully integrated Transmission System; and

0.6 WHEREAS, the members believe that an agreement which provides for the equitable sharing among the Members of the costs incurred by the Members in connection with the ownership, operation, and maintenance of their respective portions of the Transmission System would enhance equity among the Members for the continued development of a reliable and economic Transmission System; and

0.7 WHEREAS, effective October 1, 2004 the Members joined the PJM Interconnection, LLC ("PJM"), and placed their respective transmission facilities under the functional control of PJM, a regional transmission operator or "RTO"; and

0.8 WHEREAS, PJM provides transmission service, pursuant to the PJM Open Access Transmission Tariff ("OATT"), to the Members and others who require transmission service over the Transmission System; and

0.9 WHEREAS, the Members believe that benefits and advantages could be best realized if this Agreement were administered by a single clearing agent; and

0.10 WHEREAS, the Members believe that the Agent designated herein for such purpose is qualified to perform such services;

0.11 NOW, THEREFORE, in consideration of the premises and of the mutual covenants and agreements hereinafter contained, the parties hereto hereby agree as follows:

ARTICLE 1

DESCRIPTION OF TRANSMISSION SYSTEM

1.1 The Transmission System covered by this Agreement shall include all the transmission facilities, from time to time, owned by the Members that are included in the costs of service used to determine rates for transmission service under the PJM OATT, ~~including without limitation, (i) All Member transmission lines; (ii) all facilities such as transformers, buses, switchgear, and associated facilities located at Member transmission substations, and (iii) any other transmission lines and associated substation facilities at any voltage designated by the Transmission Committee as having been, installed or leased for the mutual benefit of all Members and/or others who receive transmission service from PJM or a successor RTO or other successor transmission service provider~~or successor open access transmission tariff.

ARTICLE 2

OPERATION

2.1 Each member shall maintain its respective portion of the Bulk Transmission System, together with all associated facilities and appurtenances, in a suitable condition of repair at all times in order that said system will operate in a reliable and satisfactory manner.

ARTICLE 3

TRANSMISSION COMMITTEE

3.1 The Members shall appoint representatives to serve on a Transmission Committee. Such representatives shall have authority to act for the Members in the administration of all matters pertaining to this Agreement.

3.2 Each Member shall designate in writing, delivered to the other Members and Agent, the person who is to act as its representative on said Committee and the person or persons who may serve as alternate whenever such representative is unavailable to act. Agent shall designate in writing delivered to the Members the person who is to act as its representative on said Committee and the person or persons who may serve as alternate whenever such representative is unavailable to act. Such person designated by Agent shall act as chairman of the Transmissions Committee and shall be known as the "Transmission Manager".

ARTICLE 4

AGENTS RESPONSIBILITIES

4.1 For the purpose of carrying out the provisions of this Agreement the Members hereby delegate to Agent, and Agent hereby accepts, the responsibility of administration of this Agreement, and in furtherance thereof Agent hereby agrees:

4.11 To arrange for and conduct such meetings of the Transmission Committee as may be required to insure the effective and efficient carrying out of all matters of procedure essential to the complete performance of the provisions of this Agreement.

4.12 To carry out settlements under this Agreement. Settlements by the Members shall be made for each calendar month through General Ledger accounts (hereby designated and hereinafter called the "TRANSMISSION ACCOUNTS") to be administered by Agent. For the purposes of This Agreement, Transmission Accounts shall be consistent with the accounts listed in the FERC Uniform System of Accounts, and shall include such accounts and sub-accounts as are necessary and proper, directed by the Transmission Committee, and consistent with applicable regulatory requirements.

ARTICLE 5

SETTLEMENTS

5.1 As provided in this Article, following the end of each month, the Members shall effect settlements through the TRANSMISSION ACCOUNTS. Generally, Settlements hereunder will involve the allocation among the Members of transmission-related costs and revenues as incurred and accrued under the PJM OATT,

or successor open access transmission tariff ~~among the Members~~, and the recording of same in the Transmission Accounts of the Members, as specified in Appendix I consistent with the Settlement Agreement approved in FERC Docket No. ER09-1279-000.

5.2 All amounts to be allocated among the Members hereunder shall, to the extent practicable, be included in Settlements for the month in which such cost or revenue is realized or accrued. If necessary in order to implement such timely Settlement, the Agent shall be authorized to effect Settlements on an estimated basis and make such adjustment as is needed in subsequent Settlements that will conform the Settlements to the terms of this Agreement.

5.3 For such time as Member Tennessee Company and/or Wheeling Company (Buyer) purchase power from Members Appalachian Company and Ohio Company (Seller), respectively, under agreements that provide for transmission service and related charges to Buyer from Seller (Purchased Power Agreements or "PPAs"), Seller will be allocated or assigned the costs as described on Appendix I, numbers seven (7) through fifteen (15), that would otherwise have been allocated or assigned to Buyer under this Agreement. The total amount of such allocated or assigned costs will be passed through to Buyer by Seller as the transmission service and related charges provided for in their PPAs. Such transmission and related costs will be the only transmission charges passed through to Buyer under any such PPA. When any such PPA expires or is otherwise modified or superseded, the provisions of the PPA that provide for transmission service and related charges to Buyer from Seller will be discontinued and Tennessee Company and/or Wheeling Company will receive directly, by allocation or direct assignment, the transmission and related costs pursuant to this agreement, as described on Appendix I, numbers seven (7) through fifteen (15). At such time, Seller shall no longer be allocated or assigned costs which are properly allocable or assignable to Buyer under this Agreement. Further, from the effective date of this Agreement as modified in FERC Docket No. ER09-1279, all the Members, including Tennessee Company and Wheeling Company, will receive direct allocation of revenues as provided herein and described on Appendix I, numbers one (1) though six (6).

ARTICLE 6

TAXES

6.1 If at any time during the duration of this Agreement there should be levied and/or assessed by any governmental authority against any Member any tax related to the receipt of Settlements calculated pursuant to this Agreement (such as sales, excise or similar taxes), such tax expense incurred by such Member that would not have been incurred were the Settlements hereunder not being made, such Member shall be entitled, to the extent permitted by the applicable regulatory authority(ies) to include such tax in its transmission revenue requirement under the PJM or successor OATT when transmission revenue requirements of the Members are next updated, and thereby receive an appropriate level of reimbursement (through cost sharing) for such additional taxes by Members and others receiving service from the Transmission System.

ARTICLE 7

Allocation Principles

7.1 All items of cost and revenue included in Settlements hereunder shall be related to the provision of or receipt of transmission service or a related ("ancillary") service by one or more Members~~on behalf of one or more of the Members~~. The allocation methods used to share such costs and revenues, as specified in Appendix I, shall be made pursuant to direction by the Transmission Committee.

7.2 The Transmission Committee may at any time during the Term of This Agreement, upon the recommendation of the Agent or any Member, review any item of cost or revenue, in order to determine whether such item is transmission-related, and whether it should be included in Settlements hereunder. Further, whenever the Transmission Committee determines that any change is needed in Appendix I to add or delete any item of cost or revenue, or to change the allocation or accounting basis of any item, the Transmission Committee shall authorize and direct the Agent ~~when and how~~to effect such change in Appendix I and in monthly Settlements among the Members and to make any filing with the applicable regulatory authority(ies) to implement such change. pursuant to the PJM OATT or any successor open access transmission tariff.

~~7.3 Allocations of costs shall, to the extent practicable, be based on measurable cost indicators that will effect a sharing of costs among the Members consistent with the use of such service, and will be sufficiently stable, over time, so as~~

~~not to cause undue or objectionable variability in the costs of the Members.~~

~~7.4 Allocations of revenues shall, to the extent practicable, be based on measurable indicators of the cost incurred by each Member in providing the service that gave rise to the revenue~~

ARTICLE 8

MODIFICATION

8.1 Any Member, or the Agent, by written notice given to the other Members and Agent, may call for a reconsideration of the terms and conditions herein provided. If such reconsideration is called for, the Members shall take into account any changed conditions, any results from the application of said terms and conditions, and any other facts that might cause said terms and conditions to result in an inequitable sharing of costs and benefits under this Agreement. Any modification in terms and conditions agreed to by the Members following such reconsideration shall become effective the first day of the month following authorization of such reconsideration by appropriate regulatory authority.

ARTICLE 9

EFFECTIVE DATE AND TERM OF THIS AGREEMENT

9.1 This Agreement shall become effective and shall become a binding obligation of the Parties on the date specified in an Order in such proceeding as this Agreement shall have been filed with, and accepted for filing by the Federal Energy Regulatory Commission (FERC) under the Federal Power Act as a rate schedule.

9.2 This Agreement shall continue in effect for four years from the effective date of the final order in Docket No. ER09-1279-000 ~~for an initial period from the Effective Date to December 31, 1990, and thereafter~~for successive periods of one year each until terminated as provided under subsection 9.3 below.

9.3 Any Member upon at least three years' prior written notice to the other Members and Agent may terminate this Agreement at the expiration ~~of said initial period or at the expiration of any successive period of one yea~~such notice period~~r~~.

ARTICLE 10

REGULATORY AUTHORITIES

10.1 The Members recognize that this Agreement, and any tariff or rate schedule which shall embody or supersede this Agreement or any part thereof, are in certain respects subject to the jurisdiction of the FERC under the Federal Power Act, and are also subject to such lawful action as any regulatory authority having jurisdiction shall hereafter take with respect thereto. The performance of any obligation of the Members shall be subject to the receipt from time to time as required of such authorizations, approvals or actions of regulatory authorities having jurisdiction as shall be required by law.

10.2 Subject to the terms of the Settlement in Docket NO. ER09-1279-000, ~~I~~it is expressly understood that any Member under this Agreement, as it may hereafter from time to time be modified and supplemented by the Members, shall be entitled, at any time and from time to time, unilaterally to make application to the FERC for a change in rates, charges, classification of service, or any rule, regulation or contract relating thereto, or to make any change in or supersede in whole or in part any provision of this Agreement, under Section 205 of the Federal Power Act and pursuant to the FERC's Rules and Regulations promulgated thereunder.

ARTICLE 11

ASSIGNMENT

11.1 This Agreement shall inure to the benefit of and be binding upon the successors and assigns of the respective parties.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed in their respective corporate names and on their behalf by their proper officers thereunto daily authorized as of the day and year first above written.

Next Page is Signature Page

Transmission Agreement Among:

AMERICAN ELECTRIC POWER SERVICE CORPORATION,

By: ____________________

~~Michael Heyeck~~
Senior Vice President

APPALACHIAN POWER COMPANY,

By: ____________________

~~Dana E. Waldo~~
President and Chief Operating Officer

COLUMBUS SOUTHERN POWER COMPANY,

By: ____________________

~~Joseph Hamrock~~
President and Chief Operating Officer

INDIANA MICHIGAN POWER COMPANY,

By: ____________________

~~Helen J. Murray~~
President and Chief Operating Officer

KENTUCKY POWER COMPANY,

By: ____________________

~~Timothy C. Mosher~~
President and Chief Operating Officer

KINGSPORT POWER COMPANY,

By: ____________________

~~Dana E. Waldo~~
President and Chief Operating Officer

OHIO POWER COMPANY, and

By: ____________________

~~Brian X. Tierney~~
Vice President

WHEELING POWER COMPANY

By: ____________________

~~Dana E. Waldo~~
President

Dated as of: ______________________

Appendix I

AEP Transmission Agreement
Allocation of Transmission Related Costs and Revenues

AEP as Transmission Owner (Revenues)

#	Item	FERC Account*	PJM Billing Basis	AEP Allocation Basis
1	Transmission Owner Scheduling, System Control and Dispatch Service (PJM Schedule 1A)	456.1	NSPL	ARR S1A
2	NITS (AEP LSE)	456.1	NSPL	ATRR
3	NITS (Non-Affiliates)	456.1	NSPL	ATRR
4	Grandfathered PTP (NCEMC)	456.0	Contract	ATRR
5	PJM Expansion Cost Recovery Charge (ECRC)	456.1	NSPL	ARR EC
6	RTO Startup Cost Recovery Charge (SCRC)	456.1	NSPL	ARR SC

AEP as LSE (Expenses)

#	Item	FERC Account*	PJM Billing Basis	AEP Allocation Basis
7	Transmission Owner Scheduling, System Control and Dispatch Service (PJM Schedule 1A)	456.1	MWh	MWh
8	NITS Charges (for AEP Retail Load)	456.1	NSPL	12CP
9	NITS Charges for AEP FR Customers[1/]	447.0	NSPL	DA
10	NITS Reimbursement from AEP FR Customers[1/]	447.0	NSPL	DA
~~11~~	~~Schedule 1A Charge for AEP FR Customers~~	~~447.0~~	~~NSPL~~	~~DA~~
~~12~~	~~Schedule 1A Reimbursement from AEP FR Customers~~	~~447.0~~	~~NSPL~~	~~DA~~
11	Firm Point-to-Point Credits (for AEP Retail Load)	456.1	NSPL	12CP
12	Non-Firm Point-to-Point Credits (AEP Retail Load)	456.1	NSPL	12CP
13	Transmission Enhancement (Schedule 12)	565.0	NSPL	12CP
14	PJM Expansion Cost Recovery Charge (ECRC)	456.1	NSPL	12CP
15	RTO Startup Cost Recovery Charge (SCRC)	456.1	NSPL	12CP

NSPL	PJM Network Service Peak Load
Contract	Pre-OATT FERC Rate Schedules
ARR S1A	Annual Revenue Requirement - Schedule 1A
ATRR	Annual Transmission Revenue Requirement
ARR EC	Annual Revenue Requirement - Expansion Cost Recovery
ARR SC	Annual Revenue Requirement - Startup Cost Recovery
12CP	Average of 12 coincident peaks through 10/31 of prior year
DA	Directly Assigned to Operating Company

* Note: Should the net amount in 456.1 for any Member be negative, e.g. more expense than revenue, the net expense will be recorded in 565.0.

Issued By: Richard E. Munczinski
Senior Vice President, Regulatory Services

Effective: first day of the month after the Commission issues a final, non- appealable order accepting the Agreement for filing

Issued On: August 4, 2010

1/ Includes all transmission-related LSE expenses (NITS, Schedule 1A, Point-to-Point Credits, Schedule 12, ECRC, SCRC) which are directly assigned to Operating Company for AEP FR Customers.

ATTACHMENT B -2
(Unmarked Version)

TRANSMISSION AGREEMENT

By and among

APPALACHIAN POWER COMPANY

COLUMBUS SOUTHERN POWER COMPANY

INDIANA MICHIGAN POWER COMPANY

KENTUCKY POWER COMPANY

KINGSPORT POWER COMPANY

OHIO POWER COMPANY

WHEELING POWER COMPANY

and with

AMERICAN ELECTRIC POWER SERVICE CORPORATION

AS AGENT

DATED APRIL 1984, AS AMENDED

CONTENTS

0.1 THIS AGREEMENT, made and entered into as of the 1st day of April, 1984, and as subsequently amended, by and among APPALACHIAN POWER COMPANY (Appalachian Company), a Virginia corporation, COLUMBUS AND SOUTHERN POWER COMPANY (Columbus Company), an Ohio corporation, INDIANA MICHIGAN POWER COMPANY (Indiana Company), an Indiana corporation, KENTUCKY POWER COMPANY (Kentucky Company), a Kentucky corporation, OHIO POWER COMPANY (Ohio Company), an Ohio corporation, KINGSPORT POWER COMPANY (Tennessee Company), a Tennessee corporation, and WHEELING POWER COMPANY (Wheeling Company), a West Virginia corporation, said companies (herein sometimes called 'Members' when referred to collectively and 'Member' when referred to individually) being affiliated companies of the integrated public utility electric system known as the American Electric Power SYSTEM (AEP System), and AMERICAN ELECTRIC POWER SERVICE CORPORATION (Agent), a New York corporation, being a service company engaged solely in the business of furnishing essential services to the aforesaid companies and to other affiliated companies.

W I T N E S S E T H,

T H A T:

0.2 WHEREAS, the Members own and operate electric facilities in the states herein indicated, (i) Appalachian Company in Virginia, West Virginia, and Tennessee (ii) Columbus Company in Ohio, (iii) Indiana Company in Indiana and Michigan, (iv) Kentucky Company in Kentucky, (v) Tennessee Company in Tennessee, (vi) Ohio Company in Ohio and West Virginia, and (vii) Wheeling Company in West Virginia; and

0.3 WHEREAS, certain of the Members have entered into an interconnection agreement, dated July 6, 1951, with modification thereto, which provides for certain understandings, conditions, and procedures designed to achieve the full benefits and advantages available through the coordinated operation of their electric power supply facilities; and

0.4 WHEREAS, The Members' electric facilities are now and for many years have been interconnected through their respective transmission facilities at a number of points, forming an integrated transmission network; and

0.5 WHEREAS, the Members have achieved benefits through the coordinated planning and development of a fully integrated Transmission System; and

0.6 WHEREAS, the members believe that an agreement which provides for the equitable sharing among the Members of the costs incurred by the Members in connection with the ownership, operation, and maintenance of their respective portions of the Transmission System would enhance equity among the Members for the continued development of a reliable and economic Transmission System; and

0.7 WHEREAS, effective October 1, 2004 the Members joined the PJM Interconnection, LLC ("PJM"), and placed their respective transmission facilities under the functional control of PJM, a regional transmission operator or "RTO"; and

0.8 WHEREAS, PJM provides transmission service, pursuant to the PJM Open Access Transmission Tariff ("OATT"), to the Members and others who require transmission service over the Transmission System; and

0.9 WHEREAS, the Members believe that benefits and advantages could be best realized if this Agreement were administered by a single clearing agent; and

0.10 WHEREAS, the Members believe that the Agent designated herein for such purpose is qualified to perform such services;

0.11 NOW, THEREFORE, in consideration of the premises and of the mutual covenants and agreements hereinafter contained, the parties hereto hereby agree as follows:

ARTICLE 1

DESCRIPTION OF TRANSMISSION SYSTEM

1.1 The Transmission System covered by this Agreement shall include all the transmission facilities, from time to time, owned by the Members that are included in the costs of service used to determine rates for transmission service under the PJM OATT, or successor open access transmission tariff.

ARTICLE 2

OPERATION

2.1 Each member shall maintain its respective portion of the Bulk Transmission System, together with all associated facilities and appurtenances, in a suitable condition of repair at all times in order that said system will operate in a reliable and satisfactory manner.

ARTICLE 3

TRANSMISSION COMMITTEE

3.1 The Members shall appoint representatives to serve on a Transmission Committee. Such representatives shall have authority to act for the Members in the administration of all matters pertaining to this Agreement.

3.2 Each Member shall designate in writing, delivered to the other Members and Agent, the person who is to act as its representative on said Committee and the person or persons who may serve as alternate whenever such representative is unavailable to act. Agent shall designate in writing delivered to the Members the person who is to act as its representative on said Committee and the person or persons who may serve as alternate whenever such representative is unavailable to act. Such person designated by Agent shall act as chairman of the Transmissions Committee and shall be known as the "Transmission Manager".

ARTICLE 4

AGENTS RESPONSIBILITIES

4.1 For the purpose of carrying out the provisions of this Agreement the Members hereby delegate to Agent, and Agent hereby accepts, the responsibility of administration of this Agreement, and in furtherance thereof Agent hereby agrees:

4.11 To arrange for and conduct such meetings of the Transmission Committee as may be required to insure the effective and efficient carrying out of all matters of procedure essential to the complete performance of the provisions of this Agreement.

4.12 To carry out settlements under this Agreement. Settlements by the Members shall be made for each calendar month through General Ledger accounts (hereby designated and hereinafter called the "TRANSMISSION ACCOUNTS") to be administered by Agent. For the purposes of This Agreement, Transmission Accounts shall be consistent with the accounts listed in the FERC Uniform System of Accounts, and shall include such accounts and sub-accounts as are necessary and proper, directed by the Transmission Committee, and consistent with applicable regulatory requirements.

ARTICLE 5

SETTLEMENTS

5.1 As provided in this Article, following the end of each month, the Members shall effect settlements through the TRANSMISSION ACCOUNTS. Generally, Settlements hereunder will involve the allocation among the Members of transmission-related costs and revenues as incurred and accrued under the PJM OATT,

or successor open access transmission tariff, and the recording of same in the Transmission Accounts of the Members, as specified in Appendix I consistent with the Settlement Agreement approved in FERC Docket No. ER09-1279-000.

5.2 All amounts to be allocated among the Members hereunder shall, to the extent practicable, be included in Settlements for the month in which such cost or revenue is realized or accrued. If necessary in order to implement such timely Settlement, the Agent shall be authorized to effect Settlements on an estimated basis and make such adjustment as is needed in subsequent Settlements that will conform the Settlements to the terms of this Agreement.

5.3 For such time as Member Tennessee Company and/or Wheeling Company (Buyer) purchase power from Members Appalachian Company and Ohio Company (Seller), respectively, under agreements that provide for transmission service and related charges to Buyer from Seller (Purchased Power Agreements or "PPAs"), Seller will be allocated or assigned the costs as described on Appendix I, numbers seven (7) through fifteen (15), that would otherwise have been allocated or assigned to Buyer under this Agreement. The total amount of such allocated or assigned costs will be passed through to Buyer by Seller as the transmission service and related charges provided for in their PPAs. Such transmission and related costs will be the only transmission charges passed through to Buyer under any such PPA. When any such PPA expires or is otherwise modified or superseded, the provisions of the PPA that provide for

transmission service and related charges to Buyer from Seller will be discontinued and Tennessee Company and/or Wheeling Company will receive directly, by allocation or direct assignment, the transmission and related costs pursuant to this agreement, as described on Appendix I, numbers seven (7) through fifteen (15). At such time, Seller shall no longer be allocated or assigned costs which are properly allocable or assignable to Buyer under this Agreement. Further, from the effective date of this Agreement as modified in FERC Docket No. ER09-1279, all the Members, including Tennessee Company and Wheeling Company, will receive direct allocation of revenues as provided herein and described on Appendix I, numbers one (1) though six (6).

ARTICLE 6

TAXES

6.1 If at any time during the duration of this Agreement there should be levied and/or assessed by any governmental authority against any Member any tax related to the receipt of Settlements calculated pursuant to this Agreement (such as sales, excise or similar taxes), such tax expense incurred by such Member that would not have been incurred were the Settlements hereunder not being made, such Member shall be entitled, to the extent permitted by the applicable regulatory authority(ies) to include such tax in its transmission revenue requirement under the PJM or successor OATT when transmission revenue requirements of the Members are next updated, and thereby receive an appropriate level of reimbursement (through cost sharing) for such additional taxes by Members and others receiving service from the Transmission System.

ARTICLE 7

Allocation Principles

7.1 All items of cost and revenue included in Settlements hereunder shall be related to the provision of or receipt of transmission service or a related ("ancillary") service by one or more Members. The allocation methods used to share such costs and revenues, as specified in Appendix I, shall be made pursuant to direction by the Transmission Committee.

7.2 The Transmission Committee may at any time during the Term of This Agreement, upon the recommendation of the Agent or any Member, review any item of cost or revenue, in order to determine whether such item is transmission-related, and whether it should be included in Settlements hereunder. Further, whenever the Transmission Committee determines that any change is needed in Appendix I to add or delete any item of cost or revenue, or to change the allocation or accounting basis of any item, the Transmission Committee shall authorize and direct the Agent to effect such change in Appendix I and in monthly Settlements among the Members and to make any filing with the applicable regulatory authority(ies) to implement such change. pursuant to the PJM OATT or any successor open access transmission tariff.

ARTICLE 8

MODIFICATION

8.1 Any Member, or the Agent, by written notice given to the other Members and Agent, may call for a reconsideration of the terms and conditions herein provided. If such

reconsideration is called for, the Members shall take into account any changed conditions, any results from the application of said terms and conditions, and any other facts that might cause said terms and conditions to result in an inequitable sharing of costs and benefits under this Agreement. Any modification in terms and conditions agreed to by the Members following such reconsideration shall become effective the first day of the month following authorization of such reconsideration by appropriate regulatory authority.

ARTICLE 9
EFFECTIVE DATE AND TERM OF THIS AGREEMENT

9.1 This Agreement shall become effective and shall become a binding obligation of the Parties on the date specified in an Order in such proceeding as this Agreement shall have been filed with, and accepted for filing by the Federal Energy Regulatory Commission (FERC) under the Federal Power Act as a rate schedule.

9.2 This Agreement shall continue in effect for four years from the effective date of the final order in Docket No. ER09-1279-000 for successive periods of one year each until terminated as provided under subsection 9.3 below.

9.3 Any Member upon at least three years' prior written notice to the other Members and Agent may terminate this Agreement at the expiration of such notice period.

ARTICLE 10
REGULATORY AUTHORITIES

10.1 The Members recognize that this Agreement, and any tariff or rate schedule which shall embody or supersede this

Agreement or any part thereof, are in certain respects subject to the jurisdiction of the FERC under the Federal Power Act, and are also subject to such lawful action as any regulatory authority having jurisdiction shall hereafter take with respect thereto. The performance of any obligation of the Members shall be subject to the receipt from time to time as required of such authorizations, approvals or actions of regulatory authorities having jurisdiction as shall be required by law.

10.2 Subject to the terms of the Settlement in Docket NO. ER09-1279-000, it is expressly understood that any Member under this Agreement, as it may hereafter from time to time be modified and supplemented by the Members, shall be entitled, at any time and from time to time, unilaterally to make application to the FERC for a change in rates, charges, classification of service, or any rule, regulation or contract relating thereto, or to make any change in or supersede in whole or in part any provision of this Agreement, under Section 205 of the Federal Power Act and pursuant to the FERC's Rules and Regulations promulgated thereunder.

ARTICLE 11

ASSIGNMENT

11.1 This Agreement shall inure to the benefit of and be binding upon the successors and assigns of the respective parties.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed in their respective corporate names and on their behalf by their proper officers thereunto daily authorized as of the day and year first above written.

Next Page is Signature Page

Transmission Agreement Among:

AMERICAN ELECTRIC POWER SERVICE CORPORATION,

By:________________________

Senior Vice President

APPALACHIAN POWER COMPANY,

By:________________________

President and Chief Operating Officer

COLUMBUS SOUTHERN POWER COMPANY,

By:________________________

President and Chief Operating Officer

INDIANA MICHIGAN POWER COMPANY,

By:________________________

KENTUCKY POWER COMPANY,

By:________________________

President and Chief Operating Officer

KINGSPORT POWER COMPANY,

By:________________________

President and Chief Operating Officer

OHIO POWER COMPANY, and

By:________________________

Vice President

WHEELING POWER COMPANY

By:________________________

President

Dated as of:

____

Appendix I

AEP Transmission Agreement
Allocation of Transmission Related Costs and Revenues

AEP as Transmission Owner (Revenues)

#	Item	FERC Account*	PJM Billing Basis	AEP Allocation Basis
1	Transmission Owner Scheduling, System Control and Dispatch Service (PJM Schedule 1A)	456.1	NSPL	ARR S1A
2	NITS (AEP LSE)	456.1	NSPL	ATRR
3	NITS (Non-Affiliates)	456.1	NSPL	ATRR
4	Grandfathered PTP (NCEMC)	456.0	Contract	ATRR
5	PJM Expansion Cost Recovery Charge (ECRC)	456.1	NSPL	ARR EC
6	RTO Startup Cost Recovery Charge (SCRC)	456.1	NSPL	ARR SC

AEP as LSE (Expenses)

#	Item	FERC Account*	PJM Billing Basis	AEP Allocation Basis
7	Transmission Owner Scheduling, System Control and Dispatch Service (PJM Schedule 1A)	456.1	MWh	MWh
8	NITS Charges (for AEP Retail Load)	456.1	NSPL	12CP
9	NITS Charges for AEP FR Customers[1/]	447.0	NSPL	DA
10	NITS Reimbursement from AEP FR Customers[1/]	447.0	NSPL	DA
11	Firm Point-to-Point Credits (for AEP Retail Load)	456.1	NSPL	12CP
12	Non-Firm Point-to-Point Credits (AEP Retail Load)	456.1	NSPL	12CP
13	Transmission Enhancement (Schedule 12)	565.0	NSPL	12CP
14	PJM Expansion Cost Recovery Charge (ECRC)	456.1	NSPL	12CP
15	RTO Startup Cost Recovery Charge (SCRC)	456.1	NSPL	12CP

NSPL	PJM Network Service Peak Load
Contract	Pre-OATT FERC Rate Schedules
ARR S1A	Annual Revenue Requirement - Schedule 1A
ATRR	Annual Transmission Revenue Requirement
ARR EC	Annual Revenue Requirement - Expansion Cost Recovery
ARR SC	Annual Revenue Requirement - Startup Cost Recovery
12CP	Average of 12 coincident peaks through 10/31 of prior year
DA	Directly Assigned to Operating Company

* Note: Should the net amount in 456.1 for any Member be negative, e.g. more expense than revenue, the net expense will be recorded in 565.0.

1/ Includes all transmission-related LSE expenses (NITS, Schedule 1A, Point-to-Point Credits, Schedule 12, ECRC, SCRC) which are directly assigned to Operating Company for AEP FR Customers.

Issued By: Richard E. Munczinski
Senior Vice President, Regulatory Services

Effective: first day of the month after the Commission issues a final, non- appealable order accepting the Agreement for filing

Issued On: August 4, 2010

AMERICAN ELECTRIC POWER

American Electric Power
801 Pennsylvania Avenue N W
Suite 320
Washington DC 20004
AEP.com

June 5, 2009

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

Monique Rowtham-Kennedy
Senior Counsel - Regulatory Services
(202) 383-3436
(202) 383-3459 (F)

Re: American Electric Power Service Corporation
Docket No. ER09-____-000

Dear Secretary Bose:

I. Introduction.

American Electric Power Service Corporation ("AEPSC"), on behalf of Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company (collectively "AEP") hereby files, pursuant to Section 205 of the Federal Power Act, 16 U.S.C. S 824d, proposed amendments to the Transmission Agreement by and among such companies and with AEPSC as Agent dated as of April 1, 1984 as amended ("Transmission Agreement").

II. Background.

AEP is a multi-state electric utility holding company system, whose operating companies provide electric service to approximately five million customers in parts of eleven states. Prior to 2000, when AEP merged with the former Central and South West System, AEP consisted of seven electric utility operating companies. The five largest companies operate generation, transmission and distribution facilities and are parties to the Transmission Agreement. The two smaller companies – Kingsport Power Company ("Kingsport") and Wheeling Power Company ("Wheeling") operate only transmission and distribution facilities. These seven AEP operating companies provide electric service to customers in parts of seven states – Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia and West Virginia. AEPSC provides management and professional services at cost to these companies and others in the AEP System.

AEP was a registered holding company system under the Public Utility Holding Company Act of 1935 (PUHCA 1935) which, until its repeal in 2005, required such systems to be planned and operated on an integrated basis, *i.e.*, as a single system. Integrated planning and operation of the AEP System has been carried out under a number of "pooling" agreements under which the AEP operating companies pool or combine their power supply and delivery facilities to achieve the benefits of an integrated system. The first such agreement was the Interconnection Agreement entered into in 1951 by the generation, transmission and distribution operating companies (Members), the same companies that are parties to the Transmission Agreement. AEPSC acts as Agent under the agreement. The Interconnection Agreement provides for the integrated planning and operation of the Members' power supply facilities and provides for allocation among the Members of the generation-related costs and benefits of integrated planning and operation.[1]

A. Origin of the Transmission Agreement

AEP has developed an extensive transmission system which serves as the medium for integrating the power supply resources of the Member companies. The East Zone system stretches from the southeastern shores of Lake Michigan through northern Indiana and Ohio to the mountains of Kentucky, Tennessee, Virginia, and West Virginia. AEP pioneered extra-high-voltage (EHV) transmission operating at voltages of 345 kV and 765 kV as a means of achieving the advantages of large scale system integration. The ability to site generation at its most advantageous locations and move power to widely separated load areas via high voltage and EHV transmission has situated AEP for many decades as an efficient low-cost electric energy producer. The integrated operation of the system, also enabled by the strong transmission system, allows the lowest cost power at any given time to be dispatched to serve the combined load obligations of the members.

The AEP Interconnection Agreement provides for sharing the costs of the Members' generating facilities, and provides that each Member's transmission facilities shall be made available to the others to enable system integration, including the centralized dispatch and shared use of generation. The Interconnection Agreement does not, however, provide for a sharing of the cost of transmission facilities, which are owned by the members providing service in the state or service area where such facilities are located. In the early 1980s, the addition of some major 765-kV facilities caused a significant imbalance in transmission investment among the Members. To achieve a

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1 CSW was also a registered holding company under PUHCA 1935 and had its own generation and transmission pooling agreements. These agreements as well as the pre-merger AEP pooling agreements, have been retained since the merger, and the two formerly separate systems are integrated pursuant to two "bridge" agreements called the System Integration Agreement ("SIA") and the System Transmission Integration Agreement ("STIA"). The former CSW is now sometimes referred to as the AEP West Zone and the pre-merger AEP as the East Zone. The amendments proposed in this filing do not substantively affect the former CSW pooling agreements or the two bridge agreements. Upon acceptance for filing of the proposed amendments, AEP will file conforming changes to the STIA reflecting the addition of Kingsport and Wheeling as parties to the Transmission Agreement.

more equitable distribution of those investments among the Members, AEP filed the Transmission Agreement, proposing that the cost of ownership and operation of the Members' EHV facilities would be shared on the basis of their relative peak loads. The matter was litigated at FERC, with affected state regulatory commissions, other customer representatives and the FERC Trial Staff offering their opinions on the proposal. Ultimately, the Commission, in Opinion No. 311, issued in 1988, approved the proposed Agreement with a few changes, the most notable being the inclusion of 138-kV facilities among the facilities whose costs are shared under the Agreement.[2]

B. Description of the Existing Agreement

Under the AEP transmission Agreement, as approved by the Commission, each Member's investment in bulk transmission facilities is compared to its Member Load Ratio (MLR) share of the total of all the members' investments. MLR is a demand-related allocation factor used in both the Transmission Agreement and the Interconnection Agreement. Specifically, it is the ratio of a Member's non-coincident peak load in the past twelve months to the sum of the individual Members' non-coincident peak loads for the same period. Those Members whose bulk transmission investment is deficit relative to their MLR share of the total system investment make monthly settlement payments that are distributed by the Agent to those whose investments are surplus relative to their MLR share. The payments are determined by multiplying the Surplus Members' investment surplus by a carrying charge reflecting the Member's ownership and operation costs, including a Commission-approved return on equity of 12.84%. The investment levels are updated yearly, except that additions to a Member's investment exceeding $10 million are recognized the month after they occur. I&M and KPCO have been surplus Members and the two Ohio companies – CSP and OPCO – have been deficit Members from the beginning. APCO has been a surplus member since 2006, after completion of the Wyoming-Jacksons Ferry 765 kV transmission line

C. Reasons for Amending the Agreement

The background of the proposed changes is described in direct testimony being filed herewith by J. Craig Baker, Senior Vice President – Regulatory Services for AEPSC. Mr. Baker explains that the proposed changes are driven by fundamental changes that have occurred in the electric utility industry and its regulatory framework in recent years. The most important changes have been open-access transmission under Order No. 888 and its progeny, and the Commission's policy encouraging utilities' participation in RTOs. In accordance with the commission's RTO policy, AEP, in 2004, placed its East Zone transmission facilities under the functional control of PJM Interconnection, L.L.C. ("PJM"). A number of aspects of AEP's having a single-system rate and participating in PJM have led to a re-examination of the method of allocating transmission costs among

[2] *American Electric Power Service Corp.*, Opinion No. 311, 44 FERC ¶ 61, 206 (1987) *reh denied*, Opinion No. 311-A, 45 FERC ¶ 61, 382 (1988).

the AEP operating companies under the Transmission Agreement. Prior to joining PJM, AEP provided transmission service to itself and others pursuant to its own Open Access Transmission Tariff (OATT). Since joining PJM, AEP's status has changed from being a Transmission Provider under its OATT to being a Transmission Customer under PJM's OATT. As load-serving entities in PJM, the AEP east companies must purchase Network Integration Transmission Service (NITS) from PJM to serve their native loads. AEP must also purchase from PJM the ancillary services and other services that it needs to serve its native load customers, and, as a Transmission Owner within PJM, AEP receives compensation from PJM for AEP's costs associated with allowing its transmission facilities to be used for regional OATT service.

As a NITS customer, AEP pays PJM for its load share of zonal transmission service. The allocation method used by PJM to determine AEP's load ratio share of costs, is similar in concept to the MLR allocation used in the Transmission Agreement, in that it also relies on annual peak demands, but it differs from the MLR method in that PJM uses a single coincident peak (1-CP) method to allocate among LSE's in AEP's zone, whereas the MLR reflects the Members' non-coincident annual peak demands.

Since the AEP east companies are both LSEs and transmission owners in PJM, they now receive comprehensive statements from PJM for transmission and related services used and supplied. AEP's proposal in this case provides for an allocation of all transmission-related items on those PJM statements to the AEP east operating companies. Unlike the existing Transmission Agreement, the proposed amended Transmission Agreement would allocate costs and revenues associated with all transmission facilities, not just investments in Bulk Transmission facilities, e.g., EHV stations and lines operated at 138 kV and above. Moreover, unlike the existing Transmission Agreement, the proposed amended Agreement would include Kingsport and Wheeling, which own transmission facilities and are PJM members, in the allocation. Thus, the proposed amendments will effect a comprehensive allocation of transmission related costs and revenues among the AEP operating companies that own transmission facilities.

Also, in the next several years, the AEP east companies expect to be charged significant amounts of money by PJM for a share of the cost of major transmission projects whose costs are socialized to all PJM LSEs. In Opinion No. 494,[3] the Commission held that the cost of new transmission facilities operated at 500 kV and above and approved as part of PJM's regional transmission expansion planning (RTEP) process would be shared by all LSE's in the region. PJM has already approved several billion dollars worth of regional projects. The Commission's rationale in ordering such socialization is that the new 500-kV and above facilities are "backbone" facilities that benefit the entire region, so all LSEs and their customers in the region should share the cost of such facilities. PJM allocates the costs of new regional projects among the zones based on a sum of non-coincident demands method similar to the MLR, and then

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[3] *PJM Interconnection, L.L.C.*, Opinion No. 494, 119 FERC ¶ 61, 063 (2007) *order on reh'g*, Opinion No. 494-A, 122 FERC ¶ 61, 082 (2008).

allocates the costs among the LSEs in each zone using the 1CP method. AEP expects to be charged approximately 15% of the cost of such projects. The proposed amendments to the Transmission Agreement provide a contractual framework for the allocation of those costs among the companies on the same basis as other transmission related costs.

Another important change in circumstances leading to a reexamination of the terms and conditions of the Transmission Agreement has been legislation in some of the states in AEP's East Zone that has changed the nature of electric regulation in those states. Three of AEP's East Zone states have adopted electric utility restructuring and customer choice. As part of electric restructuring, the retail rates of the companies in those states have been unbundled. In Ohio, the FERC OATT rate is used to set the retail transmission charge. Because of FERC policies requiring transmission service to be provided by integrated utility systems at a single rate [4] the cost of service used to develop charges for regional service in the AEP zone is the cost of all transmission facilities owned by the East Zone companies. It is, therefore, an average rate. In the remaining states, other than Ohio, that have retained bundled rates for electric service, the transmission component of those rates is based on the cost of owning, operating and maintaining the transmission facilities owned by the individual operating company, increased or decreased by net payments or receipts from non-affiliates and charges and payments under the existing Transmission Agreement. For various reasons, the transmission component of retail rates can be above or below the system average OATT rate. The use of an average AEP transmission cost of service in some states and individual company cost of service in others can cause under collection of transmission costs. The cost and revenue allocations under the proposed revisions to the Transmission Agreement will provide a reasonable basis for each state to set rates that will reduce or eliminate the differences in per kW costs of transmission among the companies, and alleviate the cost under collection problem.

III. Description of the Proposed Amendments

The proposed amendments are described in detail in direct testimony filed herewith by Dennis W. Bethel – Managing Director – Regulated Tariffs for AEPSC. As Mr. Bethel points out, the major proposed change to the Agreement is the modification of Articles 5 (Definitions of Factors Associated With Settlements) and 6 (Settlements) which implement the MLR-based cost sharing of facilities operated at 138 kV and above described earlier. The proposed new Articles 5 and 6 would implement the allocation of costs and revenues in the Transmission Accounts under the Uniform System of Accounts. The items to be allocated are set forth in Proposed Appendix I. All the proposed changes are shown in Exhibit AEP-202, black-lined version of the amended Transmission Agreement. The proposed changes are reflected in the enclosed clean format version of

[4] *See, e.g. Southern Company Services, Inc.*, 55 FERC ¶ 61,173, *reh'g denied*, 57 FERC ¶61,093 (1991), *aff'd sub nom Alabama Power Co. v. FERC*, 933 F.2d 1557 (D.C. Cir. 1993).

the revised agreement (Attachment A), that includes the header and footer designations consistent with Order 614.

Since its inception, the Transmission Agreement has had one purpose, to effect a sharing of the AEP East Companies' ("Members") costs of owning and operating Bulk Transmission facilities, defined in Opinion No. 311, *supra*, to include transmission lines operating at 138 kV or higher and all facilities, without regard to voltage, at transmission stations that contain at least some EHV facilities.

The scope of the changes to the Transmission Agreement proposed by the Members is consistent with the significance of the changes in the provision and regulation of transmission service in the twenty years since the Commission's Order approving it as discussed by witness Baker. The proposed changes recognize that, pursuant to the PJM Open Access Transmission Tariff ("OATT", or "PJM OATT"), the Members, and other Load Serving Entities ("LSEs") in the AEP Zone of PJM, now share the cost of the AEP East Companies' transmission facilities of all voltages, including those operated at voltages below 138 kV. Further, while the Transmission Agreement included only the five largest AEP East Companies, all seven of them own and operate transmission facilities that are used by PJM to provide service, and the costs of all those facilities is reflected in the rates charged under the PJM OATT. The proposed changes also recognize that, as a result of open access and RTO participation, the Members now are obligated to provide certain transmission related services, and to purchase such services and additional RTO supplied services. Accordingly, the proposed Transmission Agreement changes address the allocation of OATT-based transmission and related costs and revenues among all seven of the AEP East Companies.

Mr. Bethel also presents Exhibit AEP-203, showing the effects of the proposed amendments on each of the East Zone operating companies' transmission costs and rates, and Exhibits AEP – 204 through 210. These Exhibits detail the cost impacts of the proposed changes in the Transmission Agreement, and compare AEP's proposed allocation method – 12-CP-- with two others that AEP considered but chose not to propose 1-CP and MLR. The Exhibits show that AEP's proposed method will produce more stable costs and rates for AEP customers, over the long-term, compared to the other methods.[5]

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[5] AEP's proposal to adopt the 12-CP methodology is not barred by the Commission's order in *American Elec. Power et al., 103 FERC ¶61,008 (2003) at par 47-48.* This order required AEP to adopt the 1-CP methodology for transmission ratemaking to be consistent with the manner in which PJM allocates FTRs. As noted in this filing, the proposed allocations will not affect transmission rates or FTR allocations under the OATT.

IV. No Effect on Wholesale Customers

Further as Mr. Bethel indicates in his testimony, the proposed changes will have no impact on wholesale transmission rates.[6] While the proposed Transmission Agreement will change the transmission costs and revenues allocated to each of the AEP East Companies individually, the total costs included in the OATT will remain unchanged.

V. Proposed Effective Date

Article 9 of the Transmission Agreement provides that any modification in the terms and conditions of the Agreement agreed to by the Members shall become effective the first day of the month following authorization by the appropriate regulatory authority. In accordance with this provision, AEP requests that the proposed changes not become effective until the first day of the month after the Commission issues a final, non-appealable order accepting the Agreement for filing. In other words, AEP requests that if the instant filing is set for settlement or hearing, the effective date be delayed until resolution of such settlement or hearing.

In addition to being in accordance with the terms of the Agreement AEP submits that such a delayed effective date is appropriate for other reasons. As explained by Mr. Baker in his accompanying direct testimony, AEP's pooling Agreements, including the proposed amended transmission Agreement, are meant to govern integrated planning and operations over the long term. Therefore, while AEP is concerned with getting the amendments in place as soon as possible, it is also concerned with achieving a result that is acceptable to state regulators and other stakeholders, or at least has been found by the Commission to be just and reasonable with respect to such stakeholders. Second, the proposed changes will result in some changes in the level of transmission-related costs historically experienced by some for the operating companies. A delayed effective date will allow the affected members and stakeholders to adapt to the new system. Finally, a delayed effective date will obviate the need to impose refunds or surcharges, which would entail administrative costs and potential issues associated with retail rate recovery.

AEP requests waiver of the notice provisions in the Commission's regulations, and any other regulation as necessary to allow the delayed effective date sought herein. A similar proposal was accepted by the Commission in connection with a filing in 2006 of amendments to AEP's System Integration Agreement, the pooling agreement between AEP's east and West Zones.

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[6] *See* Exhibit AEP-200 p. 9.

VI. State Commission Review

In recognition of the serious interest that the state commissions that regulate AEP's retail rates in its East Zone have in the proposed filing, AEP has provided advance notice of the planned filing to all seven state commissions. AEP met with those that requested such meetings to present and explain the proposed amendments, including the financial effects. AEP has endeavored to explain the reasons behind its proposal, assure that the state commissions fully understand the proposal and minimize any concerns the commissions may have.

VII. Compliance with the Requirements of 18 C.F.R. § 35.13

In compliance with the requirements of 18 C.F.R. § 35.13, AEP states the following:

A. List of Documents Enclosed – Section 35.13(b)(1)

The following documents are being submitted with this filing:

1. this letter of transmittal;
2. Attachment A, the revised Transmission Agreement with Order 714 compliant designations.
3. Testimony of J. Craig Baker (Exhibit AEP-100) and Dennis W. Bethel (Exhibit AEP-200);
4. Exhibits AEP 201-210 (including a blacklined version of the Transmission Agreement in AEP-202).
5. Workpapers supporting certain Exhibits;
6. Certificate of Service and List of Person Served;
7. Attestation of J. C. Baker; and

B. Proposed Effective Date – Section 35.13 (b0(2)

See Section IV, above

C. Names and Addresses of Persons to Whom a Copy of the Rate Schedule Change Has Been Mailed – Section 35.13(b)(3)

A copy of this filing has been served upon the state commissions of Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia and West Virginia, and the consumer advocates in those states. In addition, AEP has also posted this filing on its website at http://www.aep.com/go/FERCRateScheduleFilings and will provide a complete copy of this filing, on paper or CD, to any person who requests a copy

D. Brief Description of the Rate Schedule Change – Section 35.13(b)(4)

Please refer to Sections I, II and III of this transmittal letter for a brief description of the proposed rates.

E. Statement of the Reasons for the Rate Schedule Change – Section 35.13(b)(5)

Please refer to Section I of this transmittal letter for a statement of the reasons for the proposed rates.

F. Statement Regarding Whether AEP has Obtained the Requisite Agreement(s) to the Rate Schedule Change or Filing of Rate Schedule – Section 35.13(b)(6)

AEP has obtained the approval of the proposed amendments as required by the existing Agreement.

G. Statement Regarding Inclusion of Any Expenses or Costs in Cost of Service Statements that have been Alleged or Adjudged Illegal, Duplicative, or Unnecessary that are Demonstrably the Project of Discriminatory Employment Practices – Section 35.13(b)(7)

None of the costs or expenses underlying the cost of service have been alleged or adjudged to be illegal, duplicative, or unnecessary demonstrably due to discriminatory employment practices.

H. Cost of Service Information and Revenue Comparisons – Sections 35.13 (c) and (d)

Exhibit AEP-203 shows the effect on each of the AEP East operating companies of the proposed amendments, using the cost of service underlying the transmission formula rates accepted for filing by the Commission in Docket No. ER-08-1329-000.[7]

VIII. Order No. 714

AEP has elected to designate the amended Transmission Agreement in accordance with the Order No. 714 in which the Commission determined:

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[7] *American Electric Power Service Corporation*, Order Accepting and Suspending Formula Rate Subject to Refund and Establishing Refund and Settlement Judge Procedures, 124 FERC ¶61,306 (2009).

> We will no longer require utilities to follow the Order No. 614 preamble instructions to file multiple copies of a tariff. Instead, the joint filers will be permitted to designate one filer to submit a single tariff filing for inclusion in its database that reflects the joint tariff, along with the requisite certificates of concurrence. The non-designated joint filers would include in their tariff database a tariff section consisting of a single page or section that would provide the appropriate name of the tariff and the identity of the utility designated as the filer for the joint tariff. [8]

While Order No. 714 is not yet effective, the Commission has permitted utilities to follow the procedures outlined in Order No. 714 for designation of joint tariffs.[9] For this reason, rather than including with this filing seven separate copies of the Transmission Agreement designated pursuant to Order No. 614, AEP has designated the Transmission Agreement as Appalachian Power Company Rate Schedule FERC No.100 and has included certificates of concurrence for the remaining AEP East Companies as joint filers.

IX. Request For Waiver and Settlement Procedures

The proposed amendments, while affecting a reallocation of costs among the east operating companies, does not result in any increase in transmission or related revenues or revenue requirements beyond those already authorized by the Commission. For this reason, AEP believes that the instant filing qualifies for the abbreviated filing requirements allowed by 18 C.F.R.§ 35.13 (a) (2) (iii) in cases not involving a rate increase. However, should the Commission believe that a rate increase is involved in this filing, AEP seeks waiver of the cost-of-service statements required by 18 C.F.R. § 35.13 (d). Since the proposal involves a reallocation, rather than an overall increase in costs, AEP believes that the information that will be most helpful to the Commission and stakeholders is a comparison of the financial effects, under a given existing cost of service, of changing the allocation of costs from the existing method to the proposed method. AEP submits that the before and after comparison and comparison of alternative allocation methods set forth in Exhibits AEP-203 through AEP-210 is far more meaningful than the type of cost of service analysis underlying a proposal to increase rates.

In the event any other waivers are required in connection with this filing, the Commission should grant waivers given the benefits of updating costs and rates under the proposed formula approach.

[8] *Electronic Tariff Filings*, Order No. 714, FERC Stats. & Regs. ¶ 31,276 (2008).
[9] *See Portland General Electric Company et al.,* 126 FERC ¶ 61,220 (2009).

Further, to the extent this filing is contested by any party, AEP respectfully requests that the Commission hold any required hearing in abeyance pending the establishment of settlement procedures to resolve issues raised by such contesting party.

X. Communications

Communication regarding this matter should be directed to the following individuals:

Monique Rowtham-Kennedy
American Electric Power
Service Corporation
801 Pennsylvania Ave, N.W.
Suite 320
Washington, DC 20004
Telephone: (202) 383-3436
e-mail:mrowtham-kennedy@aep.com

Dennis W. Bethel
American Electric Power
Service Corporation
1 Riverside Plaza
Columbus, Ohio 43215
Telephone: (614) 716-2764
Fax: (614) 716-2352
e-mail:dwbethel@aep.com

Please acknowledge receipt of this filing by date stamping the enclosed extra copy of this transmittal letter and returning it in the enclosed postage prepaid envelope. Any questions concerning this filing may be directed to me.

Respectfully submitted,

Monique Rowtham-Kennedy

CERTIFICATE OF SERVICE

I hereby certify that I have this day arranged for service of the foregoing documents on each party on the attached service list.

Monique Rowtham-Kennedy
American Electric Power Service Corporation
801 Pennsylvania Avenue, N.W.
Suite 320
Washington, D.C. 20004-2684
Telephone: 202-383-3436
Fax: 202-383-3459

June 5, 2009

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

America Electric Power Service Corporation on Behalf of:	)	Docket No. ER09-___-000
	)	
Appalachian Power Company,	)	
Columbus Southern Power Company,	)	
Indiana Michigan Power Company,	)	
Kentucky Power Company,	)	
Kingsport Power Company,	)	
Ohio Power Company, and	)	
Wheeling Power Company	)	

ATTESTATION

I, the undersigned, being duly sworn, depose and say, under penalty of perjury, that, to the best of my knowledge, information and belief, the statements and supporting data submitted herewith are true, accurate, and current representations of the books, budgets, or other corporate documents of Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company.

J. Craig Baker

J Craig Baker
Senior Vice President
Regulatory Services

Subscribed and sworn to before me this
31st day of May, 2009

My Commission expires:

Catherine Hurston
Notary Public

NOTARIAL SEAL
STATE OF OHIO

CATHERINE HURSTON
Notary Public, State of Ohio
My Commission Expires 11 15 2009

PSC Exhibit 6

TRANSMISSION AGREEMENT

By and among

APPALACHIAN POWER COMPANY

COLUMBUS SOUTHERN POWER COMPANY

INDIANA MICHIGAN POWER COMPANY

KENTUCKY POWER COMPANY

KINGSPORT POWER COMPANY

OHIO POWER COMPANY

WHEELING POWER COMPANY

and with

AMERICAN ELECTRIC POWER SERVICE CORPORATION

AS AGENT

DATED APRIL 1984, AS AMENDED

CONTENTS

0.1 THIS AGREEMENT, made and entered into as of the 1st day of April, 1984, and as subsequently amended, by and among APPALACHIAN POWER COMPANY (Appalachian Company), a Virginia corporation, COLUMBUS AND SOUTHERN POWER COMPANY (Columbus Company), an Ohio corporation, INDIANA MICHIGAN POWER COMPANY (Indiana Company), an Indiana corporation, KENTUCKY POWER COMPANY (Kentucky Company), a Kentucky corporation, OHIO POWER COMPANY (Ohio Company), an Ohio corporation, KINGSPORT POWER COMPANY (Tennessee Company), a Tennessee corporation, and WHEELING POWER COMPANY (Wheeling Company), a West Virginia corporation, said companies (herein sometimes called ‘Members’ when referred to collectively and ‘Member’ when referred to individually) being affiliated companies of the integrated public utility electric system known as the American Electric Power SYSTEM (AEP System), and AMERICAN ELECTRIC POWER SERVICE CORPORATION (Agent), a New York corporation, being a service company engaged solely in the business of furnishing essential services to the aforesaid companies and to other affiliated companies.

W I T N E S S E T H,

T H A T:

0.2 WHEREAS, the Members own and operate electric facilities in the states herein indicated, (i) Appalachian Company in Virginia, West Virginia, and Tennessee (ii) Columbus Company in Ohio, (iii) Indiana Company in Indiana and Michigan, (iv) Kentucky Company in Kentucky, (v) Tennessee Company in Tennessee, (vi) Ohio Company in Ohio and West Virginia, and (vii) Wheeling Company in West Virginia; and

0.3 WHEREAS, certain of the Members have entered into an interconnection agreement, dated July 6, 1951, with modification thereto, which provides for certain understandings, conditions, and procedures designed to achieve the full benefits and advantages available through the coordinated operation of their electric power supply facilities; and

0.4 WHEREAS, The Members' electric facilities are now and for many years have been interconnected through their respective transmission facilities at a number of points, forming an integrated transmission network; and

0.5 WHEREAS, the Members have achieved benefits through the coordinated planning and development of a fully integrated Transmission System; and

0.6 WHEREAS, the members believe that an agreement which provides for the equitable sharing among the Members of the costs incurred by the Members in connection with the ownership, operation, and maintenance of their respective portions of the Transmission System would enhance equity among the Members for the continued development of a reliable and economic Transmission System; and

0.7 WHEREAS, effective October 1, 2004 the Members joined the PJM Interconnection, LLC ("PJM"), and placed their respective transmission facilities under the functional control of PJM, a regional transmission operator or "RTO"; and

0.8 WHEREAS, PJM provides transmission service, pursuant to the PJM Open Access Transmission Tariff ("OATT"), to the Members and others who require transmission service over the Transmission System; and

0.9 WHEREAS, the Members believe that benefits and advantages could be best realized if this Agreement were administered by a single clearing agent; and

0.10 WHEREAS, the Members believe that the Agent designated herein for such purpose is qualified to perform such services;

0.11 NOW, THEREFORE, in consideration of the premises and of the mutual covenants and agreements hereinafter contained, the parties hereto hereby agree as follows:

ARTICLE 1

DESCRIPTION OF TRANSMISSION SYSTEM

1.1 The Transmission System covered by this Agreement shall include all the transmission facilities, from time to time, owned by the Members that are included in the costs of service used to determine rates for transmission service under the PJM OATT, including without limitation, (i) All Member transmission lines; (ii) all facilities such as transformers, buses, switchgear, and associated facilities located at Member transmission substations, and (iii) any other transmission lines and associated substation facilities at any voltage designated by the Transmission Committee as having been, installed or leased for the mutual benefit of all Members and/or others who receive transmission service from PJM or a successor RTO or other successor transmission service provider.

ARTICLE 2

OPERATION

2.1 Each member shall maintain its respective portion of the Bulk Transmission System, together with all associated facilities and appurtenances, in a suitable condition of repair at all times in order that said system will operate in a reliable and satisfactory manner.

ARTICLE 3

TRANSMISSION COMMITTEE

3.1 The Members shall appoint representatives to serve on a Transmission Committee. Such representatives shall have authority to act for the Members in the administration of all matters pertaining to this Agreement.

3.2 Each Member shall designate in writing, delivered to the other Members and Agent, the person who is to act as its representative on said Committee and the person or persons who may serve as alternate whenever such representative is unavailable to act. Agent shall designate in writing delivered to the Members the person who is to act as its representative on said Committee and the person or persons who may serve as alternate whenever such representative is unavailable to act. Such person designated by Agent shall act as chairman of the Transmissions Committee and shall be known as the “Transmission Manager”.

ARTICLE 4

AGENTS RESPONSIBILITIES

4.1 For the purpose of carrying out the provisions of this Agreement the Members hereby delegate to Agent, and Agent hereby accepts, the responsibility of administration of this Agreement, and in furtherance thereof Agent hereby agrees:

4.11 To arrange for and conduct such meetings of the Transmission Committee as may be required to insure the effective and efficient carrying out of all matters of procedure essential to the complete performance of the provisions of this Agreement.

4.12 To carry out settlements under this Agreement. Settlements by the Members shall be made for each calendar month through General Ledger accounts (hereby designated and hereinafter called the “TRANSMISSION ACCOUNTS”) to be administered by Agent. For the purposes of This Agreement, Transmission Accounts shall be consistent with the accounts listed in the FERC Uniform System of Accounts, and shall include such accounts and sub-accounts as are necessary and proper, directed by the Transmission Committee, and consistent with applicable regulatory requirements.

ARTICLE 5

SETTLEMENTS

5.1 As provided in this Article, following the end of each month, the Members shall effect settlements through the TRANSMISSION ACCOUNTS. Generally, Settlements hereunder will involve the allocation of transmission-related costs and revenues among the Members, and the recording of same in the

Transmission Accounts of the Members, as specified in Appendix I.

5.2 All amounts to be allocated among the Members hereunder shall, to the extent practicable, be included in Settlements for the month in which such cost or revenue is realized or accrued. If necessary in order to implement such timely Settlement, the Agent shall be authorized to effect Settlements on an estimated basis and make such adjustment as is needed in subsequent Settlements that will conform the Settlements to the terms of this Agreement.

ARTICLE 6

TAXES

6.1 If at any time during the duration of this Agreement there should be levied and/or assessed by any governmental authority against any Member any tax related to the receipt of Settlements calculated pursuant to this Agreement (such as sales, excise or similar taxes), such tax expense incurred by such Member that would not have been incurred were the Settlements hereunder not being made, such Member shall be entitled, to the extent permitted by the applicable regulatory authority(ies) to include such tax in its transmission revenue requirement under the PJM or successor OATT when transmission revenue requirements of the Members are next updated, and thereby receive an appropriate level of reimbursement (through cost sharing) for such additional taxes by Members and others receiving service from the Transmission System.

ARTICLE 7

Allocation Principles

7.1 All items of cost and revenue included in Settlements hereunder shall be related to the provision of or receipt of transmission service or a related (“ancillary”) service by one or more Members on behalf of one or more of the Members. The allocation methods used to share such costs and revenues, as specified in Appendix I, shall be made pursuant to direction by the Transmission Committee.

7.2 The Transmission Committee may at any time during the Term of This Agreement, upon the recommendation of the Agent or any Member, review any item of cost or revenue, in order to determine whether such item is transmission-related, and whether it should be included in Settlements hereunder. Further, whenever the Transmission Committee determines that any change is needed in Appendix I to add or delete any item of cost or revenue, or to change the allocation or accounting basis of any item, the Transmission Committee shall authorize and direct the Agent when and how to effect such change in Appendix I and in monthly Settlements among the Members.

7.3 Allocations of costs shall, to the extent practicable, be based on measurable cost indicators that will effect a sharing of costs among the Members consistent with the use of such service, and will be sufficiently stable, over time, so as not to cause undue or objectionable variability in the costs of the Members.

7.4 Allocations of revenues shall, to the extent practicable, be based on measurable indicators of the cost incurred by each Member in providing the service that gave rise to the revenue.

ARTICLE 8

MODIFICATION

8.1 Any Member, or the Agent, by written notice given to the other Members and Agent, may call for a reconsideration of the terms and conditions herein provided. If such reconsideration is called for, the Members shall take into account any changed conditions, any results from the application of said terms and conditions, and any other facts that might cause said terms and conditions to result in an inequitable sharing of costs and benefits under this Agreement. Any modification in terms and conditions agreed to by the Members following such reconsideration shall become effective the first day of the month following authorization of such reconsideration by appropriate regulatory authority.

ARTICLE 9

EFFECTIVE DATE AND TERM OF THIS AGREEMENT

9.1 This Agreement shall become effective and shall become a binding obligation of the Parties on the date specified in an Order in such proceeding as this Agreement shall have been filed with, and accepted for filing by the Federal Energy Regulatory Commission (FERC) under the Federal Power Act as a rate schedule.

9.2 This Agreement shall continue in effect for an initial period from the Effective Date to December 31, 1990, and thereafter for successive periods of one year each until terminated as provided under subsection 10.3 below.

9.3 Any Member upon at least three years' prior written notice to the other Members and Agent may terminate this Agreement at the expiration of said initial period or at the expiration of any successive period of one year.

ARTICLE 10
REGULATORY AUTHORITIES

10.1 The Members recognize that this Agreement, and any tariff or rate schedule which shall embody or supersede this Agreement or any part thereof, are in certain respects subject to the jurisdiction of the FERC under the Federal Power Act, and are also subject to such lawful action as any regulatory authority having jurisdiction shall hereafter take with respect thereto. The performance of any obligation of the Members shall be subject to the receipt from time to time as required of such authorizations, approvals or actions of regulatory authorities having jurisdiction as shall be required by law.

10.2 It is expressly understood that any Member under this Agreement, as it may hereafter from time to time be modified and supplemented by the Members, shall be entitled, at any time and from time to time, unilaterally to make application to the FERC for a change in rates, charges, classification of service, or any rule, regulation or contract relating thereto, or to make any change in or supersede in whole or in part any provision of this Agreement, under Section 205 of the Federal Power Act and pursuant to the FERC's Rules and Regulations promulgated thereunder.

ARTICLE 11

ASSIGNMENT

11.1 This Agreement shall inure to the benefit of and be binding upon the successors and assigns of the respective parties.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed in their respective corporate names and on their behalf by their proper officers thereunto daily authorized as of the day and year first above written.

Next Page is Signature Page

Transmission Agreement Among:

AMERICAN ELECTRIC POWER SERVICE CORPORATION,

By:___________________________

Michael Heyeck
Senior Vice President

APPALACHIAN POWER COMPANY,

By:___________________________

Dana E. Waldo
President and Chief Operating Officer

COLUMBUS SOUTHERN POWER COMPANY,

By:___________________________

Joseph Hamrock
President and Chief Operating Officer

INDIANA MICHIGAN POWER COMPANY,

By:___________________________

Helen J. Murray
President and Chief Operating Officer

KENTUCKY POWER COMPANY,

By:___________________________

Timothy C. Mosher
President and Chief Operating Officer

KINGSPORT POWER COMPANY,

By:___________________________

Dana E. Waldo
President and Chief Operating Officer

OHIO POWER COMPANY, and

By:___________________________

Brian X. Tierney
Vice President

WHEELING POWER COMPANY

By:___________________________

Dana E. Waldo
President

Dated as of: ______________________________

Appendix I

AEP Transmission Agreement
Allocation of Transmission Related Costs and Revenues

AEP as Transmission Owner (Revenues)

#	Item	FERC Account*	PJM Billing Basis	AEP Allocation Basis
1	Transmission Owner Scheduling, System Control and Dispatch Service (PJM Schedule 1A)	456.1	NSPL	ARR S1A
2	NITS (AEP LSE)	456.1	NSPL	ATRR
3	NITS (Non-Affiliates)	456.1	NSPL	ATRR
4	Grandfathered PTP (CPL & NCEMC)	456.0	Contract	ATRR
5	PJM Expansion Cost Recovery Charge (ECRC)	456.1	NSPL	ARR EC
6	RTO Startup Cost Recovery Charge (SCRC)	456.1	NSPL	ARR SC

AEP as LSE (Expenses)

#	Item	FERC Account*	PJM Billing Basis	AEP Allocation Basis
7	Transmission Owner Scheduling, System Control and Dispatch Service (PJM Schedule 1A)	456.1	MWh	MWh
8	NITS Charges (for AEP Retail Load)	456.1	NSPL	12CP
9	NITS Charges for AEP FR Customers	447.0	NSPL	DA
10	NITS Reimbursement from AEP FR Customers	447.0	NSPL	DA
11	Schedule 1A Charge for AEP FR Customers	447.0	NSPL	DA
12	Schedule 1A Reimbursement from AEP FR Customers	447.0	NSPL	DA
13	Firm Point-to-Point Credits (for AEP Retail Load)	456.1	NSPL	12CP
14	Non-Firm Point-to-Point Credits (AEP Retail Load)	456.1	NSPL	12CP
15	Transmission Enhancement (Schedule 12)	565.0	NSPL	12CP
16	PJM Expansion Cost Recovery Charge (ECRC)	456.1	NSPL	12CP
17	RTO Startup Cost Recovery Charge (SCRC)	456.1	NSPL	12CP

NSPL PJM Network Service Peak Load
Contract Pre-OATT FERC Rate Schedules
ARR S1A Annual Revenue Requirement - Schedule 1A
ATRR Annual Transmission Revenue Requirement
ARR EC Annual Revenue Requirement - Expansion Cost Recovery
ARR SC Annual Revenue Requirement - Startup Cost Recovery
12CP Average of 12 coincident peaks through 10/31 of prior year
DA Directly Assigned to Operating Company

* Note: Should the net amount in 456.1 for any Member be negative, e.g. more expense than revenue, the net expense will be recorded in 565.0.

PSC Exhibit 7

Exhibit AEP-100

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

American Electric Power Service Corporation	)	Docket No. ER09-____-000
On behalf of:	)	
Appalachian Power Company	)	
Columbus Southern Power Company	)	
Indiana Michigan Power Company	)	
Kentucky Power Company	)	
Kingsport Power Company	)	
Ohio Power Company	)	
Wheeling Power Company	)	
Collectively, the “AEP East Companies”	)	

PREPARED DIRECT TESTIMONY OF

J. CRAIG BAKER

ON BEHALF OF THE AEP EAST COMPANIES

June 5, 2009

I. INTRODUCTION.

Q. PLEASE STATE YOUR NAME.

A. My name is J. Craig Baker and my business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by American Electric Power Service Corporation (AEPSC) AEPSC is a subsidiary of American Electric Power Company, Inc. (AEP). My title is Senior Vice President – Regulatory Services.

Q. WHAT ARE YOUR RESPONSIBILITIES AS SENIOR VICE PRESIDENT – REGULATORY SERVICES?

A. I am responsible for AEP's utilities' interaction with the regulatory bodies in the eleven states in which they provide retail electric service as well as with the Federal Energy Regulatory Commission (Commission or FERC). This responsibility involves day-to-day interaction as well as periodic rate filings to ensure recovery of their cost of service. In addition, I am responsible for developing and advocating public policy positions on emerging or changing issues affecting AEP's utilities.

Q. WHAT IS YOUR EDUCATION AND PROFESSIONAL BACKGROUND?

A. I received a Bachelor's Degree in Business Administration from Walsh College in 1970 and a Masters Degree in Business Administration in Finance from Akron University in 1980. I joined the AEP System in 1968 and through 1979 held various positions in the Computer Applications Division. I transferred to the System Operation Division in 1979 and held positions of Administrative Assistant and Assistant Manager. In 1985, I took the position of Staff Analyst in the Controllers Department and, in 1987; I became Manager-Power Marketing in the System Power Markets Department. In 1991, I became Director, Interconnection Agreements and Marketing. I became Vice President-Power Marketing for AEPSC and Senior Vice President of Energy Marketing for AEP Energy Services, Inc. in November 1996 and August 1997, respectively. On July 1, 1998 I became Vice President of Transmission Policy for AEPSC. In January 2001, I became Senior Vice President – Regulatory Services.

Following my involvement in wholesale market activities I had AEP's major responsibilities relating to AEP's development of and participation in RTO's and have been heavily involved in developing and supporting AEP's policies in the areas of RTO participation, transmission access and pricing and AEP's pooling agreements. I have submitted testimony in several FERC proceedings.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to explain, in concept, the changes AEP proposes to make to the Transmission Agreement by and among Appalachian Power Company (APCO), Columbus Southern Power Company (CSP), Indiana Michigan Power Company (I & M), Kentucky Power Company (KPCO) and Ohio Power Company (OPC) and with AEPSC as Agent, dated April 1, 1984, as amended ("Transmission Agreement"). AEP witness Dennis W. Bethel will describe the proposed changes in more detail and present analyses of the financial effects of the changes.

III. DESCRIPTION OF THE AEP SYSTEM

Q. PLEASE DESCRIBE THE AEP SYSTEM.

A. AEP is a multi-state electric utility holding company system, whose operating companies provide electric service to approximately 5 million customers in parts of eleven states. Prior to 2000, when AEP merged with the former Central and South West (CSW) system, AEP consisted of the five operating companies that are parties to the Transmission Agreement and two smaller companies – Kingsport Power Company ("Kingsport") and Wheeling Power Company ("Wheeling") that own no generating facilities. These seven AEP companies provide electric service to customers in parts of seven states – Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia, and West Virginia. AEPSC provides management and professional services to these companies and others in the AEP system at cost.

AEP was a registered holding company system under the Public Utility Holding Company Act of 1935 (PUHCA 1935), which, until its repeal in 2005, required such systems to be planned and operated on an integrated basis – that is, as a single system. Integrated planning and operation of the AEP system has been carried out under a series of "pooling" agreements under which the AEP operating companies pool or combine their power supply and delivery facilities to achieve the benefits of an integrated system. The first such agreement was the

Interconnection Agreement entered into in 1951 by the same operating companies (Members) that are parties to the Transmission Agreement, with AEPSC as Agent. The Interconnection Agreement provides for the integrated planning and operation of the Members' power supply facilities, and provides for the allocation among the Members of the generation-related costs and benefits of integrated planning and operation.

CSW was also a registered holding company under PUHCA 1935, and had its own generation and transmission pooling agreements. These agreements, as well as the pre-merger AEP's pooling agreements, have been retained since the merger, and the two formerly separate systems are integrated pursuant to "bridge" agreements called the System Integration Agreement (SIA) and the System Transmission Integration Agreement (STIA). The former CSW is now sometimes referred to as the AEP West Zone and the pre-merger AEP as the East Zone. All parts of the AEP system are now in regional transmission organizations (RTOs) or their equivalent. The East Zone companies are in PJM Interconnection L.L.C. (PJM) and the West Zone companies are either in the Southwest Power Pool or the Electric Reliability Council of Texas.

Because the Transmission Agreement was not affected by the merger and because only the East Zone companies are in PJM, AEP's filing in this case does not affect the West Zone.

IV. HISTORY OF THE TRANSMISSION AGREEMENT

Q. WHAT LED TO THE FILING OF THE AGREEMENT IN 1984?

A. AEP has developed an extensive transmission system which serves as the medium for integrating the power supply resources of the Member companies. The East Zone system stretches from the shores of Lake Michigan, across northern Indiana, and through Ohio to the mountains of Indiana, Kentucky, Virginia, and West Virginia. AEP planned and built an extensive extra-high-voltage ("EHV") transmission network operating at voltages of 345 kV and 765 kV as a means of achieving the advantages of large-scale system integration. The ability to site generation at its most advantageous locations and move power to widely separated load areas via high voltage and EHV transmission has situated AEP for many decades as an efficient low-cost electric energy provider. The integrated operation of the system, enabled by the strong transmission system, allows the lowest cost power at any given time to be dispatched to serve the combined load obligations of the Members.

The Interconnection Agreement provides for a sharing of the cost of the Members' generating facilities, and provides that each Member's transmission facilities shall be made available to the other Members to effect the centralized use of generation necessary for system integration. It does not, however, provide for a sharing of the cost of transmission facilities, which are owned by the Member providing service in the state or service area where such facilities are located. In the early 1980s, the addition of some major 765-kV facilities caused a significant imbalance in transmission investment among the Members. To achieve a more equitable distribution of those investment costs among the Members, AEP filed the Transmission Agreement, providing that the cost of ownership and operation of Members' EHV transmission facilities would be shared on the basis of the Members' relative peak loads. The matter was litigated at FERC, with affected state commissions, other customer representatives and the FERC staff offering their opinions on the proposal. Ultimately, the Commission, in Opinion No. 311, issued in 1988, approved the proposed Agreement with a few changes, the most notable being the inclusion of 138-kV facilities.

Q. PLEASE DESCRIBE THE AGREEMENT AS APPROVED BY THE COMMISSION.

A. Under the Agreement, as approved, each Member's investment in transmission stations containing equipment operated at extra high voltage ("EHV"), and transmission lines operated at voltages of 138 kV and above ("Bulk Transmission") is compared to its Member Load Ratio (MLR) share of the total of all the Members' Bulk Transmission investments. MLR is a demand-related allocation factor used in both the Transmission Agreement and the Interconnection Agreement. Specifically, it is the ratio of a member's non-coincident peak load in the previous 12 months to the sum of the individual Members' non-coincident peak loads for the same period. Those Members whose Bulk Transmission investment is deficit relative to their MLR share of the total Bulk Transmission investment make monthly settlement payments that are distributed by the Agent to those whose investments are surplus relative to their MLR share. The payments are determined by multiplying the surplus Member's surplus investment by a carrying charge rate reflecting the Member's ownership and operation costs, including a Commission approved return on equity of 12.84%. The investment levels are updated yearly, except that additions to a Member's investment of $10 million or greater are recognized when they occur.

Q. WHAT HAVE BEEN THE SURPLUS OR DEFICIT RELATIONSHIPS OVER THE TERM OF THE AGREEMENT?

A. I&M and KPCO have been surplus members and the two Ohio companies – CSP and OPCO -- have been deficit members from the beginning. APCO has been a surplus member since the 2006, after completion of the Wyoming- Jacksons Ferry 765 kV transmission line. Settlements average about $6 million per month, with the Ohio companies making payments to the others.

V. REASONS FOR THE PROPOSED AMENDMENTS.

Q. WHY IS AEP NOW PROPOSING TO CHANGE THE AGREEMENT?

A. The proposed changes are driven by the fundamental changes that have occurred in the electric utility industry and its regulatory framework that have occurred in recent years. Those changes began in 1996 with Order No. 888, which required transmission-owning utilities to offer open-access transmission service on their systems. Integrated public utility holding company systems such as AEP were required to offer open access to their entire systems at a single cost-based price. In addition, transmission-owning utilities that are load-serving entities were required to take service under the non-rate terms and conditions of their own open-access transmission tariffs (OATTs) to serve their own load. The most important change has been the Commission's policy encouraging utilities' participation in RTOs. In accordance with this policy, AEP, in 2004, placed its East Zone transmission facilities under the functional control of PJM. The consequences of having a single system-wide OATT rate and our participation in PJM have led to a reexamination of the method of allocating transmission costs under the Transmission Agreement. Another important change leading to such a reexamination has been legislation in some of the states in AEP's East Zone that has changed the treatment of transmission costs as a part of plans for electric regulation in those states.

Q. HOW HAS PARTICIPATION IN PJM LED TO REEXAMINATION OF THE AGREEMENT?

A. Participation in PJM has brought about a number of significant changes in AEP's uses of its transmission system and in the relationships among AEP and its retail and wholesale customers. Prior to joining PJM, AEP operated its transmission system and provided transmission service to itself and others pursuant to its own OATT. Since joining PJM, AEP's status has changed from being a Transmission Provider under its OATT to being a Transmission Customer under PJM's OATT. As load-serving entities in PJM, the AEP East companies must purchase Network Integration Transmission Service (NITS) from PJM to serve their native loads. Unlike the pre-RTO situation, AEP is explicitly billed by PJM for such service. By this arrangement separating ownership of transmission facilities from functional control and tariff administration, the Commission has not only assured that all users of the transmission facilities receive non-discriminatory open access transmission service, but that they also have broad stakeholder participation rights in the RTO's development and administration. AEP must also purchase from PJM the ancillary services and other services that it needs to serve its native load customers, and as a transmission owner within PJM, AEP receives compensation from PJM for AEP's costs associated with allowing its transmission facilities to be used for regional OATT service. Also, of major importance to this filing is that membership in PJM involves participation in stakeholder-driven regional transmission planning. In connection with that planning, and in recognition that certain "backbone" transmission facilities enable efficient organized markets, the Commission approved in 2007 the "socialization" of the costs of certain new facilities to all load serving entities in PJM.

Q. HOW DO THE ABOVE-DESCRIBED ATTRIBUTES OF PJM MEMBERSHIP SPECIFICALLY AFFECT AEP'S PROPOSAL IN THIS CASE?

A. There are a number of specific aspects of PJM membership that affect this filing. First, as a NITS customer, AEP pays to PJM a load-ratio share of transmission costs. The allocation method used by PJM to determine AEP's load ratio share of costs, while roughly similar in concept to the MLR allocation used in the Transmission Agreement, differs from that method. Second, the AEP East companies, in their capacity as LSEs in PJM, now receive a comprehensive statement from PJM for transmission and related services they provide and an invoice for transmission and related services they receive. AEP's proposal in this case provides for an allocation of all transmission-related items on those PJM statements to the AEP operating companies. Third, the AEP East companies are charged by PJM for their share of the cost of new major transmission projects whose costs are socialized to all PJM LSEs. Those charges presently are on the order of $1 million per month, but in the next few years will increase to more than $10 million per month. The proposed amendments to the Transmission Agreement provide a contractual framework for the allocation of those costs among the companies.

Q. PLEASE EXPLAIN YOUR POINT ABOUT PJM'S DEMAND ALLOCATION FACTOR BEING DIFFERENT FROM THAT CONTAINED IN THE TRANSMISSION AGREEMENT.

A. Under the Commission's pro-forma OATT, NITS customers pay a load ratio share of the costs associated with PJM's transmission system. Currently, PJM employs a zonal rate design for the majority of its costs, which means that the customers located in AEP's zone within PJM pay the costs associated with ownership and operation of AEP's transmission system. Within AEP's zone, however, costs are allocated among customers based on their relative demands on the system. For purposes of such allocation, demands are measured as each LSE's (including non AEP LSEs) contribution to the AEP Zone single coincident peak experienced in a particular year. This method of demand allocation is commonly referred to as "1CP". As indicated above, the demand allocator used in the Transmission Agreement is the MLR method, which is based on the non-coincident peak of each Member for the previous twelve months.

Q. PLEASE EXPLAIN YOUR POINT ABOUT THE COMPREHENSIVE STATEMENTS RECEIVED FROM PJM.

A. Each month PJM submits to AEP a statement breaking down, in detail, the various services it provides for AEP and the amount of charges or payments it is making for such services. While many of the charges are not transmission-related and are thus not relevant to this filing, AEP's proposal ties the transmission-related monthly settlements among the East operating companies more closely to PJM's monthly statements**.** I also note that the existing Transmission Agreement, unlike the OATT, does not allocate all transmission or transmission related costs, but only those associated with Bulk Transmission facilities. In addition, the Agreement does not presently include Wheeling or Kingsport, although those entities own transmission facilities and are members of PJM. AEP's proposed amendments to the Agreement would more comprehensively allocate transmission-related costs among the AEP operating companies that use the network and own transmission facilities.

Q. PLEASE EXPLAIN YOUR POINT ABOUT SOCIALIZATION OF EHV COSTS WITHIN PJM.

A. In Opinion No. 494, issued in 2007, the Commission, among other things, established cost allocation principles for new transmission facilities built under PJM's regional transmission expansion plan ("RTEP") process. The cost of new EHV facilities operated at 500 kV and above, however, is spread to all transmission zones within PJM. The Commission's rationale in ordering such socialization is that the new 500-kV and above facilities are “backbone” facilities that benefit the entire regions, so all LSEs and their customers in the region should share in the cost of such facilities. The cost of new facilities operated at voltages below 500 kV is borne by the transmission zones within PJM that are shown by load flow simulations to benefit from the transmission upgrades.

Q. HOW ARE THE NEW 500-KV AND ABOVE COSTS ALLOCATED AMONG ALL ZONES?

A. They are allocated on a 1CP basis.

Q. WHAT PERCENTAGE OF PJM’S TOTAL PEAK LOAD DOES AEP’S PEAK REPRESENT?

A. The AEP Zone’s percentage share of the PJM peak demand is about 17%, and the AEP Operating Companies’ load is nearly 87% of the zonal load. This means that AEP and its customers will be charged for about 15% of the costs of all new 500-kV and above facilities built in PJM pursuant to the RTEP.

Q. WHY DOES AEP EXPECT THE PJM SOCIALIZED COSTS TO GROW SO RAPIDLY?

A. Since issuance of Opinion No. 494, PJM has already approved a number of “backbone: EHV projects through its RTEP process. These include 1) the Trans-Allegheny Interstate Line (“TrAIL’), a $1.2 billion 500-kV transmission line and station project being built in Pennsylvania, West Virginia and Virginia by Allegheny Energy Inc. (Allegheny”) and Dominion Virginia Power

("Dominion"), 2) the Potomac Appalachian Transmission Highline ('PATH"), a $1.8 billion 765-kV transmission line and station project being built by subsidiaries of Allegheny and AEP in West Virginia, Virginia and Maryland, 3) Susquehanna-Roseland, a $1.2 billion 500 kV project in Pennsylvania and New Jersey being built by PPL, Inc. and Public Service Electric and Gas Company ("PSEG"), 4) Branchburg – Hudson, a $940 million 500 kV PSEG project, and 5) the Mid-Atlantic Power Pathway ("MAPP") project, a $1.4 billion 500 kV East coast line to be built by Dominion, PSEG and Potomac Electric Power Company ("PEPCo"). Mr. Bethel provides more information about these projects and their costs to AEP in his testimony and exhibits. The approval of these projects reflects the reality that much of PJM is deficient in transmission infrastructure, and many new upgrades to that infrastructure can be expected to be built.

Q. HOW DOES AEP CURRENTLY ALLOCATE THESE COSTS AMONG ITS EAST OPERATING COMPANIES?

A. Since socialization of regional transmission costs is a new phenomenon, the AEP Companies currently have no contractual mechanism in place to allocate these costs. The relatively small amount of costs we are experiencing thus far has been allocated by MLR. However, with the prospect of these costs becoming very significant in the near future, the companies need to have a contractual, Commission-accepted allocation methodology in place.

Q. EXPLAIN HOW ELECTRIC INDUSTRY RESTRUCTURING HAS LED TO A REEVALUATION OF THE TRANSMISSION AGREEMENT.

A. During the past 10-15 years, several states enacted retail customer choice legislation for electric utilities. The object was to interject competition rather than regulation into the provision of retail service. Typically, such legislation involved the unbundling of electric service into generation and wires (transmission and distribution) components. While the wires functions of electric utilities remained regulated monopolies (with open-access requirements) the generation function became a competitive business, with customers allowed to shop among competing suppliers. To facilitate shopping, retail electric rates were unbundled into generation, transmission and distribution components. In recognition of industry restructuring, this Commission added retail customers who could shop for generation pursuant to state retail choice programs to the definition of Eligible Customers under the Commission's pro-forma OATT. As part of their unbundling of retail electric rates, it was common for states with customer choice to require participation in ISO/RTOs and to adopt the incumbent utility's FERC OATT rate as the transmission component of retail electric rates.

Q. WHICH STATES IN AEP'S EAST ZONE ENACTED ELECTRIC RESTRUCTURING LEGISLATION?

A. Three of the seven states that regulate retail electric service by AEP's East operating companies adopted such legislation – Ohio, Michigan and Virginia. As part of such legislation, all three provided for unbundling of retail electric rates.

Even though Michigan and Virginia have amended their electric regulation laws returning to a more traditional regulatory system, and Ohio has changed its legislation from its original restructuring law, all three jurisdictions still require electric rates to be unbundled, and still provide that the unbundled transmission component of retail electric service is the FERC OATT rate.

Q. HOW DOES THIS AFFECT THE TRANSMISSION AGREEMENT?

A. It does not directly affect the Agreement, but it creates anomalies in the recovery of transmission costs.

Q. PLEASE EXPLAIN YOUR LAST ANSWER.

A. As discussed earlier, from the earliest days of open-access transmission, FERC has made it clear that companies in an integrated public utility holding company system must provide service within, out of or through their entire system at a single system-wide rate. The Commission rejected the idea that individual companies within the system could charge additive rates reflecting their individual costs. This was an early form of eliminating "pancaked" transmission rates. In accordance with the Commission's policy in this regard, AEP has, from the first days of its OATT, provided single-system rates across its system. As relevant to AEP's East Zone, these rates have been designed to recover the cost of owning and operating all of the transmission facilities owned by the operating companies in the East Zone. (AEP created separate, non-pancaked rates for its West Zone when it merged with CSW, but those rates are not relevant here). So rates under AEP's OATT were designed by dividing the total system costs by the system peak load, resulting in an average system rate. Rates for the AEP zone under PJM's tariff are designed essentially the same way, and also result in an average rate for the AEP zone.

Q. HOW ARE RATES FOR RETAIL TRANSMISSION SERVICE ESTABLISHED?

A. To begin with, in AEP's "bundled" states, there are no such things as rates for retail transmission service. The operating companies provide electric service at rates based on each company's total electric cost of service. The cost of service that forms the basis for those rates are set by multiplying each company's rate base, including its investment in generation, transmission, distribution and common facilities, by a fair rate of return on investment, then adding its expenses for a given test period. While there are no such things as retail transmission rates in bundled states, it is possible to estimate the transmission component of retail rates by determining the return on transmission plant and related expenses. As would be expected, the estimated transmission component of the each individual company's rate does not equal the average, system-wide rate used in the OATT. The transmission components of some companies' rates are above the average (OATT) rate and some are below. Witness Bethel explains the reasons for these differences.

Q. DOESN'T THE TRANSMISSION AGREEMENT EQUALIZE COSTS?

A. No. The Agreement does not, and never was intended to completely equalize each company's transmission-related costs. It was intended merely to alleviate large differences in such costs caused by major imbalances in investment in costly major EHV (and 138-kV) facilities. I should note, in this regard that, the Agreement has sometimes been referred to informally within AEP as the "transmission equalization agreement" or "TEA." However, that is something of a misnomer, since, as indicated, it does not cause the AEP Companies transmission costs to be equalized.

Q. HOW DO THE ABOVE FACTS, COUPLED WITH ELECTRIC RESTRUCTURING, CAUSE ANOMALIES AND COST RECOVERY PROBLEMS?

A. Such anomalies and problems are caused when some states use the OATT rate – an average rate – for the transmission component of retail rates and others use traditionally-developed rates that can be above or below the average. For example, assume a two-company system, the A-B System, operating in adjoining states: State A is a bundled state and Company A's transmission costs are below the system average. Company B is in a restructured state which uses the OATT rate, and Company B's costs are above the system average. The OATT rate would under-recover Company B's actual transmission costs, while Company A would recover its actual, below-average, transmission costs. The OATT rate would be irrelevant to Company A, because its retail customers would not pay that rate. However, the two company A-B system, as a whole, would under-recover its transmission costs from its retail customers. If the situation were reversed, and state B's costs were below average, the system would over-recover its costs from retail customers. The problem stems from mixing two rate methodologies, using system average rates for some states and non-average rates for others. As it happens, Ohio, the state jurisdiction where about 40% of AEP's East system load resides, uses the OATT as the transmission component of retail rates. Further, Ohio has above-average transmission costs, so AEP under-recovers its costs on a system-wide basis.

Q. HOW DO THE PROPOSED AMENDMENTS TO THE TRANSMISSION AGREEMENT REMEDY THIS PROBLEM?

A. The amendments remedy this problem by bringing each state's transmission costs into equilibrium. Under the proposal, all transmission costs through the PJM OATT, not just costs of facilities 138-kV and above, are allocated among the companies. Further, transmission costs and revenues are allocated to all seven transmission-owning operating companies – not just the five companies that operate EHV facilities. As discussed above, the costs are allocated to each operating company on a coincident peak basis, 12 versus 1, instead of the non-coincident peak method used under the transmission agreement. All of these factors taken together will cause the revised Transmission Agreement to "equalize" transmission costs among the East companies.

Q. DOES AEP PROPOSE TO USE A 1 CP ALLOCATION METHOD LIKE PJM?

A. No. AEP proposes a 12 CP method. As explained in more detail by AEP witness Dennis W. Bethel, a 12 CP method produces more stable, predictable results than the 1 CP method used by PJM.

VI. DELAYED EFFECTIVE DATE

Q. WHEN IS AEP PROPOSING THAT THE PROPOSED AMENDMENTS TO THE AGREEMENT BECOME EFFECTIVE?

A. AEP is asking that the amendments not become effective until they are accepted in a final order by the Commission. We are requesting waiver of the Commission's notice requirement to allow such a delayed effective date.

Q. WHY ARE YOU REQUESTING A DELAYED EFFECTIVE DATE?

A. There are several reasons for this request. First, AEP's pooling agreements, including the proposed amended Agreement, are meant to govern integrated planning and operations over the long term. Therefore, while AEP would prefer to get the amendments in place as soon as possible, it is also important to achieve a result that is acceptable to state regulators and other stakeholders, or at least has been found by the Commission to be just and reasonable with respect to such stakeholders. Second, there are some cost shifts involved in the proposed amendments. A delayed effective date will allow the affected Members and stakeholders to adapt to the new system. Finally, a delayed effective date will obviate the need to impose refunds or surcharges, which would entail administrative costs and potential issues associated with retail recovery.

Q. HAS THE COMMISSION ACCEPTED A SIMILAR PROPOSAL IN THE PAST?

A. Yes. In 2006, when AEP filed proposed changes to its System Integration Agreement, we made a similar proposal, which was accepted by the Commission, albeit through a delegated letter order after no party had protested our filing.

Q. **DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?**

A. Yes it does.

PSC Exhibit 8

Exhibit AEP-200

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

American Electric Power Service Corporation	)	Docket No. ER09-____-000
On behalf of:	)	
Appalachian Power Company	)	
Columbus Southern Power Company	)	
Indiana Michigan Power Company	)	
Kentucky Power Company	)	
Kingsport Power Company	)	
Ohio Power Company	)	
Wheeling Power Company	)	
Collectively, the “AEP East Companies”	)	

PREPARED DIRECT TESTIMONY OF

DENNIS W. BETHEL

ON BEHALF OF THE AEP EAST COMPANIES

June 5, 2009

INDEX OF EXHIBITS

**Exhibit AEP-200: Prepared Direct Testimony of Dennis W. Bethel,
On Behalf of the AEP East Companies**

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Exhibit AEP-202: Revised AEP Transmission Agreement, in Black-lined Format;

Exhibit AEP-203: AEP East Companies' Transmission Cost of Service and Comparison of Retail Transmission Rates Present and Proposed;

Exhibit AEP-204: Comparison of Variation in Using MLR, 1CP, and 12 CP

Exhibit AEP-205: Summary of Agreement Modification Impacts for 2008 and 2009

Exhibit AEP-206: Summary of Revenue, Demand, Energy and Other Allocation Ratios

Exhibit AEP-207: Settlements under the Present Transmission Agreement

Exhibit AEP-208: Cost Impact Comparison of Present and Revised Allocations – 1 CP

Exhibit AEP-209: Cost Impact Comparison of Present and Revised Allocations - MLR

Exhibit AEP-210: Cost Impact Comparison of Present and Revised Allocations – 12 CP

Work Papers for Exhibits AEP-206 and AEP-207

I. INTRODUCTION

Q. BY WHOM ARE YOU EMPLOYED, AND IN WHAT CAPACITY?

A. My name is Dennis W. Bethel. I am employed by American Electric Power Service Corporation ("AEPSC" or "AEP"), as Managing Director – Regulated Tariffs. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. PLEASE REVIEW YOUR TRAINING AND EXPERIENCE IN ELECTRIC UTILITY SERVICE MATTERS RELEVANT TO THIS PROCEEDING?

A. In 1973, I earned a Bachelor of Science Degree in Electrical Engineering from the University of Evansville (Indiana). I began my career with AEP, at Indiana Michigan Power Company (I&M), that same year, as a commercial and industrial customer service engineer. In 1977 I transferred to I&M's rate department. In 1980 I transferred to AEPSC, where I have held positions in Rate Research and Design, System Transactions, Transmission Operations, and Regulated Tariffs. At I&M I worked directly with customers on new and expanded service, was responsible for retail and wholesale contract development and administration, cost of service studies, rate design, fuel clause adjustments and other regulatory analyses. In the AEPSC Rate Research and Design Division, from 1980 to 1988, I performed and supervised cost of service and rate design studies and testified in a number of retail rate cases on those topics for several of the AEP East Companies. In 1988 I transferred to the Systems Transactions Department where I was responsible for power, interconnection and transmission-related agreements and tariffs. In 1991 was promoted to Manager – Interconnection Agreements. During this time I helped to develop and support AEP's first Open Access Transmission Tariff ("OATT") filed in Docket No. ER93-540-000. In 1997 I moved to the Transmission Operations Department as Manager – Transmission Contracts and Regulatory Support, a position that was functionally separated from the merchant operations function. In June 2000, the merger of AEP and Central and Southwest Corporation was approved, and I was named Director – Transmission and Interconnection Services in the AEPSC Regulatory Services Department. In that position I was responsible for the development and implementation of transmission, interconnection and related agreements, tariffs and policies on behalf of the AEP companies in the three regions where we provide service, SPP, PJM and ERCOT. I assumed my present position in July 2005. As Managing Director- Regulated Tariffs, I direct a staff that is responsible for cost of service studies, rate design, agreements and tariffs for retail and regulated wholesale services through out the eleven-state AEP service area. I frequently represent AEP in Regional Transmission Organization ("RTO") forums, particularly relating to the transmission tariffs, rate design, and related committee matters in the Southwest Power Pool ("SPP") and PJM.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY UTILITY REGULATORY COMMISSIONS?

A. Yes. I have previously submitted testimony or affidavits on transmission and related services before the Federal Energy Regulatory Commission ("Commission") in Dockets ER93-540, ER98-2786, EL02-111, et al, EL01-73, EL05-74, EL05-121, EL07-101, and ER05-751, the AEP East Companies last rate case for transmission service under the PJM OATT ("PJM Tariff" or "Tariff"). In presently open Dockets

No. ER07-1069 and ER08-1329, I sponsor formula rates and protocols for inclusion in, respectively, the SPP OATT, on behalf of Public Service Company of Oklahoma and Southwestern Electric Power Company, and in the PJM OATT, on behalf of the AEP East Companies. I have also provided expert testimony on various electric cost-of-service and rate design issues before the utility regulatory commissions of Michigan, Kentucky, Ohio, Oklahoma, Tennessee, Virginia, and West Virginia. I am registered as a Professional Engineer in the States of Indiana and Ohio.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony discusses and supports the proposed changes to the Transmission Agreement, the rationale behind the cost and revenue allocation methods specified in the revised Transmission Agreement, and the changes in cost and revenue allocations that each of the AEP East Companies will experience after the changes take effect. I will also address the characteristics and cost impacts of two cost allocation methods that were also considered by the AEP East Companies.

Q. ARE YOU SPONSORING ANY EXHIBITS?

Yes. In addition to this Testimony, I am sponsoring the following Exhibits:

Exhibit AEP-201: Existing AEP Transmission Agreement, in Clean Format;

Exhibit AEP-202: Revised AEP Transmission Agreement, in Black-lined Format;

Exhibit AEP-203: AEP East Companies' Transmission Cost of Service and Comparison of Retail Transmission Rates Present and Proposed;

Exhibit AEP-204: Comparison of Variation in Using MLR, 1CP, and 12 CP.

Exhibit AEP-205: Summary of Agreement Modification Impacts for 2008 and 2009;

Exhibit AEP-206: Summary of Revenue, Demand, Energy and Other Allocation Ratios;

Exhibit AEP-207: Settlements under the Present Transmission Agreement;

Exhibit AEP-208: Cost Impact Comparison of Present and Revised Allocations – 1 CP;

Exhibit AEP-209: Cost Impact Comparison of Present and Revised Allocations – MLR; and

Exhibit AEP-210: Cost Impact Comparison of Present and Revised Allocations – 12 CP

III. DISCUSSION OF THE PROPOSED AGREEMENT CHANGES

Q. PLEASE BRIEFLY DESCRIBE THE SCOPE OF THE PROPOSED CHANGES TO THE TRANSMISSION AGREEMENT.

A. Since its inception, the Transmission Agreement has had one purpose, to effect a sharing of the participating AEP East Companies' ("Members") costs of owning and operating Bulk Transmission facilities. The Members originally intended Bulk Transmission facilities to include extra high voltage ("EHV") transmission lines and station facilities operating at 345 kV and higher voltages, but in its final order in Docket No. ER84-348, the Commission directed the Members, in 1989, to include transmission lines operating at 138 kV and higher and all facilities, without regard to voltage, at transmission stations that contain at least some EHV facilities.

Since that time, some very significant changes have occurred in the provision and regulation of transmission and transmission-related services, affecting the electric industry generally, and the AEP East Companies in particular. The two most significant changes are the advent of open access transmission service, pursuant to Orders 888, 889, and their successors, and the AEP East Companies' relinquishment of functional control of their transmission facilities to the PJM RTO. The scope of the changes to the Transmission Agreement proposed by the AEP East Companies is consistent with the significance of the changes in the provision and regulation of transmission service in the twenty years since the Commission's Order approving it. The proposed changes recognize that, pursuant to the PJM Open Access Transmission Tariff ("OATT", or "PJM OATT"), the AEP East Companies, and other Load Serving Entities ("LSEs") in the AEP Zone of PJM, now share the cost of the AEP East Companies' transmission facilities of all voltages, including those operated at voltages below 138 kV. Further, while the Transmission Agreement included only the five largest AEP East Companies, all seven of them own and operate transmission facilities that are used to provide transmission service under the OATT. The proposed Transmission Agreement changes also recognize that, as a result of open access and RTO participation, the AEP East Companies now are obligated to provide certain transmission-related ("ancillary") services, and to purchase such services and additional RTO supplied services. Accordingly, the proposed Transmission Agreement changes address the allocation of OATT-based transmission related costs and revenues among all seven of the AEP East Companies.

Q. PLEASE SUMMARIZE THE CHANGES TO THE TRANSMISSION AGREEMENT.

A. As can be seen by examination of Exhibits AEP-201 and AEP-202, the significant changes, by Agreement section are as follows:

- The Preamble, is amended to include Kingsport Power Company and Wheeling Power Company as Members, and recognize the Members' participation in the PJM RTO;

- Article 1, Description of Transmission System, is amended to recognize all transmission facilities of the Members, and delete the provisions defining and providing for periodic updates to investments of the Members in Bulk Transmission Facilities;
- Article 4, Agent's Responsibilities, amends the Agent's Responsibilities to recognize the changed nature of Settlements under the revised agreement;
- Article 5, Description of Factors Associated With Settlements, is deleted;
- Article 6, Settlements, is rewritten consistent with RTO participation, and renumbered as Article 5;
- Article 7, Taxes, amends the provisions for recovery of settlement related taxes to recognize the OATT as the recovery mechanism, and is renumbered as Article 6;
- Article 8, Billing and Payments, is replaced with provisions describing the Allocation Principles for transmission related costs and revenues and is renumbered and renamed the section as Article 7, Allocation Principles;
- Article 9, Modification, is amended to include the Agent, that is, the AEP Service Corporation, among those that may call for a reconsideration of the terms and conditions of the Agreement, and is renumbered as Article 8
- Article 10, Effective Date and Term of This Agreement, is modified consistent with the Commission's Order approving the Agreement in Docket No. ER84-348, and is renumbered as Article 9;
- Article 11, Termination of Special Facilities Agreement, is deleted as no longer relevant;
- Article 12, Regulatory Authorities, is renumbered as Article 10;

- Article 13, Assignment, is renumbered as Article 11;
- The signature page is amended to add Kingsport and Wheeling Power Companies' signature lines; and
- Appendix I is added. It is a new attachment, in the form of a table summarizing the costs and revenues to be allocated under the Transmission Agreement, the allocation methods to be used, and describing the expense and revenue accounts where the Members will record the costs and revenues so allocated.

Q. OF THE CHANGES YOU HAVE SUMMARIZED, WHICH IS THE MOST SIGNIFICANT?

A. The most significant change is the replacement of the present bulk transmission investment cost sharing method, specified in Articles 5 and 6, with the comprehensive transmission cost and revenue allocations, contained in new Article 5 and Appendix I.

Q. DO THE PROPOSED CHANGES AFFECT THE WHOLESALE TRANSMISSION RATES CHARGED TO ANY CUSTOMER?

A. No. I think it is important to point out that the proposed changes do not affect the rates for transmission or related services that the AEP East Companies as a group or any other LSE currently is charged by PJM under its OATT. The rates for transmission and related services in the AEP Zone of PJM already reflect the rolled-in costs of all transmission facilities operated by the seven AEP East Companies. What will change, as a result of the new settlement process embodied in the revised Transmission Agreement, is the share of transmission related costs and revenues that will be allocated to each of the AEP East Companies. This means that, while the

AEP Companies' net costs for retail service will be changed, no wholesale transmission customers will be affected.

Q. YOU MENTIONED THAT THE NEW APPENDIX I TO THE TRANSMISSION AGREEMENT SUMMARIZES THE PROPOSED ALLOCATION OF TRANSMISSION RELATED COSTS AND REVENUES AMONG THE AEP EAST COMPANIES. PLEASE EXPLAIN WHETHER ALL OF THOSE COSTS AND REVENUES ARE SHARED TODAY, AND IF SO HOW.

A. The AEP East Companies do share all of the transmission related costs and revenues that come to them by way of the PJM LSE and PJM Transmission Owner settlements today. Except for two minor items, the charges billed to the AEP East Companies by PJM for transmission service and the revenues paid to them for use of the AEP transmission system are allocated among the AEP East Companies by the Member Load Ratio ("MLR"), the same allocation method used in the present Transmission Agreement.

Q. WHAT TYPE OF ALLOCATION METHOD IS THE MLR?

A. The MLR is a peak demand allocation method that has been used by the AEP East Companies since 1951 to share costs related to generation capacity under the AEP Interconnection Agreement "Generation Pool". The MLR is calculated monthly based on the non-coincident peak demands of each of the five largest AEP East Companies during the previous twelve months. The MLR load includes each Members' retail and firm sales for resale load. The load of Kingsport Power Company ("KgPCo") is included in the MLR of Appalachian Power Company

("APCo"), while the load of Wheeling Power Company ("WPCo") is included in the load of Ohio Power Company ("OPCo"). The highest peak demand of each Member during the last twelve months are summed, and then each Member's MLR is calculated as its peak demand in the previous twelve months divided by the sum of the five Members' non-coincident peaks. Unlike a single coincident peak or 1 CP, demand allocation basis such as the PJM Network Service Peak Load ("NSPL") billing unit, the MLR recognizes the seasonal diversity among the AEP East Companies' loads by incorporating each company's peak demand during the past twelve months, whether it occurs in the winter or summer.

Q. WHAT IS THE NET EFFECT OF THE PRESENT METHODS OF ALLOCATING TRANSMISSION RELATED COSTS AND REVENUES AMONG THE AEP EAST COMPANIES?

A. The net effect of the allocations used presently by the AEP East Companies is to cause the charges PJM makes to the AEP East Companies for transmission and related services provided by the AEP East Companies to be offset by the revenues they receive from PJM for those same services. As a result, the Companies' net costs for transmission and related services are made up of (1) each Company's cost to own and operate the transmission facilities that each has constructed, (2) their receipts or payments under the Transmission Agreement, (3) the revenues from non-affiliates they receive, and (4) the charges related to services provided by other transmission owners. I will refer to these net transmission costs as "Residual Costs" in discussing the costs that each AEP East Company presently incurs on behalf of their retail customers.

Q. PLEASE IDENTIFY EACH OF THE COMPONENTS OF TRANSMISSION COST AND REVENUE THAT WILL BE AFFECTED BY THE PROPOSED MODIFICATION OF THE TA?

A. The following table summarizes the transmission related costs and revenues experienced by the AEP Companies:

Item	**Table 1: Items of Both Expense and Revenue**	**Billed By**	**Revenue To:**
1	AEP Transmission Agreement Payments and Receipts	AEP	Surplus Cos.
2	Network Integration Transmission Service (NITS)	PJM	AEP Cos.
3	Scheduling, System Control and Dispatch Service (Sch. 1A)	PJM	AEP Cos.
4	RTO Start-Up Cost Recovery Charges (SCRC)	PJM	AEP Cos.
5	PJM Expansion Cost Recovery Charges (ECRC, Sch. 13)	PJM	AEP Cos. 48%
6	PJM Transmission Enhancement Charges (Sch. 12)	PJM	Various
	Additional Revenue and Credit Expense Items		
7	PJM Point-to-Point Transmission Service Credits	PJM	AEP Cos.
8	Grandfathered Transmission Service (Pre-PJM Contracts)	AEP	AEP Cos.
Underlying Cost of Service for AEP Provided Services			
a	Owning and operating the AEP transmission system	Note: Each of the AEP Companies accounts for their own plant, capital and expense for these services.	
b	Performing AEP System Control and Dispatch Operations		
c	Amortization of Deferred RTO Start-up Expenses		
d	Amortization of Deferred PJM Expansion Cost Funding		

Q. WHAT TRANSMISSION RELATED COSTS ARE THE AEP EAST COMPANIES PERMITTED TO RECOVER THROUGH THEIR RETAIL RATES?

A. There is no consistent basis for determining the cost of transmission service among the retail jurisdictions served by the AEP Companies. In Ohio, Columbus Southern Power Company ("CSP") and OPCo are permitted to charge, through a Transmission Cost Recovery Rider ("TCRR"), the share of the PJM OATT costs billed to the AEP Companies that they incur on behalf of retail customers. Ohio adopted this method as a step toward the introduction of retail supply competition. As in some other states that have unbundled retail tariffs, the OATT rate is used as the transmission charge so that retail customers experience the same costs for transmission and related services whether they buy their power from the local utility or another competitive supplier.

The Tennessee Public Service Commission has also recently approved a transmission cost adjustment that permits KgPCo to recover its share of the charges billed to the AEP East Companies by PJM, which charges are allocated to KgPCo pursuant to a Power Purchase Agreement (PPA) with APCo.

The other AEP Companies' retail rates presently in effect in Kentucky, Michigan, Virginia and West Virginia reflect the Residual Costs of transmission and related services where the companies' jurisdictional costs of owning and operating the transmission system are adjusted by the net cost or credit resulting from jurisdictional allocation of transmission service charges and revenues from third parties and AEP affiliates. Although AEP's retail rates in Virginia presently reflect Residual Costs (separated into OATT and retail cost components), Virginia regulation now permits the recovery of OATT-based costs, as in Ohio.

The Indiana Utilities Regulatory Commission recently approved an RTO Cost Tracker that will periodically adjust retail rates for changes in a number of PJM charges and credits, including some of the items listed above; however, I&M's Indiana base rates still reflect the company's Residual Cost to own and operate its transmission facilities, net of affiliate and third party revenues.

Q. WITH THE PRESENT MIX OF RETAIL RATE MAKING METHODS, ARE THE AEP EAST COMPANIES ABLE TO RECOVER ALL THEIR TRANSMISSION RELATED COSTS?

A. No. Presently, the AEP East Companies are experiencing a significant transmission cost recovery short-fall. The sum of the transmission and related revenues that the AEP East Companies are able to include in retail rates, together with the revenues they receive from non-affiliates is less than their cost of service for transmission and related services.

Q. WILL THE COST RECOVERY SHORT-FALL PROBLEM BE AMELIORATED BY THE APPROVAL OF THE TRANSMISSION AGREEMENT CHANGES PROPOSED IN THIS PROCEEDING?

A. The proposed changes will create the conditions necessary to ameliorate the problem, but retail rate changes will still be required. The cost recovery issue is primarily a result of the way transmission related costs and revenues are allocated among the AEP Companies. If the cost and revenue allocation changes proposed in this case are approved, the Residual Cost of transmission service determined by states that may continue to set retail rates that way, will come more closely into line with the RTO-based costs allowed in Ohio, Tennessee and Virginia.

Q. CAN YOU QUANTIFY THE MAGNITUDE OF THE COST RECOVERY PROBLEM, AND ILLUSTRATE THE RETAIL RATE IMPACTS THAT WOULD RESULT IF THE PROPOSED SOLUTION IS APPROVED AND THE RETAIL RATES OF EACH AEP COMPANY ARE ADJUSTED TO REFLECT THE REALLOCATED COSTS AND REVENUES?

A. Yes. Exhibit AEP-203 illustrates (i) the Residual Costs that each AEP Company experiences today to provide transmission service on behalf of retail customers (line 8), calculated as the approximate total cost of service experienced by the AEP Companies for transmission and related services that they provide (line 6), plus the net charge or credit they experience from the present allocation of costs and revenues among them (line 7); (ii) the approximate cost each Company is able to include in retail rates (line 11); and (iii) the Residual Costs they would each experience with the transmission cost and revenue allocations proposed in this proceeding (line 13).

Comparing the totals of lines 8 and 11, it can be seen that the cost recovery short-fall problem is approximately $58 million per year. It can also be seen that this problem is not merely the result of Ohio and Tennessee charging retail customers based on the PJM OATT. The problem instead results from the Bulk Transmission settlement method in the present Transmission Agreement, and the allocation of other transmission related costs and revenues using the same method, e.g., MLR. The proposed Transmission Agreement changes will fix the problem by allocating transmission costs among the Companies based on their use of each service, and sharing revenues based on each Company's cost to provide the service. With the present settlements and allocations, the Companies are being charged for services on a load share basis, but they are not receiving revenues in proportion to the costs of the services they provide.

Q. PLEASE EXPLAIN THE SIGNIFICANCE OF THE $/kW-Month VALUES SHOWN IN EXHIBIT AEP-203.

A. Those values are important in demonstrating the reasonableness of the proposed changes. The first set of values on line 10 shows each AEP East Company's Residual Cost of transmission per kilo-Watt (kW) of monthly peak demand, based on present settlements and allocations. The variation in the per kW costs that the Companies need to recover from retail customers, is presently more than 200%. As shown, the costs vary from a low of $1.59/kW-month for I&M to a high of $3.27/kW-month for KgPCo. The values on line 12 represent the average cost per kW of demand that the Companies are permitted to recover from retail customers. Those values show the same wide variation, although the CSP and OPCo values are lower than the actual residual cost to the Ohio Companies. Comparing lines 10 and 12, one sees that even with the Ohio cost recovery limited to the PJM OATT costs, as presently allocated using the MLR method, the transmission costs charged to Ohio retail customers is higher than for APCo and I&M customers. Finally, line 14 shows that the proposed cost and revenue allocations will equalize the per-kW transmission and related costs among the AEP Companies.

Q. WHAT LOGIC SHOULD DRIVE THE CHOICE OF COST AND REVENUE SHARING METHODS IN A POOLING ARRANGEMENT AMONG SISTER COMPANIES SUCH AS THE AEP EAST COMPANIES?

A. Costs should be allocated proportionate to the amount of service that each Member uses, typically measured by relative contributions to total peak demand; however, there are various methods that can be used to measure relative contributions to peak demand. The choice among reasonable alternative cost allocation methods should consider factors such as administrative efficiency and stability of the relative cost shares the allocation methods will produce.

Revenues for transmission and related services should be allocated proportionate to the costs that each Member incurs in making its facilities and services available to its affiliates, and in this case the RTO, such that when all sources of transmission revenues are taken into account, e.g., wholesale and retail, each Member will receive revenues equal to its cost of service.

Q. WHAT BILLING BASIS DOES PJM USE TO CHARGE LOAD SERVING ENTITIES FOR TRANSMISSION AND RELATED SERVICES?

A. PJM uses the prior year single peak or 1CP demand method to charge LSEs for network transmission service ("NTS"), expansion cost recovery charge ("ECRC") and RTO start up cost recovery charge ("SCRC"), and to allocate revenue credits for point-to-point transmission service among NITS customers. PJM charges Transmission Owner Scheduling, System Control and Dispatch Service based on delivered energy.

Q. WHAT COSTS ARE BEING COLLECTED THROUGH THE ECRC AND SCRC RATES?

A. The ECRC rates are billed by PJM to recover the costs that PJM originally charged to the AEP East Companies, Commonwealth Edison Company and the Dayton Power and Light Company to fund the expansion of the RTO's operations in order to accommodate the addition of new zones in 2004 and 2005. ECRC rates are charged to loads in all zones of PJM, except the Dominion Virginia Power Zone. Dominion also funded a share of the PJM expansion costs, but elected not to participate in the region-wide recovery of the costs. The SCRC rate is a charge that recovers the AEP East Companies' direct costs for RTO development and start-up. That charge is only billed to the AEP East Companies and other NITS customers in the AEP Zone. The ECRC and SCRC rates collect the underlying PJM expansion and AEP RTO start-up costs and carrying costs over the periods that the costs are being amortized, ten years and fifteen years, respectively.

Q. WHAT METHOD DO THE AEP EAST COMPANIES PROPOSE TO USE TO SHARE COSTS THAT PJM BILLS BASED ON THE PRIOR YEAR 1CP DEMANDS?

A. The AEP East Companies propose to use the twelve month average coincident peak or 12CP method to allocate the costs billed to them as a group by PJM using the 1CP method.

Q. PLEASE EXPLAIN WHY AEP IS PROPOSING THE 12CP METHOD.

A. The 12 CP method will result in more stable cost sharing among the AEP Companies than other alternatives. Rate stability is an important consideration for customers, state regulators and for AEP. Exhibit AEP-204 shows the relative stability of several alternative demand allocation methods, on an actual basis from 2005 through 2008, and as projected for 2009. The exhibit shows (1) the present MLRs, (2) the MLRs with KgPCo and WPCo separated from APCo and OPCo, the seven-Member MLRs, (3) the annual 1CP load ratios, and (4) the 12CP load ratios for each of the AEP East Companies. The exhibit calculates the year to year percentage changes, the maximum annual deviation, and the range of deviations. Over the five years, the 1CP would cause four companies to have single year cost allocation shifts of 20% to more than 33%. Cost variations under the seven-Member MLR method would be relatively low, topping out at 13%. Cost allocation variances under the 12CP method would be the smallest. Similar differences appear when the high to low annual allocation percentage ranges are compared. APCo's 1CP share would range from a high of 34.18% to a low of 26.84%, a 7.34% spread, while the largest spread for 12CP is only 2.85% for I&M. Again the seven-Member MLR comes in second, with a 3.5% spread for APCo.

Q. WHY DOES THE 1CP METHOD CAUSE INSTABILITY IN THE SHARING OF TRANSMISSION COSTS AMONG THE AEP EAST COMPANIES?

A. The 1CP transmission billing demand is inherently less stable than the 12CP method because it measures each customer's load in only one hour of the year. When applied to individual customers, the 1CP method can result in cost allocations reflecting anywhere from zero to 100% of a customer's annual peak load. When applied to utilities like the AEP East Companies that serve the diversified load of many customers, the 1CP can still produce significant variability in cost allocations when the annual peak occurs in the summer than when it occurs in the winter. That is exactly what happened this year in the AEP Zone of PJM. The 1CP in 2007, which was used for billing purposes in 2008, was a summer peak. The 1CP for 2008, that is the network integration transmission service (NITS) billing demand in the AEP Zone during 2009, was a winter demand peak. Three of the AEP East Companies, APCo, KPCo and KgPCo, typically have their annual peak in the winter, while the others typically peak in the summer. Thus, in a year like 2009, when a change from summer peak allocations to winter peak allocations occurs, costs will be shifted from the summer peaking companies to the winter peaking companies. Of course the reverse will occur when the peak again occurs in the summer.

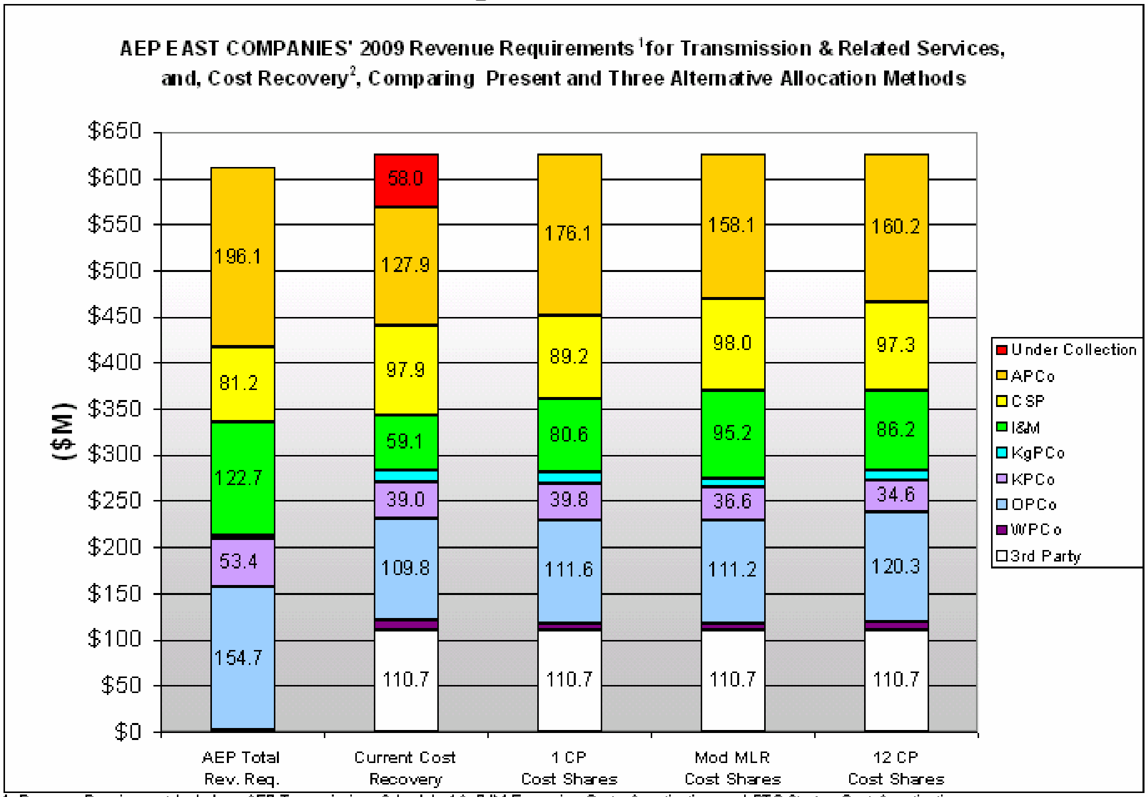
Q. CAN YOU ILLUSTRATE HOW THE NET TRANSMISSION COSTS OF EACH OF THE AEP EAST COMPANIES WOULD CHANGE UNDER THE 12CP AND ALTERNATIVE ALLOCATION METHODS?

A. Yes. Figure 1 shows in bar graph form, from left to right, (1) the total transmission service revenue requirement of the AEP East Companies, (2) the approximate amounts they are currently able to reflect in retail rates, the costs they would experience if the Transmission Agreement changes as proposed are approved, but assuming (3) that the 1CP method is used to share transmission service costs, (4) that the modified 7-Member MLR method is used, and (5) if the 12CP method, as proposed is used.

Q. PLEASE DESCRIBE FIGURE 1.

A. Last year, in Docket No. ER08-1329, the AEP East Companies filed a transmission formula rate, which was accepted, effective as of March 1, 2009, subject to refund after settlement and potential hearing processes. The first bar graph in Figure 1 shows that the transmission and related services revenue requirements of the various AEP East Companies total $612.5 million based on the proposed formula rate. Based on the billing demands effective during 2009, non-affiliates, or third parties, would pay approximately $110.7 million of the AEP Companies' cost of transmission and related services.

Figure 1



1. Revenue Requirement Includes: AEP Transmission, Schedule 1A, PJM Expansion Costs Amortization, and RTO Startup Cost Amortization.
2. Cost Recovery totals exceed AEP Revenue Requirement due to PJM RTEP project socialization charges.

The AEP East Companies would be responsible for the remainder. The second bar graph shows the present situation with regard to retail cost recovery, and the under-recovery problem. The other bar graphs show the relative costs that each of the AEP East Companies would experience if transmission service costs are allocated by the 1CP method, the seven member MLR method or the 12CP method, and illustrate the concept that the under-recovery issue will be resolved if the changes proposed in the Transmission Agreement are approved.

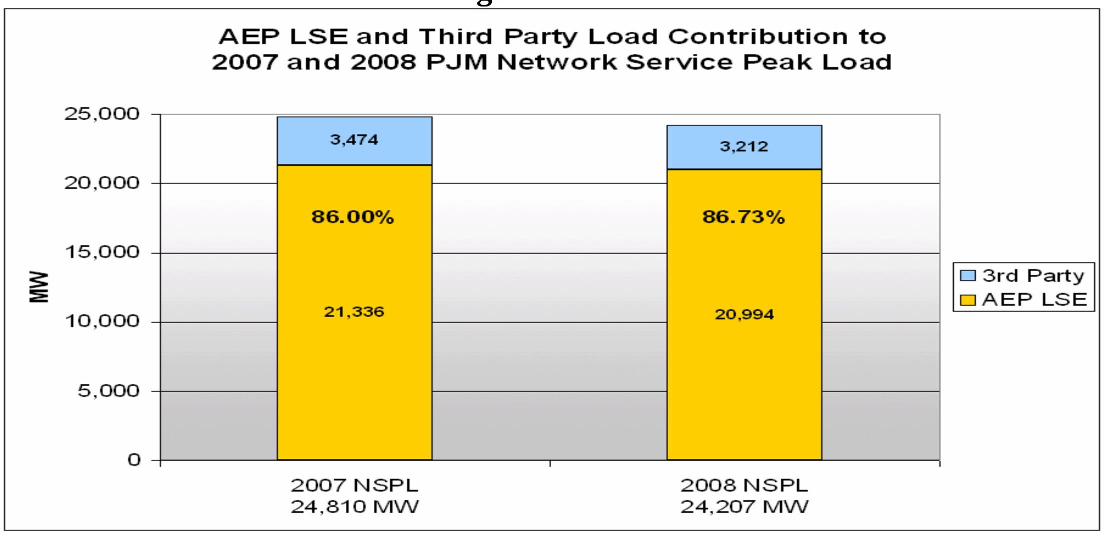
IV. COMPARISON OF ALTERNATIVE ALLOCATION METHODS

Q. HAVE YOU PREPARED A MORE DETAILED ANALYSIS OF THE IMPACTS THE COST AND REVENUE ALLOCATION CHANGES WILL HAVE ON THE AEP EAST COMPANIES?

A. Yes. Exhibit AEP-205 summarizes three cost impact analyses contained in Exhibits AEP- 208, AEP-209 and AEP-210 that show, respectively, the revenues that each AEP East Company would share as a Transmission Owner and the expenses each would incur as an LSE under the Transmission Agreement as it stands today, and as modified in this proceeding if transmission costs are shared by the AEP East Companies, as LSEs, based on the 1CP Method (Exhibit AEP-208), by the MLR method adjusted to allocate costs to all seven of the AEP East Companies based on their peak retail loads (Exhibit AEP-209), and based on the 12CP method (Exhibit AEP-210). The AEP East Companies are proposing in this proceeding to adopt the 12CP method for transmission and related service cost allocations, other than the PJM Schedule 1A charges that are based on energy deliveries.

As can be seen by summary Exhibit AEP-205, in total, the AEP Companies presently receive more revenue from PJM as Transmission Owners than they pay as LSEs, and based on the rates and billing demands effective during 2008, those net receipts were about $104 million. In 2009, even recognizing the annualized effect of the higher rates that started March 1, the net receipts will be lower, at about $96.5 million. There are two primary reasons the for the reduction in net receipts, (1) the AEP East Companies' share of the AEP transmission costs increased, because the AEP Companies' share of the 2008 winter peak demand is larger than their share of the 2007 summer peak demand, as shown in the following graph (Figure 2), and (2) the AEP Companies are being charged 15% of the cost of new PJM transmission projects that are being socialized under PJM OATT Schedule 12, Transmission Enhancements.

Figure 2

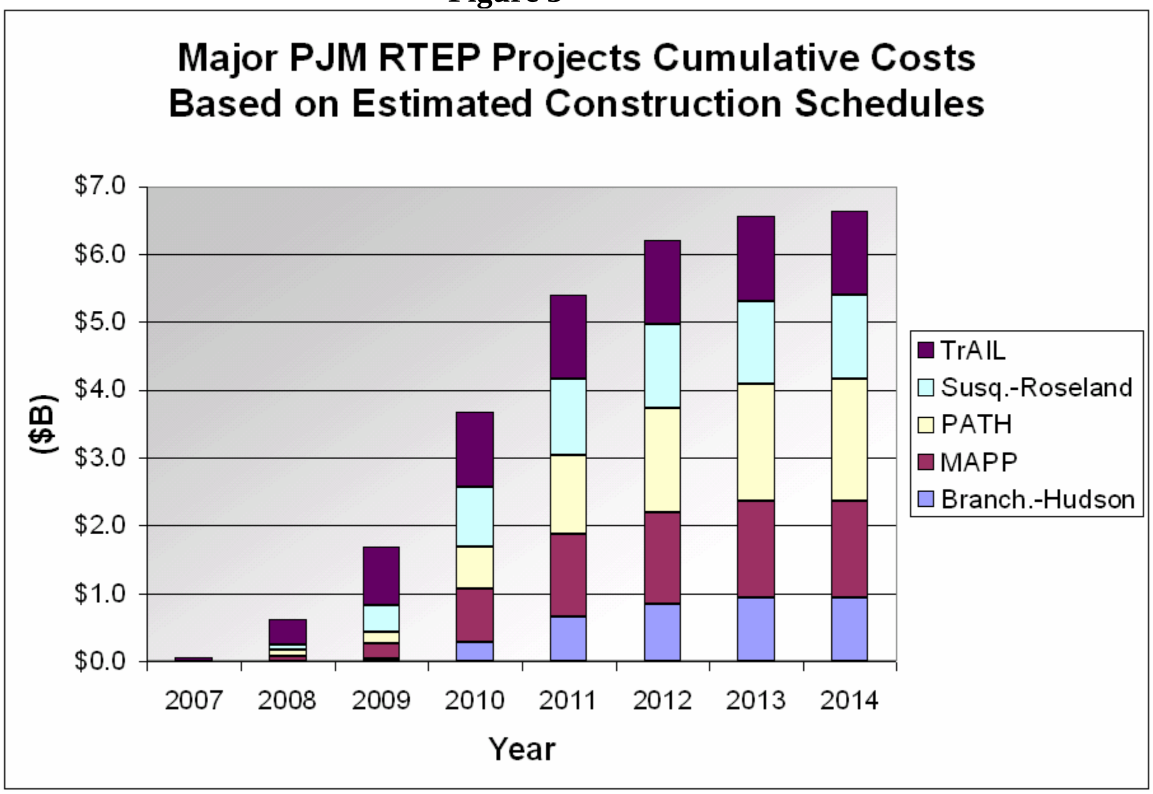


In 2008 PJM began charging the AEP Companies for socialized RTEP projects. So far those charges have not been significant, compared to the cost of the AEP East Companies' facilities; however, those charges are increasing quite rapidly. The 2009 cost impact analyses, summarized in Exhibit AEP-205, include about $14 million for Schedule 12 charges. The $14 million estimate is based on Schedule 12 charges experienced so far in 2009, but several major projects will receive increases in their revenue requirements during 2009, based on inclusion of CWIP in the rate base. AEP does not know with any certainty how much the Schedule 12 charges will actually be during 2009, but estimates of the charges show that they could be as much three times the amount reflected in the analyses.

Q. HAVE YOU PERFORMED AN ANALYSIS TO PROJECT THE SCHEDULE 12 CHARGES EXTENDING BEYOND 2009?

A. Yes. Figure 3 shows the trajectory of PJM capital spending on major PJM Regional Transmission Expansion Plan ("RTEP") projects, for which socialized cost recovery has been approved. Figure 3 illustrates an explosive growth pattern for such projects.

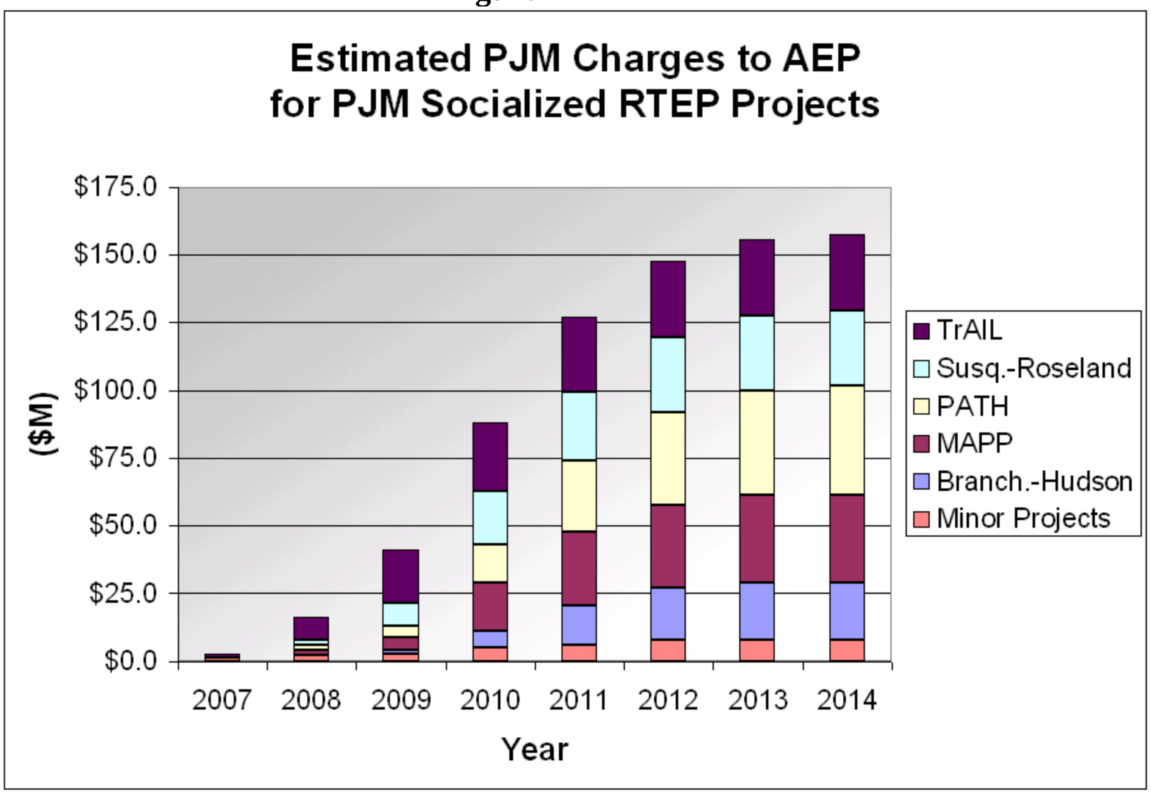
Figure 3



Q. WHAT IS THE BASIS OF THE PROJECTED SPENDING, AND HOW MUCH MIGHT THE AEP COMPANIES ULTIMATELY BE CHARGED FOR THOSE PROJECTS?

A. The spending projections in Figure 3 are based on the estimated cost and in-service dates of the RTEP projects, as published by PJM. The estimated start-to-end spending projection for the various projects has been developed using estimated spending schedules that assume most of the costs will be incurred in the middle and last years of the construction schedules. Figure 4 shows that the AEP Companies might expect to see Schedule 12 charges increase to about $160 million per year over the next six years, assuming a 15% annual carrying charge rate, and current recovery of construction work in-progress costs for the largest projects. Actual carrying costs may be less than 15% during construction, but the figure is likely to yield a conservative estimate of annual costs once the projects are in service.

Figure 4



Q. **PLEASE CONTINUE WITH YOUR DISCUSSION OF Exhibit AEP-205.**

A. Exhibit AEP-205 distills a lot of information derived in Exhibits AEP-208, AEP-209 and AEP-210. The exhibit is understood most easily by tracking through the numbers from top to bottom three columns at a time. Note that the line descriptions apply to all columns, and are arranged in three blocks. The block header "Present Allocation" refers to the present application of the five-company MLR to all costs and revenues, except for the two minor exceptions noted earlier, the ECRC and the SCRC related expenses and revenues which are shared by transmission pole-mile ratios. The Block header "Proposed Allocation" refers to allocations under a modified Transmission Agreement where revenues are allocated based on each AEP East Companies' revenue requirement for each service, and costs are allocated proportionate to relevant measures of load.

The first three columns of numbers under the Header "Summary of Impact, 1CP Cost Allocation, (Exhibit AEP-207)" shows the Present Allocations for each AEP East Company during 2008 and 2009 and the differences in the top block of rows, then the Proposed Allocation for 2008 and 2009 and the differences in the middle block of rows. Bear in mind that on this exhibit the values represent the net of revenues received by and expenses charged to the Members in RTO settlements. The bottom block of rows shows the changes that would result in 2008 and 2009 from replacing the present Transmission Agreement and allocation methods, with the proposed load-based allocation of costs and revenue requirement-based allocations of revenues. The first block of columns show that if the 1CP method were to be used for transmission service cost allocations, the Net Transmission Cost for APCo would increase by $46.5 million from 2008 to 2009 because of the change from a summer peak to a winter peak. The one year change for CSP is $28 million. Two other companies would change by more than $10 million from 2008 to 2009 using the 1CP method.

Moving across to the next block of columns, and tracking down through the rows, one can see that if the seven-Member MLR method is used, instead of the 1CP method, the largest year to year change is reduced by about 2/3 to $18.1 million. The last block of columns shows the results for the 12CP method. The 2008 to 2009 cost changes are slightly larger for the 12CP method than for the 7-Member MLR, but over a longer period of time, as illustrated by Exhibit AEP-204, the 12CP will be the most stable of the methods.

Q. PLEASE DESCRIBE EXHIBITS AEP-206 THROUGH AEP-210?

A. Exhibits AEP-206 and AEP-207 summarize the allocation factors and other data underlying the analyses in Exhibits AEP-208 through AEP-210. Page 1 of Exhibit AEP-206 shows the revenue requirements of each AEP East Company for transmission and PJM Schedule 1A service pursuant both to the rates effective before and after March 1, 2009. Also shown there are the revenue requirements for RTO Start-up and PJM Expansion costs. Page 2 of Exhibit AEP-206 summarizes the AEP East Companies' demand allocation percentages for 2008 and 2009 under the three methods discussed earlier. Page 3 of Exhibit AEP-206 summarizes the energy allocation factors for 2008 and 2009 used to allocate the PJM Schedule 1A service charges. Page 4 of Exhibit AEP-206 summarizes Other Operating revenue and transmission costs that are presently directly assigned. Page 5 of Exhibit AEP-206 summarizes transmission charges to KgPCo and WPCo in 2008 and 2009 under their PPAs with APCo and OPCo, respectively.

Q. WHAT INFORMATION DOES EXHIBIT AEP-207 PROVIDE?

A. Exhibit AEP-207 summarizes the going-level monthly settlements under the Transmission Agreement as it presently operates. In 2008 the total payments by Deficit Members was $68.4 million, with $54.9 million paid by CSP and $13.5 million paid by OPCo. The Surplus Members, APCo, I&M and KPCo, received $28.7 million, $37.7 million and $1.9 million, respectively. Exhibit AEP-205 shows that the Transmission Agreement settlements for 2008 and 2009, based on the investments as of January 2009, would increase slightly to about $71.5 million.

Q. HOW ARE EXHIBITS AEP-208 THROUGH AEP-210 STRUCTURED?

A. Each of the Exhibits AEP-208, AEP-209 and AEP-210 consist of 5 pages. The first page summarizes the information developed on pages 2 through 5. Page 1 looks similar to Exhibit AEP-205, but displays different information. Page 1 of Exhibits AEP-208 through AEP-210 each have three blocks of rows and three blocks of columns. The blocks of rows tabulate Present Allocations, Proposed Allocations and the differences as in Exhibit AEP-205, but the first block of columns shows revenues ("T-Related"), costs ("LSE Related"), and the net cost or receipt for each AEP East Company for 2008. The middle block of columns shows revenues ("T-Related"), costs ("LSE Related"), and the net cost or receipt for each AEP East Company for 2009. Then the third block of columns shows the change from 2008 to 2009 in the revenues and costs, and in the net cost or receipt for each AEP East Company. The "Present Allocation" values are the same in all three exhibits, as are the revenue allocations in the "Proposed Allocation" sections. What is different about Exhibits AEP-208, AEP-209 and AEP-210 is the "Proposed Allocation" for transmission service costs and the ECRC and SCRC amounts. In Exhibit AEP-208, the transmission costs are allocated using the 1CP method, in Exhibit AEP-209 the seven-Member MLR method is used to allocate transmission costs, and in Exhibit AEP-210, the 12CP method is employed.

Page 2 of each of the three Exhibits shows present, proposed and differences in the allocation of 2008 revenues (T-Related). Page 3 shows present, proposed and differences in the allocation of 2008 costs (LSE-Related). Pages 4 and 5 of each Exhibit AEP-208 through AEP-210 shows the same allocations and differences as pages 2 and 3, but for the 2009 revenues and costs.

V. CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.

A. The AEP Companies initiated the AEP Transmission Agreement in 1984 with the goal of levelizing the cost of bulk transmission investments that they each had made and planned to make. Over time, events and new goals have over-taken the Companies and the agreement, resulting in wide differences in per kW costs for transmission service among the AEP East Companies, and a significant cost recovery short-fall. The AEP East Companies have studied the issues, considered the relative affects of several alternative courses of action, and have agreed, pursuant to the terms of the Transmission Agreement, that the agreement should be modified, as has been proposed in this proceeding. My study of the issues and impacts, presented in the for-going testimony, and attached exhibits, lead me to conclude that the proposed changes are consistent with the principles of cost allocation, and the Commission's policies, will improve equity in the sharing of costs among the AEP East Companies and stability in the costs of their customers. For these and other reasons that Mr. Baker and I have discussed, I recommend that the changes to the Transmission Agreement, reflected in Exhibit AEP-202, be accepted and made effective upon their approval by Order of the Commission.

Q. DO YOU HAVE ANYTHING FURTHER TO ADD?

A. At this time I do not.

Composite Copy

TRANSMISSION AGREEMENT

By and among

APPALACHIAN POWER COMPANY

COLUMBUS SOUTHERN POWER COMPANY

INDIANA MICHIGAN POWER COMPANY

KENTUCKY POWER COMPANY

OHIO POWER COMPANY

and with

AMERICAN ELECTRIC POWER SERVICE CORPORATION

AS AGENT

DATED APRIL 1984, AS MODIFIED BY:

MODIFICATION NO. 1, DATED JANUARY 1, 1989

and

SUPPLEMENT A TO MODIFICATION NO. 1

Dated December 12, 1989

CONTENTS

0.1 THIS AGREEMENT, made and entered into as of the 1st day of April, 1984 by and among APPALACHIAN POWER COMPANY (Appalachian Company), a Virginia corporation, COLUMBUS AND SOUTHERN OHIO ELECTRIC COMPANY (Columbus Company), an Ohio corporation, INDIANA & MICHIGAN ELECTRIC COMPANY (Indiana Company), an Indiana corporation, KENTUCKY POWER COMPANY (Kentucky Company), a Kentucky corporation, OHIO POWER COMPANY (Ohio Company), an Ohio corporation, said companies (herein sometimes called 'Members' when referred to collectively and 'Member' when referred to individually) being affiliated companies of the integrated public utility electric system known as the American Electric Power SYSTEM (AEP System), and AMERICAN ELECTRIC POWER SERVICE CORPORATION (Agent), a New York corporation, being a service company engaged solely in the business of furnishing essential services to the aforesaid companies and to other affiliated companies.

W I T N E S S E T H
T H A T:

0.2 WHEREAS, the Members own and operate electric facilities in the states herein indicated, (i) Appalachian Company in Virginia, West Virginia, and Tennessee (ii) Columbus Company in Ohio, (iii) Indiana Company in Indiana and Michigan, (iv) Kentucky Company in Kentucky, and (v) Ohio Company in Ohio and West Virginia; and

0.3 WHEREAS, the Members have entered into an interconnection agreement, dated July 6, 1951, with modification thereto, which provides for certain understandings, conditions, and procedures designed to achieve the full benefits and advantages available through the coordinated operation of their electric power supply facilities; and

0.4 WHEREAS, Appalachian Company, Indiana Company, Kentucky Company, and Ohio Company entered into an agreement, dated April 24, 1958, with modification thereto, (said agreement, as so modified, herein called Special Facilities Agreement) which fixed the terms and conditions under which the 345-kV transmission facilities interconnecting the AEP System and Commonwealth Edison Company (Special Facilities) were provided, owned, operated, and maintained; and

0.5 WHEREAS, The Members' electric facilities are now and for many years have been interconnected through their respective transmission facilities at a number of points, forming an integrated transmission network; and

0.6 WHEREAS, the Members have achieved benefits through the coordinated planning and development of a fully integrated Extra High Voltage (EHV) Transmission System; and

0.7 WHEREAS, the members believe that an agreement which provides for the equitable sharing among the Members of the costs incurred by the Members in connection with the ownership, operation, and maintenance of their respective portions of the EHV Transmission System would enhance equity among the Members for the continued development of a reliable and economic EHV Transmission System; and

0.8 WHEREAS, the Members believe that benefits and advantages could be best realized if this Agreement were administered by a single clearing agent; and

0.9 WHEREAS, the Members believe that the Agent designated herein for such purpose is qualified to perform such services;

0.10 NOW, THEREFORE, in consideration of the premises and of the mutual covenants and agreements hereinafter contained, the parties hereto hereby agree as follows:

ARTICLE 1
DESCRIPTION OF EHV TRANSMISSION SYSTEM

1.1 The Bulk Power Transmission System covered by this Agreement shall include the following transmission facilities owned by the Members: (i) All transmission lines operating at a nominal voltage of 138 – kV or higher; (ii) all facilities such as transformers, buses, switchgear, and associated facilities located at transmission substations operating at a nominal voltage of 345 – kV and above including EHV/138 – kV substations, and (iii) any other transmission lines and associated substation facilities at any voltage designated by the Transmission Committee as having been, installed for the mutual benefit of all Members.

1.11 In determining the investments in the Bulk Power Transmission System referred to under subsection 1.1 (i) above, only those transmission line costs includable in Accounts 350 and .354-359, inclusive, of the Federal Energy Regulatory Commission's Uniform System of Accounts Prescribed for Public Utilities and Licenses, as in effect on January 1, 1984, shall be used.

1.12 The investments in the Bulk Power Transmission System referred to in subsection 1.1 (ii) and (iii) above are amounts includable in the accounts listed in the preceding subsection 1.11 plus Accounts 352 and 353.

1.2 All investments referred to in Section 1.1 above shall be determined annually as of the end of each calendar year and shall prevail as the basis for monthly settlement payments during the immediately following calendar year, provided, however, that if in any month a Member's investment pursuant to Section 1.1 shall be increased by the addition of facilities costing $10,000,000 or more, that Member's transmission investment shall be redetermined and, together with the investment of the other Members then prevailing, shall prevail as the basis for monthly settlements during the next and remaining months of the calendar year.

ARTICLE 2
OPERATION

2.1 Each member shall maintain its respective portion of the Bulk Transmission System, together with all associated facilities and appurtenances, in a suitable condition of repair at all times in order that said system will operate in a reliable and satisfactory manner.

ARTICLE 3
TRANSMISSION COMMITTEE

3.1 The Members shall appoint representatives to serve on a Transmission Committee. Such representatives shall have authority to act for the Members in the administration of all matters pertaining to this Agreement.

3.2 Each Member shall designate in writing, delivered to the other Members and Agent, the person who is to act as its representative on said Committee and the person or persons who may serve as alternate whenever such representative is unavailable to act. Agent shall designate in writing delivered to the Members the person who is to act as its representative on said Committee and the person or persons who may serve as alternate whenever such representative is unavailable to act. Such person designated by Agent shall act as chairman of the Transmissions Committee and shall be known as the "Transmission Manager".

ARTICLE 4
AGENTS RESPONSIBILITIES

4.1 For the purpose of carrying out the provisions of this Agreement the Members hereby delegate to Agent, and Agent hereby accepts, the responsibility of administration of this Agreement, and in furtherance thereof Agent hereby agrees:

> 4.11 To arrange for and conduct such meetings of the Transmission Committee as may be required to insure the effective and efficient carrying out of all matters of procedure essential to the complete performance of the provisions of this Agreement.
>
> 4.12 To render to each Member as promptly as possible after the end of each calendar month a statement setting forth the settlements hereunder for such preceding calendar month, in such detail and with such segregations as may be needed for accounting, operating, or other proper purposes.
>
> 4.13 To carry out cash settlements under this Agreement. Settlements by the Members shall be made for each calendar month through an account (hereby designated and hereinafter called "TRANSMISSION ACCOUNT") to be administered by Agent. Payments to or from such account shall be made to or by Agent as clearing agent of the account. The total amount of the

payments made by members to the TRANSMISSION ACCOUNT for a particular month shall be equal to the total amount of the payments made to the Members from the TRANSMISSION ACCOUNT for such month.

ARTICLE 5
DEFINITIONS OF FACTORS ASSOCIATED WITH SETTLEMENTS

5.1 Factors associated with settlements under this Agreement are defined as follows:

5.2 MEMBER LOAD OBLIGATION – A Member's internal electric load plus any firm power sales by the Member to affiliated and non-affiliated companies other than Members, Which firm power sales by the member are principally characterized by the Member's assuming the load obligation as its own firm power commitment and by the Member's retaining the advantages accruing from meeting the load.

5.3 MEMBER DEMAND – A Member's MEMBER LOAD OBLIGATION determined on a clock-hour integrated kilowatt basis.

5.4 MEMBER MAXIMUM DEMAND – The MEMBER MAXIMUM DEMAND in effect for a calendar month for a particular Member shall be equal to the maximum MEMBER DEMAND experienced by such Member during the twelve consecutive calendar months next preceding such calendar month.

5.5 MEMBER LOAD RATIO – The ratio of a particular member's MEMBER MAXIMUM DEMAND in effect for a calendar month to the sum of the MEMBER MAXIMUM DEMANDS of all the members in effect for such month.

5.6 MEMBER BULK TRANSMISSION INVESTMENT – The aggregate dollar investment of a particular Member in its Bulk Power Transmission System, as described in Article I, less the Investment Tax Credit generated by such investment.

Pursuant to the Order of the Federal Energy Regulatory Commission issued November 3, 1989 – in Docket No. ER84-348-012, the Investment Tax Credit used in the determination of MEMBER BULK TRANSMISSION INVESTMENT amounts shall be the result of multiplying the investment tax credit generated by such Member's investment by the following respective factors:

i)	Appalachian Company	=	0.79127
ii)	Columbus Company	·	0.80245
iii)	Indiana Company	·	0.79220
iv)	Kentucky Company	·	0.79211
v)	Ohio Company	·	0.78515

5.7 SYSTEM BULK TRANSMISSION INVESTMENT – The sum of the MEMBER BULK TRANSMISSION INVESTMENTS of all the Members.

5.8 MEMBER BULK TRANSMISSION OBLIGATION – The SYSTEM BULK TRANSMISSION INVESTMENT multiplied by the MEMBER LOAD RATIO of a particular Member.

5.9 MEMBER BULK TRANSMISSION SURPLUS The difference between the MEMBER BULK TRANSMISSION INVESTMENT and MEMBER BULK TRANSMISSION OBLIGATION of a particular Member, when such MEMBER BULK TRANSMISSION INVESTMENTS exceeds such MEMBER BULK TRANSMISSION OBLIGATION.

5.10 MEMBER BULK TRANSMISSION DEFICIT – The difference between the MEMBER BULK TRANSMISSION OBLIGATION and MEMBER BULK TRANSMISSION INVESTMENT of a particular Member, when such MEMBER BULK TRANSMISSION INVESTMENT is less than such MEMBER BULK TRANSMISSION OBLIGATION.

ARTICLE 6
SETTLEMENTS

6.1 As provided in Article 8 below, following the end of each month, the members shall carry out cash settlements through the TRANSMISSION ACCOUNT.

6.2 BULK TRANSMISSION EQUALIZATION RECEIPT – Each Member having a MEMBER BULK TRANSMISSION SURPLUS (MBTS) shall receive a BULK TRANSMISSION EQUALIZATION RECEIPT (BTER), each month, in dollars from the TRANSMISSION ACCOUNT determined by the following formula:

BTER = MBTS X MCC

Where:
MCC = The particular Member's monthly carrying charge factor as listed below:

i)	Appalachian Company	=	1.4933%
ii)	Columbus Company	=	1.5733%
iii)	Indiana Company	=	1.5000%
iv)	Kentucky Company	=	1.4950%
v)	Ohio Company	=	1.4508%

6.3 BULK TRANSMISSION EQUALIZATION PAYMENT – Each Member having a MEMBER BULK TRANSMISSION DEFICIT (MBTD) shall make a BULK TRANSMISSION EQUALIZATION PAYMENT (BTEP), each month, in dollars to the TRANSMISSION ACCOUNT determined by the following formula:

BTEP = SBTER X MBTD/SMBTD

Where:

SBTER = The sum of all Members' BTERs
SMBTD = The sum of all Members' MBTDs

ARTICLE 7
TAXES

7.1 If at any time during the duration of this Agreement there should be levied and/or assessed by any governmental authority against any Member having an MBTS any tax related to the receipt of settlements calculated pursuant to Article 6 of this Agreement (such as sales, excise or similar taxes not included in such Member's MCC), such tax expense incurred by such Member that would not have been incurred were the transmission settlements hereunder not being made, such Member shall be entitled to reimbursement for such additional taxes by Members having an MBTD, i.e.,, in calculating the monthly settlements hereunder, such Member having an MBTS shall receive an amount in dollars equal to the sum of (a) the amount of settlement calculated pursuant to Article 6 of this Agreement plus (b) an amount sufficient to reimburse such Member for the amount of such additional taxes which it has incurred. Each Member having an MBTD shall pay such reimbursement in (b) above in dollars as determined by the formula in Section 6.3 of this Agreement.

ARTICLE 8
BILLINGS AND PAYMENT

8.1 All bills for amounts owing hereunder shall be due and payable on the fifteenth day of the month next following the month or other period to which such bills are applicable, or on the tenth day following receipt of the bill, whichever date is later. Interest on unpaid amounts shall accrue daily at the prime interest rate per annum in effect on the due date at the Citibank, plus 2% per annum, from the due date until the date upon which payment is made. Unless otherwise agreed upon the calendar month shall be the standard period for the purpose of settlements under this Agreement. If bills cannot be accurately determined at any time, they shall be rendered on an estimated basis and subsequently adjusted to conform to the terms of this Agreement.

ARTICLE 9
MODIFICATION

9.1 Any Member, by written notice given to the other Members and Agent, may call for a reconsideration of the terms and conditions herein provided. If such reconsideration is called for, the Members shall take into account any changed conditions, any results from the application of said terms and conditions, and any other facts that might cause said terms and conditions to result in an inequitable sharing of costs and benefits under this Agreement. Any modification in terms and conditions agreed to by the Members following such reconsideration shall become effective the first day of the month following authorization of such reconsideration by appropriate regulatory authority.

ARTICLE 10
EFFECTIVE DATE AND TERM OF THIS AGREEMENT

10.1 This Agreement shall become effective and shall become a binding obligation of the Parties on the date on which the last of the following events shall have occurred (Effective Date):

(a) June 1, 1984;
(b) This Agreement shall have been filed with, and accepted for filing by the Federal Energy Regulatory Commission (FERC) under the Federal Power Act as a rate schedule, under circumstances where the FERC (i) shall not have suspended this Agreement or any part thereof, or (ii) if suspended, at the end of the suspension period.

10.2 This Agreement shall continue in effect for an initial period from the Effective Date to December 31, 1990, and thereafter for successive periods of one year each until terminated as provided under subsection 10.3 below.

10.3 Any Member upon at least three years' prior written notice to the other Members and Agent may terminate this Agreement at the expiration of said initial period or at the expiration of any successive period of one year.

ARTICLE 11
TERMINATION OF SPECIAL FACILITIES AGREEMENT

11.1 The Members agree that the Special Facilities Agreement, dated April 24, 1958, and all supplements and amendments thereto shall terminate as of the Effective Date of this Transmission Agreement and that all further obligations among them in respect thereof shall cease and terminate as of such date, except in respect of any payments or liabilities incurred in respect thereof prior to such termination date.

ARTICLE 12
REGULATORY AUTHORITIES

12.1 The Members recognize that this Agreement, and any tariff or rate schedule which shall embody or supersede this Agreement or any part thereof, are in certain respects subject to the jurisdiction of the FERC under the Federal Power Act, and are also subject to such lawful action as any regulatory authority having jurisdiction shall hereafter take with respect thereto. The performance of any obligation of the Members shall be subject to the receipt from time to time as required of such authorizations, approvals or actions of regulatory authorities having jurisdiction as shall be required by law.

12.2 It is expressly understood that any Member under this Agreement, as it may hereafter from time to time be modified and supplemented by the Members, shall be entitled, at any time and from time to time, unilaterally to make application to the FERC for a change in rates, charges, classification of service, or any rule, regulation or contract relating thereto, or to make any change in or supersede in whole or in part any provision of this Agreement, under Section 205 of the Federal Power Act and pursuant to the FERC's Rules and Regulations promulgated thereunder.

ARTICLE 13
ASSIGNMENT

13.1 This Agreement shall inure to the benefit of and be binding upon the successors and assigns of the respective parties.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed in their respective corporate names and on their behalf by their proper officers thereunto daily authorized as of the day and year first above written.

APPALACHIAN POWER COMPANY

By: ________________________________

COLUMBUS AND SOUTHERN OHIO
ELECTRIC COMPANY

By: ________________________________

INIDIAN & MICHIGAN ELECTRIC COMPANY

By: ________________________________

KENTUCKY POWER COMPANY

By: ________________________________

OHIO POWER COMPANY

By: ________________________________

AMERICAN ELECTRIC POWER
SERVICE CORPORATION

By: ________________________________

~~Composite Copy~~

TRANSMISSION AGREEMENT

By and among

APPALACHIAN POWER COMPANY

COLUMBUS SOUTHERN POWER COMPANY

INDIANA MICHIGAN POWER COMPANY

KENTUCKY POWER COMPANY

KINGSPORT POWER COMPANY

OHIO POWER COMPANY

WHEELING POWER COMPANY

and with

AMERICAN ELECTRIC POWER SERVICE CORPORATION

AS AGENT

DATED APRIL 1984, AS ~~MODIFIED BY:~~AMENDED

~~MODIFICATION NO. 1, DATED JANUARY 1, 1989~~

~~and~~

~~SUPPLEMENT A TO MODIFICATION NO. 1~~

~~Dated December 12, 1989~~

CONTENTS

0.1 THIS AGREEMENT, made and entered into as of the 1st day of April, ~~1984~~1984, and as subsequently amended, by and among APPALACHIAN POWER COMPANY (Appalachian Company), a Virginia corporation, COLUMBUS AND SOUTHERN ~~OHIO ELECTRIC~~POWER COMPANY (Columbus Company), an Ohio corporation, INDIANA ~~&~~ MICHIGAN ~~ELECTRIC~~POWER COMPANY (Indiana Company), an Indiana corporation, KENTUCKY POWER COMPANY (Kentucky Company), a Kentucky corporation, OHIO POWER COMPANY (Ohio Company), an Ohio corporation, KINGSPORT POWER COMPANY (Tennessee Company), a Tennessee corporation, and WHEELING POWER COMPANY (Wheeling Company),a West Virginia corporation, said companies (herein sometimes called 'Members' when referred to collectively and 'Member' when referred to individually) being affiliated companies of the integrated public utility electric system known as the American Electric Power SYSTEM (AEP System), and AMERICAN ELECTRIC POWER SERVICE CORPORATION (Agent), a New York corporation, being a service company engaged solely in the business of furnishing essential services to the aforesaid companies and to other affiliated companies.

W I T N E S S E T H,

T H A T:

0.2 WHEREAS, the Members own and operate electric facilities in the states herein indicated, (i) Appalachian Company in Virginia, West Virginia, and Tennessee (ii) Columbus Company in Ohio, (iii) Indiana Company in Indiana and Michigan, (iv) Kentucky Company in Kentucky, ~~and~~ (v) ~~Ohio~~Tennessee Company in ~~Ohio and~~Tennessee, (vi) Ohio Company in Ohio and West Virginia, and (vii) Wheeling Company in West Virginia; and

0.3 WHEREAS, certain of the Members have entered into an interconnection agreement, dated July 6, 1951, with modification thereto, which provides for certain understandings, conditions, and procedures designed to achieve the full benefits and advantages available through the coordinated operation of their electric power supply facilities; and

0.4 WHEREAS, ~~Appalachian Company, Indiana Company, Kentucky Company, and Ohio Company entered into an agreement, dated April 24, 1958, with modification thereto, (said agreement, as so modified, herein called Special Facilities Agreement) which fixed the terms and conditions under which the 345 kV transmission facilities interconnecting the AEP System and Commonwealth Edison Company (Special Facilities) were provided, owned, operated, and maintained; and0.5 WHEREAS,~~ The Members' electric facilities are now and for many years have been interconnected through their respective transmission facilities at a number of points, forming an integrated transmission network; and

~~0.6~~ 0.5 WHEREAS, the Members have achieved benefits through the coordinated planning and development of a fully integrated ~~Extra High Voltage (EHV)~~ Transmission System; and

~~0.7~~ 0.6 WHEREAS, the members believe that an agreement which provides for the equitable sharing among the Members of the costs incurred by the Members in connection with the ownership, operation, and maintenance of their respective portions of the ~~EHV~~ Transmission System would enhance equity among the Members for the continued development of a reliable and economic ~~EHV~~ Transmission System; and

0.7 WHEREAS, effective October 1, 2004 the Members joined the PJM Interconnection, LLC ("PJM"), and placed their respective transmission facilities under the functional control of PJM, a regional transmission operator or "RTO"; and

0.8 WHEREAS, PJM provides transmission service, pursuant to the PJM Open Access Transmission Tariff ("OATT"), to the Members and others who require transmission service over the Transmission System; and

~~0.8~~ 0.9 WHEREAS, the Members believe that benefits and advantages could be best realized if this Agreement were administered by a single clearing agent; and

~~0.9~~ 0.10 WHEREAS, the Members believe that the Agent designated herein for such purpose is qualified to perform such services;

~~0.10~~ 0.11 NOW, THEREFORE, in consideration of the premises and of the mutual covenants and agreements hereinafter contained, the parties hereto hereby agree as follows:

ARTICLE 1

DESCRIPTION OF ~~EHV~~ TRANSMISSION SYSTEM

1.1 The ~~Bulk Power~~ Transmission System covered by this Agreement shall include all the ~~following~~ transmission facilities, from time to time, owned by the Members~~: (i) All transmission lines operating at a nominal voltage of 138 – kV or higher~~ that are included in the costs of service used to determine rates for transmission service under the PJM OATT, including without limitation, (i) All Member transmission lines; (ii) all facilities such as transformers, buses, switchgear, and associated facilities located at Member transmission ~~substations operating at a nominal voltage of 345 kV and above including EHV/138 kV~~ substations, and (iii) any other transmission lines and associated substation facilities at any voltage designated by the Transmission Committee as having been, installed or leased for the mutual benefit of all Members and/or others who receive transmission service from PJM or a successor RTO or other successor transmission service provider.

~~1.11 In determining the investments in the Bulk Power Transmission System referred to under subsection 1.1 (i) above, only those transmission line costs includable in Accounts 350 and .354-359, inclusive, of the Federal Energy Regulatory Commission's Uniform System of Accounts Prescribed for Public Utilities and Licenses, as in effect on January 1, 1984, shall be used.~~

~~1.12 The investments in the Bulk Power Transmission System referred to in subsection 1.1 (ii) and (iii) above are amounts includable in the accounts listed in the preceding subsection 1.11 plus Accounts 352 and 353.~~

~~1.2 All investments referred to in Section 1.1 above shall be determined annually as of the end of each calendar year and shall prevail as the basis for monthly settlement payments during the immediately following calendar year, provided, however, that if in any month a Member's investment pursuant to Section 1.1 shall be increased by the addition of facilities costing $10,000,000 or more, that Member's transmission investment shall be redetermined and, together with the investment of the other Members then prevailing, shall prevail as the basis for monthly settlements during the next and remaining months of the calendar year.~~

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ARTICLE 2

OPERATION

2.1 Each member shall maintain its respective portion of the Bulk Transmission System, together with all associated facilities and appurtenances, in a suitable condition of repair at all times in order that said system will operate in a reliable and satisfactory manner.

ARTICLE 3

TRANSMISSION COMMITTEE

3.1 The Members shall appoint representatives to serve on a Transmission Committee. Such representatives shall have authority to act for the Members in the administration of all matters pertaining to this Agreement.

3.2 Each Member shall designate in writing, delivered to the other Members and Agent, the person who is to act as its representative on said Committee and the person or persons who may serve as alternate whenever such representative is unavailable to act. Agent shall designate in writing delivered to the Members the person who is to act as its representative on said Committee and the person or persons who may serve as alternate whenever such representative is unavailable to act. Such person designated by Agent shall act as chairman of the Transmissions Committee and shall be known as the “Transmission Manager”.

ARTICLE 4

AGENTS RESPONSIBILITIES

4.1 For the purpose of carrying out the provisions of this Agreement the Members hereby delegate to Agent, and Agent hereby accepts, the responsibility of administration of this Agreement, and in furtherance thereof Agent hereby agrees:

4.11 To arrange for and conduct such meetings of the Transmission Committee as may be required to insure the effective and efficient carrying out of all matters of procedure essential to the complete performance of the provisions of this Agreement.

4.12 To ~~render to each Member as promptly as possible after the end of each calendar month a statement setting forth the settlements hereunder for such preceding calendar month, in such detail and with such segregations as may be needed for accounting, operating, or other proper purposes. 4.13 To~~ carry out ~~cash~~ settlements under this Agreement. Settlements by the Members shall be made for each calendar month through ~~an account~~ General Ledger accounts (hereby designated and hereinafter called the "TRANSMISSION ~~ACCOUNT~~ACCOUNTS") to be administered by Agent. ~~Payments to or from such account shall be~~ For the purposes of This Agreement, Transmission Accounts shall be consistent with the accounts listed in the FERC Uniform System of Accounts, and shall include such accounts and sub-accounts as are necessary and proper, directed by the Transmission Committee, and consistent with applicable regulatory requirements.

~~made to or by Agent as clearing agent of the account. The total amount of the payments made by members to the TRANSMISSION ACCOUNT for a particular month shall be equal to the total amount of the payments made to the Members from the TRANSMISSION ACCOUNT for such month.~~

ARTICLE 5

~~DEFINITIONS OF FACTORS ASSOCIATED WITH SETTLEMENTS~~

~~5.1 Factors associated with settlements under this Agreement are defined as follows:~~

~~5.2 MEMBER LOAD OBLIGATION – A Member's internal electric load plus any firm power sales by the Member to affiliated and non-affiliated companies other than Members, Which firm power sales by the member are principally characterized by the Member's assuming the load obligation as its own firm power commitment and by the Member's retaining the advantages accruing from meeting the load.~~

~~5.3 MEMBER DEMAND – A Member's MEMBER LOAD OBLIGATION determined on a clock-hour integrated kilowatt basis.~~

~~5.4 MEMBER MAXIMUM DEMAND – The MEMBER MAXIMUM DEMAND in effect for a calendar month for a particular Member shall be equal to the maximum MEMBER DEMAND experienced by such Member during the twelve consecutive calendar months next preceding such calendar month.~~

~~5.5 MEMBER LOAD RATIO – The ratio of a particular member's MEMBER MAXIMUM DEMAND in effect for a calendar month to the sum of the MEMBER MAXIMUM DEMANDS of all the members in effect for such month.~~

~~5.6 MEMBER BULK TRANSMISSION INVESTMENT – The aggregate dollar investment of a particular Member in its Bulk Power Transmission System, as described in Article I, less the Investment Tax Credit generated by such investment.~~

~~Pursuant to the Order of the Federal Energy Regulatory Commission issued November 3, 1989 in Docket No. ER84-348-012, the Investment Tax Credit used in the determination of MEMBER BULK TRANSMISSION INVESTMENT amounts shall be the result of multiplying the investment tax credit generated by such Member's investment by the following respective factors:~~

~~i) Appalachian Company – 0.79127~~
~~ii) Columbus Company · 0.80245~~
~~iii) Indiana Company · 0.79220~~
~~iv) Kentucky Company · 0.79211~~
~~v) Ohio Company · 0.78515~~

~~5.7 SYSTEM BULK TRANSMISSION INVESTMENT – The sum of the MEMBER BULK TRANSMISSION INVESTMENTS of all the Members.~~

~~5.8 MEMBER BULK TRANSMISSION OBLIGATION – The SYSTEM BULK TRANSMISSION INVESTMENT multiplied by the MEMBER LOAD RATIO of a particular Member.~~

~~5.9 MEMBER BULK TRANSMISSION SURPLUS The difference between the MEMBER BULK TRANSMISSION INVESTMENT and MEMBER BULK TRANSMISSION~~

~~OBLIGATION of a particular Member, when such MEMBER BULK TRANSMISSION INVESTMENTS exceeds such MEMBER BULK TRANSMISSION OBLIGATION.~~

~~5.10 MEMBER BULK TRANSMISSION DEFICIT – The difference between the MEMBER BULK TRANSMISSION OBLIGATION and MEMBER BULK TRANSMISSION INVESTMENT of a particular Member, when such MEMBER BULK TRANSMISSION INVESTMENT is less than such MEMBER BULK TRANSMISSION OBLIGATION.~~

~~ARTICLE 6~~

SETTLEMENTS

~~6.1~~ 5.1 As provided in this Article~~ 8 below~~, following the end of each month, the ~~members~~Members shall ~~carry out cash~~effect settlements through the TRANSMISSION ~~ACCOUNT.~~ACCOUNTS. Generally, Settlements hereunder will involve the allocation of transmission-related costs and revenues among the Members, and the recording of same in the Transmission Accounts of the Members, as specified in Appendix I.

~~6.2 BULK TRANSMISSION EQUALIZATION RECEIPT – Each Member having a MEMBER BULK TRANSMISSION SURPLUS (MBTS) shall receive a BULK TRANSMISSION EQUALIZATION RECEIPT (BTER), each month, in dollars from the TRANSMISSION ACCOUNT determined by the following formula:~~

~~BTER = MBTS X MCC~~

~~Where:~~

~~MCC = The particular Member's monthly carrying charge factor as listed below:~~

~~i)~~	~~Appalachian Company~~	~~=~~	~~1.4933%~~
~~ii)~~	~~Columbus Company~~	~~=~~	~~1.5733%~~
~~iii)~~	~~Indiana Company~~	~~=~~	~~1.5000%~~
~~iv)~~	~~Kentucky Company~~	~~=~~	~~1.4950%~~
~~v)~~	~~Ohio Company~~	~~=~~	~~1.4508%~~

~~6.3 BULK TRANSMISSION EQUALIZATION PAYMENT – Each Member having a MEMBER BULK TRANSMISSION DEFICIT (MBTD) shall make a BULK TRANSMISSION EQUALIZATION PAYMENT (BTEP), each month, in dollars to the TRANSMISSION ACCOUNT determined by the following formula:~~

~~BTEP = SBTER X MBTD/SMBTD~~

~~Where:~~

~~SBTER = The sum of all Members' BTERs~~

~~SMBTD = The sum of all Members' MBTDs~~

5.2 All amounts to be allocated among the Members hereunder shall, to the extent practicable, be included in Settlements for the month in which such cost or revenue is realized or accrued. If necessary in order to implement such timely Settlement, the Agent shall be authorized to effect Settlements on an estimated basis and make such adjustment as is needed in subsequent Settlements that will conform the Settlements to the terms of this Agreement.

~~ARTICLE 7~~
ARTICLE 6

TAXES

~~7.1~~ 6.1 If at any time during the duration of this Agreement there should be levied and/or assessed by any governmental authority against any Member ~~having an MBTS~~ any tax related to the receipt of ~~settlements~~Settlements calculated pursuant to ~~Article 6 of this Agreement~~ this Agreement (such as sales, excise or similar taxes ~~not included in such Member's MCC~~), such tax expense incurred by such Member that would not have been incurred were the ~~transmission settlements~~Settlements hereunder not being made, such Member shall be entitled ~~to reimbursement~~, to the extent permitted by the applicable regulatory authority(ies) to include such tax in its transmission revenue requirement under the PJM or successor OATT when transmission revenue requirements of the Members are next updated, and thereby receive an appropriate level of reimbursement (through cost sharing) for such additional taxes by Members ~~having an MBTD, i.e.,, in calculating the monthly settlements hereunder, such Member having an MBTS shall receive an amount in dollars equal to the sum of (a) the amount of settlement calculated pursuant to Article 6 of this Agreement plus (b) an amount sufficient to reimburse such Member for the amount of such additional taxes which it has incurred. Each Member having an MBTD shall pay such reimbursement in (b) above in dollars as determined~~

~~by the formula in Section 6.3 of this Agreement.~~and others receiving service from the Transmission System.

ARTICLE 7

Allocation Principles

7.1 All items of cost and revenue included in Settlements hereunder shall be related to the provision of or receipt of transmission service or a related ("ancillary") service by one or more Members on behalf of one or more of the Members. The allocation methods used to share such costs and revenues, as specified in Appendix I, shall be made pursuant to direction by the Transmission Committee.

7.2 The Transmission Committee may at any time during the Term of This Agreement, upon the recommendation of the Agent or any Member, review any item of cost or revenue, in order to determine whether such item is transmission-related, and whether it should be included in Settlements hereunder. Further, whenever the Transmission Committee determines that any change is needed in Appendix I to add or delete any item of cost or revenue, or to change the allocation or accounting basis of any item, the Transmission Committee shall authorize and direct the Agent when and how to effect such change in Appendix I and in monthly Settlements among the Members.

7.3 Allocations of costs shall, to the extent practicable, be based on measurable cost indicators that will effect a sharing of costs among the Members consistent with the use of such service, and will be sufficiently stable, over time, so as not to cause undue or objectionable variability in the costs of the Members.

7.4 Allocations of revenues shall, to the extent practicable, be based on measurable indicators of the cost incurred by each Member in providing the service that gave rise to the revenue

ARTICLE 8

~~BILLINGS AND PAYMENT~~

~~8.1 All bills for amounts owing hereunder shall be due and payable on the fifteenth day of the month next following the month or other period to which such bills are applicable, or on the tenth day following receipt of the bill, whichever date is later. Interest on unpaid amounts shall accrue daily at the prime interest rate per annum in effect on the due date at the Citibank, plus 2% per annum, from the due date until the date upon which payment is made. Unless otherwise agreed upon the calendar month shall be the standard period for the purpose of settlements under this Agreement. If bills cannot be accurately determined at any time, they shall be rendered on an estimated basis and subsequently adjusted to conform to the terms of this Agreement.~~

~~ARTICLE 9~~

MODIFICATION

~~9.1~~ 8.1 Any Member, or the Agent, by written notice given to the other Members and Agent, may call for a reconsideration of the terms and conditions herein provided. If such reconsideration is called for, the Members shall take into account any changed conditions, any results from the application of said terms and conditions, and any other facts that might cause said terms and conditions to result in an inequitable sharing of costs and benefits under this Agreement. Any modification in terms and conditions agreed to by the Members following such reconsideration shall become effective the first day of the month following authorization of such reconsideration by appropriate regulatory authority.

ARTICLE ~~10~~9

EFFECTIVE DATE AND TERM OF THIS AGREEMENT

~~10.1~~ 9.1 This Agreement shall become effective and shall become a binding obligation of the Parties on the date ~~on which the last of the following events shall have occurred (Effective Date):~~

~~(a) June 1, 1984; (b) This~~specified in an Order in such proceeding as this Agreement shall have been filed with, and accepted for filing by the Federal Energy Regulatory Commission (FERC) under the Federal Power Act as ~~a rate schedule, under~~

~~circumstances where the FERC (i) shall not have suspended this Agreement or any part thereof, or (ii) if suspended, at the end of the suspension period~~a rate schedule.

~~10.2~~ 9.2 This Agreement shall continue in effect for an initial period from the Effective Date to December 31, 1990, and thereafter for successive periods of one year each until terminated as provided under subsection 10.3 below.

~~10.3~~ 9.3 Any Member upon at least three years' prior written notice to the other Members and Agent may terminate this Agreement at the expiration of said initial period or at the expiration of any successive period of one year.

ARTICLE ~~11~~10

~~TERMINATION OF SPECIAL FACILITIES AGREEMENT~~

~~11.1 The Members agree that the Special Facilities Agreement, dated April 24, 1958, and all supplements and amendments thereto shall terminate as of the Effective Date of this Transmission Agreement and that all further obligations among them in respect thereof shall cease and terminate as of such date, except in respect of any payments or liabilities incurred in respect thereof prior to such termination date.~~

~~ARTICLE 12~~

REGULATORY AUTHORITIES

~~12.1~~ 10.1 The Members recognize that this Agreement, and any tariff or rate schedule which shall embody or supersede this Agreement or any part thereof, are in certain respects subject to the jurisdiction of the FERC under the Federal Power Act, and are also subject to such lawful action as any regulatory authority having jurisdiction shall hereafter take with respect thereto. The performance of any obligation of the Members shall be subject to the receipt from time to time as required of such authorizations, approvals or actions of regulatory authorities having jurisdiction as shall be required by law.

~~12.2~~ 10.2 It is expressly understood that any Member under this Agreement, as it may hereafter from time to time be modified and supplemented by the Members, shall be entitled, at any time and from time to time, unilaterally to make application to the FERC for a change in rates, charges, classification of service, or any rule, regulation or contract relating thereto, or to make any change in or supersede in whole or in part any provision of this Agreement, under Section 205 of the Federal Power Act and pursuant to the FERC’s Rules and Regulations promulgated thereunder.

ARTICLE ~~13~~11

ASSIGNMENT

~~13.1~~11.1 This Agreement shall inure to the benefit of and be binding upon the successors and assigns of the respective parties.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed in their respective corporate names and on their behalf by their proper officers thereunto daily authorized as of the day and year first above written.

Next Page is Signature Page

Transmission Agreement Among:

AMERICAN ELECTRIC POWER SERVICE CORPORATION,

By:________________________

Michael Heyeck
Senior Vice President

APPALACHIAN POWER COMPANY,

By:________________________

Dana E. Waldo
President and Chief Operating Officer

COLUMBUS SOUTHERN POWER COMPANY,

By:________________________

Joseph Hamrock
President and Chief Operating Officer

INDIANA MICHIGAN POWER COMPANY,

By:________________________

Helen J. Murray
President and Chief Operating Officer

KENTUCKY POWER COMPANY,

By:________________________

Timothy C. Mosher
President and Chief Operating Officer

KINGSPORT POWER COMPANY,

By:________________________

Dana E. Waldo
President and Chief Operating Officer

OHIO POWER COMPANY, and

By:________________________

Brian X. Tierney
Vice President

WHEELING POWER COMPANY

By:________________________

Dana E. Waldo
President

Dated as of: ________________________

Appendix I

#	Item	FERC Account*	PJM Billing Determinant	Allocation	Comment
	AEP as Transmission Owner (Revenues)				
1	Transmission Owner Scheduling, System Control and	456.1	NSPL	ARR S1A	From AEP Affiliates
2	Dispatch Service (PJM Schedule 1A)	456.1	NSPL	ARR S1A	From Non-affiliates
3	NITS (AEP LSE)	456.1	NSPL	ATRR	
4	NITS (Non-Affiliates)	456.1	NSPL	ATRR	
5	Grandfathered PTP (CPL & NCEMC)	456.0	Contract	ATRR	
6	PJM Expansion Cost Recovery Charge (PJM ECRC)	456.1	NSPL	ARR EC	
7	RTO Startup Cost Recovery Charge (RTO SCRC)	456.1	NSPL	ARR SC	
	AEP as LSE (Expenses)				
8	Transmission Owner Scheduling, System Control and Dispatch Service (PJM Schedule 1A)	456.1	MWh	MWh	From service to AEP Affiliates
9	NITS Charges (for AEP Retail Load)	456.1	NSPL	12CP	
10	NITS Charges for AEP FR Customers	447.0	NSPL	DA	
11	NITS Reimbursement from AEP FR Customers	447.0	NSPL	DA	
12	Schedule 1A Charge for AEP FR Customers	447.0	NSPL	DA	
13	Schedule 1A Reimbursement from AEP FR Customers	447.0	NSPL	DA	
14	Firm Point-to-Point Credits (for AEP Retail Load)	456.1	NSPL	12CP	
15	Non-Firm Point-to-Point Credits (AEP Retail Load)	456.1	NSPL	12CP	
16	Transmission Enhancement (Sched. 12)	565.0	NSPL	12CP	
17	PJM Expansion Cost Recovery Charge (PJM ECRC)	456.1	NSPL	12CP	
18	RTO Startup Cost Recovery Charge (RTO SCRC)	456.1	NSPL	12CP	

* **Note:** Should the net amount in 456.1 for any Member be negative, e.g. more expense than revenue, the net expense will be recorded in 565.0.

NSPL PJM Network Service Peak Load
Contract Pre-OATT FERC Rate Schedules

ARR S1A Annual Revenue Requirement - Schedule 1A
ATRR Annual Transmission Revenue Requirement
ARR EC Annual Revenue Requirement - Expansion Cost Recovery
ARR SC Annual Revenue Requirement - Startup Cost Recovery
12CP Average of 12 coincident peaks through 10/31 of prior year
DA Directly Assigned to Operating Company

AEP East Companies' Transmission Cost of Service and Comparison of Retail Transmission Rates
Present and Proposed

Transmission Cost of Service and Retail Cost Recovery and Rates

		APCo	CSP	I&M	KgPCo	KPCo	OPCo	WPCo	TOTAL
1	Transmission Cost of Service	$191,200,964	$79,810,462	$120,368,570	$2,671,422	$52,270,060	$149,496,020	$1,698,429	$597,515,927
2	Schedule 1A	$3,517,597	$859,827	$1,235,106	$42,164	$763,784	$3,386,085	$42,983	$9,847,546
3	Expansion Cost Amortization	$715,319	$296,081	$568,434	$0	$173,000	$838,546	$0	$2,591,381
4	Startup Cost Amortization	$652,052	$269,894	$518,158	$0	$157,699	$764,381	$0	$2,362,185
5	PJM Schedule 12	$0	$0	$0	$0	$0	$223,864	$0	$223,864
6	Total Cost of Service	$196,085,932	$81,236,265	$122,690,268	$2,713,586	$53,364,544	$154,708,896	$1,741,412	$612,540,902
7	Net Credits or Charges From 3rd Party and Affiliates	($68,228,980)	$40,985,193	($63,567,440)	$10,988,238	($14,346,666)	($11,165,025)	$8,773,129	($96,561,551)
8	**Present Residual T-COS**	**$127,856,953**	**$122,221,458**	**$59,122,827**	**$13,701,824**	**$39,017,877**	**$143,543,871**	**$10,514,541**	**$515,979,351**
9	**12-Mo. Avg. Coincident Load (MW)**	**5,763**	**3,498**	**3,098**	**349**	**1,244**	**4,325**	**277**	**18,553**
10	**Residual $/kW-Month**	**$1.85**	**$2.91**	**$1.59**	**$3.27**	**$2.61**	**$2.77**	**$3.17**	**$2.32**
11	**Retail Collection Opportunity in Each State Jurisdiction**	**$127,856,953**	**$97,933,137**	**$59,122,827**	**$13,701,824**	**$39,017,877**	**$109,833,075**	**$10,514,541**	**$457,980,235**
12	**Collection Opp. $/kW-Month**	**$1.85**	**$2.33**	**$1.59**	**$3.27**	**$2.61**	**$2.12**	**$3.17**	**$2.06**
13	**Proposed Retail T-COS**	**$160,185,925**	**$97,275,196**	**$86,189,287**	**$9,695,713**	**$34,577,916**	**$120,343,739**	**$7,711,576**	**$515,979,352**
14	**Proposed $/kW-Month**	**$2.32**	**$2.32**	**$2.32**	**$2.32**	**$2.32**	**$2.32**	**$2.32**	**$2.32**

Notes:

1 & 2 The cost of service for each of these services reflects the costs accepted for filing by the FERC, subject to settlement, and if necessary hearings, and refunds.

3 & 4 Annual cost recovery permitted under FERC-approved 10-year and 15-year amortizations, respectively.

5 AEP has included one project, two new 765 kV breakers at Hanging Rock Station, in its PJM Transmission Formula rate effective March 1, 2009. Amount shown is the projected year end 2008 revenue requirement.

7 Values reflect the netting of charges and credits that each AEP Company would presently experience over a full year based on going-level rates, the projected Transmission Agreement settlements, and allocation methods.

9 The 12-Mo. Average Coincident Load is calculated as the average of the monthly PJM NSPL in the AEP Zone for the year ending October 31, 2008. Details are provided in WP AEP-206.2.3, Page 3 of 3.

11 Except in Ohio, the analysis assumes that AEP has the opportunity to recover the Residual T-COS. In Ohio, OPCo's and CSP's MLR share of the PJM OATT is recovered as shown in Exhibit AEP-208, Page 5 of 5.

13 The Proposed Retail T-COS is calculated in Exhibit AEP-210, Page 5 of 5.

AEP Transmission Agreement
Comparison of Variation in MLR, 1 CP and 12 CP Allocation Factors
2005 through 2009

PRESENT MLR

	12 MONTHS AVERAGE MLR					12 MONTHS AVERAGE MLR VARIANCE				MAX	MLR		
	2005 Actual	**2006** Actual	**2007** Actual	**2008** Actual	**2009** Projected	**2006** Actual	**2007** Actual	**2008** Actual	**2009** Projected	**1 Year Deviation**	5 YR MAX	5 YR MIN	RANGE
Appalachian Power	32.178%	29.566%	33.034%	32.760%	32.440%	-8.119%	11.730%	-0.830%	-0.974%	11.730%	33.034%	29.566%	3.468%
Columbus Southern Power	17.412%	18.860%	18.772%	19.125%	19.032%	8.317%	-0.470%	1.881%	-0.484%	8.317%	19.125%	17.412%	1.713%
Indiana & Michigan Power	18.658%	19.546%	19.137%	18.418%	18.487%	4.756%	-2.091%	-3.759%	0.376%	4.756%	19.546%	18.418%	1.128%
Kingsport Power	--	--	--	--	--	--	--	--	--	--	--	--	--
Kentucky Power	7.631%	7.435%	6.895%	6.959%	7.113%	-2.569%	-7.262%	0.924%	2.214%	-7.262%	7.631%	6.895%	0.736%
Ohio Power	24.120%	24.593%	22.163%	22.739%	22.928%	1.961%	-9.884%	2.602%	0.828%	-9.884%	24.593%	22.163%	2.431%
Wheeling Power	--	--	--	--	--	--	--	--	--	--	--	--	--

7 MEMBER MLR

	AVERAGE MODIFIED 7 MEMBER MLR					AVERAGE MODIFIED 7 MEMBER MLR VARIANCE				MAX	MODIFIED MLR		
	2005 Actual	**2006** Actual	**2007** Actual	**2008** Actual	**2009** Projected	**2006** Actual	**2007** Actual	**2008** Actual	**2009** Projected	**1 Year Deviation**	5 YR MAX	5 YR MIN	RANGE
Appalachian Power	30.136%	27.823%	31.302%	30.855%	30.656%	-7.676%	12.507%	-1.430%	-0.645%	12.507%	31.302%	27.823%	3.480%
Columbus Southern Power	17.378%	18.854%	18.764%	19.113%	19.002%	8.498%	-0.477%	1.855%	-0.576%	8.498%	19.113%	17.378%	1.735%
Indiana & Michigan Power	18.621%	19.540%	19.130%	18.406%	18.458%	4.933%	-2.098%	-3.783%	0.284%	4.933%	19.540%	18.406%	1.134%
Kingsport Power	1.994%	1.733%	1.719%	1.898%	1.794%	-13.052%	-0.810%	10.372%	-5.441%	-13.052%	1.994%	1.719%	0.274%
Kentucky Power	7.616%	7.433%	6.892%	6.954%	7.102%	-2.405%	-7.268%	0.900%	2.121%	-7.268%	7.616%	6.892%	0.723%
Ohio Power	22.751%	23.201%	20.846%	21.363%	21.509%	1.979%	-10.152%	2.481%	0.680%	-10.152%	23.201%	20.846%	2.355%
Wheeling Power	1.505%	1.416%	1.346%	1.411%	1.479%	-5.899%	-4.974%	4.864%	4.774%	-5.899%	1.505%	1.346%	0.159%

1CP

	1CP (AEP Zonal Peak)					1CP (AEP Zonal Peak) VARIANCE					1CP		
	2005 2004 NSPL 08/03/04 1700	**2006** 2005 NSPL 07/26/05 1500	**2007** 2006 NSPL 08/02/06 1700	**2008** 2007 NSPL 08/08/07 1400	**2009** 2008 NSPL 01/25/08 0800	**2006** 2005 NSPL 07/26/05 1500	**2007** 2006 NSPL 08/02/06 1700	**2008** 2007 NSPL 08/08/07 1400	**2009** 2008 NSPL 01/25/08 0800	**MAX 1 Year Deviation**	5 YR MAX	5 YR MIN	RANGE
Appalachian Power	29.443%	26.841%	27.485%	28.452%	34.183%	-8.837%	2.398%	3.518%	20.146%	20.146%	34.183%	26.841%	7.342%
Columbus Southern Power	18.332%	19.356%	20.854%	21.630%	17.261%	5.585%	7.739%	3.721%	-20.199%	-20.199%	21.630%	17.261%	4.369%
Indiana & Michigan Power	19.913%	19.423%	19.110%	17.428%	15.592%	-2.458%	-1.612%	-8.800%	-10.537%	-10.537%	19.913%	15.592%	4.321%
Kingsport Power	1.463%	1.564%	1.569%	1.640%	2.191%	6.959%	0.313%	4.528%	33.567%	33.567%	2.191%	1.463%	0.728%
Kentucky Power	5.820%	6.484%	6.419%	6.048%	7.736%	11.413%	-1.007%	-5.783%	27.925%	27.925%	7.736%	5.820%	1.917%
Ohio Power	23.613%	24.863%	23.045%	23.340%	21.588%	5.293%	-7.310%	1.277%	-7.504%	-7.504%	24.863%	21.588%	3.275%
Wheeling Power	1.416%	1.468%	1.518%	1.462%	1.448%	3.650%	3.360%	-3.637%	-0.979%	3.650%	1.518%	1.416%	0.101%

PROPOSED 12CP

	AVERAGE 12CP					AVERAGE 12CP VARIANCE					12CP		
	2005 Avg MonthlyCP 11/03 thru 10/04	**2006** Avg MonthlyCP 11/04 thru 10/05	**2007** Avg MonthlyCP 11/05 thru 10/06	**2008** Avg MonthlyCP 11/06 thru 10/07	**2009** Avg MonthlyCP 11/07 thru 10/08	**2006** Avg MonthlyCP 11/04 thru 10/05	**2007** Avg MonthlyCP 11/05 thru 10/06	**2008** Avg MonthlyCP 11/06 thru 10/07	**2009** Avg MonthlyCP 11/07 thru 10/08	**MAX 1 Year Deviation**	5 YR MAX	5 YR MIN	RANGE
Appalachian Power	28.638%	28.331%	29.800%	30.603%	31.062%	-1.073%	5.184%	2.694%	1.502%	5.184%	31.062%	28.331%	2.731%
Columbus Southern Power	17.355%	17.064%	17.741%	19.253%	18.852%	-1.676%	3.965%	8.521%	-2.080%	8.521%	19.253%	17.064%	2.188%
Indiana & Michigan Power	19.327%	19.400%	19.544%	17.083%	16.696%	0.373%	0.747%	-12.592%	-2.267%	-12.592%	19.544%	16.696%	2.848%
Kingsport Power	1.744%	1.751%	1.737%	1.672%	1.880%	0.407%	-0.848%	-3.744%	12.477%	12.477%	1.880%	1.672%	0.209%
Kentucky Power	6.891%	6.924%	7.022%	6.926%	6.705%	0.472%	1.422%	-1.367%	-3.197%	-3.197%	7.022%	6.705%	0.317%
Ohio Power	24.521%	25.008%	22.608%	23.076%	23.313%	1.986%	-9.599%	2.073%	1.029%	-9.599%	25.008%	22.608%	2.401%
Wheeling Power	1.522%	1.522%	1.549%	1.388%	1.491%	-0.038%	1.769%	-10.405%	7.461%	-10.405%	1.549%	1.388%	0.161%

AEP Transmission Agreement
Summary of Agreement Modification Impacts
Proformed 2008[1] Cost Sharing vs. Proposed 2009[2] Cost Sharing
$(000)

Present Allocation:[3]

Company	1CP Cost Allocation (Exhibit AEP-208): 2008 Total T & LSE Related	1CP: 2009 Total T & LSE Related	1CP: AEP Net Change 2009 - 2008	MLR[5] Cost Allocation (Exhibit AEP-209): 2008 Total T & LSE Related	MLR: 2009 Total T & LSE Related	MLR: AEP Net Change 2009 - 2008	12CP Cost Allocation (Exhibit AEP-210): 2008 Total T & LSE Related	12CP: 2009 Total T & LSE Related	12CP: AEP Net Change 2009 - 2008
Appalachian Power	($68,764)	($68,229)	$536	($68,764)	($68,229)	$535	($68,764)	($68,229)	$536
Columbus Southern Power	$39,209	$40,985	$1,776	$39,209	$40,985	$1,776	$39,209	$40,985	$1,776
Indiana & Michigan Power	($65,596)	($63,567)	$2,029	($65,596)	($63,567)	$2,029	($65,596)	($63,567)	$2,029
Kingsport Power	$9,696	$10,988	$1,292	$9,696	$10,988	$1,292	$9,696	$10,988	$1,292
Kentucky Power	($14,880)	($14,347)	$533	($14,880)	($14,347)	$533	($14,880)	($14,347)	$533
Ohio Power	($11,800)	($11,165)	$635	($11,800)	($11,165)	$635	($11,800)	($11,165)	$635
Wheeling Power	$8,091	$8,773	$682	$8,091	$8,773	$682	$8,091	$8,773	$682
Total	($104,043)	($96,562)	$7,482	($104,043)	($96,562)	$7,482	($104,043)	($96,562)	$7,482

Proposed Allocation:[4]

Company	1CP: 2008 Total T & LSE Related	1CP: 2009 Total T & LSE Related	1CP: AEP Net Change 2009 - 2008	MLR: 2008 Total T & LSE Related	MLR: 2009 Total T & LSE Related	MLR: AEP Net Change 2009 - 2008	12CP: 2008 Total T & LSE Related	12CP: 2009 Total T & LSE Related	12CP: AEP Net Change 2009 - 2008
Appalachian Power	($67,333)	($20,241)	$47,092	($56,807)	($38,199)	$18,608	($57,912)	($36,130)	$21,782
Columbus Southern Power	$34,191	$7,989	($26,202)	$23,164	$16,855	($6,310)	$23,778	$16,090	($7,688)
Indiana & Michigan Power	($33,351)	($41,858)	($8,507)	($29,070)	($27,268)	$1,801	($34,863)	($36,238)	($1,375)
Kingsport Power	$4,998	$8,554	$3,556	$6,125	$6,534	$410	$5,135	$6,971	$1,836
Kentucky Power	($17,499)	($13,551)	$3,949	($13,528)	($16,781)	($3,253)	($13,652)	($18,803)	($5,151)
Ohio Power	($28,520)	($43,193)	($14,673)	($37,177)	($43,599)	($6,421)	($29,675)	($34,411)	($4,736)
Wheeling Power	$3,471	$5,739	$2,267	$3,249	$5,896	$2,647	$3,145	$5,959	$2,814
Total	($104,043)	($96,562)	$7,482	($104,043)	($96,562)	$7,482	($104,043)	($96,562)	$7,482

Net Change From Trans. Agreement Modification:

(Proposed - Present) Company	1CP: 2008 Net T & LSE Related	1CP: 2009 Net T & LSE Related	1CP: AEP Net Change T & LSE 2009 - 2008	MLR: 2008 Net T & LSE Related	MLR: 2009 Net T & LSE Related	MLR: AEP Net Change T & LSE 2009 - 2008	12CP: 2008 Net T & LSE Related	12CP: 2009 Net T & LSE Related	12CP: AEP Net Change T & LSE 2009 - 2008
Appalachian Power	$1,432	$47,988	$46,556	$11,958	$30,030	$18,072	$10,853	$32,099	$21,246
Columbus Southern Power	($5,019)	($32,996)	($27,977)	($16,045)	($24,131)	($8,085)	($15,431)	($24,895)	($9,464)
Indiana & Michigan Power	$32,245	$21,709	($10,536)	$36,527	$36,299	($228)	$30,734	$27,330	($3,404)
Kingsport Power	($4,698)	($2,435)	$2,264	($3,572)	($4,454)	($882)	($4,562)	($4,017)	$545
Kentucky Power	($2,619)	$796	$3,415	$1,353	($2,434)	($3,787)	$1,228	($4,457)	($5,685)
Ohio Power	($16,721)	($32,028)	($15,308)	($25,378)	($32,434)	($7,056)	($17,875)	($23,246)	($5,371)
Wheeling Power	($4,620)	($3,034)	$1,586	($4,843)	($2,877)	$1,966	($4,947)	($2,814)	$2,133
Total	$0	($0)	($0)	$0	$0	$0	$0	($0)	($0)

1. Revenues and Costs with Calendar 2008 Allocations
2. Projected Revenues, Costs and Allocations
3. T-related revenues and costs as presently shared, primarily by 5 Member MLR
4. Three "Proposed" allocation scenarios compared. All share T revenues by annual revenue requirements. T cost sharing varies as labeled.
5. Modified 7 Member MLR in Proposed

AEP Transmission Agreement
Summary of Revenue, Demand, Energy and Other Allocation Factors
Summary of Revenue Requirement Allocation Factors

		Transmission and Related Services Annual Revenue Requirement of Each AEP-East Company and in Total							
	Transmission and Related Services	**AEP-East Total**	**APCo**	**CSP**	**I&M**	**KgPCo**	**KPCo**	**OPCo**	**WPCo**
	AEP Zonal ATRR For PJM OATT (w/o TEA) [1]	$507,227,581	$177,851,214	$58,897,471	$101,432,448	$2,397,126	$40,766,848	$122,759,546	$3,122,928
	Other Operating Revenues (other than T Svc)	($11,071,122)	($1,713,887)	($2,824,184)	($1,460,433)	($285,000)	($155,411)	($4,317,207)	($315,000)
	Net Annual Transmission Rev. Req. w/o GF Rev Cred	$496,156,459	$176,137,327	$56,073,287	$99,972,015	$2,112,126	$40,611,437	$118,442,339	$2,807,928
1	**% ATRR Present**	100.00%	**35.50%**	**11.30%**	**20.15%**	**0.43%**	**8.19%**	**23.87%**	**0.57%**
	AEP Schedule 1A Revenue Requirement[1]	$14,031,886	$4,029,637	$1,551,294	$3,260,004	$71,760	$581,160	$4,473,961	$64,070
2	**% ARR S1 Present**	100.00%	**28.72%**	**11.06%**	**23.23%**	**0.51%**	**4.14%**	**31.88%**	**0.46%**
	AEP Zonal ATRR For PJM OATT (w/o TEA) [2]	$606,660,130	$194,760,242	$80,634,099	$121,604,664	$2,729,719	$52,537,787	$151,527,693	$2,865,926
	Other Operating Revenues (other than T Svc)	($8,920,339)	($3,559,278)	($823,637)	($1,236,094)	($58,297)	($267,727)	($1,807,809)	($1,167,497)
	Net Annual Transmission Rev. Req. w/o GF Rev Cred	$597,739,791	$191,200,964	$79,810,462	$120,368,570	$2,671,422	$52,270,060	$149,719,884	$1,698,429
3	**% ATRR Proposed**	100.00%	**31.99%**	**13.35%**	**20.14%**	**0.45%**	**8.74%**	**25.05%**	**0.28%**
	AEP Schedule 1A Revenue Requirement[2]	$9,847,546	$3,517,597	$859,827	$1,235,106	$42,164	$763,784	$3,386,085	$42,983
4	**% ARR S1 Proposed**	100.00%	**35.72%**	**8.73%**	**12.54%**	**0.43%**	**7.76%**	**34.39%**	**0.44%**
	AEP Expansion Cost[3]	$17,461,244	$4,892,470	$1,954,758	$3,882,938	$0	$1,178,359	$5,552,719	$0
	ECRC Amortization/Year Avg. Est.	$2,591,381	$715,319	$296,081	$568,434	$0	$173,000	$838,546	$0
5	**% ARR ECRC**	100.00%	**27.60%**	**11.43%**	**21.94%**	**0.00%**	**6.68%**	**32.36%**	**0.00%**
	Startup Cost Recovery Charge[3]	$17,522,217	$4,980,238	$2,139,051	$3,697,098	$0	$1,086,074	$5,619,756	$0
	SCRC Amortization/Year Avg. Est.	$2,362,185	$671,390	$288,367	$498,409	$0	$146,415	$757,604	$0
6	**% ARR SCRC**	100.00%	**28.42%**	**12.21%**	**21.10%**	**0.00%**	**6.20%**	**32.07%**	**0.00%**
7	**Total Pole Miles (TPM)**	100.00%	**28.01%**	**11.19%**	**22.25%**	**0.00%**	**6.75%**	**31.80%**	**0.00%**

1 As approved in Docket No. ER05-751, including Wyoming-Jacksons Ferry
2 As proposed in Docket No. ER08-1329, effective 3/1/09 subject to further determination.
3 Total Deferred PJM Expansion and RTO Start Up costs as of 1/1/05, prior to beginning amortization

AEP Transmission Agreement
Summary of Revenue, Demand, Energy and Other Allocation Factors
AEP NSPL[1] (1CP), 12CP, and MLR[2] Demand Allocation Factors
For 2008 and 2009

Company (1)	2008 Demand Factors: AEP Zone 1CP % (2)	AEP Zone 12CP % (3)	Average MLR % (4)	Average 7 Mbr MLR % (5)	2009 Demand Factors: AEP Zone 1CP % (6)	AEP Zone 12CP % (7)	Average MLR % (8)	Average 7 Mbr MLR % (9)
Appalachian Power	28.452%	30.603%	32.760%	30.855%	34.183%	31.062%	32.440%	30.656%
Columbus Southern Power	21.630%	19.253%	19.125%	19.113%	17.261%	18.852%	19.032%	19.002%
Indiana & Michigan Power	17.428%	17.083%	18.418%	18.406%	15.592%	16.696%	18.487%	18.458%
Kingsport Power	1.640%	1.672%	0.000%	1.898%	2.191%	1.880%	0.000%	1.794%
Kentucky Power	6.048%	6.926%	6.959%	6.954%	7.736%	6.705%	7.113%	7.102%
Ohio Power	23.340%	23.076%	22.739%	21.363%	21.588%	23.313%	22.928%	21.509%
Wheeling Power	1.462%	1.388%	0.000%	1.411%	1.448%	1.491%	0.000%	1.479%
Total	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%

1 NSPL = Network Service Peak Load, per PJM OATT
2 MLR = Member Load Ratio, per Existing Agreement (4 and 8), and Modified for 7 Members (5 and 9)

AEP Transmission Agreement
Summary of Revenue, Demand, Energy and Other Allocation Factors
Energy Allocation Factors (MWh%)
2008 Actual and Projected 2009

Actual	**APCo**	**CSP**	**I&M**	**KGP**	**KPCO**	**OPCO**	**WPCO**	**TOTAL**
AEP LSE MWH	37,132,091	23,454,972	21,427,297	2,286,344	7,815,097	31,188,241	2,221,448	**125,525,490**
AEP LSE %	29.58%	18.69%	17.07%	1.82%	6.23%	24.85%	1.77%	**100.00%**
AEP Formula Rt. Cust.	1,271,249	506,488	4,020,711		100,098			**5,898,546**
Formula Rt. %	21.55%	8.59%	68.16%		1.70%			**100.00%**
Other LSE								**12,498,836**
								143,922,872

Actual costs from transmission settlement statements	**$12,105,495**		
Schedule 1A Rate $ / MWH from filing	$0.0686	LSE	$8,613,559
Total Schedule 1A Charge (Total MWH * Rate)	$9,875,987	Formula	$404,758
Out and Through (Actual Total - Calculated Total)	$2,229,507	Other LSE	$857,670

Projected	**APCo**	**CSP**	**I&M**	**KGP**	**KPCO**	**OPCO**	**WPCO**	**TOTAL**	**% of Total**
AEP LSE MWH	38,075,628	24,120,383	22,095,126	2,300,259	8,271,268	30,747,842	2,225,337	**127,835,844**	**87.16%**
AEP LSE %	29.78%	18.87%	17.28%	1.80%	6.47%	24.05%	1.74%	**100.00%**	
AEP Formula Rt. Cust.	1,345,006	532,509	4,228,333		103,718			**6,209,565**	**4.23%**
Formula Rt. %	21.66%	8.58%	68.09%		1.67%			**100.00%**	
Other LSE								**12,623,824**	**8.61%**
								146,669,233	**100.00%**

		Allocation of ARR based on % of Total	
Existing Schedule 1A Zonal ARR [1]	**$7,942,546**	LSE	**$6,922,666**
		Formula	**$336,265**
		Other LSE	$683,615
		Point to Point Service Credit [1]	$1,905,000
		Other LSE TOTAL	**$2,588,615**

1 As proposed in Docket No. ER08-1329, effective 3/1/09 subject to further determination.

AEP Transmission Agreement
Summary of Revenue, Demand, Energy and Other Allocation Factors

A.

GFA and Other Operating Revenue

	Transmission and Related Services	AEP-East Total	APCo	CSP	I&M	KgPCo	KPCo	OPCo	WPCo
	AEP Zonal ATRR For PJM OATT	$606,660,130	$169,811,081	$132,533,491	$87,006,625	$2,729,719	$51,721,957	$159,991,331	$2,865,926
	Other Operating Revenues (other than T Svc)	($8,920,339)	($3,559,278)	($823,637)	($1,236,094)	($58,297)	($267,727)	($1,807,809)	($1,167,497)
	Net Annual Transmission Rev. Req.	$597,739,791	$166,251,803	$131,709,854	$85,770,531	$2,671,422	$51,454,230	$158,183,522	$1,698,429
1	Account 450, Forfeited Discounts	-	-	-	-	-	-	-	-
2	Account 451,Miscellaneous Service Revenues	616,998	418,201	123,327	56,787	-	13,556	5,127	-
3	Account 454, Rent from Electric Property	4,429,200	1,561,493	574,955	418,178	36,417	11,638	1,778,742	47,777
4	Account 4560015, Associated Business Developm	2,683,705	1,579,584	125,355	761,129	21,880	171,817	23,940	-
5	Account 456 - Other Electric Revenues	1,190,436	-				70,716	-	1,119,720
7	Total Other Operating Revenues To Reduce Revei	8,920,339	3,559,278	823,637	1,236,094	58,297	267,727	1,807,809	1,167,497
6	Accounts 4470004 & 5, Revenues from Grandfath	10,751,403	3,536,055	2,017,366	2,056,747	-	758,527	2,382,708	-

B.

Direct Assignment: Formula Rate Power Sales and Schedule 1A Allocations

Using the 2008 NSPL information to be billed in 2009, the LSE, Formula, and 3rd Party allocation percentages based on respective load are multiplied by the EXISTING ZONAL ATRR FOR PJM OATT in Docket No. ER08-1329.

	MW TOTAL	Allocation for NTS	ATRR x $24,239.56
NTS AEP LSE (b2, h1)	20,994.20	86.73%	$508,890,100
NTS Formula (b3)	944.00	3.90%	$22,882,141
3rd Party NTS (b1)	2,268.70	9.37%	$54,992,282
TOTAL	**24,206.90**	**$586,764,524**	

DA Formula Allocations for:
Sched 1A Formula (a3)
NTS AEP Formula (b3)

Formula Total	I&M	APCo	KPCo	CSP
944.00	600.70	236.80	23.80	82.70
ALLOCATIONS	**63.63%**	**25.08%**	**2.52%**	**8.76%**

AEP Transmission Agreement
Summary of Revenue, Demand, Energy and Other Allocation Factors
Power Purchase Agreement (PPA) Settlements
Actual 2008 and Projected 2009

A. Intra-Company Payments Made by Wheeling Power Co. to Ohio Power Co.

2008			
Month	Year	Trans Revenue from Monthly Invoice	WPCo Load at OPCo Peak (MW)
NOV	2007	$637,711	264
DEC	2007	$675,427	285
JAN	2008	$695,866	280
FEB	2008	$696,920	325
MAR	2008	$673,185	263
APR	2008	$625,377	296
MAY	2008	$595,584	265
JUN	2008	$732,694	336
JUL	2008	$724,797	297
AUG	2008	$708,376	313
SEP	2008	$703,151	293
OCT	2008	$622,367	297
2008 TOTAL		**$8,091,454**	3515
		$ / MW	**$2,301.87**

2009			
Month	Year	Projected WPCo Load (MW)	Projected Revenue to OPCo
JAN	2009	326	$751,429
FEB	2009	328	$755,291
MAR	2009	289	$665,154
APR	2009	296	$682,046
MAY	2009	335	$771,370
JUN	2009	368	$846,100
JUL	2009	310	$712,497
AUG	2009	332	$763,458
SEP	2009	347	$799,796
OCT	2009	269	$618,311
NOV	2009	317	$730,099
DEC	2009	294	$677,578
		2009 TOTAL	**$8,773,129**

B. Intra-Company Payments Made by Kingsport Power Co. to Appalachian

Month	Year	Kingsport On Peak Demand (kW)	Trans Revenue at Rate of $2.272 / kW
NOV	2007	337,551	$766,916
DEC	2007	404,085	$918,081
JAN	2008	460,885	$1,047,131
FEB	2008	402,357	$914,155
MAR	2008	360,129	$818,213
APR	2008	318,217	$722,989
MAY	2008	281,020	$638,477
JUN	2008	353,263	$802,614
JUL	2008	338,259	$768,524
AUG	2008	343,173	$779,689
SEP	2008	338,481	$769,029
OCT	2008	330,360	$750,578
		2008 TOTAL	**$9,696,396**

2009 Intra-Company Payments by KgPCo for Trans. Service Pursuant to Purchase Power Agreement	
KgPCo 2009 1CP Share (%)	2.19%
KgPCo MWH Share (Projected)	2.14%
KgPCo 2009 1CP Load (MW)	460

Total Third Party PTP Firm Credit	($12,164,722)
Total Third Party PTP Non-Firm Credit	($5,414,573)
ECRC Charge	$1,315,000
SCRC Charge	$2,111,000
NTS AEP LSE	$508,890,100
Total	$494,736,805
x KgPCo 1CP Share	**$10,839,955**

Schedule 1A AEP LSE Charge	$6,922,666
x KgPCo MWH Share	**$148,283**
2009 TOTAL ($000)	**$10,988**

AEP Transmission Agreement
Settlements Under the Present AEP Transmission Agreement
Summary of 2008 and Projected 2009 Statements of AEP System Transmission Account

2008	Surplus Members				Deficit Members		
	Credit				Debit		
Month	APCo	KPCo	I&M	**TOTAL**	OPCo	CSP	**TOTAL**
JAN	$1,811,347	$761,589	$3,069,473	**$5,642,409**	$964,554	$4,677,855	**$5,642,409**
FEB	$1,819,698	$737,490	$3,074,407	**$5,631,595**	$958,647	$4,672,948	**$5,631,595**
MAR	$2,204,357	$698,144	$2,967,818	**$5,870,319**	$1,087,481	$4,782,838	**$5,870,319**
APR	$2,204,357	$698,144	$2,967,818	**$5,870,319**	$1,087,481	$4,782,838	**$5,870,319**
MAY	$2,204,357	$698,144	$2,967,818	**$5,870,319**	$1,087,481	$4,782,838	**$5,870,319**
JUN	$2,466,789	$671,278	$2,895,077	**$6,033,144**	$1,175,349	$4,857,795	**$6,033,144**
JUL	$2,674,589	$649,993	$2,837,486	**$6,162,068**	$1,244,919	$4,917,149	**$6,162,068**
AUG	$2,615,930	$818,960	$2,803,489	**$6,238,379**	$1,286,026	$4,952,353	**$6,238,379**
SEP	$2,202,907	$730,354	$3,124,440	**$6,057,701**	$1,505,940	$4,551,761	**$6,057,701**
OCT	$2,202,907	$730,354	$3,124,440	**$6,057,701**	$1,505,940	$4,551,761	**$6,057,701**
NOV	$2,202,907	$730,354	$3,124,440	**$6,057,701**	$1,505,940	$4,551,761	**$6,057,701**
DEC	$2,202,907	$730,354	$3,124,440	**$6,057,701**	$1,505,940	$4,551,761	**$6,057,701**
TOTAL	**$26,813,052**	**$8,655,158**	**$36,081,146**	**$71,549,356**	**$14,915,698**	**$56,633,658**	**$71,549,356**

2009	Surplus Members				Deficit Members		
	Credit				Debit		
Month	APCo	KPCo	I&M	**TOTAL**	OPCo	CSP	**TOTAL**
JAN	$1,929,991	$722,443	$3,167,385	**$5,819,819**	$1,288,970	$4,530,849	**$5,819,819**
FEB	$2,169,077	$673,598	$3,109,693	**$5,952,368**	$1,362,525	$4,589,843	**$5,952,368**
MAR	$2,169,077	$673,598	$3,109,693	**$5,952,368**	$1,362,525	$4,589,843	**$5,952,368**
APR	$2,169,077	$673,598	$3,109,693	**$5,952,368**	$1,362,525	$4,589,843	**$5,952,368**
MAY	$2,169,077	$673,598	$3,109,693	**$5,952,368**	$1,362,525	$4,589,843	**$5,952,368**
JUN	$2,169,077	$673,598	$3,109,693	**$5,952,368**	$1,362,525	$4,589,843	**$5,952,368**
JUL	$2,096,666	$657,667	$3,012,123	**$5,766,456**	$1,062,515	$4,703,941	**$5,766,456**
AUG	$2,513,783	$749,439	$2,655,434	**$5,918,656**	$951,978	$4,966,678	**$5,918,656**
SEP	$2,579,265	$763,846	$2,694,481	**$6,037,592**	$1,110,862	$4,926,730	**$6,037,592**
OCT	$2,579,265	$763,846	$2,694,481	**$6,037,592**	$1,110,862	$4,926,730	**$6,037,592**
NOV	$2,579,265	$763,846	$2,694,481	**$6,037,592**	$1,110,862	$4,926,730	**$6,037,592**
DEC	$2,579,265	$763,846	$2,694,481	**$6,037,592**	$1,110,862	$4,926,730	**$6,037,592**
TOTAL	**$27,702,885**	**$8,552,923**	**$35,161,331**	**$71,417,139**	**$14,559,536**	**$56,857,603**	**$71,417,139**

AEP Transmission Agreement
Cost Impact Comparison of Present and Revised Allocations - 1CP
Proformed 2008 Cost Sharing vs. Proposed 2009 Cost Sharing
$(000)

Present Allocation:

	2008 Revenues and Costs with Calendar 2008 Allocations			2009 Projected Revenues, Costs and Allocations			Change 2008 vs. 2009 Proformed 2008 vs. Projected 2009		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Company	Total T-Related	Total LSE-Related	Total T & LSE Related	Total T-Related	Total LSE-Related	Total T & LSE Related	(d)-(a) T-Related	(e)-(b) LSE-Related	(g)+(h) AEP Net
Appalachian Power	($205,218)	$136,454	($68,764)	($224,474)	$156,245	($68,229)	($19,256)	$19,792	$536
Columbus Southern Power	($45,932)	$85,142	$39,209	($56,948)	$97,933	$40,985	($11,016)	$12,792	$1,776
Indiana & Michigan Power	($147,990)	$82,393	($65,596)	($159,085)	$95,518	($63,567)	($11,096)	$13,125	$2,029
Kingsport Power	$0	$9,696	$9,696	$0	$10,988	$10,988	$0	$1,292	$1,292
Kentucky Power	($45,953)	$31,073	($14,880)	($51,035)	$36,688	($14,347)	($5,082)	$5,615	$533
Ohio Power	($105,586)	$93,786	($11,800)	($120,998)	$109,833	($11,165)	($15,412)	$16,047	$635
Wheeling Power	$0	$8,091	$8,091	$0	$8,773	$8,773	$0	$682	$682
Total	($550,679)	$446,635	($104,043)	($612,541)	$515,979	($96,562)	($61,862)	$69,344	$7,482

1CP Allocation:

Company	Total T-Related	Total LSE-Related	Total T & LSE Related	Total T-Related	Total LSE-Related	Total T & LSE Related	Total T-Related	Total LSE-Related	Total T & LSE Related
Appalachian Power	($194,505)	$127,172	($67,333)	($196,316)	$176,075	($20,241)	($1,810)	$48,902	$47,092
Columbus Southern Power	($62,162)	$96,353	$34,191	($81,185)	$89,174	$7,989	($19,023)	($7,179)	($26,202)
Indiana & Michigan Power	($111,162)	$77,811	($33,351)	($122,427)	$80,569	($41,858)	($11,265)	$2,758	($8,507)
Kingsport Power	($2,344)	$7,342	$4,998	($2,725)	$11,278	$8,554	($380)	$3,936	$3,556
Kentucky Power	($44,525)	$27,026	($17,499)	($53,381)	$39,831	($13,551)	($8,856)	$12,805	$3,949
Ohio Power	($132,893)	$104,373	($28,520)	($154,755)	$111,561	($43,193)	($21,861)	$7,189	($14,673)
Wheeling Power	($3,086)	$6,558	$3,471	($1,753)	$7,492	$5,739	$1,333	$934	$2,267
Total	($550,679)	$446,635	($104,043)	($612,541)	$515,979	($96,562)	($61,862)	$69,344	$7,482

Net Change From Trans. Agreement Modification:

(Proposed - Present) Company	Net T-Related	Net LSE-Related	Net T & LSE Related	Net T-Related	Net LSE-Related	Net T & LSE Related	Net T-Related	Net LSE-Related	Net T & LSE Related
Appalachian Power	$10,713	($9,281)	$1,432	$28,159	$19,829	$47,988	$17,446	$29,111	$46,556
Columbus Southern Power	($16,230)	$11,212	($5,019)	($24,237)	($8,759)	($32,996)	($8,007)	($19,971)	($27,977)
Indiana & Michigan Power	$36,828	($4,582)	$32,245	$36,658	($14,949)	$21,709	($169)	($10,367)	($10,536)
Kingsport Power	($2,344)	($2,354)	($4,698)	($2,725)	$290	($2,435)	($380)	$2,644	$2,264
Kentucky Power	$1,428	($4,047)	($2,619)	($2,346)	$3,142	$796	($3,774)	$7,189	$3,415
Ohio Power	($27,307)	$10,587	($16,721)	($33,757)	$1,728	($32,028)	($6,449)	($8,859)	($15,308)
Wheeling Power	($3,086)	($1,534)	($4,620)	($1,753)	($1,281)	($3,034)	$1,333	$252	$1,586
Total	($0)	$0	$0	$0	$0	$0	$0	($0)	$0

AEP Transmission Agreement
Cost Impact Comparison of Present and Revised Allocations - 1CP
Revenues and Costs October 2007 - September 2008
$(000)

AEP as a Transmission Owner - Revenue Allocations

Present Allocation:

Company	A Total Sched. 1A (Credit)	a1 Third Party Sched. 1A (Credit) (MLR)	a2 Sched. 1A AEP LSE (Credit) (MLR)	a3 Sched. 1A Formula (Credit) (DA)	B Total T-Svc. (Credit)	b1 Third Party NTS (Credit) (MLR)	b2 NTS AEP LSE (Credit) (MLR)	b3 NTS AEP Formula (Credit) (DA)	C TEA Charge (Credit)	D GFA PTP (Credit) (MLR)	E ECRC (Credit) (TPM)	F SCRC (Credit) (TPM)	Total T-Related
Appalachian Power	($3,920)	($1,011)	($2,822)	($87)	($169,457)	($16,875)	($146,981)	($5,600)	($26,813)	($3,638)	($708)	($682)	($205,218)
Columbus Southern Power	($2,272)	($590)	($1,647)	($35)	($97,614)	($9,852)	($85,806)	($1,956)	$56,634	($2,124)	($283)	($272)	($45,932)
Indiana & Michigan Power	($2,431)	($569)	($1,586)	($276)	($106,328)	($9,487)	($82,634)	($14,207)	($36,081)	($2,045)	($563)	($541)	($147,990)
Kingsport Power	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Kentucky Power	($821)	($215)	($599)	($7)	($35,369)	($3,585)	($31,221)	($563)	($8,655)	($773)	($171)	($164)	($45,953)
Ohio Power	($2,661)	($702)	($1,959)	$0	($113,737)	($11,714)	($102,024)	$0	$14,916	($2,525)	($804)	($774)	($105,586)
Wheeling Power	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	($12,105)	($3,087)	($8,614)	($405)	($522,505)	($51,512)	($448,666)	($22,326)	$0	($11,106)	($2,529)	($2,434)	($550,679)

1CP Allocation:

Company	A Total Sched. 1A (Credit) (ARR S1)	a1 Third Party Sched. 1A (Credit) (ARR S1)	a2 Sched. 1A AEP LSE (Credit) (ARR S1)	a3 Sched. 1A Formula (Credit) (ARR S1)	B Total T-Svc. (Credit) (ATRR)	b1 Third Party NTS (Credit) (ATRR)	b2 NTS AEP LSE (Credit) (ATRR)	b3 NTS AEP Formula (Credit) (ATRR)	C Eliminate TEA Charge (Credit)	D GFA PTP (Credit) (ATRR)	E ECRC (Credit) (ARR ECRC)	F SCRC (Credit) (ARR SCRC)	Total T-Related
Appalachian Power	($3,476)	($887)	($2,474)	($116)	($185,491)	($18,287)	($159,278)	($7,926)	$0	($3,943)	($903)	($692)	($194,505)
Columbus Southern Power	($1,338)	($341)	($952)	($45)	($59,051)	($5,822)	($50,706)	($2,523)	$0	($1,255)	($221)	($297)	($62,162)
Indiana & Michigan Power	($2,812)	($717)	($2,001)	($94)	($105,281)	($10,379)	($90,403)	($4,499)	$0	($2,238)	($317)	($513)	($111,162)
Kingsport Power	($62)	($16)	($44)	($2)	($2,224)	($219)	($1,910)	($95)	$0	($47)	($11)	$0	($2,344)
Kentucky Power	($501)	($128)	($357)	($17)	($42,768)	($4,216)	($36,724)	($1,827)	$0	($909)	($196)	($151)	($44,525)
Ohio Power	($3,860)	($984)	($2,746)	($129)	($124,732)	($12,297)	($107,105)	($5,330)	$0	($2,651)	($870)	($780)	($132,893)
Wheeling Power	($55)	($14)	($39)	($2)	($2,957)	($292)	($2,539)	($126)	$0	($63)	($11)	$0	($3,086)
Total	($12,105)	($3,087)	($8,614)	($405)	($522,505)	($51,512)	($448,666)	($22,326)	$0	($11,106)	($2,529)	($2,434)	($550,679)

Net Change:

(Proposed - Present) Company	A Total Sched. 1A (Credit) (Net)	a1 Third Party Sched. 1A (Credit) (Net)	a2 Sched. 1A AEP LSE (Credit) (Net)	a3 Sched. 1A Formula (Credit) (Net)	B Total T-Svc. (Credit) (Net)	b1 Third Party NTS (Credit) (Net)	b2 NTS AEP LSE (Credit) (Net)	b3 NTS AEP Formula (Credit) (Net)	C Eliminate TEA (Net)	D GFA PTP (Credit) (Net)	E ECRC (Credit) (Net)	F SCRC (Credit) (Net)	Net T-Related
Appalachian Power	$444	$125	$348	($29)	($16,034)	($1,412)	($12,297)	($2,325)	$26,813	($304)	($195)	($10)	$10,713
Columbus Southern Power	$934	$249	$695	($10)	$38,563	$4,030	$35,100	($567)	($56,634)	$869	$62	($25)	($16,230)
Indiana & Michigan Power	($382)	($149)	($415)	$182	$1,047	($892)	($7,769)	$9,708	$36,081	($192)	$245	$28	$36,828
Kingsport Power	($62)	($16)	($44)	($2)	($2,224)	($219)	($1,910)	($95)	$0	($47)	($11)	$0	($2,344)
Kentucky Power	$320	$87	$243	($10)	($7,399)	($632)	($5,503)	($1,265)	$8,655	($136)	($25)	$13	$1,428
Ohio Power	($1,199)	($282)	($788)	($129)	($10,995)	($583)	($5,082)	($5,330)	($14,916)	($126)	($65)	($7)	($27,307)
Wheeling Power	($55)	($14)	($39)	($2)	($2,957)	($292)	($2,539)	($126)	$0	($63)	($11)	$0	($3,086)
Total	$0	($0)	$0	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0

AEP Transmission Agreement
Cost Impact Comparison of Present and Revised Allocations - 1CP
Revenues and Costs October 2007 - September 2008
$(000)

AEP as a Load Serving Entity - Cost Allocations

Present Allocation:

Company	G Sched. 1A AEP LSE Charge (MLR)	H Total NTS & Trans. Enh. Charge (MLR)	h1 NTS AEP LSE Charge (MLR)	h2 Sch. 12 Trans. Enh. Charge (MLR)	I Total PTP (Credit) (MLR)	i1 Third Party PTP Firm (Credit) (MLR)	i2 Third Party PTP Non-Firm (Credit) (MLR)	J PPA Charge (Credit)	K ECRC Charge (TPM)	L SCRC Charge (TPM)	Total LSE-Related
Appalachian Power	$2,822	$148,111	$146,981	$1,131	($5,759)	($3,985)	($1,774)	($9,696)	$373	$603	$136,454
Columbus Southern Power	$1,647	$86,466	$85,806	$660	($3,362)	($2,326)	($1,036)	$0	$149	$241	$85,142
Indiana & Michigan Power	$1,586	$83,269	$82,634	$636	($3,238)	($2,240)	($997)	$0	$296	$479	$82,393
Kingsport Power	$0	$0	$0	$0	$0	$0	$0	$9,696	$0	$0	$9,696
Kentucky Power	$599	$31,462	$31,221	$240	($1,223)	($847)	($377)	$0	$90	$145	$31,073
Ohio Power	$1,959	$102,808	$102,024	$785	($3,997)	($2,766)	($1,231)	($8,091)	$423	$685	$93,786
Wheeling Power	$0	$0	$0	$0	$0	$0	$0	$8,091	$0	$0	$8,091
Total	$8,614	$452,117	$448,666	$3,451	($17,579)	($12,165)	($5,415)	$0	$1,331	$2,153	$446,635

1CP Allocation:

Company	G Sched. 1A AEP LSE Charge (MWH)	H Total NTS & Trans. Enh. Charge (1CP)	h1 NTS AEP LSE Charge (1CP)	h2 Sch. 12 Trans. Enh. Charge (1CP)	I Total PTP (Credit) (1CP)	i1 Third Party PTP Firm (Credit) (1CP)	i2 Third Party PTP Non-Firm (Credit) (1CP)	J Eliminate PPA Charge (Credit)	K ECRC Charge (1CP)	L SCRC Charge (1CP)	Total LSE-Related
Appalachian Power	$2,548	$128,635	$127,653	$982	($5,002)	($3,461)	($1,541)	$0	$379	$613	$127,172
Columbus Southern Power	$1,609	$97,793	$97,046	$746	($3,802)	($2,631)	($1,171)	$0	$288	$466	$96,353
Indiana & Michigan Power	$1,470	$78,797	$78,196	$601	($3,064)	($2,120)	($944)	$0	$232	$375	$77,811
Kingsport Power	$157	$7,417	$7,360	$57	($288)	($200)	($89)	$0	$22	$35	$7,342
Kentucky Power	$536	$27,342	$27,133	$209	($1,063)	($736)	($327)	$0	$80	$130	$27,026
Ohio Power	$2,140	$105,523	$104,717	$805	($4,103)	($2,839)	($1,264)	$0	$311	$502	$104,373
Wheeling Power	$152	$6,611	$6,561	$50	($257)	($178)	($79)	$0	$19	$31	$6,558
Total	$8,614	$452,117	$448,666	$3,451	($17,579)	($12,165)	($5,415)	$0	$1,331	$2,153	$446,635

Net Change:

(Proposed - Present) Company	G Total 1A AEP LSE Charge (Net)	H Total NTS & Trans. Enh. Charge (Net)	h1 NTS AEP LSE Charge (Net)	h2 Sch. 12 Trans. Enh. Charge (Net)	I Total PTP (Credit) (Net)	i1 Third Party PTP Firm (Credit) (Net)	i2 Third Party MLR Non-Firm (Net)	J Eliminate PPA (Net)	K ECRC (Credit) (Net)	L SCRC (Credit) (Net)	Net LSE-Related
Appalachian Power	($274)	($19,477)	($19,328)	($149)	$757	$524	$233	$9,696	$6	$10	($9,281)
Columbus Southern Power	($38)	$11,326	$11,240	$86	($440)	($305)	($136)	$0	$139	$225	$11,212
Indiana & Michigan Power	($116)	($4,472)	($4,438)	($34)	$174	$120	$54	$0	($64)	($104)	($4,582)
Kingsport Power	$157	$7,417	$7,360	$57	($288)	($200)	($89)	($9,696)	$22	$35	($2,354)
Kentucky Power	($63)	($4,119)	($4,088)	($31)	$160	$111	$49	$0	($9)	($15)	($4,047)
Ohio Power	$181	$2,714	$2,693	$21	($106)	($73)	($33)	$8,091	($113)	($182)	$10,587
Wheeling Power	$152	$6,611	$6,561	$50	($257)	($178)	($79)	($8,091)	$19	$31	($1,534)
Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	($0)	$0

AEP Transmission Agreement
Cost Impact Comparison of Present and Revised Allocations - 1CP
Proformed for Rates Effective March 1, 2009 and 2009 Load Shares
$(000)

AEP as a Transmission Owner - Revenue Allocations

Present Allocation:

Company	A Total Sched. 1A (Credit)	a1 Third Party Sched. 1A (Credit) (MLR)	a2 Sched. 1A AEP LSE (Credit) (MLR)	a3 Sched. 1A Formula (Credit) (DA)	B Total T-Svc. (Credit)	b1 Third Party NTS (Credit) (MLR)	b2 NTS AEP LSE (Credit) (MLR)	b3 NTS AEP Formula (Credit) (DA)	b4 Sch. 12 Trans. Enh. Charge (MLR)	C TEA Charge (Credit)	D GFA PTP (Credit) (MLR)	E ECRC (Credit) (TPM)	F SCRC (Credit) (TPM)	Total T-Related
Appalachian Power	**($3,158)**	($840)	($2,246)	($73)	**($188,738)**	($17,840)	($165,086)	($5,740)	($73)	**($27,703)**	**($3,488)**	**($726)**	**($662)**	($224,474)
Columbus Southern Power	**($1,839)**	($493)	($1,318)	($29)	**($109,366)**	($10,466)	($96,853)	($2,005)	($43)	**$56,858**	**($2,046)**	**($290)**	**($264)**	($56,948)
Indiana & Michigan Power	**($1,987)**	($479)	($1,280)	($229)	**($118,847)**	($10,166)	($94,079)	($14,561)	($41)	**($35,161)**	**($1,988)**	**($577)**	**($526)**	($159,085)
Kingsport Power	**$0**	$0	$0	$0	**$0**	$0	$0	$0	$0	**$0**	**$0**	**$0**	**$0**	$0
Kentucky Power	**($682)**	($184)	($492)	($6)	**($40,701)**	($3,912)	($36,196)	($577)	($16)	**($8,553)**	**($765)**	**($175)**	**($159)**	($51,035)
Ohio Power	**($2,181)**	($594)	($1,587)	$0	**($129,337)**	($12,608)	($116,677)	$0	($51)	**$14,560**	**($2,465)**	**($824)**	**($751)**	($120,998)
Wheeling Power	**$0**	$0	$0	$0	**$0**	$0	$0	$0	$0	**$0**	**$0**	**$0**	**$0**	$0
Total	**($9,848)**	($2,589)	($6,923)	($336)	**($586,988)**	($54,992)	($508,890)	($22,882)	($224)	**$0**	**($10,751)**	**($2,591)**	**($2,362)**	($612,541)

1CP Allocation:

Company	A Total Sched. 1A (Credit) (ARR S1)	a1 Third Party Sched. 1A (Credit) (ARR S1)	a2 Sched. 1A AEP LSE (Credit) (ARR S1)	a3 Sched. 1A Formula (Credit) (ARR S1)	B Total T-Svc. (Credit) (ATRR)	b1 Third Party NTS (Credit) (ATRR)	b2 NTS AEP LSE (Credit) (ATRR)	b3 NTS AEP Formula (Credit) (ATRR)	b4 Sch. 12 Trans. Enh. Charge (ATRR)	C Eliminate TEA Charge (Credit)	D GFA PTP (Credit) (ATRR)	E ECRC (Credit) (ARR ECRC)	F SCRC (Credit) (ARR SCRC)	Total T-Related
Appalachian Power	**($3,518)**	($925)	($2,473)	($120)	**($187,762)**	($17,591)	($162,780)	($7,319)	($72)	**$0**	**($3,439)**	**($926)**	**($671)**	($196,316)
Columbus Southern Power	**($860)**	($226)	($604)	($29)	**($78,375)**	($7,343)	($67,947)	($3,055)	($30)	**$0**	**($1,436)**	**($226)**	**($288)**	($81,185)
Indiana & Michigan Power	**($1,235)**	($325)	($868)	($42)	**($118,204)**	($11,074)	($102,477)	($4,608)	($45)	**$0**	**($2,165)**	**($325)**	**($498)**	($122,427)
Kingsport Power	**($42)**	($11)	($30)	($1)	**($2,623)**	($246)	($2,274)	($102)	($1)	**$0**	**($48)**	**($11)**	**$0**	($2,725)
Kentucky Power	**($764)**	($201)	($537)	($26)	**($51,330)**	($4,809)	($44,500)	($2,001)	($20)	**$0**	**($940)**	**($201)**	**($146)**	($53,381)
Ohio Power	**($3,386)**	($890)	($2,380)	($116)	**($147,027)**	($13,774)	($127,465)	($5,731)	($56)	**$0**	**($2,693)**	**($891)**	**($758)**	($154,755)
Wheeling Power	**($43)**	($11)	($30)	($1)	**($1,668)**	($156)	($1,446)	($65)	($1)	**$0**	**($31)**	**($11)**	**$0**	($1,753)
Total	**($9,848)**	($2,589)	($6,923)	($336)	**($586,988)**	($54,992)	($508,890)	($22,882)	($224)	**$0**	**($10,751)**	**($2,591)**	**($2,362)**	($612,541)

Net Change:

(Proposed - Present) Company	A Total Sched. 1A (Credit) (Net)	a1 Third Party Sched. 1A (Credit) (Net)	a2 Sched. 1A AEP LSE (Credit) (Net)	a3 Sched. 1A Formula (Credit) (Net)	B Total T-Svc. (Credit) (Net)	b1 Third Party NTS (Credit) (Net)	b2 NTS AEP LSE (Credit) (Net)	b3 NTS AEP Formula (Credit) (Net)	b4 Sch. 12 Trans. Enh. Charge (Net)	C Eliminate TEA (Net)	D GFA PTP (Credit) (Net)	E ECRC (Credit) (Net)	F SCRC (Credit) (Net)	**Net T-Related**
Appalachian Power	**($359)**	($85)	($227)	($47)	**$976**	$249	$2,305	($1,579)	$1	**$27,703**	**$49**	**($200)**	**($10)**	$28,159
Columbus Southern Power	**$979**	$267	$713	($1)	**$30,991**	$3,124	$28,905	($1,051)	$13	**($56,858)**	**$611**	**$64**	**($24)**	($24,237)
Indiana & Michigan Power	**$752**	$154	$412	$187	**$644**	($908)	($8,398)	$9,953	($4)	**$35,161**	**($177)**	**$252**	**$27**	$36,658
Kingsport Power	**($42)**	($11)	($30)	($1)	**($2,623)**	($246)	($2,274)	($102)	($1)	**$0**	**($48)**	**($11)**	**$0**	($2,725)
Kentucky Power	**($82)**	($17)	($45)	($20)	**($10,629)**	($897)	($8,304)	($1,424)	($4)	**$8,553**	**($175)**	**($26)**	**$13**	($2,346)
Ohio Power	**($1,205)**	($297)	($793)	($116)	**($17,690)**	($1,166)	($10,788)	($5,731)	($5)	**($14,560)**	**($228)**	**($67)**	**($6)**	($33,757)
Wheeling Power	**($43)**	($11)	($30)	($1)	**($1,668)**	($156)	($1,446)	($65)	($1)	**$0**	**($31)**	**($11)**	**$0**	($1,753)
Total	**$0**	$0	($0)	$0	**$0**	($0)	($0)	$0	($0)	**$0**	**($0)**	**($0)**	**$0**	($0)

AEP Transmission Agreement
Cost Impact Comparison of Present and Revised Allocations - 1CP
Proformed for Rates Effective March 1, 2009 and 2009 Load Shares
$(000)

AEP as a Load Serving Entity - Cost Allocations

Present Allocation:

Company	G Sched. 1A AEP LSE Charge (MLR)	H Total NTS & Trans. Enh. Charge (MLR)	h1 *NTS AEP LSE Charge (MLR)*	h2 *Sch. 12 Trans. Enh. Charge (MLR)*	I Total PTP (Credit) (MLR)	i1 *Third Party PTP Firm (Credit) (MLR)*	i2 *Third Party PTP Non-Firm (Credit) (MLR)*	J PPA Charge (Credit)	K ECRC Charge (TPM)	L SCRC Charge (TPM)	Total LSE-Related
Appalachian Power	$2,246	$169,731	$165,086	$4,645	($5,703)	($3,946)	($1,757)	($10,988)	$368	$591	$156,245
Columbus Southern Power	$1,318	$99,578	$96,853	$2,725	($3,346)	($2,315)	($1,031)	$0	$147	$236	$97,933
Indiana & Michigan Power	$1,280	$96,726	$94,079	$2,647	($3,250)	($2,249)	($1,001)	$0	$293	$470	$95,518
Kingsport Power	$0	$0	$0	$0	$0	$0	$0	$10,988	$0	$0	$10,988
Kentucky Power	$492	$37,215	$36,196	$1,019	($1,250)	($865)	($385)	$0	$89	$142	$36,688
Ohio Power	$1,587	$119,960	$116,677	$3,283	($4,031)	($2,789)	($1,241)	($8,773)	$418	$671	$109,833
Wheeling Power	$0	$0	$0	$0	$0	$0	$0	$8,773	$0	$0	$8,773
Total	$6,923	$523,210	$508,890	$14,320	($17,579)	($12,165)	($5,415)	$0	$1,315	$2,111	$515,979

1CP Allocation:

Company	G Sched. 1A AEP LSE Charge (MWH)	H Total NTS & Trans. Enh. Charge (1CP)	h1 *NTS AEP LSE Charge (1CP)*	h2 *Sch. 12 Trans. Enh. Charge (1CP)*	I Total PTP (Credit) (1CP)	i1 *Third Party PTP Firm (Credit) (1CP)*	i2 *Third Party PTP Non-Firm (Credit) (1CP)*	J Eliminate PPA Charge (Credit)	K ECRC Charge (1CP)	L SCRC Charge (1CP)	Total LSE-Related
Appalachian Power	$2,062	$178,851	$173,956	$4,895	($6,009)	($4,158)	($1,851)	$0	$450	$722	$176,075
Columbus Southern Power	$1,306	$90,311	$87,839	$2,472	($3,034)	($2,100)	($935)	$0	$227	$364	$89,174
Indiana & Michigan Power	$1,197	$81,579	$79,346	$2,233	($2,741)	($1,897)	($844)	$0	$205	$329	$80,569
Kingsport Power	$125	$11,464	$11,150	$314	($385)	($267)	($119)	$0	$29	$46	$11,278
Kentucky Power	$448	$40,478	$39,370	$1,108	($1,360)	($941)	($419)	$0	$102	$163	$39,831
Ohio Power	$1,665	$112,952	$109,860	$3,091	($3,795)	($2,626)	($1,169)	$0	$284	$456	$111,561
Wheeling Power	$121	$7,576	$7,369	$207	($255)	($176)	($78)	$0	$19	$31	$7,492
Total	$6,923	$523,210	$508,890	$14,320	($17,579)	($12,165)	($5,415)	$0	$1,315	$2,111	$515,979

Net Change:
(Proposed - Present)

Company	G Total 1A AEP LSE Charge (Net)	H Total NTS & Trans. Enh. Charge (Net)	h1 *NTS AEP LSE Charge (Net)*	h2 *Sch. 12 Trans. Enh. Charge (Net)*	I Total PTP (Credit) (Net)	i1 *Third Party PTP Firm (Credit) (Net)*	i2 *Third Party MLR Non-Firm (Net)*	J Eliminate PPA (Net)	K ECRC (Credit) (Net)	L SCRC (Credit) (Net)	**Net LSE-Related**
Appalachian Power	($184)	$9,120	$8,870	$250	($306)	($212)	($94)	$10,988	$81	$130	$19,829
Columbus Southern Power	($11)	($9,267)	($9,013)	($254)	$311	$215	$96	$0	$80	$128	($8,759)
Indiana & Michigan Power	($83)	($15,147)	($14,732)	($415)	$509	$352	$157	$0	($88)	($141)	($14,949)
Kingsport Power	$125	$11,464	$11,150	$314	($385)	($267)	($119)	($10,988)	$29	$46	$290
Kentucky Power	($44)	$3,263	$3,173	$89	($110)	($76)	($34)	$0	$13	$21	$3,142
Ohio Power	$78	($7,008)	($6,817)	($192)	$235	$163	$73	$8,773	($134)	($216)	$1,728
Wheeling Power	$121	$7,576	$7,369	$207	($255)	($176)	($78)	($8,773)	$19	$31	($1,281)
Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

AEP Transmission Agreement
Cost Impact Comparison of Present and Revised Allocations - 7 Member MLR
Proformed 2008 Cost Sharing vs. Proposed 2009 Cost Sharing
$(000)

Present Allocation:

	2008 Revenues and Costs with Calendar 2008 Allocations			2009 Projected Revenues, Costs and Allocations			Change 2008 vs. 2009 Proformed 2008 vs. Projected 2009		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Company	Total T-Related	Total LSE-Related	Total T & LSE Related	Total T-Related	Total LSE-Related	Total T & LSE Related	(d)-(a) T-Related	(e)-(b) LSE-Related	(g)+(h) AEP Net
Appalachian Power	($205,218)	$136,454	($68,764)	($224,474)	$156,245	($68,229)	($19,256)	$19,792	$535
Columbus Southern Power	($45,932)	$85,142	$39,209	($56,948)	$97,933	$40,985	($11,016)	$12,792	$1,776
Indiana & Michigan Power	($147,990)	$82,393	($65,596)	($159,085)	$95,518	($63,567)	($11,096)	$13,125	$2,029
Kingsport Power	$0	$9,696	$9,696	$0	$10,988	$10,988	$0	$1,292	$1,292
Kentucky Power	($45,953)	$31,073	($14,880)	($51,035)	$36,688	($14,347)	($5,082)	$5,615	$533
Ohio Power	($105,586)	$93,786	($11,800)	($120,998)	$109,833	($11,165)	($15,412)	$16,047	$635
Wheeling Power	$0	$8,091	$8,091	$0	$8,773	$8,773	$0	$682	$682
Total	($550,679)	$446,635	($104,043)	($612,541)	$515,979	($96,562)	($61,862)	$69,344	$7,482

7 Member MLR Allocation:

Company	Total T-Related	Total LSE-Related	Total T & LSE Related	Total T-Related	Total LSE-Related	Total T & LSE Related	Total T-Related	Total LSE-Related	Total T & LSE Related
Appalachian Power	($194,505)	$137,699	($56,807)	($196,316)	$158,117	($38,199)	($1,811)	$20,418	$18,608
Columbus Southern Power	($62,162)	$85,327	$23,164	($81,185)	$98,039	$16,855	($19,023)	$12,713	($6,310)
Indiana & Michigan Power	($111,162)	$82,092	($29,070)	($122,427)	$95,159	($27,268)	($11,265)	$13,067	$1,801
Kingsport Power	($2,344)	$8,469	$6,125	($2,725)	$9,259	$6,534	($380)	$790	$410
Kentucky Power	($44,525)	$30,998	($13,528)	($53,381)	$36,601	($16,781)	($8,856)	$5,603	($3,253)
Ohio Power	($132,893)	$95,716	($37,177)	($154,755)	$111,156	($43,599)	($21,861)	$15,440	($6,421)
Wheeling Power	($3,086)	$6,335	$3,249	($1,753)	$7,649	$5,896	$1,333	$1,314	$2,647
Total	($550,679)	$446,635	($104,043)	($612,541)	$515,979	($96,562)	($61,862)	$69,344	$7,482

Net Change From Trans. Agreement Modification:

(Proposed - Present)

Company	Net T-Related	Net LSE-Related	Net T & LSE Related	Net T-Related	Net LSE-Related	Net T & LSE Related	Net T-Related	Net LSE-Related	Net T & LSE Related
Appalachian Power	$10,713	$1,245	$11,958	$28,159	$1,871	$30,030	$17,446	$626	$18,072
Columbus Southern Power	($16,230)	$185	($16,045)	($24,237)	$106	($24,131)	($8,007)	($79)	($8,085)
Indiana & Michigan Power	$36,828	($301)	$36,527	$36,658	($359)	$36,299	($169)	($58)	($228)
Kingsport Power	($2,344)	($1,227)	($3,572)	($2,725)	($1,729)	($4,454)	($380)	($502)	($882)
Kentucky Power	$1,428	($75)	$1,353	($2,346)	($88)	($2,434)	($3,774)	($13)	($3,787)
Ohio Power	($27,307)	$1,930	($25,378)	($33,757)	$1,323	($32,434)	($6,449)	($607)	($7,056)
Wheeling Power	($3,086)	($1,756)	($4,843)	($1,753)	($1,124)	($2,877)	$1,333	$632	$1,966
Total	($0)	$0	$0	$0	$0	$0	$0	($0)	$0

AEP Transmission Agreement
Cost Impact Comparison of Present and Revised Allocations - 7 Member MLR
Revenues and Costs October 2007 - September 2008
$(000)

AEP as a Transmission Owner - Revenue Allocations

Present Allocation:

Company	A Total Sched. 1A (Credit)	a1 *Third Party Sched. 1A (Credit) (MLR)*	a2 *Sched. 1A AEP LSE (Credit) (MLR)*	a3 *Sched. 1A Formula (Credit) (DA)*	B Total T-Svc. (Credit)	b1 *Third Party NTS (Credit) (MLR)*	b2 *NTS AEP LSE (Credit) (MLR)*	b3 *NTS AEP Formula (Credit) (DA)*	C TEA Charge (Credit)	D GFA PTP (Credit) (MLR)	E ECRC (Credit) (TPM)	F SCRC (Credit) (TPM)	Total T-Related
Appalachian Power	**($3,920)**	($1,011)	($2,822)	($87)	**($169,457)**	($16,875)	($146,981)	($5,600)	**($26,813)**	**($3,638)**	**($708)**	**($682)**	($205,218)
Columbus Southern Power	**($2,272)**	($590)	($1,647)	($35)	**($97,614)**	($9,852)	($85,806)	($1,956)	**$56,634**	**($2,124)**	**($283)**	**($272)**	($45,932)
Indiana & Michigan Power	**($2,431)**	($569)	($1,586)	($276)	**($106,328)**	($9,487)	($82,634)	($14,207)	**($36,081)**	**($2,045)**	**($563)**	**($541)**	($147,990)
Kingsport Power	**$0**	$0	$0	$0	**$0**	$0	$0	$0	**$0**	**$0**	**$0**	**$0**	$0
Kentucky Power	**($821)**	($215)	($599)	($7)	**($35,369)**	($3,585)	($31,221)	($563)	**($8,655)**	**($773)**	**($171)**	**($164)**	($45,953)
Ohio Power	**($2,661)**	($702)	($1,959)	$0	**($113,737)**	($11,714)	($102,024)	$0	**$14,916**	**($2,525)**	**($804)**	**($774)**	($105,586)
Wheeling Power	**$0**	$0	$0	$0	**$0**	$0	$0	$0	**$0**	**$0**	**$0**	**$0**	$0
Total	**($12,105)**	($3,087)	($8,614)	($405)	**($522,505)**	($51,512)	($448,666)	($22,326)	**$0**	**($11,106)**	**($2,529)**	**($2,434)**	($550,679)

7 Member MLR Allocation:

Company	A Total Sched. 1A (Credit) (ARR S1)	a1 *Third Party Sched. 1A (Credit) (ARR S1)*	a2 *Sched. 1A AEP LSE (Credit) (ARR S1)*	a3 *Sched. 1A Formula (Credit) (ARR S1)*	B Total T-Svc. (Credit) (ATRR)	b1 *Third Party NTS (Credit) (ATRR)*	b2 *NTS AEP LSE (Credit) (ATRR)*	b3 *NTS AEP Formula (Credit) (ATRR)*	C Eliminate TEA Charge (Credit)	D GFA PTP (Credit) (ATRR)	E ECRC (Credit) (ARR ECRC)	F SCRC (Credit) (ARR SCRC)	Total T-Related
Appalachian Power	**($3,476)**	($887)	($2,474)	($116)	**($185,491)**	($18,287)	($159,278)	($7,926)	**$0**	**($3,943)**	**($903)**	**($692)**	($194,505)
Columbus Southern Power	**($1,338)**	($341)	($952)	($45)	**($59,051)**	($5,822)	($50,706)	($2,523)	**$0**	**($1,255)**	**($221)**	**($297)**	($62,162)
Indiana & Michigan Power	**($2,812)**	($717)	($2,001)	($94)	**($105,281)**	($10,379)	($90,403)	($4,499)	**$0**	**($2,238)**	**($317)**	**($513)**	($111,162)
Kingsport Power	**($62)**	($16)	($44)	($2)	**($2,224)**	($219)	($1,910)	($95)	**$0**	**($47)**	**($11)**	**$0**	($2,344)
Kentucky Power	**($501)**	($128)	($357)	($17)	**($42,768)**	($4,216)	($36,724)	($1,827)	**$0**	**($909)**	**($196)**	**($151)**	($44,525)
Ohio Power	**($3,860)**	($984)	($2,746)	($129)	**($124,732)**	($12,297)	($107,105)	($5,330)	**$0**	**($2,651)**	**($870)**	**($780)**	($132,893)
Wheeling Power	**($55)**	($14)	($39)	($2)	**($2,957)**	($292)	($2,539)	($126)	**$0**	**($63)**	**($11)**	**$0**	($3,086)
Total	**($12,105)**	($3,087)	($8,614)	($405)	**($522,505)**	($51,512)	($448,666)	($22,326)	**$0**	**($11,106)**	**($2,529)**	**($2,434)**	($550,679)

Net Change:

(Proposed - Present) Company	A Total Sched. 1A (Credit) (Net)	a1 *Third Party Sched. 1A (Credit) (Net)*	a2 *Sched. 1A AEP LSE (Credit) (Net)*	a3 *Sched. 1A Formula (Credit) (Net)*	B Total T-Svc. (Credit) (Net)	b1 *Third Party NTS (Credit) (Net)*	b2 *NTS AEP LSE (Credit) (Net)*	b3 *NTS AEP Formula (Credit) (Net)*	C Eliminate TEA (Net)	D GFA PTP (Credit) (Net)	E ECRC (Credit) (Net)	F SCRC (Credit) (Net)	Net T-Related
Appalachian Power	**$444**	$125	$348	($29)	**($16,034)**	($1,412)	($12,297)	($2,325)	**$26,813**	**($304)**	**($195)**	**($10)**	$10,713
Columbus Southern Power	**$934**	$249	$695	($10)	**$38,563**	$4,030	$35,100	($567)	**($56,634)**	**$869**	**$62**	**($25)**	($16,230)
Indiana & Michigan Power	**($382)**	($149)	($415)	$182	**$1,047**	($892)	($7,769)	$9,708	**$36,081**	**($192)**	**$245**	**$28**	$36,828
Kingsport Power	**($62)**	($16)	($44)	($2)	**($2,224)**	($219)	($1,910)	($95)	**$0**	**($47)**	**($11)**	**$0**	($2,344)
Kentucky Power	**$320**	$87	$243	($10)	**($7,399)**	($632)	($5,503)	($1,265)	**$8,655**	**($136)**	**($25)**	**$13**	$1,428
Ohio Power	**($1,199)**	($282)	($788)	($129)	**($10,995)**	($583)	($5,082)	($5,330)	**($14,916)**	**($126)**	**($65)**	**($7)**	($27,307)
Wheeling Power	**($55)**	($14)	($39)	($2)	**($2,957)**	($292)	($2,539)	($126)	**$0**	**($63)**	**($11)**	**$0**	($3,086)
Total	**$0**	($0)	$0	($0)	**$0**	$0	$0	$0	**$0**	**$0**	**$0**	**$0**	$0

AEP Transmission Agreement

Cost Impact Comparison of Present and Revised Allocations - 7 Member MLR

Revenues and Costs October 2007 - September 2008

$(000)

AEP as a Load Serving Entity - Cost Allocations

Present Allocation:

Company	G Sched. 1A AEP LSE Charge (MLR)	H Total NTS & Trans. Enh. Charge (MLR)	h1 NTS AEP LSE Charge (MLR)	h2 Sch. 12 Trans. Enh. Charge (MLR)	I Total PTP (Credit) (MLR)	i1 Third Party PTP Firm (Credit) (MLR)	i2 Third Party PTP Non-Firm (Credit) (MLR)	J PPA Charge (Credit)	K ECRC Charge (TPM)	L SCRC Charge (TPM)	Total LSE-Related
Appalachian Power	$2,822	$148,111	$146,981	$1,131	($5,759)	($3,985)	($1,774)	($9,696)	$373	$603	$136,454
Columbus Southern Power	$1,647	$86,466	$85,806	$660	($3,362)	($2,326)	($1,036)	$0	$149	$241	$85,142
Indiana & Michigan Power	$1,586	$83,269	$82,634	$636	($3,238)	($2,240)	($997)	$0	$296	$479	$82,393
Kingsport Power	$0	$0	$0	$0	$0	$0	$0	$9,696	$0	$0	$9,696
Kentucky Power	$599	$31,462	$31,221	$240	($1,223)	($847)	($377)	$0	$90	$145	$31,073
Ohio Power	$1,959	$102,808	$102,024	$785	($3,997)	($2,766)	($1,231)	($8,091)	$423	$685	$93,786
Wheeling Power	$0	$0	$0	$0	$0	$0	$0	$8,091	$0	$0	$8,091
Total	$8,614	$452,117	$448,666	$3,451	($17,579)	($12,165)	($5,415)	$0	$1,331	$2,153	$446,635

7 Member MLR Allocatio

Company	G Sched. 1A AEP LSE Charge (MWH)	H Total NTS & Trans. Enh. Charge (MLR)	h1 NTS AEP LSE Charge (MLR)	h2 Sch. 12 Trans. Enh. Charge (MLR)	I Total PTP (Credit) (MLR)	i1 Third Party PTP Firm (Credit) (MLR)	i2 Third Party PTP Non-Firm (Credit) (MLR)	J Eliminate PPA Charge (Credit)	K ECRC Charge (MLR)	L SCRC Charge (MLR)	Total LSE-Related
Appalachian Power	$2,548	$139,500	$138,435	$1,065	($5,424)	($3,753)	($1,671)	$0	$411	$664	$137,699
Columbus Southern Power	$1,609	$86,411	$85,752	$660	($3,360)	($2,325)	($1,035)	$0	$254	$411	$85,327
Indiana & Michigan Power	$1,470	$83,216	$82,581	$635	($3,236)	($2,239)	($997)	$0	$245	$396	$82,092
Kingsport Power	$157	$8,580	$8,514	$65	($334)	($231)	($103)	$0	$25	$41	$8,469
Kentucky Power	$536	$31,442	$31,202	$240	($1,223)	($846)	($377)	$0	$93	$150	$30,998
Ohio Power	$2,140	$96,587	$95,850	$737	($3,756)	($2,599)	($1,157)	$0	$284	$460	$95,716
Wheeling Power	$152	$6,381	$6,333	$49	($248)	($172)	($76)	$0	$19	$30	$6,335
Total	$8,614	$452,117	$448,666	$3,451	($17,579)	($12,165)	($5,415)	$0	$1,331	$2,153	$446,635

Net Change:

(Proposed - Present) Company	G Total 1A AEP LSE Charge (Net)	H Total NTS & Trans. Enh. Charge (Net)	h1 NTS AEP LSE Charge (Net)	h2 Sch. 12 Trans. Enh. Charge (Net)	I Total PTP (Credit) (Net)	i1 Third Party PTP Firm (Credit) (Net)	i2 Third Party MLR Non-Firm (Net)	J Eliminate PPA (Net)	K ECRC (Credit) (Net)	L SCRC (Credit) (Net)	Net LSE-Related
Appalachian Power	($274)	($8,612)	($8,546)	($66)	$335	$232	$103	$9,696	$38	$61	$1,245
Columbus Southern Power	($38)	($55)	($55)	($0)	$2	$1	$1	$0	$105	$171	$185
Indiana & Michigan Power	($116)	($53)	($53)	($0)	$2	$1	$1	$0	($51)	($83)	($301)
Kingsport Power	$157	$8,580	$8,514	$65	($334)	($231)	($103)	($9,696)	$25	$41	($1,227)
Kentucky Power	($63)	($20)	($20)	($0)	$1	$1	$0	$0	$3	$4	($75)
Ohio Power	$181	($6,222)	($6,174)	($47)	$242	$167	$75	$8,091	($139)	($225)	$1,930
Wheeling Power	$152	$6,381	$6,333	$49	($248)	($172)	($76)	($8,091)	$19	$30	($1,756)
Total	$0	$0	$0	$0	$0	$0	$0	$0	($0)	$0	($0)

AEP Transmission Agreement
Cost Impact Comparison of Present and Revised Allocations - 7 Member MLR
Proformed for Rates Effective March 1, 2009 and 2009 Load Shares
$(000)

AEP as a Transmission Owner - Revenue Allocations

Present Allocation:

Company	A Total Sched. 1A (Credit)	a1 Third Party Sched. 1A (Credit) (MLR)	a2 Sched. 1A AEP LSE (Credit) (MLR)	a3 Sched. 1A Formula (Credit) (DA)	B Total T-Svc. (Credit)	b1 Third Party NTS (Credit) (MLR)	b2 NTS AEP LSE (Credit) (MLR)	b3 NTS AEP Formula (Credit) (DA)	b4 Sch. 12 Trans. Enh. Charge (MLR)	C TEA Charge (Credit)	D GFA PTP (Credit) (MLR)	E ECRC (Credit) (TPM)	F SCRC (Credit) (TPM)	Total T-Related
Appalachian Power	**($3,158)**	($840)	($2,246)	($73)	**($188,738)**	($17,840)	($165,086)	($5,740)	($73)	**($27,703)**	**($3,488)**	**($726)**	**($662)**	($224,474)
Columbus Southern Power	**($1,839)**	($493)	($1,318)	($29)	**($109,366)**	($10,466)	($96,853)	($2,005)	($43)	**$56,858**	**($2,046)**	**($290)**	**($264)**	($56,948)
Indiana & Michigan Power	**($1,987)**	($479)	($1,280)	($229)	**($118,847)**	($10,166)	($94,079)	($14,561)	($41)	**($35,161)**	**($1,988)**	**($577)**	**($526)**	($159,085)
Kingsport Power	**$0**	$0	$0	$0	**$0**	$0	$0	$0	$0	**$0**	**$0**	**$0**	**$0**	$0
Kentucky Power	**($682)**	($184)	($492)	($6)	**($40,701)**	($3,912)	($36,196)	($577)	($16)	**($8,553)**	**($765)**	**($175)**	**($159)**	($51,035)
Ohio Power	**($2,181)**	($594)	($1,587)	$0	**($129,337)**	($12,608)	($116,677)	$0	($51)	**$14,560**	**($2,465)**	**($824)**	**($751)**	($120,998)
Wheeling Power	**$0**	$0	$0	$0	**$0**	$0	$0	$0	$0	**$0**	**$0**	**$0**	**$0**	$0
Total	**($9,848)**	($2,589)	($6,923)	($336)	**($586,988)**	($54,992)	($508,890)	($22,882)	($224)	**$0**	**($10,751)**	**($2,591)**	**($2,362)**	($612,541)

7 Member MLR Allocation:

Company	A Total Sched. 1A (Credit) (ARR S1)	a1 Third Party Sched. 1A (Credit) (ARR S1)	a2 Sched. 1A AEP LSE (Credit) (ARR S1)	a3 Sched. 1A Formula (Credit) (ARR S1)	B Total T-Svc. (Credit) (ATRR)	b1 Third Party NTS (Credit) (ATRR)	b2 NTS AEP LSE (Credit) (ATRR)	b3 NTS AEP Formula (Credit) (ATRR)	b4 Sch. 12 Trans. Enh. Charge (ATRR)	C Eliminate TEA Charge (Credit)	D GFA PTP (Credit) (ATRR)	E ECRC (Credit) (ARR ECRC)	F SCRC (Credit) (ARR SCRC)	Total T-Related
Appalachian Power	**($3,518)**	($925)	($2,473)	($120)	**($187,762)**	($17,591)	($162,780)	($7,319)	($72)	**$0**	**($3,439)**	**($926)**	**($671)**	($196,316)
Columbus Southern Power	**($860)**	($226)	($604)	($29)	**($78,375)**	($7,343)	($67,947)	($3,055)	($30)	**$0**	**($1,436)**	**($226)**	**($288)**	($81,185)
Indiana & Michigan Power	**($1,235)**	($325)	($868)	($42)	**($118,204)**	($11,074)	($102,477)	($4,608)	($45)	**$0**	**($2,165)**	**($325)**	**($498)**	($122,427)
Kingsport Power	**($42)**	($11)	($30)	($1)	**($2,623)**	($246)	($2,274)	($102)	($1)	**$0**	**($48)**	**($11)**	**$0**	($2,725)
Kentucky Power	**($764)**	($201)	($537)	($26)	**($51,330)**	($4,809)	($44,500)	($2,001)	($20)	**$0**	**($940)**	**($201)**	**($146)**	($53,381)
Ohio Power	**($3,386)**	($890)	($2,380)	($116)	**($147,027)**	($13,774)	($127,465)	($5,731)	($56)	**$0**	**($2,693)**	**($891)**	**($758)**	($154,755)
Wheeling Power	**($43)**	($11)	($30)	($1)	**($1,668)**	($156)	($1,446)	($65)	($1)	**$0**	**($31)**	**($11)**	**$0**	($1,753)
Total	**($9,848)**	($2,589)	($6,923)	($336)	**($586,988)**	($54,992)	($508,890)	($22,882)	($224)	**$0**	**($10,751)**	**($2,591)**	**($2,362)**	($612,541)

Net Change:

(Proposed - Present) Company	A Total Sched. 1A (Credit) (Net)	a1 Third Party Sched. 1A (Credit) (Net)	a2 Sched. 1A AEP LSE (Credit) (Net)	a3 Sched. 1A Formula (Credit) (Net)	B Total T-Svc. (Credit) (Net)	b1 Third Party NTS (Credit) (Net)	b2 NTS AEP LSE (Credit) (Net)	b3 NTS AEP Formula (Credit) (Net)	b4 Sch. 12 Trans. Enh. Charge (Net)	C Eliminate TEA (Net)	D GFA PTP (Credit) (Net)	E ECRC (Credit) (Net)	F SCRC (Credit) (Net)	Net T-Related
Appalachian Power	**($359)**	($85)	($227)	($47)	**$976**	$249	$2,305	($1,579)	$1	**$27,703**	**$49**	**($200)**	**($10)**	$28,159
Columbus Southern Power	**$979**	$267	$713	($1)	**$30,991**	$3,124	$28,905	($1,051)	$13	**($56,858)**	**$611**	**$64**	**($24)**	($24,237)
Indiana & Michigan Power	**$752**	$154	$412	$187	**$644**	($908)	($8,398)	$9,953	($4)	**$35,161**	**($177)**	**$252**	**$27**	$36,658
Kingsport Power	**($42)**	($11)	($30)	($1)	**($2,623)**	($246)	($2,274)	($102)	($1)	**$0**	**($48)**	**($11)**	**$0**	($2,725)
Kentucky Power	**($82)**	($17)	($45)	($20)	**($10,629)**	($897)	($8,304)	($1,424)	($4)	**$8,553**	**($175)**	**($26)**	**$13**	($2,346)
Ohio Power	**($1,205)**	($297)	($793)	($116)	**($17,690)**	($1,166)	($10,788)	($5,731)	($5)	**($14,560)**	**($228)**	**($67)**	**($6)**	($33,757)
Wheeling Power	**($43)**	($11)	($30)	($1)	**($1,668)**	($156)	($1,446)	($65)	($1)	**$0**	**($31)**	**($11)**	**$0**	($1,753)
Total	**$0**	$0	($0)	$0	**$0**	($0)	($0)	$0	($0)	**$0**	**($0)**	**($0)**	**$0**	($0)

AEP Transmission Agreement
Cost Impact Comparison of Present and Revised Allocations - 7 Member MLR
Proformed for Rates Effective March 1, 2009 and 2009 Load Shares
$(000)

AEP as a Load Serving Entity - Cost Allocations

Present Allocation:	G	H	h1	h2	I	i1	i2	J	K	L	
Company	Sched. 1A AEP LSE Charge (MLR)	Total NTS & Trans. Enh. Charge (MLR)	NTS AEP LSE Charge (MLR)	Sch. 12 Trans. Enh. Charge (MLR)	Total PTP (Credit) (MLR)	Third Party PTP Firm (Credit) (MLR)	Third Party PTP Non-Firm (Credit) (MLR)	PPA Charge (Credit)	ECRC Charge (TPM)	SCRC Charge (TPM)	Total LSE-Related
Appalachian Power	$2,246	$169,731	$165,086	$4,645	($5,703)	($3,946)	($1,757)	($10,988)	$368	$591	$156,245
Columbus Southern Power	$1,318	$99,578	$96,853	$2,725	($3,346)	($2,315)	($1,031)	$0	$147	$236	$97,933
Indiana & Michigan Power	$1,280	$96,726	$94,079	$2,647	($3,250)	($2,249)	($1,001)	$0	$293	$470	$95,518
Kingsport Power	$0	$0	$0	$0	$0	$0	$0	$10,988	$0	$0	$10,988
Kentucky Power	$492	$37,215	$36,196	$1,019	($1,250)	($865)	($385)	$0	$89	$142	$36,688
Ohio Power	$1,587	$119,960	$116,677	$3,283	($4,031)	($2,789)	($1,241)	($8,773)	$418	$671	$109,833
Wheeling Power	$0	$0	$0	$0	$0	$0	$0	$8,773	$0	$0	$8,773
Total	$6,923	$523,210	$508,890	$14,320	($17,579)	($12,165)	($5,415)	$0	$1,315	$2,111	$515,979

7 Member MLR Allocatio	G	H	h1	h2	I	i1	i2	J	K	L	
Company	Sched. 1A AEP LSE Charge (MWH)	Total NTS & Trans. Enh. Charge (MLR)	NTS AEP LSE Charge (MLR)	Sch. 12 Trans. Enh. Charge (MLR)	Total PTP (Credit) (MLR)	Third Party PTP Firm (Credit) (MLR)	Third Party PTP Non-Firm (Credit) (MLR)	Eliminate PPA Charge (Credit)	ECRC Charge (MLR)	SCRC Charge (MLR)	Total LSE-Related
Appalachian Power	$2,062	$160,394	$156,004	$4,390	($5,389)	($3,729)	($1,660)	$0	$403	$647	$158,117
Columbus Southern Power	$1,306	$99,423	$96,702	$2,721	($3,340)	($2,312)	($1,029)	$0	$250	$401	$98,039
Indiana & Michigan Power	$1,197	$96,575	$93,932	$2,643	($3,245)	($2,245)	($999)	$0	$243	$390	$95,159
Kingsport Power	$125	$9,389	$9,132	$257	($315)	($218)	($97)	$0	$24	$38	$9,259
Kentucky Power	$448	$37,158	$36,141	$1,017	($1,248)	($864)	($385)	$0	$93	$150	$36,601
Ohio Power	$1,665	$112,535	$109,455	$3,080	($3,781)	($2,616)	($1,165)	$0	$283	$454	$111,156
Wheeling Power	$121	$7,737	$7,526	$212	($260)	($180)	($80)	$0	$19	$31	$7,649
Total	$6,923	$523,210	$508,890	$14,320	($17,579)	($12,165)	($5,415)	$0	$1,315	$2,111	$515,979

Net Change: (Proposed - Present)	G	H	h1	h2	I	i1	i2	J	K	L	
Company	Total 1A AEP LSE Charge (Net)	Total NTS & Trans. Enh. Charge (Net)	NTS AEP LSE Charge (Net)	Sch. 12 Trans. Enh. Charge (Net)	Total PTP (Credit) (Net)	Third Party PTP Firm (Credit) (Net)	Third Party MLR Non-Firm (Net)	Eliminate PPA (Net)	ECRC (Credit) (Net)	SCRC (Credit) (Net)	Net LSE-Related
Appalachian Power	($184)	($9,338)	($9,082)	($256)	$314	$217	$97	$10,988	$35	$56	$1,871
Columbus Southern Power	($11)	($155)	($151)	($4)	$5	$4	$2	$0	$103	$165	$106
Indiana & Michigan Power	($83)	($151)	($147)	($4)	$5	$4	$2	$0	($50)	($80)	($359)
Kingsport Power	$125	$9,389	$9,132	$257	($315)	($218)	($97)	($10,988)	$24	$38	($1,729)
Kentucky Power	($44)	($57)	($56)	($2)	$2	$1	$1	$0	$5	$7	($88)
Ohio Power	$78	($7,425)	($7,222)	($203)	$249	$173	$77	$8,773	($135)	($217)	$1,323
Wheeling Power	$121	$7,737	$7,526	$212	($260)	($180)	($80)	($8,773)	$19	$31	($1,124)
Total	$0	$0	$0	$0	$0	$0	$0	$0	($0)	$0	$0

AEP Transmission Agreement
Cost Impact Comparison of Present and Revised Allocations - 12CP
Proformed 2008 Cost Sharing vs. Proposed 2009 Cost Sharing
$(000)

Present Allocation:

	2008 Revenues and Costs with Calendar 2008 Allocations			2009 Projected Revenues, Costs and Allocations			Comparison 2008 vs. 2009 Proformed 2008 vs. Projected 2009		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Company	Total T-Related	Total LSE-Related	Total T & LSE Related	Total T-Related	Total LSE-Related	Total T & LSE Related	(d)-(a) T-Related	(e)-(b) LSE-Related	(g)+(h) AEP Net
Appalachian Power	($205,218)	$136,454	($68,764)	($224,474)	$156,245	($68,229)	($19,256)	$19,792	$536
Columbus Southern Power	($45,932)	$85,142	$39,209	($56,948)	$97,933	$40,985	($11,016)	$12,792	$1,776
Indiana & Michigan Power	($147,990)	$82,393	($65,596)	($159,085)	$95,518	($63,567)	($11,096)	$13,125	$2,029
Kingsport Power	$0	$9,696	$9,696	$0	$10,988	$10,988	$0	$1,292	$1,292
Kentucky Power	($45,953)	$31,073	($14,880)	($51,035)	$36,688	($14,347)	($5,082)	$5,615	$533
Ohio Power	($105,586)	$93,786	($11,800)	($120,998)	$109,833	($11,165)	($15,412)	$16,047	$635
Wheeling Power	$0	$8,091	$8,091	$0	$8,773	$8,773	$0	$682	$682
Total	($550,679)	$446,635	($104,043)	($612,541)	$515,979	($96,562)	($61,862)	$69,344	$7,482

12CP Allocation:

Company	Total T-Related	Total LSE-Related	Total T & LSE Related	Total T-Related	Total LSE-Related	Total T & LSE Related	Total T-Related	Total LSE-Related	Total T & LSE Related
Appalachian Power	($194,505)	$136,594	($57,912)	($196,316)	$160,186	($36,130)	($1,810)	$23,592	$21,782
Columbus Southern Power	($62,162)	$85,941	$23,778	($81,185)	$97,275	$16,090	($19,023)	$11,335	($7,688)
Indiana & Michigan Power	($111,162)	$76,299	($34,863)	($122,427)	$86,189	($36,238)	($11,265)	$9,890	($1,375)
Kingsport Power	($2,344)	$7,479	$5,135	($2,725)	$9,696	$6,971	($380)	$2,217	$1,836
Kentucky Power	($44,525)	$30,874	($13,652)	($53,381)	$34,578	($18,803)	($8,856)	$3,704	($5,151)
Ohio Power	($132,893)	$103,218	($29,675)	($154,755)	$120,344	($34,411)	($21,861)	$17,125	($4,736)
Wheeling Power	($3,086)	$6,231	$3,145	($1,753)	$7,712	$5,959	$1,333	$1,481	$2,814
Total	($550,679)	$446,635	($104,043)	($612,541)	$515,979	($96,562)	($61,862)	$69,344	$7,482

Net Change From Trans. Agreement Modification:

(Proposed - Present) Company	Net T-Related	Net LSE-Related	Net T & LSE Related	Net T-Related	Net LSE-Related	Net T & LSE Related	Net T-Related	Net LSE-Related	Net T & LSE Related
Appalachian Power	$10,713	$140	$10,853	$28,159	$3,940	$32,099	$17,446	$3,801	$21,246
Columbus Southern Power	($16,230)	$799	($15,431)	($24,237)	($658)	($24,895)	($8,007)	($1,457)	($9,464)
Indiana & Michigan Power	$36,828	($6,094)	$30,734	$36,658	($9,329)	$27,330	($169)	($3,235)	($3,404)
Kingsport Power	($2,344)	($2,217)	($4,562)	($2,725)	($1,293)	($4,017)	($380)	$925	$545
Kentucky Power	$1,428	($199)	$1,228	($2,346)	($2,110)	($4,457)	($3,774)	($1,911)	($5,685)
Ohio Power	($27,307)	$9,432	($17,875)	($33,757)	$10,511	($23,246)	($6,449)	$1,078	($5,371)
Wheeling Power	($3,086)	($1,861)	($4,947)	($1,753)	($1,062)	($2,814)	$1,333	$799	$2,133
Total	$0	($0)	($0)	($0)	($0)	$0	($0)	($0)	$0

AEP Transmission Agreement
Cost Impact Comparison of Present and Revised Allocations - 12CP
Revenues and Costs October 2007 - September 2008
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AEP as a Transmission Owner - Revenue Allocations

Present Allocation:

Company	A Total Sched. 1A (Credit)	a1 Third Party Sched. 1A (Credit) (MLR)	a2 Sched. 1A AEP LSE (Credit) (MLR)	a3 Sched. 1A Formula (Credit) (DA)	B Total T-Svc. (Credit)	b1 Third Party NTS (Credit) (MLR)	b2 NTS AEP LSE (Credit) (MLR)	b3 NTS AEP Formula (Credit) (DA)	C TEA Charge (Credit)	D GFA PTP (Credit) (MLR)	E ECRC (Credit) (TPM)	F SCRC (Credit) (TPM)	Total T-Related
Appalachian Power	**($3,920)**	($1,011)	($2,822)	($87)	**($169,457)**	($16,875)	($146,981)	($5,600)	**($26,813)**	**($3,638)**	**($708)**	**($682)**	($205,218)
Columbus Southern Power	**($2,272)**	($590)	($1,647)	($35)	**($97,614)**	($9,852)	($85,806)	($1,956)	**$56,634**	**($2,124)**	**($283)**	**($272)**	($45,932)
Indiana & Michigan Power	**($2,431)**	($569)	($1,586)	($276)	**($106,328)**	($9,487)	($82,634)	($14,207)	**($36,081)**	**($2,045)**	**($563)**	**($541)**	($147,990)
Kingsport Power	**$0**	$0	$0	$0	**$0**	$0	$0	$0	**$0**	**$0**	**$0**	**$0**	$0
Kentucky Power	**($821)**	($215)	($599)	($7)	**($35,369)**	($3,585)	($31,221)	($563)	**($8,655)**	**($773)**	**($171)**	**($164)**	($45,953)
Ohio Power	**($2,661)**	($702)	($1,959)	$0	**($113,737)**	($11,714)	($102,024)	$0	**$14,916**	**($2,525)**	**($804)**	**($774)**	($105,586)
Wheeling Power	**$0**	$0	$0	$0	**$0**	$0	$0	$0	**$0**	**$0**	**$0**	**$0**	$0
Total	**($12,105)**	($3,087)	($8,614)	($405)	**($522,505)**	($51,512)	($448,666)	($22,326)	**$0**	**($11,106)**	**($2,529)**	**($2,434)**	($550,679)

12CP Allocation:

Company	A Total Sched. 1A (Credit) (ARR S1)	a1 Third Party Sched. 1A (Credit) (ARR S1)	a2 Sched. 1A AEP LSE (Credit) (ARR S1)	a3 Sched. 1A Formula (Credit) (ARR S1)	B Total T-Svc. (Credit) (ATRR)	b1 Third Party NTS (Credit) (ATRR)	b2 NTS AEP LSE (Credit) (ATRR)	b3 NTS AEP Formula (Credit) (ATRR)	C Eliminate TEA Charge (Credit)	D GFA PTP (Credit) (ATRR)	E ECRC (Credit) (ARR ECRC)	F SCRC (Credit) (ARR SCRC)	Total T-Related
Appalachian Power	**($3,476)**	($887)	($2,474)	($116)	**($185,491)**	($18,287)	($159,278)	($7,926)	**$0**	**($3,943)**	**($903)**	**($692)**	($194,505)
Columbus Southern Power	**($1,338)**	($341)	($952)	($45)	**($59,051)**	($5,822)	($50,706)	($2,523)	**$0**	**($1,255)**	**($221)**	**($297)**	($62,162)
Indiana & Michigan Power	**($2,812)**	($717)	($2,001)	($94)	**($105,281)**	($10,379)	($90,403)	($4,499)	**$0**	**($2,238)**	**($317)**	**($513)**	($111,162)
Kingsport Power	**($62)**	($16)	($44)	($2)	**($2,224)**	($219)	($1,910)	($95)	**$0**	**($47)**	**($11)**	**$0**	($2,344)
Kentucky Power	**($501)**	($128)	($357)	($17)	**($42,768)**	($4,216)	($36,724)	($1,827)	**$0**	**($909)**	**($196)**	**($151)**	($44,525)
Ohio Power	**($3,860)**	($984)	($2,746)	($129)	**($124,732)**	($12,297)	($107,105)	($5,330)	**$0**	**($2,651)**	**($870)**	**($780)**	($132,893)
Wheeling Power	**($55)**	($14)	($39)	($2)	**($2,957)**	($292)	($2,539)	($126)	**$0**	**($63)**	**($11)**	**$0**	($3,086)
Total	**($12,105)**	($3,087)	($8,614)	($405)	**($522,505)**	($51,512)	($448,666)	($22,326)	**$0**	**($11,106)**	**($2,529)**	**($2,434)**	($550,679)

Net Change:

(Proposed - Present) Company	A Total Sched. 1A (Credit) (Net)	a1 Third Party Sched. 1A (Credit) (Net)	a2 Sched. 1A AEP LSE (Credit) (Net)	a3 Sched. 1A Formula (Credit) (Net)	B Total T-Svc. (Credit) (Net)	b1 Third Party NTS (Credit) (Net)	b2 NTS AEP LSE (Credit) (Net)	b3 NTS AEP Formula (Credit) (Net)	C Eliminate TEA (Net)	D GFA PTP (Credit) (Net)	E ECRC (Credit) (Net)	F SCRC (Credit) (Net)	**Net T-Related**
Appalachian Power	**$444**	$125	$348	($29)	**($16,034)**	($1,412)	($12,297)	($2,325)	**$26,813**	**($304)**	**($195)**	**($10)**	$10,713
Columbus Southern Power	**$934**	$249	$695	($10)	**$38,563**	$4,030	$35,100	($567)	**($56,634)**	**$869**	**$62**	**($25)**	($16,230)
Indiana & Michigan Power	**($382)**	($149)	($415)	$182	**$1,047**	($892)	($7,769)	$9,708	**$36,081**	**($192)**	**$245**	**$28**	$36,828
Kingsport Power	**($62)**	($16)	($44)	($2)	**($2,224)**	($219)	($1,910)	($95)	**$0**	**($47)**	**($11)**	**$0**	($2,344)
Kentucky Power	**$320**	$87	$243	($10)	**($7,399)**	($632)	($5,503)	($1,265)	**$8,655**	**($136)**	**($25)**	**$13**	$1,428
Ohio Power	**($1,199)**	($282)	($788)	($129)	**($10,995)**	($583)	($5,082)	($5,330)	**($14,916)**	**($126)**	**($65)**	**($7)**	($27,307)
Wheeling Power	**($55)**	($14)	($39)	($2)	**($2,957)**	($292)	($2,539)	($126)	**$0**	**($63)**	**($11)**	**$0**	($3,086)
Total	**$0**	($0)	$0	($0)	**$0**	$0	$0	$0	**$0**	**$0**	**$0**	**$0**	$0

AEP Transmission Agreement
Cost Impact Comparison of Present and Revised Allocations - 12CP
Revenues and Costs October 2007 - September 2008
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AEP as a Load Serving Entity - Cost Allocations

Present Allocation:

Company	G Sched. 1A AEP LSE Charge (MLR)	H Total NTS & Trans. Enh. Charge (MLR)	h1 NTS AEP LSE Charge (MLR)	h2 Sch. 12 Trans. Enh. Charge (MLR)	I Total PTP (Credit) (MLR)	i1 Third Party PTP Firm (Credit) (MLR)	i2 Third Party PTP Non-Firm (Credit) (MLR)	J PPA Charge (Credit)	K ECRC Charge (TPM)	L SCRC Charge (TPM)	Total LSE-Related
Appalachian Power	$2,822	$148,111	$146,981	$1,131	($5,759)	($3,985)	($1,774)	($9,696)	$373	$603	$136,454
Columbus Southern Power	$1,647	$86,466	$85,806	$660	($3,362)	($2,326)	($1,036)	$0	$149	$241	$85,142
Indiana & Michigan Power	$1,586	$83,269	$82,634	$636	($3,238)	($2,240)	($997)	$0	$296	$479	$82,393
Kingsport Power	$0	$0	$0	$0	$0	$0	$0	$9,696	$0	$0	$9,696
Kentucky Power	$599	$31,462	$31,221	$240	($1,223)	($847)	($377)	$0	$90	$145	$31,073
Ohio Power	$1,959	$102,808	$102,024	$785	($3,997)	($2,766)	($1,231)	($8,091)	$423	$685	$93,786
Wheeling Power	$0	$0	$0	$0	$0	$0	$0	$8,091	$0	$0	$8,091
Total	$8,614	$452,117	$448,666	$3,451	($17,579)	($12,165)	($5,415)	$0	$1,331	$2,153	$446,635

12CP Allocation:

Company	G Sched. 1A AEP LSE Charge (MWH)	H Total NTS & Trans. Enh. Charge (12CP)	h1 NTS AEP LSE Charge (12CP)	h2 Sch. 12 Trans. Enh. Charge (12CP)	I Total PTP (Credit) (12CP)	i1 Third Party PTP Firm (Credit) (12CP)	i2 Third Party PTP Non-Firm (Credit) (12CP)	J Eliminate PPA Charge (Credit)	K ECRC Charge (12CP)	L SCRC Charge (12CP)	Total LSE-Related
Appalachian Power	$2,548	$138,359	$137,303	$1,056	($5,380)	($3,723)	($1,657)	$0	$407	$659	$136,594
Columbus Southern Power	$1,609	$87,045	$86,380	$664	($3,384)	($2,342)	($1,042)	$0	$256	$414	$85,941
Indiana & Michigan Power	$1,470	$77,237	$76,647	$590	($3,003)	($2,078)	($925)	$0	$227	$368	$76,299
Kingsport Power	$157	$7,558	$7,500	$58	($294)	($203)	($91)	$0	$22	$36	$7,479
Kentucky Power	$536	$31,314	$31,075	$239	($1,218)	($843)	($375)	$0	$92	$149	$30,874
Ohio Power	$2,140	$104,331	$103,535	$796	($4,057)	($2,807)	($1,249)	$0	$307	$497	$103,218
Wheeling Power	$152	$6,274	$6,226	$48	($244)	($169)	($75)	$0	$18	$30	$6,231
Total	$8,614	$452,117	$448,666	$3,451	($17,579)	($12,165)	($5,415)	$0	$1,331	$2,153	$446,635

Net Change:

(Proposed - Present) Company	G Total 1A AEP LSE Charge (Net)	H Total NTS & Trans. Enh. Charge (Net)	h1 NTS AEP LSE Charge (Net)	h2 Sch. 12 Trans. Enh. Charge (Net)	I Total PTP (Credit) (Net)	i1 Third Party PTP Firm (Credit) (Net)	i2 Third Party MLR Non-Firm (Net)	J Eliminate PPA (Net)	K ECRC (Credit) (Net)	L SCRC (Credit) (Net)	**Net LSE-Related**
Appalachian Power	($274)	($9,752)	($9,678)	($74)	$379	$262	$117	$9,696	$34	$56	$140
Columbus Southern Power	($38)	$579	$574	$4	($22)	($16)	($7)	$0	$107	$174	$799
Indiana & Michigan Power	($116)	($6,032)	($5,986)	($46)	$235	$162	$72	$0	($69)	($111)	($6,094)
Kingsport Power	$157	$7,558	$7,500	$58	($294)	($203)	($91)	($9,696)	$22	$36	($2,217)
Kentucky Power	($63)	($148)	($147)	($1)	$6	$4	$2	$0	$2	$4	($199)
Ohio Power	$181	$1,523	$1,511	$12	($59)	($41)	($18)	$8,091	($116)	($188)	$9,432
Wheeling Power	$152	$6,274	$6,226	$48	($244)	($169)	($75)	($8,091)	$18	$30	($1,861)
Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	($0)	($0)

AEP Transmission Agreement
Cost Impact Comparison of Present and Revised Allocations - 12CP
Proformed for Rates Effective March 1, 2009 and 2009 Load Shares
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AEP as a Transmission Owner - Revenue Allocations

Present Allocation:

Company	A Total Sched. 1A (Credit)	a1 Third Party Sched. 1A (Credit) (MLR)	a2 Sched. 1A AEP LSE (Credit) (MLR)	a3 Sched. 1A Formula (Credit) (DA)	B Total T-Svc. (Credit)	b1 Third Party NTS (Credit) (MLR)	b2 NTS AEP LSE (Credit) (MLR)	b3 NTS AEP Formula (Credit) (DA)	b4 Sch. 12 Trans. Enh. Charge (MLR)	C TEA Charge (Credit)	D GFA PTP (Credit) (MLR)	E ECRC (Credit) (TPM)	F SCRC (Credit) (TPM)	Total T-Related
Appalachian Power	**($3,158)**	($840)	($2,246)	($73)	**($188,738)**	($17,840)	($165,086)	($5,740)	($73)	**($27,703)**	**($3,488)**	**($726)**	**($662)**	($224,474)
Columbus Southern Power	**($1,839)**	($493)	($1,318)	($29)	**($109,366)**	($10,466)	($96,853)	($2,005)	($43)	**$56,858**	**($2,046)**	**($290)**	**($264)**	($56,948)
Indiana & Michigan Power	**($1,987)**	($479)	($1,280)	($229)	**($118,847)**	($10,166)	($94,079)	($14,561)	($41)	**($35,161)**	**($1,988)**	**($577)**	**($526)**	($159,085)
Kingsport Power	**$0**	$0	$0	$0	**$0**	$0	$0	$0	$0	**$0**	**$0**	**$0**	**$0**	$0
Kentucky Power	**($682)**	($184)	($492)	($6)	**($40,701)**	($3,912)	($36,196)	($577)	($16)	**($8,553)**	**($765)**	**($175)**	**($159)**	($51,035)
Ohio Power	**($2,181)**	($594)	($1,587)	$0	**($129,337)**	($12,608)	($116,677)	$0	($51)	**$14,560**	**($2,465)**	**($824)**	**($751)**	($120,998)
Wheeling Power	**$0**	$0	$0	$0	**$0**	$0	$0	$0	$0	**$0**	**$0**	**$0**	**$0**	$0
Total	**($9,848)**	($2,589)	($6,923)	($336)	**($586,988)**	($54,992)	($508,890)	($22,882)	($224)	**$0**	**($10,751)**	**($2,591)**	**($2,362)**	($612,541)

12CP Allocation:

Company	A Total Sched. 1A (Credit) (ARR S1)	a1 Third Party Sched. 1A (Credit) (ARR S1)	a2 Sched. 1A AEP LSE (Credit) (ARR S1)	a3 Sched. 1A Formula (Credit) (ARR S1)	B Total T-Svc. (Credit) (ATRR)	b1 Third Party NTS (Credit) (ATRR)	b2 NTS AEP LSE (Credit) (ATRR)	b3 NTS AEP Formula (Credit) (ATRR)	b4 Sch. 12 Trans. Enh. Charge (ATRR)	C Eliminate TEA Charge (Credit)	D GFA PTP (Credit) (ATRR)	E ECRC (Credit) (ARR ECRC)	F SCRC (Credit) (ARR SCRC)	Total T-Related
Appalachian Power	**($3,518)**	($925)	($2,473)	($120)	**($187,762)**	($17,591)	($162,780)	($7,319)	($72)	**$0**	**($3,439)**	**($926)**	**($671)**	($196,316)
Columbus Southern Power	**($860)**	($226)	($604)	($29)	**($78,375)**	($7,343)	($67,947)	($3,055)	($30)	**$0**	**($1,436)**	**($226)**	**($288)**	($81,185)
Indiana & Michigan Power	**($1,235)**	($325)	($868)	($42)	**($118,204)**	($11,074)	($102,477)	($4,608)	($45)	**$0**	**($2,165)**	**($325)**	**($498)**	($122,427)
Kingsport Power	**($42)**	($11)	($30)	($1)	**($2,623)**	($246)	($2,274)	($102)	($1)	**$0**	**($48)**	**($11)**	**$0**	($2,725)
Kentucky Power	**($764)**	($201)	($537)	($26)	**($51,330)**	($4,809)	($44,500)	($2,001)	($20)	**$0**	**($940)**	**($201)**	**($146)**	($53,381)
Ohio Power	**($3,386)**	($890)	($2,380)	($116)	**($147,027)**	($13,774)	($127,465)	($5,731)	($56)	**$0**	**($2,693)**	**($891)**	**($758)**	($154,755)
Wheeling Power	**($43)**	($11)	($30)	($1)	**($1,668)**	($156)	($1,446)	($65)	($1)	**$0**	**($31)**	**($11)**	**$0**	($1,753)
Total	**($9,848)**	($2,589)	($6,923)	($336)	**($586,988)**	($54,992)	($508,890)	($22,882)	($224)	**$0**	**($10,751)**	**($2,591)**	**($2,362)**	($612,541)

Net Change:

(Proposed - Present) Company	A Total Sched. 1A (Credit) (Net)	a1 Third Party Sched. 1A (Credit) (Net)	a2 Sched. 1A AEP LSE (Credit) (Net)	a3 Sched. 1A Formula (Credit) (Net)	B Total T-Svc. (Credit) (Net)	b1 Third Party NTS (Credit) (Net)	b2 NTS AEP LSE (Credit) (Net)	b3 NTS AEP Formula (Credit) (Net)	b4 Sch. 12 Trans. Enh. Charge (Net)	C Eliminate TEA (Net)	D GFA PTP (Credit) (Net)	E ECRC (Credit) (Net)	F SCRC (Credit) (Net)	Net T-Related
Appalachian Power	**($359)**	($85)	($227)	($47)	**$976**	$249	$2,305	($1,579)	$1	**$27,703**	**$49**	**($200)**	**($10)**	$28,159
Columbus Southern Power	**$979**	$267	$713	($1)	**$30,991**	$3,124	$28,905	($1,051)	$13	**($56,858)**	**$611**	**$64**	**($24)**	($24,237)
Indiana & Michigan Power	**$752**	$154	$412	$187	**$644**	($908)	($8,398)	$9,953	($4)	**$35,161**	**($177)**	**$252**	**$27**	$36,658
Kingsport Power	**($42)**	($11)	($30)	($1)	**($2,623)**	($246)	($2,274)	($102)	($1)	**$0**	**($48)**	**($11)**	**$0**	($2,725)
Kentucky Power	**($82)**	($17)	($45)	($20)	**($10,629)**	($897)	($8,304)	($1,424)	($4)	**$8,553**	**($175)**	**($26)**	**$13**	($2,346)
Ohio Power	**($1,205)**	($297)	($793)	($116)	**($17,690)**	($1,166)	($10,788)	($5,731)	($5)	**($14,560)**	**($228)**	**($67)**	**($6)**	($33,757)
Wheeling Power	**($43)**	($11)	($30)	($1)	**($1,668)**	($156)	($1,446)	($65)	($1)	**$0**	**($31)**	**($11)**	**$0**	($1,753)
Total	**$0**	$0	($0)	$0	**$0**	($0)	($0)	$0	$0	**$0**	**($0)**	**($0)**	**$0**	($0)

AEP Transmission Agreement
Cost Impact Comparison of Present and Revised Allocations - 12CP
Proformed for Rates Effective March 1, 2009 and 2009 Load Shares
$(000)

AEP as a Load Serving Entity - Cost Allocations

Present Allocation:

Company	G Sched. 1A AEP LSE Charge (MLR)	H Total NTS & Trans. Enh. Charge (MLR)	*h1* *NTS AEP LSE Charge (MLR)*	*h2* *Sch. 12 Trans. Enh. Charge (MLR)*	I Total PTP (Credit) (MLR)	*i1* *Third Party PTP Firm (Credit) (MLR)*	*i2* *Third Party PTP Non-Firm (Credit) (MLR)*	J PPA Charge (Credit)	K ECRC Charge (TPM)	L SCRC Charge (TPM)	Total LSE-Related
Appalachian Power	**$2,246**	**$169,731**	$165,086	$4,645	**($5,703)**	($3,946)	($1,757)	**($10,988)**	**$368**	**$591**	$156,245
Columbus Southern Power	**$1,318**	**$99,578**	$96,853	$2,725	**($3,346)**	($2,315)	($1,031)	**$0**	**$147**	**$236**	$97,933
Indiana & Michigan Power	**$1,280**	**$96,726**	$94,079	$2,647	**($3,250)**	($2,249)	($1,001)	**$0**	**$293**	**$470**	$95,518
Kingsport Power	**$0**	**$0**	$0	$0	**$0**	$0	$0	**$10,988**	**$0**	**$0**	$10,988
Kentucky Power	**$492**	**$37,215**	$36,196	$1,019	**($1,250)**	($865)	($385)	**$0**	**$89**	**$142**	$36,688
Ohio Power	**$1,587**	**$119,960**	$116,677	$3,283	**($4,031)**	($2,789)	($1,241)	**($8,773)**	**$418**	**$671**	$109,833
Wheeling Power	**$0**	**$0**	$0	$0	**$0**	$0	$0	**$8,773**	**$0**	**$0**	$8,773
Total	**$6,923**	**$523,210**	$508,890	$14,320	**($17,579)**	($12,165)	($5,415)	**$0**	**$1,315**	**$2,111**	$515,979

12CP Allocation:

Company	G Sched. 1A AEP LSE Charge (MWH)	H Total NTS & Trans. Enh. Charge (12CP)	*h1* *NTS AEP LSE Charge (12CP)*	*h2* *Sch. 12 Trans. Enh. Charge (12CP)*	I Total PTP (Credit) (12CP)	*i1* *Third Party PTP Firm (Credit) (12CP)*	*i2* *Third Party PTP Non-Firm (Credit) (12CP)*	J Eliminate PPA Charge (Credit)	K ECRC Charge (12CP)	L SCRC Charge (12CP)	Total LSE-Related
Appalachian Power	**$2,062**	**$162,520**	$158,072	$4,448	**($5,461)**	($3,779)	($1,682)	**$0**	**$408**	**$656**	$160,186
Columbus Southern Power	**$1,306**	**$98,637**	$95,938	$2,700	**($3,314)**	($2,293)	($1,021)	**$0**	**$248**	**$398**	$97,275
Indiana & Michigan Power	**$1,197**	**$87,356**	$84,965	$2,391	**($2,935)**	($2,031)	($904)	**$0**	**$220**	**$352**	$86,189
Kingsport Power	**$125**	**$9,837**	$9,568	$269	**($331)**	($229)	($102)	**$0**	**$25**	**$40**	$9,696
Kentucky Power	**$448**	**$35,079**	$34,119	$960	**($1,179)**	($816)	($363)	**$0**	**$88**	**$142**	$34,578
Ohio Power	**$1,665**	**$121,978**	$118,640	$3,338	**($4,098)**	($2,836)	($1,262)	**$0**	**$307**	**$492**	$120,344
Wheeling Power	**$121**	**$7,802**	$7,589	$214	**($262)**	($181)	($81)	**$0**	**$20**	**$31**	$7,712
Total	**$6,923**	**$523,210**	$508,890	$14,320	**($17,579)**	($12,165)	($5,415)	**$0**	**$1,315**	**$2,111**	$515,979

Net Change:

(Proposed - Present) Company	G Total 1A AEP LSE Charge (Net)	H Total NTS & Trans. Enh. Charge (Net)	*h1* *NTS AEP LSE Charge (Net)*	*h2* *Sch. 12 Trans. Enh. Charge (Net)*	I Total PTP (Credit) (Net)	*i1* *Third Party PTP Firm (Credit) (Net)*	*i2* *Third Party MLR Non-Firm (Net)*	J Eliminate PPA (Net)	K ECRC (Credit) (Net)	L SCRC (Credit) (Net)	Net LSE-Related
Appalachian Power	**($184)**	**($7,211)**	($7,013)	($197)	**$242**	$168	$75	**$10,988**	**$40**	**$64**	$3,940
Columbus Southern Power	**($11)**	**($941)**	($915)	($26)	**$32**	$22	$10	**$0**	**$101**	**$162**	($658)
Indiana & Michigan Power	**($83)**	**($9,370)**	($9,114)	($256)	**$315**	$218	$97	**$0**	**($73)**	**($117)**	($9,329)
Kingsport Power	**$125**	**$9,837**	$9,568	$269	**($331)**	($229)	($102)	**($10,988)**	**$25**	**$40**	($1,293)
Kentucky Power	**($44)**	**($2,136)**	($2,078)	($58)	**$72**	$50	$22	**$0**	**($1)**	**($1)**	($2,110)
Ohio Power	**$78**	**$2,018**	$1,963	$55	**($68)**	($47)	($21)	**$8,773**	**($112)**	**($179)**	$10,511
Wheeling Power	**$121**	**$7,802**	$7,589	$214	**($262)**	($181)	($81)	**($8,773)**	**$20**	**$31**	($1,062)
Total	**$0**	**$0**	$0	$0	**$0**	$0	$0	**$0**	**$0**	**($0)**	($0)

AEP Transmission Agreement
AEP Member Peak Demands and Member Load Ratios (MLR)
2005 though Projected 2009

Year	Month	APCo Monthly Peak	APCo Rolling 12 Mo. Max	APCo MLR %	CSP Monthly Peak	CSP Rolling 12 Mo. Max	CSP MLR %	I&M Monthly Peak	I&M Rolling 12 Mo. Max	I&M MLR %	KPCo Monthly Peak	KPCo Rolling 12 Mo. Max	KPCo MLR %	OPCo Monthly Peak	OPCo Rolling 12 Mo. Max	OPCo MLR %	Total Load
2004	1	6,298			3,150			3,500			1,478			5,018			
2004	2	5,734			2,851			3,390			1,391			4,881			
2004	3	5,557			2,704			3,224			1,351			4,330			
2004	4	4,927			2,535			2,974			1,167			4,248			
2004	5	5,017			3,380			3,396			1,132			4,563			
2004	6	5,322			3,590			3,977			1,174			4,990			
2004	7	5,366			3,623			4,051			1,209			4,981			
2004	8	5,508			3,622			4,012			1,228			5,059			
2004	9	4,785			3,102			3,722			1,060			4,573			
2004	10	4,276			2,401			3,075			950			4,230			
2004	11	5,122			2,571			3,162			1,220			4,508			
2004	12	7,080			3,068			3,354			1,615			4,891			
2005	1	6,978	7,080	33.041%	3,074	3,623	16.908%	3,465	4,051	18.905%	1,685	1,615	7.537%	4,955	5,059	23.609%	21,428
2005	2	5,869	7,080	32.933%	2,778	3,623	16.853%	3,426	4,051	18.844%	1,319	1,685	7.838%	4,717	5,059	23.532%	21,498
2005	3	6,054	7,080	32.933%	2,862	3,623	16.853%	3,198	4,051	18.844%	1,429	1,685	7.838%	4,679	5,059	23.532%	21,498
2005	4	4,578	7,080	32.933%	2,344	3,623	16.853%	2,936	4,051	18.844%	1,075	1,685	7.838%	4,242	5,059	23.532%	21,498
2005	5	4,593	7,080	32.933%	2,795	3,623	16.853%	3,090	4,051	18.844%	1,112	1,685	7.838%	4,301	5,059	23.532%	21,498
2005	6	5,381	7,080	32.933%	3,779	3,623	16.853%	4,102	4,051	18.844%	1,236	1,685	7.838%	5,389	5,059	23.532%	21,498
2005	7	5,953	7,080	32.131%	4,105	3,779	17.150%	4,093	4,102	18.616%	1,358	1,685	7.647%	5,470	5,389	24.457%	22,035
2005	8	5,816	7,080	31.548%	3,976	4,105	18.292%	4,193	4,102	18.278%	1,310	1,685	7.508%	5,638	5,470	24.374%	22,442
2005	9	5,323	7,080	31.188%	3,295	4,105	18.083%	3,980	4,193	18.471%	1,181	1,685	7.423%	4,900	5,638	24.836%	22,701
2005	10	4,992	7,080	31.188%	2,962	4,105	18.083%	3,577	4,193	18.471%	1,125	1,685	7.423%	4,436	5,638	24.836%	22,701
2005	11	5,867	7,080	31.188%	2,746	4,105	18.083%	3,240	4,193	18.471%	1,370	1,685	7.423%	4,636	5,638	24.836%	22,701
2005	12	6,596	7,080	31.188%	3,212	4,105	18.083%	3,537	4,193	18.471%	1,665	1,685	7.423%	4,983	5,638	24.836%	22,701
2006	1	6,469	6,978	30.877%	3,392	4,105	18.165%	3,363	4,193	18.554%	1,426	1,685	7.456%	4,341	5,638	24.948%	22,599
2006	2	6,420	6,596	29.716%	3,043	4,105	18.493%	3,402	4,193	18.890%	1,468	1,665	7.501%	4,258	5,638	25.400%	22,197
2006	3	5,965	6,596	29.716%	2,973	4,105	18.493%	3,311	4,193	18.890%	1,342	1,665	7.501%	4,258	5,638	25.400%	22,197
2006	4	5,092	6,596	29.716%	2,624	4,105	18.493%	3,068	4,193	18.890%	1,153	1,665	7.501%	3,819	5,638	25.400%	22,197
2006	5	5,765	6,596	29.716%	3,909	4,105	18.493%	4,116	4,193	18.890%	1,256	1,665	7.501%	4,623	5,638	25.400%	22,197
2006	6	6,137	6,596	29.716%	3,902	4,105	18.493%	3,801	4,193	18.890%	1,293	1,665	7.501%	4,865	5,638	25.400%	22,197
2006	7	6,282	6,596	29.716%	4,313	4,105	18.493%	4,650	4,193	18.890%	1,362	1,665	7.501%	5,212	5,638	25.400%	22,197
2006	8	6,395	6,596	28.851%	4,425	4,313	18.865%	4,615	4,650	20.339%	1,388	1,665	7.283%	5,260	5,638	24.661%	22,862
2006	9	5,247	6,596	29.191%	2,990	4,425	19.583%	3,432	4,650	20.579%	1,087	1,665	7.369%	4,061	5,260	23.278%	22,596
2006	10	5,590	6,596	29.191%	2,921	4,425	19.583%	3,274	4,650	20.579%	1,242	1,665	7.369%	4,015	5,260	23.278%	22,596
2006	11	5,674	6,596	29.191%	2,868	4,425	19.583%	3,312	4,650	20.579%	1,310	1,665	7.369%	4,054	5,260	23.278%	22,596
2006	12	6,990	6,596	29.191%	3,283	4,425	19.583%	3,623	4,650	20.579%	1,636	1,665	7.369%	4,438	5,260	23.278%	22,596
2007	1	7,214	6,990	30.443%	3,436	4,425	19.272%	3,773	4,650	20.252%	1,549	1,636	7.125%	4,479	5,260	22.908%	22,961
2007	2	8,132	7,214	31.115%	3,694	4,425	19.086%	3,945	4,650	20.056%	1,665	1,636	7.056%	5,011	5,260	22.687%	23,185
2007	3	6,289	8,132	33.698%	3,180	4,425	18.337%	3,581	4,650	19.269%	1,350	1,665	6.900%	4,598	5,260	21.797%	24,132
2007	4	5,692	8,132	33.698%	2,941	4,425	18.337%	3,494	4,650	19.269%	1,303	1,665	6.900%	4,208	5,260	21.797%	24,132
2007	5	5,766	8,132	33.698%	3,954	4,425	18.337%	3,854	4,650	19.269%	1,140	1,665	6.900%	4,711	5,260	21.797%	24,132
2007	6	6,184	8,132	33.698%	4,333	4,425	18.337%	4,377	4,650	19.269%	1,306	1,665	6.900%	5,204	5,260	21.797%	24,132
2007	7	6,274	8,132	33.698%	4,305	4,425	18.337%	4,460	4,650	19.269%	1,226	1,665	6.900%	5,212	5,260	21.797%	24,132
2007	8	6,755	8,132	33.747%	4,713	4,425	18.363%	4,528	4,615	19.152%	1,348	1,665	6.910%	5,491	5,260	21.828%	24,097
2007	9	6,311	8,132	33.153%	4,171	4,713	19.214%	4,211	4,528	18.460%	1,203	1,665	6.788%	5,195	5,491	22.386%	24,529
2007	10	5,684	8,132	33.153%	3,955	4,713	19.214%	3,961	4,528	18.460%	1,096	1,665	6.788%	4,806	5,491	22.386%	24,529
2007	11	6,154	8,132	33.153%	3,121	4,713	19.214%	3,541	4,528	18.460%	1,287	1,665	6.788%	4,442	5,491	22.386%	24,529
2007	12	6,997	8,132	33.153%	3,495	4,713	19.214%	3,754	4,528	18.460%	1,418	1,665	6.788%	4,826	5,491	22.386%	24,529
2008	1	7,848	8,132	33.153%	3,727	4,713	19.214%	3,875	4,528	18.460%	1,678	1,665	6.788%	4,943	5,491	22.386%	24,529
2008	2	6,961	8,132	33.135%	3,634	4,713	19.204%	3,842	4,528	18.450%	1,437	1,678	6.837%	4,950	5,491	22.374%	24,542
2008	3	6,272	7,848	32.352%	3,322	4,713	19.429%	3,579	4,528	18.666%	1,304	1,678	6.917%	4,575	5,491	22.636%	24,258
2008	4	5,643	7,848	32.352%	2,908	4,713	19.429%	3,288	4,528	18.666%	1,100	1,678	6.917%	4,142	5,491	22.636%	24,258
2008	5	5,108	7,848	32.352%	3,087	4,713	19.429%	3,166	4,528	18.666%	986	1,678	6.917%	4,095	5,491	22.636%	24,258
2008	6	6,542	7,848	32.352%	4,406	4,713	19.429%	4,134	4,528	18.666%	1,249	1,678	6.917%	5,458	5,491	22.636%	24,258
2008	7	6,493	7,848	32.352%	4,380	4,713	19.429%	4,264	4,528	18.666%	1,247	1,678	6.917%	5,298	5,491	22.636%	24,258
2008	8	6,095	7,848	32.352%	4,277	4,713	19.429%	4,217	4,528	18.666%	1,170	1,678	6.917%	5,074	5,491	22.636%	24,258
2008	9	6,126	7,848	33.178%	4,403	4,406	18.627%	4,227	4,264	18.027%	1,204	1,678	7.094%	5,050	5,458	23.074%	23,654
2008	10	6,020	7,848	33.178%	3,100	4,406	18.627%	3,230	4,264	18.027%	1,212	1,678	7.094%	4,307	5,458	23.074%	23,654
2008	11	6,763	7,848	33.178%	3,480	4,406	18.627%	3,668	4,264	18.027%	1,381	1,678	7.094%	4,518	5,458	23.074%	23,654
2008	12	7,279	7,848	33.178%	3,582	4,406	18.627%	3,878	4,264	18.027%	1,514	1,678	7.094%	4,734	5,458	23.074%	23,654
2009	1	7,690	7,848	33.178%	3,636	4,406	18.627%	3,898	4,264	18.027%	1,690	1,678	7.094%	4,975	5,458	23.074%	23,654
2009	2	7,657	7,690	32.712%	3,494	4,406	18.743%	3,685	4,264	18.139%	1,558	1,690	7.189%	4,938	5,458	23.218%	23,508
2009	3	7,013	7,690	32.712%	3,544	4,406	18.743%	3,761	4,264	18.139%	1,479	1,690	7.189%	4,583	5,458	23.218%	23,508
2009	4	5,563	7,690	32.712%	3,249	4,406	18.743%	3,415	4,264	18.139%	1,212	1,690	7.189%	4,248	5,458	23.218%	23,508
2009	5	5,920	7,690	32.712%	3,796	4,406	18.743%	3,789	4,264	18.139%	1,170	1,690	7.189%	4,513	5,458	23.218%	23,508
2009	6	6,370	7,690	32.712%	4,439	4,406	18.743%	4,290	4,264	18.139%	1,299	1,690	7.189%	5,053	5,458	23.218%	23,508
2009	7	6,725	7,690	32.853%	4,675	4,439	18.964%	4,565	4,290	18.328%	1,365	1,690	7.220%	5,381	5,298	22.634%	23,407
2009	8	6,655	7,690	32.040%	4,559	4,675	19.478%	4,443	4,565	19.020%	1,317	1,690	7.041%	5,477	5,381	22.420%	24,001
2009	9	6,421	7,690	31.913%	4,132	4,675	19.401%	4,161	4,565	18.944%	1,183	1,690	7.013%	4,738	5,477	22.729%	24,097
2009	10	5,713	7,690	31.913%	3,504	4,675	19.401%	3,621	4,565	18.944%	1,144	1,690	7.013%	4,350	5,477	22.729%	24,097
2009	11	6,836	7,690	31.913%	3,507	4,675	19.401%	3,733	4,565	18.944%	1,389	1,690	7.013%	4,551	5,477	22.729%	24,097
2009	12	7,354	7,690	31.913%	3,595	4,675	19.401%	3,896	4,565	18.944%	1,523	1,690	7.013%	4,776	5,477	22.729%	24,097

	APCo MLR %	CSP MLR %	I&M MLR %	KPCo MLR %	OPCo MLR %
2005 AVERAGE	**32.178%**	**17.412%**	**18.658%**	**7.631%**	**24.120%**
2006 AVERAGE	**29.566%**	**18.860%**	**19.546%**	**7.435%**	**24.593%**
2007 AVERAGE	**33.034%**	**18.772%**	**19.137%**	**6.895%**	**22.163%**
2008 AVERAGE	**32.760%**	**19.125%**	**18.418%**	**6.959%**	**22.739%**
2009 AVERAGE	**32.440%**	**19.032%**	**18.487%**	**7.113%**	**22.928%**

ACTUAL
FORECASTED

AEP Member Peak Demands and Member Load Ratios (MLR)
2005 through Projected 2009

		APCo			CSP			I&M			KgPCo			KPCo			OPCo			WPCo			
Year	Month	Monthly Peak	Rolling 12 Mo. Max	MLR %	Monthly Peak	Rolling 12 Mo. Max	MLR %	Monthly Peak	Rolling 12 Mo. Max	MLR %	Monthly Peak	Rolling 12 Mo. Max	MLR %	Monthly Peak	Rolling 12 Mo. Max	MLR %	Monthly Peak	Rolling 12 Mo. Max	MLR %	Monthly Peak	Rolling 12 Mo. Max	MLR %	Total Load
2004	**1**	5,898			3,150			3,500			400			1,478			4,708			310			
2004	**2**	5,426			2,851			3,390			308			1,391			4,619			262			
2004	**3**	5,220			2,704			3,224			337			1,351			4,020			310			
2004	**4**	4,653			2,535			2,974			274			1,167			4,011			237			
2004	**5**	4,742			3,380			3,396			275			1,132			4,280			283			
2004	**6**	5,026			3,590			3,977			296			1,174			4,719			271			
2004	**7**	5,076			3,623			4,051			290			1,209			4,705			276			
2004	**8**	5,209			3,622			4,012			299			1,228			4,770			289			
2004	**9**	4,503			3,102			3,722			282			1,060			4,296			277			
2004	**10**	4,056			2,401			3,075			220			950			3,984			246			
2004	**11**	4,825			2,571			3,162			297			1,220			4,242			266			
2004	**12**	6,644			3,068			3,354			436			1,615			4,586			305			
2005	**1**	6,538	6,644	30.976%	3,074	3,623	16.891%	3,465	4,051	18.887%	440	436	2.033%	1,685	1,615	7.530%	4,621	4,770	22.240%	334	310	1.443%	21,449
2005	**2**	5,525	6,644	30.835%	2,778	3,623	16.814%	3,426	4,051	18.801%	344	440	2.041%	1,319	1,685	7.820%	4,429	4,770	22.139%	288	334	1.550%	21,547
2005	**3**	5,692	6,644	30.835%	2,862	3,623	16.814%	3,198	4,051	18.801%	362	440	2.041%	1,429	1,685	7.820%	4,355	4,770	22.139%	324	334	1.550%	21,547
2005	**4**	4,299	6,644	30.835%	2,344	3,623	16.814%	2,936	4,051	18.801%	279	440	2.041%	1,075	1,685	7.820%	3,944	4,770	22.139%	298	334	1.550%	21,547
2005	**5**	4,345	6,644	30.835%	2,795	3,623	16.814%	3,090	4,051	18.801%	248	440	2.041%	1,112	1,685	7.820%	4,048	4,770	22.139%	253	334	1.550%	21,547
2005	**6**	5,073	6,644	30.835%	3,779	3,623	16.814%	4,102	4,051	18.801%	308	440	2.041%	1,236	1,685	7.820%	5,167	4,770	22.139%	222	334	1.550%	21,547
2005	**7**	5,628	6,644	29.994%	4,105	3,779	17.060%	4,093	4,102	18.518%	325	440	1.986%	1,358	1,685	7.607%	5,158	5,167	23.327%	312	334	1.508%	22,151
2005	**8**	5,486	6,644	29.559%	3,976	4,105	18.263%	4,193	4,102	18.250%	330	440	1.957%	1,310	1,685	7.497%	5,328	5,167	22.989%	310	334	1.486%	22,477
2005	**9**	5,015	6,644	29.232%	3,295	4,105	18.061%	3,980	4,193	18.448%	308	440	1.935%	1,181	1,685	7.414%	4,658	5,328	23.441%	242	334	1.469%	22,728
2005	**10**	4,717	6,644	29.232%	2,962	4,105	18.061%	3,577	4,193	18.448%	275	440	1.935%	1,125	1,685	7.414%	4,195	5,328	23.441%	241	334	1.469%	22,728
2005	**11**	5,516	6,644	29.232%	2,746	4,105	18.061%	3,240	4,193	18.448%	351	440	1.935%	1,370	1,685	7.414%	4,321	5,328	23.441%	315	334	1.469%	22,728
2005	**12**	6,212	6,644	29.232%	3,212	4,105	18.061%	3,537	4,193	18.448%	384	440	1.935%	1,665	1,685	7.414%	4,713	5,328	23.441%	270	334	1.469%	22,728
2006	**1**	6,120	6,538	28.901%	3,392	4,105	18.146%	3,363	4,193	18.535%	349	440	1.944%	1,426	1,685	7.448%	4,050	5,328	23.550%	291	334	1.476%	22,623
2006	**2**	6,037	6,212	27.968%	3,043	4,105	18.482%	3,402	4,193	18.878%	383	384	1.729%	1,468	1,665	7.496%	4,002	5,328	23.987%	256	324	1.458%	22,210
2006	**3**	5,644	6,212	27.968%	2,973	4,105	18.482%	3,311	4,193	18.878%	321	384	1.729%	1,342	1,665	7.496%	4,015	5,328	23.987%	243	324	1.458%	22,210
2006	**4**	4,822	6,212	27.980%	2,624	4,105	18.490%	3,068	4,193	18.886%	270	384	1.730%	1,153	1,665	7.499%	3,607	5,328	23.997%	212	315	1.419%	22,202
2006	**5**	5,458	6,212	27.980%	3,909	4,105	18.490%	4,116	4,193	18.886%	307	384	1.730%	1,256	1,665	7.499%	4,347	5,328	23.997%	276	315	1.419%	22,202
2006	**6**	5,822	6,212	27.980%	3,902	4,105	18.490%	3,801	4,193	18.886%	315	384	1.730%	1,293	1,665	7.499%	4,596	5,328	23.997%	269	315	1.419%	22,202
2006	**7**	5,964	6,212	27.980%	4,313	4,105	18.490%	4,650	4,193	18.886%	318	384	1.730%	1,362	1,665	7.499%	4,912	5,328	23.997%	300	315	1.419%	22,202
2006	**8**	6,065	6,212	27.166%	4,425	4,313	18.862%	4,615	4,650	20.335%	330	384	1.680%	1,388	1,665	7.281%	4,950	5,328	23.299%	310	315	1.377%	22,867
2006	**9**	4,954	6,212	27.486%	2,990	4,425	19.579%	3,432	4,650	20.575%	293	384	1.699%	1,087	1,665	7.367%	3,754	4,950	21.900%	307	315	1.393%	22,600
2006	**10**	5,300	6,212	27.486%	2,921	4,425	19.579%	3,274	4,650	20.575%	290	384	1.699%	1,242	1,665	7.367%	3,731	4,950	21.900%	284	315	1.393%	22,600
2006	**11**	5,349	6,212	27.486%	2,868	4,425	19.579%	3,312	4,650	20.575%	325	384	1.699%	1,310	1,665	7.367%	3,768	4,950	21.900%	286	315	1.393%	22,600
2006	**12**	6,610	6,212	27.491%	3,283	4,425	19.583%	3,623	4,650	20.579%	380	384	1.700%	1,636	1,665	7.369%	4,182	4,950	21.904%	256	310	1.374%	22,596
2007	**1**	6,831	6,610	28.784%	3,436	4,425	19.270%	3,773	4,650	20.250%	383	383	1.666%	1,549	1,636	7.124%	4,206	4,950	21.554%	273	310	1.352%	22,963
2007	**2**	7,711	6,831	29.463%	3,694	4,425	19.086%	3,945	4,650	20.056%	421	383	1.652%	1,665	1,636	7.056%	4,699	4,950	21.348%	312	310	1.339%	23,185
2007	**3**	5,957	7,711	31.953%	3,180	4,425	18.336%	3,581	4,650	19.268%	332	421	1.743%	1,350	1,665	6.899%	4,282	4,950	20.509%	316	312	1.291%	24,133
2007	**4**	5,390	7,711	31.948%	2,941	4,425	18.333%	3,494	4,650	19.265%	302	421	1.743%	1,303	1,665	6.898%	3,992	4,950	20.506%	216	316	1.308%	24,137
2007	**5**	5,462	7,711	31.948%	3,954	4,425	18.333%	3,854	4,650	19.265%	304	421	1.743%	1,140	1,665	6.898%	4,382	4,950	20.506%	329	316	1.308%	24,137
2007	**6**	5,856	7,711	31.930%	4,333	4,425	18.322%	4,377	4,650	19.254%	328	421	1.742%	1,306	1,665	6.894%	4,925	4,950	20.494%	279	329	1.363%	24,151
2007	**7**	5,938	7,711	31.930%	4,305	4,425	18.322%	4,460	4,650	19.254%	336	421	1.742%	1,226	1,665	6.894%	4,917	4,950	20.494%	295	329	1.363%	24,151
2007	**8**	6,396	7,711	31.976%	4,713	4,425	18.349%	4,528	4,615	19.137%	359	421	1.744%	1,348	1,665	6.904%	5,167	4,950	20.524%	324	329	1.365%	24,116
2007	**9**	5,983	7,711	31.431%	4,171	4,713	19.210%	4,211	4,528	18.456%	328	421	1.715%	1,203	1,665	6.787%	4,889	5,167	21.059%	306	329	1.342%	24,534
2007	**10**	5,393	7,711	31.431%	3,955	4,713	19.210%	3,961	4,528	18.456%	291	421	1.715%	1,096	1,665	6.787%	4,465	5,167	21.059%	341	329	1.342%	24,534
2007	**11**	5,816	7,711	31.416%	3,121	4,713	19.201%	3,541	4,528	18.447%	338	421	1.714%	1,287	1,665	6.783%	4,178	5,167	21.049%	264	341	1.390%	24,546
2007	**12**	6,593	7,711	31.416%	3,495	4,713	19.201%	3,754	4,528	18.447%	404	421	1.714%	1,418	1,665	6.783%	4,541	5,167	21.049%	285	341	1.390%	24,546
2008	**1**	7,387	7,711	31.416%	3,727	4,713	19.201%	3,875	4,528	18.447%	461	421	1.714%	1,678	1,665	6.783%	4,663	5,167	21.049%	280	341	1.390%	24,546
2008	**2**	6,579	7,711	31.348%	3,634	4,713	19.159%	3,842	4,528	18.407%	382	461	1.874%	1,437	1,678	6.821%	4,625	5,167	21.003%	325	341	1.387%	24,599
2008	**3**	5,924	7,387	30.431%	3,322	4,713	19.415%	3,579	4,528	18.653%	348	461	1.899%	1,304	1,678	6.913%	4,312	5,167	21.284%	263	341	1.406%	24,275
2008	**4**	5,330	7,387	30.431%	2,908	4,713	19.415%	3,288	4,528	18.653%	313	461	1.899%	1,100	1,678	6.913%	3,846	5,167	21.284%	296	341	1.406%	24,275
2008	**5**	4,840	7,387	30.431%	3,087	4,713	19.415%	3,166	4,528	18.653%	268	461	1.899%	986	1,678	6.913%	3,830	5,167	21.284%	265	341	1.406%	24,275
2008	**6**	6,200	7,387	30.431%	4,406	4,713	19.415%	4,134	4,528	18.653%	342	461	1.899%	1,249	1,678	6.913%	5,122	5,167	21.284%	336	341	1.406%	24,275
2008	**7**	6,155	7,387	30.431%	4,380	4,713	19.415%	4,264	4,528	18.653%	338	461	1.899%	1,247	1,678	6.913%	5,001	5,167	21.284%	297	341	1.406%	24,275
2008	**8**	5,770	7,387	30.431%	4,277	4,713	19.415%	4,217	4,528	18.653%	325	461	1.899%	1,170	1,678	6.913%	4,761	5,167	21.284%	313	341	1.406%	24,275
2008	**9**	5,798	7,387	31.223%	4,403	4,406	18.623%	4,227	4,264	18.023%	328	461	1.948%	1,204	1,678	7.092%	4,757	5,122	21.649%	293	341	1.442%	23,659
2008	**10**	5,690	7,387	31.223%	3,100	4,406	18.623%	3,230	4,264	18.023%	330	461	1.948%	1,212	1,678	7.092%	4,010	5,122	21.649%	1	341	1.442%	23,659
2008	**11**	6,370	7,387	31.230%	3,480	4,406	18.627%	3,668	4,264	18.027%	393	461	1.948%	1,381	1,678	7.094%	4,234	5,122	21.653%	284	336	1.421%	23,654
2008	**12**	6,876	7,387	31.230%	3,582	4,406	18.627%	3,878	4,264	18.027%	403	461	1.948%	1,514	1,678	7.094%	4,409	5,122	21.653%	325	336	1.421%	23,654
2009	**1**	7,282	7,387	31.230%	3,636	4,406	18.627%	3,898	4,264	18.027%	408	461	1.948%	1,690	1,678	7.094%	4,649	5,122	21.653%	326	336	1.421%	23,654
2009	**2**	7,232	7,282	30.976%	3,494	4,406	18.743%	3,685	4,264	18.139%	425	408	1.736%	1,558	1,690	7.189%	4,610	5,122	21.788%	328	336	1.430%	23,508
2009	**3**	6,645	7,282	30.954%	3,544	4,406	18.729%	3,761	4,264	18.125%	368	425	1.807%	1,479	1,690	7.184%	4,294	5,122	21.772%	289	336	1.429%	23,525
2009	**4**	5,259	7,282	30.954%	3,249	4,406	18.729%	3,415	4,264	18.125%	304	425	1.807%	1,212	1,690	7.184%	3,952	5,122	21.772%	296	336	1.429%	23,525
2009	**5**	5,623	7,282	30.954%	3,796	4,406	18.729%	3,789	4,264	18.125%	297	425	1.807%	1,170	1,690	7.184%	4,178	5,122	21.772%	335	336	1.429%	23,525
2009	**6**	6,045	7,282	30.954%	4,439	4,406	18.729%	4,290	4,264	18.125%	325	425	1.807%	1,299	1,690	7.184%	4,685	5,122	21.772%	368	336	1.429%	23,525
2009	**7**	6,389	7,282	30.993%	4,675	4,439	18.893%	4,565	4,290	18.259%	336	425	1.810%	1,365	1,690	7.193%	5,071	5,001	21.287%	310	368	1.564%	23,495
2009	**8**	6,315	7,282	30.245%	4,559	4,675	19.418%	4,443	4,565	18.961%	340	425	1.766%	1,317	1,690	7.019%	5,145	5,071	21.064%	332	368	1.527%	24,076
2009	**9**	6,105	7,282	30.153%	4,132	4,675	19.358%	4,161	4,565	18.903%	316	425	1.761%	1,183	1,690	6.998%	4,391	5,145	21.306%	347	368	1.522%	24,150
2009	**10**	5,401	7,282	30.153%	3,504	4,675	19.358%	3,621	4,565	18.903%	312	425	1.761%	1,144	1,690	6.998%	4,081	5,145	21.306%	269	368	1.522%	24,150
2009	**11**	6,478	7,282	30.153%	3,507	4,675	19.358%	3,733	4,565	18.903%	358	425	1.761%	1,389	1,690	6.998%	4,234	5,145	21.306%	317	368	1.522%	24,150
2009	**12**	6,947	7,282	30.153%	3,595	4,675	19.358%	3,896	4,565	18.903%	407	425	1.761%	1,523	1,690	6.998%	4,482	5,145	21.306%	294	368	1.522%	24,150
		2005 AVERAGE		**30.136%**			**17.378%**			**18.621%**			**1.994%**			**7.616%**			**22.751%**			**1.505%**	
		2006 AVERAGE		**27.823%**			**18.854%**			**19.540%**			**1.733%**			**7.433%**			**23.201%**			**1.416%**	
		2007 AVERAGE		**31.302%**			**18.764%**			**19.130%**			**1.719%**			**6.892%**			**20.846%**			**1.346%**	
		2008 AVERAGE		**30.855%**			**19.113%**			**18.406%**			**1.898%**			**6.954%**			**21.363%**			**1.411%**	
		2009 AVERAGE		**30.656%**			**19.002%**			**18.458%**			**1.794%**			**7.102%**			**21.509%**			**1.479%**	

ACTUAL | **FORECASTED**

AEP Transmission Agreement
Monthly AEP Coincident Demand Allocation Factors for PJM NSPLs
Effective 2005 Through 2009

	APCo		CSP		I&M		KgPCo		KPCo		OPCo		WPCo		
	Monthly NSPL		Monthly NSPL		Monthly NSPL		Monthly NSPL		Monthly NSPL		Monthly NSPL		Monthly NSPL		TOTAL
	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%	MW
Nov-03	4,690	29.089%	2,581	16.008%	3,192	19.798%	320	1.985%	1,210	7.505%	3,894	24.152%	236	1.464%	16,123
Dec-03	5,224	29.771%	2,985	17.011%	3,290	18.750%	306	1.744%	1,230	7.010%	4,302	24.517%	210	1.197%	17,547
Jan-04	5,803	30.610%	3,012	15.888%	3,409	17.982%	383	2.020%	1,444	7.617%	4,598	24.254%	309	1.630%	18,958
Feb-04	5,426	30.953%	2,727	15.556%	3,224	18.391%	308	1.757%	1,302	7.427%	4,279	24.410%	264	1.506%	17,530
Mar-04	5,220	31.621%	2,510	15.205%	2,982	18.064%	337	2.041%	1,351	8.184%	3,793	22.977%	315	1.908%	16,508
Apr-04	4,485	29.532%	2,393	15.757%	2,884	18.990%	308	2.028%	1,167	7.684%	3,730	24.560%	220	1.449%	15,187
May-04	4,607	28.293%	3,380	20.758%	2,763	16.969%	275	1.689%	1,085	6.663%	3,931	24.142%	242	1.486%	16,283
Jun-04	**5,737**	**29.443%**	**3,572**	**18.332%**	**3,880**	**19.913%**	**285**	**1.463%**	**1,134**	**5.820%**	**4,601**	**23.613%**	**276**	**1.416%**	**19,485**
Jul-04	5,076	26.833%	3,623	19.152%	3,771	19.934%	290	1.533%	1,204	6.365%	4,680	24.740%	273	1.443%	18,917
Aug-04	4,873	25.581%	3,622	19.014%	3,977	20.878%	306	1.606%	1,212	6.363%	4,771	25.046%	288	1.512%	19,049
Sep-04	4,257	25.438%	3,091	18.470%	3,635	21.721%	270	1.613%	1,040	6.215%	4,174	24.942%	268	1.601%	16,735
Oct-04	3,836	26.431%	2,401	16.544%	2,969	20.458%	220	1.516%	874	6.022%	3,965	27.320%	248	1.709%	14,513
1CP (Jun-04)	**5,737**	**29.443%**	**3,572**	**18.332%**	**3,880**	**19.913%**	**285**	**1.463%**	**1,134**	**5.820%**	**4,601**	**23.613%**	**276**	**1.416%**	**19,485**
12CP Avg.	**59,234**	**28.638%**	**35,897**	**17.355%**	**39,976**	**19.327%**	**3,608**	**1.744%**	**14,253**	**6.891%**	**50,718**	**24.521%**	**3,149**	**1.522%**	**206,835**
Net Change		**-0.805%**		**-0.977%**		**-0.585%**		**0.282%**		**1.071%**		**0.908%**		**0.106%**	

	APCo		CSP		I&M		KgPCo		KPCo		OPCo		WPCo		
	Monthly NSPL		Monthly NSPL		Monthly NSPL		Monthly NSPL		Monthly NSPL		Monthly NSPL		Monthly NSPL		TOTAL
	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%	MW
Nov-04	4,358	27.537%	2,526	15.961%	3,131	19.784%	258	1.630%	1,045	6.603%	4,243	26.810%	265	1.674%	15,826
Dec-04	6,600	33.648%	2,933	14.953%	3,297	16.809%	435	2.218%	1,615	8.233%	4,450	22.687%	285	1.453%	19,615
Jan-05	6,525	32.961%	3,021	15.261%	3,452	17.438%	405	2.046%	1,602	8.093%	4,470	22.580%	321	1.622%	19,796
Feb-05	5,517	30.701%	2,682	14.925%	3,426	19.065%	338	1.881%	1,319	7.340%	4,397	24.469%	291	1.619%	17,970
Mar-05	5,478	30.632%	2,862	16.004%	3,198	17.883%	341	1.907%	1,329	7.432%	4,350	24.325%	325	1.817%	17,883
Apr-05	4,113	28.674%	2,191	15.275%	2,674	18.642%	262	1.827%	1,035	7.216%	3,810	26.562%	259	1.806%	14,344
May-05	4,119	26.809%	2,790	18.159%	2,900	18.875%	263	1.712%	1,037	6.750%	3,995	26.002%	260	1.692%	15,364
Jun-05	4,879	24.969%	3,728	19.079%	4,094	20.952%	301	1.540%	1,149	5.880%	5,166	26.438%	223	1.141%	19,540
Jul-05	**5,576**	**26.841%**	**4,021**	**19.356%**	**4,035**	**19.423%**	**325**	**1.564%**	**1,347**	**6.484%**	**5,165**	**24.863%**	**305**	**1.468%**	**20,774**
Aug-05	5,330	25.842%	3,933	19.069%	4,199	20.359%	327	1.585%	1,299	6.298%	5,277	25.585%	260	1.261%	20,625
Sep-05	4,629	25.559%	3,286	18.144%	3,947	21.793%	267	1.474%	1,130	6.239%	4,604	25.421%	248	1.369%	18,111
Oct-05	4,084	25.213%	2,894	17.866%	3,559	21.972%	262	1.617%	1,051	6.488%	4,102	25.324%	246	1.519%	16,198
1CP (Jul-05)	**5,576**	**26.841%**	**4,021**	**19.356%**	**4,035**	**19.423%**	**325**	**1.564%**	**1,347**	**6.484%**	**5,165**	**24.863%**	**305**	**1.468%**	**20,774**
12CP Avg.	**61,208**	**28.331%**	**36,867**	**17.064%**	**41,912**	**19.400%**	**3,784**	**1.751%**	**14,958**	**6.924%**	**54,029**	**25.008%**	**3,288**	**1.522%**	**216,046**
Net Change		**1.490%**		**-2.292%**		**-0.024%**		**0.187%**		**0.439%**		**0.145%**		**0.054%**	

	APCo		CSP		I&M		KgPCo		KPCo		OPCo		WPCo		
	Monthly NSPL		Monthly NSPL		Monthly NSPL		Monthly NSPL		Monthly NSPL		Monthly NSPL		Monthly NSPL		TOTAL
	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%	MW
Nov-05	5,516	32.010%	2,641	15.326%	2,948	17.108%	351	2.037%	1,370	7.950%	4,101	23.799%	305	1.770%	17,232
Dec-05	6,212	31.687%	3,100	15.813%	3,446	17.578%	384	1.959%	1,627	8.299%	4,546	23.189%	289	1.474%	19,604
Jan-06	6,111	34.172%	2,847	15.920%	3,064	17.134%	357	1.996%	1,394	7.795%	3,807	21.288%	303	1.694%	17,883
Feb-06	5,872	32.819%	2,992	16.723%	3,220	17.997%	335	1.872%	1,347	7.529%	3,860	21.574%	266	1.487%	17,892
Mar-06	5,277	30.921%	2,973	17.421%	3,041	17.819%	266	1.559%	1,251	7.330%	4,016	23.532%	242	1.418%	17,066
Apr-06	4,795	31.550%	2,418	15.910%	2,804	18.450%	282	1.856%	1,139	7.494%	3,521	23.168%	239	1.573%	15,198
May-06	5,426	28.327%	3,741	19.530%	3,914	20.433%	312	1.629%	1,240	6.474%	4,238	22.125%	284	1.483%	19,155
Jun-06	5,536	28.939%	3,894	20.355%	3,488	18.233%	307	1.605%	1,223	6.393%	4,413	23.068%	269	1.406%	19,130
Jul-06	5,592	26.806%	4,220	20.229%	4,160	19.942%	334	1.601%	1,343	6.438%	4,909	23.532%	303	1.452%	20,861
Aug-06	**5,832**	**27.485%**	**4,425**	**20.854%**	**4,055**	**19.110%**	**333**	**1.569%**	**1,362**	**6.419%**	**4,890**	**23.045%**	**322**	**1.518%**	**21,219**
Sep-06	4,366	27.900%	2,990	19.107%	2,999	19.164%	269	1.719%	1,021	6.524%	3,687	23.561%	317	2.026%	15,649
Oct-06	4,997	26.272%	2,773	14.579%	5,841	30.710%	289	1.519%	1,125	5.915%	3,728	19.600%	267	1.404%	19,020
1CP (Aug-06)	**5,832**	**27.485%**	**4,425**	**20.854%**	**4,055**	**19.110%**	**333**	**1.569%**	**1,362**	**6.419%**	**4,890**	**23.045%**	**322**	**1.518%**	**21,219**
12CP Avg.	**65,532**	**29.800%**	**39,014**	**17.741%**	**42,980**	**19.544%**	**3,819**	**1.737%**	**15,442**	**7.022%**	**49,716**	**22.608%**	**3,406**	**1.549%**	**219,909**
Net Change		**2.315%**		**-3.113%**		**0.434%**		**0.167%**		**0.603%**		**-0.438%**		**0.031%**	

	APCo		CSP		I&M		KgPCo		KPCo		OPCo		WPCo		
	Monthly NSPL		Monthly NSPL		Monthly NSPL		Monthly NSPL		Monthly NSPL		Monthly NSPL		Monthly NSPL		TOTAL
	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%	MW
Nov-06	5,215	31.993%	2,776	17.027%	2,762	16.942%	316	1.938%	1,288	7.904%	3,690	22.637%	254	1.558%	16,301
Dec-06	6,098	32.778%	3,253	17.484%	3,117	16.753%	319	1.715%	1,463	7.866%	4,108	22.081%	246	1.322%	18,604
Jan-07	6,500	33.643%	3,243	16.786%	3,210	16.616%	367	1.900%	1,655	8.568%	4,064	21.033%	281	1.454%	19,321
Feb-07	7,559	36.257%	3,505	16.812%	3,133	15.027%	249	1.194%	1,786	8.569%	4,386	21.038%	230	1.103%	20,847
Mar-07	5,545	31.165%	3,159	17.753%	3,006	16.894%	306	1.720%	1,284	7.219%	4,232	23.783%	261	1.467%	17,793
Apr-07	5,241	31.583%	2,808	16.919%	2,827	17.036%	310	1.868%	1,286	7.752%	3,903	23.516%	220	1.326%	16,595
May-07	5,306	29.129%	3,912	21.476%	3,111	17.081%	309	1.696%	1,120	6.152%	4,214	23.138%	242	1.329%	18,214
Jun-07	5,685	28.267%	4,282	21.290%	3,559	17.696%	326	1.621%	1,189	5.914%	4,810	23.916%	261	1.298%	20,112
Jul-07	5,716	28.036%	4,283	21.008%	3,727	18.281%	334	1.638%	1,208	5.927%	4,824	23.662%	295	1.447%	20,387
Aug-07	**6,070**	**28.452%**	**4,615**	**21.630%**	**3,719**	**17.428%**	**350**	**1.640%**	**1,290**	**6.048%**	**4,980**	**23.340%**	**312**	**1.462%**	**21,336**
Sep-07	5,636	28.289%	4,136	20.757%	3,511	17.623%	332	1.666%	1,168	5.864%	4,866	24.420%	275	1.380%	19,924
Oct-07	5,161	28.003%	3,900	21.161%	3,245	17.611%	291	1.579%	1,040	5.646%	4,507	24.453%	285	1.546%	18,429
1CP (Aug-07)	**6,070**	**28.452%**	**4,615**	**21.630%**	**3,719**	**17.428%**	**350**	**1.640%**	**1,290**	**6.048%**	**4,980**	**23.340%**	**312**	**1.462%**	**21,336**
12CP Avg.	**69,732**	**30.603%**	**43,870**	**19.253%**	**38,927**	**17.083%**	**3,809**	**1.672%**	**15,782**	**6.926%**	**52,582**	**23.076%**	**3,162**	**1.388%**	**227,864**
Net Change		**2.151%**		**-2.377%**		**-0.345%**		**0.031%**		**0.878%**		**-0.264%**		**-0.075%**	

	APCo		CSP		I&M		KgPCo		KPCo		OPCo		WPCo		
	Monthly NSPL		Monthly NSPL		Monthly NSPL		Monthly NSPL		Monthly NSPL		Monthly NSPL		Monthly NSPL		TOTAL
	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%	MW
Nov-07	5,631	32.356%	3,005	17.269%	2,917	16.765%	338	1.942%	1,268	7.289%	3,989	22.925%	253	1.454%	17,402
Dec-07	6,386	33.276%	3,273	17.058%	3,132	16.323%	404	2.105%	1,392	7.256%	4,331	22.569%	271	1.412%	19,189
Jan-08	**7,177**	**34.183%**	**3,624**	**17.261%**	**3,273**	**15.592%**	**460**	**2.191%**	**1,624**	**7.736%**	**4,532**	**21.588%**	**304**	**1.448%**	**20,994**
Feb-08	6,225	31.832%	3,514	17.970%	3,227	16.501%	396	2.025%	1,417	7.248%	4,490	22.961%	286	1.463%	19,555
Mar-08	5,732	32.717%	3,038	17.337%	2,904	16.577%	361	2.060%	1,226	7.000%	3,986	22.751%	273	1.558%	17,521
Apr-08	5,168	32.031%	2,783	17.250%	2,705	16.764%	318	1.971%	1,083	6.715%	3,856	23.900%	221	1.370%	16,136
May-08	4,614	30.078%	2,928	19.092%	2,616	17.052%	260	1.695%	957	6.237%	3,737	24.366%	227	1.480%	15,339
Jun-08	5,867	28.644%	4,219	20.599%	3,489	17.035%	336	1.640%	1,230	6.007%	5,016	24.488%	325	1.587%	20,484
Jul-08	5,890	29.528%	4,260	21.359%	3,271	16.399%	320	1.604%	1,228	6.158%	4,683	23.478%	294	1.474%	19,947
Aug-08	5,503	28.047%	4,126	21.030%	3,545	18.066%	325	1.656%	1,149	5.859%	4,674	23.824%	298	1.519%	19,620
Sep-08	5,470	27.975%	4,273	21.851%	3,396	17.365%	338	1.728%	1,156	5.914%	4,628	23.668%	293	1.498%	19,555
Oct-08	5,494	32.514%	2,928	17.328%	2,696	15.957%	330	1.953%	1,193	7.063%	3,981	23.558%	275	1.627%	16,898
1CP (Jan-08)	**7,177**	**34.183%**	**3,624**	**17.261%**	**3,273**	**15.592%**	**460**	**2.191%**	**1,624**	**7.736%**	**4,532**	**21.588%**	**304**	**1.448%**	**20,994**
12CP Avg.	**69,157**	**31.062%**	**41,973**	**18.852%**	**37,172**	**16.696%**	**4,186**	**1.880%**	**14,927**	**6.705%**	**51,905**	**23.313%**	**3,320**	**1.491%**	**222,639**
Net Change		**-3.121%**		**1.591%**		**1.104%**		**-0.311%**		**-1.032%**		**1.725%**		**0.043%**	

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Actual Year End Balances and Derivation of Projected 2009 EHV Investments

Investment in EHV and 138kV Transmission Facilities In-Service as of 12/31/07

Description	Comined AEP	APCo	CSP	I&M	KPCo	OPCo
EHV Transmission Facilities In-Svc.	$3,368,737,800	$1,235,650,700	$326,269,100	$837,540,000	$280,374,500	$688,903,500

Investment in EHV and 138kV Transmission Facilities In-Service as of 12/31/08

Description	Comined AEP	APCo	CSP	I&M	KPCo	OPCo
EHV Transmission Facilities In-Svc.	$3,514,128,600	$1,292,745,300	$343,850,600	$856,020,600	$298,147,600	$723,364,500

EHV Transmission Investment - 2008

Description	Comined AEP	APCo	CSP	I&M	KPCo	OPCo
Net Increase EHV Trans. In-Svc.	**$145,390,800**	**$57,094,600**	**$17,581,500**	**$18,480,600**	**$17,773,100**	**$34,461,000**

MEMBER GROSS AND NET TRANSMISSION INVESTMENT
Per TRANSMISSION AGREEMENT, Dated April 1, 1984
as AMENDED and SUPPLEMENTED
Final BALANCES as of 12/31/2007

AEP POOL MEMBER	MEMBER EHV TRANSMISSION INVESTMENT (before ITC) $	MEMBER GENERATED INVESTMENT TAX CREDIT $	MEMBER ITC ADJUSTMENT FACTOR	MEMBER ADJUSTED INVESTMENT TAX CREDIT $	MEMBER BULK TRANSMISSION INVESTMENT (net of ITC) $	ADDITIONAL TRANSMISSION INVESTMENT IN 2008 $	2008 YEAR END MEMBER BULK TRANSMISSION INVESTMENT $
(1)	(2)	(3)	(4)	(5)=(3)*(4)	(6)=(2)-(5)	(7)	(8)=(6)+(7)
APCO	1,235,650,700	29,959,448	0.79127	23,706,012	1,211,944,688	57,094,600	1,269,039,288
KPCO	280,374,500	7,727,622	0.79211	6,121,127	274,253,373	17,773,100	292,026,473
I&M	837,540,000	32,295,029	0.79220	25,584,122	811,955,878	18,480,600	830,436,478
OPCO	688,903,500	21,362,144	0.78515	16,772,487	672,131,013	34,461,000	706,592,013
CSP	326,269,100	8,201,491	0.80245	6,581,286	319,687,814	17,581,500	337,269,314
TOTAL	3,368,737,800	99,545,734		78,765,034	3,289,972,766	145,390,800	3,435,363,566

	TOTAL BULK TRANSMISSION EQUALIZATION RECEIPTS $	TOTAL BULK TRANSMISSION EQUALIZATION PAYMENTS $
APCO	**27,702,885**	**0**
KPCO	**8,552,923**	**0**
I&M	**35,161,331**	**0**
OPCO	**0**	**14,559,536**
CSP	**0**	**56,857,603**
TOTAL	**71,417,139**	**71,417,139**

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JANUARY

	FACTORS ASSOCIATED WITH SETTLEMENT					SETTLEMENT		
AEP POOL MEMBER	JAN MLR	MEMBER BULK TRANSMISSION INVESTMENT (net of ITC) PAGE 1, COL. 6 $	MEMBER BULK TRANSMISSION OBLIGATION COL. 2 ALLOC. USING MLR $	MEMBER BULK TRANSMISSION SURPLUS $	MEMBER BULK TRANSMISSION DEFICIT $	MONTHLY CARRYING CHARGE	BULK TRANSMISSION EQUALIZATION RECEIPTS $	BULK TRANSMISSION EQUALIZATION PAYMENTS $
	(1)	(2)	(3)	(4)=(2)-(3)	(5)=(3)-(2)	(6)	(7)=(4)*(6)	(8)=(5)/SUM COL. 5 *SUM COL. 7
APCO	0.33178	1,269,039,288	1,139,795,944	129,243,344	0	1.4933%	1,929,991	0
KPCO	0.07094	292,026,473	243,702,548	48,323,925	0	1.4950%	722,443	0
I&M	0.18027	830,436,478	619,277,511	211,158,967	0	1.5000%	3,167,385	0
OPCO	0.23074	706,592,013	792,686,833	0	86,094,820	1.4508%	0	1,288,970
CSP	0.18627	337,269,314	639,900,730	0	302,631,416	1.5733%	0	4,530,849
TOTAL	1.00000	3,435,363,566	3,435,363,566	388,726,236	388,726,236	---	5,819,819	5,819,819

FEBRUARY

	FACTORS ASSOCIATED WITH SETTLEMENT					SETTLEMENT		
AEP POOL MEMBER	FEB MLR	MEMBER BULK TRANSMISSION INVESTMENT (net of ITC) PAGE 1, COL. 6 $	MEMBER BULK TRANSMISSION OBLIGATION COL. 2 ALLOC. USING MLR $	MEMBER BULK TRANSMISSION SURPLUS $	MEMBER BULK TRANSMISSION DEFICIT $	MONTHLY CARRYING CHARGE	BULK TRANSMISSION EQUALIZATION RECEIPTS $	BULK TRANSMISSION EQUALIZATION PAYMENTS $
	(1)	(2)	(3)	(4)=(2)-(3)	(5)=(3)-(2)	(6)	(7)=(4)*(6)	(8)=(5)/SUM COL. 5 *SUM COL. 7
APCO	0.32712	1,269,039,288	1,123,785,342	145,253,946	0	1.4933%	2,169,077	0
KPCO	0.07189	292,026,473	246,969,731	45,056,742	0	1.4950%	673,598	0
I&M	0.18139	830,436,478	623,123,628	207,312,850	0	1.5000%	3,109,693	0
OPCO	0.23218	706,592,013	797,609,935	0	91,017,922	1.4508%	0	1,362,525
CSP	0.18743	337,269,314	643,874,931	0	306,605,617	1.5733%	0	4,589,843
TOTAL	1.00000	3,435,363,566	3,435,363,567	397,623,538	397,623,539	---	5,952,368	5,952,368

MARCH

	FACTORS ASSOCIATED WITH SETTLEMENT					SETTLEMENT		
AEP POOL MEMBER	MAR MLR	MEMBER BULK TRANSMISSION INVESTMENT (net of ITC) PAGE 1, COL. 6 $	MEMBER BULK TRANSMISSION OBLIGATION COL. 2 ALLOC. USING MLR $	MEMBER BULK TRANSMISSION SURPLUS $	MEMBER BULK TRANSMISSION DEFICIT $	MONTHLY CARRYING CHARGE	BULK TRANSMISSION EQUALIZATION RECEIPTS $	BULK TRANSMISSION EQUALIZATION PAYMENTS $
	(1)	(2)	(3)	(4)=(2)-(3)	(5)=(3)-(2)	(6)		(8)=(5)/SUM COL. 5 *SUM COL. 7
APCO	0.32712	1,269,039,288	1,123,785,342	145,253,946	0	1.4933%	2,169,077	0
KPCO	0.07189	292,026,473	246,969,731	45,056,742	0	1.4950%	673,598	0
I&M	0.18139	830,436,478	623,123,628	207,312,850	0	1.5000%	3,109,693	0
OPCO	0.23218	706,592,013	797,609,935	0	91,017,922	1.4508%	0	1,362,525
CSP	0.18743	337,269,314	643,874,931	0	306,605,617	1.5733%	0	4,589,843
TOTAL	1.00000	3,435,363,566	3,435,363,567	397,623,538	397,623,539	---	5,952,368	5,952,368

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APRIL

		FACTORS ASSOCIATED WITH SETTLEMENT				SETTLEMENT		
AEP POOL MEMBER	APR MLR	MEMBER BULK TRANSMISSION INVESTMENT (net of ITC) PAGE 1, COL. 6 $	MEMBER BULK TRANSMISSION OBLIGATION COL. 2 ALLOC. USING MLR $	MEMBER BULK TRANSMISSION SURPLUS $	MEMBER BULK TRANSMISSION DEFICIT $	MONTHLY CARRYING CHARGE	BULK TRANSMISSION EQUALIZATION RECEIPTS $	BULK TRANSMISSION EQUALIZATION PAYMENTS $
	(1)	(2)	(3)	(4)=(2)-(3)	(5)=(3)-(2)	(6)	(7)=(4)*(6)	(8)=(5)/SUM COL. 5 *SUM COL. 7
APCO	0.32712	1,269,039,288	1,123,785,342	145,253,946	0	1.4933%	2,169,077	0
KPCO	0.07189	292,026,473	246,969,731	45,056,742	0	1.4950%	673,598	0
I&M	0.18139	830,436,478	623,123,628	207,312,850	0	1.5000%	3,109,693	0
OPCO	0.23218	706,592,013	797,609,935	0	91,017,922	1.4508%	0	1,362,525
CSP	0.18743	337,269,314	643,874,931	0	306,605,617	1.5733%	0	4,589,843
TOTAL	1.00000	3,435,363,566	3,435,363,567	397,623,538	397,623,539	---	5,952,368	5,952,368

MAY

		FACTORS ASSOCIATED WITH SETTLEMENT				SETTLEMENT		
AEP POOL MEMBER	MAY MLR	MEMBER BULK TRANSMISSION INVESTMENT (net of ITC) PAGE 1, COL. 6 $	MEMBER BULK TRANSMISSION OBLIGATION COL. 2 ALLOC. USING MLR $	MEMBER BULK TRANSMISSION SURPLUS $	MEMBER BULK TRANSMISSION DEFICIT $	MONTHLY CARRYING CHARGE	BULK TRANSMISSION EQUALIZATION RECEIPTS $	BULK TRANSMISSION EQUALIZATION PAYMENTS $
	(1)	(2)	(3)	(4)=(2)-(3)	(5)=(3)-(2)	(6)	(7)=(4)*(6)	(8)=(5)/SUM COL. 5 *SUM COL. 7
APCO	0.32712	1,269,039,288	1,123,785,342	145,253,946	0	1.4933%	2,169,077	0
KPCO	0.07189	292,026,473	246,969,731	45,056,742	0	1.4950%	673,598	0
I&M	0.18139	830,436,478	623,123,628	207,312,850	0	1.5000%	3,109,693	0
OPCO	0.23218	706,592,013	797,609,935	0	91,017,922	1.4508%	0	1,362,525
CSP	0.18743	337,269,314	643,874,931	0	306,605,617	1.5733%	0	4,589,843
TOTAL	1.00000	3,435,363,566	3,435,363,567	397,623,538	397,623,539	---	5,952,368	5,952,368

JUNE

		FACTORS ASSOCIATED WITH SETTLEMENT				SETTLEMENT		
AEP POOL MEMBER	JUN MLR	MEMBER BULK TRANSMISSION INVESTMENT (net of ITC) PAGE 1, COL. 6 $	MEMBER BULK TRANSMISSION OBLIGATION COL. 2 ALLOC. USING MLR $	MEMBER BULK TRANSMISSION SURPLUS $	MEMBER BULK TRANSMISSION DEFICIT $	MONTHLY CARRYING CHARGE	BULK TRANSMISSION EQUALIZATION RECEIPTS $	BULK TRANSMISSION EQUALIZATION PAYMENTS $
	(1)	(2)	(3)	(4)=(2)-(3)	(5)=(3)-(2)	(6)	(7)=(4)*(6)	(8)=(5)/SUM COL. 5 *SUM COL. 7
APCO	0.32712	1,269,039,288	1,123,785,342	145,253,946	0	1.4933%	2,169,077	0
KPCO	0.07189	292,026,473	246,969,731	45,056,742	0	1.4950%	673,598	0
I&M	0.18139	830,436,478	623,123,628	207,312,850	0	1.5000%	3,109,693	0
OPCO	0.23218	706,592,013	797,609,935	0	91,017,922	1.4508%	0	1,362,525
CSP	0.18743	337,269,314	643,874,931	0	306,605,617	1.5733%	0	4,589,843
TOTAL	1.00000	3,435,363,566	3,435,363,567	397,623,538	397,623,539	---	5,952,368	5,952,368

AEP Transmission Agreement
Summary (page 1) and Monthly Calculations of
Projected 2009 Transmission Agreement Settlements

JULY

		FACTORS ASSOCIATED WITH SETTLEMENT					SETTLEMENT	
AEP POOL MEMBER	JUL MLR	MEMBER BULK TRANSMISSION INVESTMENT (net of ITC) PAGE 1, COL. 6 $	MEMBER BULK TRANSMISSION OBLIGATION COL. 2 ALLOC. USING MLR $	MEMBER BULK TRANSMISSION SURPLUS $	MEMBER BULK TRANSMISSION DEFICIT $	MONTHLY CARRYING CHARGE	BULK TRANSMISSION EQUALIZATION RECEIPTS $	BULK TRANSMISSION EQUALIZATION PAYMENTS $
	(1)	(2)	(3)	(4)=(2)-(3)	(5)=(3)-(2)	(6)	(7)=(4)*(6)	(8)=(5)/SUM COL. 5 *SUM COL. 7
APCO	0.32853	1,269,039,288	1,128,634,418	140,404,870	0	1.4933%	2,096,666	0
KPCO	0.07220	292,026,473	248,035,392	43,991,081	0	1.4950%	657,667	0
I&M	0.18328	830,436,478	629,628,303	200,808,175	0	1.5000%	3,012,123	0
OPCO	0.22634	706,592,013	777,568,940	0	70,976,927	1.4508%	0	1,062,515
CSP	0.18964	337,269,314	651,496,513	0	314,227,199	1.5733%	0	4,703,941
TOTAL	1.00000	3,435,363,566	3,435,363,566	385,204,126	385,204,126	---	5,766,456	5,766,456

AUGUST

		FACTORS ASSOCIATED WITH SETTLEMENT					SETTLEMENT	
AEP POOL MEMBER	AUG MLR	MEMBER BULK TRANSMISSION INVESTMENT (net of ITC) PAGE 1, COL. 6 $	MEMBER BULK TRANSMISSION OBLIGATION COL. 2 ALLOC. USING MLR $	MEMBER BULK TRANSMISSION SURPLUS $	MEMBER BULK TRANSMISSION DEFICIT $	MONTHLY CARRYING CHARGE	BULK TRANSMISSION EQUALIZATION RECEIPTS $	BULK TRANSMISSION EQUALIZATION PAYMENTS $
	(1)	(2)	(3)	(4)=(2)-(3)	(5)=(3)-(2)	(6)	(7)=(4)*(6)	(8)=(5)/SUM COL. 5 *SUM COL. 7
APCO	0.32040	1,269,039,288	1,100,701,880	168,337,408	0	1.4933%	2,513,783	0
KPCO	0.07041	292,026,473	241,896,772	50,129,701	0	1.4950%	749,439	0
I&M	0.19020	830,436,478	653,407,553	177,028,925	0	1.5000%	2,655,434	0
OPCO	0.22420	706,592,013	770,205,048	0	63,613,035	1.4508%	0	951,978
CSP	0.19478	337,269,314	669,152,313	0	331,882,999	1.5733%	0	4,966,678
TOTAL	1.00000	3,435,363,566	3,435,363,566	395,496,034	395,496,034	---	5,918,656	5,918,656

SEPTEMBER

		FACTORS ASSOCIATED WITH SETTLEMENT					SETTLEMENT	
AEP POOL MEMBER	SEP MLR	MEMBER BULK TRANSMISSION INVESTMENT (net of ITC) PAGE 1, COL. 6 $	MEMBER BULK TRANSMISSION OBLIGATION COL. 2 ALLOC. USING MLR $	MEMBER BULK TRANSMISSION SURPLUS $	MEMBER BULK TRANSMISSION DEFICIT $	MONTHLY CARRYING CHARGE	BULK TRANSMISSION EQUALIZATION RECEIPTS $	BULK TRANSMISSION EQUALIZATION PAYMENTS $
	(1)	(2)	(3)	(4)=(2)-(3)	(5)=(3)-(2)	(6)	(7)=(4)*(6)	(8)=(5)/SUM COL. 5 *SUM COL. 7
APCO	0.31913	1,269,039,288	1,096,316,796	172,722,492	0	1.4933%	2,579,265	0
KPCO	0.07013	292,026,473	240,933,080	51,093,393	0	1.4950%	763,846	0
I&M	0.18944	830,436,478	650,804,444	179,632,034	0	1.5000%	2,694,481	0
OPCO	0.22729	706,592,013	780,822,768	0	74,230,755	1.4508%	0	1,110,862
CSP	0.19401	337,269,314	666,486,478	0	329,217,164	1.5733%	0	4,926,730
TOTAL	1.00000	3,435,363,566	3,435,363,566	403,447,919	403,447,919	---	6,037,592	6,037,592

AEP Transmission Agreement
Summary (page 1) and Monthly Calculations of
Projected 2009 Transmission Agreement Settlements

OCTOBER

		FACTORS ASSOCIATED WITH SETTLEMENT					SETTLEMENT	
AEP POOL MEMBER	OCT MLR	MEMBER BULK TRANSMISSION INVESTMENT (net of ITC) PAGE 1, COL. 6 $	MEMBER BULK TRANSMISSION OBLIGATION COL. 2 ALLOC. USING MLR $	MEMBER BULK TRANSMISSION SURPLUS $	MEMBER BULK TRANSMISSION DEFICIT $	MONTHLY CARRYING CHARGE	BULK TRANSMISSION EQUALIZATION RECEIPTS $	BULK TRANSMISSION EQUALIZATION PAYMENTS $
	(1)	(2)	(3)	(4)=(2)-(3)	(5)=(3)-(2)	(6)	(7)=(4)*(6)	(8)=(5)/SUM COL. 5 *SUM COL. 7
APCO	0.31913	1,269,039,288	1,096,316,796	172,722,492	0	1.4933%	2,579,265	0
KPCO	0.07013	292,026,473	240,933,080	51,093,393	0	1.4950%	763,846	0
I&M	0.18944	830,436,478	650,804,444	179,632,034	0	1.5000%	2,694,481	0
OPCO	0.22729	706,592,013	780,822,768	0	74,230,755	1.4508%	0	1,110,862
CSP	0.19401	337,269,314	666,486,478	0	329,217,164	1.5733%	0	4,926,730
TOTAL	1.00000	3,435,363,566	3,435,363,566	403,447,919	403,447,919	---	6,037,592	6,037,592

NOVEMBER

		FACTORS ASSOCIATED WITH SETTLEMENT					SETTLEMENT	
AEP POOL MEMBER	NOV MLR	MEMBER BULK TRANSMISSION INVESTMENT (net of ITC) PAGE 1, COL. 6 $	MEMBER BULK TRANSMISSION OBLIGATION COL. 2 ALLOC. USING MLR $	MEMBER BULK TRANSMISSION SURPLUS $	MEMBER BULK TRANSMISSION DEFICIT $	MONTHLY CARRYING CHARGE	BULK TRANSMISSION EQUALIZATION RECEIPTS $	BULK TRANSMISSION EQUALIZATION PAYMENTS $
	(1)	(2)	(3)	(4)=(2)-(3)	(5)=(3)-(2)	(6)	(7)=(4)*(6)	(8)=(5)/SUM COL. 5 *SUM COL. 7
APCO	0.31913	1,269,039,288	1,096,316,796	172,722,492	0	1.4933%	2,579,265	0
KPCO	0.07013	292,026,473	240,933,080	51,093,393	0	1.4950%	763,846	0
I&M	0.18944	830,436,478	650,804,444	179,632,034	0	1.5000%	2,694,481	0
OPCO	0.22729	706,592,013	780,822,768	0	74,230,755	1.4508%	0	1,110,862
CSP	0.19401	337,269,314	666,486,478	0	329,217,164	1.5733%	0	4,926,730
TOTAL	1.00000	3,435,363,566	3,435,363,566	403,447,919	403,447,919	---	6,037,592	6,037,592

DECEMBER

		FACTORS ASSOCIATED WITH SETTLEMENT					SETTLEMENT	
AEP POOL MEMBER	DEC MLR	MEMBER BULK TRANSMISSION INVESTMENT (net of ITC) PAGE 1, COL. 6 $	MEMBER BULK TRANSMISSION OBLIGATION COL. 2 ALLOC. USING MLR $	MEMBER BULK TRANSMISSION SURPLUS $	MEMBER BULK TRANSMISSION DEFICIT $	MONTHLY CARRYING CHARGE	BULK TRANSMISSION EQUALIZATION RECEIPTS $	BULK TRANSMISSION EQUALIZATION PAYMENTS $
	(1)	(2)	(3)	(4)=(2)-(3)	(5)=(3)-(2)	(6)	(7)=(4)*(6)	(8)=(5)/SUM COL. 5 *SUM COL. 7
APCO	0.31913	1,269,039,288	1,096,316,796	172,722,492	0	1.4933%	2,579,265	0
KPCO	0.07013	292,026,473	240,933,080	51,093,393	0	1.4950%	763,846	0
I&M	0.18944	830,436,478	650,804,444	179,632,034	0	1.5000%	2,694,481	0
OPCO	0.22729	706,592,013	780,822,768	0	74,230,755	1.4508%	0	1,110,862
CSP	0.19401	337,269,314	666,486,478	0	329,217,164	1.5733%	0	4,926,730
TOTAL	1.00000	3,435,363,566	3,435,363,566	403,447,919	403,447,919	---	6,037,592	6,037,592

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; (4) An Order Approving Accounting Practices To Establish Regulatory Assets Or Liabilities; And (5) An Order Granting All Other Required Approvals And Relief	)))))))))	Case No. 2017-00179

TESTIMONY OF

MATTHEW J. SATTERWHITE

ON BEHALF OF KENTUCKY POWER COMPANY

IN SUPPORT OF THE SETTLEMENT AGREEMENT

SETTLEMENT TESTIMONY OF
MATTHEW J. SATTERWHITE, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2017-00179

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SETTLEMENT TESTIMONY OF
MATTHEW J. SATTERWHITE, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND POSITION WITH KENTUCKY POWER COMPANY.

A. My name is Matthew J. Satterwhite, and I am the President and Chief Operating Officer of Kentucky Power Company ("Kentucky Power" or "Company").

Q. DID YOU FILE TESTIMONY IN THIS RATE PROCEEDING?

A. Yes. I filed both direct testimony and rebuttal testimony.

Q ARE YOU FAMILIAR WITH THE ISSUES PRESENTED IN THIS CASE BY THE COMPANY AND THE OTHER PARTIES GRANTED INTERVENTION?

A. Yes.

Q. DID YOU PARTICIPATE IN THE NEGOTIATIONS WHICH LED TO THE SETTLEMENT AGREEMENT BEING SUBMITTED FOR CONSIDERATION AND APPROVAL BY THE COMMISSION?

A. Yes. I participated in an initial informal meeting on October 24, 2017 at the Company's office in Frankfort with the parties to the case and informal conferences on October 26, 2017 and November 7, 2017 at the Commission that led to the agreement in principle. The Settlement Agreement is attached as **EXHIBIT MJS-S1**.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In my testimony I explain and support the terms of the Settlement Agreement, as well as demonstrating why the terms of the Settlement Agreement will produce fair, just, and reasonable rates. The underlying support for the issues in the case-in-chief is still sponsored by the Company witnesses sponsoring those issues. My testimony explains the deviation from the Company's filed case and summarizes the settlement process leading to those changes.

II. <u>THE SETTLEMENT AGREEMENT</u>

Q. PLEASE DESCRIBE GENERALLY THE AREAS ADDRESSED BY THE SETTLEMENT AGREEMENT.

A. The comprehensive Settlement Agreement addresses a number of substantive areas that differ from the Company's June 28, 2017 application in this case ("June 2017 Application") as updated on August 8, 2017 to reflect the impact of June 2017 refinancing activities on the Company's application ("August 2017 Refinancing Update"). The Settlement Agreement only reflects changes to the June 2017 Application and the August 2017 Refinancing Update. Unless otherwise altered in the Settlement Agreement, the Signatory Parties agreed to the proposed rates and other changes to the Company's terms and conditions of providing service set forth in the June 2017 Application and the August 2017 Refinancing Update (Paragraph 1). For example, the parties agreed to the Company's 2017 Environmental Compliance Plan as filed.

The major terms of the Settlement Agreement are:

1. A net annual increase in the Company's retail revenues of $31,780,734 (Paragraph 2) which represents a decrease of $28,616,704 from the requested $60,397,438 set forth in the August 2017 Refinancing Update;

2. Establishment of deferral and recovery mechanisms for $50 million of Rockport Unit Power Agreement ("UPA") Expenses (Paragraph 3);

3. Changes to the proposed Tariff P.P.A. to recover 80% of the change in annual PJM OATT LSE expense as compared to the annual amount included in base rates and to include an offset for the difference in return on transmission system investment (Paragraph 4);

4. An agreement by the Company to not file a request to change the general base rates for rates to be effective until the first day of the January 2021 billing cycle in exchange for the other provisions outlined in the agreement (Paragraph 5);

5. An agreement to change the depreciation rates for Big Sandy Unit 1 to use the 20 year expected life of the unit and a further adjustment to depreciation rates for Big Sandy Unit 1 and the Mitchell Plant to remove terminal net salvage costs for the setting of rates at this time (Paragraph 7);

6. The establishment of a return on equity of 9.75% and an update to the Company's capitalization to reflect short term debt as 1% of the Company's total capital structure (Paragraph 8);

7. Amortization of the remaining deferred storm expense regulatory asset authorized in Case No. 2012-00445 and the deferred storm expense regulatory asset from Case No. 2016-00180 over a five-year period beginning with approval of the settlement agreement in this case at an annual amount of $2,092,867 (Paragraph 9);

8. Amendment to the proposed structure of the Kentucky economic development surcharge ("KEDS") to decrease the residential charge to $0.10 per month and increase the non-residential per meter charge to $1.00 per month and to adjust the matching contribution by the Company (Paragraph 10);

9. A commitment to work with Marathon Petroleum on a backup and maintenance service agreement or to seek a Commission ruling if an agreement cannot be reached (Paragraph 11);

10. Inclusion of the DSM-based School Energy Manager Program as a program for Commission approval in the 2018 and 2019 DSM program filings and the extension of Tariff K-12 School which will now include private schools (Paragraphs 12 and 13);

11. Acceptance of the bill formatting changes proposed by the Company and a commitment by the Company to conduct training sessions with representatives from municipal customers to discuss bill format and tools available to better understand bills (Paragraphs 14);

12. Approval of the Renewable Power Option Rider with amended language to allow customers with meters under the same parent company to aggregate for purposes of qualifying for Option B (Paragraph 15).

13. Increase in the Company's customer charge for Tariff R.S. to $14.00 per month (Paragraph 16(a));

14. Approval of certain other new tariffs set out in the Company's application, as well as modifications of the Company's existing tariffs (Paragraph 16(b)); and

15. Approval of a new pole attachment rates under Tariff C.A.T.V. of $10.82 for attachments on two-user poles and $6.71 for attachments on three-user poles (Paragraph 16(c)).

I discuss each of these areas, and the pertinent terms, in more detail below. In addition, the Settlement Agreement contains standard terms regarding its operation, interpretation, and applicability. Chief among these is Paragraph 19, which stresses the importance of Commission approval of the Settlement Agreement in its entirety. The Parties understand that no agreement binds the Commission in its ultimate initial jurisdiction over a general rate case filed before it. However, the Settlement Agreement represents significant give and take among the Signatory Parties. Further, the Company believes many of the items agreed to involve commitments beyond the unilateral authority of a regulatory body to impose absent an agreement, such as the Company's commitment to a base rate case "stay out."

Q. BEFORE DISCUSSING THE SPECIFIC TERMS OF THE SETTLEMENT AGREEMENT, PLEASE IDENTIFY THE PARTIES TO THE AGREEMENT.

A. The settling parties in this case include: Kentucky Power, Kentucky Industrial Utility Customers, Inc. ("KIUC"), Kentucky School Boards Association, ("KSBA"), Kentucky League of Cities ("KLC"); Wal-Mart Stores East, LP and Sam's East, Inc. ("Wal-Mart"); and Kentucky Cable Telecommunications Association ("KCTA") (collectively "Signatory Parties").

Q. ARE THERE OTHER PARTIES TO THIS PROCEEDING WHO ARE NOT SIGNATORIES TO THE SETTLEMENT AGREEMENT?

A. Yes. The Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention, ("Attorney General") and Kentucky Commercial Utility Customers, Inc. ("KCUC") are not signatories to the Settlement Agreement.

Q. WERE ALL PARTIES TO THIS PROCEEDING OFFERED THE OPPORTUNITY TO PARTICIPATE IN THE NEGOTIATIONS THAT LED TO THE EXECUTION OF THE SETTLEMENT AGREEMENT?

A. Yes. Representatives of the Office of the Attorney General attended the informal meeting on October 24, 2017 and the October 26, 2017 informal conference at the Commission. They indicated they would not attend the November 7, 2017 informal conference because of a scheduling conflict. In an e-mail exchange with Commission Staff on November 7, 2017, that Staff shared with the parties attending the informal conference, the Attorney General's representatives further indicated the settlement conference should proceed as scheduled and not be rescheduled. Kentucky Power discussed settlement individually with representatives of the Attorney General and kept them abreast of the developments, provided the information exchanged at the November 7, 2017 informal conference, and repeatedly offered the Attorney General the opportunity to join the other parties or engage in further negotiation. Representatives of KCUC attended all three settlement conferences and the Signatory Parties provided copies of all term sheets to KCUC.

Q. DOES THE SETTLEMENT AGREEMENT REPRESENT THE COMPLETE SETTLEMENT IN THIS CASE?

A. Yes. There are no agreements or understandings regarding the Company's application that are not reflected in the Settlement Agreement. The agreements and terms in the Settlement Agreement represent the sum total of the give and take of the Signatory Parties. Further, there are no agreements nor understandings with non-signatory parties relating to the subject matter of the Company's application.

Q. IS THE COMMISSION STAFF A PARTY TO THE SETTLEMENT AGREEMENT?

A. No. Commission Staff attended two informal conferences but made clear that it could not be a party to any agreement, that it was not speaking for the Commission, and that its participation in no way would bind the Commission to the agreement.

Q. DID THE PARTIES TO THIS CASE ACTIVELY LITIGATE THIS MATTER?

A. Yes. In addition to the four sets of data requests propounded by the Commission Staff and answered by Kentucky Power, multiple rounds of data requests, consisting of 793 separate data requests, not including subparts, also were propounded by KIUC, the Attorney General, Wal-Mart, KCUC, KLC, KSBA, and KCTA and answered by the Company. Testimony was filed by witnesses for all intervenors, and discovery taken regarding certain of these witnesses' testimony by Commission Staff, the Attorney General, and Kentucky Power. The Company also filed rebuttal testimony. Thus, Kentucky Power and the parties were fully informed of each other's respective positions while engaging in settlement negotiations.

Q. WHAT WAS THE TONE OF THE NEGOTIATIONS?

A. Without discussing specific matters raised during the negotiations, as they are confidential, I would like to thank the parties who worked in a constructive manner. There is recognition that Kentucky Power is working to help rebuild Eastern Kentucky's economy and as part of that effort the Company has needs that must be addressed under the regulatory compact. Likewise, the Parties advocated for their clients and the affordability of bills for all customers as the region deals with the economic situation it is facing. The settlement is a reflection of that creative thinking to allow Kentucky Power to meet its obligation to provide reasonable service while limiting the impact of the rate adjustment on all customers. I am encouraged by the constructive approach to the negotiations to put Eastern Kentucky first and work to a mutually agreeable solution that will allow the focus to return to rebuilding the economy in the region.

III. THE TERMS OF THE SETTLEMENT AGREEMENT

Q. IN SEVERAL PLACES IN YOUR TESTIMONY BELOW YOU NOTE THAT THE SETTLEMENT AGREEMENT EMBODIES A POSITION ADVOCATED BY ONE OR MORE OF THE INTERVENORS. DOES THE INCORPORATION OF THE INTERVENOR POSITION IN THE SETTLEMENT AGREEMENT CONSTITUTE AN ENDORSEMENT BY THE COMPANY OF THAT POSITION IN ABSENCE OF THE SETTLEMENT AGREEMENT?

A. Absolutely not. Like any fair and reasonable settlement, the Settlement Agreement represents a compromise by all parties to the agreement of their positions in a fully-litigated case. In fact, Paragraph 24 recognizes that the agreement is not to be construed as an admission by any party to agreement. Likewise, the agreement provides that it is not to be read as incorporating fully the objectives of the parties to the agreement. The Settlement Agreement is a package that balances out the interests of the Signatory Parties to provide the Commission a unique option to rule upon the issues in this case.

A. <u>Net Increase In Annual Revenues</u>

Q. YOU INDICATED THAT THE NET EFFECT OF THE SETTLEMENT AGREEMENT ON THE COMPANY'S RETAIL RATES WAS AN ANNUAL INCREASE OF $31.8 MILLION. HOW DOES THAT COMPARE TO THE REQUEST IN THIS CASE?

A. The net annual increase in the Company's retail revenues of $31,780,734 is described in Paragraph 2 of the Settlement Agreement. The updated revenue requirement reflects a decrease of $28,616,704 from the $60,397,438 requested by Kentucky Power in the August 2017 Refinancing Update. To be clear, and except when I expressly state to the contrary, when I discuss the Company's revenue requirement I am referring to the amount requested in the August 2017 Refinancing Update.

Q. DOES THE SETTLEMENT AGREEMENT IDENTIFY THE DERIVATION OF THE $28,616,704 REDUCTION IN REQUESTED ADDITIONAL REVENUE?

A. Yes. This is not a black box settlement. The drivers for the $28.6 million decrease in the Company's requested additional annual revenue requirement reflect agreed upon adjustments that are itemized in Paragraph 2 of the Settlement Agreement.

Q. DOES THE SETTLEMENT AGREEMENT EQUALIZE RATES OF RETURN ACROSS ALL CUSTOMER CLASSES?

A. No. It is unlikely that doing so could be accomplished in a single proceeding. That said, the Settlement Agreement reduces the inter-class subsidies to the residential class while limiting the effect of doing so on residential rates. The Signatory Parties used the decrease in the revenue requirement first to remove the subsidy provided to residential customers by industrial customers receiving service under Tariff I.G.S. The remainder of the rate reduction was then used to reduce the rate impact across the other classes. The result of the subsidy removal and decrease in the revenue requirement is a decrease across the board for all customer classes. The impact of the Settlement Agreement on revenue requirements by customer class is provided in **EXHIBIT 1** to the Settlement Agreement. Additional information about the allocation of the revenue requirement is included in the Settlement Testimony of Company Witness Vaughan.

B. <u>Return On Equity</u>

Q. DOES THE SETTLEMENT AGREEMENT SPECIFY A RETURN ON EQUITY?

A. Yes. The Signatory Parties agreed for settlement purposes that the Company shall be authorized a return on equity of 9.75%. The negotiated amount is below the 10.31% return justified in the testimony of Company Witness Adrien McKenzie. The only intervenors to file testimony regarding the Company's proposed rate of return were the Attorney General and KIUC. Attorney General Witness Woolridge proposed a return on equity of 8.60% while KIUC Witness Baudino proposed a rate of 8.85%. The settlement negotiations led to a compromise of 9.75% ROE. The testimony of Company Witness McKenzie stresses the importance of a fair and reasonable return on equity for the health of the utility and to permit the Company to provide adequate service. A return on equity of 9.75% provides this fair and reasonable return in the overall context of this settlement.

C. Rockport Deferral Mechanism

Q. DID THE SIGNATORY PARTIES AND THE COMPANY AGREE ON A METHOD TO DEFER A PORTION OF THE ROCKPORT UPA EXPENSES?

A. Yes. The Company was able to work with the parties to manage the deferral of non-fuel, non-environmental Rockport UPA Expense in a manner that minimized the risk associated with deferrals described by Company Witness Wohnhas in his rebuttal testimony while still relieving the pressure of customer bills in the near term. The agreement reflects a deferral of fifty million dollars ($50 million) over five years and provides that the deferral will be established as a regulatory asset for later recovery ("Rockport Deferral Regulatory Asset"). The Rockport Deferral Regulatory Asset, plus a WACC carrying charge, will be recovered through the Company's Tariff P.P.A. over a five- year period starting in December 2022. The end of the deferral period, and the start of the five-year amortization period, coincide with the anticipated end of the Rockport UPA in December 2022.

Q. WHAT IS THE DEFERRAL SCHEDULE?

A. The Signatory Parties agreed on an initial deferral of $15 million a year for the first two years of the deferral period and then a step down in the deferral amount in the final three years of the five-year deferral period. In calendar years 2018 and 2019 the Company will defer $15 million each year. The settlement's annual revenue requirement reflects that $15 million decrease to base rates. In 2020, the deferral will step-down to $10 million. The $5 million difference between the initial $15 million deferral in each of the first two years, and upon which base rates are established, and the $10 million deferral in 2020 will be recovered through an offsetting increase in the amount recovered through Tariff

P.P.A. In calendar years 2021 and 2022 the deferral is reduced by an additional $5 million each year to an annual deferral of $5 million. This additional reduction in the deferral amount is recovered through with an incremental offsetting increase of $5 million to the annual amount to be recovered through Tariff P.P.A. In 2022, the amount recovered through Tariff P.P.A. will be prorated through December 8 – the termination date of Rockport UPA. Utilizing Tariff P.P.A. provides a mechanism to achieve the reduction in the deferral amount without changing base rates. A summary of the Rockport UPA Expense deferral timeline is provided below:

YEAR	CREDIT IN BASE RATES	DEFERRAL AMT	AMT RECOVERED VIA TARIFF PPA
2018	$15 million	$15 million	$0
2019	$15 million	$15 million	$0
2020	$15 million	$10 million	$5 million
2021	$15 million	$5 million	$10 million
2022	$15 million	$5 million	$10 million[1]

Q. WHAT HAPPENS TO THE REGULATORY ASSET AFTER THE FIVE YEARS?

A. The Signatory Parties agreed to start recovery of the regulatory asset beginning in December 2022. The regulatory asset will be amortized over five years starting in December 2022 through Tariff P.P.A. The Rockport Deferral Regulatory Asset will be subject to carrying charges based on a weighted average cost of capital ("WACC") of 9.11% until the Regulatory Asset is fully recovered. The Company estimates the regulatory asset will total approximately $59 million at the end of 2022. That amount will decrease over the five-year amortization period until fully collected.

[1] Will be prorated through December 8 – the termination date of the Rockport UPA.

Q. HOW IS THE ROCKPORT DEFERRAL IN THIS SETTLEMENT AGREEMENT BENEFICIAL FOR CUSTOMERS?

A. The Rockport UPA Expense deferral as structured in the Settlement Agreement provides a more affordable rate structure in the immediate future balanced by the need to avoid too heavy of a burden on customers in the later years when it will be recovered. The concept is similar to public comments shared in Hazard, Kentucky during the Commission's public meeting. Some of the commenters expressed an understanding that Kentucky Power needed a rate increase to adequately operate, but the individuals asked the Commission to look for a way to delay the impact of the request for just a few years while the region fights back against the economic downturn. The proposed Rockport UPA Expense deferral helps accomplish that request. Rates in the near term will be set at a lower level than otherwise would be required with the guarantee that those deferred amounts will be collected by the Company for carrying those costs over a number of years.

Q. WHAT IS THE SIGNIFICANCE OF THE FIVE YEAR DEFERRAL TERM PROVIDED BY THE SIGNATORY PARTIES?

A. The Rockport UPA expires in December 2022. While the decision on whether to extend or not extend the Rockport UPA is not an issue in this case and a matter to be decided at a later date, the potential for the end of that agreement and its accompanying expenses provided an opportunity to structure the adjustment to rates to take advantage of that potential reduction in purchase power costs. If the Company is not paying the expenses associated with the Rockport agreement beginning in December 2022 then there is an opportunity to begin recovery of the deferred amount at the same time as the other

Rockport UPA expenses fall off the customer bills. The ultimate decision on whether to extend or not extend the Rockport UPA will be made at another time, but the timelines in place today provided a convenient framework to propose the concept and focus on the impact on customer bills.

Q. WHY IS THE DEFERRAL AMOUNT SUBJECT TO A CARRYING CHARGE?

A. The Company will be incurring and paying the Rockport UPA expenses prior to their recovery and will be financing the associated under-recovery with a combination of debt and equity. Thus, applying a carrying charge at the Company's WACC, which represents Kentucky Power's financing costs, is appropriate. This is especially true in light of the magnitude of the under-recovery and the time frame for recovering the regulatory asset.

Q. WHAT IS THE ROCKPORT CREDIT AND OFFSET THAT IS INCLUDED IN THE DEFERRAL PLAN AGREED TO BY THE SIGNATORY PARTIES?

A. The Rockport Offset and Credit are described in Paragraph 3(f-h) of the Settlement Agreement. If Kentucky Power does not extend the Rockport agreement then it will begin to credit the Rockport Fixed Cost Savings through Tariff P.P.A. until new base rates are set. The credit will be offset, however, by the retention by Kentucky Power of that portion of the Rockport Fixed Cost Savings in 2023 necessary to allow the Company to earn its Commission-authorized return on equity if it should be earning below that level at that time ("Rockport Offset").

Q. HOW WILL THE ROCKPORT FIXED COSTS SAVINGS AND OFFSET BE APPLIED?

A. As outlined in Paragraph 3(h) of the Settlement Agreement, the Company will file an updated factor for Tariff P.P.A. for rates effective December 9, 2022 to reflect the impact of the Fixed Cost Saving and Estimated Rockport Offset. This will represent the sum of the fixed cost savings and the estimated offset related to the estimated level necessary to meet the return on equity component in 2023. By February 1, 2024 the Company will file a final accounting to wrap up this credit/offset in the Tariff P.P.A. for rates effective March 1, 2024. This update will serve as the final true-up to provide a credit back to customers for any amount of any over-collection from the offset or collect any further amount due to finalize the mechanism. That true-up will be applied over the three months of March, April and May of 2024.

D. <u>PJM OATT LSE Expense Recovery and General Rate Case Stay Out</u>

Q. WILL YOU PLEASE EXPLAIN THE SETTLEMENT AGREEMENT'S TREATMENT OF THE COMPANY'S PJM OATT LSE EXPENSE RECOVERY?

A. Yes. Kentucky Power will track, on a monthly basis via deferral accounting, the amount of OATT LSE charges and credits above or below the amount embedded in base rates as discussed in the testimony of Company Witness Vaughan. Kentucky Power will recover 80% of this annual over- or under-collection of PJM OATT LSE charges ("Annual PJM OATT LSE Recovery") through Tariff P.P.A. That means that the Company will absorb 20% of any annual under-collection through base rates of PJM OATT LSE charges.

Q. WHY DOES THE SETTLEMENT AGREEMENT SINGLE OUT THE COMPANY'S PJM OATT LSE CHARGES FOR THIS TREATMENT?

A. Kentucky Power has the ability to manage most of its expenses. By contrast, PJM OATT LSE expenses are largely outside the Company's control and are volatile within the regulatory compact and test year construct. Coupled with the magnitude of the expected increases in the Company's PJM OATT LSE expenses – Kentucky Power forecasts that its PJM OATT LSE expenses will increase by approximately $14 million or approximately 19% in 2018 over the test year amount – the Company would be forced to file another base rate case early in 2018 without the recovery mechanism provided in the Settlement Agreement.

Q. WHAT IS THE TRANSMISSION RETURN DIFFERENCE THE SETTLEMENT AGREEMENT PROVIDES AS AN OFFSET TO THE PJM OATT LSE EXPENSE?

A. Kentucky Power agreed to credit the difference in the return it receives on transmission investment in excess of the investment level already included in the Company's retail rate base between the FERC-approved return on equity and the 9.75% return on equity agreed to by the parties to the Settlement Agreement. The calculation of that credit is shown in **EXHIBIT 3** to the Settlement Agreement and is described in detail in the Settlement Testimony of Company Witness Vaughan.

Q. WILL THE COMMISSION HAVE THE OPPORTUNITY TO REVIEW THE ANNUAL UPDATES TO TARIFF P.P.A. REFLECTING THE PJM OATT LSE RECOVERY AND OFFSET?

A. Yes. The Company will make Tariff P.P.A. filings quantifying and describing the amounts to be recovered and the offset. The first update will not occur until August 2018. That means the rate impact of the costs (or credits) tracked under this mechanism will not impact customer bills until the fourth quarter of 2018.

E. <u>Rate Case Stay Out</u>

Q. PLEASE DESCRIBE THE RATE CASE STAY OUT PROVISION IN THE SETTLEMENT AGREEMENT?

A. The parties agreed to balance the Company's recovery of the 80% of incremental PJM OATT LSE expenses and the Rockport Deferral Regulatory Asset with an agreement by the Company not to file for a general adjustment of base rates to be effective prior to cycle 1 of the January 2021 billing cycle. That is essentially a three-year stay out from changing base rates. This provision also serves to address the concerns raised by customers on the frequency of general rate cases. This stay out is a settlement term that can only be done under the structure of a settlement agreement like the one entered into in this proceeding. Chapter 278 of the Kentucky Revised Statutes and the Commission's regulations do not authorize the Commission to order a utility not to file a general rate case. The balance provided by the Settlement Agreement, and particularly the Company's ability to recover 80% of the amount by which its actual PJM OATT LSE expenses exceed the amounts embedded in base rates, provide the Company the ability to agree to such an extreme restriction. Without all of the considerations provided by the Settlement Agreement, Kentucky Power lacks that ability.

Q. ARE THERE ANY EXCEPTIONS TO THIS AGREEMENT TO STAY-OUT FROM IMPLEMENTING NEW GENERAL RATES?

A. There are emergency clauses tied to a major change in law or where required to address an emergency that could adversely impact Kentucky Power or its customers. These clauses are intended for emergency situations that would significantly change the operations of the Company. An example of a material change in law would be the deregulation of the electric market in Kentucky. Such a change would have a material impact on the operations of the Company and could require a new general rate structure.

Q. DOES THAT LIMIT THE COMMISSION'S AUTHORITY OVER THE COMPANY'S RATES UNTIL 2021?

A. No, the Commission retains its ultimate jurisdiction over rates. Rates could change for other reasons, but the Company is agreeing not to file a general rate case to change rates in that time period. The Commission is not giving up any of its authority as a result of the Settlement Agreement to change the Company's general rates in a base rate case. In addition, the Commission retains its full regulatory authority with respect to the Company's riders and surcharges. This provision of the Settlement Agreement is a commitment by the Company not to file an application for the general adjustment of its base rates that would be effective prior to the first cycle of the January 2021 billing cycle. Customer bills will still change as a result of changes in existing riders.

F. <u>Additional Settlement Terms</u>

Q. WHAT CHANGES WERE MADE TO DEPRECIATION RATES FOR BIG SANDY UNIT 1 AND THE MITCHELL PLANT IN THE SETTLEMENT AGREEMENT?

A. The Signatory Parties agreed to use the 20-year expected life of Big Sandy Unit 1 in calculating the related depreciation expense. The Signatory Parties also agreed to adjust its depreciation rates for Big Sandy Unit 1 and for the Mitchell Plant to remove terminal net salvage costs. Terminal net salvage, which is discussed in more detail in the direct and rebuttal testimony of Company Witness Cash, reflects the difference between salvage and removal cost upon retirement of a unit. The changes to the depreciation rates as a result of the updated anticipated retirement date of Big Sandy Unit 1 and the removal of terminal net salvage rates from the calculation of the Company's depreciation expense are found in **EXHIBIT 5** to the Settlement Agreement.

Q. WHAT OTHER FINANCIAL UPDATES THAT IMPACT RATES ARE INCLUDED IN THE SETTLEMENT AGREEMENT?

A. Paragraph 8 of the Settlement Agreement discusses a number of updates. The 9.75% ROE agreed to in this Settlement Agreement is also applicable to the calculation of the Company's Environmental Surcharge factor and the carrying charges for the Rockport Deferral and Decommissioning Rider regulatory assets. Kentucky Power also agreed to a capital structure that reflects one percent short term debt with a 1.25% annual interest rate for the short term debt. The change to short term debt resulted in a decrease of approximately $350,000 to the revenue requirement. Likewise, the Settlement Agreement reflects the calculations of the WACC and GRCF as shown on **EXHIBIT 6** to the Agreement.

Q. WHAT DOES THE SETTLEMENT AGREEMENT PROVIDE FOR IN CONNECTION WITH STORM DAMAGE EXPENSE AMORTIZATION?

A. The Signatory Parties agreed to amortize the remaining unamortized balance of its existing deferred storm expense regulatory asset, authorized in Case No. 2012-00445, over a period of five years beginning January 1, 2018. This is consistent with the recommendation of KIUC and has the effect of extending the previous amortization period and reducing the Company's annual storm damage amortization expense. The unamortized balance of the existing storm damage regulatory asset will total $6,087,000 on December 31, 2017 and will be amortized over five years at an annual amount of

$1,217,400. In addition, the Settlement Agreement provides for the amortization of the regulatory asset authorized in Case No. 2016-00180 over a period of 5 years beginning January 1, 2018 consistent with the testimony of Company Witness Wohnhas. The balance of the regulatory asset authorized in Case No. 2016-00180 totals $4,377,336 and will be amortized over five years at an annual amount of $875,467. The combined balance of the Kentucky Power's deferred storm expense regulatory assets (the remaining unamortized balance authorized in Case No. 2012-00445 and the amount authorized in Case No. 2016-00180) will total $10,464,336 on December 31, 2017 and will be amortized over five years at an annual amount of $2,092,867.

Q. DID THE SETTLEMENT AGREEMENT PROPOSE ANY CHANGES TO THE COMPANY'S INCENTIVE COMPENSATION PLAN?

A. Yes. The Settling Parties agreed to decrease the level of incentive compensation by $3.15 million in the revenue requirement. While the Company still supports the full recovery of its incentive compensation plan as an important part of attracting and retaining top talent, for purposes of settlement at this time in this case, the Company agreed to remove that amount from the revenue requirement.

Q. HOW DOES THE SETTLEMENT IMPACT THE PROPOSED CHANGES TO THE KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE (KEDS)?

A. The Signatory Parties supported the increase in the funding for economic development through an increase in the KEDS charge. The adjustment made to the Company's proposal was to change the responsibility for payment levels. Under the Settlement Agreement (Paragraph 10), residential customers will pay a fixed monthly charge of $0.10 instead of the proposed $0.25. This is a reduction from the current $0.15 monthly charge. To make up that difference, non-residential customers will pay an increased level of per meter charges. The non-residential customers will pay a monthly charge of $1.00 per meter as opposed to the $0.25 proposed by the Company. This decreases the charge to the residential class of customers while still allowing them to be involved in the partnership of rebuilding the economy. This allocation will produce slightly more funds to be used for the KEDS grants. Kentucky Power will continue to match dollar-for-dollar the funds provided by customers at the modified levels provided for by the Settlement Agreement.

Q. WHAT PROVISION IS INCLUDED IN THE AGREEMENT RELATED TO THE REQUEST ON BACKUP AND MAINTENANCE SERVICE OPTIONS BY THE COMPANY?

A. The Settlement Agreement includes a provision (Paragraph 11) that sets up a path for discussions between Marathon Petroleum LP and Kentucky Power. The settlement term provides for a discussion between the two entities and if an agreement cannot be reached within 120 days of Marathon providing a specific proposal, then the issue may be presented to the Commission for a decision.

Q. HOW DOES THE SETTLEMENT TREAT THE SCHOOL ENERGY MANAGER PROGRAM?

A. The Signatory Parties agreed that Kentucky Power would seek to include funding up to $200,000 for the School Energy Manager Program as part of its 2018 and 2019 DSM Program offerings. The parties recognize that the Commission is not bound to approve the School Energy Manager Program or its funding level, and that both will be addressed in a separate proceeding. However, Kentucky Power supports the program and believes that it provides a tool by which the region's schools – both public and private – can reduce that portion of their budgets devoted to electric energy costs. As the result, Kentucky Power committed to seek to fund that program up to $200,000 in 2018 and 2019 through the DSM factor. The Settlement Agreement also recognizes that the Commission is currently studying the costs and benefits associated with the Company's DSM programs and their future offerings.

Q. DOES THE SETTLEMENT EXTEND THE PILOT TARIFF K-12 SCHOOL?

A. Yes. The Settlement Agreement (Paragraph 13) removes the pilot designation on the tariff and provides for the general service to all K-12 schools, both public and private, in the Company's territory. Under the offering, eligible schools may elect to take service under rates designed to produce $500,000 less annually in the aggregate from the Tariff K-12 eligible customers than would be produced if those same customers took service under the Tariff L.G.S. proposed as part of this Settlement Agreement. Also, the agreement provides that the total annual revenues produced by both Tariff L.G.S. and Tariff K-12 under the new rates will equal the total revenues that would be produced if all customers taking service under the two tariffs were taking service under the new Tariff L.G.S.

Q. WHAT DOES THE SETTLEMENT CHANGE RELATED TO THE BILL FORMAT REQUEST IN THE COMPANY'S FILING?

A. The bill formatting changes proposed by the Company in Case No. 2017-00231 and consolidated in this case will be approved to the extent they are not already approved (Paragraph 14). Kentucky Power will also hold training sessions for representatives of the municipal customers to address concerns their understanding of consolidated bills and other bill items. The Company has already visited with the City of Paintsville since KLC filed testimony raising a concern with the city's understanding of Company bills. The Company customer service representative walked the Paintsville staff through an online tool that provides customers access to data underlying the bill and how to better understand what is provided. The Company appreciates the time the city personnel spent with its customer service representative to ensure we could meet the customer's expectations. In addition, the Settling Parties agreed that any charges under Rider R.P.O. will be identified as a separate line on the bills of customers taking advantage of Rider R.P.O.

Q. DID THE SIGNATORY PARTIES AGREE ON THE STRUCTURE INTRODUCED BY THE COMPANY ON THE RENEWABLE POWER OPTION RIDER?

A. Yes, with one modification (Paragraph 15). The Settlement Agreement allows customers seeking to receive service under Option B to aggregate accounts to reach the 1,000 kW of peak demand needed as long as there is a common ownership under a single parent company. A revised Rider R.P.O incorporating the updated language is included as **EXHIBIT 8** to the Settlement Agreement.

Q. WHAT OTHER CHANGES DID THE SETTLEMENT AGREEMENT MAKE TO THE REQUEST FILED BY THE COMPANY IN ITS APPLICATION?

A. The Settlement Agreement reflects a change in the requested residential service charge. The Company requested a residential service charge of $17.50 as explained in the direct testimony of Company Witness Vaughan. The Signatory Parties agreed to decrease that customer charge to a value of $14.00. The current charge was updated in the last

Company base case and raised $3.00 to the current level of $11.00. In that previous case the Commission cited the concept of gradualism in only raising the charge $3.00 to $11.00. The $3.00 increase in this case is consistent with that precedent by raising the charge only $3.00 and not the $6.50 requested by the Company.

Q. WHAT DOES THE SETTLEMENT AGREEMENT DO TO ASSIST THE ECONOMIC SITUATION FACING THE COAL INDUSTRY IN EASTERN KENTUCKY?

A. The Settlement Agreement proposes to extend the Coal Plus program that currently is set to expire at the end of 2017. Earlier this year the Commission approved an effort by Kentucky Power to remove barriers to the opening and re-opening of coal operations. The Commission approved Tariff C.S.-Coal, and the amendments to Tariff C.S. – I.R.P., as well as Tariff E.D.R. approved in Case No. 2017-00099, through December 31, 2017. The Settlement Agreement seeks to extend that framework for another year. There are customers already taking advantage of the Coal Plus program and others have expressed an interest. The rate allocation in this case is also a benefit for the large coal operations. Many of the coal operations are served under Tariff I.G.S. The allocation proposed by the Settlement Agreement limits the impact to this rate class by removing the subsidy it pays to support the residential class. This served to limit the impact on these companies and encourage more operations to open or expand to new business in Eastern Kentucky.

Q. WHAT DID THE SETTLEMENT AGREEMENT DO TO ADDRESS THE POLE ATTACHMENT CONCERNS RAISED IN THE RECORD?

A. The Settlement Agreement includes a provision that establishes pole attachment rates for users under Tariff C.A.T.V. The agreement provides that the pole attachment rate under

Tariff C.A.T.V. shall be $10.82 for attachments on two-user poles and $6.71 for attachments on three-user poles. In its application, the Company proposed rates of $11.97 for attachments on two-user poles and $7.42 for attachments on three-user poles. The modification to the unified rate included in the November 22, 2017 filing was made following additional communication with KCTA. The Company does not anticipate that, based on the test year number of attachments, the modified rates will change the estimated revenue to be produced under Tariff C.A.T.V. as compared to the estimated revenue that would have been produced using the unified rate filed on November 22, 2017. The settled-upon rates reflects a reasonable increase in pole costs in the twelve years since the Company's pole attachment rates were last updated.

IV. REASONABLENESS OF THE SETTLEMENT AGREEMENT AND THE PROPOSED RATES

Q. DOES THE SETTLEMENT AGREEMENT FAIRLY BALANCE THE INTERESTS OF THE COMPANY AND ITS CUSTOMERS?

A. Yes. The Settlement Agreement represents a fair and proper balance between Kentucky Power's right to a fair return on its investment and the requirement that customers be charged fair, just, and reasonable rates.

Q. WHAT IS THE BASIS FOR THAT CONCLUSION?

A. Kentucky Power has faced multiple financial challenges since its last base rate case. The Company sought to address these challenges over the longer-term through its economic development efforts. Those efforts already have borne fruit as evidenced by the economic development successes described by Company Witness Hall. The Company's economic development successes do not address, however, the Company's need for financial relief in the near term. The Settlement Agreement addresses this near term need while providing important benefits, such as the Rockport Deferral and the base case stay-out provision, to all customers. Further, the increase of $31,780,734 in the Company's revenue requirement represents approximately 53% of the Kentucky Power's request.

Q. DOES THE SETTLEMENT AGREEMENT PROVIDE FOR FAIR, JUST, AND REASONABLE RATES?

A. Yes. Rates and tariffs should be designed to reflect and capture the opportunity to earn revenues that will produce a fair return on equity for the Company without posing an unfair or unreasonable burden on the ratepayers. The terms of the Settlement Agreement accomplish these objectives by balancing the need to provide for the existence of the utility while addressing the affordability of the rate increase through deferrals. In particular, the actions agreed to by the Company in this case related to the agreement to stay out from filing a general rate case are actions only achievable through a settlement agreement. The revenue allocations, tariffs and charges, while not those originally proposed by the Company, reflect a fair and proper balancing of the interests of the affected customer classes.

Q. DO YOU HAVE A RECOMMENDATION FOR THE COMMISSION?

A. Yes. The Settlement Agreement should be approved by the Commission without modification. In addition, the Commission should establish rates and charges in conformity with the agreement.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

VERIFICATION

The undersigned, Matthew J. Satterwhite, being duly sworn, deposes and says he is the President and COO for Kentucky Power Company that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief

Matthew J. Satterwhite

COMMONWEALTH OF KENTUCKY)
) 2017-00179
COUNTY OF BOYD)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Matthew J. Satterwhite, this 27 day of November 2017.

Trisha M. Young Blum
Notary Public

Notary ID Number: 530202

My Commission Expires: 3-18-19

COMMONWEALTH OF KENTUCKY
TRISHA M. YOUNG
NOTARY ID 530202
COMMISSION EXPIRES 3-18-19

EXHIBIT MJS-1S

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; (4) An Order Approving Accounting Practices To Establish Regulatory Assets Or Liabilities; And (5) An Order Granting All Other Required Approvals And Relief	)))))))))	Case No. 2017-00179

SETTLEMENT AGREEMENT

This Settlement Agreement, made and entered into this 22nd day of November, 2017, by and among Kentucky Power Company ("Kentucky Power" or "Company"); Kentucky Industrial Utility Customers, Inc. ("KIUC"); Kentucky School Boards Association ("KSBA"); Kentucky League of Cities ("KLC"); Wal-Mart Stores East, LP and Sam's East, Inc. ("Wal-Mart"); and Kentucky Cable Telecommunications Association ("KCTA"); (collectively Kentucky Power, KIUC, KSBA, KLC, Wal-Mart, and KCTA, are "Signatory Parties").

RECITALS

1. On June 28, 2017 Kentucky Power filed an application pursuant to KRS 278.190, KRS 278.183, and the rules and regulations of the Public Service Commission of Kentucky ("Commission"), seeking an annual increase in retail electric rates and charges totaling \$69,575,934, seeking approval of its 2017 Environmental Compliance Plan, an order approving accounting practices to establish regulatory assets or liabilities, and further seeking authority to implement or amend certain tariffs ("June 2017 Application").

2. On August 8, 2017, Kentucky Power supplemented its filing to reflect the impact of subsequent refinancing activities on the Company's Application ("August 2017 Refinancing Update"). The refinancing activities reduced the Company's requested annual increase in retail electric rates and charges from $69,575,934 to $60,397,438.

3. KIUC, KSBA, KLC, Wal-Mart, and KCTA filed motions for full intervention in Case No. 2017-00179. The Commission granted the intervention motions. Collectively KIUC, KSBA, KLC, Wal-Mart, and KCTA are referred to in this Settlement Agreement as the "Settling Intervenors."

4. The Attorney General of the Commonwealth of Kentucky ("Attorney General") and Kentucky Commercial Utility Customers, Inc. ("KCUC") also filed motions to intervene. The Attorney General and KCUC, who are not parties to this agreement, were granted leave to intervene.

5. Certain of the Settling Intervenors, KCUC, and the Attorney General filed written testimony in Case No. 2017-00179 raising issues regarding Kentucky Power's Rate Application.

6. Kentucky Power, KCUC, the Attorney General, and the Settling Intervenors have had a full opportunity for discovery, including the filing of written data requests and responses.

7. Kentucky Power offered the Settling Intervenors, KCUC, and the Attorney General, along with Commission Staff, the opportunity to meet and review the issues presented by Kentucky Power's application in this proceeding and for purposes of settlement.

8. The Signatory Parties execute this Settlement Agreement for purposes of submitting it to the Kentucky Public Service Commission for approval pursuant to KRS 278.190 and KRS 278.183 and for further approval by the Commission of the rate increase, rate structure, and tariffs as described herein.

9. The Signatory Parties believe that this Settlement Agreement provides for fair, just, and reasonable rates.

NOW, THEREFORE, for and in consideration of the mutual promises set forth above, and the agreements and covenants set forth herein, Kentucky Power and the Settling Intervenors hereby agree as follows:

AGREEMENT

1. Kentucky Power's Application

(a) Except as modified in this Settlement Agreement, Kentucky Power's June 2017 Application as updated by the August 2017 Refinancing Update is approved.

2. Revenue Requirement

(a) Effective for service rendered on or after January 19, 2018, Kentucky Power shall implement a base rate adjustment sufficient to generate additional annual retail revenues of $31,780,734. This annual retail revenue amount represents a $28,616,704 million reduction from the $60,397,438 sought in the Company's August 2017 Refinancing Update.

(b) The $28,616,704 million reduction was the result of the following adjustments to the Company's request in the June 2017 Rate Application as modified in the August 2017 Refinancing Update:

Adjustment	Reduction in Revenue Requirement ($Millions)
Defer a portion of Rockport UPA non-fuel, non-environmental expenses	15.0
Increase revenues to Apply Weather Normalization to Commercial Sales Net of Variable O&M	0.40
Reduce Incentive Compensation	3.15
Reduce Amortization Expense to Recalibrate Storm Damage Amortization	1.22

Reduce Depreciation Expense by Extending Service Life of BS1 to 20 years	2.84
Reduce Depreciation Expense by Removing Terminal Net Salvage for BSU1	0.37
Reduce Depreciation Expense by Removing Terminal Net Salvage for Mitchell	0.57
Increase Short Term Debt to 1% and Set Debt Rate at 1.25%	0.36
Change in Return on Equity from 10.31% to 9.75%	4.70
Total Adjustments	**28.6**

(c) Kentucky Power agrees to allocate the $31,780,734 in additional annual revenue as illustrated on **Exhibit 1.** The Company will design rates and tariffs consistent with this allocation of additional revenue.

(i) As part of the Commission's consideration of the reasonableness of this Settlement Agreement, the tariffs designed in accordance with this subparagraph shall be filed with the Commission and served on counsel for all parties to this case no later than December 1, 2017.

(ii) Within ten days of the entry of the Commission's Order approving without modification this Settlement Agreement and the rates thereunder, Kentucky Power shall file with the Commission signed copies of the tariffs in conformity with 807 KAR 5:011.

3. Rockport UPA Expense Deferral

(a) Kentucky Power is a party to a FERC-approved Unit Power Agreement with AEP Generating Company for capacity and energy produced at the Rockport Plant ("Rockport UPA"). The Rockport UPA expires on December 8, 2022.

(b) Kentucky Power will defer a total of $50 million in non-fuel, non-environmental Rockport UPA Expense for later recovery as follows:

(i) Kentucky Power will defer $15M annually of Rockport UPA Expense in 2018 and 2019 for later recovery.

(ii) Kentucky Power will defer \$10M of Rockport UPA Expense in 2020 for later recovery.

(iii) Kentucky Power will defer \$5M annually of Rockport UPA Expense in years 2021 and 2022 for later recovery.

(c) The Rockport UPA Expense of \$50 million described in Paragraph 3(b) above will be deferred into a regulatory asset ("the Rockport Deferral Regulatory Asset") and will be subject to carrying charges based on a weighted average cost of capital ("WACC") of 9.11%[1] until the Regulatory Asset is fully recovered. From January 1, 2018 through December 8, 2022, the WACC will be applied to the monthly Rockport Deferral Regulatory Asset principal balance net of accumulated deferred income taxes ("ADIT"). From December 9, 2022 until the Rockport Deferral Regulatory Asset is fully recovered, the WACC will be applied to the monthly Rockport Deferral Regulatory Asset balance including deferred carrying charges net of ADIT. The Rockport Deferral Regulatory Asset shall be recovered on a levelized basis through the demand component of Tariff P.P.A. and amortized over five years beginning on December 9, 2022. Kentucky Power estimates that the regulatory asset balance will total approximately \$59 million on December 8, 2022.

(d) Additional expenses reflecting the declining deferral amount in years 2020 through 2022 will be recovered through the demand component of Tariff P.P.A. as follows:

(i) Kentucky Power will recover \$5 million through Tariff P.P.A. in 2020

(ii) Kentucky Power will recover \$10 million through Tariff P.P.A. in 2021

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[1] 6.48% grossed up for applicable State and Federal taxes, uncollectible accounts expense, and the KPSC maintenance fee

(iii) Kentucky Power will recover $10 million through Tariff P.P.A. in 2022, prorated through December 8, 2022.

(e) The Signatory Parties acknowledge that the Company's decision whether to seek Commission approval to extend the Rockport UPA will be made at a later date. Whether or not the Company seeks to extend the Rockport UPA, beginning December 9, 2022, the Capacity Charge recovered through Tariff C.C., approved in Case No. 2004-00420, will end. Any final over- or under-recovery balance will be included in the subsequent calculation of the purchase power adjustment under Tariff P.P.A. In the event that Kentucky Power elects not to extend the Rockport UPA, it will experience a reduction in Rockport UPA fixed costs ("Rockport Fixed Costs Savings").

(f) If Kentucky Power elects not to extend the Rockport UPA, it will, beginning December 9, 2022, credit the Rockport Fixed Cost Savings through the demand component of Tariff P.P.A. until new base rates are set. However, for 2023 only, the Rockport Fixed Cost Savings credit will be offset by the amount, if any, necessary for the Company to earn its Kentucky Commission-authorized return on equity (ROE) for 2023 ("Rockport Offset"). An example of the calculation of the Rockport Offset is included as **EXHIBIT 2**.

(g) For the purposes of implementing the Rockport Fixed Costs Savings credit described in Paragraph 3(f) above, the following definitions apply:

(i) "Rockport Fixed Costs Savings" shall mean the annual amount of non-fuel, non-environmental Rockport UPA expense included in base rates for rates effective in November 2022.

(ii) "Estimated Rockport Offset" shall mean the amount of additional annual revenue the Company estimates would be necessary for it to earn the Commission-authorized return on equity for 2023 considering the termination of the Rockport UPA and the Rockport Fixed Cost Savings.

(iii) "Actual Rockport Offset" shall mean the amount of additional annual revenue that would have been necessary for the Company to earn the Commission-authorized return on equity for 2023 considering the termination of the Rockport UPA and the Rockport Fixed Cost Savings. The Company shall calculate the Actual Rockport Offset using a comparison of the per books return on equity for 2023 to the Commission-approved return on equity. The Actual Rockport Offset cannot exceed the Rockport Fixed Costs Savings.

(iv) "Rockport Offset True-Up" shall mean the difference between the Estimated Rockport Offset and the Actual Rockport Offset.

(h) The Company shall implement the Rockport Fixed Costs Savings credit described in Paragraph 3(f) above as follows:

(i) By November 15, 2022, the Company shall file an updated purchase power adjustment factor under Tariff P.P.A. for rates effective December 9, 2022. This filing shall reflect the impact of the Rockport Fixed Cost Savings and the Estimated Rockport Offset on the purchase power adjustment factor. This filing shall also reflect the commencement of recovery of the Rockport Deferral Regulatory Asset.

(ii) The Company shall make its normal August 15, 2023 Tariff P.P.A. filing for rates effective in October 2023. The Rockport Fixed Cost Savings and the Estimated Rockport Offset will continue to be factored into the calculation of the purchase power adjustment factor through the end of 2023. Beginning in January 2024, the Estimated Rockport Offset will not be factored into the calculation of the purchase power adjustment factor.

(iii) By February 1, 2024, the Company shall file an updated purchase power adjustment factor under Tariff P.P.A. for rates effective March 1, 2024. This filing shall only reflect the impact of the Rockport Offset True-Up on the purchase power adjustment factor. The purchase power adjustment factor shall be established to recover or credit the Rockport Offset True-Up amount in three months.

(iv) Beginning with the August 15, 2024 Tariff P.P.A. filing, the Company will incorporate the Rockport Fixed Cost Savings in its annual calculation of the purchase power adjustment factor.

4. PJM OATT LSE Expense Recovery

(a) As described in the testimony of Company Witness Vaughan, Kentucky Power has included an adjusted test year amount of net PJM OATT LSE charges and credits in base rates. Kentucky Power will track, on a monthly basis, the amount of OATT LSE charges and credits above or below the base rate level using deferral accounting. Kentucky Power will recover and collect 80% of the annual over or under collection of PJM OATT LSE charges, as compared to the annual amount included in base rates, ("Annual PJM OATT LSE Recovery") through the operation of Tariff P.P.A.

(b) Kentucky Power will credit against the Annual PJM OATT LSE Recovery 100% of the difference between the return on its incremental transmission investments calculated using the FERC-approved PJM OATT return on equity and the return on its incremental transmission investments calculated using the 9.75% return on equity provided for in this settlement (the "Transmission Return Difference"). Kentucky Power shall calculate the Transmission Return Difference as shown in **EXHIBIT 3**.

(c) These changes to Tariff P.P.A. to allow for the Annual PJM OATT LSE Recovery will terminate on the effective date when base rates are reset in the next base rate proceeding unless otherwise specifically extended by the Commission. Nothing in this Paragraph 4(c) prohibits Kentucky Power or any other Signatory Party from taking any position regarding the extension of the Annual PJM OATT LSE Recovery mechanism or any other treatment of the Company's PJM OATT LSE expenses.

5. <u>Rate Case Stay Out</u>

(a) Kentucky Power will not file an application for a general adjustment of base rates for rates that would be effective prior to the first day of the January 2021 billing cycle. This rate case "stay out" is expressly conditioned on Commission approval of this Settlement Agreement without modification including the recovery of the Rockport Deferral Regulatory Asset as described in Section 3 above and the incremental PJM OATT LSE expense through Tariff P.P.A. as described in Section 4 above.

(b) This stay out will not apply if a change in law occurs that will result in a material adverse effect on the Company's financial condition.

(c) Nothing in this stay out provision should be interpreted as prohibiting the Commission from altering the Company's rates upon its own investigation, or upon complaint, including to reflect changes in the tax code, including the federal corporate income tax rate, depreciation provisions, or upon a request by the Company to seek leave to address an emergency that could adversely impact Kentucky Power or its customers. In the event the Commission initiates an investigation or a complaint is filed with the Commission regarding the Company's rates, the Company retains the right to defend the reasonableness of its rates in such proceedings.

6. Tariff P.P.A.

(a) Kentucky Power's proposed changes to Tariff P.P.A., as set forth in the testimony of Company Witness Vaughan and modified by Sections 2 and 3 above, are approved.

(b) A revised version of Tariff P.P.A. incorporating the modifications described in Sections 2 and 3 above is included as **EXHIBIT 4.**

7. Depreciation Rates

(a) Kentucky Power and the Settling Intervenors agree that Big Sandy Unit 1 has an expected life of 20 years following its conversion from a coal-fired to a natural gas-fired generating unit. The depreciation rates for Big Sandy Unit 1 have been adjusted to reflect the 20 year expected life. Kentucky Power and the Signatory Parties retain the right to propose updated depreciation rates for Big Sandy Unit 1 in future proceedings to reflect updates to the expected life.

(b) Kentucky Power has adjusted depreciation rates for Big Sandy Unit 1 and for the Mitchell Plant to remove terminal net salvage costs. Kentucky Power retains the right to propose updated depreciation rates for Big Sandy Unit 1 and for the Mitchell Plant in future proceedings to include terminal net salvage costs, and the Settling Intervenors retain the right to challenge the inclusion of such costs in future proceedings.

(c) Kentucky Power's updated depreciation rates are included as **EXHIBIT 5**.

8. Return on Equity, Capitalization, WACC, and GRCF

(a) Kentucky Power shall be authorized a 9.75% return on equity. The authorized return on equity of 9.75% will be used in the calculation of the Company's Environmental Surcharge factor (for non-Rockport environmental projects) and the carrying charges for the Rockport Deferral and Decommissioning Rider regulatory assets.

(b) Kentucky Power will update its capitalization to reflect short term debt as 1% of the Company's total capital structure. The annual interest rate for the short term debt will be set at 1.25%.

(c) Kentucky Power shall utilize a weighted average cost of capital ("WACC") of 9.11% including a gross revenue conversion factor ("GRCF") of 1.6433%. The GRCF does not include a Section 199 deduction. This WACC and GRCF shall remain constant (including for the riders and surcharges described in Paragraph 8(a) above) until such time as the Commission sets base rates in the Company's next base rate case proceeding. The calculations of the WACC and GRCF are shown on **EXHIBIT 6**.

9. Storm Damage Expense Amortization

(a) Kentucky Power will recover and amortize the remaining unamortized balance of its deferred storm expense regulatory asset authorized in Case No. 2012-00445 over a period of five years beginning January 1, 2018, consistent with the recommendation of KIUC. The unamortized balance of the regulatory asset authorized in Case No. 2012-00445 will total $6,087,000 on December 31, 2017 and will be amortized over five years at an annual amount of $1,217,400.

(b) Kentucky Power will recover and amortize the deferred storm expense regulatory asset authorized in Case No. 2016-00180 over a period of 5 years beginning January 1, 2018 consistent with the testimony of Company Witness Wohnhas. The balance of the regulatory asset authorized in Case No. 2016-00180 totals $4,377,336 and will be amortized over five years at an annual amount of $875,467.

(c) The combined balance of the Kentucky Power's deferred storm expense regulatory assets (the remaining unamortized balance authorized in Case No. 2012-00445 and the amount authorized in Case No. 2016-00180) will total \$10,464,336 on December 31, 2017 and will be amortized over five years at an annual amount of \$2,092,867.

10. Kentucky Economic Development Surcharge

(a) Kentucky Power's new Kentucky Economic Development Surcharge Tariff ("Tariff K.E.D.S.") shall be approved with rates amended as follows:

(i) The KEDS rate for residential customers will be set at \$0.10 per meter instead of \$0.25 as proposed by the Company.

(ii) The KEDS rate for non-residential customers for which the KEDS applies will be set at \$1.00 per meter instead of \$0.25 as proposed by the Company.

(b) All KEDS funds collected by Kentucky Power shall be matched dollar-for-dollar by Kentucky Power from shareholder funds. The proceeds of KEDS and Kentucky Power's shareholder contribution shall be used by Kentucky Power for economic development projects, including the training of local economic development officials, in the Company's service territory. The KEDS, and the matching shareholder contribution, shall remain in effect until changed by order of the Commission.

(c) Kentucky Power will continue to file on or before March 31st of each year a report with the Commission describing: (i) the amount collected through the Economic Development Surcharge; and (ii) the matching amount contributed by Kentucky Power from shareholder funds. The annual report to be filed by the Company shall also describe the amount, recipients, and purposes of its expenditure of the funds collected through the Economic Development Surcharge and shareholder contribution.

(d) Kentucky Power shall serve a copy of the annual report to be filed with the Commission in accordance with subparagraph (c) on counsel for all parties to this proceeding.

11. Backup and Maintenance Service

(a) In order for Marathon Petroleum LP ("Marathon") to evaluate the economics of self or co-generation, Kentucky Power and Marathon will begin negotiations regarding the terms, conditions and pricing for backup and maintenance service within 30 days of a Commission Order approving this provision and will complete negotiations within the next 120 days. Prior to the start of the 120 day negotiation period, Marathon will provide Kentucky Power with specific information regarding the MW size of a potential self or co-generation facility and the type of generation technology being considered.

(b) If Kentucky Power and Marathon cannot reach an agreement on backup and maintenance service within 120 days, Kentucky Power and Marathon agree to submit the issue to the Commission for resolution.

12. School Energy Manager Program

(a) Kentucky Power shall seek leave from the Commission to include up to $200,000 for the School Energy Manager Program in its each of its 2018 and 2019 DSM Program offerings.

(b) Kentucky Power and KSBA both expressly acknowledge that there is in Case No. 2017-00097 a currently-pending Commission investigation of the Company's DSM programs and funding and that the outcome of that investigation could impact the School Energy Manager Program.

13. Tariff K-12 School

(a) Kentucky Power shall continue its current Pilot Tariff K-12 School but shall remove the Pilot designation as set forth in **EXHIBIT 7**. Tariff K-12 School shall be available for general service to all K-12 schools in the Company's service territory, public and private, with normal maximum demands greater than 100 kW. Tariff K-12 School shall reflect rates for customers taking service under the tariff designed to produce annually in the aggregate $500,000 less from Tariff K-12 School customers than would be produced under the new L.G.S. rates to be established under this Settlement Agreement from customers eligible to take service under Tariff K-12 School. The aggregate total revenues to be produced by Tariff K-12 School and Tariff L.G.S. shall be equal to the revenues that would be produced in the aggregate by the new rates in the absence of Tariff K-12 School. Service under Tariff K-12 School shall be optional.

14. Bill Format Changes

(a) The bill formatting changes proposed by the Company in Case No. 2017-00231 and consolidated into this case by Commission Order dated July 17, 2017, to the extent not already approved, are approved.

(b) Within 180 days of a Commission Order approving this Settlement, Kentucky Power will conduct a training session with representatives from its municipal clients and KLC to explain the new bill format and tools available to clients to evaluate their electric usage.

15. Renewable Power Option Rider

(a) The proposed changes to the Company's Green Pricing Option Rider, including renaming the rider to the Renewable Power Option Rider ("Rider R.P.O."), are approved except that the availability of service provision for Option B will state the following:

> "Customers who wish to directly purchase the electrical output and all associated environmental attributes from a renewable energy generator may contract bilaterally with the Company under Option B. Option B is available to customers taking metered service under the Company's I.G.S., and C.S.-I.R.P. tariffs, or multiple L.G.S. tariff accounts with common ownership under a single parent company that can aggregate multiple accounts to exceed 1000 kW of peak demand."

A revised version of Rider R.P.O. incorporating the modifications described above is included as **EXHIBIT 8**. Bills for customers receiving service under Rider R.P.O. will include a separate line item for Rider R.P.O. charges.

(b) Beginning no later than March 31, 2018, and no later than each March 31 thereafter, Kentucky Power will file a report with the Commission describing the previous year's activity under Rider R.P.O. This annual report will replace the semi-annual reports filed in Case No. 2008-00151.

16. Modifications To Kentucky Power's Rate Tariffs

In addition to the rate and tariff changes described and agreed to above, Kentucky Power and the Settling Intervenors agree that the following tariffs shall be modified or implemented as described below:

(a) The Customer charge for the Residential Class ("Tariff R.S.") shall be increased to $14.00 per month instead of the $17.50 per month proposed by the Company in its filing in this case.

(b) The Company is extending the termination date for Tariff C.S. – Coal and the amendments to Tariff C.S. – I.R.P. and Tariff E.D.R. approved in Case No. 2017-00099 from December 31, 2017 to December 31, 2018.

(c) The pole attachment rate under Tariff C.A.T.V. shall be $10.82 for attachments on two-user poles and $6.71 for attachments on three-user poles for all attachments instead of the $11.97 for attachments on two-user poles and $7.42 for attachments on three-user poles proposed by the Company in its filing in this case.

17. Filing Of Settlement Agreement With The Commission And Request For Approval

Following the execution of this Settlement Agreement, Kentucky Power and the Settling Intervenors shall file this Settlement Agreement with the Commission along with a joint request to the Commission for consideration and approval of this Settlement Agreement so that Kentucky

Power may begin billing under the approved adjusted rates for service rendered on or before January 19, 2018.

18. Good Faith And Best Efforts To Seek Approval

(a) This Settlement Agreement is subject to approval by the Public Service Commission.

(b) Kentucky Power and the Settling Intervenors shall act in good faith and use their best efforts to recommend to the Commission that this Settlement Agreement be approved in its entirety and without modification and that the rates and charges set forth herein be implemented.

(c) Kentucky Power and the Settling Intervenors filed testimony in this case. Kentucky Power also filed testimony in support of the Settlement Agreement. For purposes of any hearing, the Settling Intervenors and Kentucky Power waive all cross-examination of the other Signatory Parties' witnesses except for purposes of supporting this Settlement Agreement unless the Commission disapproves this Settlement Agreement. Each further stipulates and recommends that the Notice of Intent, Application, testimony, pleadings, and responses to data requests filed in this proceeding be admitted into the record.

(d) The Signatory Parties further agree to support the reasonableness of this Settlement Agreement before the Commission, and to cause their counsel to do the same, including in connection with any appeal from the Commission's adoption or enforcement of this Settlement Agreement.

(e) No party to this Settlement Agreement shall challenge any Order of the Commission approving the Settlement Agreement in its entirety and without modification.

19. Failure Of Commission To Approve Settlement Agreement

If the Commission does not accept and approve this Stipulation in its entirety, then any adversely affected Party may withdraw from the Stipulation within the statutory periods provided for rehearing and appeal of the Commission's order by (1) giving notice of withdrawal to all other Parties and (2) timely filing for rehearing or appeal. Upon the latter of (1) the expiration of the statutory periods provided for rehearing and appeal of the Commission's order and (2) the conclusion of all rehearing's and appeals, all Parties that have not withdrawn will continue to be bound by the terms of the Stipulation as modified by the Commission's order.

20. Continuing Commission Jurisdiction

This Settlement Agreement shall in no way be deemed to divest the Commission of jurisdiction under Chapter 278 of the Kentucky Revised Statutes.

21. Effect of Settlement Agreement

This Settlement Agreement shall inure to the benefit of, and be binding upon, the parties to this Settlement Agreement, their successors, and assigns.

22. Complete Agreement

This Settlement Agreement constitutes the complete agreement and understanding among the parties to this Settlement Agreement, and any and all oral statements, representations, or agreements. Any and all such oral statements, representations, or agreements made prior hereto or contained contemporaneously herewith shall be null and void and shall be deemed to have been merged into this Settlement Agreement.

23. Independent Analysis

The terms of this Settlement Agreement are based upon the independent analysis of the parties to this Settlement Agreement, are the product of compromise and negotiation, and reflect a fair, just, and reasonable resolution of the issues herein. Notwithstanding anything contained in this Settlement Agreement, Kentucky Power and the Settling Intervenors recognize and agree that the effects, if any, of any future events upon the income of Kentucky Power are unknown and this Settlement Agreement shall be implemented as written.

24. Settlement Agreement And Negotiations Are Not An Admission

(a) This Settlement Agreement shall not be deemed to constitute an admission by any party to this Settlement Agreement that any computation, formula, allegation, assertion, or contention made by any other party in these proceedings is true or valid. Nothing in this Settlement Agreement shall be used or construed for any purpose to imply, suggest or otherwise indicate that the results produced through the compromise reflected herein represent fully the objectives of the Signatory Parties.

(b) Neither the terms of this Settlement Agreement nor any statements made or matters raised during the settlement negotiations shall be admissible in any proceeding, or binding on any of the parties to this Settlement Agreement, or be construed against any of the parties to this Settlement Agreement, **except that** in the event of litigation or proceedings involving the approval, implementation or enforcement of this Agreement, the terms of this Settlement Agreement shall be admissible. This Settlement Agreement shall not have any precedential value in this or any other jurisdiction.

25. Consultation With Counsel

The parties to this Settlement Agreement warrant that they have informed, advised, and consulted with their respective counsel with regard to the contents and significance of this Settlement Agreement and are relying upon such advice in entering into this agreement.

26. Authority To Bind

Each of the signatories to this Settlement Agreement hereby warrant they are authorized to sign this agreement upon behalf of, and bind, their respective parties.

27. Construction Of Agreement

This Settlement Agreement is a product of negotiation among all parties to this Settlement Agreement, and no provision of this Settlement Agreement shall be construed in favor of or against any party hereto. This Settlement Agreement is submitted for purposes of this case only and is not to be deemed binding upon the parties hereto in any other proceeding, nor is it to be offered or relied upon in any other proceeding involving Kentucky Power or any other utility.

28. Counterparts

This Settlement Agreement may be executed in multiple counterparts.

29. Future Rate Proceedings

Nothing in this Settlement Agreement shall preclude, prevent, or prejudice any party to this Settlement Agreement from raising any argument or issue, or challenging any adjustment, in any future rate proceeding of Kentucky Power.

IN WITNESS WHEREOF, this Settlement Agreement has been agreed to as of this 22nd day of November 2017.

KENTUCKY POWER COMPANY

By: ______________________

Its: Counsel

KENTUCKY INDUSTRIAL UTILITY
CUSTOMERS, INC.

By: Mi M. Kurt

Its: Counsel

KENTUCKY SCHOOL BOARDS
ASSOCIATION, INC.

By: Matthew Malone

Its: Legal Counsel

KENTUCKY LEAGUE OF CITIES

By: [signature]

Its: Director of Municipal Law & Training

KENTUCKY CABLE
TELECOMMUNICATION
ASSOCIATION, INC.

By: Jason [illegible]

Its: KCTA Board Chairman

WAL-MART STORES EAST, LP AND
SAM'S EAST, INC.

By: ______________________

Its: Counsel

CASE NO. 2017-00179
SETTLEMENT AGREEMENT
EXHIBIT LIST

1. Revenue Allocation
2. Rockport Offset Calculation
3. Transmission Return Difference Calculation
4. Revised Tariff P.P.A.
5. Depreciation Rates
6. Calculation of WACC and GRCF
7. Revised Tariff K-12 School
8. Revised R.P.O. Rider

EXHIBIT 1

Kentucky Power Company
Settlement Agreement Exhibit-1
Case No. 2017-00179
Settlement Revenue Allocation

Customer Class	Base Rate Case Settlement Increase						Increase Incorporating Surcharge Changes			Return on Rate Base		Settlement
	Settlement Base Rate Increase	ECP	HEAP KEDS	Total Increase	Test Year Rev	% Increase	Carrying Charge Savings in ES	Net Increase	Total Bill % Increase	Current ROR	Proposed ROR	Proposed Non-Fuel Base Revenue Increase
	a	b	c	d = a+b+c	e	= d/e	f	g = d+f	= g/e			
RS	$ 20,076,436	$1,734,600	594	21,811,630	$232,952,481	9.36%	($835,019)	$20,976,611	9.00%	1.90%	3.77%	14.15%
SGS	$ 984,981	$184,183	247,506	1,416,670	$21,371,729	6.63%	($88,664)	$1,328,006	6.21%	11.30%	12.90%	7.19%
MGS	$ 3,421,623	$500,403	69,324	3,991,350	$60,245,787	6.63%	($240,889)	$3,750,461	6.23%	9.14%	10.96%	9.24%
GS*	$ 4,406,604	$ 684,586	$ 316,830	$ 5,406,020	$ 81,617,516	6.63%	($329,553)	$5,076,467	6.22%	9.67%	11.43%	8.68%
LGS/PS	$ 3,520,149	$549,861	8,467	4,078,477	$70,567,216	5.78%	($264,696)	$3,813,779	5.40%	8.78%	10.46%	8.61%
IGS	$ 3,534,466	$836,950	694	4,372,110	$157,911,866	2.77%	($402,899)	$3,969,211	2.51%	6.82%	7.71%	5.85%
MW	$ 4,956	$1,620	102	6,678	$221,405	3.02%	($780)	$5,898	2.66%	12.12%	13.02%	3.94%
OL	$ 201,254	$82,080	0	283,334	$8,984,564	3.15%	($39,512)	$243,822	2.71%	15.03%	15.68%	2.87%
SL	$ 36,869	$13,751	0	50,620	$1,645,931	3.08%	($6,620)	$44,000	2.67%	15.92%	16.84%	3.29%
Total	$ 31,780,734	$ 3,903,448	$ 326,687	$ 36,010,869	$ 553,900,979	6.50%	($1,879,080)	$34,131,789	6.16%	4.85%	5.48%	9.47%

* GS is the combination of the SGS and MGS classes

EXHIBIT 2

Kentucky Power Company
Exhibit 2 - Rockport Offset Calculation Example
Case No. 2017-00179

	*Calculation**				*Source*
a	12 Month GAAP Net Income	$	97,000,000		Q4 2023 Per Books as Reported SEC Kentucky Power Company
b	13 Month Average Common Equity	$	1,000,000,000		Q4 2023 Per Books as Reported SEC Kentucky Power Company
c = a/b	Return on Common Equity		9.70%		Calculation
d	Kentucky Power Allowed Retail ROE		9.75%	**	Commission Order
	If D < C, Stop If D > C, Continue to Part e				
e = (b*d)-a	Net GAAP Income Increase Required to Earn Allowed Retail ROE	$	500,000		Calculation
f	Gross Revenue Conversion Factor		1.6433	**	Commission Order
g = e*f	Rockport Earnings Retainer Revenue	$	821,670		Calculation
= g	***Amount to Be Recovered Through Tariff PPA***	$	***821,670***		

*These numbers are illustrative
** Or as updated in a future Commission proceeding

EXHIBIT 3

Kentucky Power Company
Settlement Exhibit 3 - Transmission Return Difference Calculation
Case No. 2017-00179

	*Calculation**			*Source*	*Frequency*
a	TO Transmission Rate Base	$	319,471,085	2018 OATT TCOS	Update Annually
b	KY Juris Retail Demand Factor		0.985	2017-00179 Section V, Allocation Factors	Remains Static
c = a*b	KY Retail TO Trans Rate Base	$	314,679,018	calculation	
d	Base Rate KY Retail Trans Rate Base	$	266,193,980	2017-00179 Class Cost of Service	Remains Static
e = c-d	Difference	$	48,485,038	calculation	
f	TO WACC @ 11.49 ROE		7.55%	2018 OATT TCOS	Update Annually
g	TO WACC @ 9.75 ROE		6.78%	2018 OATT TCOS	Update Annually
h = f-g	Difference		0.77%	calculation	
j = e*h	TO Return Delta	$	371,431	calculation	
k	GRCF		1.6351	2018 OATT TCOS	Update Annually
= j*k	*2018 Tariff PPA Revenue Credit*	*$*	*607,326*	calculation	Update Annually

*These numbers are illustrative

EXHIBIT 4

TARIFF P.P.A.
(Purchase Power Adjustment)

APPLICABLE.

To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., K-12 School, L.G.S., L.G.S.-T.O.D., I.G.S., C.S. – I.R.P., M.W., O.L. and S.L.

RATE.

The annual purchase power adjustment factor will be computed using the following formula:

1. Annual Purchase Power Net Costs (PPANC)

PPANC = N+RP+CSIRP+G+OATT+RKP-BPP

Where:
BPP = The annual amount of purchase power costs included in base rates, $78,737,938.

a. N = The annual cost of power purchased by the Company through new Purchase Power Agreements. All new purchase power agreements shall be approved by the Commission to the extent required by KRS 278.300.
b. RP = The annual purchased power costs not otherwise recoverable in the Fuel Adjustment Clause including but not limited to the cost of fuel related substitute generation less the cost of fuel which would have been used in plants suffering forced generation or transmission outages and the cost of purchases in excess of the highest cost owned or leased unit.
c. CSIRP = The net annual cost of any credits provided to customers under Tariff C.S.-I.R.P. for interruptible service.
d. G = The annual gains and losses on incidental gas sales; and
e. OATT = 80% The net annual PJM load-serving entity Open Access Transmission Tariff Charges above or below the $74,038,517 included in BPP, less the transmission return difference pursuant to the Commission approved Settlement agreement in Case No. 2017-00179.
f. RKP = Rockport related items includable in Tariff PPA pursuant to the Commission approved Settlement agreement in Case No. 2017-00179:
   i. Increase in Rockport collection resulting from reduction in base rate deferral;
   ii. Rockport deferral amount to be recovered;
   iii. Rockport fixed cost savings; and T
   iv. Rockport offset estimate and true-up.
   v. Final (over)/under recovery associated with tariff CC following its expiration

(Cont'd on Sheet No. 35-2)

DATE OF ISSUE:

DATE EFFECTIVE: Service Rendered On And After January 19, 2018

ISSUED BY: Ranie K. Wohnhas

TITLE: Managing Director, Regulatory & Finance

By Authority Of an Order of the Public Service Commission

In Case No. 2017-00179 Dated XXXXXXX

N

TARIFF P.P.A. (Cont'd)
(Purchase Power Adjustment)

RATES.

Tariff Class	$/kWh	$/kW
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and R.S.-T.O.D. 2, R.S.D.	$0.00000	--
S.G.S.-T.O.D.	$0.00000	--
M.G.S.-T.O.D.	$0.00000	--
G.S.	$0.00000	--
L.G.S., P.S, L.G.S.-T.O.D.	$0.00000	$0.00
L.G.S.-L.M.-T.O.D.	$0.00000	--
I.G.S. and C.S.-I.R.P.	$0.00000	$0.00
M.W.	$0.00000	--
O.L.	$0.00000	--
S.L.	$0.00000	--

The kWh factor as calculated above will be applied to all billing kilowatt-hours for those tariff classes listed above. The kW factor as calculated above will be applied to all on-peak and minimum billing demand kW for the LGS and IGS tariff classes.

The Purchase Power Adjustment factors shall be modified annually using the following formula:

The Purchase Power Adjustment factors shall be determined as follows:
For all tariff classes without demand billing:

$$\text{kWh Factor} = \frac{PPA(E) \times (BE_{Class} / BE_{Total}) + PPA(D) \times (CP_{Class} / CP_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = 0$$

For all tariff classes with demand billing:

$$\text{kWh Factor} = \frac{PPA(E) \times (BE_{Class} / BE_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = \frac{PPA(D) \times (CP_{Class} / CP_{Total})}{BD_{Class}}$$

N

(Cont'd on Sheet No. 35-3)

DATE OF ISSUE:

DATE EFFECTIVE: Service Rendered On And After January 19, 2018

ISSUED BY: Ranie K. Wohnhas

TITLE: Managing Director, Regulatory & Finance

In Case No. 2017-00179 Dated XXXXXXX

N

TARIFF P.P.A. (Cont'd)
(Purchase Power Adjustment)

RATES. (Cont'd)

Where:

1. "PPA(D)" is the actual annual retail PPA demand-related costs, plus any prior review period (over)/under recovery.
2. "PPA(E) is the actual annual retail PPA energy-related costs, plus any prior review period (over)/under recovery.
3. "BE_{Class}" is the historic annual retail jurisdictional billing kWh for each tariff class for the current year.
4. "BD_{Class}" is the historic annual retail jurisdictional billing kW for each applicable tariff class for the current year.
5. "CP_{Class}" is the coincident peak demand for each tariff class estimated as follows:

Tariff Class	BE_{Class}	CP/kWh Ratio	CP_{Class}
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and R.S.-T.O.D. 2, R.S.D.		0.0240909%	
S.G.S.-T.O.D.		0.0196553%	
M.G.S.-T.O.D.		0.0196553%	
G.S.		0.0196553%	
L.G.S., P.S, L.G.S.-T.O.D		0.0170480%	
L.G.S.-L.M.-T.O.D.		0.0170480%	
I.G.S. and C.S.-I.R.P.		0.0118222%	
M.W.		0.0135480%	
O.L.		0.0000000%	
S.L.		0.0000000%	

6. "BE_{Total}" is the sum of the BE_{Class} for all tariff classes.
7. "CP_{Total}" is the sum of the CP_{Class} for all tariff classes.
8. The factors as computed above are calculated to allow the recovery of Uncollectible Accounts Expense of 0.34% and the KPSC Maintenance Fee of 0.1996% and other similar revenue based taxes or assessments occasioned by the Purchase Power Adjustment revenues.
9. The annual PPA factors shall be filed with the Commission by August 15 of each year with the exception of the Rockport items includable in Tariff PPA pursuant to the Commission approved Settlement agreement in Case No. 2017-00179, with rates to begin with the October billing period, along with all necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.

   Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884. N

DATE OF ISSUE:

DATE EFFECTIVE: Service Rendered On And After January 19, 2018

ISSUED BY: Ranie K. Wohnhas

TITLE: Managing Director, Regulatory & Finance

By Authority Of an Order of the Public Service Commission

In Case No. 2017-00179 Dated XXXXXXX

EXHIBIT 5

Exhibit 5 - Depreciation Rates
Case No. 2017-00179

KENTUCKY POWER COMPANY
BIG SANDY UNIT 1 AND MITCHELL PLANT SETTLEMENT DEPRECIATION RATES CALCULATION
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2013 (MITCHELL) AND AT DECEMBER 31, 2016 (BIG SANDY UNIT 1)
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

Acct.	Title	Original Cost	Net Salvg. Ratio	Total to be Recovered	Calculated Depreciation Requirement	Accumulated Depreciation	Remaining to Be Recovered	Avg. Remain Life	Annual Accrual Amount	Annual Accrual Percent
(I)	(II)	(III)	(IV)	(V)	(VI)	(VII)	(VIII)	(IX)	(X)	(XI)
STEAM PRODUCTION PLANT										
Big Sandy Unit 1										
311.0	Structures & Improvements	11,756,127	1.02	11,991,250	7,526,502	4,805,397	7,185,853	20.00	359,293	3.06%
312.0	Boiler Plant Equipment	75,388,722	1.02	76,896,496	22,552,265	9,774,280	67,122,216	20.00	3,356,111	4.45%
314.0	Turbogenerator Units	61,392,346	1.02	62,620,193	36,338,075	28,424,981	34,195,212	20.00	1,709,761	2.78%
315.0	Accessory Electrical Equip.	3,877,136	1.02	3,954,679	2,964,549	2,578,951	1,375,728	20.00	68,786	1.77%
316.0	Misc. Power Plant Equip.	3,321,344	1.02	3,387,771	2,153,127	1,512,867	1,874,904	20.00	93,745	2.82%
	Total	155,735,675		158,850,389	71,534,518	47,096,476	111,753,913		5,587,696	3.59%
Mitchell Plant										
311	Structures & Improvements	42,000,197	1.03	43,260,203	18,282,178	16,183,402	27,076,801	25.01	1,082,639	2.58%
312	Boiler Plant Equipment	765,644,984	1.03	788,614,334	245,324,500	238,518,432	550,095,902	24.25	22,684,367	2.96%
312	Boiler Plant Equip SCR Catalyst	8,190,115	1.00	8,190,115	4,023,394	2,378,493	5,811,622	4.07	1,023,764	12.50%
314	Turbogenerator Units	53,295,697	1.03	54,894,568	29,106,660	33,613,523	21,281,045	23.84	892,661	1.67%
315	Accessory Electrical Equip.	17,080,672	1.03	17,593,092	9,466,086	11,043,285	6,549,807	25.81	253,770	1.49%
316	Misc. Power Plant Equip.	7,693,412	1.03	7,924,214	3,289,590	3,072,520	4,851,694	23.96	202,491	2.63%
	Total	893,905,077	1.03	920,476,526	309,492,408	304,809,655	615,666,871	23.55	26,139,693	2.92%

Notes:

1.) Terminal net salvage removed as a component of net salvage ratio for both plants (column IV).
2.) Average remaining life adjusted to reflect a 20 year useful life of BS1 (column IX).
3.) Mitchell Plant information from schedule used to calculate depreciation rates in settlement of Case No. 2014-00396.

EXHIBIT 6

Kentucky Power Company
Exhibit 6a - Calculation of Weighted Average Cost of Capital
Case No. 2017-00179

KENTUCKY POWER COMPANY
COST OF CAPITAL
TEST YEAR ENDED FEBRUARY 28, 2017

Line No.	Description	Reapportioned Kentucky Jurisdictional Capital 1/	Percentage of Total	Annual Cost Percentage Rate		Weighted Average Cost Percent	Gross Up	Pre-Tax Weighted Average Cost Percent
(1)	(2)	(3)	(4)	(5)		(6) = (4) X (5)	(7)	(8) = (6) X (7)
1	Long Term Debt	$636,995,903	53.45%	4.36%	2/	2.33%	1.00540	2.34%
2	Short Term Debt	11,917,855	1.00%	1.25%	3/	0.01%	1.00540	0.01%
3	Accounts Receivable F	46,105,009	3.87%	1.95%	5/	0.08%	1.00540	0.08%
4	Common Equity	496,766,726	41.68%	9.75%	6/	4.06%	1.64334	6.67%
5	Total	$1,191,785,493	100.00%			6.48%		9.11%

Kentucky Power Company
Exhibit 6b - Calculation of Gross Revenue Conversion Factor
Case No. 2017-00179

KENTUCKY POWER COMPANY
COMPUTATION OF THE GROSS REVENUE
CONVERSION FACTOR
TEST YEAR ENDED FEBRUARY 28,2017

Line No. (1)	Description (2)		Percent of Incremental Gross Revenues (3)
1	Operating Revenues		100.00%
2	Less: Uncollectible Accounts Expense 1/		0.3400%
3	KPSC Maintenance Fee		0.1996%
4	Income Before income Taxes		99.4604%
5	Less: State Income Taxes (L4 X 5.8742%) 2/	5.87%	5.843%
6	Income Before Federal Income Taxes		93.6179%
7	Less: Federal income Taxes (L6 X 35.00%)	35.00%	32.7663%
8	Operating Income Percentage		60.8516%
9	Gross Revenue Conversion Factor (100% / L8)		**1.6433**

EXHIBIT 7

TARIFF K-12 SCHOOL
(Public and Private School)

AVAILABILITY OF SERVICE.

Available for general service to K-12 School customers subject to KRS 160.325 with normal maximum demands greater than 100 KW but not more than 1,000 KW.

RATE.

	Service Voltage			
	Secondary	Primary	Subtransmission	Transmission
Tariff Code	260	264	268	270
Service Charge per Month	$ 85.00	$ 127.50	$ 660.00	$ 660.00
Demand Charge per KW	$ 7.97	$ 7.18	$ 5.74	$ 5.60
Excess Reactive Charge per KVA	$ 3.46	$ 3.46	$ 3.46	$ 3.46
Energy Charge per KWH	7.671¢	6.709¢	5.535¢	5.429¢

MINIMUM CHARGE.

Bills computed under the above rate are subject to a monthly minimum charge comprised of the sum of the service charge and the minimum demand charge. The minimum demand charge is the product of the demand charge per KW and the monthly billing demand.

ADJUSTMENT CLAUSES.

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 5
System Sales Clause	Sheet No. 19
Franchise Tariff	Sheet No. 20
Demand-Side Management Adjustment Clause	Sheet No. 22
Kentucky Economic Development Surcharge	Sheet No. 24
Capacity Charge	Sheet No. 28
Environmental Surcharge	Sheet No. 29
School Tax	Sheet No. 33
Purchase Power Adjustment	Sheet No. 35
Decommissioning Rider	Sheet No. 38

(Cont'd on Sheet No. 9-10)

DATE OF ISSUE:

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ISSUED BY: Ranie K. Wohnhas

TITLE: Managing Director, Regulatory & Finance

By Authority Of an Order of the Public Service Commission

In Case No. 2017-00179 Dated XXXXXXX

TARIFF K-12 SCHOOL (Cont'd)
(Public and Private School)

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.

METERED VOLTAGE.

The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

(1) Measurements taken at the low-side of a customer-owned transformer will be multiplied by 1.01.

(2) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

MONTHLY BILLING DEMAND.

Billing demand in KW shall be taken each month as the highest 15-minute integrated peak in kilowatts as registered during the month by a 15-minute integrating demand meter or indicator, or at the Company's option as the highest registration of a thermal type demand meter or indicator. The monthly billing demand so established shall in no event be less than 60% of the greater of (a) the customer's contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months.

DETERMINATION OF EXCESS KILOVOLT-AMPERE (KVA) DEMAND.

The maximum KVA demand shall be determined by the use of a multiplier equal to the reciprocal of the average power factor recorded during the billing month, leading or lagging, applied to the metered demand. The excess KVA demand, if any, shall be the amount by which the maximum KVA demand established during the billing period exceeds 115% of the kilowatts of metered demand.

(Cont'd on Sheet No. 9-11)

DATE OF ISSUE:

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TITLE: Managing Director, Regulatory & Finance

[redacted]

In Case No. 2017-00179 Dated XXXXXXX

TARIFF K-12 SCHOOL (Cont'd)
(Public and Private School)

TERM OF CONTRACT.

Contracts under this tariff will be made for customers requiring a normal maximum monthly demand between 500 KW and 1,000 KW and be made for an initial period of not less than 1 (one) year and shall remain in effect thereafter until either party shall give at least 6 months written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts or periods greater than 1 (one) year. For customers with demands less than 500 KW, a contract may, at the Company's option, be required.

Where new Company facilities are required, the Company reserves the right to require initial contracts for periods greater than one year for all customers served under this tariff.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

CONTRACT CAPACITY.

The Customer shall set forth the amount of capacity contracted for (the "contract capacity") in an amount up to 1,000 KW. Contracts will be made in multiples of 25 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company.

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is also available to Customers having other sources of energy supply but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the customer shall contract for the maximum amount of demand in KW, which the Company might be required to furnish, but not less than 100 KW nor more than 1,000 KW. The Company shall not be obligated to supply demands in excess of the contract capacity. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billings periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or II or by special agreement with the Company.

EXHIBIT 8

RIDER R.P.O.
(Renewable Power Option Rider)

AVAILABILITY OF SERVICE.

Available to customers taking metered service under the Company's R.S., R.S.D. , R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., K-12 School, L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P. and M.W. tariffs. T T

Participation in this program under Option A may be limited by the ability of the Company to procure renewable energy certificates (RECs) from Renewable Resources. If the total of all kWh under contract under this Rider equals or exceeds the Company's ability to procure RECs, the Company may suspend the availability of this Rider to new participants. T

Customers who wish to directly purchase the electrical output and all associated environmental attributes from a renewable energy generator may contract bilaterally with the Company under Option B. Option B is available to customers taking metered service under the Company's I.G.S., and C.S.-I.R.P. tariffs, or multiple L.G.S. tariff accounts with common ownership under a single parent company that can aggregate multiple accounts to exceed 1000 kW of peak demand. N N

CONDITIONS OF SERVICE.

Customers who wish to support the development of electricity generated by Renewable Resources may under Option A contract to purchase each month a specific number of fixed kWh blocks, or choose to cover all of their monthly usage. T T

Renewable Resources shall be defined as Wind, Solar Photovoltaic, Biomass Co-Firing of Agricultural crops and all energy crops, Hydro (as certified by the Low Impact Hydro Institute), Incremental Improvements in Large Scale Hydro, Coal Mine Methane, Landfill Gas, Biogas Digesters, Biomass Co-Firing of All Woody Waste including mill residue, but excluding painted or treated lumber. All REC's purchased under Option A of this tariff shall be retained or retired by the Company on behalf of customers. T T

T

RATES.

N

Option A:

In addition to the monthly charges determined according to the Company's tariff under which the customer takes metered service, the customer shall also pay the following rate for the REC option of their choosing. The charge will be applied to the customer's bill as a separate line item. T

The Company will provide customers at least 30-days' advance notice of any change in the Rate. At such time, the customer may modify or cancel their automatic monthly purchase agreement. Any cancellation will be effective at the end of the current billing period when notice is provided.

A1. Solar RECs:

Block Purchase:	Charge ($ per 100 kWh block): $ 1.00/month	N
All Usage Purchase:	Charge: $0.010/kWh consumed	N

(Cont'd on Sheet 31-2)

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RIDER R.P.O. T
(Renewable Power Option Rider) T

RATES. (Cont'd)

A2. Wind RECs: N

Block Purchase:	Charge ($ per 100 kWh block): $ 1.00/month
All Usage Purchase:	Charge: $0.010/kWh consumed

A3. Hydro & Other RECs:

Block Purchase:	Charge ($ per 100 kWh block): $ 0.30/month
All Usage Purchase:	Charge: $0.003/kWh consumed

Option B:

Charges for service under option B of this Tariff will be set forth in the written agreement between the Company and the Customer and will reflect a combination of the firm service rates otherwise available to the Customer and the cost of the renewable energy resource being directly contracted for by the Customer. N

TERM.

This is a voluntary program.

Under Option A Customers may participate through a one-time purchase, or establish an automatic monthly purchase agreement. Any payments under this program are nonrefundable. Customers participating under Option A may terminate service under this Rider by notifying the Company with at least thirty (30) days prior notice. T T T

Under Option B, the term of the agreement will be determined in the written agreement between the Company and the Customer. T

SPECIAL TERMS AND CONDITIONS.

This Rider is subject to the Company's Terms and Conditions of Service and all provisions of the tariff under which the customer takes service, including all payment provisions. The Company may deny or terminate service under this Rider to customers who are delinquent in payment to the Company.

Funds collected under this Renewable Power Option Rider will be used solely to purchase RECs for the program. T

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In Case No. 2017-00179 Dated XXXXXXX

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; (4) An Order Approving Accounting Practices To Establish Regulatory Assets And Liabilities; And (5) An Order Granting All Other Required Approvals And Relief	)	Case No. 2017-00179

REBUTTAL TESTIMONY OF

MATTHEW J. SATTERWHITE

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Matthew J. Satterwhite, being duly sworn, deposes and says he is the President and COO for Kentucky Power Company that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief

Matthew J. Satterwhite

COMMONWEALTH OF KENTUCKY)
) 2017-00179
COUNTY OF BOYD)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Matthew J. Satterwhite, this 3rd day of November 2017.

Trisha M. Young Blum
Notary Public

Notary ID Number: 530202

My Commission Expires: 3-18-19

TRISHA M. YOUNG
NOTARY ID 530202
COMMISSION EXPIRES 3-18-19

REBUTTAL TESTIMONY OF
MATTHEW J. SATTERWHITE, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2017-00179

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REBUTTAL TESTIMONY OF
MATTHEW J. SATTERWHITE, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Matthew J. Satterwhite, and I am the President and Chief Operating Officer of Kentucky Power Company ("Kentucky Power" or "Company"). My business address is 855 Central Avenue, Suite 200, Ashland, Kentucky 41101.

Q. ARE YOU THE SAME MATTHEW SATTERWHITE THAT FILED DIRECT TESTIMONY IN THIS CASE?

A. Yes I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to intervenor testimony on four topics:

- the Company's economic development efforts;
- the need for timely recovery of the Company's volatile PJM LSE OATT expense through Tariff P.P.A.;
- KIUC Witness Kollen's proposal to defer costs associated with the Rockport Unit Power Agreement for future recovery; and
- the recovery of costs associated with the Rockport Unit 1 SCR.

II. KENTUCKY POWER'S ECONOMIC DEVELOPMENT EFFORTS

Q. ATTORNEY GENERAL WITNESS DISMUKES RECOMMENDS ELIMINATING THE K-PEGG PROGRAM. HOW DO YOU RESPOND TO HIS RECOMMENDATION?

A. The Commission should adopt the Company's proposed continuation and expansion of the K-PEGG program. Mr. Dismukes' recommendation to reject the program outright would be harmful to economic development efforts in the Company's service territory. As described in more detail by Company Witness Hall, the K-PEGG program allows Kentucky Power to aggregate small contributions from customers through the KEDS, with matching contributions from the Company, to provide much needed economic development assistance grants to municipalities and economic development agencies. These grants bolster the ability of these front-line economic development organizations to position the region to compete for new business and jobs.

Economic development is the best remedy for the Company's declining load and the pressure that decline is placing on rates. It is appropriate that Kentucky Power and its customers be at the forefront of economic development. Kentucky Power's economic development efforts include its economic development grant programs, its Coal Plus tariff program, and its coordination with state and local economic development entities to attract new industry to the service territory. The Company's economic development efforts are gaining momentum, and the K-PEGG program is a key part of these efforts.

Grants issued by the Company through the K-PEGG program have supported economic development agencies in the region by providing them with resources necessary to train their personnel, develop strategic plans, obtain key trade group certifications, and make improvements to industrial park sites. These actions may seem small, compared to the types of tax-incentives and other financial incentives provided directly to companies by the Cabinet for Economic Development, but without these funds the communities in our service territory would struggle even to be a part of the economic development conversation. Now is not the time to derail an important part of economic development in eastern Kentucky by eliminating the K-PEGG Program.

Q. WHAT IS YOUR REACTION TO MR. DISMUKES' ATTACK ON THE K-PEGG PROGRAM?

A. I find it both surprising and disappointing. Beyond providing safe and reliable electric service to its customers, Kentucky Power's organizational focus is on economic development. I have made this a focus for the Company because economic opportunities provide job opportunities for our customers while helping assure an increase in customers in our service territory. Absent job opportunities and additional businesses, the Company's customer totals will continue to shrink. As the number of customers and associated load declines, the fixed costs of providing service is spread out over fewer remaining customers. At its core, the Company's economic development efforts are based on the ultimate goal of increasing the denominator in the rate setting equation – more customers and more load means that the cost of providing service can be spread over more billing units to everyone's benefit.

Mr. Dismukes' objections to economic development and the K-PEGG Program specifically are disappointing to me. I am disappointed because it appears Mr. Dismukes fails to understand the focus of the K-PEGG Program on filling gaps in the region's economic development infrastructure. The K-PEGG

Program is a key component of the Company's economic development plan. Without the support to local economic development agencies that the K-PEGG Program provides, the broader economic development efforts in the region will struggle. It is true that K-PEGG requires a small customer contribution ($3.00/customer/year if the Company's proposed expansion is approved), but the ability of the Company to aggregate these contributions with matching funds from the Company allows the K-PEGG Program to support economic development efforts throughout the service territory. Mr. Dismukes' suggestion to shut the K-PEGG Program down would take away this necessary support.

III. RECOVERY OF PJM LSE OATT EXPENSE

Q. DO YOU AGREE WITH THE RECOMMENDATIONS BY MESSRS. KOLLEN AND SMITH THAT THE COMMISSION REJECT THE COMPANY'S PROPOSAL TO RECOVER OR REFUND CHANGES IN ITS BASE RATE LEVEL OF PJM LSE OATT EXPENSE THOROUGH TARIFF P.P.A.?

A. No. The adjusted test year level of PJM LSE OATT expense included in base rates in this case represents a $20.6[1] million increase in these expenses since the September 30, 2014 test year in Kentucky Power's last rate case. This increase has put considerable downward pressure on the Company's ability to earn its authorized return. The Company projects that in 2018 these expenses will increase by $17.0 million over the amount included in the Company's test year in this case. That is a significant impact on the Company, and absent the requested amendment of Tariff P.P.A. or some measure to recover these expenses,

[1] Company Witness Vaughan Direct Testimony at 29.

Kentucky Power will have to file another base rate case within months of the January 2018 Order in this case.

Q. ARE YOU THREATENING THE COMMISSION WITH ANOTHER RATE CASE FILING IF THE COMPANY'S PROPOSAL IS NOT GRANTED?

A. Absolutely not. I do, however, want to make clear the importance of the issue and what the implications would be and the steps the Company would be forced to take in the event it is unable to recover its incremental PJM LSE OATT. The Commission is charged with setting rates that provide the utility an opportunity to earn a fair return. These PJM LSE OATT expenses are real costs that will impact the Company and immediately upset the balance of any Commission order that authorizes rates to give the Company an opportunity to earn a fair return. Knowing this now allows the Company and the Commission an opportunity to deal with it now. Ignoring it now, just to push it to an immediately subsequent filing, is inefficient.

These PJM charges produce a material financial impact that must be addressed one way or another. The Company proposes to avoid the inefficiency of another rate case immediately on the heels of this one through the Company's proposed changes to Tariff P.P.A. Doing so as proposed by the Company addresses the issue in a manner through which customers pay no more or no less for these PJM LSE OATT expenses.

As stated throughout the case, the volatile nature of these costs that are beyond the Company's control makes the proposed recovery mechanism appropriate. However, the Company must have a path to deal with these expenses that will be charged to the Company regardless of the outcome of the case. Thus, if the Company cannot recover these costs as proposed then the financial impact of the real costs charged to Kentucky Power will require the filing of another rate case shortly after an order is issued in this case to ensure rates provide that fair opportunity.

Q. WHAT IS THE HARM IN KENTUCKY POWER FILING A NEW RATE CASE IN 2018?

A. Rate cases require a significant dedication of resources from the Company, intervenors, and the Commission. The cases can also be expensive. The Company has estimated that the subset of rate case expenses the Company to be recovered in this case will total $1.375 million. This expense includes legal, consulting, and advertising costs. Advertising for the Commission-required notice alone cost approximately $600,000. These Company costs are part of the rate making process and are, accordingly, recovered from the Company's customers. The Company prefers to deal with the impact of these known PJM LSE OATT expenses now and avoid the increased cost of another case. The seven intervenors in this case also undoubtedly have legal and expert witness costs in this case.

Q. ARE FINANCIAL COSTS THE ONLY COSTS IMPOSED BY RATE CASES?

A. Far from it. Rate cases require enormous time and effort by the parties and the Commission. In the case of Kentucky Power, the time and effort required in preparing and litigating a rate case otherwise could be devoted to building on the safe, efficient, and reliable service being provided and to improving its operations. Most importantly, the effort otherwise could be devoted to the Company's customer service and economic development efforts.

With regard to economic development, rate cases produce rate uncertainty for customers evaluating whether to locate within the Company's service territory. The Company's proposal to track incremental PJM LSE OATT costs through Tariff P.P.A. would not produce the same effect on the region's competitiveness since many other utilities in the region, including those in Virginia, West Virginia, Ohio, and Indiana, utilize trackers for OATT costs. Forcing the Company into rate cases to recover these costs would result in a competitive disadvantage as compared to regions where utilities are not subject to the unnecessary rate uncertainty that rate cases bring.

There is also an impact on customers, many of whom are unfamiliar with the regulatory process. Rate cases are never a popular topic, and that is why there is a set regulatory paradigm in the Commonwealth to establish rates to ensure a fair opportunity to earn a fair return for public utilities. Yet failing to provide a regulatory mechanism in this case to address these volatile expenses likely will require Kentucky Power to file a new rate case in 2018. Dealing with the PJM LSE OATT expenses now will help prevent the customer confusion concerning why the Company would need to file a new case immediately, and avoid undermining public trust in the regulatory system.

Q. MANY BASE RATE EXPENSES INCREASE OVER TIME. WHY SHOULD PJM LSE OATT EXPENSE BE RECOVERED AS PROPOSED BY THE COMPANY INSTEAD OF SOLELY THROUGH BASE RATES?

A. There are two principal reasons. First is the magnitude of the estimated increase. Second, is the fact that, unlike many base rate expenses, the increases are largely out of the Company's control.

Q. WHAT IS THE MAGNITUDE OF THE ESTIMATED INCREASE?

A. Kentucky Power estimates that its 2018 PJM LSE OATT expense will be $91.4 million.[2] This is an increase of $17.0 million (22.8%) above the $74.4 million in test year PJM LSE OATT expense. Very few, if any, of the Company's expenses are likely to experience such volatility or increases of this magnitude over a similar period. By avoiding the need to file annual base rate cases, the Company's proposal will allow it to reflect only the actual costs incurred by Kentucky Power without the need to file full rate cases to address the known expenses. These types of changes are consistent with the principles of gradualism.

Q. WHY DO YOU SAY THE AMOUNT OF KENTUCKY POWER'S PJM LSE OATT EXPENSE IS LARGELY OUTSIDE ITS CONTROL?

A. The LSE OATT expense is largely a reflection of Kentucky Power's share of the costs to rebuild the transmission system in the region. These are expenses charged to Kentucky Power regardless of whether the Company has relief for the expenses in its rate structure. Additional detail regarding the nature of the

[2] The increase in anticipated 2018 PJM LSE OATT expense from the $84.4 million presented in the Company's response to KIUC 1-67 is a result of the AEP Companies updated formula rate filing with PJM made on October 31, 2017.

Company's PJM LSE OATT expense is provided in the direct and rebuttal testimonies of Company Witness Vaughan.

Q. SHOULD THERE BE ANY CONCERN THAT THE ESTIMATED $17.0 MILLION INCREASE IN 2018 PJM LSE OATT EXPENSES IS AN ESTIMATE?

A. No. Under the Company's proposal, the adjusted test year amount of PJM LSE OATT charges will remain in base rates and the Company will track for recovery only the annual incremental change in these expenses. The P.P.A. factor will be set at zero for the first year and not adjusted until the end of 2018 based on the actual costs incurred for the year. In addition, as discussed in the direct testimony of Company Witness Vaughan, there is a possibility for adjustments in the rate due to certain proceedings at FERC that could offset some of the costs that would be captured in the tracking of the costs. A tracking mechanism, like the Company's proposed change to Tariff P.P.A., allows those refunds to flow through the mechanism and benefit customers. Ultimately, Kentucky Power's proposed changes to Tariff P.P.A. will ensure that the Company recovers no more and no less than its actual PJM LSE OATT expense.

Q. IS THERE ANY OTHER ASPECT OF MESSRS. KOLLEN AND SMITH'S RECOMMENDATION CONCERNING THE COMPANY'S PROPOSED METHOD FOR TRACKING AND RECOVERING THE MANDATED PJM LSE OATT CHARGES THAT YOU WOULD LIKE TO COMMENT ON?

A. Yes. Fundamental to the establishment of fair, just, and reasonable rates is that the utility be provided the opportunity to earn a reasonable return on equity. The Commission in its Order in this case is charged with establishing a reasonable return on equity. The $17.0 million increase in PSM LSE OATT expense estimated in 2018 means that the failure to provide for recovery of the increase as proposed will reduce the Company's return on equity by 160 basis points and ensure the Company is denied the opportunity to earn its authorized rate return. The Company prefers to deal with the issue now and avoid having to file an entirely new rate case in 2018 for an issue that is currently known.

IV. DEFERRAL OF ROCKPORT UNIT POWER AGREEMENT EXPENSES

Q. CAN YOU DESCRIBE KIUC WITNESS KOLLEN'S PROPOSAL TO DEFER ROCKPORT EXPENSES FOR FUTURE RECOVERY?

A. Yes. Mr. Kollen has proposed for the Company to defer $20.3 million of what he refers to as "Rockport 2 Lease Expense" annually until the end of 2022 and then amortize the deferral amount to expense and recover the amount over the subsequent ten years.

Q WHAT IS THE BASIS FOR MR. KOLLEN'S PROPOSAL?

A. Mr. Kollen argues that because the Company's FERC-approved Unit Power Agreement ("UPA") for capacity and energy expires on December 7, 2022, and because it appears to him unlikely at this point that Kentucky Power will extend the UPA beyond 2022, the Company could defer some of the Rockport UPA costs and recover them after UPA terminates. According to Mr. Kollen, this proposal would allow the Company to implement part of the rate reduction associated with the termination of the Rockport UPA now as method to limit the rate increase in this case.

Q. DO YOU AGREE WITH MR. KOLLEN'S PROPOSED ROCKPORT UPA DEFERRAL?

A. No. While the concept proposed by Mr. Kollen is a creative way of reducing the Company's revenue requirement, the details of the deferral are problematic. The use of a deferral must be carefully considered. While it appears attractive because it lowers bills in the near term, it should not be forgotten that a deferral pushes payment off to a later date.

The risk to the Company is two-fold. First, there is a detriment to its financial statements carrying such a large unrecovered regulatory asset with the promise of future recovery. Details regarding this risk are described in the rebuttal testimony of Company Witness Wohnhas. Second, while the expectation is that a Commission Order that authorizes a deferral will be honored in the future, there are still parties that could seek to deny collection of the deferred amount. In fact, in this case Attorney General Witness Smith testifies that the Commission should consider writing off the unrecovered Big Sandy Retirement regulatory asset. Denying the collection of deferrals on the back end that were agreed upon or ordered to assist with lowering customer bills in the near-term is an undoing of the deal and punishes the Company for participating in the exercise.

V. RECOVERY OF ROCKPORT UNIT 1 SCR COSTS

Q. ON PAGES 59-60 OF HIS TESTIMONY, ATTORNEY GENERAL WITNESS SMITH RECOMMENDS THAT THE COMMISSION

DISALLOW RECOVERY OF THE COSTS ASSOCIATED WITH THE ROCKPORT UNIT 1 SCR. DO YOU AGREE WITH HIS RECOMMENDATION?

A. Absolutely not. Mr. Smith argues that because the Rockport Unit 1 SCR is related to the NSR Consent Decree, Kentucky Power should not be allowed to recover the costs. Company Witness McManus clarifies in his rebuttal testimony, Mr. Smith's misunderstandings about the NSR Consent Decree. The costs associated with the Rockport Unit 1 SCR are part of the required costs to produce capacity and energy at Rockport and, as such, they are costs properly recoverable by Kentucky Power.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; And (4) An Order Approving Accounting Practices To Establish Regulatory Assets And Liabilities; And (5) An Order Granting All Other Required Approvals And Relief	)))))))))	Case No. 2017-00179

REBUTTAL TESTIMONY OF

ANDREW R. CARLIN

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Andrew R. Carlin, being duly sworn, deposes and says he is the Director, Compensation and Executive Benefits for American Electric Power Service Corporation and that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief.

Andrew R. Carlin

Andrew R. Carlin

STATE OF OHIO)
) Case No. 2017-00179
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Andrew R. Carlin, this the 2nd day of November 2017.

Cheryl L. Strawser

Notary Public

NOTARIAL SEAL
STATE OF OHIO

Cheryl L. Strawser
Notary Public, State of Ohio
My Commission Expires 10-01-2021

My Commission Expires: October 1, 2021

REBUTTAL TESTIMONY OF
ANDREW R. CARLIN
ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2017-00179

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REBUTTAL TESTIMONY OF
ANDREW R. CARLIN ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Andrew R. Carlin. My position is Director of Compensation & Executive Benefits for the American Electric Power Service Corporation ("AEPSC"), a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP"). AEP is the parent company of Kentucky Power Company ("Kentucky Power" or the "Company"). My business address is American Electric Power, 15th Floor, One Riverside Plaza, Columbus, Ohio 43215.

Q. ARE YOU THE SAME ANDREW R. CARLIN WHO OFFERED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to correct mischaracterizations in the testimonies of Attorney General Witness Smith and Kentucky Industrial Utility Customers ("KIUC") Witness Kollen with respect to compensation expenses included in the Company's filing. In particular, I will show that:

- the Company's 2017 wage increases were reasonable;
- the incentive compensation expenses in question provide substantial benefits to customers and, as such, should be included in the revenue requirement without reduction; and
- the requested non-qualified post-retirement plan expenses are reasonable and appropriate costs to be borne by customers.

II. PAYROLL EXPENSE – EMPLOYEE BASE PAY INCREASES

Q. WHAT OPERATING INCOME ADJUSTMENT DOES ATTORNEY GENERAL WITNESS SMITH RECOMMEND WITH RESPECT TO PAYROLL EXPENSE?

A. Mr. Smith recommends reducing the Company's cost of service to reflect only 3.0% merit increases for 2017 for all salaried employees, rather than the 3.5% total increases that the Company has already made and requested be included in its cost of service?

Q. WHAT RATIONALE DOES MR. SMITH PROVIDE FOR HIS RECOMMENDED ADJUSTMENT?

A. Mr. Smith states that the requested increase "is higher than the 2.70% to 3.0% noted for 2009 through 2016 and the 3.0% median salary increase for 2017"[1] based on industry survey data.

Q. DO YOU AGREE?

A. No, I do not agree for several reasons.

Q. PLEASE EXPLAIN THE REASONS YOU DO NOT AGREE.

A. First and foremost, the Company's merit increases lagged the market median practice by a total cumulative deficit of from 1.975% to 3.725% from 2009 through 2016.[2] It would be unreasonable to limit cost recovery for utility wage increases to no more than the market median because this would, at best, only allow wages to keep up with the market and would never allow wages to catch up

[1] Direct testimony of Ralph C. Smith (Smith) on behalf of the Kentucky Office of Attorney General; October 3, 2017; p. 32, lines 3-5.
[2] Direct Testimony of Andrew R. Carlin (Carlin Direct); June 28, 2017; p. 18, Table ARC-2.

to the market, should they ever fall behind market for any reason, as is the Company's situation.

Secondly, the Company's total compensation for these employees is not above the market median on average and it is well within the market competitive range.[3] As such, the Company's compensation is both reasonable and market competitive. In addition, pay compression between the non-salaried and salaried workforces would have been exacerbated if the total increase for salaried workers was reduced to 3.0% given that base wages for the non-salaried workforce were higher as the result of the collective bargaining of wages for union represented employees. This would have reduced the Company's ability to attract employees from its physical workforce to take supervisory and other salaried positions. It also creates employee relations issues when supervisors, who arguably have more responsibility, make the same or less than the employees they are supervising.

Furthermore, the Company's 3.0% merit budget for 2017 was in line with utility and general industry practices. The Company also provided a combined 0.5% budget for line of progression promotions and equity adjustments for a total increase budget of 3.5%. In my experience, other utilities and general industry companies also provide these types of increases. However, these increases are not generally included in the salary increase budget and are instead made outside the salary budget process and funded with vacancy days for open positions or out of other budgets. Changes in the Company's process for salary increases eliminated avenues for out of cycle line of progression promotion and equity adjustment

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[3] Carlin direct, Exhibit ARC-4 (Kentucky Power Company Target Total Compensation vs. Market for Technical, Craft and Clerical Jobs)

increases, which led to the need for the Company to create a small separate budget for this purpose.

Line of progression promotions in particular and equity adjustments to a lesser degree are often awarded to the Company's highest performing employees, namely those most deserving of promotion and those whose work performance is comparable to higher paid employees inside and outside the Company. As such, these types of increases are a valuable retention tool.

Finally, the additional 0.5% budget for promotions and equity adjustments is not large enough to drive compensation levels that could be considered excessive by any definition, particularly given that the Company's average compensation is slightly below the market median.

Q. WHAT ARE THE ADDITIONAL REASONS THAT KIUC WITNESS KOLLEN PUTS FORWARD FOR RECOMMENDING A REDUCTION IN THE COMPANY'S REQUESTED LEVEL OF PAYROLL EXPENSE?

A. Mr. Kollen states that these are selective post-test year adjustments that could be offset by other post-test year items that were not proposed.[4] He states that mixing and matching historic and forecast test years is unfair to customers and easily manipulated.[5] In addition, he states that these adjustments simply assume that the Company will not achieve any offsetting cost reductions.[6] However, Mr. Kollen recognizes that if the post-test year increases are denied then the Company would

[4] Direct Testimony of Lane Kollen on behalf of the Kentucky Industrial Utility Customers, Inc. (Kollen), J. Kennedy and Associates, Inc., October 2017, p. 23, lines 18-21.
[5] Kollen, p. 24, lines 3-5.
[6] Kollen, p. 24, lines 6-7.

be forced to reduce other costs or limit other cost increases for its costs to more closely match its revenues.[7]

Q. DO YOU AGREE WITH THESE RATIONALES?

A. No. The post-test year adjustments to payroll expense are for increases that were approved by Company management during or before the test year and have been implemented. As such, they are known and measurable. The criticism about using forecasted and historical information for different data points suggests it would be necessary for the Company to file an entire base rate case on a forecasted test year basis in order to include a small number of known and measurable adjustments in its cost of service. This is obviously not required, and therefore Mr. Kollen's criticism in this regard is without basis.

Including these post-test year items will lead to a revenue requirement that more accurately reflects the Company's costs going forward. This reduces regulatory lag and the frequency of base rate cases. As such, including these post-test year costs is a more fair and reasonable approach for both the Company and its customers.

Furthermore, the Company is not aware of any significant offsetting cost reductions. As Mr. Kollen recognizes, if the post-test year increases are denied, the Company will not be able to earn the rate of return authorized in this case unless it reduces other costs or limits other cost increases.[8]

Q. IF MESSRS. SMITH'S AND KOLLEN'S RECOMMENDED ADJUSTMENTS TO PAYROLL EXPENSE ARE NOT ADOPTED,

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[7] Kollen, p. 24, lines 11-12.
[8] Kollen, p. 24, lines 9-12.

WOULD THE RECOMMENDED ADJUSTMENTS TO OVERTIME AND PAYROLL TAX APPLY?

A. No. These adjustments are secondary impacts of the payroll adjustments and they would only apply to the extent that the proposed payroll adjustments are adopted. As described above, the adjustments proposed by the Attorney General and KIUC should not be adopted.

III. <u>ANNUAL INCENTIVE COMPENSATION</u>

Q. WHAT ADJUSTMENTS HAVE BEEN PROPOSED WITH RESPECT TO THE COMPANY'S REQUESTED LEVEL OF ANNUAL INCENTIVE COMPENSATION EXPENSE?

A. Attorney General Witness Smith proposes denying cost recovery for 25% of the Company's annual incentive compensation expense while KIUC Witness Kollen proposes denying cost recovery for 75% of this this expense.

Q. WHAT IS MR. SMITH'S RATIONALE FOR HIS RECOMMENDATION TO REMOVE 25% OF ANNUAL INCENTIVE EXPENSE?

A. Mr. Smith cites the following excerpt from Commission's order in the Company's last base rate case:

> While the Commission agrees with the AG conceptually, we find that the amount that should be removed for ratemaking purposes should be based on the performance measures of the plan, not the funding measures. Among the performance measures, only 15% is based on financial performance. Accordingly, the Commission's adjustment removes only 15%, or $442,181, of the cost of $2,947,874 Kentucky Power provided in rebuttal from test-period operating expenses for ratemaking purposes.[9]

Mr. Smith continues and cites an AEP document that states:

[9] Order of the Kentucky Public Service Commission, Case No. 2014-00396, June 22, 2015, pp. 25-26.

> Generally, at least 25% of the total target award for each incentive plan or group should be based on quantitative financial objectives.[10]

Q. DO YOU AGREE WITH MR. SMITH'S ASSERTION THAT ELIMINATING 25% OF THE COMPANY'S REQUESTED ANNUAL INCENTIVE COMPENSATION AS THE RESULT OF THE STATEMENT IN THIS DOCUMENT ABOVE IS IN KEEPING WITH THE COMMISSION'S ORDER IN THE PRIOR CASE?

A. No, for several reasons. First and foremost, "quantitative financial objectives" as used in this document can be and usually are performance measures that unquestionably benefit customers, such as efficiency measures. The Company does not interpret this as requiring an earnings per share ("EPS") or other earnings measure, and it is only the Company's interpretation of its own document that has any impact on incentive compensation. For example, the 2017 annual incentive plan for Kentucky Power distribution and staff employees meets this requirement with a 10% weight on continuous improvement activities, a 5% weight on economic development and a 10% weight on Kentucky Power net income.

The 10% net income measure is the measure that the Commission removed from the Company's cost of service in the prior base rate case. However, the weight for this measure has been reduced from 15% to 10% in the intervening period. The 10% weight on continuous improvement and the 5% weight on economic development both are clearly in customer's interests. Therefore, the net income measure is the only earnings measure in the Company annual incentive plan, other than a portion of the funding measures, which the

[10]AEP Incentive Compensation Guiding Principles and Policies, p. 3.

Commission declined to remove from the cost of service in the Company's last base rate case. Therefore, if the Commission chooses to act in a manner that is consistent with its order in the prior base rate case, it would remove 10% of the Company's annual incentive compensation expense, not 25% as recommend by Mr. Smith.

In addition, this language in the aforementioned company document is outdated and likely to be revised or eliminated. It was written at a time when controlling expenses to budget was a key emphasis of the Company's annual incentive compensation plan. However, the Company's budget, forecasting and management processes have evolved to the point that, to my knowledge, significant expense budget exceedances do not occur without advanced approval from senior management. Therefore, this is no longer an important incentive plan design consideration.

Q. HOW DOES KIUC WITNESS KOLLEN CHARACTERIZE THE COMMISSION'S ORDER IN THE COMPANY'S LAST BASE RATE CASE WITH RESPECT TO ANNUAL AND LONG-TERM INCENTIVE COMPENSATION?

A. Mr. Kollen states that "the Commission specifically disallowed incentive compensation expense incurred to achieve shareholder goals"[11] in support of his recommendation to remove 75% of annual incentive compensation from the Company's cost of service for rate making purposes. However, Mr. Kollen neglects to mention that the Commission found in the previous case "that the amount that should be removed for ratemaking purposes should be based on the

[11] Kollen, p. 21, lines 8-9.

performance measures of the plan, not the funding measures. Among the performance measures, only 15% is based on financial performance."[12] The weight for the net income measure for which cost recovery was denied in the previous case was 10% in this case, not the 75% denial Mr. Kollen recommended, and no new performance measures of this type have been added.

Q. DOES THE COMPANY'S ANNUAL INCENTIVE COMPENSATION, PRIMARILY BENEFIT SHAREHOLDERS?

A. No. The Company's annual incentive compensation, including the portion tied to Company net income, primarily benefits customers. This is because the Company's annual incentive compensation is an integral component of a reasonable and market competitive compensation package that enables the Company to attract and retain employees with the skills and experience needed to efficiently and effectively provide service to customers. As explained in my direct testimony, the overall value of the Company's total compensation package would fall well below market competitive levels without the annual incentive compensation portion of employee pay. This is undisputed thus far in this case.

Furthermore, the customers already receive, and will continue to receive in connection with this filing, the accumulated benefits from past incentive compensation arrangements. Annual incentive compensation is not a limitless productivity engine that generates incremental productivity gains each and every year sufficient to offset the reasonable, prudent and necessary costs associated with it. Denying any portion of this expense would provide all the accumulated benefits to customers without a portion of the corresponding payroll expense that

[12] Order of the Kentucky Public Service Commission, Case No. 2014-00396, June 22, 2015, pp. 25-26.

sustains and builds on these efficiencies over time. Such an approach would be unreasonable and unbalanced.

As such, the expense associated with annual incentive compensation, including the portion associated with the 10% net income measure and the funding measures, provides significant benefits to customers. The annual incentive compensation plan is an integral part of the overall compensation plan of the Company, and the total compensation (the combination of base pay and incentive pay) that eligible employees receive is intended to place that total compensation at or near the market rate for each particular job or salary band. Moreover, improvement in metrics such as safety, efficiency of operations and financial performance can and does lead to savings that eventually benefit the customer when those improvements are captured in a base rate case. 100% of the annual incentive plan costs proposed by the Company for both the Company's employees and employees of AEPSC should be allowed.[13]

The benefit to customers is not diminished by tying a portion of plan funding to AEP's earnings. Because the primary, and often only lever, most employees have in a regulated utility to meet financial objectives is cost efficiency, tying incentive compensation to financial objectives directly benefits customers by providing an incentive that promotes efficiency. Furthermore, the robust nature of this and other rate case proceedings mitigates the risk that employees will be unduly motivated by such earnings measures to pursue rate increases at the expense of rate payers.

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[13] See, e.g., Public Service Commission of West Virginia Charleston, Case Nos. 14- 1 152-E-42T and 14- 1 15 1 -E-D, Appalachian Power Company and Wheeling Power Company, Commission Order, May 26, 2015 (WV Commission Order), pp. 75-76. (adopting similar rationale).

Finally, eliminating the financial component of annual incentive compensation is based on the unfounded and inaccurate assumption that the Company's customers have no interest in the Company's financial performance. Earnings that approach the Company's authorized rate of return provide a favorable environment and more capital for discretionary investment, increase the period between rate cases and provide greater rate stability. Companies that provide a clear financial incentive to employees to strive to cut costs, increase efficiency, manage risk, and respond to change likewise are less likely to need to seek rate adjustments.

Q. WOULD THE ELIMINATION OF ANY PORTION OF THE COMPANY'S REQUESTED ANNUAL INCENTIVE COMPENSATION BE IN KEEPING WITH THE COMMISSION'S ORDER IN THE PRIOR CASES?

A. No. The Company's annual incentive compensation, including the portion associated with the funding measures, provides substantial benefits to customers. Without the requested target level of annual incentive compensation, or an equivalent amount of additional base pay, the Company would not be able to attract and retain employees with the skills and experience needed to efficiently and effectively provide service to customers. The Company's annual incentive compensation is also clearly tied to many measures of improvement in service quality. These measures include SAIDI, customer satisfaction, mobile alert penetration, a reliability work plan, a customer experience work plan, a risk mitigation work plan, and emergency restoration planning.

The Company has shown with substantive and sufficient evidence that its incentive compensation program is a critical component of market competitive total compensation that benefits customers by enabling the Company to attract and retain the employees needed to efficiently and effectively provide its service to customers. Neither the need for market competitive total compensation nor the appropriate level of such compensation is contested in the testimony in this case.

Q. IS KIUC'S PROPOSAL TO ELIMINATE 75% OF ANNUAL INCENTIVE EXPENSE BASED ON AN ACCURATE ASSESSMENT OF THE COMPANY'S ANNUAL INCENTIVE PLAN?

A. No. While 75% of the funding measures for the Company's annual incentive compensation was tied to the AEP EPS measure for the test year (only 70% for 2017), this is only a part of the equation. The final award score is the product (z) of three equally weighted components: (w) Kentucky Power Company's overall operating performance score, (x) the overall funding score and (y) the normalizing factor in the equation $w \times x \div y = z$. The normalizing factor (y) is the average operating performance score (AOPS) for all AEP business units. Setting aside the normalizing factor, the funding factor is only half the equation. As such, if the Commission deems it appropriate to make this adjustment, then only half of the 75% weight associated with the AEP EPS measure (37.5%) should be removed from the Company's cost of service.

Q. IS THE COMPANIES' ANNUAL INCENTIVE COMPENSATION WEIGHTED TOWARDS FINANCIAL GOALS?

A. No. Mr. Kollen inappropriately focuses on funding measures while ignoring the operating performance measures in the Company's annual incentive program. The majority of Kentucky Power employees participate in the Kentucky Power Company version of Annual Incentive Compensation Plan for AEP Utilities, which includes the many Kentucky Power specific performance measures. The 2016 Kentucky Power annual incentive compensation performance measures are outlined below.

<u>Infrastructure Development (25%)</u>
Kentucky Power Company Net Income (10%)
Kentucky Power Company / AEP Utilities Economic Development (5%)
Kentucky Power Company Efficiency and Effectiveness Measures (10%)
Kentucky Power Company Cost per ASB (as built) Hour (5%)
Kentucky Power Company ASB Hours per FTE Equivalent (2.5%)
Kentucky Power Company MRO (Meter Revenue Operations) Cost per Order Completed (2.5%)
<u>Customer Experience (40%)</u>
Kentucky Power Company SAIDI (5%)
Kentucky Power Company Reliability Work Plan Execution (5%)
Kentucky Power Company Regulatory Execution (pursuit of customer driven initiatives with regulators that improve the customer experience) (5%)
J.D. Power Residential Overall Customer Satisfaction Index (5%)
Risk Mitigation Work Plan Execution (5%)
Customer Experience Work Plans (10%)
Kentucky Power Company Work Plan Including Mobile Alert
System-Wide Outage Mapping & Data Analytics (5%)
Emergency Restoration Planning / ICS Execution (5%)

Employee Experience (35%)
Kentucky Power Company Employee Culture / Experience Work Plan
Kentucky Power Company DART Rate (10%)
Proactive Employee Safety Measures (20%)
Quality Assurance on Jobsite Observations (5%)
Engage Employees to identify and address top five high-risk activities (5%)
Good Catch Program (5%)
Site Inspection Program (5%)

Only one of the performance measures in these Kentucky Power operating goals, the 10% Net Income measure, is a financial measure.

Q. ARE THERE ANY OTHER REASONS WHY YOU DISAGREE WITH MESSRS. SMITH'S AND KOLLEN'S RECOMMENDATIONS ON INCENTIVE COMPENSATION?

A. Yes. It is not proper for the companies to "charge" employee compensation costs to shareholders when this compensation is a reasonable, prudent and necessary expense for Kentucky Power. It is not accurate to infer that shareholders are the main beneficiaries of the funding pool, when it is simply a mechanism to provide goal oriented variable compensation which directly encourages employees to reduce expense, and operate safely and efficiently to provide reliable service to Kentucky Power customers. Stated another way, objections to the form of the Company's compensation arrangements, but not its reasonableness, is literally a matter of form over substance.

Q. IS MR. KOLLEN'S PROPOSAL TO ELIMINATE 75% OF ANNUAL INCENTIVE EXPENSE CONSISTENT WITH COMPENSATION PRACTICES USED BY INDUSTRIAL EMPLOYERS IN THE UNITED STATES?

A. No. It is common practice among U.S. industrial companies is to heavily utilize annual incentive compensation in the design of their employee compensation programs, and the benefits incentive compensation provides are well-understood.

Q. HOW WOULD THE COMPANY BE AFFECTED BY REDUCING OR ELIMINATING VARIABLE INCENTIVE COMPENSATION FROM ITS COST OF SERVICE FOR RATEMAKING PURPOSES?

A. Denying cost recovery for a portion of the variable component of employee pay would reduce the Company's rate of return to below the level to be set in this rate case, all else being equal. It would also encourage shifting variable incentive compensation into fixed base pay to enable the Company to recover its reasonable payroll costs. The Company would need to continue to offer employees the same target level of total compensation, in one form or another, in order to continue to maintain compensation at the market competitive levels needed to attract and retain employees with the skills and experience needed to efficiently and effectively provide service to customers. Therefore, shifting annual incentive compensation into base pay would not reduce the Company's payroll costs to less than the target level the Company requested be included in its cost of service in this case.

However, transferring variable incentive compensation into fixed base pay would lead to the gradual erosion of the efficiencies, productivity enhancements and operational benefits gained by the proven strategy of linking pay to performance. The loss of these efficiency, productivity and operational benefits, would lead to increased expenses, reduced company performance in many areas and higher rates for customers. Therefore, these proposals offered by KIUC and the Attorney General should be rejected by the Commission.

Furthermore, it is not reasonable to expect that the incremental benefit that annual incentive compensation may produce between rate cases, if any, will be sufficient to cover any significant portion of the Company's annual incentive expense. As a fundamental matter, it is important to recognize that the Company's incentive compensation plan has no incremental cost above the cost of providing market competitive compensation. Annual incentive compensation has encouraged and supported the development of a culture of high performance within the Company over the decades that it has been in place for all employees. The efficiency gains and other benefits that have resulted from incentive compensation and this high performance culture will already be incorporated in rates through this and prior rates case proceedings. It is not known if any further gains will be achieved as a result of the Company's annual incentive program and it is unreasonable to expect that such gains would or even could be sufficient to offset the denial of cost recovery for any significant portion of the Company's annual incentive compensation, let alone the 25% and 75% denials proposed by Messrs. Smith and Kollen, respectively. Because it has been in place for such a long period, only small, incremental benefits, if any, should be expected from incentive compensation going forward. However, even if incentive compensation only produces small incremental benefits or no new benefits going forward, it will still provide a positive net benefit because it has no incremental cost above the cost of providing market competitive compensation through base pay alone and because it helps maintain the efficiency gains and other cost savings that have already been achieved.

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO KIUC'S PROPOSAL TO REDUCE EMPLOYEE COMPENSATION EXPENSE BY ELIMINATING COST RECOVERY FOR 75% OF ANNUAL INCENTIVE EXPENSE?

A. I recommend that the Commission reject KIUC Witness Kollen's proposal to eliminate three quarters of direct employees' and AEPSC employees' annual variable incentive opportunity from cost of service. This is a necessary expense that is properly included as market competitive employee compensation and a reasonable and prudent cost of providing service to our customers.

IV. LONG-TERM INCENTIVE COMPENSATION

Q. WHAT JUSTIFICATIONS ARE CITED BY ATTORNEY GENERAL WITNESS SMITH FOR EXCLUDING 100% OF THE COMPANY'S LONG-TERM COMPENSATION?

A. First Mr. Smith states his position that "ratepayers should not be required to pay executive or management compensation that is based on the performance of the Company's (or its parent company's) stock price, or which has the primary purpose of benefitting the parent company's stockholders and aligning the interests of participants in the stock-based compensation plans with those of such stockholders."[14]

Mr. Smith also points out that stock option expense, which the Company has not had in many years, was at one point many years ago treated as a dilution

[14] Smith, p. 37, lines 5-9.

of shareholder's investment. Despite the fact that this is no longer the case and the fact that the types of stock-based compensation that the Company currently provides have never been accounted for as a dilution of shareholder's investment, Mr. Smith believes that "this does not provide a reason for shifting the cost responsibility for stock-based compensation from shareholders to utility ratepayers."[15]

Q. DO YOU AGREE WITH MR. SMITH?

A. No. There are several mischaracterizations in his testimony and I disagree with both his philosophical view and his recommendation. The first mischaracterization is that the Companies' stock-based compensation is exclusive to executives and management. In the test year the Companies provided stock-based compensation to approximately 1,025 employees, which more than any reasonable definition of executive and management employees. Many participants in this program were, in fact, single contributor professionals.

The expansion of long-term incentive compensation to large numbers of employees at levels that have little, if any, ability to control or influence the value at which it pays out, undermines the view that it provides an incentive for participants to act in shareholder's interests to the detriment of customers. The only incentive or inducement it can possibly have for most participants is simply to control costs because this is the primary and often only lever all but a few participants have available. This cost control directly benefits customers. Eliminating cost recovery of a portion of reasonable and market competitive compensation for a large number of employees, when only a few such employees

[15] Smith, p. 37, lines 19-20.

have any incentive or ability to affect the results is over-reaching and would result in a disallowance that is greatly disproportionate to any concern that this is detrimental to customers beyond the role of the Commission to fully mitigate this concern.

Even if the long-term incentive program was limited to executives and management employees it should not make any difference. The Company needs to provide market competitive compensation to attract and retain executives, management and all other types of employees who participate in it in order to efficiently and effectively provide service to customers. This undeniably benefits customers even with respect to executive and management compensation.

The second mischaracterization is that stock-based compensation is based on the performance of the Company’s (or its parent company’s) stock price. Unlike stock options, which have no value unless the underlying stock price increases in value, the Companies’ stock-based compensation has a substantial value on day one. While the parent Company’s stock price is one of several factors that determine the value of this compensation for participants, the amount the Company has requested be included in cost of service is a static value that is unaffected by stock price changes, parent company earnings and all other factors. Shareholders will gladly accept responsibility for any compensation associated with improvements in stock price and earnings provided customers accept responsibility for the cost associated with the static portion of employee compensation, in all forms, that is part of a market competitive compensation package. Furthermore, the impact that Company executives and management may have on a company's stock price is highly attenuated. As such, simply denominating long-term compensation in company shares or stock units does not create a significant incentive for any action whatsoever. This is why some pundits on compensation topics characterize RSUs as "pay for pulse."[16]

Mr. Smith's third mischaracterization is that stock-based compensation provided to officers and other employees that is "beyond their other compensation should be borne by shareholders and not by ratepayers."[17] This implies that the Company's long-term compensation is not a component of reasonable and market competitive compensation for participants but is instead additional to such reasonable and market competitive compensation. I have shown in my direct testimony is not the case.[18]

Lastly, Mr. Smith mischaracterizes the Companies' current stock-based compensation program by associating it with stock options, which the Companies last granted as a regular part of its long-term incentive program in 2013 and last grated at all in 2006. Stock options and the Companies' current forms of stock-based compensation are different instruments, with different accounting, granted in different periods in different volumes to different populations for different reasons. Any comparison between the Company's current stock-based compensation to stock options is unreasonable.

Q. IS ALL OF THE COMPANY'S LONG-TERM COMPENSATION BASED ON THE PERFORMANCE OF AEP STOCK?

[16] Equilar Blog, Companies Just Say No to "Pay for Pulse".
[17] Smith, p. 39, lines 6-7.
[18] See, Carlin Direct Testimony, pp. 32-33, lines 14-33 and Exhibit ARC-6 (Target Total Compensation vs. Market for Executive Positions)

A. No, there is a distinction between performance units, the value of which is tied to earnings per share and total shareholder return performance measures, and restricted stock units ("RSUs") that are merely denominated in AEP stock. RSUs, constitute 25% of the initial value of the Company's long-term incentive compensation granted in the test year and are not tied to any performance measures. Instead participants must continue their AEP employment through specified vesting dates in order for RSUs to vest, which is simply a retention incentive.

Q. WHY DOES AEP DENOMINATE LONG-TERM INCENTIVE COMPENSATION IN SHARES OR STOCK UNITS?

A. AEP denominates long-term incentive compensation in AEP shares or stock units for several reasons. First and foremost, long-term incentive compensation provides value to participants in future periods. The time value of money and risk of non-payment is taken into consideration by participants in the same way that investors take it into consideration. If the Company does not tie the value of long-term incentive compensation to a suitable investment vehicle that reflects the time value of money and risk of non-payment to participants, then participants will discount the value of the Company's long-term incentive compensation. Denominating long-term incentive compensation in AEP shares meets this need.

Secondly, the accounting treatment for share-based payments is more favorable than using any other vehicle, including cash. Because company stock is a company's currency and companies generally control the supply of it, compensation that is paid in company stock is basically treated as fully hedged.

As a result, any gain or loss attributable to share price changes and dividends does not have an expense impact. This is the accounting treatment that applies to AEP's RSUs. If the long-term cash awards were issued, then any interest or investment gain applied to it would cause an additional expense.

Furthermore, using stock creates a shared fate between employees and shareholders. It is a false dichotomy that such alignment is not also in customers' interests. The view that this is detrimental to customers ignores the Commission's control over rates through robust regulatory proceedings such as this rate case, which the Commission presumably believes adequately addresses the incentive that any regulated company has to seek higher rates. To the extent that the Company is able to obtain regulatory approval of its rate requests and other initiatives, such approval will customarily require that the Commission finds the rates and other initiatives to be consistent with the interests of customers, or otherwise reasonable and necessary from their perspective. The scrutiny that rate requests undergo inherently encourages Company employees to put together proposals that can be approved as consistent with the public interest, not just the utility's interest, and that are just and reasonable to consumers as well as to the utility. It also ignores the alignment of interests between shareholders and customers with respect to keeping costs low, which is the primary and often only lever most employee-participants have available to improve the value of their long-term incentive compensation.

Q. WHAT JUSTIFICATIONS ARE CITED BY KIUC WITNESS KOLLEN FOR EXCLUDING 100% OF LONG-TERM INCENTIVE COMPENSATION?

A. Mr. Kollen mischaracterizes the Company's long-term incentive compensation in her statement that it "was implemented to incentivize AEP executives and managers to enhance shareholder value."[19] He attributes this statement to the Company's response to KIUC I-30, which provided each of the Company's incentive compensation plans. However, the Company's long-term incentive plan, which was provided in this response, actually states the following:

> **Section 1.03. Purpose of This Plan.** The purposes of the Plan are to: (a) strengthen the alignment of interests between those Employees and Directors of the Company and its Subsidiaries who share responsibility for the success of the business and those of the Company's shareholders, (b) facilitate the use of long-term incentive compensation and the provisions of market competitive total compensation to Employees, (c) increase Employee ownership of shares of the Company's common stock to encourage ownership behaviors, and (d) encourage Plan Participant retention.[20]

Nowhere does in this plan document say that the Company's long-term incentive plan was implemented to enhance shareholder value.

Furthermore, even if the primary objective of long-term incentive compensation was to enhance shareholder value, language in a plan document would not be a good reason to exclude its expense from the Company's cost of service for rate making purposes. Only if it actually enhances shareholder value in a manner that is contrary or inconsistent with providing long-term benefits to customers that are commensurate with its costs, would there be reason to exclude

[19] Kollen, p. 19, lines 19-20

[20] Company response to KIUC's First Set of Data Requests, Item 30 (KIUC 1-30), August 14th, 2017, p. 317.

some or all of it from a Company's cost of service. However, any denial of cost recovery in such circumstances should be commensurate with the actual harm to customers, if any.

Q. DOES THE LONG-TERM COMPENSATION PROGRAM PRIMARILY BENEFIT CUSTOMERS OR SHAREHOLDERS?

A. It primarily benefits customers because all of the financial and operational benefits that have accrued as a result are reflected in the Company's cost of service in the test year and will inure to customers through this and prior base rate case proceedings. Very little, if any, additional improvements can be expected going forward. However maintenance the long-term incentive program prevents a gradual backslide with respect to all the cost and operational performance improvements achieved through these many years.

Furthermore, the Company must provide long-term incentive compensation, or an equivalent value of some other type of compensation, in order for its compensation for participants to remain within the market-competitive range. Aside from post-test year base pay adjustments, no party in this case has challenged the reasonableness of the Company's compensation, of which long-term compensation is an integral component. Therefore, long-term incentive compensation benefits customers by enabling the Company to attract, motivate, engage and retain the highly qualified executives, managers and other long-term incentive participants needed to manage its operations efficiently and effectively.

In addition, the increased participant retention that long-term compensation enables benefits customers by fostering management continuity and stability, which leads to better operational performance and lower costs for customers.

Long-term incentive compensation also benefits customers by linking a substantial portion of compensation for participants to longer-term measures of performance. This is prudent because it avoids encouraging short-term performance at the expense of long-term performance, which is analogous to farmers eating their seed corn. Compensating participants with only base pay and short-term incentive compensation would be counter to both shareholder and customer interests because it would discourage executive management from taking on prudent long-term risks that are in the interests of both shareholders and customers. This is because taking on such appropriate and prudent risks, even if they are likely to benefit both shareholders and ratepayers in the longer-term, could otherwise impair short-term performance. This could discourage that achievement of appropriate long-term objectives and performance goals that are beneficial to both customers and the Company.

Q. IS MR. KOLLEN'S ASSERTION TRUE THAT IF PARTICIPANTS ACHIEVE OR EXCEED TOTAL SHAREHOLDER RETURN ("TSR") AND EARNINGS PER SHARE ("EPS") OBJECTIVES, THEY ARE REWARDED WITH ADDITIONAL COMPENSATION?[21]

A. This is only partially true, and it is misleading. While it is true that performance units are tied to TSR and EPS metrics, this is not true with respect to RSUs, which

[21] Kollen, pp. 21-22, lines 20-2

constitute 25% of long term incentive awards granted in the test year. As previously mentioned, RSUs are not tied to any performance measures. It is also misleading to suggest that the Company's long-term incentive compensation "additional," because, as explained in my direct testimony,[22] the target compensation opportunity it provides is an integral component of a reasonable and market competitive compensation for employee-participants.

Q. DO YOU AGREE WITH MR. KOLLEN'S ASSERTION THAT "STOCK PRICE, BY DEFINITION, IS A MEASURE OF AEP'S FINANCIAL PERFORMANCE"?

A. No. As I previously explained, the effect financial performance has on stock price is highly attenuated and the Commission's responsibility for setting the Company's rates mitigates the risk this poses to customers. Mr. Kollen's statement suggest he would prefer that Company management sacrifice the interests of shareholders to those of customers by not seeking to recover the Company's reasonable and appropriate costs of providing service to customers. This would be unbalanced and ultimately detrimental to customers because it would reduce both the dollars available to the Company for investment and the amount of the Company's discretionary investment. The ability to earn an appropriate rate of return on its investment is fundamental to the regulatory compact.

Q. IS THE COMMISSION'S PRACTICE WITH RESPECT TO INCENTIVE COMPENSATION IMMUTABLE?

[22] Carlin Direct Testimony, pp. 32-33, lines 14-33 and Exhibit ARC-6 (Target Total Compensation vs. Market for Executive Positions)

A. No. Recommendations in any rate case should stand on the testimony and exhibits in evidence in the particular case. The Commission's practice is based on the view that incentive compensation tied to earnings and similar financial measures of the Company or its parent are detrimental to customers or at least primarily benefit shareholders. This testimony shows, to the contrary, that the Company's long-term incentive compensation, including the performance units that are tied to TSR and EPS measures, primarily benefit customers. Accordingly, the Commission should allow the inclusion of the Company's long-term incentive compensation in its cost of service for rate making purposes in this case.

The Company has shown that its long-term incentive compensation is a critical component of market competitive total compensation that benefits customers by enabling the Companies to attract and retain the employees needed to efficiently and effectively provide its service to customers. Neither the need for market competitive total compensation nor the reasonableness of the Company's total compensation, aside from post-test year adjustments, is contended in pre-filed testimony in this case.

Mr. Kollen portrays a false dichotomy by suggesting that the Companies' long term incentive program incentivizes the achievement of shareholder but not customer goals. The primary objective of the Companies' long-term incentive plan is to provide an integral component of the reasonable and market competitive compensation needed to attract, retain and motivate the appropriately skilled and experienced employees needed to efficiently and effectively provide electric service to customers. This fundamental aspect of the plan clearly benefits both customers and the Company. Furthermore, the financial measures included in the performance unit portion of the Companies' long-term incentive compensation (75% of the total) benefit customers by providing an incentive to control costs, which is the primary and often only lever most utility employees have available to improve company financial performance.

The remaining 25% of AEP's long-term incentive program takes the form of RSUs, which are tied primarily to participant retention through vesting requirements and are not tied to any performance measures.

The belief that long-term compensation benefits shareholders to the detriment of customers by encouraging participants to seek unwarranted rate increases, ignores the robust nature of such proceedings and questions the effectiveness of this and other Commissions.

My testimony shows that the Companies' long-term incentive compensation plan provides substantial benefits to customers by enabling the company to attract and retain suitable employees, by encouraging cost control and by encouraging employee retention. These benefits certainly exceed the incremental cost of long-term incentive compensation, which is $0 relative to the cost of providing market competitive compensation through other types of compensation.

Q. ARE THERE ANY OTHER REASONS THAT LONG-TERM INCENTIVE COMPENSATION SHOULD BE INCLUDED IN THE COMPANY'S COST OF SERVICE.

A. Yes, as with annual incentive compensation, each rate case conveys to customers all of the benefits that have accumulated over the many years that the Company's long-term compensation program has been in place. As was the case with annual incentive compensation, Messrs. Smith's and Kollen's proposals would provide customers with all the accumulated benefits of the long-term incentive compensation but none of its costs. This is disproportional to any perceived harm to customers, which in any case is mitigated by the Commission, which is responsible for setting utility rates.

In addition, the Companies' long-term incentive compensation is intended, as the name implies, to encourage participants to consider the long-term impact of their decisions on the Company and all of its stakeholders, including current and future customers. The long-term incentive program also serves as a way of compensating employees for performance that often has significant benefits to customers, for example, by designing new equipment and procedures in-house, and thus avoiding the cost of much more expensive outside contractors and consultants.

Without a market competitive total compensation program that includes either long-term incentive compensation or some other form of compensation of equal value, the Company cannot successfully compete for appropriately skilled and experienced personnel. Therefore, providing market competitive compensation to employees at all levels of the organization is a necessary and a basic cost of providing utility service to our customers. This is particularly true at leadership levels where management continuity is often critical. Simply put, no company of the Companies' size and complexity can function effectively without highly skilled people in a large number of key positions. Including long-term incentive compensation as a component of a reasonable and market compensation package for many of these positions, is the best way to compensate these positions from both shareholder and customer's point of view.

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO INTERVENOR'S PROPOSALS TO ELIMINATE THE STOCK UNIT PORTION OF EMPLOYEE LONG-TERM INCENTIVE COMPENSATION?

A. I recommend that the Commission reject Messrs. Smith's and Kollen's proposals. Long-term incentive compensation simply brings employee compensation to reasonable and market competitive rates and the incentive that it creates provide substantial benefits to customers.

V. <u>SAVINGS PLAN EXPENSE</u>

Q. DID ATTORNEY GENERAL WITNESS SMITH'S ADJUSTMENTS TO PAYROLL EXPENSE, INCENTIVE COMPENSATION EXPENSE AND LONG-TERM INCENTIVE EXPENSE FLOW THROUGH TO SAVINGS PLAN EXPENSE?

A. Yes, although his recommendation goes further than these adjustments. I will address the flow-through adjustments related to compensation and Company Witness Cooper will address Mr. Smith's recommendation for further adjustments.

Q. DO YOU AGREE THAT IF THE ANNUAL OR LONG-TERM INCENTIVE COMPENSATION ADJUSTMENTS ARE ADOPTED THEY SHOULD FLOW THROUGH AND RESULT IN RELATED ADJUSTMENTS TO SAVINGS PLAN EXPENSE?

A. No. The rationale for the adjustments to incentive compensation relate entirely to the form of such compensation and whether customers or shareholders should pay for it. No witness has argued that total compensation is unreasonable or more than is needed to provide market competitive compensation. As such, if the Company chose not to offer incentive compensation, it would still need to provide an equivalent value of base salary and it would still incur the associated savings plan expense. As such, any incentive compensation adjustments should not flow through to cause savings plan adjustments.

VI. NON-QUALIFIED POST-RETIREMENT BENEFITS

Q. PLEASE EXPLAIN THE COMPANIES' POST-RETIREMENT BENEFITS.

A. The Company maintains non-qualified post-retirement benefit plans for its employees to provide benefits that cannot be provided under qualified post retirement plans due to IRS limits imposed on ERISA-qualified plans. These plans are commonly referred to as Supplemental Employee Retirement Plans or "SERPs." The Company utilizes such plans to provide the same retirement benefits to employees as are provided under the ERISA-qualified retirement plans to the extent that such benefits cannot be provided due to the constraints imposed on qualified plans. AEP's non-qualified pension plans use the same benefit formulas as are used under the qualified AEP Retirement Plan for each respective employee, except that the non-qualified benefits are reduced by the amount of qualified benefits. Therefore, the total benefit provided by the Company under both its qualified and non-qualified retirement plans is equal to the benefit that would be produced by the formulas utilized under the qualified retirement plans if these plans were not subject to the benefit limitations imposed on qualified plans.

The Companies' non-qualified defined benefit plans also provide contractual benefits that were negotiated with respect to a few executives, nearly all of whom are now retired. No new contractual benefits have been negotiated in many years.

Q. HOW PREVALENT ARE NON-QUALIFIED DEFINED BENEFIT PENSION PLANS?

A. In my experience, most large companies that provide qualified defined benefit or defined contribution pension plans also provide non-qualified restoration plans that are similar to the Companies' non-qualified pension plans. This is because, to do otherwise, would be to accept arbitrary limits on retirement benefits to the detriment of the highly valuable employees who command compensation that exceeds the limits on qualified retirement plans. By arbitrary, I mean that these qualified plan rules limit the extent of favorable tax treatment, and should not be construed as serving any other purpose, such as designating the maximum acceptable level of retirement benefits that a company should provide or as a limit on amount of utility company benefit expense that customers should bear with respect to a single employee. These plans are more prevalent with larger companies, simply because larger companies are generally more complex and generally need more employees who command compensation in excess of the arbitrary limits on qualified retirement plans. Customers benefit from the economies of scale that larger companies generally provide. As such, they should bear the related cost of the additional compensation and benefits expense associated with managing larger companies.

Q. WHAT TREATMENT OF SERP EXPENSE IS RECOMMENDED BY ATTORNEY GENERAL WITNESS SMITH?

A. Mr. Smith recommends excluding all SERP expense from the Company's cost of service because "the provision of additional retirement compensation to the Company's highest paid executives is not a reasonable expense that should be recovered in rates."[23]

Q. DO YOU AGREE?

A. No, I do not agree. First, the Company's non-qualified post-retirement benefits are not limited to the "Company's highest paid executives."[24] There are several hundred participants in these programs, which goes well beyond any reasonable definition of "highest paid" or "executives."[25]

Second, these programs are not "additional."[26] They are an integral component of a reasonable and market competitive total rewards package. The Company needs employees with specialized experience, knowledge, capabilities and skills to efficiently and effectively provide electric service to customers.

[23] Smith, p. 42, lines 18-19.
[24] Smith, p. 42, lines 18-19.
[25] Smith, p. 42, lines 18-19.
[26] Smith, p. 42, lines 18-19.

Therefore, it is reasonable, prudent and in the customers' interests for the Company to attract and retain such employees. The experience and attributes that such higher paid employees possess makes them scarce and highly sought after, and enables them to command compensation that exceeds IRS-qualified plan compensation limits. Therefore, the cost associated with attracting and retaining such employees is necessary and prudent if the Company is to provide its utility service to customers as efficiently and effectively as possible.

While continuing to provide incremental non-qualified defined benefit pension is a discretionary decision, eliminating this benefit without an offsetting increase in some other form of remuneration would have significant negative consequences on the Companies' ability to attract and retain highly talented employees and this would ultimately have negative impacts on the cost and quality of the service the Company is able to provide to customers.

One of the primary reasons for the existence of the benefit limits on ERISA-qualified plans is the U.S. Federal Government's need for current tax revenue. It is arbitrary to use these tax-driven benefit limits for other purposes, such as setting the maximum level of pension expense that is deemed necessary and prudent for the provision of electric services. Consider, for example, whether it would be reasonable for the Commission to utilize this approach irrespective of substantial changes to these limits (up or down), as have occurred. In fact, utilizing any fixed limit for such a determination is biased against larger companies. Economies of scale enable such companies to be more efficient and, thereby, provide lower cost and higher quality electric service to customers.

However, efficiently and effectively managing larger and more diverse organizations requires more skilled and experienced managers and these managers command higher compensation in the marketplace, which is therefore more likely to exceed any fixed amount established for tax purposes.

The Companies' non-qualified deferred compensation benefits have been designed as part of the market competitive total rewards package, which the Company provides to all employees whose skills and experience command higher pay in the market. It is not an additional benefit above and beyond what is needed to provide market-competitive total rewards to these employees or high quality service to customers. As such, customers benefit from the provision of these benefits as part of a market-competitive total rewards package in the same way as they benefit from the provision of base pay as part of the same market-competitive package.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power	)	
Company For (1) A General Adjustment Of Its	)	
Rates For Electric Service; (2) An Order	)	
Approving Its 2017 Environmental Compliance	)	Case No. 2017-00179
Plan; (3) An Order Approving Its Tariffs And	)	
Riders; And (4) An Order Granting All Other	)	
Required Approvals And Relief	)	

REBUTTAL TESTIMONY OF

JASON A. CASH

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Jason A Cash, being duly sworn, deposes and says he is employed by American Electric Power as Accountant Policy and Research Staff that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief

Jason A Cash

STATE OF OHIO	)	
	)	2017-00179
COUNTY OF FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by (Insert Name), this the 2nd day of November 2017.

Notary Public

Notary ID Number: NA

NOTARIAL SEAL STATE OF OHIO

Amanda E. Owen, Attorney At Law
NOTARY PUBLIC - STATE OF OHIO
My commission has no expiration date
Sec. 147.03 R.C.

My Commission Expires: Never

REBUTTAL TESTIMONY OF
JASON A. CASH
ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2017-00179

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**REBUTTAL TESTIMONY OF
JASON A. CASH ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION.

A. My name is Jason A. Cash. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. My position is Staff Accountant in Accounting Policy and Research for American Electric Power Service Corporation ("AEPSC"), a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP").

Q. ARE YOU THE SAME JASON A. CASH WHO PREVIOUSLY FILED DIRECT TESTIMONY IN THIS PROCEEDING ON BEHALF OF KENTUCKY POWER COMPANY?

A. Yes, I am.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. My rebuttal testimony responds to depreciation related recommendations made by Lane Kollen on behalf of the Kentucky Industrial Utility Customers, Inc.

Q. PLEASE SUMMARIZE THE ACTIONS YOU PROPOSE THE COMMISSION TAKE IN CONNECTION WITH THE RECOMMENDATIONS, SUGGESTIONS AND PROPOSALS MADE BY INTERVENOR WITNESS KOLLEN?

A. For the reasons I discuss in more detail in this rebuttal testimony, I recommend the Commission:

1. Reject Mr. Kollen's proposal to eliminate terminal net salvage amount when calculating depreciation rates for both Big Sandy Unit 1 and the Company's ownership share of the Mitchell Plant. The Commission should accept the Big Sandy Unit 1 depreciation rates as filed by the Company in this case, and continue to use the deprecation rates approved in Case No. 2014-00396 for the Mitchell Plant for reasons explained in Section III, below.

2. Reject Mr. Kollen's further recommendation to eliminate an inflation rate factor in connection with the calculation of the terminal net salvage amounts used for determining depreciation rates for Big Sandy Unit 1. The Commission should accept the Big Sandy Unit 1 depreciation rates as filed by the Company in this case for reasons explained in Section III, below.

Q. WHAT IS THE TOTAL EFFECT ON DEPRECIATION EXPENSE OF MR. KOLLEN'S PROPOSAL FOR CALCULATING THE BIG SANDY UNIT 1 AND MITCHELL PLANT TERMINAL NET SALVAGE AMOUNTS?

A. Mr. Kollen's adjustment to remove terminal net salvage from depreciation rates reduces depreciation expense by $0.370 million for Big Sandy Unit 1 and $0.567 million for the Mitchell Plant. Mr. Kollen references this depreciation expense change on page 35, lines 4 thru 6 of his testimony and provides a detailed calculation of the adjustment in his Exhibit ___(LK-14).

III. TERMINAL NET SALVAGE

Q. WHAT IS NET SALVAGE AND HOW DOES IT AFFECT DEPRECIATION RATES AND DEPRECIATION EXPENSE?

A. Salvage includes amounts received for depreciable property retired due to sale, reimbursement or reuse of the property. Removal cost is the expenditure incurred in connection with retiring, removing or disposing of property. Net salvage is the difference between salvage and removal cost.

Positive net salvage occurs when salvage exceeds removal cost. Positive net salvage decreases depreciation rates and hence depreciation expense. Negative net salvage occurs when removal cost exceeds salvage. Negative net salvage increases depreciation rates and hence depreciation expense.

Q. WHAT TYPES OF NET SALVAGE ARE TYPICALLY CONSIDERED FOR PRODUCTION PLANT TYPE PROPERTY IN A DEPRECIATION STUDY?

A. A depreciation study for production plant type property typically considers both terminal and interim net salvage.

Q. HOW DOES TERMINAL NET SALVAGE DIFFER FROM INTERIM NET SALVAGE?

A. Terminal net salvage includes the final cost to retire the plant at the end of its useful life less any salvage received from the property retired (net salvage). Interim net salvage represents amounts received (salvage) net of removal cost incurred from retirements from the time a plant is placed in service until its final retirement. Net salvage is included in a depreciation study to recognize that there will be a cost and/or potential salvage value associated with those retirements that needs to be included in the depreciation calculation.

Q. DOES MR. KOLLEN TAKE EXCEPTION TO THE INCLUSION OF TERMINAL OR INTERIM NET SALVAGE IN THE CALCULATION OF BIG SANDY UNIT 1'S AND MITCHELL PLANTS DEPRECIATION RATES AND EXPENSES?

A. Yes. Mr. Kollen takes exception to the inclusion of terminal net salvage in the calculation of Big Sandy Unit 1's and Mitchell Plant's depreciation rates and expenses. In addition, Mr. Kollen takes exception to escalating the terminal net salvage amounts of Big Sandy Unit 1 when calculating its depreciation rates. Mr. Kollen does not take exception to the inclusion of interim net salvage in the calculation of Big Sandy Unit 1's and Mitchell Plant's depreciation rates and expenses.

Q. IS THE COMPANY PROPOSING TO REVISE THE DEPRECIATION RATES FOR ITS SHARE OF THE MITCHELL PLANT DURING THIS PROCEEDING?

A. No. As stated in my direct testimony, Kentucky Power intends to continue to use the depreciation rates for its ownership share of the Mitchell Plant as approved by the Commission in Case No. 2014-00396.

Q. WHAT REASONS DOES MR. KOLLEN GIVE FOR EXCLUDING TERMINAL NET SALVAGE FROM THE CALCULATION OF DEPRECIATION RATES FOR BIG SANDY UNIT 1 AND THE MITCHELL PLANT?

A. Mr. Kollen's explanation is set forth at pages 32 to 34 of his testimony and is premised upon his contention that:

1. The Commission should not attempt to forecast today the scope of any future dismantling activities and site restoration necessary or reasonable when the Company's generating units are retired decades in the future.

2. Including terminal net salvage in the calculation of depreciation rates for Big Sandy Unit 1 will result in double recovery, once in the base revenue requirement and again in the proposed renamed Decommissioning Rider.

Q. DO YOU AGREE WITH MR. KOLLEN THAT THE COMMISSION SHOULD NOT ATTEMPT TO FORECAST ANY FUTURE DISMANTLING ACTIVITIES AND SITE RESTORATION PLANS?

A. No. Mr. Kollen's recommendation to wait until the Company's production plants are retired or are close to retirement, before including the dismantling costs in rates is contrary to generational equity. It forces future ratepayers to pay for the dismantling costs of retired plants in which they receive no benefit. Including terminal net salvage in current depreciation rates allows for current ratepayers to pay for the cost of the production plant for which they receive service.

Q. DO YOU AGREE WITH MR. KOLLEN THAT INCLUDING TERMINAL NET SALVAGE IN CALCULATION OF DEPRECIATION RATES FOR BIG SANDY UNIT 1 WILL RESULT IN DOUBLE RECOVERY?

A. No. The Company is only including costs related to the decommissioning of the coal related assets at Big Sandy in the proposed Decommissioning Rider. The net salvage amount used to calculate depreciation rates for Big Sandy Unit 1 only includes the estimated cost to demolish Big Sandy Unit 1. When the Company retires Big Sandy Unit 1 and begins demolition of the plant a portion will be applied to the Decommissioning Rider and a portion will be applied to the accumulated depreciation accrual for Big Sandy Unit 1. Applying a portion of the cost to each eliminates any type of double recovery.

Q. DOES MR. KOLLEN ALSO CHALLENGE THE MANNER IN WHICH KENTUCKY POWER CALCULATED THE TERMINAL NET SALVAGE AMOUNT?

A. Yes. Mr. Kollen argues at page 34 of his testimony that Kentucky Power erred by including an escalation factor in the calculation of Big Sandy Unit 1's terminal net salvage amount on page 34 of his testimony. His reasons for excluding an escalation factor are:

1. The escalation methodology "front-loads" recovery of an uncertain estimate of future costs in future dollars, which is also uncertain.

2. There will be no changes in the physical dismantling and site restoration approach assumed by Sargent & Lundy, no efficiencies from technology, equipment and disposal advances, and no improvements in productivity, any of which could offset future inflation costs.

3. Use of 2031 dollars for 2017 ratemaking purposes is an inherent mismatch and forces today's customers to subsidize future customers. If the cost estimate escalates in future years, then if the increased cost is reasonable and prudent, those increases can be reflected in future depreciation rates.

Q. HOW DO YOU RESPOND TO MR. KOLLEN'S CRITICISM OF THE COMPANY'S INCLUSION OF AN ESCALATION RATE IN THE CALCULATION OF DEPRECIATION RATES FOR BIG SANDY UNIT 1?

A. Since the terminal net salvage amount represents the net salvage the Company expects to incur when the plant retires and the demolition study used to determine the terminal net salvage was performed in 2013, it is necessary to inflate the 2013 demolition cost estimates to the 2031 estimated retirement date to obtain an accurate estimate of the final demolition cost.

Doing so is consistent with standard and accepted depreciation practices. For example, NARUC's "Public Utility Depreciation Practices" (August 1996), at page 18, lines 9-13 indicates that net salvage positive or negative is to be calculated as of the date of the retirement and not as of the date of the depreciation study:

> Net salvage is expressed as a percentage of plant retired by dividing the dollars of net salvage by the dollars of original cost of plant retired. The goal of accounting for net salvage is to allocate the net cost of an asset to accounting periods, making due allowance for the net salvage positive or negative, **that will be obtained when the asset is retired**. (emphasis added)

The amount that will be obtained when the asset is retired will be the inflated 2031 amount.

In states where other American Electric Power Company, Inc. companies operate, utility commissions have adopted depreciation calculations based on production plant demolition studies comparable to the ones sponsored by KPCo in this proceeding, and have accepted the practice of escalating generating unit retirement costs to the date of retirement. For example, the Indiana Utility Regulatory Commission ruled in a case involving non-AEP affiliate Public Service Company of Indiana, Cause No. 42359 (Order dated May 18, 2004, page 71), that escalation (inflation) should be factored into dismantlement costs. The Indiana commission addressed a depreciation study sponsored by Mr. John Spanos for the utility stating:

> We find Mr. Spanos' approach to be realistic and consistent with past experience. Inflation has been a fact of life in the American economy for many years. Not factoring inflation into dismantlement costs to be incurred in the future would understate those costs, with the result being that future customers would have to pay costs arising from facilities that are not serving them. This result flies in the face of matching rates with costs incurred for service, as sound ratemaking principle followed by this Commission. Moreover, current customers receive a benefit by factoring in inflation, as it may appropriately allow for a reduction in rate base

> because of the increased accumulated reserve for depreciation. **Accordingly**, **this Commission finds that accounting for inflation in determining the dismantlement estimates to be used as part of PSI's depreciation rates is reasonable.** (emphasis added)

Q. HOW DO YOU RESPOND TO MR. KOLLEN'S CRITICISM THAT INCLUSION OF AN ESCALATION RATE "FRONT-LOADS" RECOVERY OF AN UNCERTAIN ESTIMATE OF FUTURE COSTS?

A. Mr. Kollen implies that that the Company will not dismantle Big Sandy Unit 1 after the plant is no longer in use. Based on its historical record, AEP has demonstrated that it demolishes retired generating plants. Since 1955, Appalachian Power Company which is a wholly owned subsidiary of AEP has retired five steam generating plants including Kingsport, Roanoke, Kenova, Logan and Cabin Creek Plants. All five of these plants have been demolished. AEP affiliate Indiana Michigan Power Company ("I&M") completed the demolition of its Breed generating plant in 2006. In 2016, I&M completed the sale of its retired Tanners Creek generating plant site at a cost to I&M. The sale of the Tanners Creek plant site included demolition of the plant and the associated liabilities at the plant site.

The cost associated with dismantling the plant is a cost that the Company will incur after the plant is no longer in use. Straight-line depreciation calculations are designed to produce equal annual depreciation amounts by calculating depreciation rates that allocate the remaining cost of a utility's investment, including net salvage, over the remaining life of the investment. Adding an escalation rate does not "front-load" future costs. It evenly spreads the final cost to dismantle the plant at retirement evenly over the remaining life of the plant.

Q. IS THE COMPANY'S ESTIMATE OF THE FINAL COST TO DISMANTLE THE PLANT REASONABLE?

A. Yes. The company contracted with an independent engineering firm, Sargent & Lundy, to provide an estimate of the cost to dismantle the Big Sandy Plant. That estimate provides a basis for the final costs that will be incurred at the plant site. Mr. Kollen does not provide a different estimate.

Q. **HOW DO YOU RESPOND TO MR. KOLLEN'S ASSERTION THAT S&L FAILS TO FACTOR INTO ITS ESTIMATE FUTURE EFFICIENCIES WHICH COULD OFFSET FUTURE INFLATION COSTS?**

A. Mr. Kollen similarly fails to provide any examples of the type of efficiencies that can be obtained in the future and the effect those efficiencies could have on the estimate provided by Sargent & Lundy.

Q. IS MR. KOLLEN ACCURATE WHEN HE INDICATES THAT USE OF 2031 DOLLARS FOR 2017 RATEMAKING PURPOSES IS AN INHERENT MISMATCH AND FORCES TODAY'S CUSTOMERS TO SUBSIDIZE FUTURE CUSTOMERS?

A. No, in fact the opposite is correct. A central tenant of regulatory practice is generational equity where the cost of electric service is borne by the customers who benefit from that service. Using an escalated 2031 terminal demolition cost for Big Sandy Unit 1 creates a level amount of depreciation expense to be included in rates for current and future customers. Failure to incorporate escalation in the terminal demolition cost estimate would cause future customers to pay continually increasing amounts. The lack of an escalation would also be contrary to straight line depreciation principles.

IV. SUMMARY AND CONCLUSION

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING MR. KOLLEN'S RECOMMENDATION TO ELIMINATE THE TERMINAL NET SALVAGE AMOUNTS FOR BOTH BIG SANDY UNIT 1 AND THE MITCHELL PLANT FROM THE CALCULATION OF DEPRECIATION RATES.

A. Mr. Kollen is incorrect in his assumption that terminal net salvage should be excluded when calculating depreciation rates for both Big Sandy Unit 1 and the Mitchell Plant. The Commission should accept the Big Sandy Unit 1 depreciation rates as filed by the Company in this case and continue to use the deprecation rates approved in Case No. 2014-00396 for the Mitchell Plant.

Q. DO YOU HAVE ANY FURTHER COMMENTS REGARDING MR. KOLLEN'S RECOMMENDATIONS AROUND TERMINAL NET SALVAGE?

Yes. Mr. Kollen is also incorrect in his assumption that no escalation should be applied to calculate Big Sandy Unit 1's terminal net salvage cost. As previously mentioned, the Commission should accept the Big Sandy Unit 1 depreciation rates as filed by the Company in this case.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; And (4) An Order Approving Accounting Practices To Establish Regulatory Assets And Liabilities; And (5) An Order Granting All Other Required Approvals And Relief	)))))))))	Case No. 2017-00179

REBUTTAL TESTIMONY OF

CURT D. COOPER

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Curt Cooper, being duly sworn, deposes and says he is the Director of Employee Benefits for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing testimony for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge and belief

Curt Cooper

STATE OF OHIO)
) Case No. 2017-00179
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Curt Cooper, this the 2nd day of November 2017.

NOTARIAL SEAL STATE OF OHIO

Cheryl L. Strawser
Notary Public, State of Ohio
My Commission Expires 10-01-2021

Notary Public

My Commission Expires: October 1, 2021

REBUTTAL TESTIMONY OF
CURT D. COOPER
ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2017-00179

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REBUTTAL TESTIMONY OF
CURT D. COOPER ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME.

A. My name is Curt D. Cooper.

Q. PLEASE PROVIDE YOUR POSITION IN THE COMPANY AND BUSINESS ADDRESS.

A. I am the Director of Employee Benefits with American Electric Power Service Corporation (AEPSC). My business address is American Electric Power, 1 Riverside Plaza, Columbus, Ohio 43215.

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY?

A. I am responsible for implementing and managing the employee benefits offered to the employees and retirees of Kentucky Power Company and its affiliates, including AEPSC. My department manages the third-party vendors used to administer our self-insured benefit plans and negotiates the contracts and fees paid for these services. I serve as the Company’s chief privacy officer as required under the federal Health Insurance Portability and Accountability Act.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I earned a degree in Business Administration from Ashland College in Ashland, Ohio in 1982 and a Juris Doctorate degree from Ohio State University Moritz College of Law in 1986. I was admitted to the Ohio Bar in 1986. From 1986 until 1990 I was employed as a tax consultant at the accounting firm of Ernst and Young. I have been a Certified Public Accountant since 1989. I began work at AEP in the Benefits Design department in 1990 and assumed my current position as Director of Employee Benefits in 2003.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my testimony is to rebut mischaracterizations in the testimony of Ralph C. Smith on behalf of the Kentucky Attorney General's (AG) office with respect to Kentucky Power's retirement benefit costs included in the Company's Application. I will show that the costs the Company incurs in connection with the retirement benefit component of its employees' compensation is not duplicative, is different from other plans cited by AG Witness Smith, and that to remove these costs from the Company's cost of service as suggested by witness Smith would be without basis, arbitrary, and inconsistent with Commission precedent. The employee retirement benefits contributions paid by the Company were reasonable, are a cost of providing service to Kentucky Power's customers and, as such, should be included in the revenue requirement without reduction.

II. EMPLOYEE BENEFIT EXPENSE

Q. AG WITNESS SMITH MENTIONS SOME SUPPORT IN PAGES 40 AND 41 OF HIS TESTIMONY TO RECOMMEND REDUCTION FOR CERTAIN AMOUNTS RELATED TO EMPLOYEE COMPENSATION AND BENEFITS FROM THE KENTUCKY POWER'S COST OF SERVICE IN CERTAIN COMMISSION ORDERS. DO YOU AGREE WITH HIS INFERENCE?

A. Not at all. The factual situations in the cases Mr. Smith mentioned are not appropriately comparable to Kentucky Power's employee compensation and benefits plans, and therefore do not lend support to his suggestion to arbitrarily remove from the Company's cost of service a portion of the employee compensation costs.

Specifically, the effective plan design and the costs Kentucky Power incurs as part of its employees' compensation is quite different than the plans described for Kentucky Utilities (KU) in Case No. 2016-0370, Louisville Gas and Electric (LGE) in Case No. 2016-00371, and Cumberland Valley Electric, Inc. (Cumberland Valley Electric) in Case No. 2016-00169.

The most significant difference between the Company's benefits plan and the plans disallowed in those three cases is the plans' structure.

First, a common thread among the plans described in the cases noted by AG Witness Smith is that each employer had Defined Benefit Plans in place that had both contribution and distribution attributes. In contrast, Kentucky Power provides two distinct retirement savings plans for its employees. Notably, since 2001 Kentucky Power's defined benefit plan employs a cash balance formula, causing this plan to operate as a defined contribution plan. As a result of this change the contribution percentage in Kentucky Power's plan is substantially below the plans in the noted cases. By way of example, the Cumberland Valley Electric plan's defined benefit contribution had a 30.22% rate. This number is more than three times greater than the upper range of Kentucky Power's defined contribution, and more than ten times greater than the lower range. Kentucky

Power's contribution to employee retirement savings accounts currently ranges between 3% and 8.5%, dependent on employee age and years of service. This difference is illustrated even more clearly by the fact that Kentucky Power's *combined* maximum contribution under its employee defined benefit *and* defined contribution plans is 13%, less than half of Cumberland's *defined benefit alone*.

The differences between the Kentucky Power employee retirement benefit plan and the plans of Kentucky Utilities AG Witness Smith cites, are even more contrasting. Under the Kentucky Utilities plans all employees that were hired prior to January 1, 2006, were eligible to participate in *both* a Pre 2006 defined distribution benefits (DDB) Plan *and* a 401 (k) Plan. Unlike Kentucky Power's, the plan cited by AG Witness Smith from Kentucky Utilities contributed 100% (one hundred percent) of the Pre 2006 DDB Plan costs. In addition to this payment, Kentucky Utilities also contributed to the 401 (k) Plan and additional amount of between 3% to 7% of eligible employee compensation, and another $0.70 per dollar match for employee contributions up to 6 percent of the employee's eligible contribution. The Kentucky Power plans, in contrast, do not provide similar aggregate benefits. AG Witness' Smith characterization that the Company's plans are comparable should be rejected, when (unlike Kentucky Power's plans) the Kentucky Utilities plans referred to by Mr. Smith provided a Kentucky Utilities' employee hired before 2006: 1) a DDB plan contribution funded 100% by the employer and not requiring any employee contribution, *plus* 2) a 401k contribution by Kentucky Utilities of between 3% and 7%, *plus* 3) a

$0.70 per dollar employer match up to 6 percent of the employee's eligible contribution.

The design of Louisville Gas and Electric plan also cited by AG Witness Smith is substantially similar to the Kentucky Utilities' plans described above. They are completely different from the Kentucky Power plans included in the Company's cost of service. Kentucky Power's plans do not provide duplicative benefits as those that Mr. Smith states are "excessive and not reasonable" for LGE and KU. Contrary to Mr. Smith's inference, Kentucky Power's plans do not provide "multiple layers" of retirement programs for their employees. The Company's costs associated with its contribution to employee retirement benefit accounts is simply a component of the employee compensation expenses the Company must incur to be able to provide service to its customers. It follows that all the reported expenses associated with these costs should be allowed.

Q. HOW DOES KENTUCKY POWER'S SAVINGS PLAN BENEFIT COMPARE TO THE EMPLOYEE BENEFITS OFFERED BY ITS INDUSTRY PEERS?

A. The survey results analyzed by the Company demonstrate that as compared to other industry peers the Kentucky Power's Savings Plan Benefit is below average and that reducing this employee benefit would impair Kentucky Power's ability to offer market competitive employee compensation, and therefore would erode its ability to attract and retain qualified employees.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; (4) An Order Approving Accounting Practices To Establish Regulatory Assets And Liabilities; And (5) An Order Granting All Other Required Approvals And Relief	)))))))))	Case No. 2017-00179

REBUTTAL TESTIMONY OF

BRAD N. HALL

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Brad N. Hall, being duly sworn, deposes and says he is the External Affairs Manager for Kentucky Power that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief

Brad N. Hall

Brad N. Hall

COMMONWEALTH OF KENTUCKY)
) CASE NO. 2017-00179
COUNTY OF BOYD)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Brad N. Hall, this the 2nd day of November 2017.

Trisha M. Young Blum

Notary Public

Notary ID Number: 530202

My Commission Expires: 3-18-19

TRISHA M. YOUNG
NOTARY ID 530202
COMMISSION EXPIRES 3-18-19

REBUTTAL TESTIMONY OF
BRAD N. HALL, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2017-00179

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REBUTTAL TESTIMONY OF
BRAD N. HALL, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Brad N. Hall, and I am the Manager, External Affairs, for Kentucky Power Company ("Kentucky Power" or "Company"). My business address is 855 Central Avenue, Suite 200, Ashland, Kentucky 41101.

Q. ARE YOU THE SAME BRAD HALL HALL THAT FILED DIRECT TESTIMONY IN THIS CASE?

A. Yes I am.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my rebuttal testimony is to respond to the direct testimony of Attorney General Witness Dismukes. In particular, my rebuttal testimony covers the following specific topics:

- Why the specific and limited purpose of the K-PEGG Program makes Mr. Dismukes' comparisons to other types of economic development programs inappropriate;
- Why abandoning the K-PEGG Program would blunt economic development momentum in eastern Kentucky; and
- Why the Company's proposed expansion of the K-PEGG Program is beneficial to customers.

II. REBUTTAL TESTIMONY

Q. BEFORE RESPONDING TO MR. DISMUKES' TESTIMONY, CAN YOU UPDATE THE COMMISSION ON ADDITIONAL K-PEGG PROGRAM GRANTS ISSUED BY THE COMPANY SINCE THE INCEPTION OF THIS CASE?

A. Happily. As detailed in my direct testimony, Kentucky Power issues K-PEGG Program grants when funds become available. Since the filing of the application in this case, the Company has issued the following seven additional K-PEGG grants totaling $214,230:

DATE	RECIPIENT	PROJECT DESCR.	PROJECT TYPE	AMT.
9/6/2017[1]	One East Kentucky & Ashland Alliance	Aerospace Marketing	EDA Support/Mktg. & Promotion	$60,00
9/6/2017	Ashland Alliance	Braidy Industries Due Diligence Work	Site Development	$50,000
9/6/2017	Ashland Alliance	Wright Concrete Closing Fund	EDA Support	$23,334
9/6/2017	Appalachian Industrial Authority Inc.	Creation UAV Marketing Video	Mktg. & Promotion	$6,000
9/6/2017	Coal Fields Regional Industrial Authority Inc.	Improvement of industrial site appearance	Site Development	$15,000
10/18/2017	Lawrence County Fiscal County	Improvement of industrial site appearance	Site Development	$19,836
10/27/2017	City of Pikeville	Geotechnical	Site Development	$100,000

[1] The six grants dated September 6, 2017 were included in the Company's response to AG 1-390, albeit without disbursement dates. The grants dated October 18 and October 27 were issued after the Company's response to AG 1-390 was filed.

Q. HAVE ANY OF THESE RECENTLY ISSUED K-PEGG GRANTS RESULTED IN NEW ECONOMIC DEVELOPMENT IN THE SERVICE TERRITORY?

A. Yes. Recently, SilverLiner announced that it will construct a new manufacturing facility in Pikeville that will bring 50 employees initially and up to 300 employees eventually. Kentucky Power issued a K-PEGG grant to the City of Pikeville to support geotechnical evaluations at the proposed SilverLiner site. This geotechnical evaluation of the site confirmed that SilverLiner could construct its facility there.

Q. DOES ATTORNEY GENERAL WITNESS DISMUKES MISSTATE THE PURPOSE OF THE K-PEGG PROGRAM?

A. Yes. On pages 39 and 40 of his testimony, Mr. Dismukes identifies the recent economic downturn and the need for promoting economic diversity as the rationales for the Company's K-PEGG Program. In reality, the conditions and needs Mr. Dismukes references are the bases for Kentucky Power's entire economic development efforts. The K-PEGG Program has a far narrower purpose.

Q. WHAT IS THE PURPOSE OF THE K-PEGG PROGRAM?

A. The K-PEGG Program is designed specifically to address the following key gaps in economic development efforts in the Company's service territory:

- a lack of functional and properly trained local or regional economic development organizations;
- limited competitive and marketable industrial parks and buildings;

- insufficient marketing infrastructure for available opportunities; and
- insufficient workforce development and training.

These gaps were identified by InSite in their 2012 gap analysis. The InSite report was attached to my direct testimony as **EXHIBIT BNH-1**.

The K-PEGG program accomplishes its goals by issuing economic development grants to municipalities and economic development organizations to support:

- economic development agency support projects;
- workforce training projects;
- site development projects; and
- marketing and promotional projects.

Unlike the KEAP program, which has similar goals but is narrowly focused on Lawrence County and the contiguous Kentucky counties, the K-PEGG Program provides economic development grants for projects throughout the Company's service territory.

Q. ON PAGE 48 OF HIS TESTIMONY, MR. DISMUKES CRITICIZES THE K-PEGG PROGRAM FOR NOT REQUIRING K-PEGG PROGRAM GRANT RECIPIENTS TO COMMIT TO A MINIMUM LEVEL OF CAPITAL INVESTMENT OR TO REQUIRE GRANT RECIPIENTS TO PAY BACK GRANT FUNDING IF THEY LEAVE THE COMPANY'S SERVICE TERRITORY. IS THIS CRITICISM WARRANTED?

A. No. Mr. Dismukes' criticism ignores the fundamental differences between financial incentives or tax credits issued by the Kentucky Cabinet for Economic Development and grants issued under the K-PEGG Program. First, unlike state financial incentives which are issued directly to a company, K-PEGG Program grants are only issued to municipalities or economic development agencies within the service territory. Second, and perhaps more importantly, state financial incentives are issued directly to a specific company for the purpose of enticing that specific company to locate or expand a business in a specific location. K-PEGG Program grants, on the other hand, are issued to municipalities or economic development agencies for projects that upgrade the economic development infrastructure in the region through improvements to the skill of economic development professionals and to sites available for development.

Comparing state financial incentives with K-PEGG Program grants is an apples-to-oranges comparison. While the scale and company-specific economic development purpose of state incentives make the commitment criteria cited by Mr. Dismukes appropriate, that is not the case for K-PEGG Program grants. K-PEGG Program grants are not issued to specific target companies to incent specific development. The broader goal of the K-PEGG Program – to upgrade the region's economic development infrastructure – makes such criteria impossible.

Q. ON PAGE 48 AND 49 OF HIS TESTIMONY, MR. DISMUKES MAKES SIMILAR COMPARISONS OF THE K-PEGG PROGRAM TO THE COMPANY'S ECONOMIC DEVELOPMENT RATE TARIFF. IS THIS COMPARISON APPROPRIATE?

A. No. Much like the state financial incentives described above, the Company's economic development rate tariff is designed to incent specific companies to locate or expand operations within the Company's service territory. As such, it is fundamentally different than the K-PEGG Program which seeks to improve the economic development infrastructure in the service territory. For the same reasons it is inappropriate to compare the K-PEGG Program to state financial incentives, it is also inappropriate to compare the K-PEGG Program to the Company's economic development rate tariff.

Q. ON PAGES 50 AND 51 OF MR. DISMUKES' TESTIMONY HE IDENTIFIES A FAILURE TO JUSTIFY THE COST EFFECTIVENESS AS EVIDENCE OF INEFFICIENCIES OF THE KEDS. IS MR. DISMUKES CORRECT?

A. No. Once again, Mr. Dismukes conflates the purpose of the K-PEGG Program with the purpose of the Company's economic development efforts as a whole. The purpose of the K-PEGG program is not as Mr. Dismukes claims to "incentivize businesses, such as large commercial and industrial customers to relocate or expand in Kentucky…" Instead, the narrow focus of the K-PEGG Program is to fill the identified gaps in the economic development infrastructure in Company's service territory through support of economic development entities, training, and site development activities. Shoring up this infrastructure is necessary for the region to compete nationally and internationally for economic development opportunities that will bring needed jobs.

Q. DID KENTUCKY POWER'S ECONOMIC DEVELOPMENT GRANT PROGRAMS PLAY A ROLE IN KEEPING THE BRAIDY INDUSTRIES PROJECT IN THE SERVICE TERRITORY?

A. Yes. Braidy Industries announced there was an unacceptable extension of the construction timeline to support the heavy equipment in its planned aluminum mill facility at the original site. Instead of moving outside of the Company's service territory, Braidy Industries has relocated its proposed facility to the EastPark Industrial Site on the Boyd – Greenup County line. Kentucky Power has issued economic development grants to the Northeast Kentucky Regional Industrial Authority, the owner of EastPark, for improvements at the park. The existence of a ready-to-go site allowed the region to keep the planned investment. Without the investment in the EastPark made possible by Kentucky Power economic development grants, the region may have missed out on a transformative economic development opportunity.

Q. ON PAGES 43 AND 44 OF HIS TESTIMONY, MR. DISMUKES ASSERTS THAT THE COMPANY'S REQUEST TO EXPAND THE K-PEGG PROGRAM IS CONTRADICTORY. IS THE COMPANY'S REQUEST CONTRADICTORY?

A. No. Mr. Dismukes argues that because the KEAP Program was undersubscribed in 2016 while the K-PEGG Program was oversubscribed, the Company's request to expand the K-PEGG Program is contradictory. Mr. Dismukes logic is baffling. If anything, the oversubscription of the K-PEGG Program and undersubscription of the KEAP Program is evidence supporting the Company's decision to transition from the dual programs to an expanded K-PEGG Program. The Company's proposed consolidation and expansion removes the geographic barrier in the KEAP Program allowing more economic development grants for the entire service territory. The K-PEGG program is not "unfocused in either regional scope or purpose" as Mr. Dismukes claims. The K-PEGG Program provides needed economic development support to municipalities and economic development entities in the Company's service territory.

Q. WHY IS THE KEDS A NECESSARY COMPONENT OF THE K-PEGG PROGRAM?

A. The KEDS allows the Company to aggregate immaterial contributions from individual customers into material contributions towards improving the economic development infrastructure in the Company's service territory. Under the Company's proposed K-PEGG expansion, the individual customer contribution to this program will increase from a dime and nickel each month to a quarter each month. Annually, the proposed expansions increase the customer's contribution from $1.80 per year to $3.00 per year.

This increase will, when aggregated across all of the Company's customers, add an estimated $200,000 annually to the K-PEGG program. With the dollar-for-dollar Company match, the $1.20 annual increase to individual customers will result in an additional $400,000 in economic development support funds. All told, if the K-PEGG program is expanded, the Company will be able to aggregate annual $3.00 contributions from individual customers with dollar-for-dollar matching funds from the Company to create a K-PEGG Program capable of providing approximately $1.0 million dollars per year in economic development grants.

Q. SHOULD THE COMMISSION APPROVE THE COMPANY'S REQUEST TO EXPAND THE K-PEGG PROGRAM?

A. Absolutely. In the limited time that Kentucky Power has issued economic development grants through the KEAP and K-PEGG Programs, the economic development infrastructure within the Company's service territory has seen remarkable growth. These grants allow municipalities and economic development agencies to invest in human capital through training and professional development of their employees and in upgrading economic development sites to make them ready to go. Expanding the K-PEGG Program at this time capitalizes on the momentum that these economic development grants have created and will put the service territory on more competitive footing for economic development opportunities.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application of Kentucky Power Company For (1) A General Adjustment Of Its Rates for Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; (4) An Order Approving Accounting Practices To Establish Regulatory Assets And Liabilities; And (5) An Order Granting All Other Required Approvals And Relief	)))))))))	Case No. 2017-00179

REBUTTAL TESTIMONY OF

ADRIEN M. MCKENZIE, CFA

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Adrien M. McKenzie being duly sworn deposes and says he is the Vice President of FINCAP, Inc., and that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Adrien M .McKenzie

STATE OF TEXAS)
) Case No. 2017-00179
COUNTY OF TRAVIS)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by, Adrien M .McKenzie this 2nd day of November 2017.

Notary Public

ROBERT LEE MARTINEZ
NOTARY PUBLIC STATE OF TEXAS
MY COMM. EXP. 4/17/2019
NOTARY ID 13019391-2

NOTARY PUBLIC STATE OF TEXAS

My Commission Expires: 04/17/2019

REBUTTAL TESTIMONY OF

ADRIEN M. MCKENZIE

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I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. Adrien M. McKenzie, 3907 Red River, Austin, Texas, 78751.

Q2. ARE YOU THE SAME ADRIEN M. MCKENZIE THAT PREVIOUSLY SUBMITTED PREFILED DIRECT TESTIMONY IN THIS CASE?

A2. Yes, I am.

Q3. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A3. My testimony to the Kentucky Public Service Commission ("KPSC" or the "Commission") addresses the testimony of Dr. J. Randall Woolridge, submitted on behalf of the Kentucky Office of Attorney General ("OAG"), Mr. Richard Baudino, on behalf of the Kentucky Industrial Utility Consumers, Inc. ("KIUC"), and Mr. Gregory W. Tillman, on behalf of Wal-Mart Stores East, LP and Sam's East, Inc. ("Wal-Mart"),[1] concerning the fair rate of return on equity ("ROE") that Kentucky Power Company ("Kentucky Power" or "the Company") should be authorized to earn on their investment in providing electric utility service.

Q4. HAVE YOU PREPARED WORKPAPERS SUPPORTING YOUR REBUTTAL TESTIMONY?

A4. Yes. Workpapers including supporting documents referenced in my rebuttal testimony and related exhibits are attached as Appendix A.

A. Summary of Conclusions

Q5. PLEASE SUMMARIZE THE RECOMMENDATIONS OF THE ROE WITNESSES.

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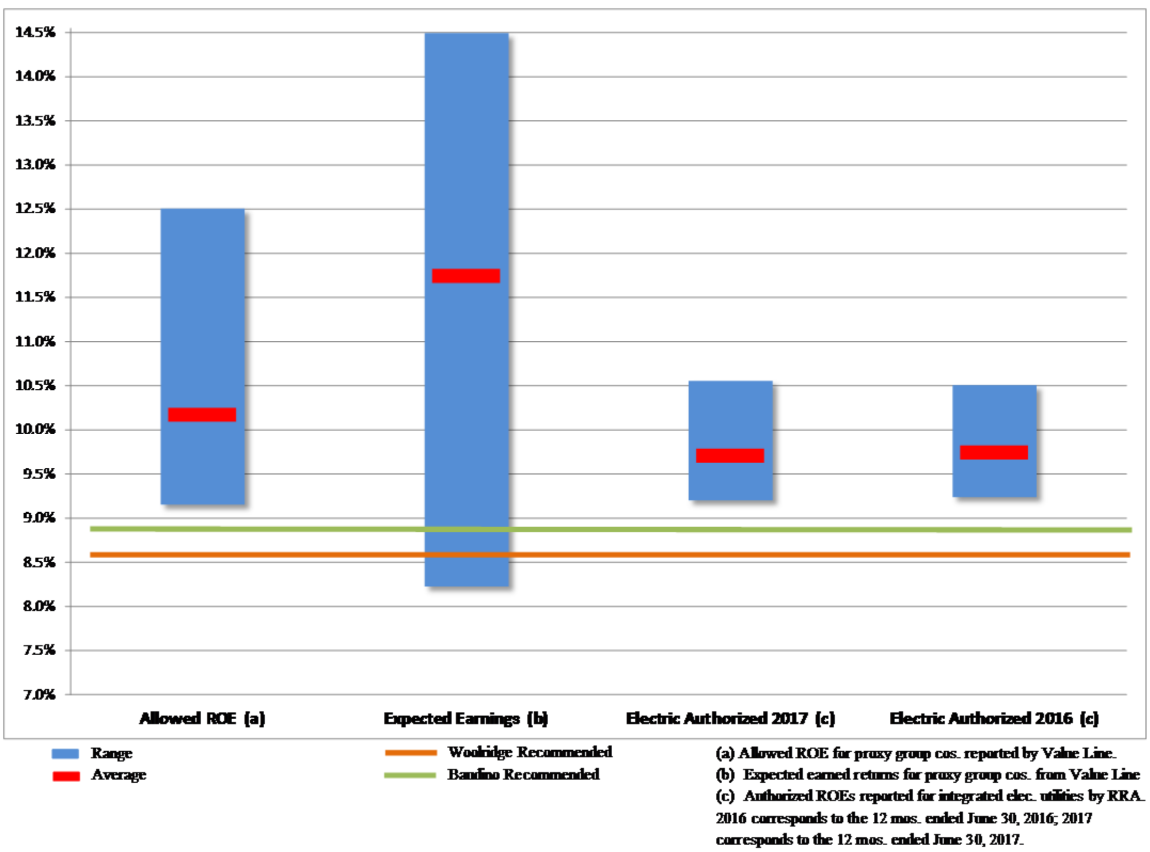
[1] I refer, collectively, to Dr. Woolridge and Mr. Baudino as the "ROE Witnesses" since they made specific ROE recommendations. Mr. Tillman testified generally about the ROE issue without making a specific proposal.

A5. Dr. Woolridge recommends an ROE of 8.60% for the Company, while Mr. Baudino proposes an ROE of 8.85%.

Q6. PLEASE SUMMARIZE YOUR RESPONSE TO THE ROE WITNESSES' TESTIMONY.

A6. Their cost of equity recommendations are simply too low and fail to reflect the risk perceptions and return requirements of real-world investors in the capital markets. The significant shortfall between their recommendations and the ROE benchmarks discussed in my rebuttal testimony are illustrated in the figure below.

FIGURE R-1
COMPARISON OF ROE RECOMMENDATIONS TO BENCHMARKS



Q7. WHAT ARE YOUR PRINCIPAL CONCLUSIONS REGARDING THE RECOMMENDATIONS OF DR. WOOLRIDGE?

A7. I demonstrate that Dr. Woolridge's recommendations should be ignored in their entirety based on the following findings:

- Dr. Woolridge's recommended ROE of 8.60% is an extreme outlier and should be rejected on its face.
- Dr. Woolridge's discussion of current capital market conditions is potentially misleading.
- Dr. Woolridge's focus on market-to-book ratios ("M/B") is misguided and not relevant to the determination of reasonable ROEs in this case.
- The proxy group selected by Dr. Woolridge incorrectly excludes several utilities that should have been considered in his analyses.
- His Discounted Cash Flow ("DCF") analysis contains several flaws, including his reliance on dividend per share and historical data for estimating the DCF growth term, his inclusion of illogical results stemming from unrealistically low growth rates (including numerous negative growth rates), and his reference to growth in gross domestic product ("GDP") as an upper bound on utility company growth rates. As a result, his conclusions are unreliable and should be ignored.
- Dr. Woolridge's application of the DCF model based on the internal, "br" growth rate is flawed and incomplete,
- The Capital Asset Pricing Model ("CAPM") results reported by Dr. Woolridge are based on a hodge-podge of historical data that fail to reflect forward-looking expectations, particularly in light of current conditions in the capital markets.

Furthermore, Dr. Woolridge failed to consider the Empirical CAPM ("ECAPM") and risk premium approaches, which are legitimate ROE methods. His rejection of flotation costs is at odds with the conclusions of recognized financial research and his own admission that these are legitimate expenses that should be recovered. Finally, his criticisms of my size adjustment, market return calculation, expected earnings approach, and non-utility DCF analysis are without merit. Taken as a whole, these shortcomings ensure that Dr. Woolridge's recommended ROE falls well below a fair and reasonable level for the

Company's utility operations. In fact, his recommendation is so far below a reasonable ROE range that it should be rejected on its face.

Q8. WHAT ARE YOUR PRINCIPAL CONCLUSIONS REGARDING THE RECOMMENDATIONS OF MR. BAUDINO?

A8. Mr. Baudino's 8.85% ROE recommendation is also below realistic investor expectations. My rebuttal testimony demonstrates that:

- Mr. Baudino mistakenly excludes legitimate companies from his proxy group, casting doubt on his ROE conclusions.
- Mr. Baudino places too much emphasis on dividend growth and failed to evaluate the reasonableness of individual DCF estimates. As a result, his conclusions are unreliable and should be ignored.
- Mr. Baudino's application of the DCF model based on the internal, "br" growth rate is flawed and incomplete.
- Mr. Baudino's application of the CAPM was compromised by reliance on historical data, while his forward-looking approach was marred by methodological shortcomings and inconsistencies.
- Like Dr. Woolridge, Mr. Baudino's rejection of a flotation cost adjustment contradicts the findings of the financial literature and the economic requirements underlying a fair rate of return on equity.

Finally, my rebuttal testimony demonstrates that Mr. Baudino's criticisms of my alternative applications and conclusions are misguided and should be ignored.

B. Comparison of ROE Recommendations to Accepted Benchmarks

Q9. CAN YOU ILLUSTRATE THE EXTREME NATURE OF THE ROE WITNESSES' RECOMMENDATIONS?

A9. Yes. If adopted, the 8.60% ROE suggested by Dr. Woolridge and the 8.85% value offered by Mr. Baudino would be the lowest ROEs granted to a vertically-integrated electric utility by a state commission in recent history, if not ever.[2] These recommendations are significantly below the 9.70% ROE authorized for Kentucky Utilities Company and Louisville Gas and Electric Company by the Commission in June 2017.[3] These comparisons demonstrate that the recommendations of the ROE Witnesses would not meet the judicial standards underpinning a fair rate of return for Kentucky Power.

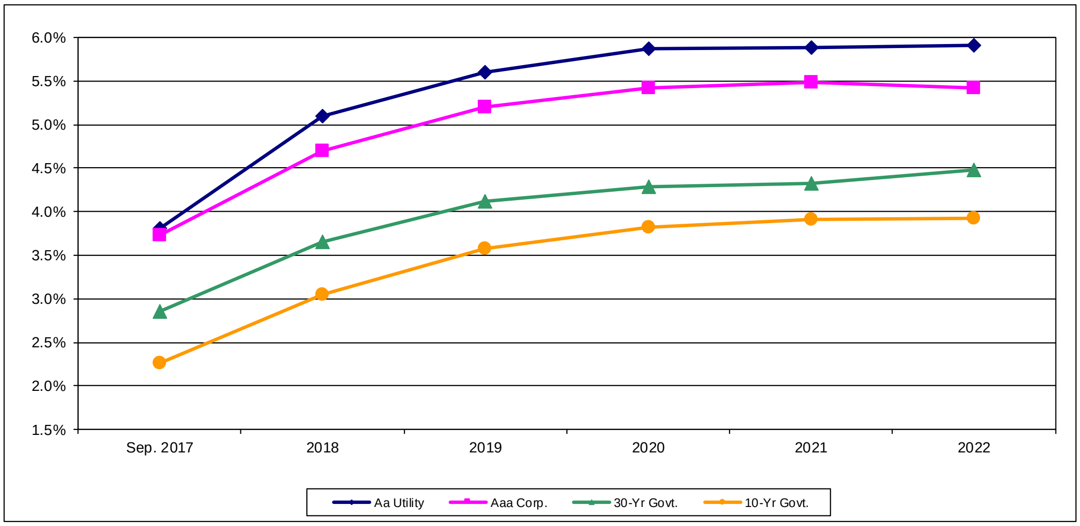
Q10. WHAT IS THE EXPECTED DIRECTION OF INTEREST RATES AND HOW DOES THIS IMPACT THE EVALUATION OF A FAIR ROE IN THIS PROCEEDING?

A10. Interest rates are expected to increase. Below is an update of Figure 3 (Interest Rate Trends) from my Direct Testimony:

[2] Regulatory Research Associated reported that Maui Electric was granted an ROE of 9.0% on May 31, 2013. However, the base ROE determined by the Public Utilities Commission of Hawaii was 9.50%, to which a 50 basis point penalty was applied due to "apparent system inefficiencies which negatively impact MECO's customers." (Docket No. 2011-0092, Decision and Order No. 31288, p, 107). Beyond that, the lowest authorized ROE for a vertically-integrated electric utility was 9.20% authorized for Northern States Power-Minnesota on May 11, 2017. As I discuss later in this testimony, this ROE award was accompanied by a number of risk-reducing regulatory mechanisms not available to the Company.

[3] Case Nos. 2016-00370 (Kentucky Utilities Company) and 2016-00371 (Louisville Gas and Electric Company), Final Order, June 22, 2017.

FIGURE R-2
PROJECTED INTEREST RATE TRENDS



Source:
Value Line Investment Survey, Forecast for the U.S. Economy (Sep. 1, 2017)
IHS Global Insight (Aug. 24, 2017)
Energy Information Administration, Annual Energy Outlook 2017 (Jan. 5, 2017)
Wolters Kluwer, Blue Chip Financial Forecasts, Vol. 36, No. 6 (Jun. 1, 2017)

As the figure shows, investors continue to anticipate that interest rates will increase significantly from present levels. These projections are from forecasting services that are highly regarded and widely referenced, as I discuss in my Direct Testimony (at 20-22). The interest rate increases shown in the figure above are on the order of 150-200 basis points through 2022, which implies higher long-term capital costs over the period when rates established in this proceeding will be in effect.

Q11. DID DR. WOOLRIDGE ACKNOWLEDGE THAT INTEREST RATES ARE EXPECTED TO INCREASE?

A11. Yes. In selecting the risk-free rate for use in his CAPM analysis, Dr. Woolridge states that "[g]iven the recent range of yields and the possibility of higher interest rates, I use the higher end 4.0% as the risk-free rate, or R_f, in my CAPM."[4] Given that the current 30-year U.S. Treasury bond rate (the rate Dr. Woolridge uses as

[4] Woolridge Direct at 50 (emphasis added).

the risk-free rate in his CAPM analysis) is around 2.9%, Dr. Woolridge clearly recognizes that investors anticipate a substantial increase in future interest rates.

Q12. WHAT DO THESE EXPECTATIONS IMPLY WITH RESPECT TO THE ROE FOR THE COMPANY MORE GENERALLY?

A12. Largely because of unprecedented Federal Reserve policies, current capital costs are not representative of what is likely to prevail over the near-term future. As indicated in my Direct Testimony,[5] regulators have recognized the shortcomings of the DCF approach. FERC has reiterated its position that current capital market conditions may undermine the reliability of the DCF model, and for this reason, ROE model results should be evaluated with even more critical judgment and focus:

> As described above, evidence in the record regarding historically low interest rates and Treasury bond yields as well as the Federal Reserve's large and persistent intervention in markets for debt securities are sufficient to find that current capital market conditions are anomalous.[6]
>
> Similarly, while Complainants provide evidence that interest rates have been trending downwards, the current levels may be so low as to cause irregularities in the outputs of the DCF. Despite such yields remaining low for several years, we find that they are anomalous and could distort the results of the DCF model.[7]

Current capital market conditions make the process of setting a fair ROE even more demanding. In this environment, it is imperative that ROE model results be thoroughly tested against accepted benchmarks and compared to other checks of reasonableness.

Q13. IS IT NECESSARY THAT INTEREST RATE FORECASTS, LIKE THOSE MENTIONED ABOVE, BE PERFECTLY ACCURATE IN ORDER TO BE RELIED UPON?

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[5] McKenzie Direct at 7-8, 22-23.
[6] Opinion No. 551, 156 FERC ¶ 61,234 at P 124 (2016).
[7] *Id.*

A13. Absolutely not. I dealt with this topic in my Direct Testimony (at 37-38) in discussing the validity of analysts' growth forecasts, and the same principle applies here. In estimating investors' required rate of return, what investors expect, not what actually happens, is what matters most. While the projections of various services may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing expected interest rates and how they might influence the Company's allowed ROE. Any difference in actual rates as compared to analysts' forecasts is beside the point. What is most important is that investors share analysts' views when the forecasts were made and incorporate those views into their decision making process, not the actual rates that ultimately transpire.

Q14. HOW DO THE ROE WITNESSES' RECOMMENDATIONS COMPARE TO RECENTLY-ALLOWED RETURNS FROM OTHER STATE COMMISSIONS?

A14. Allowed ROEs by other state commissions provide a general gauge of reasonableness for the outcome of a cost of equity analysis. In considering utilities with comparable risks, investors will always prefer to provide capital to the opportunity with the highest expected return. If a utility is unable to offer a return similar to that available from other investment opportunities posing equivalent risks, investors will become unwilling to supply the utility with capital on reasonable terms. While the ROEs approved in other jurisdictions do not constrain the Commission's decision-making in this proceeding, it is important to understand that there would be a disincentive for investors to provide equity capital to the Company if the Commission were to apply an unreasonably low ROE, compared to entities of comparable risk.

The recommendations of the ROE Witnesses are significantly below equity returns that have been allowed by other state regulatory commissions around the country. As shown on Exhibit No. 12, over the past 24 months ended

September 30, 2017, the average allowed ROE (excluding adders and penalties) reported by S&P Global (formerly Regulatory Research Associates) for vertically-integrated electric utilities is 9.73%,[8] with the midpoint of the high and low values being 9.88%. Similarly, authorized ROE data reported to investors by The Value Line Investment Survey ("Value Line") for the specific firms in my proxy group also indicate that the recommendations of the ROE Witnesses are insufficient.[9] As shown in Exhibit No. 13, these ROEs average 10.18%, with the midpoint of the lowest and highest values being 10.83%. In other words, allowed returns for the utilities that the ROE Witnesses generally consider comparable to the Company indicate that their recommendations are too low to meet regulatory standards.

Q15. MR. TILLMAN EXCLUSIVELY REFERENCES ROES AWARDED IN RECENT RATE CASES.[10] WOULD IT BE APPROPRIATE TO USE RECENT ALLOWED RETURNS TO ESTABLISH THE COMPANY'S ROE DIRECTLY?

A15. No. As discussed in my direct testimony (pp. 58-63), while allowed ROE data is a valuable "secondary" approach in judging whether an ROE estimate based on the application of accepted financial models makes sense, there is no basis to place undue weight on a single, summary statistic in lieu of comprehensive analyses and a case-specific evidentiary record. Setting a utility's ROE is a very company-specific process, and is a function of investors' perceptions of the risks and prospects for the subject company at a given point in time. As a result, the

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[8] For the 12 months ended September 30, 2017, the average is 9.71%; for the 12 months ended September 30, 2016, the average is 9.77%.

[9] Dr. Woolridge relies on my proxy group as one of his two electric groups, after removing Emera, Inc. and Fortis, Inc. due to his unexplained statement (fn. 18) that "they based on Canada" (sic). Likewise, Mr. Baudino starts with my group before removing three companies, AVANGRID, Inc., Emera, Inc., and Fortis, Inc. I address the errors and misconceptions associated with these exclusions at pages 28-29 and 61-64 of my rebuttal testimony.

[10] Tillman Direct at 10-11.

standard practice in regulatory proceedings is to consider the results of numerous approaches that are grounded in current capital market evidence when establishing a utility's ROE. Meanwhile, quarterly allowed ROEs reported by RRA are not necessarily representative or directly comparable to the utility at hand.[11] That is, there may be an "apples and oranges" issue when the RRA data is applied in the current rate setting environment.

Q16. WHAT OTHER BENCHMARKS INDICATE THAT THE ROE WITNESSES' RECOMMENDATIONS ARE TOO LOW TO BE CONSIDERED REASONABLE?

A16. Expected earned rates of return for other utilities provide yet another useful benchmark to gauge the reasonableness of the ROE Witnesses' recommendations. The expected earnings approach is predicated on the comparable earnings test, which developed as a direct result of the Supreme Court decisions in *Bluefield* and *Hope,* as I discuss in my Direct Testimony.[12] This test recognizes that investors compare the allowed ROE with returns available from other alternatives of comparable risk.

Importantly, the expected earnings approach explicitly recognizes that regulators do not set the returns that investors earn in the capital markets. Regulators can only establish the allowed return on the value of a utility's investment, as reflected on its accounting records. As a result, the expected earnings approach provides a direct guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital.

[11] For example, the lowest ROE granted over the last two-year period was 9.20% to Northern States Power Company ("NSP") in a Minnesota case decided May 11, 2017. This stipulated case resulted in a four-year multiyear rate plan spanning calendar years 2016 through 2019, a 2016 sales-forecast true-up which allowed it to collect nearly $59.99 million due to a one million megawatt-hour sales shortfall in 2016, and extension of full revenue decoupling for residential and small commercial customers through the end of the settlement period. These circumstances are not comparable to those faced by the Company in this proceeding.

[12] McKenzie Direct at 64-66.

This opportunity cost test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q17. HAS THE EXPECTED EARNINGS APPROACH BEEN RECOGNIZED AS A VALID ROE BENCHMARK?

A17. Yes. This method predominated before the DCF model became fashionable with academic experts, and it continues to be used around the country.[13] A textbook prepared for the Society of Utility and Regulatory Analysts labels the comparable earnings approach the "granddaddy of cost of equity methods" and points out that the amount of subjective judgment required to implement this method is "minimal," particularly when compared to the DCF and CAPM methods.[14] The *Practitioner's Guide* notes that the comparable earnings test method is "easily understood" and firmly anchored in the regulatory tradition of the *Bluefield* and *Hope* cases,[15] as well as sound regulatory economics. Similarly, *New Regulatory Finance* concluded that, "because the investment base for ratemaking purposes is expressed in book value terms, a rate of return on book value, as is the case with Comparable Earnings, is highly meaningful."[16]

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[13] For example, the Virginia State Corporation Commission is required by statute (Virginia Code § 56-585.1.A.2.a) to consider the earned returns on book value of electric utilities in its region. Similarly, FERC concluded that, "The returns on book equity that investors expect to receive from a group of companies with risks comparable to those of a particular utility are relevant to determining that utility's market cost of equity." Opinion No. 531-B, 150 FERC ¶ 61,165 at P 128 (2015). Another example is the Idaho Public Utilities Commission, which also references return on book equity evidence. *See, e.g.,* Order No. 29505, Case No. IC-E-03-13 at 38 (Idaho Public Utilities Commission, May 25, 2004).

[14] David C. Parcell, "The Cost of Capital – A Practitioner's Guide," (2010) at 115-116.

[15] *Id.*

[16] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 395.

Q18. DID MR. BAUDINO RECOGNIZE THE ECONOMIC PREMISE UNDERLYING THE EXPECTED EARNINGS APPROACH?

A18. Yes. The simple, but powerful concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. As Mr. Baudino recognized, economists refer to the returns that an investor must forgo by not being invested in the next best alternative as "opportunity costs."[17] Mr. Baudino went on to explain that, "investor's opportunity cost is measured by what she or he could have invested in as the next best alternative."[18]

Q19. WHAT ROES ARE IMPLIED BY THE EXPECTED EARNINGS APPROACH FOR THE UTILITY PROXY GROUP?

A19. The year-end returns on common equity projected by Value Line over its forecast horizon for the firms in the utility proxy groups referenced by myself and the ROE Witnesses are shown on Exhibit No. 14. As shown there, once adjusted to mid-year, reference to the expected earnings approach implies an average cost of equity for my proxy group of utilities of 11.8%, while the expected annual average cost of equity for Dr. Woolridge's group and Mr. Baudino's group is 11.9%. These book return estimates are an "apples to apples" comparison to the 8.60% and 8.85% ROE recommendations of the ROE Witnesses.

Q20. PLEASE EXPLAIN THE RATIONALE FOR THE ADJUSTMENT TO CONVERT YEAR-END RETURNS TO AVERAGE RETURNS WHEN APPLYING THIS METHOD.

A20. The adjustment factor incorporated in my evaluation of expected returns is required because Value Line's reported returns are based on end-of-year book values. Since earnings are a flow over the year while book value is determined at

[17] Baudino Direct at 13.
[18] *Id.* at 14.

a given point in time, the measurement of earnings and book value are distinct concepts. It is this fundamental difference between a flow (earnings) and point estimate (book value) that makes it necessary to adjust to mid-year in calculating the ROE. Given that book value will increase or decrease over the year, using year-end book value (as Value Line does) understates or overstates the average investment that corresponds to the flow of earnings. To address this concern, earnings must be matched with a corresponding representative measure of book value, or the resulting ROE will be distorted.

The need for this adjustment has been recognized in the financial literature.[19] Similarly, FERC has also cited the necessity to adjust year-end data from Value Line to reflect average values when computing earned rates of return.[20] In its June 2014 decision establishing new policies regarding ROE and confirmed in its most recent opinion in September 2016, FERC relied directly on the expected earnings approach, which incorporates the exact same adjustment formula used in my Direct Testimony in this proceeding.[21] Similarly, the Virginia State Corporation Commission has determined that it is appropriate to rely on average book equity, rather than year-end equity, when evaluating earned rates of return.[22]

Q21. WHAT OTHER EVIDENCE INDICATES THAT THE RECOMMENDATIONS OF THE ROE WITNESSES FAIL TO MEET REGULATORY STANDARDS?

A21. As discussed in my Direct Testimony, required equity returns for firms in the competitive sector of the economy are also relevant in determining the

[19] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 305-06.
[20] *Bangor Hydro-Elec. Co.*, 122 FERC ¶ 61,265 (2008).
[21] Opinion No. 531, 147 FERC ¶ 61,234 at P 146 (2014) and Opinion No. 551, 156 FERC ¶ 61,234 at P 239 (2016).
[22] *See, e.g., Case No. PUE-2014-00026,* Final Order at n. 84 (2014).

appropriate return to be allowed for rate-setting purposes.[23] The idea that investors evaluate utilities against the returns available from other investment alternatives – including the low-risk companies in my Non-Utility Group – is a fundamental cornerstone of modern financial theory. Aside from this theoretical underpinning, any casual observer of stock market commentary and the investment media quickly comes to the realization that investors' choices are almost limitless. It follows that utilities must offer a return that can compete with other risk-comparable alternatives, or capital will simply go elsewhere.

In fact, returns in the competitive sector of the economy form the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. The Supreme Court has recognized that the degree of risk, not the nature of the business, is relevant in evaluating an allowed ROE for a utility.[24] The cost of capital is based on the returns that investors could realize by putting their money in other alternatives, and the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment.

Q22. DID THE ROE WITNESSES PRESENT ANY OBJECTIVE EVIDENCE THAT WOULD SUPPORT A FINDING THAT YOUR NON-UTILITY PROXY GROUP IS RISKIER THAN THE COMPANIES IN HIS PROXY GROUP?

A22. No. Mr. Baudino, for instance, simply alluded to a general assertion that companies in the non-utility proxy group "face risks that a lower risk electric company like KPC does not face."[25] But my Direct Testimony did not contend that the specific operations or risk consideration of the companies in the Non-

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[23] McKenzie Direct at 73-77.
[24] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).
[25] Baudino Direct at 43.

Utility Group are the same as those for utilities. Clearly, operating a worldwide enterprise in the beverage, pharmaceutical, retail, or food industry involves unique circumstances that are as distinct from one another as they are from an electric utility.

But as the Supreme Court recognized, investors consider the expected returns available from all these opportunities in evaluating where to commit their scarce capital. The simple observation that a firm operates in non-utility businesses says nothing at all about the overall investment risks perceived by investors, which is the very basis for a fair rate of return. So long as the risks associated with the Non-Utility Group are comparable to the Company and other utilities the resulting DCF estimates provide a meaningful benchmark for the cost of equity. As demonstrated in my Direct Testimony, a comparison of objective risk measures demonstrates conclusively that the Non-Utility Group is regarded as less risky than Kentucky Power, making it a conservative benchmark for a fair ROE in this case.[26]

Q23. DR. WOOLRIDGE SAYS THAT ONE REASON YOUR NON-UTILITY ANALYSIS IS FLAWED IS THAT SUCH COMPANIES "DO NOT OPERATE IN A HIGHLY REGULATED ENVIRONMENT."[27] DOES THE FACT THAT UTILITIES ARE REGULATED SOMEHOW INVALIDATE THIS COMPARISON OF OBJECTIVE RISK INDICATORS?

A23. Absolutely not. While I agree that utilities operate under a regulatory regime that differs from firms in the competitive sector, any risk-reducing benefit of regulation is already incorporated in the overall indicators of investment risk presented in Table 7 to my Direct Testimony. The impact of regulation on a

[26] McKenzie Direct, Table 7, at 75.
[27] Woolridge Direct at 83.

utility's investment risks is one of the key elements considered by credit rating agencies and investment advisory services, such as Moody's, S&P Global ("S&P"), and Value Line, when establishing corporate credit ratings and other risk measures. As a result, the impact of regulatory protections is already reflected in my risk analysis. Meanwhile, the beta values supported by modern financial theory are premised on stock price volatility relative to the market as a whole, and are not dependent on an assessment of firm-specific considerations. As a result, the impact of regulatory differences on investment risk is accounted for in the published risk indicators relied on by investors and cited in my Direct Testimony.

Q24. WHAT WERE THE RESULTS OF YOUR ROE ANALYSIS FOR THE NON-UTILITY GROUP?

A24. As shown in Exhibit No. 11, page 3, the average ROEs for the Non-Utility group ranged from 10.4% to 10.8%. The midpoint of this range is 10.6%.

Q25. BASED ON YOUR COMPARISON OF THE ROE WITNESSES' RECOMMENDATIONS WITH ACCEPTED BENCHMARKS AND, IN LIGHT OF THE PROSPECT FOR HIGHER INTEREST RATES, WHAT DO YOU CONCLUDE?

A25. Based on these comparisons, the 8.60% and 8.85% ROE recommendations of Dr. Woolridge and Mr. Baudino, respectively, are below any reasonable outcomes. One fundamental standard underlying the regulation of public utilities, as set forth by the Supreme Court's *Bluefield* and *Hope* decisions, requires that the Company must have the opportunity to earn an ROE comparable to contemporaneous returns available from alternative investments of similar risk if it is to maintain its financial flexibility and ability to attract capital. The recommendations of the ROE Witnesses do not provide such an opportunity.

If the utility is unable to offer a return similar to the returns available from other opportunities of comparable risk, investors will become unwilling to supply capital to the utility on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their cost of capital. Both of these outcomes, which would be the result produced by the ROE Witnesses' recommendations, violate regulatory standards.

Q26. WHAT OTHER PITFALLS ARE ASSOCIATED WITH AN ROE THAT FALLS BELOW THOSE AUTHORIZED FOR OTHER COMPARABLE COMPANIES?

A26. Adopting an ROE for the Company that is well below the ROEs for comparable utilities could lead investors to view the Commission's regulatory framework as unsupportive, an outcome that would undermine investors' willingness to support future capital availability for investment in Kentucky. Security analysts study regulatory orders in order to advise investors where to invest their money. Moody's Investors Service ("Moody's) noted that, "[f]undamentally, the regulatory environment is the most important driver of our outlook."[28] Similarly, S&P concluded that "[t]he regulatory framework/regime's influence is of critical importance when assessing regulated utilities' credit risk because it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance."[29] Value Line summarizes these sentiments:

> As we often point out, the most important factor in any utility's success, whether it provides electricity, gas, or water, is the regulatory climate in which it operates. Harsh regulatory

[28] Moody's Investors Service, "Regulation Will Keep Cash Flow Stable As Major Tax Break Ends," *Industry Outlook* (Feb. 19, 2014).
[29] Standard & Poor's Corporation, "Key Credit Factors For The Regulated Utilities Industry," *RatingsDirect* (Nov. 19, 2013).

> conditions can make it nearly impossible for the best run utilities to earn a reasonable return on their investment.[30]

Utilities and their investors must lock up large sums of capital and are exposed to many risks over the long time horizon when they invest in utility infrastructure. At the levels proposed by the ROE Witnesses, the ability of Kentucky utilities to attract and retain capital would be compromised. This would have a long-term, chilling effect on investors' willingness to support capital investment in utility infrastructure, not just for the Company, but for all utilities in the state. On the other hand, if Commission actions instill confidence that the regulatory environment is supportive, investors will provide the necessary capital, which ultimately benefits customers and the service area economy.

II. RESPONSE TO DR. WOOLRIDGE

Q27. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR REBUTTAL TESTIMONY?

A27. My purpose here is to address Dr. Woolridge's mischaracterization of financial market conditions and the failings of his evaluation of a fair ROE for the Company.

A. Capital Market Conditions

Q28. WHAT ARE DR. WOOLRIDGE'S VIEWS REGARDING CURRENT CAPITAL MARKET CONDITIONS?

A28. Dr. Woolridge summarizes his review of current capital market conditions by concluding that "interest rates and capital costs are at low levels and are likely to remain low for some time."[31] He then adds, "[o]n this issue, I show that

[30] Value Line Investment Survey, *Water Utility Industry*, January 13, 2017, p. 1780.
[31] Woolridge Direct at 5.

economists' forecasts of higher interest rates and capital costs, which are used by Mr. McKenzie, have been consistently wrong for a decade."[32]

Q29. HAVE RECENT DECISIONS BY THE FEDERAL RESERVE REINFORCED INVESTOR SENTIMENT THAT INTEREST RATES WILL TREND HIGHER?

A29. Yes. On June 14, 2017 the Federal Reserve increased the target range for the Federal Funds rate by another 25 basis points to 1.00% to 1.25%. This is in addition to similar increases in March 2017, December 2016, and December 2015. More rate hikes by the Federal Reserve are anticipated.

Q30. ARE INTEREST RATE FORECASTERS STILL PROJECTING HIGHER LONG-TERM RATES FOR COMPANIES LIKE KENTUCKY POWER?

A30. Yes. As illustrated in Figure R-2 above, investors continue to anticipate that interest rates will increase significantly from present levels.

Q31. DR. WOOLRIDGE SUGGESTS THAT INTEREST RATE FORECASTS SHOULD BE IGNORED BY THE COMMISSION BECAUSE FORECASTS HAVE BEEN WRONG IN THE PAST. DO YOU AGREE?

A31. Absolutely not. In estimating investors' required rate of return, what investors expect, not what actually happens, is what matters most. Any difference in actual rates as compared to analysts' forecasts is beside the point. What is most important is that investors share analysts' views when the forecasts were made and incorporate those views into their decision making process, not the actual rates that ultimately transpire.

Q32. DR. WOOLRIDGE DISCUSSES THE MARKET-TO-BOOK RATIO AND REACHES SEVERAL BOLD CONCLUSIONS IN THIS AREA. ARE HIS CONCLUSIONS REALISTIC?

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[32] *Id.*

A32. No. He says that a historical market-to-book ratio greater than one for the utility industry means that "for at least the last decade, returns on common equity have been greater than the cost of capital"[33] and "customers have been paying more than necessary to support an appropriate profit level for regulated utilities."[34]

Dr. Woolridge wants the Commission to sacrifice the Company's financial strength to favor a theoretical ideal of M/B equaling unity. The Commission does not purport to regulate utility stock market prices as Dr. Woolridge urges. Further, and as discussed below, there are many leaps between his economic theory and reality. But if the theory is correct, then Dr. Woolridge is asking the Commission to order an ROE that would almost certainly lead to a capital loss on shareholders' investment in the Company. From an economic perspective, such an action would violate the standards underlying a fair ROE.

Q33. IS THERE A CLEAR LINK BETWEEN M/B FOR UTILITIES AND ALLOWED RATES OF RETURN?

A33. No. Underlying Dr. Woolridge's conclusions is the supposition that regulators should set an ROE to produce a M/B of approximately 1.0. This is fallacious. For example, Regulatory Finance: Utilities Cost of Capital noted that:

> The stock price is set by the market, not by regulators. The market-to-book ratio is the end result of regulation, and not its starting point. The view that regulation should set an allowed rate of return so as to produce a market-to-book of 1.0, presumes that investors are irrational. They commit capital to a utility with a market-to-book in excess of 1.0, knowing full well that they will be inflicted a capital loss by regulators. This is certainly not a realistic or accurate view of regulation.[35]

With M/B for most utilities above 1.0, Dr. Woolridge is suggesting that, unless book value grows rapidly, regulators should establish equity returns that will

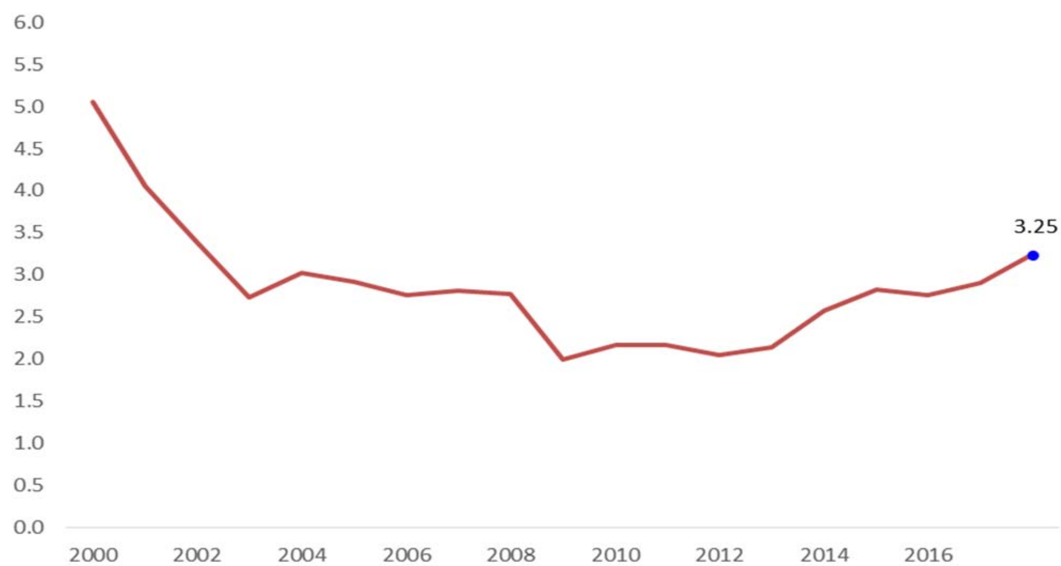
[33] *Id.* at 30.
[34] *Id.*
[35] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 376.

cause share prices to fall. Given the regulatory imperative of preserving a utility's ability to attract capital, this would be a truly nonsensical result. The M/B is determined by investors in the stock market, and a utility would be foreclosed from attracting capital if regulators were to push market-to-book to 1.0 while other firms command prices well in excess of 1.0 times book value.

Q34. IS THERE ANYTHING UNUSUAL ABOUT A STOCK PRICE EXCEEDING BOOK VALUE?

A34. No. In fact the majority of stocks currently sell substantially above book value. For example, Value Line reports that approximately 1,450 of the roughly 1,700 stocks it follows (including utilities and other industries) sell for prices in excess of book value.[36] In the figure below, I provide the average historical market price-to-book value ratios for the companies in the S&P 500 Composite Index.

FIGURE R-3
S&P 500 PRICE TO BOOK VALUE



Current S&P 500 Price To Book Value: 3.25
Mean: 2.76
Median: 2.74
Min: 1.78 (Mar. 2009)
Max: 5.06 (Mar. 2000)

[36] www.valueline.com (retrieved Oct. 10, 2017).

Current Price To Book Ratio Is Estimated Based On Current Market Price And S&P 500 Book Value As Of March 2017, The Latest Reported By S&P.

Source: Standard & Poor's, www.multpl.com/s-p-500-price-to-book (retrieved Oct. 10, 2017).

For the 500 largest publicly-traded companies in the U.S. economy, stock market prices have averaged almost three times book value. The lowest value occurred at the market bottom in early 2009 during the "great recession," at 1.78 times.

The table below provides a listing of recent market-to-book ratios by industry.

TABLE R-1
MARKET-TO-BOOK RATIO BY SECTOR

Sector	Ratio
Financial	1.67
Energy	1.71
Utilities	1.89
Consumer Discretionary	2.69
Basic Materials	3.04
Conglomerates	3.41
Services	3.77
Healthcare	4.07
Transportation	4.76
Consumer Non-cyclical	5.05
Technology	5.07
Capital Goods	5.35
Retail	6.64

Source: https://csimarket.com/screening/index1.php?s=pb (retrieved Oct. 10, 2017).

The market-to-book ratio for the utilities sector of 1.89 is among the lowest of the industry groups, and it is well below the 2.76 times historical average for the S&P 500. The consistently higher market-to-book relationship for unregulated companies shows that Dr. Woolridge's theoretical 1.0 benchmark is misplaced and that his claims about excessive utility earnings based on this benchmark are incorrect.

Q35. ARE THERE OTHER IMPORTANT FACTORS BEYOND ROE THAT EXPLAIN M/B FOR UTILITIES ABOVE 1.0?

A35. Yes. Although Dr. Woolridge's comparison would make it appear that utility ROEs are the cause for M/B greater than one, this contention entirely ignores accounting issues and other considerations. Consider, for example, the merger and acquisition activity that has significantly affected utility stock market prices in recent years. Investors know that many acquisitions have occurred and that significant premiums and large capital gains have been associated with those transactions. While earnings expectations are a part of market pricing, Dr.

Woolridge's contention about direct causation between ROEs and market-to-book ratios is an extremely narrow view.

Q36. ARE ADJUSTMENTS BASED ON M/B A COMMON FEATURE IN DETERMINING ALLOWED ROES FOR UTILITIES?

A36. No. While arguments regarding the implications of a market-to-book greater than 1.0 are not uncommon, I am not aware of a single instance in recent history where a state regulator has approved a market-to-book adjustment in establishing a fair ROE. Meanwhile, FERC has explicitly recognized the fallacy of relying on market-to-book in evaluating cost of equity estimates. For example, the Presiding Judge in *Orange & Rockland* concluded, and the FERC affirmed that:

> The presumption that a market-to-book ratio greater than 1.0 will destroy the efficacy of the DCF formula disregards the realities of the market place principally because the market-to-book ratio is rarely equal to 1.0.[37]

The Initial Decision found that there was no support in FERC precedent for the use of market-to-book to adjust market derived cost of equity estimates based on the DCF model and concluded that such arguments were to be treated as "academic rhetoric" unworthy of consideration. Similarly, FERC rejected similar arguments from Dr. Woolridge more recently, concluding that "If, all else being equal, the regulator sets a utility's ROE so that the utility does not have the opportunity to earn a return on its book value comparable to the amount that investors expect that other utilities of comparable risk will earn on their book equity, the utility will not be able to provide investors the return they require to invest in that utility."[38]

Q37. IS DR. WOOLRIDGE'S M/B DISCUSSION RELEVANT TO THE SETTING OF THE COMPANY'S ROE IN THIS CASE?

[37] *Orange & Rockland Utilities, Inc.*, Initial Decision, 40 FERC ¶ 63,053, 1987 WL 118,352 (F.E.R.C.).
[38] *Martha Coakely, et al.,* Opinion No. 531-B, 150 FERC ¶ 61,165 at P 129 (2015).

A37. No. Even in the unlikely event that the long trail of breadcrumbs between Dr. Woolridge's theoretical postulations on M/B and allowed returns remained unbroken, his conclusion is directed at the wrong hypothesis. The question before the Commission is <u>not</u> what ROE will produce a M/B of 1.0 for utilities; rather, the question is what ROE will allow Kentucky Power to maintain access to capital and grant stockholders the opportunity to earn a fair return on investment vis-à-vis alternatives of comparable risk.

B. Discounted Cash Flow Model

Q38. WHAT ARE THE FUNDAMENTAL PROBLEMS WITH THE DCF ANALYSES CONDUCTED BY DR. WOOLRIDGE (AT 33-48)?

A38. There are numerous problems with the DCF analyses presented by Dr. Woolridge that lead to biased end results:

- One of the proxy groups relied on by Dr. Woolridge is defective due to flaws in the screening criteria and data he used, causing the exclusion of comparable utilities.
- Reliance on dividend growth rates and historical growth measures do not reflect a meaningful guide to investors' expectations.
- Dr. Woolridge discounts reliance on analysts' earnings per share ("EPS") growth forecasts as somehow biased, and fails to sufficiently recognize that it is investors' *perceptions and expectations* that must be considered in applying the DCF model.
- Because Dr. Woolridge failed to test the reasonableness of model inputs, he incorrectly includes data that results in illogical cost of equity estimates.
- Dr. Woolridge's internal growth ("br") rates are downward biased because of computational errors and omissions.
- Rather than looking to the capital markets for guidance as to investors' forward-looking expectations, Dr. Woolridge applies the DCF model based on his own personal views.

As a result of these flaws and omissions, the resulting DCF cost of equity estimates are erroneously downward biased and fail to reflect investors' required rate of return.

Q39. DR. WOOLRIDGE APPLIED HIS ROE ANALYSES TO TWO GROUPS OF ELECTRIC UTILITIES, YOURS AND ONE BASED ON A DIFFERENT SET OF SELECTION CRITERIA. ARE THERE FLAWS IN HIS ELECTRIC PROXY GROUP?

A39. Yes. One of the selection criteria relied on by Dr. Woolridge required that at least 50% of the utility's revenues must come from regulated electric operations as reported by AUS Utility Report ("AUS").[39] There are several problems with this approach.

Q40. DO YOU AGREE WITH DR. WOOLRIDGE THAT THE NATURE OF A UTILITY'S REVENUES IS A VALID CRITERION IN SELECTING A PROXY GROUP FOR THE COMPANY?

A40. No. Dr. Woolridge failed to demonstrate how his subjective 50% revenue criterion translates into differences in the investment risks perceived by investors, while comparisons of objective indicators demonstrate that investment risks for the firms in my proxy groups are relatively homogeneous and comparable to the Company.

Q41. DID DR. WOOLRIDGE DEMONSTRATE ANY NEXUS BETWEEN A SUBJECTIVE CRITERION BASED ON REGULATED REVENUES AND OBJECTIVE MEASURES OF INVESTMENT RISK?

A41. No. Under the regulatory standards established by *Hope* and *Bluefield*, the salient criterion in establishing a meaningful proxy group to estimate investors' required

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[39] Woolridge Direct at 23. While Dr. Woolridge testimony references AUS, this report is no longer in publication, with the last monthly edition dated September 2016. It appears that Dr. Woolridge actually relied on information from the 2016 Form 10-K reports for the companies in his proxy groups. *See* "Electric_Utilities_-_Regulated_Revenue_-_2016_10-k.xlsx."

return is relative risk, not the source of the revenue stream or the nature of the asset base. Dr. Woolridge presented no evidence to demonstrate a connection between the subjective revenue criterion that he employed and the views of real-world investors in the capital markets. Nor did Dr. Woolridge provide any evidentiary support for his 50% threshold. Dr. Woolridge's testimony offers no explanation why a revenue cut-off of 50%, rather than, say, 40% or 60%, supposedly impacts a utility's operations sufficiently to justify its exclusion.

Moreover, due to differences in business segment definition and reporting between utilities, it is often impossible to accurately apportion financial measures, such as revenues and total assets, between regulated and non-regulated sources. As a result, even if one were to ignore the fact that there is no clear link between the nature of a utility's revenues or assets and investors' risk perceptions, it is generally not possible to accurately and consistently apply asset or revenue-based criteria. In fact, other regulators have rebuffed these notions, with FERC specifically rejecting arguments that utilities "should be excluded from the proxy group given the risk factors associated with its unregulated, non-utility business operations."[40]

Q42. CAN YOU ILLUSTRATE HOW A SCREEN BASED ON REVENUE COMPOSITION CAN LEAD TO AN ERRONEOUS CONCLUSION?

A42. Yes. Consider Public Service Enterprise Group, Sempra, and Vectren, which Dr. Woolridge omitted because regulated electric revenues were less than 50% of total revenue. However, after further inspection of their revenue composition, a different story is revealed. On page 1 of Exhibit JRW-4, Dr. Woolridge lists not only the level of regulated electric revenue, but also the level of regulated gas revenue. Gas distribution operations are regulated by the states in the same

[40] *Bangor Hydro-Elec. Co.*, 117 FERC ¶ 61,129 at PP 19, 26 (2006).

manner as electric operations, and there is no basis to distinguish between revenues from electric and gas utility operations. When gas revenues are combined with electric revenues, these companies all have regulated revenues that exceed the artificial, 50% threshold.[41]

Q43. DR. WOOLRIDGE ALSO EXCLUDED AVANGRID, ANOTHER COMPANY THAT IS IN YOUR GROUP. IS THERE A LOGICAL BASIS TO EXCLUDE AVANGRID?

A43. No. AVANGRID meets all of Dr. Woolridge's criteria: it is followed by Value Line, it has investment grade bond ratings, it has not cut or omitted any recent dividends, and long-term analyst growth forecasts are available.[42] Moreover, data from in AVANGRID's most recent SEC Form 10-K indicate that regulated operations contributed approximately 84% of total revenues.[43] For these reasons, AVANGRID should properly be included in the proxy group in this case.

Q44. DR. WOOLRIDGE NOTED THAT HE EXCLUDED EMERA INC. ("EMERA") AND FORTIS INC. ("FORTIS") FROM HIS PROXY GROUP BECAUSE THEY ARE BASED IN CANADA.[44] DOES THIS OBSERVATION SUPPORT HIS ELIMINATION OF THESE FIRMS?

A44. No. Other than his simple factual observation, Dr. Woolridge provided no evidence or explanation as to why investors would not regard Emera and Fortis to be comparable opportunities to the other utilities included in his proxy group. Like the other companies included by Dr. Woolridge, Emera is primarily engaged in electricity generation, transmission, and distribution; gas transmission and

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[41] From Exhibit JRW-4, page 1, the combined electric and gas revenue percentages are 78% for Sempra, 70% for Public Service Enterprise Group, and 56% for Vectren.
[42] While AVANGRID is not included in the AUS report cited in Dr. Woolridge's testimony, this is more likely to be a function of the cancellation of the publication and the resultant staleness of the data.
[43] AVANGRID reports regulated revenues of $5,030 million, out of total revenues of $6,018 million.
[44] Woolridge Direct at footnote 18.

distribution; and utility energy services, and serves approximately 2.4 million customers. As Value Line reported:

> With the addition of TECO's Florida and New Mexico operations, more than 75 percent of earnings are now generated from rate regulated businesses.[45]

Emera noted that, "With our Florida and New Mexico businesses integrated, more than 90 percent of Emera's earnings now come from our regulated businesses, surpassing our target of 75-85 percent," and that approximately 70% of future adjusted net income will be generated from its US subsidiaries.[46] Similarly, CRFA highlighted Emera's primary focus on electric utility operations, and classified Emera in its "Electric Utilities" industry group.[47] Thus, investors would regard Emera as a comparable investment alternative that is relevant to an evaluation of the required rate of return for Kentucky Power.

Similarly, like the other companies included in Dr. Woolridge's proxy group, Value Line observed that Fortis' "main focus is electricity, hydroelectric, and gas utility operations."[48] With $48 billion in assets, Fortis is one of the leading utility companies in North America, which include the Arizona operations of UNS Energy (including Tucson Electric Power), the New York operations of Central Hudson Gas & Electric, and ITC Holdings, which is the largest independent electricity transmission company in the U.S. There is no support for Dr. Woolridge's exclusion of Emera and Fortis simply because they are headquartered in Canada, and his position on this issue should be ignored.[49]

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[45] The Value Line Investment Survey (June 23, 2017) at 1218.
[46] Emera, Inc., 2016 Annual Report at 2, 19. In addition to its Florida and New Mexico utility operations, Emera also owns Bangor Hydro-Electric Company, which provides electric utility service in New England.
[47] CRFA, "Emera Incorporated," *Quantitative Stock Report* (June 24, 2017). CRFA, one of the world's largest providers of institutional-grade independent equity research, acquired the equity and fund research arm of S&P in October 2016.
[48] The Value Line Investment Survey (Sep. 15, 2017).
[49] Moreover, Dr. Woolridge is selective on the issue of involvement in foreign operations. His proxy group includes PPL Corporation, which serves 7.8 million electric customers in the United Kingdom.

Q45. DO YOU BELIEVE THAT HISTORICAL TRENDS IN DIVIDENDS PER SHARE ("DPS") PROVIDE A MEANINGFUL GUIDE TO INVESTORS' EXPECTATIONS?

A45. No. As discussed at length in my direct testimony, it is investors' future expectations – and not actual, historical results – that determine the current price they are willing to pay for commons stocks. If past trends in DPS are to be representative of investors' expectations for the future, then the historical conditions giving rise to these growth rates should be expected to continue. That is clearly not the case for utilities, which have experienced declining dividend payouts, earnings pressure, and, in many cases, significant write-offs.

Dr. Woolridge noted the pitfalls associated with historical growth measures. As he correctly observed:

> [T]o best estimate the cost of common equity capital using the conventional DCF model, one must look to long-term growth rate expectations.[50]

As he acknowledged, historical growth rates can differ significantly from the forward-looking growth rate required by the DCF model:

> However, one must use historical growth numbers as measures of investors' expectations with caution. In some cases, past growth may not reflect future growth potential. Also, employing a single growth rate number (for example, for five or ten years), is unlikely to accurately measure investors' expectations due to the sensitivity of a single growth rate figure to fluctuations in individual firm performance as well as overall economic fluctuations (i.e., business cycles).[51]

While past conditions for utilities serve to depress historical DPS growth rates, they are not representative of long-term expectations for the electric utility industry. Moreover, to the extent historical trends for electric utilities are

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[50] Woolridge Direct at 40.
[51] *Id.*

meaningful, they are also captured in projected growth rates, such as those published by Value Line and Zacks Investment Research ("Zacks"), since securities analysts also routinely examine and assess the impact and continued relevance (if any) of historical trends. Similarly, the Regulatory Commission of Alaska ("RCA") has previously determined that analysts' EPS growth rates provide a superior basis on which to estimate investors' expectations:

> We also find persuasive the testimony . . . that projected EPS returns are more indicative of investor expectations of dividend growth than historical growth data because persons making the forecasts already consider the historical numbers in their analyses.[52]

The RCA has concluded that arguments against exclusive reliance on analysts' EPS growth rates to apply the DCF model "are not convincing."[53] This is consistent with the Commission's conclusions cited in my direct testimony, which noted that, "analysts' projections of growth will be relatively more compelling in forming investors' forward-looking expectations than relying on historical performance, especially given the current state of the economy."[54]

Q46. DR. WOOLRIDGE ARGUES (AT 39) THAT THE GROWTH RATE COMPONENT IN THE DCF MODEL REFLECTS "THE LONG-TERM DIVIDEND GROWTH RATE." DO YOU AGREE THAT THIS IS WHAT INVESTORS ARE MOST LIKELY TO CONSIDER IN DEVELOPING THEIR LONG-TERM GROWTH EXPECTATIONS?

A46. No. Again, implementation of the DCF model is solely concerned with replicating the forward-looking evaluation of real-world investors. In the case of utilities, growth rates in DPS are not likely to provide a meaningful guide to investors' current growth expectations.

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[52] Regulatory Commission of Alaska, U-07-76(8) at 65, n. 258.
[53] Regulatory Commission of Alaska, U-08-157(10) at 36.
[54] *Kentucky Utilities Co.*, Case No. 2009-00548 (Ky PSC Jul. 30, 2010) at 30-31.

Q47. WHAT ARE INVESTORS MOST LIKELY TO CONSIDER IN DEVELOPING THEIR LONG-TERM GROWTH EXPECTATIONS?

A47. As documented in my direct testimony, future trends in EPS, which provide the source for future dividends and ultimately support share prices, play a pivotal role in determining investors' long-term growth expectations. The continued success of investment services such as IBES,[55] Value Line, and Zacks, and the fact that projected growth rates from such sources are widely referenced, provides strong evidence that investors give considerable weight to analysts' earnings projections in forming their expectations for future growth. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community, and surveys of analytical techniques relied on by professional analysts indicate that growth in EPS is far more influential than trends in DPS. As explained in *New Regulatory Finance*:

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of *g* [growth].[56]

The availability of projected EPS growth rates also is key to investors relying upon this measure as compared to future trends in DPS. Apart from Value Line, investment advisory services do not generally publish comprehensive DPS growth projections, and this scarcity of dividend growth rates relative to the abundance of EPS forecasts attests to their relative influence. The fact that analyst EPS growth estimates are routinely referenced in the financial media and

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[55] Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by Thomson Reuters.

[56] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 298.

in investment advisory publications implies that investors use them as a primary basis for their expectations. As observed in *New Regulatory Finance*:

> The sheer volume of earnings forecasts available from the investment community relative to the scarcity of dividend forecasts attests to their importance. The fact that these investment information providers focus on growth in earnings rather than growth in dividends indicates that the investment community regards earnings growth as a superior indicator of future long-term growth. Surveys of analytical techniques actually used by analysts reveal the dominance of earnings and conclude that earnings are considered far more important than dividends.[57]

While I did not rely solely on EPS projections in applying the DCF model,[58] my evaluation clearly supports greater reliance on EPS growth rate projections than other alternatives. Similarly, my Direct Testimony documented the Commission's preference for relying on analysts' growth forecasts, which is supported by the findings of other regulatory agencies.[59]

Q48. IS DR. WOOLRIDGE CONSISTENT IN HIS INSISTENCE THAT HISTORICAL GROWTH RATES AND TRENDS IN DPS MUST BE CONSIDERED IN APPLYING THE DCF MODEL?

A48. No. In testimony before FERC, Dr. Woolridge has applied the DCF model without any reference to historical trends or growth rates in DPS.[60] In the present case, despite his indictment of analysts' EPS growth projections, this data largely serves as the basis for his own DCF analysis. When selecting the final growth rates for both proxy groups referenced in his testimony, Dr. Woolridge gives "primary weight" to the projected EPS growth rates of Wall Street analysts.[61] So, while Dr. Woolridge complains vociferously about the suitability of analysts' EPS

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[57] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 302-303.
[58] As discussed in my direct testimony, I also examined the "br+sv", sustainable growth rates for the companies in my proxy groups.
[59] McKenzie Direct at 38.
[60] *See, e.g.*, *Testimony of J. Randall Woolridge*, Docket No. EL11-66-000, Exhibit SC-100.
[61] Woolridge Direct at 46.

growth projections, he relies primarily on these same projections in reaching his ultimate DCF conclusions. His criticisms of the use of analysts' EPS growth projections ring hollow and are without merit in this light.

Q49. DOES MR. BAUDINO ACKNOWLEDGE THE SUPERIORITY OF FORECASTED DATA, AS OPPOSED TO HISTORICAL DATA, IN THE DCF PROCESS?

A49. Yes. Mr. Baudino concurs that analysts' forecasts are superior:

> Return on equity analysis is a forward-looking process. Five-year or ten-year historical growth rates may not accurately represent investor expectations for dividend growth. Analysts' forecasts for earnings and dividend growth provide better proxies for the expected growth component in the DCF model than historical growth rates. Analysts' forecasts are also widely available to investors and one can reasonably assume that they influence investor expectations.[62]

Q50. IS THE DOWNWARD BIAS IN DR. WOOLRIDGE'S HISTORICAL GROWTH MEASURES SELF EVIDENT?

A50. Yes, it is. As shown on page 3 of Exhibit JRW-10, thirty three of the historical growth rates reported by Dr. Woolridge for his electric proxy companies were 2.0% or less, including sixteen negative values.[63] A negative growth rate implies a cost of equity that falls below the utility's dividend yield which makes no economic sense, since investors could earn higher returns on less-risky utility bonds. These outcomes illustrate the fact that Dr. Woolridge's historical growth measures provide no meaningful information regarding the expectations and requirements of investors.

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[62] Baudino Direct at 21.

[63] For the McKenzie Proxy Group shown on page 3 of Exhibit JRW-10, fourteen of the historical growth rates reported by Dr. Woolridge were 2.0% or less, including seven negative values.

Q51. DID DR. WOOLRIDGE ALSO INCLUDE LOW AND NEGATIVE GROWTH RATES IN HIS EXAMINATION OF PROJECTED GROWTH RATES?

A51. Yes, as shown on page 4 of Exhibit JRW-10, he included five growth rates at 1.5% or less in his analysis of Value Line projected growth rates for his electric proxy group.[64] Because these growth rates imply cost of equity estimates that are not materially higher than the yields on less risky utility bonds, they are not meaningful and should be excluded from his DCF analysis. On page 5 of Exhibit JRW-10, Dr. Woolridge includes two companies (Entergy Corporation and FirstEnergy Corporation) that have negative analyst projected growth rate estimates.

Q52. DID DR. WOOLRIDGE MAKE ANY EFFORT TO TEST THE REASONABLENESS OF THE INDIVIDUAL GROWTH ESTIMATES HE RELIED ON TO APPLY THE CONSTANT GROWTH DCF MODEL?

A52. No. Despite recognizing that caution is warranted in using historical growth rates, Dr. Woolridge simply calculated the average and median of the individual growth rates with no consideration for the reasonableness of the underlying data. In fact, as indicated above, many of the cost of equity estimates implied by Dr. Woolridge's DCF application are illogical, given the risk-return tradeoff that is fundamental to finance. The table below highlights some of the individual company results that are incorporated into Dr. Woolridge's DCF analysis.

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[64] For the McKenzie Proxy Group shown on page 4 of Exhibit JRW-10, two of the projected growth rates reported by Dr. Woolridge were 1.5% or less.

TABLE R-2
SAMPLE WOOLRIDGE COST OF EQUITY ESTIMATES

Company	Dividend Yield	Growth	DCF ROE
Entergy Corp.	4.5%	-4.3%	0.2%
First Energy Corp.	4.7%	-2.9%	1.8%
MGE Energy, Inc.	2.0%	4.0%	6.0%
PPL Corporation	4.1%	2.5%	6.5%

Source: Exhibit JRW-10, pages 2 (90 Day Dividend Yield) and 5 (Mean Growth). DCF ROE is sum of dividend yield and growth.

With current triple-B utility interest rates in the 4.4% range, the above results are not reasonable ROE outcomes. And as indicated in my direct testimony[65] and illustrated in Figure R-2 above, it is generally expected that long-term interest rates will rise as the Federal Reserve normalizes its monetary policies. As shown in the table below, the increase in debt yields anticipated by IHS Global Insight and the Energy Information Administration imply an average triple-B bond yield of approximately 6.22% over the period 2018-2022.

[65] McKenzie Direct at 16-23.

TABLE R-3
BOND YIELD FORECAST

	Baa Yield 2018-22
Projected Aa Utility Yield	
IHS Global Insight (a)	5.79%
EIA (b)	5.56%
Average	5.67%
Current Baa - Aa Yield Spread (c)	0.55%
Implied Baa Utility Yield	**6.22%**

(a) IHS Global Insight (Aug. 24, 2017).
(b) Energy Information Administration, Annual Energy Outlook 2017 (Jan. 5, 2017)
(c) Based on monthly average bond yields from Moody's Investors Service for the six-month period Apr. - Sep. 2017.

Equity returns close to, or less than, this threshold are not credible. Yet, Dr. Woolridge factors them into his final conclusions, which biases his results downward.

Q53. WHAT APPROACH SHOULD DR. WOOLRIDGE HAVE USED TO EVALUATE LOW-END DCF ESTIMATES?

A53. It is a basic economic principle that investors can be induced to hold more risky assets only if they expect to earn a return to compensate them for their risk bearing. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, Dr. Woolridge should have evaluated his DCF results to eliminate estimates that are determined to be illogical when compared against the yields available to investors from less risky utility bonds. The practice of eliminating low-end outliers has been affirmed in numerous FERC proceedings. In Opinion

No. 531, FERC concluded that, "The purpose of the low-end outlier test is to exclude from the proxy group those companies whose ROE estimates are below the average bond yield or are above the average bond yield but are sufficiently low that an investor would consider the stock to yield essentially the same return as debt."[66] FERC has used 100 basis points above the six-month average public utility bond yield as an approximation of this threshold, but has also recognized that this is a flexible test.[67]

Q54. DR. WOOLRIDGE ARGUES YOUR ANALYSIS IS FLAWED BECAUSE OF YOUR "ASYMMETRICAL ELIMINATION OF DCF RESULTS."[68] IS THIS A VALID ARGUMENT?

A54. No. As discussed above, low-end outliers were evaluated against the observable returns available from long-term bonds. But the fact that there are numerous results that fail this test of reasonableness says nothing about the validity of estimates at the upper end of the range of results, and there is no basis to discard an equal number of values from the top of the range. While the upper end cost of equity estimate of 14.0% from my Exhibit No. 5 may exceed expectations for most utilities, the remaining low-end estimates in the 7.0% range are assuredly far below investors' required rate of return. Taken together and considered along with the balance of the DCF estimates, these values provides a reasonable basis on which to evaluate investors' required rate of return.

Q55. DR. WOOLRIDGE RELIED ON SUSTAINABLE, "BR" GROWTH RATES (EXHIBIT JRW-10, P. 4). SHOULD THE COMMISSION PLACE ANY WEIGHT ON THESE VALUES?

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[66] Opinion No. 531 at P 122.
[67] *Id.*
[68] Woolridge Direct at 65.

A55. No. Dr. Woolridge's internal growth rates are downward biased because of computational errors (use of year-end book value) and omissions (failure to incorporate the impact of issuing new shares). Dr. Woolridge based his calculations of the internal, "br" retention growth rate on data from Value Line. If the rate of return, or "r" component of the internal growth rate, is based on end-of-year book values, such as those reported by Value Line, it will understate actual returns because of growth in common equity over the year.

Q56. WHAT OTHER CONSIDERATION LEADS TO A DOWNWARD BIAS IN DR. WOOLRIDGE'S CALCULATION OF INTERNAL, "BR" GROWTH?

A56. Dr. Woolridge ignored the impact of additional issuances of common stock in his analysis of the sustainable growth rate. Under DCF theory, the "sv" factor is a component designed to capture the impact on growth of issuing new common stock at a price above, or below, book value. As noted by Myron J. Gordon in his 1974 study:

> When a new issue is sold at a price per share P = E, the equity of the new shareholders in the firm is equal to the funds they contribute, and the equity of the existing shareholders is not changed. However, if P > E, part of the funds raised accrues to the existing shareholders. Specifically…[v] is the fraction of the funds raised by the sale of stock that increases the book value of the existing shareholders' common equity. Also, "v" is the fraction of earnings and dividends generated by the new funds that accrues to the existing shareholders.[69]

In other words, the "sv" factor recognizes that when new stock is sold at a price above (below) book value, existing shareholders experience equity accretion (dilution). In the case of equity accretion, the increment of proceeds above book value (P > E in Professor Gordon's example) leads to higher growth because it increases the book value of the existing shareholders' equity. In short, the "sv" component is entirely consistent with DCF theory, and the fact that Dr. Woolridge

[69] Myron J. Gordon, "The Cost of Capital to a Public Utility," *MSU Public Utilities Studies* (1974) at 31-32.

failed to consider the incremental impact on growth results in another downward bias to his "internal" growth rates, which should be given no weight.[70]

Q57. DOES DR. WOOLRIDGE'S REFERENCE TO THE MEDIAN (AT 44-45) CORRECT FOR ANY UNDERLYING BIAS IN HIS HISTORICAL GROWTH RATES?

A57. No. The median is simply the observation with an equal number of data values above and below. For odd-numbered samples, the median relies on only a single number, *e.g.*, the fifth number in a nine-number set. Reliance on the median value for a series of illogical values does not correct for the inability of individual cost of equity estimates to pass fundamental tests of economic logic.

Q58. WHAT DO YOU CONCLUDE BASED ON YOUR REVIEW OF DR. WOOLRIDGE'S DCF ANALYSES?

A58. Even a cursory review of pages 3-5 of Exhibit JRW-10 suggests that Dr. Woolridge could basically have arrived at any DCF growth rate that he wanted. These pages are a mishmash of historical and projected growth rates over varying time periods and not just for earnings, but for dividends and book value as well. There are literally hundreds of growth rates to choose from. The averages/medians for the two proxy groups referenced in his analysis range from 3.6% to 6.0%, and almost any DCF result could have been interpreted based on this data. For this reason, his DCF-based ROE recommendations are suspect and should be weighted accordingly.

Furthermore, trends in DPS are impacted by changes in industry financial policies and Dr. Woolridge failed to evaluate the underlying reasonableness of individual growth rates. Finally, the calculations used to arrive at Dr.

[70] In prior testimony before FERC, Dr. Woolridge incorporated an adjustment to correct for the downward bias attributable to end-of-year book values, and recognized the additional growth from new share issues by incorporating the "sv" component. *See, e.g., Testimony of J. Randall Woolridge*, FERC Docket No. EL-66 at Exhibit JRW-8, pp. 3-4 (2011).

Woolridge's internal growth rates are flawed and incomplete because he did not adjust his end-of-year book values for growth in common equity over the year and because he completely left out the "sv" factor designed to capture the impact on growth of issuing new common stock. As a result, his DCF cost of equity estimates are biased downward and fail to reflect investors' required rate of return.

C. Capital Asset Pricing Model

Q59. WHAT IS THE FUNDAMENTAL PROBLEM ASSOCIATED WITH THE APPROACH THAT DR. WOOLRIDGE USED TO APPLY THE CAPM?

A59. The CAPM application presented by Dr. Woolridge was based entirely on *historical* rates of return, not current projections. Like the DCF model, risk premium methods – including the CAPM – are *ex-ante,* or forward-looking models based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM approach must be applied using data that reflects the expectations of actual investors in the market. The primacy of current expectations was recognized by Morningstar, one of the sources relied on by Dr. Woolridge to apply the CAPM:

> The cost of capital is always an expectational or forward-looking concept. While the past performance of an investment and other historical information can be good guides and are often used to estimate the required rate of return on capital, the expectations of future events are the only factors that actually determine cost of capital.[71]

By failing to look directly at the returns investors are currently requiring in the capital markets, as I did on Exhibit Nos. 7 and 8 to my direct testimony, the 7.6%

[71] Morningstar, *Ibbotson SBBI, 2013 Valuation Yearbook* at 21.

historical CAPM estimate developed by Dr. Woolridge[72] falls woefully short of investors' current required rate of return.

Q60. DR. WOOLRIDGE (AT 52) CHARACTERIZES HIS RISK PREMIUM AS *EX ANTE*. IS THIS AN ACCURATE ASSESSMENT?

A60. No. In order to be considered a forward-looking, *ex ante* estimate of the current market risk premium, the analysis must be predicated on investors' current expectations. Dr. Woolridge did not attempt to develop a market risk premium using current capital market information. Rather, he simply presented the results of various studies and surveys conducted in the past. Certain of these studies may have attempted to infer the equity risk premium using expected data at the time they were developed, but expectations at some point in the past are not equivalent to investors *ex ante* requirements in capital markets today.

Q61. IS THERE GOOD REASON TO ENTIRELY DISREGARD THE RESULTS OF HISTORICAL CAPM ANALYSES SUCH AS THOSE PRESENTED BY DR. WOOLRIDGE?

A61. Yes. Applying the CAPM is complicated by the impact of the Federal Reserve policies on investors' risk perceptions and required returns. As the Staff of the Florida Public Service Commission concluded regarding historical applications of the CAPM:

> [R]ecognizing the impact the Federal Government's unprecedented intervention in the capital markets has had on the yields on long-term Treasury bonds, staff believes models that relate the investor-required return on equity to the yield on government securities, such as the CAPM approach, produce less reliable estimates of the ROE at this time.[73]

[72] Woolridge Direct at 57.
[73] *Staff Recommendation for Docket No. 080677-E1 - Petition for increase in rates by Florida Power & Light Company*, Docket No. 080677-E1, at 280 (Dec. 23, 2009).

Similarly, in *Orange & Rockland Utilities*, FERC determined that CAPM methodologies based on historical data were suspect because whatever historical relationships existed between debt and equity securities may no longer hold.[74] FERC concluded that historical risk premiums are downward biased given recent trends of low yields for Treasury bonds.[75]

As a result, there is every indication that the historical CAPM approach fails to fully reflect the risk perceptions of real-world investors in today's capital markets, which would violate the standards underlying a fair rate of return by failing to provide an opportunity to earn a return commensurate with other investments of comparable risk.

Q62. DID DR. WOOLRIDGE ALSO RECOGNIZE THE FRAILTIES OF HIS HISTORICAL CAPM APPROACHES?

A62. Yes. Dr. Woolridge noted that *ex-post*, historical rates of return "are not the same as *ex ante* expectations," and observed that, "The use of historical returns as market expectations has been criticized in numerous academic studies."[76] Dr. Woolridge admitted that "risk premiums can change over time … such that *ex post* historical returns are poor estimates of *ex ante* expectations."[77] Finally, Dr. Woolridge conceded, that his historical CAPM approach provides "a less reliable indication of equity cost rates for public utilities."[78]

Q63. IS THERE EVIDENCE THAT THE STUDIES REFERENCED BY DR. WOOLRIDGE DO NOT REFLECT INVESTORS' EXPECTATIONS?

A63. Yes. The vast majority of the equity risk premium findings reported by Dr. Woolridge do not make economic sense and contradict his own testimony. For

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[74] *See Orange & Rockland Utils., Inc.*, 40 FERC ¶ 63,053 at 65,208-09 (1987), *aff'd*, Opinion No. 314, 44 FERC ¶ 61,253 at 65,208 (2008).
[75] *See New York Independent System Operator, Inc.*, 146 FERC ¶ 61,043 at P 105 (2014).
[76] Woolridge Direct at 52-53.
[77] *Id.*
[78] *Id.* at 33.

example, page 5 of Dr. Woolridge's Exhibit JRW-11 reveals that well over half of the historical studies included in Dr. Woolridge's review found market equity risk premiums of approximately 5.0% or below. This was also true for nearly half of the individual risk premium studies that Dr. Woolridge classified as "more recent."[79] But combining a market equity risk premium of 5.0% with Dr. Woolridge's 4.0% risk-free rate results in an indicated cost of equity for the market as a whole of 9.0%, which barely exceeds his ROE recommendation for Kentucky Power in this case.

Meanwhile, after noting that beta is the only relevant measure of investment risk under modern capital market theory, Dr. Woolridge concluded that his comparison of beta values (Exhibit JRW-8) indicates that investors' required return on the market as a whole should exceed the cost of equity for electric utilities.[80] Based on Dr. Woolridge's own logic, it follows that a market rate of return that does not significantly exceed his own downward biased ROE recommendation has no relation to the current expectations of real-world investors. The fact that much of his CAPM "evidence" violates the risk-return tradeoff that is fundamental to financial theory clearly illustrates the frailty of Dr. Woolridge's analyses.

Q64. ARE THERE OTHER SHORTCOMINGS ASSOCIATED WITH THE SOURCES CITED BY DR. WOOLRIDGE?

A64. Yes. For example, the *Fernandez* survey is the result of a mass solicitation to more than 23,000 email addresses, out of which approximately 6,900 responses were received.[81] While many of the responses were undoubtedly from informed

[79] Exhibit JRW-11, p. 6.
[80] Woolridge Direct at 31-32.
[81] Pablo Fernandez, Alberto Ortiz, and Isabela Fernandez Acin, "Market Risk Premium used in 71 Countries in 2016: a survey with 6,923 answers," (May 2016) https://papers.ssrn.com/sol3/Delivery.cfm/SSRN_ID2776636_code12696.pdf?abstractid=2776636&mirid=1&type=2 (last visited Oct. 11, 2017).

professionals, there is no ability verify the experience or familiarity of the respondents with the subject matter. In addition, the wording of the surveys is imprecise and open to interpretation. For example, the 2016 survey simply asks, "The Market Risk Premium that I am using in 2016 for USA is _____%,"[82] which is entirely unclear. The respondent has no idea whether he or she is being queried for a risk premium during 2016, or over some other time period; nor is the basis on which the risk premium is calculated even specified.[83]

Meanwhile, the approach used to derive a market risk premium in *Damodaran* forces the growth rate for all competitive firms to a constant long-term rate after five years. In addition, *Damodaran* inexplicably assumes that this long term rate of growth will equal the current yield on U.S. Treasury bonds, or 2.12% in its current rendition.[84] This is significantly below even the GDP growth rate range of 3.0% to 5.0% advocated by Dr. Woolridge.[85] There is no logical link between investors' long-term growth expectations for common stocks and the current Treasury bond yield, and I know of no credible source of investment guidance that is expecting growth for all companies in the economy to collapse to 2.12% over the next five years.

The fundamental problem with Dr. Woolridge's approach is that instead of looking directly at an equity risk premium based on current expectations – which is what is required in order to properly apply the CAPM and is the approach I took – he undertakes an unrelated exercise of compiling selected computations culled from the historical record. In short, while there are many potential definitions of the equity risk premium, the only relevant issue for application of

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[82] *Id.*
[83] One respondent to the *Fernandez* survey characterized the imprecision and ambiguity this way: "You don't define exactly what you mean by "Market Risk Premium". Different authorities define it in different ways. Is it expected return over short-term government securities (*e.g.*, 30 or 90 day T-Bills), or longer-term government bonds?" *Id.*
[84] http://www.stern.nyu.edu/~adamodar/pc/implprem/ERPSept17.xls (last visited Oct. 11, 2017).
[85] Woolridge Direct at 72.

the CAPM in a regulatory context is the return investors currently expect to earn on money invested today in the risky market portfolio versus the risk-free U.S. Treasury alternative.

Q65. WAS DR. WOOLRIDGE (EXHIBIT JRW-11, PP. 5-6) JUSTIFIED IN RELYING ON GEOMETRIC MEANS AS A MEASURE OF AVERAGE RATE OF RETURN WHEN APPLYING THE HISTORICAL CAPM?

A65. No. While both the arithmetic and geometric means are legitimate measures of average return, they provide different information. Each may be used correctly, or misused, depending upon the inferences being drawn from the numbers. The geometric mean of a series of returns measures the constant rate of return that would yield the same change in the value of an investment over time. The arithmetic mean measures what the expected return would have to be each period to achieve the realized change in value over time.

In estimating the cost of equity, the goal is to replicate what investors expect going forward, not to measure the average performance of an investment over an assumed holding period. When referencing realized rates of return in the past, investors consider the equity risk premiums in each year independently, with the arithmetic average of these annual results providing the best estimate of what investors might expect in future periods. *New Regulatory Finance* had this to say:

> The best estimate of expected returns over a given future holding period is the arithmetic average. *Only arithmetic means are correct for forecasting purposes and for estimating the cost of capital.* There is no theoretical or empirical justification for the use of geometric mean rates of returns as a measure of the appropriate discount rate in computing the cost of capital or in computing present values.[86]

Similarly, Morningstar concluded that:

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[86] Roger A. Morin, "New Regulatory Finance" *Public Utilities Reports, Inc.* (2006) at 116-117, (emphasis added).

> For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. … The geometric average is more appropriate for reporting past performance, since it represents the compound average return.[87]

Q66. WHAT DOES THIS IMPLY WITH RESPECT TO DR. WOOLRIDGE'S CAPM ANALYSES?

A66. For a variable series, such as stock returns, the geometric average will <u>always</u> be less than the arithmetic average. Accordingly, Dr. Woolridge's reference to geometric average rates of return provides yet another element of built-in downward bias.

Q67. DR. WOOLRIDGE REFERENCES CAPITAL MARKET TRENDS.[88] IS IT APPROPRIATE TO CONSIDER ANTICIPATED CAPITAL MARKET CHANGES IN APPLYING THE CAPM?

A67. Yes. As discussed in my direct testimony, there is widespread consensus that interest rates will increase materially as the economy strengthens. Accordingly, in addition to the use of current bond yields, I also applied the CAPM and ECAPM approaches based on the forecasted long-term Treasury bond yields developed based on projections published by Value Line, IHS Global Insight and Blue Chip.

D. Other ROE Issues

Q68. PLEASE RESPOND TO DR. WOOLRIDGE'S ARGUMENT THAT THERE IS NO BASIS TO INCLUDE A FLOTATION COST ADJUSTMENT.

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[87] Morningstar, *Ibbotson SBBI 2013 Valuation Yearbook* at 56.

[88] Dr. Woolridge cites "the possibility of higher interest rates" as one factor that he considered in selecting the risk-free rate used in his application of the CAPM. Woolridge Direct at 50.

A68. The need for a flotation cost adjustment to compensate for past equity issues is recognized in the financial literature. In a *Public Utilities Fortnightly* article, for example, Brigham, Aberwald, and Gapenski demonstrated that even if no further stock issues are contemplated, a flotation cost adjustment in all future years is required to keep shareholders whole, and that the flotation cost adjustment must consider total equity, including retained earnings.[89] Similarly, *Regulatory Finance: Utilities' Cost of Capital* contains the following discussion:

> Another controversy is whether the underpricing allowance should still be applied when the utility is not contemplating an imminent common stock issue. Some argue that flotation costs are real and should be recognized in calculating the fair rate of return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument implies that the company has already been compensated for these costs and/or the initial contributed capital was obtained freely, devoid of any flotation costs, which is an unlikely assumption, and certainly not applicable to most utilities. … The flotation cost adjustment cannot be strictly forward-looking unless all past flotation costs associated with past issues have been recovered.[90]

Q69. IS THERE ANY MERIT TO DR. WOOLRIDGE'S ARGUMENT (AT 80) THAT FLOTATION COSTS CAN BE IGNORED BECAUSE THEY CANNOT BE PRECISELY QUANTIFIED?

A69. No. As discussed in my direct testimony,[91] the costs incurred to issue new debt securities are recorded on the financial books of the utility and routinely recovered from customers without controversy. While equity flotation costs are every bit as necessary to supply invested capital, they are not recorded on the utility's books, so there is no precise accounting for these costs. Nevertheless,

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[89] E.F. Brigham, D.A. Aberwald, and L.C. Gapenski, "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly*, May, 2, 1985.
[90] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 335.
[91] McKenzie Direct at 67.

they represent necessary and legitimate expenses incurred to obtain the equity capital invested in utility plant, and unless some provision is made for their recovery, investors will not be offered an opportunity to fully earn their required ROE. The need to consider flotation costs has been documented in the financial literature and Dr. Woolridge's observations provide no basis to ignore issuance costs.

Q70. PLEASE RESPOND TO DR. WOOLRIDGE'S SPECIFIC CRITICISMS OF YOUR FLOTATION COST ADJUSTMENT (AT 80-82).

A70. Flotation cost adjustments are supported by recognized regulatory textbooks and based on research reported in the academic literature, and the lack of a precise accounting of past issuance expenses necessary to raise the common equity capital invested in Kentucky Power provides no basis to ignore a flotation cost adjustment.

Meanwhile, Dr. Woolridge mistakenly claims that a flotation cost adjustment "is necessary to prevent the dilution of the existing shareholders."[92] In fact, a flotation cost adjustment is required in order to allow the utility the opportunity to recover the issuance costs associated with selling common stock. Dr. Woolridge's observation about the level of market-to-book ratios (at 80) may be factually correct, but it has nothing to do with flotation costs. The fact that market prices may be above book value does not alter the fact that a portion of the capital contributed by equity investors is not available to earn a return because it is paid out as flotation costs. Even if the utility is not expected to issue additional common stock, a flotation cost adjustment is necessary to compensate for flotation costs incurred in connection with past issues of common stock.

[92] Woolridge Direct at 80.

Dr. Woolridge's argument (at 81) that flotation costs are not "out-of-pocket expenses" is simply wrong. Dr. Woolridge apparently believes that if investors in past common stock issues had paid the full issuance price directly to the utility and the utility had then paid underwriters' fees by issuing a check to its investment bankers, that flotation cost would be a legitimate expense. Dr. Woolridge's observation merely highlights the absence of an accounting convention to properly accumulate and recover these legitimate and necessary costs.

Q71. HAVE OTHER REGULATORS RECOGNIZED THAT FLOTATION COSTS ARE A LEGITIMATE CONSIDERATION IN ESTABLISHING A FAIR ROE?

A71. Yes. For example, in Docket No. UE-991606 the Washington Utilities and Transportation Commission concluded that a flotation cost adjustment of 25 basis points should be included in the allowed return on equity:

> The Commission also agrees with both Dr. Avera and Dr. Lurito that a 25 basis point markup for flotation costs should be made. This amount compensates the Company for costs incurred from past issues of common stock. Flotation costs incurred in connection with a sale of common stock are not included in a utility's rate base because the portion of gross proceeds that is used to pay these costs is not available to invest in plant and equipment.[93]

Similarly, the South Dakota Public Utilities Commission has recognized the impact of issuance costs, concluding that, "recovery of reasonable flotation costs is appropriate."[94] Another example of a regulator that approves common stock issuance costs is the Mississippi Public Service Commission, which routinely includes a flotation cost adjustment in its Rate Stabilization Adjustment Rider

[93] *Third Supplemental Order*, WUTC Docket No. UE-991606, et al., p. 95 (September 2000).
[94] *Northern States Power Co*, EL11-019, Final Decision and Order at P 22 (2012).

formula.[95] The Public Utilities Regulatory Authority of Connecticut[96] and the Minnesota Public Utilities Commission[97] have also recognized that flotation costs are a legitimate expense worthy of consideration in setting a fair ROE.

Q72. IS THERE ANY MERIT TO DR. WOOLRIDGE'S ARGUMENT (AT 75-77) THAT THE SIZE PREMIUM DOES NOT APPLY TO UTILITY COMMON STOCKS?

A72. No. There is no credible basis to conclude that utilities are immune from the well-documented relationship between smaller size and higher realized rates of return. For example, Dr. Woolridge places significant weight on a 1993 study by Annie Wong,[98] but a closer examination of this research reveals that it is largely inconclusive, and inconsistent with the CAPM. In fact, her results demonstrate no material difference between utilities and industrial firms with respect to size premiums, and her study finds no significant relationship between beta and returns, which contradicts modern portfolio theory and the CAPM. A more recent study published in the Quarterly Review of Economics and Finance reconsiders Wong's evidence and concludes that "new information . . . indicates there is a small firm effect in the utility sector."[99]

Q73. DR. WOOLRIDGE CRITICIZES THE MARKET RETURN THAT YOU USE IN YOUR CAPM AND ECAPM ANALYSES CLAIMING THAT "AS INDICATED IN RECENT RESEARCH, THE LONG-TERM EARNINGS GROWTH RATES OF COMPANIES ARE LIMITED TO THE GROWTH RATE IN GDP" (AT 73). WHAT IS YOUR RESPONSE TO THIS CLAIM?

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[95] *See, e.g.*, Entergy Mississippi, Inc., Formula Rate Plan Rider (Apr. 15, 2015), http://www.entergy-mississippi.com/content/price/tariffs/emi_frp.pdf (last visited Mar. 16, 2017).
[96] *See, e.g.*, Docket No. 14-05-06, Decision (Dec. 17, 2014) at 133-134.
[97] *See, e.g.*, Docket No. E001/GR-10-276, Findings of Fact, Conclusions, and Order at 9.
[98] Woolridge Direct at 75-76.
[99] Thomas M. Zepp, "Utility stocks and the size effect—revisited," Quarterly Review of Economics and Finance, 43 (2003) 578-582.

A73. The use of long-term GDP growth as an upper bound to the DCF growth rate is not justified. There are several reasons why GDP growth is not relevant in applying the DCF model:

- Practical application of the DCF model does not require a long-term growth estimate over a horizon of 25 years and beyond – it requires a growth estimate that matches investors' expectations.
- My evidence supports the conclusion that investors do not reference long-term GDP growth in evaluating expectations for individual common stocks.
- The theoretical proposition that growth rates for all firms converge to overall growth in the economy over the very long horizon does not guide investors' views, and growth rates for utilities can and do exceed GDP growth.

In short, there is no demonstrable evidence that investors look to GDP growth rates in the far distant future in assessing their expectations for common stocks. And while the theoretical assumptions underlying this method contemplate an infinite stream of cash flows, this is simply at odds with the practical circumstances in which real-world investors operate.

Q74. THE DCF MODEL IS BASED ON THE ASSUMPTION OF AN INFINITE STREAM OF CASH FLOWS. WHY WOULDN'T A TRANSITION TO GDP GROWTH MAKE SENSE?

A74. First, this view confuses the theory underlying the DCF model with the practicalities of its application in the real world. While the notion of long-term growth should presumably relate to the specific firm at issue, or at the very least to a particular industry, there are no long-term growth projections available for the companies in electric utility industry, or the broader market, as a whole. By applying the DCF model in a way that is inconsistent with the information that is available to investors and how they use it, the use of GDP growth places the theoretical assumptions of a financial model ahead of investor behavior. The only relevant growth rate is the growth rate used by investors. Investors do not have clarity to see far into the future, and there is little to no evidence to suggest that investors share the view that growth in GDP must be considered a limit on earnings growth over the long-term.

Second, arguments concerning the "sustainability" of any individual growth rate for a single firm in the S&P 500 miss the point. The growth rate underlying the market cost of equity represents a weighted average of the expectations for the dividend paying firms in the S&P 500. Within this large group of firms, growth expectations for some firms may be extremely anemic, while projections for other firms are considerably more optimistic. In addition, growth rates for one company may moderate over time, while for others they may increase. Finally, the composition of the S&P 500 is not static. As a result, formerly successful firms are supplanted by new firms with potential for high growth (*e.g.*, Sears is supplanted by Amazon, or Blockbuster is supplanted by Netflix). On balance, however, the growth rates used in my CAPM study are representative of the consensus expectations for the dividend paying firms in the S&P 500 Index as a whole. This contradicts Dr. Woolridge's position that investors' growth expectations should be constrained by a threshold tied to GDP.

Q75. ARE LONG-TERM GDP GROWTH RATES COMMONLY REFERENCED AS A DIRECT GUIDE TO FUTURE EXPECTATIONS FOR SPECIFIC FIRMS?

A75. No. Certainly investors consider broad secular trends in economic activity as one foundation for their expectations for a particular industry or firm. But the idea that investment advisory services view GDP growth as a direct guide to long-term expectations for a particular firm – much less every firm in an entire industry – is not borne out by evidence.

In contrast to this notion, in the financial media one observes many references to three-to-five year EPS growth forecasts for individual companies and very few references to long-term GDP forecasts. Long-term GDP growth rates are simply not discussed within the context of establishing investors' expectations for individual firms. For example, Value Line reports are routinely relied on as an important guide to apply the DCF model.[100] But despite Dr. Woolridge's suggestion that GDP has a fundamental role in shaping investors' growth estimates, Value Line does not even mention trends in GDP in its evaluation of the firms in the electric utility industry, for example. Value Line's singleness of purpose is to inform investors of the pertinent factors that impact future expectations specific to each of the common stocks it covers. If the trajectory of GDP growth out to the year 2040 and beyond had direct relevance in investors' evaluation of common stocks, it would be logical to assume that Value Line or other securities analysts would give at least passing mention to this fact. But they do not.

Q76. HOW MUCH CONFIDENCE WOULD INVESTORS BE LIKELY TO PLACE ON LONG-TERM GDP PROJECTIONS?

A76. Very little. Investors understand the complexities and inherent inaccuracies involved in forecasting, and that such uncertainties are significantly compounded for a long-term time horizon. Consider the example of IHS Global Insight, which is perhaps the world's foremost econometric forecasting service. IHS Global Insight currently publishes GDP projections for the U.S. economy for the next thirty years, but for other important economic variables (*e.g.*, bond yields) their forecast simply holds projected values constant after a five-year horizon.

[100] As noted in *New Regulatory Finance*, "Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors." Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 71.

Q77. DID THE FOUNDER OF THE DCF APPROACH SUPPORT THE USE OF A GENERIC LONG-TERM GROWTH RATE, SUCH AS THE GDP GROWTH?

A77. No. Professor Myron J. Gordon, who originated the DCF approach, concluded that reference to a generic long-term growth rate, such as Dr. Woolridge advocates, was unsupported.[101] More specifically, Dr. Gordon concluded that any assumption of a single time horizon for a transition to a generic long-term growth rate was highly questionable and failed to reduce error in DCF estimates. Instead, Dr. Gordon specifically recognized that, "it is the growth that investors expect that should be used" in applying the DCF model, and he concluded:

> A number of considerations suggest that investors may, in fact, use earnings growth as a measure of expected future growth."[102]

Similarly, a recent study reported in the *Journal of Investing* determined that there is no correlation between stock market returns or earnings growth and GDP, suggesting that investors' expectations built into observable share prices are driven by valuation measures, and not expected economic growth.[103]

Q78. PLEASE SUMMARIZE YOUR OBJECTION TO DR. WOOLRIDGE'S REFERENCE TO GDP GROWTH RATES IN YOUR MARKET DCF ANALYSIS?

A78. Dr. Woolridge presents no meaningful information to suggest that earnings growth rates of companies are limited to the growth rate in GDP. There is no link between Dr. Woolridge's GDP growth rate ceiling and the actual expectations of investors in the capital markets, which are the determining factor in any analysis of a fair ROE

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[101] Myron J. Gordon, "The Cost of Capital to a Public Utility," *MSU Public Utilities Studies* (1974) at 100-01.
[102] *Id.* at 89.
[103] Joachim Klement, "What's Growth Got to Do with It? Equity Returns and Economic Growth," *Journal of Investing,* Vol. 24, No. 2 (Summer 2015): 74:78.

Q79. DR. WOOLRIDGE SAYS THAT YOUR EXPECTED EARNINGS APPROACH IS FLAWED DUE TO UNREGULATED OPERATIONS OF THE PROXY GROUPS AND DUE TO DIFFERENCES IN M/B.[104] DO YOU AGREE WITH THIS ASSESSMENT?

A79. Not at all. The appeal of the expected earnings approach is that it does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior. While companies in the proxy groups may have varying levels of unregulated operations, they have all been judged to be of comparable overall risk and this condition overrides specific differences between them.

Again, market-to-book ratios have no place in applying the expected earnings approach. Traditional applications of the expected earnings approach do not involve a M/B adjustment. Nor is such an adjustment recommended in recognized texts such as *New Regulatory Finance.*[105] FERC has also rejected similar arguments raised by Dr. Woolridge, finding that, "considering market-to-book ratios in an expected earnings study is inconsistent with the purpose of the comparable earnings model."[106]

Q80. DR. WOOLRIDGE CRITICIZES YOUR USE OF A LOW-RISK GROUP OF NON-UTILITY COMPANIES AS AN ROE CHECK OF REASONABLENESS (AT 83). ARE HIS CRITICISMS JUSTIFIED?

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[104] Woolridge Direct at 82-83.
[105] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006).
[106] *Martha Coakely, et al.*, Opinion No. 531-B, 150 FERC ¶ 61,165 at P 132 (2015).

A80. Not at all. The implication that an estimate of the required return for firms in the competitive sector of the economy is not useful in determining the appropriate return to be allowed for rate-setting purposes is wrong and inconsistent with reality, investor behavior, and the *Bluefield* and *Hope* decisions. In fact, returns in the competitive sector of the economy form the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets.

The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives, which include all other securities available in the stock, bond or money markets. Consistent with this view, Dr. Woolridge noted the Supreme Court's economic standards and concluded that the fair rate of return on equity should be "comparable to returns investors expect to earn on other investments of similar risk."[107] Clearly the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment and there are a plethora of other "investments of comparable risk" available to investors beyond those in the utility industry.

True enough, utilities are sheltered from competition, but they undertake other obligations and lose the ability to set their own prices and decide when to exit a market. The Supreme Court has recognized that it is the degree of risk, not the nature of the business, which is relevant in evaluating an allowed ROE for a utility.[108]

Q81. DOES THE MARCH 10, 2015 REPORT FROM MOODY'S CITED BY DR. WOOLRIDGE (AT 62) SUPPORT A DRAMATIC DROP IN THE COMPANY'S ALLOWED RETURN FROM THOSE CURRENTLY BEING AUTHORIZED FOR COMPARABLE UTILITIES?

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[107] Woolridge Direct at 2-3.

[108] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

A81. No. The Moody's report discusses only very generally the impacts of a "slow" decline in utilities' authorized ROEs, and how regulators may lower authorized ROEs without harming utilities' cash flow, such as by "targeting depreciation." The Moody's report does not identify a cost of equity for regulated utilities at all, much less discuss a cost of equity for Kentucky Power, which is not even mentioned in the report. In my view, the Moody's report offers no relevant information about a fair ROE in this proceeding, and it certainly does not support the values recommended by the ROE Witnesses.

Q82. DOES THE MOODY'S REPORT INDICATE THAT EQUITY INVESTORS WOULD NOT BE CONCERNED IF THE COMPANY'S ROE WERE LOWERED TO THE LEVELS RECOMMENDED BY THE ROE WITNESSES?

A82. No. I believe no one can make such an inference based on this report. First, it is important to note that the primary mission of credit rating agencies like Moody's is to provide *debt holders* with an accurate benchmark of the relative risks of default associated with long-term bonds and other debt securities. As the report cited by Dr. Woolridge clearly observes, Moody's evaluation is premised "from the perspective of a probability of a default and expected loss given default."[109]

Bondholders, the constituency represented by Moody's, do not share in a utility's net income or profits. As a result, Moody's focus is on cash flows, which are viewed "as a more important rating driver."[110] On the other hand, *equity investors* are intensely focused on the ability of the utility to generate earnings, dividends and growth. This difference in the characteristics and priorities between debt and equity securities gives rise to the considerable distinction in the

[109] Moody's Investors Service, "Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles," *Sector In-Depth* (March 2015).

[110] *Id.* Moody's further clarified that it defines credit risk "as the risk that an entity will not meet its contractual, financial obligations as they come due and any estimated financial loss in the event of default. Credit ratings do not address any other risk …."

risks faced by debt holders and equity investors. While a moderate and gradual downturn in ROEs may not pose an immediate threat to the cash flow protection underlying the credit ratings on a utility's debt, it would have an immediate, negative impact on returns to common stockholders.

Q83. DR. WOOLRIDGE CLAIMS THAT RECENT TRENDS IN ELECTRIC UTILITY BOND RATING ACTIONS AND HISTORICAL EARNED RETURNS SUPPORT HIS ROE RECOMMENDATION.[111] DO GENERAL TRENDS IN UTILITY CREDIT RATINGS OR HISTORICAL EARNED RETURNS PROVIDE ANY JUSTIFICATION FOR AN 8.6% ROE FOR KENTUCKY POWER IN THIS CASE?

A83. No. The factors that lead to a utility company's bond rating depend on a host of considerations, including the nature of the regulatory environment, diversity and health of the service area economy, availability of supportive recovery mechanisms, weather or geographical challenges, and so on. Thus, there is no direct connection between the general pattern of credit ratings actions for other utilities in the industry and the specific determination of a fair ROE for Kentucky Power in this case. In fact, the wide disparity between Dr. Woolridge's recommendations and the benchmarks discussed earlier in my testimony indicate that an 8.6% ROE would be entirely inconsistent with the factual circumstances leading to the pattern of credit ratings actions displayed in Dr. Woolridge's Figure 6.

Moreover, Dr. Woolridge's analysis of historical earned returns is distorted and provides no useful guidance as to investors' future expectations or requirements. In his analysis, Dr. Woolridge says the "median earned ROE for the year 2016 for the companies in the Electric and McKenzie are 9.3% and 9.4%,

[111] Woolridge Direct at 61.

respectively, as shown in Exhibit JRW-4."[112] A detailed review of Exhibit JRW-4 casts significant doubt on the usefulness of these values, however. Included in the "Return on Equity" column for Dr. Woolridge's Electric Proxy Group are returns of -66.20% (FirstEnergy), -6.73% (Entergy), 3.16% (WEC Energy), and several other values in the 3%-5% range. In the McKenzie Proxy Group panel, there are five "Return on Equity" values in the 2%-5% range. Because these values clearly do not provide a reasonable guide to investors' return requirements, Dr. Woolridge's analysis in this area is not reliable and should be ignored.

III. RESPONSE TO MR. BAUDINO

Q84. HOW DID MR. BAUDINO ARRIVE AT HIS RECOMMENDED COST OF EQUITY?

A84. Mr. Baudino recommended an ROE of 8.85% based exclusively on his application of the constant growth DCF model. He included a CAPM analysis for "additional information" but did not incorporate the results of the CAPM directly in his recommendation.[113] Mr. Baudino applied these methods to the same proxy group I did, but for three utilities that he excluded due to perceived data issues.[114]

Q85. WHAT IS YOUR ASSESSMENT OF MR. BAUDINO'S ROE TESTIMONY AND RECOMMENDATION?

A85. Mr. Baudino's recommendation is not realistic. Several specific factors detract from his analysis. First and foremost, Mr. Baudino fails to apply sufficient checks of reasonableness to test his DCF results. His CAPM approach is significantly flawed and he ignores other accepted benchmarks such as the utility risk premium, expected earnings, and ECAPM methodologies, or a review of non-

[112] *Id.*
[113] Baudino Direct at 3.
[114] Mr. Baudino eliminated AVANGRID, Emera, and Fortis.

utility outcomes. Had Mr. Baudino employed these other approaches, he would have seen that his DCF-based result was not reasonable.

A. Discounted Cash Flow Model

Q86. WHAT ARE THE SPECIFIC DEFECTS THAT YOU HAVE IDENTIFIED IN MR. BAUDINO'S DCF ANALYSIS?

A86. While Mr. Baudino's application of the DCF model is fairly straightforward, there are several problems with his approach. First, I do not agree with his decision to eliminate three companies from my proxy group. Second, he repeats the mistakes made by Dr. Woolridge in giving weight to DPS growth rates and in conducting an incomplete "br" growth study. Finally, his DCF results are based on a decision to average all individual growth rates together and compute a single ROE estimate for each growth rate source. This approach masks the presence of extreme data and biases his results downward.

Q87. PLEASE ELABORATE ON YOUR DISAGREEMENT WITH MR. BAUDINO'S PROXY GROUP?

A87. I do not agree with Mr. Baudino's decision to exclude three eligible utilities from my proxy group in forming his sample. He rejects AVANGRID because "there is not enough Value Line information to include this company in the proxy group."[115] AVANGRID is a major utility with a market capitalization of $15 billion. Its subsidiaries are well known to investors and include Central Maine Power, New York State Electric & Gas, Rochester Gas and Electric, and United Illuminating. AVANGRID has a stable dividend policy, and while Value Line may not currently report projected growth rates, this data is available from comparable sources such as Zacks and IBES, which were both relied on by Mr. Baudino. It would have been easy to substitute "No Meaningful Figure" for

[115] Baudino Direct at 17-18.

AVANGRID's Value Line growth rate and continue the DCF calculation with the other two growth rate sources. Indeed, this is precisely the approach taken by Mr. Baudino in the case of PPL Corporation which, like AVANGRID, lacked a Value Line projected growth rate. For PPL Corporation, Mr. Baudino input "NMF" for its missing Value Line rate and continued the DCF process with growth rates from Zacks and IBES.[116]

Mr. Baudino excludes Emera, Inc. because, due to its 2016 acquisition of TECO Energy, it "is a different company today from what it was in 2015 and its expected short-term growth in dividends and revenues reflect this."[117] This viewpoint is mistaken on many levels. First, the acquisition of TECO Energy was completed on July 1, 2016, over 15 months ago. All related impacts are fully incorporated in the forecasts and projections of investor information services, including Value Line, Zacks, and IBES. Of course, Emera is not the same company it was prior to the merger but that is not the point; the point is that investors are fully aware of the changes it has undergone and all relevant data, going forward, reflects these impacts. This circumstance is no different than that facing Southern Company, which coincidentally, also completed a merger on July 1, 2016 (with AGL Resources). Southern Company is also not the same company it was in 2015, but exercising a clear double standard, Mr. Baudino left them in his proxy group.[118]

Mr. Baudino cites a sizeable increase in Emera's revenues following the TECO Energy acquisition and implies that this increase is short-term in nature and not reflective of long-term conditions.[119] Again, Mr. Baudino misses the point. Of course, revenues will increase as the new company is added to existing

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[116] Exhibit RAB-4, page 1.
[117] Baudino Direct at 18.
[118]
[119] *Id.*

operations, but so will expenses and investment. Mr. Baudino's focus on increased revenues is misguided and misleading; the proper focus is on net earnings and, in this light, Emera is clearly not an outlier. The 8.5% earnings growth rate for Emera cited (and excluded) by Mr. Baudino is in line with other rates he considered acceptable: 9.5% for NextEra Energy; 8.5% for Dominion Energy; and 8.5% and 8.0% for Sempra Energy.[120]

Finally, Mr. Baudino eliminates Fortis, Inc. from his proxy group stating that, due to its 2016 acquisition of ITC Holdings, its revenues and total capital will increase significantly.[121] My rebuttal to Mr. Baudino's misleading claims are the same here as above. Simple arithmetic tells us that revenues and investment will increase due to an acquisition, but it is the forward-looking impact on net earnings (after increased expenses and costs are also considered) that is most important to investors. As noted above, the 9.0% projected earnings growth rate for Fortis is not out of line with other rates accepted by Mr. Baudino. In removing AVANGRID, Emera, and Fortis from his proxy group, Mr. Baudino is inconsistent in the application of his selection criteria. His decision appears to be based more on the fact that the rates for the three excluded companies are at the upper end of the growth rate range. Such an approach is capricious and unfair and should be rejected.

Q88. MR. BAUDINO CONSIDERED DIVIDEND DATA IN THE GROWTH RATE PORTION OF HIS DCF ANALYSIS. IS THIS APPROACH LIKELY TO DISTORT HIS DCF RESULTS?

A88. Yes. As discussed earlier in my response to Dr. Woolridge, growth rates in DPS are not likely to provide a meaningful guide to investors' current growth expectations. The importance of earnings in evaluating investors' expectations

[120] Exhibit RAB-4.
[121] Baudino Direct at 18.

and requirements is well accepted in the investment community, and surveys of analytical techniques relied on by professional analysts indicate that growth in EPS is far more influential than trends in DPS.

Q89. MR. BAUDINO ALSO PRESENTED SUSTAINABLE, "BR" GROWTH RATES (EXHIBIT RAB-4, P. 1). SHOULD THE KPSC PLACE ANY WEIGHT ON THESE VALUES?

A89. No. In the same way as I explained earlier in my rebuttal to Dr. Woolridge, Mr. Baudino's "br" growth rates are downward biased because he failed to recognize the impact of year-end returns reported by Value Line. Furthermore, like Dr. Woolridge, Mr. Baudino failed to consider the impact of additional issuances of common stock in his analyses of the sustainable growth rate. Because Mr. Baudino ignored these adjustments, his internal, "br" growth rates are distorted and should be ignored. In fact, Mr. Baudino himself did not rely on sustainable "br" growth rates in his final DCF application.[122]

Q90. ARE THERE OTHER PROBLEMS WITH MR. BAUDINO'S DCF ANALYSIS?

A90. Yes. Another flaw in Mr. Baudino's DCF analyses was his decision to average all individual growth rates and then compute a single DCF estimate for each growth rate source. Each growth rate represents a stand-alone estimate of investors' future expectations, and each value should be evaluated on its own merits. The fact that an average of several growth rates might produce a DCF estimate that could be considered reasonable does not absolve the need to evaluate each underlying growth rate separately.

For example, consider a utility with a dividend yield of 3.5% and three hypothetical growth estimates of 0.0%, 6.5%, and 14.0%. Under Mr. Baudino's

[122] Baudino Direct at 21.

method, the DCF estimate would be computed by adding the 6.8% average of the three individual growth rates to the dividend yield, resulting in a cost of equity estimate of 10.3%. The problem with this method is that it disguises the fact that two of the underlying growth rates – 0.0% and 14.0% – do not provide a meaningful guide to investors' expectations. Rather than averaging the good with the bad, each implied cost of equity estimate (in this example, 3.5%, 10.0%, and 17.5%) should be evaluated on a stand-alone basis.[123] Mr. Baudino simply calculated the average of the individual growth rates with no consideration for the reasonableness of the underlying data. Because Mr. Baudino failed to perform this essential step, his DCF analysis included individual growth rates that do not reflect investors' expectations. Therefore, his results are biased downward.

Q91. CAN YOU SHOW THE DOWNWARD BIAS IN MR. BAUDINO'S CONSTANT GROWTH ANALYSIS?

A91. Yes. For example, Mr. Baudino reports a First Call/IBES growth rate of 0.04% for PPL Corporation.[124] Combining this growth rate with PPL's corresponding dividend yield of 4.13% results in a cost of equity estimate of 4.17%. Similarly, combining Public Service Enterprise Group's First Call/IBES growth rate of 0.57% with its dividend yield of 3.86% produces an ROE estimate of 4.43%. These implied costs of equity are less than, or do not sufficiently exceed current and projected yields on public utility bonds. As a result, these illogical growth measures should have been removed from Mr. Baudino's constant growth DCF analysis.

[123] The implied cost of equity estimates are calculated as the sum of the dividend yield (3.5%) and the respective growth rates (0.0%, 6.5%, and 14.0%).

[124] Exhibit RAB-4.

B. Capital Asset Pricing Model

Q92. WHAT IS THE BIGGEST ISSUE YOU HAVE WITH MR. BAUDINO'S CAPM ANALYSIS?

A92. Mr. Baudino's CAPM results are simply so low they should be rejected outright. Results from his current market premium CAPM range from 6.90% to 7.15%; while results from his historic market premium model range from 5.99% to 7.32%.[125] These outcomes are not legitimate ROE estimates.

Q93. CAN YOU IDENTIFY DEFECTS IN MR. BAUDINO'S CAPM METHODOLOGY?

A93. Yes. For instance, Mr. Baudino bases his risk-free rate on 5-year and 20-year Treasury securities when it is more appropriate to rely on the longer-term 30-year Treasury bond. As Dr. Woolridge states:

> The yield on long-term U.S. Treasury bonds has usually been viewed as the risk-free rate of interest in the CAPM. The yield on long-term U.S. Treasury bonds, in turn, has been considered to be the yield on U.S. Treasury bonds with 30-year maturities.[126]

Mr. Baudino's reliance on government debt with shorter maturities serves to unfairly deflate his CAPM results.

Next, Mr. Baudino attempts to develop a forecasted market return, which is a laudable goal. However, instead of simply relying on Value Line earnings forecasts, he introduces book value growth into the process. As I describe above, growth in EPS is the most influential driver of investors' long-term expectations. Adding book value growth only serves to depress his market return estimate, especially given that the earnings growth rate is 10.5% and the book value growth

[125] Baudino Direct, Table 3, at 29.
[126] Woolridge Direct at 49.

rate is 7.5%.[127] If Mr. Baudino had left out the book value component, his market return projection would have been much more reasonable, at 11.37%.[128]

Q94. IS THERE ANOTHER SERIOUS PROBLEM ASSOCIATED WITH CAPM ANALYSIS DEVELOPED BY MR. BAUDINO?

A94. Yes, as I mentioned earlier in my response to Dr. Woolridge, the CAPM is an *ex-ante*, or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using data that reflect the expectations of actual investors in the market. Mr. Baudino has recognized that, "There is no real support for the proposition that an unchanging, mechanically applied historical risk premium is representative of current investor expectations and return requirements."[129]

Nevertheless, at least part of Mr. Baudino's application of the CAPM method was based on *historical* – not projected – rates of return (Exhibit RAB-6). Because Mr. Baudino's backward-looking analysis ignores the returns investors are currently requiring in the capital markets, the resulting CAPM estimates fall woefully short of investors' current required rate of return.

Q95. IS THERE ANY MERIT TO MR. BAUDINO'S ARGUMENT (AT 39) THAT YOUR ANALYSIS OF THE MARKET RATE OF RETURN SHOULD NOT HAVE BEEN LIMITED SOLELY TO THE DIVIDEND PAYING FIRMS IN THE S&P 500?

A95. No. As Mr. Baudino recognized (at 15-16), under the constant growth form of the DCF model, investors' required rate of return is computed as the sum of the dividend yield over the coming year plus investors' long-term growth expectations. Because the dividend yield is a key component in applying the DCF

[127] Exhibit RAB-5, page 2.
[128] *Id.* Earnings growth of 10.50% plus the average dividend yield of 0.87% is 11.37%.
[129] *Direct Testimony and Exhibits of Richard A. Baudino*, Case No. 2012-00221 & Case No. 2012-00222, at p. 28 (October 2012).

model, its usefulness is hampered for firms that do not pay common dividends. Accordingly, my DCF analysis of the market rate of return properly focused on the dividend paying firms included in the S&P 500.

Meanwhile, Mr. Baudino (at 25-26) predicated his DCF analysis of the market rate of return on the companies followed by Value Line. Of the U.S. firms in Value Line, amounting to approximately 1,500 companies, approximately 500 do not pay common dividends. In other words, one-third of the companies that underpin Mr. Baudino's DCF analysis do not have the data necessary to implement this approach. Further, many of these firms are relatively small and lack a meaningful operating history. As a result, there is also greater uncertainty associated with estimating the future growth expectations that are central to the application of the DCF method. Taken together, these factors impugn the reliability of Mr. Baudino's market risk premium and confirm my decision to restrict the analysis to the established, dividend paying firms in the S&P 500.

Q96. DO THE ARGUMENTS ADVANCED BY MR. BAUDINO UNDERMINE THE NEED FOR A SIZE ADJUSTMENT AS PART OF THE CAPM AND ECAPM ANALYSES?

A96. No. Mr. Baudino simply observes that the average beta associated with the lower size deciles examined by Duff & Phelps is greater than the average his proxy group.[130] While I do not dispute the observation, it has no relevance whatsoever to the implications of Duff & Phelps' findings regarding the impact of firm size. The fact that the average beta for smaller size deciles is greater than for 1.00 says nothing about the range of individual beta values underlying this average. Moreover, the size premiums are beta adjusted; meaning that the risk impact of beta values (whether higher or lower than Mr. Baudino's proxy group average)

[130] Baudino Direct at 40.

have been removed. While the size premiums reported by Duff & Phelps were not estimated on an industry-by-industry basis, this provides no basis to ignore this relationship in estimating the cost of equity for utilities. Utilities are included in the companies used by Duff & Phelps to quantify the size premium, and firm size has important practical implications with respect to the risks faced by investors in the utility industry. As Duff & Phelps concluded*:*

> Despite many criticisms of the size effect, it continues to be observed in data sources. Further, observation of the size effect is consistent with a modification of the pure CAPM. Studies have shown the limitations of beta as a sole measure of risk. The size premium is an empirically derived correction to the pure CAPM.[131]

C. Other ROE Issues

Q97. DOES MR. BAUDINO ADVANCE ANY CREDIBLE CRITICISM OF YOUR RISK PREMIUM APPROACH?

A97. No. Mr. Baudino's only observation is that the risk premium method is "imprecise."[132] Of course, this "criticism" applies equally to every model of investor behavior that is used to estimate required returns, including the DCF approach that formed the sole basis for Mr. Baudino's recommendation. The DCF method is only one theoretical approach to gain insight into the return investors require, which is unobservable. While the tautology of the DCF model boils this determination down to the familiar dividend yield and growth rate components, this masks the underlying complexities that accompany any attempt to distill every facet of investors' expectations into a single growth estimate. Mr. Baudino's claim that the DCF is "far more reliable and accurate" is unsubstantiated. While the DCF model is a recognized approach to estimating the cost of equity, it is not without shortcomings and does not otherwise eliminate the

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[131] *Duff & Phelps*, "2016 Valuation Handbook," (2016) at 4-27.
[132] Baudino Direct at 41.

need to examine the results of other methods. As the Indiana Utility Regulatory Commission noted, for example:

> There are three principal reasons for our unwillingness to place a great deal of weight on the results of any DCF analysis. One is . . . the failure of the DCF model to conform to reality. The second is the undeniable fact that rarely if ever do two expert witnesses agree on the terms of a DCF equation for the same utility – for example, as we shall see in more detail below, projections of future dividend cash flow and anticipated price appreciation of the stock can vary widely. And, the third reason is that the unadjusted DCF result is almost always well below what any informed financial analysis would regard as defensible, and therefore require an upward adjustment based largely on the expert witness's judgment. In these circumstances, we find it difficult to regard the results of a DCF computation as any more than suggestive.[133]

Q98. MR. BAUDINO ARGUES THAT THE USE OF FORECASTED INTEREST RATES IN THE ROE ESTIMATION PROCESS IS A PROBLEM BECAUSE THE PROJECTIONS MAY NOT MATERIALIZE.[134] DO YOU AGREE WITH THIS POSITION?

A98. No. As I stated in my Direct Testimony and earlier in this testimony, whether the projections of various services may be proven optimistic or pessimistic in hindsight, is irrelevant in assessing expected interest rates and how they might influence the Company's allowed ROE.

Q99. HOW DO YOU RESPOND TO MR. BAUDINO'S DISCUSSION OF YOUR NON-UTILITY ANALYSIS?

A99. Mr. Baudino makes the statement that utilities "have protected markets, e.g., service territories, and may increase the prices they charge in the face of falling demand or loss of customers."[135] Based on this, Mr. Baudino summarily concluded, "Obviously, the non-utility companies face risks that a lower risk

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[133] *Ind. Michigan Power Co.*, Cause No. 38728, 116 PUR4th, 1, 17-18 (IURC 8/24/1990).
[134] Baudino Direct at 32-35.
[135] *Id.* at 43.

electric company like KPC does not face." In fact, however, investors are quite aware that utilities are not guaranteed recovery of reasonable and necessary costs incurred to provide service and that there are many instances in which utilities are unable to increase rates to fully recoup reasonable and necessary costs, resulting in an inability to earn the allowed ROE – and potentially, even bankruptcy. The simple observation that a firm operates in non-utility businesses says nothing at all about the overall investment risks perceived by investors, which is the very basis for a fair rate of return.

Q100. DOES OBJECTIVE EVIDENCE SUPPORT MR. BAUDINO'S RISK ARGUMENTS?

A100. No. My direct testimony noted that the average corporate credit rating for the Non-Utility Group of "A-" is <u>higher</u> than the "BBB+" average for the Utility Group and the Company.[136] This assessment is confirmed by the review of financial strength values and other objective indicators of investment risk presented in Table 7 to my direct testimony, which consider the impact of competition and market share and demonstrated that, if anything, the Non-Utility Group could be considered <u>less</u> risky in the minds of investors than the common stocks of the proxy group of utilities.

In other words, the objective risk measures specifically cited by Mr. Baudino as being relevant indicators of overall investment risks contradict his assertions regarding the relative risk of the Non-Utility Group. Similarly, Mr. Baudino testified that bond ratings reflect a detailed and comprehensive analysis of the key factors contributing to a firm's overall investment risk, concluding, "Bond and credit ratings are tools that investors use to assess the risk comparability of firms."[137]

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[136] McKenzie Direct, Table 7, at 75.
[137] Baudino Direct at 15.

A101. Contradicting Mr. Baudino's unsupported assertion (at 43) that the companies in my Non-Utility Group "face risks that a lower risk electric company like KPC does not face,"

Q101. MR. BAUDINO SAYS THAT AN ADJUSTMENT TO ACCOUNT FOR FLOTATION COSTS IS NOT NECESSARY SINCE "FLOTATION COSTS ARE ALREADY ACCOUNTED FOR IN CURRENT STOCK PRICES."[138] IS THIS A VALID ASSUMPTION?

A102. No. Mr. Baudino's position is akin to arguing that it is not necessary to reflect the utility's entire reasonable and necessary O&M expense in revenue requirements because such actions would be "accounted for" in the stock price. Flotation costs are legitimate expenses and unless a discrete adjustment is made to recognize them, they will not be recovered in the rate setting process.

IV. RESPONSE TO MR. TILLMAN

Q102. DID MR. TILLMAN CONDUCT AN INDEPENDENT EVALUATION OF A FAIR ROE FOR THE COMPANIES?

A103. No. Mr. Tillman did not conduct any analyses of the cost of equity. His testimony was limited to a presentation of selected data concerning previously authorized ROEs. Based on this limited review, Mr. Tillman expressed his concern that a 10.31% ROE for the Company is "excessive."[139]

Q103. DO YOU AGREE WITH MR. TILLMAN THAT ALLOWED ROES PROVIDE ONE BENCHMARK WORTHY OF CONSIDERATION IN THE COMMISSION'S EVALUATION?

[138] Baudino Direct at 43.
[139] Tillman Direct at 7.

A104. Yes, I do. Importantly, however, such comparisons of allowed ROEs are only one consideration. While this data can be useful in the KPSC's deliberations, it is not a substitute for the detailed analyses presented in my direct testimony.

Q104. DOES THE DATA PRESENTED BY MR. TILLMAN CONFIRM YOUR CONCLUSION THAT DR. WOOLRIDGE'S AND MR. BAUDINO'S RECOMMENDATIONS ARE TOO LOW?

A105. Yes. Mr. Tillman cites an average allowed ROE for vertically integrated utilities of 9.79% for 2014 through the present,[140] which confirms my earlier conclusion that the 8.60% and 8.85% ROE recommendations of the ROE Witnesses fall well below average returns authorized for other utilities, and are insufficient to meet the requirements of regulatory standards.

Q105. FROM YOUR POSITION AS A REGULATORY FINANCIAL ANALYST, WHAT DO YOU MAKE OF MR. TILLMAN'S ADMONITION (AT 7) TO CONSIDER CUSTOMER IMPACTS WHEN ESTABLISHING A FAIR ROE?

A106. First, it is important to note that the determination of the ROE is made by investors in the capital markets, and is not predicated on any notion of costs or savings to customers. The U.S. Supreme Court's regulatory standards embodied in the *Hope* and *Bluefield* decisions represent a balance between the interests of customers and investors, by setting forth the guidelines as to a fair ROE. Meanwhile, Mr. Tillman wrongly suggests that a lower ROE is *per se* in customers' benefit. This is not the case. While a downward-biased ROE may provide the illusion of customer "savings" in the form of a lower revenue requirement in the short-term, the long-term impact of an inadequate ROE can be injurious to customers and the Kentucky economy.

[140] *Id.* at 11.

As discussed earlier, there is a very real connection between the ROE and the availability of capital, and Mr. Tillman ignores the negative impact that an inadequate ROE would have on investment. The ROE is the primary signal to investors, not only with respect to attracting new capital investment, but also in supporting existing utility operations. If the utility is unable to offer a competitive ROE, existing shareholders will suffer a capital loss as investors take advantage of other, more favorable opportunities, and the utility's stock price would fall. Moreover, as investors' confidence is undermined, the ability of utilities to access equity capital markets and expand investment will suffer. While the Company would undoubtedly continue to meet their service obligations to customers, a downward-biased ROE would send an unmistakable signal to the investment community as they consider whether to commit capital in Kentucky, and at what cost.

Q106. DO YOU AGREE WITH MR. TILLMAN'S ASSESSMENT REGARDING THE IMPACT OF CONSTRUCTION WORK IN PROGRESS ("CWIP")?

A107. No. While Mr. Tillman attempts to distinguish the risks of the Company based on the opportunity to include CWIP in rate base, this is hardly novel or unique to the Company and has been widely utilized since the 1970s to address the impact of construction costs on utilities' financial integrity.

Q107. WHAT IS CWIP?

A108. CWIP consists of investment in facilities built to meet service obligations that are not yet physically providing service. For an electric utility, CWIP can be sizeable as a result of the capital intensity of utility infrastructure investment and the extended construction periods involved with these facilities. During the construction phase, the utility must pay capital carrying costs (interest, dividends, etc.) on the investment in new facilities. These capital carrying costs are typically accrued for future recovery in the form of Allowance for Funds Used During

Construction ("AFUDC"), which is included in rate base at the time the facilities are placed in service. Alternatively, regulators may allow CWIP to be included in rate base and thus permit the utility an opportunity to recover these capital costs through current rates.

Q108. WHAT IS THE FINANCIAL IMPACT OF CWIP?

A109. If CWIP is included in rate base, the utility's revenue requirements are increased by the capital costs associated with the new construction. As a result, since customers pay the capital carrying costs of CWIP in current rates, capitalized AFUDC is not added to plant cost. From the utility's standpoint, current cash flow is higher than it would have been otherwise. As a result, including CWIP in rate base improves a utility's cash flow and increases revenue requirements during the construction phase; however, this increase is offset in the future by the lower rate base that results from eliminating capitalized AFUDC.

While the level of a utility's earnings does not differ dramatically depending on whether or not CWIP is included in rate base, the cash flow implications can be significant, especially in the case of a large construction program. To finance the costs of construction, utilities such as the Company must obtain financing in the form of common equity or long-term debt. If CWIP is not included in rate base, no cash is generated from current rates to meet the interest and dividend payments associated with these securities, which in turn must be financed.

The uncertainties that investors associate with cost deferrals and a deterioration in earnings quality are significant and many of the key indicators relied on by securities analysts and bond rating agencies focus on measures of cash flow. As a result, the greater risk associated with higher levels of non-cash earnings (*i.e.*, AFUDC) would ultimately be reflected in higher rates of return required by investors. Investors recognize that including CWIP in rate base is an important tool that supports the utility's financial integrity and attenuates some of the financial risks associated with new infrastructure investment.

Q109. IS THERE ANY MERIT TO MR. TILLMAN'S CONTENTION (AT 9) THAT INCLUDING CWIP IN RATE BASE "SHIFTS RISKS ONTO RATEPAYERS?"

A110. No. Including CWIP in rate base will ease the financial pressure associated with the Company's capital projects by improving cash flow and providing greater regulatory certainty. While instrumental in supporting financial integrity and ability to attract capital, including CWIP will not have a measurable impact on the overall investment risks of the Company or investors' required rate of return. Including CWIP in rate base changes only the timing of cost recovery for projects included in CWIP. Accordingly, CWIP does not shift risks to ratepayers, as alleged by Mr. Tillman.

Q110. HAVE OTHER REGULATORS RECOGNIZED THE POTENTIAL BENEFITS ASSOCIATED WITH INCLUDING CWIP IN RATE BASE?

A111. Yes. Investors recognize that it is not uncommon for regulators to include CWIP in rate base when establishing rates. A study by the Edison Electric Institute observed that:

> The inclusion of CWIP in rate base improves cash flow and reduces future rate shocks. This practice also reduces the losses that a utility experiences making large plant additions under historical test year rates. Monitoring by the Edison Electric Institute has found that states that have recently allowed the inclusion of CWIP in rate base include CO, FL, GA, IN, KS, KY, LA, MI, MO, NC, NM, NV, SD, TN, VA, and WV.[141]

Accordingly, the cost of equity estimates developed for the proxy companies already reflects any impact associated with the opportunity to earn a return on CWIP. FERC has also recognized that including CWIP balances the

[141] Edison Electric Institute, *Forward Test Years for US Electric Utilities* (August 2010).

interest of investors and customers, and the Commission has routinely allowed electric utilities to include CWIP in rate base.[142] FERC noted in *Order No. 679* that including CWIP in rate base provides "up-front regulatory certainty, rate stability and improved cash flow" that encourage investment by "easing the financial pressures" associated with construction programs.[143]

Q111. IS MR. TILLMAN'S POSITION WITH RESPECT TO CWIP CONSISTENT WITH ESTABLISHED PRECEDENT IN KENTUCKY?

A112. No. Mr. Tillman's recommendations conflict with the KPSC's long-established support for including CWIP without any downward adjustment to the Company's ROE. Mr. Tillman has presented no evidence that would suggest the KPSC's longstanding practice no longer benefits customers or would otherwise undermine a constructive regulatory policy that is widespread in the industry. Moreover, while CWIP is supportive of the Company's credit standing, it does not allow recovery of a return on construction expenditures outside of a rate proceeding. As a result, there can be a significant lag between the time that expenditures are incurred and when they are included in CWIP, which is exacerbated for utilities with large capital expenditure programs, such as the Company. Mr. Tillman fails to address these realities, which further disprove his assessment and recommendations.

Q112. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?

A113. Yes, it does.

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[142] *Construction Work in Progress for Public Utilities; Inclusion of Costs in Rate Base*, Order No. 298, FERC Stats. & Regs. ¶ 30,455 (1983), order on reh'g, 25 FERC ¶ 61,023 (1983).
[143] *Order No.679* at P. 115. *See also, Order No. 679-A* at PP. 114-115.

Appendix A

STATE ALLOWED ROEs **Exhibit No. 12**

RRA INTEGRATED ELECTRIC UTILITIES

(24-Months Ended September 30, 2017)

	Company	State	Date	Allowed ROE	Adder / Penalty	Base ROE
1	Wisconsin Public Service Corp.	WI	11/19/15	10.00%	0.00%	10.00%
2	Consumers Energy Co.	MI	11/19/15	10.30%	0.00%	10.30%
3	Mississippi Power	MS	12/03/15	9.23%	0.00%	9.23%
4	Northern States Power Co - WI	WI	12/03/15	10.00%	0.00%	10.00%
5	DTE Electric Co.	MI	12/11/15	10.30%	0.00%	10.30%
6	Portland General Electric Co.	OR	12/15/15	9.60%	0.00%	9.60%
7	Southwestern Public Service Co	TX	12/17/15	9.70%	0.00%	9.70%
8	Avista Corp.	ID	12/18/15	9.50%	0.00%	9.50%
9	PacifiCorp	WY	12/30/15	9.50%	0.00%	9.50%
10	MDU Resources Group	ND	01/05/16	10.50%	0.00%	10.50%
11	Avista Corp	WA	01/06/16	9.50%	0.00%	9.50%
12	Entergy Arkansas	AR	02/23/16	9.75%	0.00%	9.75%
13	Virginia Electric and Power	VA	(a)	(a)	(a)	9.60%
14	Indianapolis Power & Light Co.	IN	03/16/16	9.85%	-0.15%	10.00%
15	El Paso Electric Co.	NM	06/08/16	9.48%	0.00%	9.48%
16	Virginia Electric and Power	VA	(b)	(b)	(b)	9.60%
17	Northern Indiana Public Service Co.	IN	7/18/2016	9.98%	0.00%	9.98%
18	Kingsport Power Co.	TN	08/09/16	9.85%	0.00%	9.85%
19	UNS Electric	AZ	08/18/16	9.50%	0.00%	9.50%
20	PacifiCorp	WA	09/01/16	9.50%	0.00%	9.50%
21	Upper Peninsula Power	MI	09/08/16	10.00%	0.00%	10.00%
22	Public Service Co. of New Mexico	NM	09/28/16	9.58%	0.00%	9.58%
23	Appalachian Power Co.	VA	10/06/16	9.40%	0.00%	9.40%
24	Madison Gas & Electric Co.	WI	11/09/16	9.80%	0.00%	9.80%
25	Public Service Co. of Oklahoma	OK	11/10/16	9.50%	0.00%	9.50%
26	Wisconsin Power & Light Co.	WI	11/18/16	10.00%	0.00%	10.00%
27	Florida Power & Light Co.	FL	11/29/16	10.55%	0.00%	10.55%
28	Liberty Utilities	CA	12/01/16	10.00%	0.00%	10.00%
29	Duke Energy Progress	SC	12/07/16	10.10%	0.00%	10.10%
30	Black Hills Colorado Electric	CO	12/19/16	9.37%	0.00%	9.37%
31	Sierra Pacific Power Co.	NV	12/22/16	9.60%	0.00%	9.60%
32	Virginia Electric and Power	NC	12/22/16	9.90%	0.00%	9.90%
33	Avista Corporation	ID	12/28/16	9.50%	0.00%	9.50%
34	Appalachian Power Co.	VA	12/30/16	10.00%	0.00%	10.00%
35	MDU Resources Group	WY	01/18/17	9.45%	0.00%	9.45%
36	DTE Electric Co.	MI	01/31/17	10.10%	0.00%	10.10%
37	Tucson Electric Power Co.	AZ	02/24/17	9.75%	0.00%	9.75%
38	Virginia Electric and Power	VA	(c)	(c)	(c)	9.40%
39	Consumers Energy Co.	MI	02/28/17	10.10%	0.00%	10.10%
40	Otter Tail Power Co.	MN	03/02/17	9.41%	0.00%	9.41%
41	Oklahoma Gas and Electric Co.	OK	03/20/17	9.50%	0.00%	9.50%
42	Gulf Power Co.	FL	04/04/17	10.25%	0.00%	10.25%
43	Kansas City Power & Light	MO	05/03/17	9.50%	0.00%	9.50%
44	Northern States Power Co.	MN	05/11/17	9.20%	0.00%	9.20%
45	Oklahoma Gas and Electric Co.	AR	05/18/17	9.50%	0.00%	9.50%
46	Idaho Power Co.	ID	05/31/17	9.50%	0.00%	9.50%
47	Virginia Electric and Power	VA	(d)	(d)	(d)	9.40%
48	MDU Resources Group, Inc.	ND	06/16/17	9.65%	0.00%	9.65%
49	Kentucky Utilities Co.	KY	06/22/17	9.70%	0.00%	9.70%
50	Louisville Gas and Electric Co.	KY	06/22/17	9.70%	0.00%	9.70%
51	Arizona Public Service Co.	AZ	08/15/17	10.00%	0.00%	10.00%
52	Virginia Electric and Power	VA	09/01/17	9.40%	0.00%	9.40%
	Range of Reasonableness					**9.20% -- 10.55%**
	Midpoint					**9.88%**
	Average					**9.73%**

RRA INTEGRATED ELECTRIC UTILITIES

Notes

(a) Adjusted to condense the following duplicative project-specific ROE orders:

	State	Date	Allowed ROE	Adder / Penalty	Base ROE
Virginia Electric and Power	VA	2/29/2016	11.60%	2.00%	9.60%
Virginia Electric and Power	VA	2/29/2016	10.60%	1.00%	9.60%
Virginia Electric and Power	VA	2/29/2016	10.60%	1.00%	9.60%
Virginia Electric and Power	VA	2/29/2016	10.60%	1.00%	9.60%
Virginia Electric and Power	VA	3/29/2016	9.60%	0.00%	9.60%

(b) Adjusted to condense the following duplicative project-specific ROE orders:

	State	Date	Allowed ROE	Adder / Penalty	Base ROE
Virginia Electric and Power	VA	6/30/2016	10.60%	1.00%	9.60%
Virginia Electric and Power	VA	6/30/2016	9.60%	0.00%	9.60%

(c) Adjusted to condense the following duplicative project-specific ROE orders:

	State	Date	Allowed ROE	Adder / Penalty	Base ROE
Virginia Electric and Power	VA	2/27/2017	11.40%	2.00%	9.40%
Virginia Electric and Power	VA	2/27/2017	9.40%	0.00%	9.40%
Virginia Electric and Power	VA	2/27/2017	10.40%	1.00%	9.40%
Virginia Electric and Power	VA	2/27/2017	10.40%	1.00%	9.40%
Virginia Electric and Power	VA	2/27/2017	10.40%	1.00%	9.40%

(d) Adjusted to condense the following duplicative project-specific ROE orders:

	State	Date	Allowed ROE	Adder / Penalty	Base ROE
Virginia Electric and Power	VA	6/1/2017	9.40%	0.00%	9.40%
Virginia Electric and Power	VA	6/30/2017	9.40%	0.00%	9.40%
Virginia Electric and Power	VA	6/30/2017	10.40%	1.00%	9.40%

Source: Regulatory Research Associates, "Major Rate Case Decisions," *Regulatory Focus* (Jan. 14, 2016; Jan. 18, 2017); S&P Global, "Major Rate Case Decisions," *RRA Regulatory Focus* (Oct. 26, 2017).

STATE ALLOWED ROEs

UTILITY GROUP

	Company	(a) Allowed ROE		
1	Alliant Energy		10.50%	
2	Ameren Corp.		9.15%	
3	American Elec Pwr		10.28%	
4	AVANGRID, Inc.		9.23%	
5	CMS Energy Corp.		10.10%	
6	Dominion Energy		10.90%	
7	DTE Energy Co.		10.10%	
8	Duke Energy Corp.		10.31%	
9	Emera Inc.		NA	
10	Eversource Energy		9.52%	
11	Fortis, Inc.		9.31%	
12	NextEra Energy, Inc.		10.60%	
13	PPL Corp.		9.70%	
14	Pub Sv Enterprise Grp.		10.30%	
15	SCANA Corp.		10.07%	
16	Sempra Energy		10.20%	
17	Southern Company		12.50%	
18	Vectren Corp.		10.28%	
	Range of Reasonableness	**9.15%**	--	**12.50%**
	Midpoint		**10.83%**	
	Average		**10.18%**	

(a) The Value Line Investment Survey (Jul. 28, Aug. 18 & Sep. 15, 2017).

EXPECTED EARNINGS APPROACH

UTILITY GROUP

	Company	(a) Expected Return on Common Equity	(b) Mid-Year Adjustment Factor	(c) Adjusted Return on Common Equity
1	Alliant Energy	13.0%	1.0044	13.1%
2	Ameren Corp.	10.0%	1.0196	10.2%
3	American Elec Pwr	11.0%	1.0208	11.2%
4	AVANGRID, Inc.	5.0%	1.0064	5.0%
5	CMS Energy Corp.	13.5%	1.0356	14.0%
6	Dominion Energy	19.0%	1.0025	19.0%
7	DTE Energy Co.	10.5%	1.0258	10.8%
8	Duke Energy Corp.	8.5%	1.0090	8.6%
9	Emera Inc.	13.0%	1.0183	13.2%
10	Eversource Energy	10.0%	1.0193	10.2%
11	Fortis, Inc.	8.0%	1.0273	8.2%
12	NextEra Energy, Inc.	14.0%	1.0349	14.5%
13	PPL Corp.	13.5%	1.0352	14.0%
14	Pub Sv Enterprise Grp.	11.0%	1.0175	11.2%
15	SCANA Corp.	11.0%	1.0013	11.0%
16	Sempra Energy	13.0%	1.0057	13.1%
17	Southern Company	12.5%	1.0146	12.7%
18	Vectren Corp.	12.0%	1.0119	12.1%
	Average (d)			**11.8%**
	Average-Woolridge Group (d,e)			**11.9%**
	Average-Baudino Group (d,f)			**11.9%**

(a) The Value Line Investment Survey (Jul. 28, Aug. 18 & Sep. 15, 2017).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) (a) x (b).
(d) Excluding highlighted values.
(e) Excluding Emera and Fortis.
(f) Excluding AVANGRID, Emera, and Fortis.

PSC Exhibit 14

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A GENERAL ADJUSTMENT OF ITS RATES FOR ELECTRIC SERVICE; (2) AN ORDER APPROVING ITS 2017 ENVIRONMENTAL COMPLIANCE PLAN; (3) AN ORDER APPROVING ITS TARIFFS AND RIDERS; (4) AN ORDER APPROVING ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND (5) AN ORDER GRANTING ALL OTHER REQUIRED APPROVALS AND RELIEF	**)**	**Case No. 2017-00179**

DIRECT TESTIMONY OF

SATTERWHITE, BARTSCH, BUCK, CARLIN, CASH

ON BEHALF OF KENTUCKY POWER COMPANY

SECTION III

VOLUME 1 OF 4

June 28, 2017

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; (4) An Order Approving Accounting Practices To Establish Regulatory Assets And Liabilities; And (5) An Order Granting All Other Required Approvals And Relief	)	Case No. 2017-00179

DIRECT TESTIMONY OF

MATTHEW J. SATTERWHITE

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Matthew J. Satterwhite, being duly sworn, deposes and says he is the President and COO for Kentucky Power Company that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief

Matthew J. Satterwhite

COMMONWEALTH OF KENTUCKY)
) 2017-00179
COUNTY OF BOYD)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Matthew J. Satterwhite, this 27th day of June 2017.

Trisha M. Young Blum
Notary Public

Notary ID Number: 530202

My Commission Expires: 3-18-19

TRISHA M. YOUNG
NOTARY ID 530202
COMMISSION EXPIRES 3-18-19

DIRECT TESTIMONY OF
MATTHEW J. SATTERWHITE, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2017-00179

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DIRECT TESTIMONY OF
MATTHEW J. SATTERWHITE, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Matthew J. Satterwhite, and I am the President and Chief Operating Officer of Kentucky Power Company ("Kentucky Power" or "Company"). My business address is 855 Central Avenue, Suite 200, Ashland, Kentucky 41101.

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I graduated from the University of Kansas in 1995 with a Bachelor of Arts in Political Science and from Capital Law School in 1999. After graduation from law school, I joined the Ohio Attorney General's Office, representing the Public Utilities Commission of Ohio (PUCO) from 1999 to 2004. In 2004, I became the Legal Director for the PUCO's Service Monitoring and Enforcement Department where I served until 2006. I left the Commission to serve as a Master Commissioner with the Supreme Court of Ohio from 2006-2008. In Ohio, the cases from the utility commission have the right of direct appeal to the Supreme Court of Ohio, and I served as the public utility expert for the Court. In late 2008, I joined the American Electric Power Service Corporation ("AEPSC") legal department.

Q. WHEN DID YOU ASSUME THE DUTIES OF PRESIDENT AND CHIEF OPERATING OFFICER OF KENTUCKY POWER?

A. I formally assumed the duties of President and Chief Operating Officer of Kentucky Power on December 8, 2016. Immediately following the formal announcement of my appointment in November 2016, I began traveling Kentucky Power's service territory. During these travels I had the opportunity to meet with customers and employees, and through these meetings I have come to better understand the challenges facing our part of the Commonwealth. I also have gained a better appreciation for the talented men and women in our organization and in the communities we serve.

I have also met with local, state, and federal officials to discuss key issues impacting our region. Whenever possible, I spread the word about the skilled and available workforce in eastern Kentucky. I am convinced that a concerted effort by industry and the Commonwealth of Kentucky can effectively inform the world about the opportunity for industry to locate in eastern Kentucky with the goal of diversifying the economy and creating well-paying jobs.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony addresses four topics. All are important, but I place special emphasis on Kentucky Power's focus on economic development and customer service. It is no secret that eastern Kentucky is in the midst of a fundamental transformation of its economy that in large part is driven by forces outside its control. The coal mining economy, once the primary driver of the eastern

Kentucky economy, has declined. While there have been some recent improvements in coal mining activity reported, the direct and indirect job losses over the past few years resulting from the downturn in coal mining activity are being felt throughout the Company's service territory. Kentucky Power is committed to working with its customers, public officials, and other stakeholders to address the challenges facing eastern Kentucky. Kentucky Power's customer experience focus and "Appalachian Sky" initiative, which I describe below, are important efforts to address those challenges, and underlie the Company's vision for eastern Kentucky.

Turning to the specifics of my testimony, I provide:

- an overview of Kentucky Power and its operations;
- detail on the Company's refocused customer experience focus;
- a description of Kentucky Power's efforts on economic development including its "Appalachian Sky" initiative; and
- an overview of Kentucky Power's application and request.

IV. OVERVIEW OF KENTUCKY POWER'S OPERATIONS

Q. PLEASE GIVE A BRIEF OVERVIEW OF THE COMPANY AND ITS OPERATIONS.

A. Kentucky Power is a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP") and is engaged in the generation, purchase, transmission, and distribution of electric power. The Company serves approximately 168,000 retail customers located in 20 eastern Kentucky counties. The Company's total customer count has declined by approximately 2,300 customers since September 2014. The Company also sells electric power at wholesale rates to the City of

Olive Hill and the City of Vanceburg. Exhibit MJS-1 is a map detailing the Company's service territory. Kentucky Power's service territory includes some of the most economically and geographically challenging territory in the Commonwealth.

Q. WHERE ARE KENTUCKY POWER'S OFFICES LOCATED?

A. In December 2016, Kentucky Power moved its corporate headquarters from Frankfort, Kentucky to Ashland, Kentucky. In addition to returning jobs to Ashland, the move is an important step in Kentucky Power's enhanced commitment to its service territory. I and other members of the senior management live in the service territory and are involved on the front lines rebuilding our communities.

Q. DOES KENTUCKY POWER MAINTAIN OTHER OFFICES?

A. Yes. The Company maintains distribution operations centers in Hazard, Pikeville, and Ashland. These offices serve as a base of operations for each of the Company's three districts. Kentucky Power employs staff in each of these districts and maintains offices and equipment to assist in maintaining and restoring electric service. The Company also operates a state regulatory office in Frankfort, Kentucky.

Q. HOW LARGE IS KENTUCKY POWER'S WORKFORCE?

A. Kentucky Power currently directly employs 549 persons. The Company pays competitive wages and benefits enabling it to attract and retain the skilled workers required to provide safe, adequate, and efficient service to its customers. The Company proposes to adjust the test year complement of employees in this case to add five employees to meet safety and efficiency needs. The Company will continue to look for opportunities to add staff in our territory when the cost is justified by the service and customer benefits provided. While a few salaries may not have a material impact on the ultimate cost of providing service, I am mindful of the need to be measured in our spending.

Kentucky Power's employment impact also extends beyond its direct employees. Overall, the Company employs approximately 580 contractors on a regular basis in eastern Kentucky. The Company contracts with Nelson Tree Service, Inc., Asplundh Tree Expert Company, and Wright Tree Service, Inc. to perform most of the vegetation management work in connection with the Company's on-going vegetation management plan. The Company also uses Davis H. Elliot Company, Inc. and some flagging crews to perform much of its overhead and underground construction work. The use of independent contractors allows Kentucky Power to manage this work in a cost-effective manner.

Q. DO KENTUCKY POWER AND ITS EMPLOYEES SUPPORT THE COMMUNITIES AND INSTITUTIONS OF ITS SERVICE TERRITORY?

A. Absolutely. During 2016, the Company contributed to charitable, educational, and civic organizations serving the Company's service territory. None of these contributions, or the ones discussed below, are recovered through rates; all are "below-the-line" expenditures paid by the Company shareholder.

The Company's employees also support the communities they serve through employee involvement in organizations that promote economic development, civic pride, and customer safety.

Q. WHAT ARE AMERICAN ELECTRIC POWER FOUNDATION GRANTS?

A. The American Electric Power Foundation supports the communities served by AEP operating companies like Kentucky Power. Some of the more notable contributions during 2016 included a $25,000 donation to God's Pantry in Paintsville, Kentucky and a $10,000 donation to the Governors Scholar Program.

The Foundation also just announced a grant developed by Kentucky Power and the Kentucky Education Development Corporation in the amount of $500,000. The grant will be used to bring or enhance video distance learning equipment and curriculum to the high schools in Kentucky Power's service territory. This program will allow these schools to connect with each other and resources around the world. The Foundation also announced a grant in the amount of $150,000 to the American Red Cross in eastern Kentucky for the purchase of an emergency response vehicle for the region to assist in emergencies.

Q. KENTUCKY POWER'S SHAREHOLDER'S CONTRIBUTIONS TO THE COMPANY'S SERVICE TERRITORY HAVE NOT BEEN ADDRESSED IN DETAIL IN PAST RATE CASES. WHY ARE YOU ADDRESSING THE ISSUE NOW?

A. The discussion is included as the direct result of conversations with our customers. Our customers expressed surprise to learn about the level of corporate giving, and encouraged the Company to do more to explain its charitable and economic development efforts. The Foundation grants are not recovered through base rates, and therefore were not addressed in past filings. But as I learned from our customers, these Company actions are important to share and to show a more complete picture of the Company's impact on the provision of electric service.

V. <u>KENTUCKY POWER'S CUSTOMER EXPERIENCE FOCUS</u>

Q. WHAT HAS KENTUCKY POWER DONE TO CONNECT AND COMMUNICATE WITH ITS CUSTOMERS?

A. Kentucky Power understands the importance of open communication with its customers. Starting in January of 2017, the Company set up a new approach to reach customers and held a series of community meetings to listen to customer comments, address concerns, and be available to talk in the community. Since then the Company has conducted 12 such meetings. Kentucky Power worked with legislators and County Judge Executives, and also advertised these community meetings in an attempt to reach as many customers as possible.

The Company approached the meetings in a productive manner so that it could talk directly with customers about their specific concerns and circumstances. The Company asked customers with billing concerns to bring a copy of their bill with them. The customers that brought a copy of their bills were able to talk with customer service representatives who could access customer accounts and further evaluate their bills. The Company also held discussion stations with forestry personnel to discuss vegetation management, and energy efficiency staff to discuss the Company's programs that are available to help customers to make their homes and businesses more energy efficient. The Company also provided regulatory staff and an area dedicated to discussions concerning customer confusion about specific charges on the bill and regulatory matters.

Q. WHAT OTHER EFFORTS DID KENTUCKY POWER TAKE TO IMPROVE COMMUNICATION WITH ITS CUSTOMERS?

A. As part of this focus on the customer experience, Kentucky Power began in 2016 a series of monthly public meetings called Community Advisory Panels. Community Advisory Panels were established in Ashland, Pikeville, and Hazard and were designed so that the Company could meet with active community members to ensure the Company understood the full range of issues raised by customers. The topics for presentation at the Community Advisory Panels ranged from reliability and economic development to AEP corporate governance to how to read the bill. The Company also provided community members with examples of the issues being considered for this rate case. The introduction of the issues provided the Company an opportunity to understand how potential changes were viewed and to address community concerns with any new approach.

Q. WHAT HAS THE COMPANY LEARNED FROM ITS CUSTOMER EXPERIENCE FOCUS SO FAR?

A. First and foremost, the Community Advisory Panels reinforced the Company's understanding of the importance of communication and how such communication can better enable Kentucky Power to meet its customers' energy needs and expectations. In particular, the Company learned that the number of individual riders and surcharges appearing as line items on customer bills frustrates customers. In response to this concern, and in an effort to provide customers the type of service they want, the Company recently proposed in Case No. 2017-00231 to change its bill format. The interactions also helped customers better understand what the Company faces on a daily basis, how it operates, as well as the real value of the electricity provided by Kentucky Power.

Q. HOW DOES KENTUCKY POWER PLAN TO IMPROVE THE CUSTOMER EXPERIENCE GOING FORWARD?

A. Interaction with our customers is vital and will continue. The Company intends to continue to be in the community speaking and listening. The Company headquarters moving to Ashland puts our leadership team directly in the community we serve, interacting with our neighbors on a daily basis and being part of the rebuilding of eastern Kentucky. The Company will continue to hold its Community Advisory Panel meetings to ensure a consistent forum for community members to interact with Company management and provide a platform for open and honest discussion about the region and the impact of the electric utility. I also changed the organization structure of the Company by elevating the individual responsible for customer interaction to a director of customer service and business operations position. She now reports directly to me so that I am actively involved in ensuring we are communicating with our customers.

VI. KENTUCKY POWER'S ECONOMIC DEVELOPMENT ACTIVITIES

Q. WHAT CONTRIBUTIONS HAS KENTUCKY POWER'S SHAREHOLDER MADE TO ECONOMIC DEVELOPMENT?

A. As discussed in detail in the testimony of Company Witness Hall, the Company actively supports economic development in its service territory. Through grants and other investments, Kentucky Power has provided over $2.0 million toward economic development efforts since 2014.

Q. WHAT IS THE APPALACHIAN SKY INITIATIVE?

A. The Appalachian Sky Initiative is a plan to promote central Appalachia as the premier region in the Unites States for aerospace manufacturing. This plan was developed over time through the work of Kentucky Power in partnership with key local economic development agencies in the area. Eastern Kentucky and all of central Appalachia contain a highly skilled and available workforce. Kentucky Power and the economic development agencies it supports developed a workforce study that demonstrates the aptitude and skill set of Appalachian workers, particularly coal miners and steel workers. This study showed that central Appalachia has eight times the national per capita average of metal fabricators, the key skill set needed in aerospace manufacturing, making the region a potential leader in the industry. The Appalachian Sky Initiative seeks to leverage this existing skilled workforce into a dynamic new diversified economy for the region.

Q. WILL APPALACHIAN SKY SUCCEED?

The plan and expectation is to succeed. While there are no guarantees, the nature of the skilled workforce in eastern Kentucky strongly supports both the need for and the strategy embodied in the Appalachian Sky Initiative. I have worked to share this message with our state and federal officials as well as aerospace companies. Regardless of the future of the coal industry, eastern Kentucky must diversify its economy and find alternative sources of job creation.

Q. PLEASE DESCRIBE THE RECENTLY-ANNOUNCED PLAN BY BRAIDY INDUSTRIES TO CONSTRUCT A MANUFACTURING FACILITY IN GREENUP COUNTY.

A. Braidy Industries Inc. announced on April 26, 2017 its plan to construct a $1.3 billion aluminum mill near South Shore in Greenup County. My understanding is that the mill will produce Series 5000, 6000, and 7000 aluminum sheet and plate products for use in the automotive and aerospace industry. The mill is also reported to support research and development to advance the science and technology of molten-metal manufacturing. The 2.5 million square foot facility will provide approximately 550 advanced manufacturing and administrative jobs when it opens in 2020. The construction of the mill is reported to provide up to 1,000 additional jobs in that interim period. The location of the Braidy Industries aluminum mill in eastern Kentucky taps the strong available workforce and highlights the potential for the success of the Appalachian Sky Initiative. Kentucky Power intends to be a partner to help rejuvenate the region.

VII. KENTUCKY POWER'S REQUEST TO ADJUST ITS RATES

Q. WHAT RATE ADJUSTMENT IS KENTUCKY POWER PROPOSING?

A. The base rates proposed in the Company's application are designed to increase its annual revenues by $65,387,987. This increase is based on the historical test year ending February 28, 2017 with known and measurable adjustments to test year revenues and operating expenses. The Company is also seeking to increase the amount of the Home Energy Assistance Program ("HEAP") surcharge by $0.05 per residential meter per month and the Kentucky Economic Development Surcharge ("KEDS") by $0.10 per meter per month. The Company estimates that the combined increased surcharges will add $284,891 to the annual revenue amount. The Company will match dollar-for-dollar the additional economic development dollars produced by the request. The Company is also seeking approval pursuant to KRS 278.183 of the Company's 2017 Environmental Compliance Plan. Additional information about the 2017 Plan is included in the testimony of Company Witness Elliott. If approved, the 2017 Environmental Compliance Plan will result in an estimated additional $3,903,056 increase in the Company's annual environmental surcharge revenues. The rates proposed by Kentucky Power in this case are designed to produce a total of $69,575,934 in additional annual revenue.

Q. WHAT HAS CHANGED SINCE THE COMMISSION'S ORDER IN CASE NO. 2014-00396 THAT NECESSITATES THE FILING OF THE COMPANY'S APPLICATION?

A. Kentucky Power's service territory is undergoing historic changes, and it is critical that Kentucky Power act now to address those changes. The Company's customer base continues to shrink, and the decline in usage requires the Company to spread the costs of operations over the smaller number of remaining customers. The effect of a decreasing customer base is the single largest driver of the rate request.

The rate increase requested is also required to meet increasing costs related to the federally-regulated transmission system, as well as the costs of complying with environmental regulations. Transmission system costs are volatile and are billed directly to Kentucky Power by PJM. Other major changes since 2014 include but are not limited to declining off-system sales margins and increased depreciation expense. Waiting to address these changes will not benefit the people or the economy of eastern Kentucky.

Q. WHY IS ALLOWING KENTUCKY POWER THE OPPORTUNITY TO EARN A REASONABLE RETURN AND FINANCIAL PERFORMANCE IMPORTANT?

A. Kentucky Power is an important part of the fabric of eastern Kentucky as an employer, corporate citizen, and investor. It is important that public utilities provide a financial return on investment to ensure stockholder investment. Failure to perform financially will adversely affect the capital available to the Company and its cost, as well as Kentucky Power's ability to provide safe and reliable service to customers while remaining an important part of eastern Kentucky. Company Witness McKenzie discusses the basis for his recommended return on equity and the importance of Kentucky Power being permitted the opportunity to earn it.

In addition, as a general proposition, public utilities are typically viewed as safe investment opportunities and their securities are sought by teacher retirement systems, unions, and other mainstream risk adverse investors. These are the investors that provide the capital to support Kentucky Power's operations and look to the Commission to provide the opportunity to earn, and the Company to achieve, a fair return.

As a public utility the Company must abide by the rules and regulations of the Commonwealth and the Commission. Under the regulatory compact Kentucky Power provides safe and reliable service in return for a fair opportunity to earn a reasonable return on its investment. Kentucky Power's existing rates do not provide it an opportunity to earn a reasonable return.

Q. DID KENTUCKY POWER CONSIDER THE EFFECT OF ITS REQUESTED INCREASE ON ITS CUSTOMERS?

A. Yes. Kentucky Power balances its operations and requests for rate relief with the reality of the rapidly changing electric utility industry and the circumstances facing customers. Kentucky Power's request is reasonable and necessary to position the Company to meet the significant challenges it and its customers face, and will allow it to:

- meet customer expectations for safe and reliable electric service;
- continue to maintain and improve reliability;
- continue to invest in capital improvements in the distribution system; and
- provide a safe work environment that sends each and every employee home injury-free.

Kentucky Power provides a valuable service to its customers and is a leader in the eastern Kentucky economy. The Company, however, is significantly challenged under its existing rates to continue to provide energy that is safe, reliable, and efficient.

Q. WHAT IS THE COMPANY DOING TO ADDRESS THE ECONOMIC SITUATION FACING EASTERN KENTUCKY?

A. The Company and its employees understand the problems facing our customers. We live and work in the communities we serve. Kentucky Power has taken and is proposing a number of actions to align its rate proposal with the situation facing its service territory. For example, and as described below, Kentucky Power is proposing to increase its contribution to its successful K-PEGG economic development program. Additionally, Kentucky Power has increased its contribution to the Home Heating Assistance program by 50% since 2009.

The Company also is proposing to eliminate the employee discount currently included in the rate structure. The Company determined that now was the appropriate time to end the practice. Additionally, the Company recently proposed the change requested by customers for a simpler and more focused bill format. Our customers demanded a bill without the long list of line items and the Company is proposing a much simpler bill. As discussed by Company Witnesses Wohnhas and Miller, the Company earlier this month refinanced $325 million in outstanding debt to obtain lower interest rates. The Company proposes to file supplemental testimony addressing the post-test year refinancing.

As discussed above, Kentucky Power is also taking further steps to address the underlying issues driving unemployment and economic hardship in eastern Kentucky. In addition to the economic development efforts described by Company Witness Hall, the Company filed, and the Commission expeditiously approved, a "Coal Plus" program that provides the opportunity for coal operations to reopen with the help of a special contract or to take advantage of existing tariffs. The Company also held the first of an ongoing series of meetings with coal operators in its service territory and Kentucky Power's fuel procurement group in Columbus, Ohio to address strategies to make Kentucky-mined coal more competitive and more likely to be chosen in a competitive request for proposal.

Q. WHY IS KENTUCKY POWER MAKING THIS FILING NOW?

A. Kentucky Power's return on equity for the test year was 5.80 per cent. For the 12 months ended May 31, 2017 Kentucky Power's return on equity was 5.55 percent. This is far below the range of returns on equity found to be reasonable by the Commission in Case No. 2014-00396. In fact, Kentucky Power has never achieved its authorized return on equity since the Commission's June 22, 2015 Order. Kentucky Power cannot continue to provide safe, efficient, and adequate service without the opportunity to attract the capital required to make the investments necessary.

Q. DOES THE TESTIMONY PRESENTED IN SUPPORT OF THE COMPANY'S APPLICATION IDENTIFY ANY ALTERNATIVES TO THE PROPOSALS CONTAINED IN ITS APPLICATION?

A. Yes, but each of the alternatives involves trade-offs. For example, Company Witness Phillips presents proposed modifications to Kentucky Power's 2015 Distribution Vegetation Management Plan in connection with the Company's planned transition to performing Task 3 work on a five-year cycle. As part of its ongoing efforts to address customer impacts and as part of this case, Kentucky

Power also reviewed performing the Task 3 work on a six-year cycle. Although a six-year maintenance cycle would be less expensive on annual basis, it comes with both a higher total cost for a complete cycle and the risk of decreased service reliability.

The Company also examined depreciating its assets over longer period and thereby reducing its revenue requirement, as discussed by Company Witness Wohnhas. That choice, however, results in greater costs, albeit over a longer period of time, and customers paying more in the long run.

Q. WHY HAS THE COMPANY ASKED FOR AN INCREASE IN ECONOMIC DEVELOPMENT FUNDING?

A. Economic development is the most impactful means of mitigating the primary driver behind the current rate request. Kentucky Power is requesting that the Commission authorize an $0.10 per meter per month increase in the Company's Kentucky Economic Development Surcharge first approved by the Commission in its June 22, 2015 Order in Case No. 2014-00396. If approved, the KEDS surcharge will total $0.25 per meter per month or $3.00 per meter per year. The Company proposes to again match the increase with shareholder funds on a dollar for dollar basis. This expanded 50/50 partnership will add approximately $400,000 per year in funding for economic development in Kentucky Power's service territory. Company Witness Hall provides further information about the proposal and the success of the Company's economic development efforts.

Q. WHAT ADVANTAGE IS PROVIDED BY ADDRESSING VOLATILE PJM COSTS IN A TRACKER VERSUS WAITING FOR THE COMPANY TO FILE SUBSEQUENT RATE CASES?

A. Kentucky Power incurs charges and credits as a load serving entity ("LSE") in PJM under the FERC-approved open access transmission tariff ("OATT"). PJM LSE OATT charges and credits can be volatile and can have a significant effect on the Company's revenue requirement. As discussed in more detail by Company Witness Vaughan, the net level of jurisdictional PJM LSE OATT charges and credits increased by approximately $20.6 million since the last rate case filing. Including the net values of these charges and credits among the costs that are tracked and recovered through the annual Purchase Power Adjustment will allow these costs to be added gradually as they occur versus all at once in future rate case filings. The tracking and annual recovery also helps to potentially avoid the costs and administrative inefficiencies associated with more frequent rate cases by ensuring these significant and volatile costs that are charged to Kentucky Power already have an avenue for recovery in rates. Through the use of this tracking mechanism, the Company can ensure that its customers are charged no more and no less than the actual amount of these costs.

Q. HAS THE COMPANY CONSIDERED GREATER CAPITAL INVESTMENT IN ITS SERVICE TERRITORY?

A. Yes. The Company's capital investment plans include needed electric infrastructure in Kentucky. The Company's strategy to increase its capital investment for necessary transmission projects, in particular, aligns the pressing need to update aging transmission infrastructure in the Commonwealth and the Company's strategy to support and make investments in its service territory. These transmission investments not only represent direct investment, but also support the local economy and improved transmission reliability, making the region more attractive to other forms of economic development.

Q. ARE THERE OTHER OPTIONS THE COMPANY IS EXPLORING TO MITIGATE FUTURE CUSTOMER BILL IMPACTS?

A. The Company continues to explore all possible approaches to provide safe and reliable power, in compliance with all applicable regulations, in the most cost-effective manner. The Company is committed to continually review its operations and find more efficient and improved ways to achieve its core work providing electric service to customers. Ultimately, it is increased economic development within the Company's service territory, and with it the associated increased load across which costs can be spread, that is the best opportunity Kentucky Power and its customers have to address increasing rates. Kentucky Power is deeply committed to leveraging the economic growth opportunities presented by a highly skilled and available workforce into an eastern Kentucky region that serves as a destination for modern manufacturing options.

Q. WHY IS THE COMPANY ADDING ADDITIONAL EMPLOYEES?

A. Beginning in late 2016, the Company examined the need for additional staffing in areas focused on safety, reliability of service, and revenue protection. As Company Witness Wohnhas explains in his testimony, Kentucky Power is adjusting the test year to reflect the addition of five employees to its staff. This effort will aid the Company in improving safety and customer service, while limiting the cost borne by customers from energy theft, and by adding quality jobs in Kentucky Power's service territory.

Q. ARE THE RATES REQUESTED BY KENTUCKY POWER FAIR, JUST AND REASONABLE?

A. Yes. Kentucky Power's goal is to provide reliable and cost-effective service to its customers while also producing a reasonable return for its shareholders. The evidence is provided by the Company for the Commission to review. Kentucky Power's proposed adjustments yield fair, just and reasonable rates that will allow it to continue to provide the service that customers and KRS 278.040 require.

Q. WHAT WITNESSES WILL BE OFFERING TESTIMONY IN SUPPORT OF KENTUCKY POWER'S APPLICATION AND THE GENERAL SUBJECT MATTER OF THEIR TESTIMONY?

A. The Company's proposed changes in its annual revenue requirement as well as the adjustments to test year revenues, operating expenses, rate base, capitalization, tariff changes, requests to establish regulatory assets or liabilities, and changes to its environmental compliance plan are sponsored by the following witnesses:

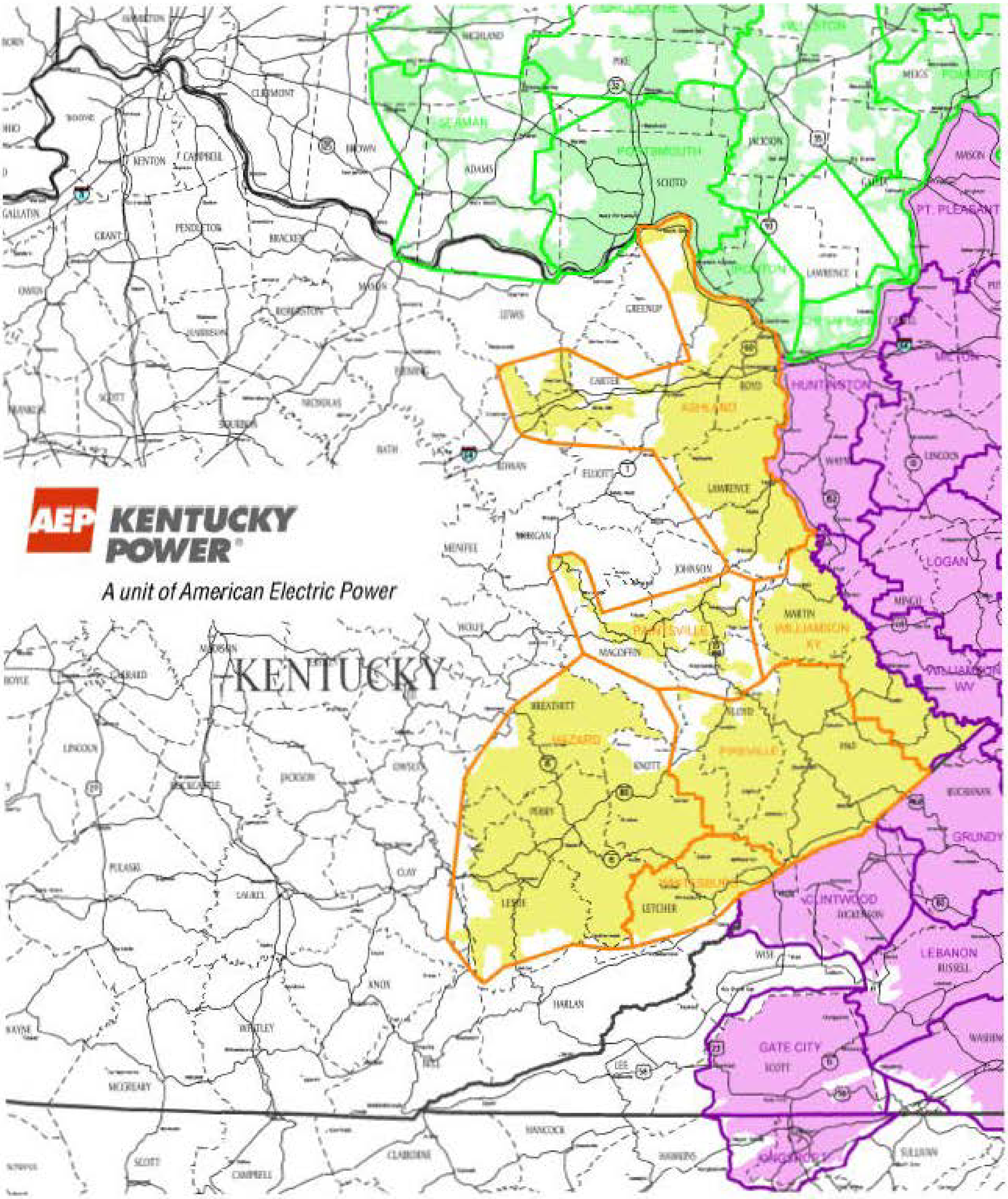
WITNESS	TOPICS
Adrien P. McKenzie	Calculation Of A Fair, Just, and Reasonable Return on Equity
Alex E. Vaughan	Overview Of The Relation Between The Company's Base Rates And Its Surcharges And Riders; Rate Design; Tariff Changes; Optional Renewable Power Tariff; Certain Revenue and Operating Expense Adjustments
Amy J. Elliott	2017 Environmental Compliance Plan; Changes To Tariff E.S.
Brad N. Hall	Kentucky Power's Investment In Economic Development
Andrew R. Carlin	Employee Compensation Strategy

WITNESS	TOPICS
Everett G. Phillips	Kentucky Power's Storm Preparedness, Response to Outages, and System Reliability; Kentucky Power's 2017 Vegetation Management Plan; Kentucky Power's Smart Grid Investments
Jason A. Cash	Revised Depreciation Rates For Big Sandy Unit 1
Jeffrey B. Bartsch	Calculation Of Gross Revenue Conversion Factor; Tax Effects Of Certain Ratemaking Adjustments
Debra L. Osborne	Kentucky Power Generation Assets; Generation Operation And Maintenance Expenses; Big Sandy Plant Status; Projects Added in 2017 Environmental Compliance Plan
John M. McManus	Environmental Requirements Met by the 2017 Environmental Compliance Plan; Environmental Requirements Under Evaluation
John A. Rogness III	Revenue And Operating Expense Adjustments; Certain Tariff Changes
Katharine I. Walsh	Jurisdictional Cost-of-Service Study
Douglas R. Buck	Class Cost-of-Service Study; Revenue Adjustments; Allocation Of Requested Increase To Customer Classes
Ranie K. Wohnhas	Proposed Revenue Requirement; Capitalization Adjustments; Establishment Of Regulatory Assets And Liabilities; Amortization Of Regulatory Assets And Liabilities
Stephen L. Sharp Jr.	Proposed Changes To Kentucky Power's Tariffs; Certain Adjustments To Test Year Revenues And Operating Expenses
Tyler H. Ross	Test Year Revenue And Operating Expense Adjustments; Capitalization And Rate Base Adjustments Related To The Decommissioning Rider
Zachary C. Miller	Kentucky Power's Proposed Capital Structure; Cost of Capital For Ratemaking Purposes; Kentucky Power's Financial Position And Credit Rating

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

Map of the KPCo Service Area



COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; (4) An Order Approving Accounting Practices To Establish Regulatory Assets And Liabilities; And (5) An Order Granting All Other Required Approvals And Relief	**)**	**Case No. 2017-00179**

DIRECT TESTIMONY OF

JEFFREY B. BARTSCH

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Jeffrey B Bartsch, being duly sworn, deposes and says he is the Director Tax Accounting & Regulatory Support for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief

Jeffrey B Bartsch

Jeffrey B Bartsch

STATE OF OHIO)
) 2017-00179
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by (Insert Name), this the 19th day of June 2017.

Pauline A Lutz

Notary Public

NOTARIAL SEAL STATE OF OHIO

PAULINE A LUTZ
NOTARY PUBLIC - OHIO
MY COMM. EXP. 9-12-21

My Commission Expires

DIRECT TESTIMONY OF
JEFFREY B. BARTSCH, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2017-00179

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DIRECT TESTIMONY OF
JEFFREY B. BARTSCH, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Jeffrey B. Bartsch. I am the Director of Tax Accounting and Regulatory Support for American Electric Power Service Corporation ("AEPSC"), a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP"), the parent company of Kentucky Power Company ("Kentucky Power" or "Company"). My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

II. BACKGROUND

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I earned a Bachelor of Business Administration Degree in Accounting from Ohio University in 1979. I am a Certified Public Accountant and have been licensed in Ohio since 1981. I am also a member of the American Institute of Certified Public Accountants. I was first employed by Arthur Andersen & Co. in 1979 in the Audit section where I was assigned to various clients, including those in the electric utility industry. In 1985, I accepted a position with the AEPSC Tax Department. I held various positions within the department until June 2000 when I was promoted to my current position.

Q. WHAT ARE YOUR RESPONSIBILITIES?

A. As Director of Tax Accounting and Regulatory Support, my responsibilities include oversight of the recording of the tax accounting entries and records of AEP and its subsidiaries, including Kentucky Power. I am also responsible for coordinating the development of state and federal tax data to be provided by the AEPSC Tax Department in regulatory proceedings. I have attended numerous tax, accounting and regulatory seminars throughout my professional career.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY PROCEEDINGS?

A. Yes. In addition to previous testimony before the Public Service Commission of Kentucky ("Commission"), I have filed testimony with the Public Utilities Commission of Ohio on behalf of Columbus Southern Power Company and Ohio Power Company; with the Michigan Public Service Commission on behalf of Indiana Michigan Power Company; with the Louisiana Public Service Commission on behalf of Southwestern Electric Power Company; and with the Federal Energy Regulatory Commission in a transmission rate case for the eastern AEP Operating Companies. I have also filed testimony with and testified before the Public Utility Commission of Texas on behalf of AEP Texas Central Company, AEP Texas North Company, Southwestern Electric Power Company and Electric Transmission Texas, LLC. In addition, I have filed testimony with and testified before the Virginia State Corporation Commission on behalf of Appalachian Power Company, the Public Service Commission of West Virginia on behalf of Appalachian Power Company and Wheeling Power Company and with the Indiana Utility Regulatory Commission on behalf of Indiana Michigan Power Company. Like Kentucky Power, all of these companies, except Electric Transmission Texas, LLC, are AEP operating companies.

III. PURPOSE OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this proceeding is to calculate the Gross Revenue Conversion Factor, to present and support the jurisdictional federal, state, and local income taxes to which Kentucky Power is subject, and to support the tax effects of certain fixed, known and measurable ratemaking adjustments for the test year ended February 28, 2017.

IV. SECTION 199 DEDUCTION AND GROSS REVENUE CONVERSION FACTOR

Q. PLEASE DESCRIBE THE GROSS REVENUE CONVERSION FACTOR (GRCF).

A. The GRCF is the factor necessary to determine the incremental amount of gross revenue required to generate an additional dollar of operating income after accounting for the effects of uncollectible accounts, Commission assessment fees, and State and Federal income taxes.

Q. HOW WAS THE GRCF RATE DETERMINED?

A. The methodology used in this case also was utilized in the Company's prior base rate cases. The uncollectible accounts rate and commission assessment fees rate were provided to me by Company Witness Wohnhas; the state income tax rates and apportionment factors are based on the most recent state income tax return information and are currently being used in the monthly closing accrual process. Please see Section V, Workpaper S-2, Page 2.

Q. DID THE COMPANY REFLECT A SECTION 199 MANUFACTURING DEDUCTION AS A COMPONENT OF THE GRCF?

A. No.

Q. HAS THE COMMISSION REQUIRED THAT THE COMPANY INCLUDE A SECTION 199 MANUFACTURING DEDUCTION AS A COMPONENT OF THE GRCF IN PREVIOUS CASES?

A. Yes. In Case No. 2005-00068, the Commission held that the Section 199 deduction "should be recognized and reflected in the gross-up factor … to the rate of return calculations for Big Sandy's environmental surcharge rate base."[1]

Q. HAS THE COMMISSION RECENTLY ALLOWED OTHER UTILITIES IN THE COMMONWEALTH TO EXCLUDE THE SECTION 199 DEDUCTION FROM THE CALCULATION OF THE GRCF?

A. Yes. In Case Nos. 2016-00214 and 2016-00215, the Commission did not require Kentucky Utilities Company and Louisville Gas and Electric Company (LG&E) to include the Section 199 deduction in their calculations of the GRCF. Specifically, the Commission held in the LG&E Case that the "gross-up factor excludes the Internal Revenue Code §199 manufacturing tax deduction ("§199 deduction"), as LG&E expects to incur a tax loss for 2015 and 2016 due to bonus

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[1] Order, *In the Matter of: Application of Kentucky Power Company for Approval of an Amended Compliance Plan for Purposes of Recovering Additional Costs of Pollution Control Facilities and to Amend Its Environmental Cost Recovery Tariff*, Case No. 2005-00068 at 26-27 (Ky. P.S.C. September 7, 2005).

depreciation. The §199 deduction is not available to companies that do not have taxable income."

Q. DID THE COMPANY SIMILARLY EXCLUDE THE SECTION 199 MANUFACTURING DEDUCTION AS A COMPONENT OF THE GRCF?

A. Yes. The Company has not reflected a Section 199 manufacturing deduction in the calculation of the Federal income tax liability in Section V, Schedule 5, and Kentucky Power has historically not been able to claim this deduction on most of its stand-alone Federal income tax returns. As was the case with LG&E, the Company has not been eligible to take advantage of the Section 199 deduction as a result of its generation losses, primarily due to bonus tax depreciation. Accordingly, the Company has not included a Section 199 deduction in the calculation of its GRCF.

Q. DOES KENTUCKY POWER EXPECT TO CLAIM A SECTION 199 DEDUCTION ON ITS 2016 TAX RETURN?

A. No. In 2016, Kentucky Power accrued a large taxable loss (negative qualified manufacturing income) on its generation activities.

Q. DOES IT MAKE A DIFFERENCE WHETHER THE SECTION 199 DEDUCTION IS INCLUDED IN THE GRCF AS OPPOSED TO IT BEING INCLUDED AS A SEPARATE SCHEDULE M ADJUSTMENT IN THE FEDERAL INCOME TAX CALCULATIONS?

A. Yes. If the Section 199 deduction is included in the GRCF, it assumes that the Company will be able to claim a deduction on each and every income tax return. The Section 199 deduction is not an automatic deduction that can be taken on income tax returns. It is determined on an annual basis based on facts and circumstances and is more closely aligned with taxable income not book income. Including the Section 199 deduction as a component of the GRCF assumes that the book return on production activities will approximate the Qualified Production Activities Income (QPAI) which would be used in calculating the Section 199 manufacturing deduction.

Q. PLEASE EXPLAIN WHY BOOK INCOME WOULD BE DIFFERENT THAN QPAI?

A. The primary difference between book income and QPAI is that QPAI is derived from taxable income associated with generation activities only. By using generation related book income, the impact of all book/tax temporary differences, including bonus tax depreciation, is excluded. There is no direct link between book income and QPAI due to differences between the reporting of revenues and expenses for book and tax purposes.

Q. WHAT IS THE IMPACT IF THE COMMISSION CONTINUES TO REQUIRE THE INCLUSION OF THE SECTION 199 MANUFACTURING DEDUCTION AS A COMPONENT OF THE GRCF?

A. The years in which the Company would have been able to claim this deduction on a stand-alone tax return basis are very limited. By embedding this deduction in rates by way of the GRCF, the Commission is passing along a permanent tax deduction in rates (through reduced income tax expense) that simply does not exist.

V. JURISDICTIONAL STATE AND FEDERAL INCOME TAXES

Q. PLEASE DESCRIBE THE COMPUTATION OF JURISDICTIONAL STATE AND CURRENT FEDERAL INCOME TAXES.

A. The computation of jurisdictional Current Federal Income Tax is accomplished by first allocating Pre-Tax Book Income and the various Schedule M Adjustments used in the determination of the Company's total separate return federal taxable income to Kentucky Power's retail customers, and applying the statutory federal income tax rate of 35%, as shown in Section V, Exhibit 3. The computation of jurisdictional Deferred Federal income tax is accomplished by applying the appropriate federal income tax rate to the allocated normalized timing differences, as shown in Section V, Exhibit 3, and by amortizing the allocated balances of the embedded Deferred Federal income taxes balances over the appropriate remaining lives. The computation of jurisdictional Deferred Investment Tax Credit is accomplished by amortizing the allocated balances over the appropriate remaining lives. State income tax expense is calculated on the same basis as the Federal income tax expense as shown in Section V, Exhibit 3. Company Witness Walsh prepared the jurisdictional allocation factors.

Q. WERE DEFERRED TAXES AND INVESTMENT TAX CREDITS ALLOCATED TO THE KENTUCKY RETAIL JURISDICTION?

A. Yes. Each component was allocated to the Kentucky retail jurisdiction as shown in Section V, Exhibit 3.

VI. RATEMAKING ADJUSTMENTS

Q. WHICH RATEMAKING ADJUSTMENTS ARE YOU SPONSORING?

A. I am sponsoring the ratemaking adjustments in Schedule 5 related to State Gross Receipts Tax and Amortization of Deferred State Income taxes related to the Mitchell Plant. These adjustments are necessary to reflect an adjusted test year level of tax expense representative of ongoing operations. In addition, I have reviewed each of the ratemaking adjustments proposed by other Company witnesses and determined the proper income tax consequences as shown on Section V, Schedule 5.

Q. PLEASE DESCRIBE THE STATE GROSS RECEIPTS TAX ADJUSTMENT YOU ARE SPONSORING.

A. Adjustment 48 on tab W48 of Section V Exhibit 2 adjusts the State Gross Receipts Tax Expense to remove an out-of-period adjustment related to the settlement of a State Gross Receipts Tax Audit that was recorded during the test period.

Q. PLEASE DESCRIBE THE ACCUMULATED DEFERRED STATE INCOME TAX AMORTIZATION ADJUSTMENT YOU ARE SPONSORING.

A. In Case No. 2014-00396 the Commission held that the Accumulated Deferred State Income Tax (ADSIT) balance that was acquired from Ohio Power Company as a result of the acquisition of the Mitchell Plant should be amortized over a three-year period. Currently the Company is amortizing $1,574,616 (total company) of Accumulated Deferred State Income Tax to cost of service each year until June 2018, at which time the balance will be completely amortized. The unamortized total company Accumulated Deferred State Income Tax balance as of December 31, 2017, when the new rates are expected to go into effect, will be \$787,325. The Company is proposing that the amortization of the Accumulated Deferred State Income Tax account balance be adjusted to reflect a new three-year period effective with the implementation of the new rates (\$262,442 annually). The effect of this adjustment is to increase Kentucky Power's State Income tax expense by \$1,312,174 or \$1,292,491 on a jurisdictional basis as shown on Section V, Schedule 5.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; (4) An Order Approving Accounting Practices To Establish Regulatory Assets And Liabilities; And (5) An Order Granting All Other Required Approvals And Relief	)	Case No. 2017-00179

DIRECT TESTIMONY OF

DOUGLAS R. BUCK

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Douglas R. Buck, being duly sworn, deposes and says he is a Regulatory Case Manager for American Electric Power Service Corporation and that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief.

Douglas R. Buck

STATE OF OHIO)
) Case No. 2017-00179
County of FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Douglas R. Buck, this the 21st day of June, 2017.

Amanda E Owen
Notary Public

Notary ID Number:______________

My Commission Expires: Never

NOTARIAL SEAL ★ STATE OF OHIO ★

Amanda E. Owen, Attorney At Law
NOTARY PUBLIC - STATE OF OHIO
My commission has no expiration date
Sec. 147.03 R.C.

DIRECT TESTIMONY OF
DOUGLAS R. BUCK, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2017-00179

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DIRECT TESTIMONY OF
DOUGLAS R. BUCK, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Douglas R. Buck. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by the American Electric Power Service Corporation ("AEPSC") as a Regulatory Case Manager, Federal Energy Regulatory Commission Regulatory Group, in the Regulatory Services Department. AEPSC, a wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP"), provides centralized professional and other services to subsidiaries of AEP. AEP is the parent company of Kentucky Power Company ("Kentucky Power" or "Company").

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I received my Bachelor of Science Degree in Mechanical Engineering in 1985 from Valparaiso University and am a Registered Professional Engineer (PE) in Ohio. I received my Master of Business Administration Degree in 1993 from Northern Illinois University. I began my career with AEP in 1997 as a Financial Analyst, Financial Forecasting group, in the Corporate Planning and Budgeting Department. In 2000 I became a Financial Analyst Coordinator, Resource Planning and Operational Analysis group, also in the Corporate Planning and

Budgeting Department. In 2006 I became the Director of Enterprise Risk Management in the Risk and Strategic Initiatives Department. From 2010 to 2016 I held various Regulatory Consultant positions in Regulated Pricing and Analysis, in the Regulatory Services Department. As a regulatory consultant in the Regulated Pricing and Analysis group, I prepared numerous cost of service studies. I accepted my current position in June 2016. Prior to joining AEP I worked for approximately 9 years in various engineering departments and the Strategic Analysis Department of Commonwealth Edison (now Exelon) in Chicago, Illinois.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY PROCEEDINGS?

A. Yes. I have sponsored testimony before the Virginia State Corporation Commission, the Public Service Commission of West Virginia, the Tennessee Regulatory Authority, and this Commission.

III. <u>PURPOSE OF DIRECT TESTIMONY</u>

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this proceeding is as follows:

- to support and describe the development of the Company's Class Cost of Service Study, and
- to address the allocation of the requested rate increase to Kentucky Power's customer classes.

Q. WHAT EXHIBITS ARE YOU SPONSORING IN THIS PROCEEDING?

A. I am sponsoring the following exhibits:

Exhibit DRB-1	Class Cost of Service Study
Exhibit DRB-2	Revenue Allocation

Q. WAS YOUR TESTIMONY EITHER PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. DO YOU AGREE WITH THE MANNER IN WHICH THE EXHIBITS YOU ARE SPONSORING WERE PREPARED AND WITH THEIR CONCLUSION?

A. Yes. The class cost of service study and related revenue allocation were prepared by staff within the Regulatory Pricing and Analysis group of the Regulatory Services Department. Shortly before the filing deadline, the staff member who prepared the class cost of service study left AEPSC for a position with another employer. I have reviewed the class cost of service study and agree with the manner in which it was prepared and its conclusions. Accordingly, I am sponsoring the class cost of service study and the revenue allocation in this case.

IV. <u>CLASS COST OF SERVICE STUDY</u>

Q. PLEASE DESCRIBE THE GENERAL PURPOSE OF A CLASS COST OF SERVICE STUDY.

A. A class cost of service study is a basic analytical tool used in traditional utility rate design to determine the revenue requirement for the services offered by the utility. It analyzes, at a very detailed level, the costs that different classes of customers impose on the utility system. A class cost of service study calculates the total functional costs the Company incurs in serving each retail rate class as well as the rate of return on rate base earned from each class during the test year. This is accomplished by classifying and allocating the jurisdictional and functionalized costs of serving Kentucky's retail customers to the various rate classes. When a cost of service study is completed and all of the costs are allocated to the customer classes, the Company is able to establish rates based on the costs to serve each customer class. A copy of the class cost of service study prepared for this case is included as Exhibit DRB-1.

Q. WHAT DATA SOURCE WAS USED IN THE DEVELOPMENT OF THE CLASS COST OF SERVICE STUDY?

A. Company witness Walsh sponsors the Company's jurisdictional cost-of-service study, shown in Section V of this filing, and describes the methods used to allocate the total Company costs between the Commission's retail jurisdictional (retail) and the non-jurisdictional customers, and to the various functions. Using various allocators derived from historic accounting records and Company data, the results of the Jurisdictional study are classified and allocated to the rate classes in order to prepare the class cost-of service study.

Q. AFTER THE COSTS RECORDED IN FERC ACCOUNTS ARE EXAMINED AND ADJUSTED, WHERE APPROPRIATE, HOW ARE THESE COSTS ASSIGNED TO EACH CUSTOMER CLASS?

A. This accounting cost information is assigned to the different customer classes in a way that reflects the costs of providing utility service to the customer classes. The

Company assigns costs to customer classes using a standard three-step process: functionalization of costs, classification of costs, and finally, allocation of costs.

Q. PLEASE EXPLAIN THE FUNCTIONALIZATION PROCESS.

A. Functionalization is the process of separating costs according to electric system functions. Typically, functions in an electric utility include the following:

1) Production and Purchased Power costs,
2) Transmission costs,
3) Distribution costs,
4) Customer Service costs, and
5) Administrative and General ("A&G") costs.

The production function includes the costs associated with power generation and power purchases and their delivery to the bulk transmission system. The transmission function consists of costs associated with the high voltage system utilized for the bulk transmission of power to and from interconnected utilities to load centers of the utility's system. The distribution function includes the radial distribution system that connects the transmission system and the ultimate customer. The customer service function encompasses the costs associated with providing meter reading, billing and collection, and customer information and services. The A&G function is comprised of costs that may not be directly assignable to other cost functions. These costs include such items as management costs and administrative buildings. A&G costs are generally allocated to the remaining functions based on labor.

Q. PLEASE EXPLAIN THE CLASSIFICATION PROCESS.

A. The second step is to separate the functionalized costs into classifications of demand costs, energy costs, and customer costs.

Typical cost classifications used in cost studies include the following:

Function	Classification
Production	Demand, Energy
Transmission	Demand
Distribution	Demand, Customer
Customer Service	Customer

Demand costs are associated with the kilowatt (kW) demand imposed by the customer. These are fixed costs which are incurred regardless of the level of energy sales. An example of a demand-related cost is the investment in production, transmission or distribution facilities, such as a generating unit including transmission and distribution poles and lines.

Energy costs vary with the number of kilowatt hours (kWh) used by the customer. Production costs such as fuel and certain production operation and maintenance expenses are energy-related since they vary with the level of sales of electricity.

Customer costs are directly related to the number of customers served. These are fixed costs which are incurred regardless of the level of energy sales. Meter and customer service costs are examples of costs whose levels are fixed by the number of customers.

The classification process provides a basis on which to allocate different categories of costs (demand, energy or customer) to the Company’s classes.

Q. PLEASE EXPLAIN THE ALLOCATION PROCESS.

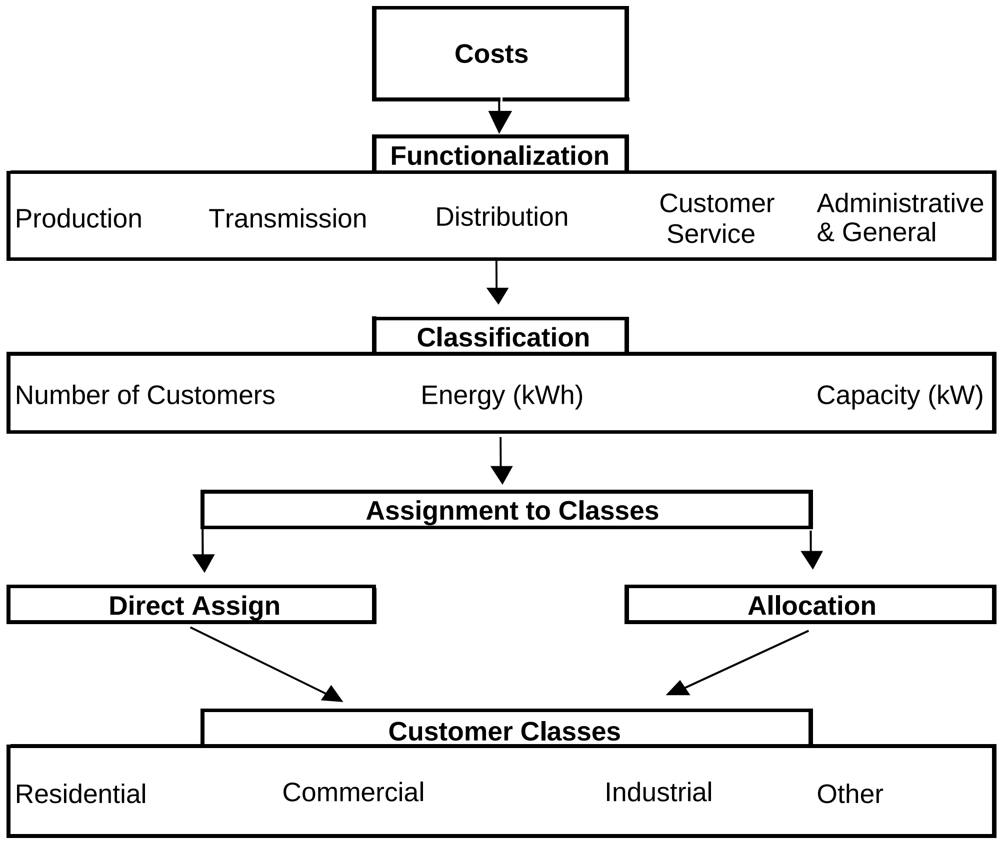
A. The third and final step is to allocate the functionalized and classified costs among the classes of customers based on how the costs are incurred for each class. Allocation factors are used to assign these costs to the various customer classes. Customer classes are determined and grouped according to the nature of service provided, voltage level, and the load usage characteristics. The three principal customer classes are residential, commercial, and industrial.

The allocation process involves multiplying the functionalized and classified costs by allocation factors, which results in costs assigned to each class. The objective in this process is to determine a reasonable, appropriate, and understandable method to assign the costs. Some costs are directly assignable to a single class, or even a single customer. For instance, the costs associated with the poles and luminaries used for street lighting are directly assigned to the street lighting class. Most costs, however, are attributable to more than one type of customer. These are joint costs that are allocated to customers by an allocation methodology that is based on the manner in which the costs are caused by the different customers.

The following flowchart (Figure 1) provides an overview of how the allocation of costs to customer classes is determined.

Figure 1:

Cost Allocation Example



In the illustration above, costs are functionalized into production, transmission, distribution, etc. Some of these costs can be functionalized and classified and directly assigned to a customer class. The remaining functionalized costs are incurred based on the number of customers, the energy used, or by the capacity demanded.

After functionalization, the next step is the classification process which leads to an allocation methodology. For example, the cost of billing customers varies with the number of customers as well as the complexity of preparing the customer’s bill, so those costs associated with billing are allocated to the customer classes based on a weighted number of customers. An allocation factor using a weighted number of customers is developed by multiplying the number of customers in each class by a factor representing the difference in cost associated with providing that service to different types of customers. Similarly, the cost of fuel varies by the number of kWh consumed and, therefore, is allocated based on the proportion of total energy used by a customer class.

The final step in the cost assignment process is to allocate the functionalized and classified costs to the customer classes through the use of allocation factors.

When this process is completed and all of the costs are allocated to the customer classes, the result is a fully allocated cost study that establishes cost responsibility, by class, and makes it possible to determine rates based on costs that are just and reasonable.

V. ALLOCATION BASIS

Q. WHAT CRITERIA ARE USED WHEN SELECTING ALLOCATION FACTORS FOR EACH FUNCTIONALIZED AND CLASSIFIED COST?

A. Generally, the following criteria should be used to determine the appropriateness of an allocation methodology:

1) The method should reflect the planning and operating characteristics of the utility's system.

2) The method should recognize customer class characteristics such as energy usage, peak demand on the system, diversity characteristics, number of customers, etc.

3) The method should produce stable results on a year-to-year basis.

4) The method should cause customers who benefit from the use of the system to bear appropriate cost responsibility for the system.

Q. DOES THE ALLOCATION METHOD EMPLOYED BY THE COMPANY MEET THESE OBJECTIVES?

A. Yes, it does. The allocation methodology utilized in the Company's class cost of service study was chosen in consideration of each of the criteria listed above. The results of the cost of service study can be relied upon to determine the appropriate revenue requirement for the Kentucky Power customer classes. The allocation of specific sections of the class cost of service study, as shown on Exhibit DRB-1, follows.

Q. PLEASE EXPLAIN THE ALLOCATION OF PRODUCTION PLANT.

A. Electric plant-in-service is functionalized into production, transmission, distribution and general plant. Production plant is classified as demand-related and allocated using the production demand allocation factor. The production demand allocation factor assigns costs to the retail classes based on their average contribution to Kentucky Power's 12 coincident peaks (CPs). The CPs used in the allocation of Production Plant were the 12 monthly internal peak demands for the test period ended February 28, 2017.

Q. PLEASE EXPLAIN HOW GENERATOR STEP-UP TRANSFORMERS WERE ALLOCATED.

A. Generator step-up transformers are included in transmission plant, but were allocated using the production demand allocation factor because they are more related to the production function.

Q. PLEASE EXPLAIN THE ALLOCATION OF TRANSMISSION PLANT.

A. Transmission plant, excluding generator step-up transformers, is classified as demand related and is allocated using the transmission demand allocation factor. The transmission demand allocation factor, similar to the Production Plant allocation factor, assigns costs based on the class average contribution to Kentucky Power’s 12 CPs on the transmission facilities.

Q. PLEASE EXPLAIN THE ALLOCATION OF DISTRIBUTION PLANT.

A. Distribution plant is classified as demand / customer related and allocated to the customer classes using factors based on demand levels or number of customers. Distribution plant accounts 360 through 368 were classified solely as demand-related. Accounts 360, 361 and 362 were allocated to the distribution customer classes based on their contributions to the average of Kentucky Power’s 12 monthly CP demands during the test year on the primary distribution system.

Accounts 364 through 368 were split into primary and secondary voltage functions based upon information contained in the company’s records and the expertise of the company’s distribution engineers. The primary portions of accounts 364 through 368 were allocated using the average of 12 monthly CP demands on the distribution system. The secondary component of accounts 364 through 368 were allocated based on a combination of each class's 12-month maximum demand and the summation of individual customers' annual maximum demands in each class served from those facilities. This process reflects the fact that some secondary facilities serve only one customer, while others serve two or more customers.

Services, account 369, was classified as customer-related and was allocated using the average number of secondary customers served.

Meter plant, account 370, was allocated using the average number of customers weighted by a factor which considers the cost differential of various metering installations. Account 371 was directly assigned to the outdoor lighting class and account 373 was directly assigned to the street lighting class.

Q. PLEASE EXPLAIN HOW GENERAL AND INTANGIBLE PLANT WAS ALLOCATED.

A. General and intangible plant and investment reflects a composite demand, energy and customer classification. General and intangible plant investment is allocated on the basis of payroll labor.

Q. PLEASE DESCRIBE THE ALLOCATION OF ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION.

A. The functionalized components of Depreciation and Amortization were obtained directly from the Jurisdictional study. Production, transmission, distribution, and general and intangible related amounts were classified and allocated based upon the allocation of their corresponding functional Electric Plant-in-Service costs excluding land and land rights.

Q. PLEASE DESCRIBE THE ALLOCATION OF WORKING CAPITAL.

A. Working Capital was divided into cash, material and supplies, and prepayments. Cash working capital is related to O&M expense and was allocated based upon the allocation of total O&M expense less purchased power and fuel.

Materials and supplies were split between fuel stock, production, emissions, and transmission and distribution and were classified and allocated using the corresponding functional plant items. Fuel stock and emissions materials were allocated using the energy allocation factor. Production-related material and supplies were allocated using the production demand allocation factor, and the transmission- and distribution-related materials and supplies were allocated using the allocation of transmission and distribution electric plant-in-service.

Prepayments were allocated based upon gross utility plant.

Q. PLEASE DESCRIBE THE ALLOCATION OF OTHER RATE BASE COMPONENTS.

A. Plant Held for Future Use is limited to a distribution component that was allocated using distribution electric plant-in-service. Construction Work-in-Progress was functionalized and allocated by the corresponding functional Electric Plant-in-Service allocators. Accumulated Deferred Federal Income Tax Credits (ITC) were allocated on gross utility plant. Customer Deposits were directly assigned based on an analysis of accounting records, and Customer Advances were allocated based on transmission and distribution plant-in-service.

Q. HOW WERE REVENUES DEVELOPED FOR EACH CLASS?

A. Sales revenues were directly assigned to each class. Energy-related system sales revenue was allocated on the basis of kWh sales.

Forfeited Discounts and Miscellaneous Service Revenue were directly assigned based on an analysis of accounting records.

Rent from Electric Property and Other Electric Revenue were functionalized in the Jurisdictional study and allocated to classes based on corresponding functional allocators.

Q. PLEASE DESCRIBE THE ALLOCATION OF PRODUCTION OPERATION AND MAINTENANCE (“O&M”) EXPENSE.

A. Production-related O&M was classified as either demand or energy related. The demand component was allocated using the production demand allocation factor and the energy component was allocated using the energy allocation factor. Supervision and Engineering accounts for both O&M were classified and allocated based on functional labor expense. For example, Accounts 500 and 510 for Steam Production accounts were allocated on production labor expense.

Q. PLEASE DESCRIBE THE ALLOCATION OF TRANSMISSION O&M.

A. Transmission-related O&M was broken down into two pieces: expenses incurred through PJM as a Load Serving Entity (“LSE”), and the traditional transmission cost of service expenses recorded in FERC accounts 560 – 575. Most Transmission O&M expenses were allocated based upon the transmission demand allocation factor. Supervision and Engineering accounts for both O&M were classified and allocated based on functional labor expense. For example, Transmission Accounts 560 and 568 were allocated on total transmission O&M

excluding PJM related costs. Expenses incurred through PJM as a LSE are classified as production expenses as they capture load (LSE) charges and are allocated using an allocation factor based on production demand.

Q. PLEASE DESCRIBE THE ALLOCATION OF DISTRIBUTION O&M AMONG THE VARIOUS CUSTOMER CLASSES.

A. Distribution O&M expenses were functionalized and classified according to the associated distribution plant accounts and allocated accordingly.

Accounts 581, Load Dispatching and 582, Station Expenses were allocated using the distribution demand allocation factor.

Account 583 Overhead Line Expense was allocated based upon the same allocation used for plant account 365 Overhead Lines.

Account 584 Underground Line Expense was allocated based upon the same allocation used for plant accounts 366 Underground Conduit and 367 Underground Lines.

Account 585, Street Lighting Operation Expense, was classified as customer-related and directly assigned to the Street Lighting class.

Meter Operation Expense, account 586, was classified customer-related and allocated in the same manner as account 370 Meter Plant.

Account 587, Customer Installation Expense was classified as customer-related and allocated based on primary customers.

Accounts 588 and 589 were allocated on total distribution plant and classified accordingly.

Account 580 was classified and allocated based on the sum of the allocated O&M expense accounts 581 through 589.

Accounts 591 and 592 were classified demand-related and allocated on the distribution demand allocation factor.

Accounts 593, 594, and 595 were functionalized and classified according to the associated distribution plant accounts and allocated accordingly.

Distribution maintenance account 596 was directly assigned to the Street Lighting class.

Account 597 was classified customer-related and allocated in the same manner as meter plant.

Account 598 was classified customer-related and directly assigned to the Outdoor Lighting class.

Account 590 was classified and allocated based on the sum of the allocated O&M expense accounts 591 through 598.

Q. CAN YOU EXPLAIN HOW CUSTOMER ACCOUNTING (ACCOUNTS 901-905), CUSTOMER SERVICES (ACCOUNTS 907-910) AND SALES EXPENSE (ACCOUNTS 911-916) WERE ALLOCATED?

A. Account 902, Meter Reading Expense, was allocated to those classes with meter installations based upon an average number of customers weighted to reflect differences in meter reading requirements. Account 903, Customer Records Expense, was divided into two categories of cost; call center and other. Call center costs were first divided into residential and other based on the number of calls received; then, other (non-residential) call center expenses were further allocated to the remaining classes based on the number of customers in each respective class. Account 904, Uncollectibles, was allocated based on the number of customers. Accounts 901 and 905 were allocated based on the sum of the allocated accounts 902, 903 and 904.

Accounts 907 through 916, Customer Service Expenses and Sales Expenses, were allocated based on the number of customers.

Q. PLEASE DESCRIBE THE ALLOCATION OF ADMINISTRATIVE AND GENERAL (“A&G”) EXPENSE.

A. A&G expenses, excluding Property Insurance, account 924, and Rate Case Expense, account 928, were functionalized, classified, and allocated using O&M labor. Property Insurance was allocated using gross utility plant. Rate Case Expense was allocated to the customer classes based on sales revenue.

Q. PLEASE DESCRIBE THE ALLOCATION OF DEPRECIATION AND AMORTIZATION EXPENSE.

A. The functionalized components of depreciation and amortization expense were allocated using the corresponding functional plant items excluding land and land rights.

Q. PLEASE DESCRIBE HOW OTHER EXPENSES WERE ALLOCATED.

A. The Gain on Disposition of Utility Plant was allocated based on distribution plant. A/R Factoring was allocated based on gross utility plant. Gain/Loss on Disposition of Allowances was allocated based on the energy allocation factor. Accretion was allocated on production demand. The Interest Income and Interest Expense items were allocated based on gross utility plant. Interest on Customer

Deposits was allocated using the customer deposit allocator that was also used for the customer deposit rate base offset.

Q. HOW WERE TAXES ASSIGNED TO THE CUSTOMER CLASSES?

A. Individual tax items other than income taxes were allocated and classified using the appropriate revenue, labor or plant allocator.

Interest Expense was allocated on rate base and individual Schedule M items were allocated using the appropriate allocators. State and current Federal Income Taxes were computed by class. Feedback of prior Investment Tax Credit Normalized was allocated based on gross utility plant and individual Deferred Federal Income Tax items were allocated using the appropriate allocation factors.

Q. PLEASE DESCRIBE THE ALLOCATION OF THE ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION ("AFUDC") OFFSET.

A. The AFUDC offset was divided into the individual functionalized components in the Jurisdictional study. The production component was allocated using the production demand allocator. The transmission and distribution components were allocated using the corresponding plant allocators. The general plant component was allocated using the labor allocation factor.

Q. PLEASE DESCRIBE THE ALLOCATION OF THE VARIOUS JURISDICTIONAL ADJUSTMENTS.

A. The jurisdictional adjustments are identified in the various sections of the cost of service study to which they apply. Each adjustment was allocated using a method consistent with both the nature of the adjustment and the underlying line item being adjusted. For example, an adjustment to employee-related expenses is allocated using the labor allocation factor, and an adjustment for Big Sandy Plant O&M expenses is allocated using the production demand allocation factor.

VI. REVENUE ALLOCATION

Q. WHAT IS THE RESULTING GOING-LEVEL AND RELATIVE RATE OF RETURN FOR EACH CLASS SHOWN IN THE CLASS COST OF SERVICE STUDY?

A. The resulting going-level rates of return (ROR) and relative rates of return prior to the rate relief requested in this case, for each customer class as shown in the class cost of service study, during the test year are presented in the table below. The going-level return is calculated from current income and rate base. The relative return provides a comparison to the total average Kentucky Power jurisdictional return. If the return earned on each class was the same as the average jurisdictional return, each would have a relative return of 1.00. A relative return less than 1.00 shows that the return earned from that class is less than the average return; and, a relative return greater than 1.00 shows that the return earned from that class is greater than the average.

Class Going-Level Rates of Return and Relative Rates of Return

CLASS	Going-Level ROR	Relative ROR
Residential	1.08 %	0.27
Small General Service	10.56 %	2.69
Medium General Service	8.27 %	2.10
Large General Service	8.29 %	2.11
IGS	5.47 %	1.39

CLASS	Going-Level ROR	Relative ROR
Public Schools	6.17 %	1.57
Municipal Waterworks	11.19 %	2.85
Outdoor Lighting	15.05 %	3.83
Street Lighting	15.68 %	3.99
Total Kentucky Power Jurisdiction	3.93 %	1.00

Q. HOW ARE THESE RATES OF RETURN USED IN THIS PROCEEDING?

A. The going-level and relative rates of return for each class form the basis for the allocation of the revenue increase required for each class. This information was provided to Company Witness Wohnhas to assist in his determination of the allocation of the requested rate increase by class.

Q. PLEASE EXPLAIN THE PRINCIPLES OR GUIDELINES USED IN ALLOCATING THE PROPOSED REVENUE INCREASE AMONG THE TARIFF CLASSES.

A. A key objective of ratemaking is to design rates such that they reflect as nearly as possible the actual costs of serving the customer. To fully meet this objective would require that the rates of return for all tariff classes be equalized. While the goal remains to move the rates for each class into alignment with the costs of service, the overall level of the needed revenue increase means that customer bill impacts will be significant even with a restrained approach to progress toward that goal. However, continuation of the gradual progress toward cost alignment of the schedules is a reasonable approach and expectation. As discussed by Company

Witness Wohnhas, the Company opted not to propose to fully equalize returns across tariff classes at this time.

Q. PLEASE DESCRIBE EXHIBIT DRB-2.

A. Exhibit DRB-2 is the calculation of the allocation of the proposed revenue increase to each class of customers. Page 1 is a summary of the calculation of the required sales revenue per class based upon the Company's proposed subsidy reduction. Page 2 of the exhibit calculates the current subsidies received by each class. Page 3, in Columns 2 through 11, shows the calculation of the required sales revenue at an equalized ROR for each class before adjusting to include 95% of each class' current subsidy.

Q. WHAT CLASS BY CLASS BASE RATE REVENUE INCREASE WILL RESULT FROM THE PROPOSED INCREASE?

A. The following table summarizes the Company's proposed revenue allocation, as sponsored by Company Witness Wohnhas, between the major customer classes and the class rate increases:

<u>Base Rate Increase</u>

CLASS	Proposed Increase ($ in Millions)	Percent Increase
Residential	$37.2	17.21 %
Small General Service	$1.8	9.92 %
Medium General Service	$5.9	11.00 %
Large General Service	$5.2	10.06 %
IGS	$12.9	9.25 %
Public Schools	$1.4	12.12 %

CLASS	Proposed Increase ($ in Millions)	Percent Increase
Municipal Waterworks	$0.02	8.45 %
Outdoor Lighting	$0.9	10.41 %
Street Lighting	$0.1	7.78 %
Total Kentucky Power Jurisdiction	$65.4	13.07 %

Q. **DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A**.** Yes, it does.

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
FEBRUARY 28, 201

Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	SGS 3	Total MGS	Total LGS	Total IGS	Total PS	MW 17	OL 18	SL 19
Rate Base													
P-T-D Plant in Service													
Production Plant & Comp. Const. not Classif.	1,147,449,346	PROD_DEMAND	TOTAL	1,147,449,346	565,214,030	27,940,549	105,868,173	99,138,886	324,685,911	24,291,768	310,029	-	-
Transmission & Comp. Const. not Classif.													
GSU	10,045,283	PROD_DEMAND	TOTAL	10,045,283	4,948,136	244,604	926,817	867,906	2,842,445	212,661	2,714	-	-
All Other Transmission Plant	556,524,133	TRANS_TOTAL	TOTAL	556,524,133	273,560,815	13,465,820	50,964,372	47,815,581	158,820,233	11,640,365	149,300	88,556	19,090
Total	566,569,416		TOTAL	566,569,416	278,508,951	13,710,424	51,891,189	48,683,487	161,662,678	11,853,026	152,014	88,556	19,090
Distribution & Comp. Const. not Classif.													
360 Land and Land Rights	7,494,757	DIST_CPD	TOTAL	7,494,757	5,009,066	236,114	883,842	762,592	392,526	197,086	2,620	8,977	1,935
361 Structures and Improvements	4,455,328	DIST_CPD	TOTAL	4,455,328	2,977,686	140,360	525,408	453,330	233,340	117,159	1,558	5,336	1,150
362 Station Equipment	97,083,308	DIST_CPD	TOTAL	97,083,308	64,884,915	3,058,506	11,448,843	9,878,230	5,084,578	2,552,950	33,941	116,278	25,066
363 Storage Battery Equipment	-	DIST_CPD	TOTAL	-	-	-	-	-	-	-	-	-	-
364 Poles	201,038,118	DIST_POLES	TOTAL	201,038,118	141,272,088	6,729,047	22,910,520	17,630,901	6,132,076	5,222,799	62,942	920,750	156,995
365 Overhead Lines	218,593,133	DIST_OHLINES	TOTAL	218,593,133	148,988,642	7,052,186	25,444,291	21,058,971	9,607,179	5,721,516	73,348	546,555	100,445
366 Underground Conduit	7,218,040	DIST_UGLINES	TOTAL	7,218,040	4,933,245	233,643	838,615	689,827	308,594	188,802	2,408	19,383	3,523
367 Underground Lines	11,083,763	DIST_UGLINES	TOTAL	11,083,763	7,575,314	358,774	1,287,747	1,059,273	473,866	289,917	3,697	29,764	5,410
368 Transformers	130,373,329	DIST_TRANSF	TOTAL	130,373,329	95,392,863	4,580,058	14,421,455	9,889,250	1,572,654	3,352,107	36,803	968,871	159,267
369 Services	59,997,917	DIST_SERV	TOTAL	59,997,917	38,270,555	6,696,555	1,880,743	164,555	1,121	45,133	2,803	12,921,033	15,418
370 Meters	24,871,958	DIST_METERS	TOTAL	24,871,958	11,151,515	6,607,574	3,344,229	2,079,939	1,423,786	262,149	2,766	-	-
371 Installations on Cust Premises	19,789,117	DIST_OL	TOTAL	19,789,117	-	-	-	-	-	-	-	19,789,117	-
373 Street Lighting	3,923,399	DIST_SL	TOTAL	3,923,399	-	-	-	-	-	-	-	-	3,923,399
Total	785,922,166		TOTAL	785,922,166	520,455,890	35,692,819	82,985,692	63,666,868	25,229,721	17,949,617	222,886	35,326,064	4,392,609
Total P-T-D Plant in Service	2,499,940,928		TOTAL	2,499,940,928	1,364,178,871	77,343,792	240,745,054	211,489,240	511,578,310	54,094,412	684,929	35,414,621	4,411,699
General & Intangible Plant & Comp. Const. not Classif.	60,690,785	LABOR_M	TOTAL	60,690,785	34,262,675	2,185,858	5,729,201	5,014,273	11,505,499	1,272,456	16,996	560,610	143,217
HR - J 765 Line - FERC AFUDC Adj.	599,342	BULK_TRANS	TOTAL	599,342	295,226	14,594	55,298	51,783	169,592	12,688	162	-	-
Total Electric Plant in Service	2,561,231,055		TOTAL	2,561,231,055	1,398,736,771	79,544,245	246,529,552	216,555,296	523,253,401	55,379,556	702,086	35,975,231	4,554,917
Adj 4 - Move FGD from Base Rates to Environmental (Mitchell)	(323,154,089)	PROD_DEMAND	TOTAL	(323,154,089)	(159,180,208)	(7,868,846)	(29,815,462)	(27,920,306)	(91,440,707)	(6,841,247)	(87,313)	-	-
Total Adjustments to Electric Plant in Service	(323,154,089)		TOTAL	(323,154,089)	(159,180,208)	(7,868,846)	(29,815,462)	(27,920,306)	(91,440,707)	(6,841,247)	(87,313)	-	-
Total Adjusted Electric Plant in Service	2,238,076,966		TOTAL	2,238,076,966	1,239,556,564	71,675,398	216,714,090	188,634,990	431,812,693	48,538,309	614,774	35,975,231	4,554,917
Depreciation Reserve													
Generation	(411,669,816)	RB_GUP-Land_P	TOTAL	(411,669,816)	(202,781,549)	(10,024,217)	(37,982,270)	(35,568,007)	(116,487,399)	(8,715,145)	(111,229)	-	-
Transmission - GSU	(5,216,286)	RB_GUP-Land_P	TOTAL	(5,216,286)	(2,569,454)	(127,017)	(481,275)	(450,684)	(1,476,017)	(110,430)	(1,409)	-	-
Transmission - All Other	(187,395,956)	RB_GUP-Land_T	TOTAL	(187,395,956)	(92,107,446)	(4,533,167)	(17,156,006)	(16,097,231)	(53,496,430)	(3,917,761)	(50,259)	(30,977)	(6,678)
Distribution	(229,090,908)	RB_GUP-Land_D	TOTAL	(229,090,908)	(151,695,816)	(10,434,896)	(24,162,545)	(18,512,706)	(7,309,578)	(5,224,564)	(64,824)	(10,393,806)	(1,292,174)
General & Intangible	(23,370,449)	RB_GUP-Land_G	TOTAL	(23,370,449)	(13,193,668)	(841,717)	(2,206,167)	(1,930,866)	(4,430,470)	(489,990)	(6,545)	(215,877)	(55,149)
HR-J Post In-Service AFUDC	(1,061,245)	BULK_TRANS	TOTAL	(1,061,245)	(522,751)	(25,841)	(97,915)	(91,691)	(300,293)	(22,467)	(287)	-	-
Total Depreciation Reserve	(857,804,660)		TOTAL	(857,804,660)	(462,870,684)	(25,986,856)	(82,086,178)	(72,651,186)	(183,500,186)	(18,480,356)	(234,553)	(10,640,660)	(1,354,001)
Adj 4 - Move FGD from Base Rates to Environmental (Mitchell)	93,260,268	PROD_DEMAND	TOTAL	93,260,268	45,938,422	2,270,900	8,604,558	8,057,627	26,389,222	1,974,341	25,198	-	-
Total Depreciation Adjustments	93,260,268		TOTAL	93,260,268	45,938,422	2,270,900	8,604,558	8,057,627	26,389,222	1,974,341	25,198	-	-
Total Adjusted Depreciation Reserve	(764,544,392)		TOTAL	(764,544,392)	(416,932,263)	(23,715,955)	(73,481,621)	(64,593,559)	(157,110,964)	(16,506,015)	(209,355)	(10,640,660)	(1,354,001)
Net Electric Plant in Service	1,473,532,574		TOTAL	1,473,532,574	822,624,301	47,959,443	143,232,469	124,041,431	274,701,729	32,032,294	405,419	25,334,571	3,200,916
Plant Held for Future Use - Tranmsission	-	RB_GUP_EPIS_T	TOTAL	-	-	-	-	-	-	-	-	-	-
Plant Held for Future Use - Distribution	626,976	RB_GUP_EPIS_D	TOTAL	626,976	415,198	28,474	66,203	50,791	20,127	14,319	178	28,182	3,504
Total Plant Held for Future Use	626,976		TOTAL	626,976	415,198	28,474	66,203	50,791	20,127	14,319	178	28,182	3,504
Working Capital													
Working Capital - Cash													
Working Capital Cash - Excl Sys Sales	21,218,686	EXP_OM_LPP	TOTAL	21,218,686	11,855,323	798,842	1,965,106	1,720,931	4,050,074	434,021	5,892	339,415	49,082
Total Working Capital - Cash	21,218,686		TOTAL	21,218,686	11,855,323	798,842	1,965,106	1,720,931	4,050,074	434,021	5,892	339,415	49,082
Cash Working Capital Adjustments													
Adj 2 - Decommissioning Rider Removal	7	PROD_DEMAND	TOTAL	7	3	0	1	1	2	0	0	-	-
Adj 3 - Env Surcharge - Remove Mitchell FGD Expenses	(490,965)	PROD_ENERGY	TOTAL	(490,965)	(184,223)	(11,939)	(41,447)	(46,509)	(191,959)	(10,055)	(180)	(3,885)	(769)
Adj 5 - Environmental Surcharge Revenue Sync - remove FGD re	(83,425)	PROD_ENERGY	TOTAL	(83,425)	(31,303)	(2,029)	(7,043)	(7,903)	(32,618)	(1,709)	(31)	(660)	(131)
Adj 6 - Big Sandy Unit 1 Operation Rider Deferrals - Demand	(329,914)	PROD_DEMAND	TOTAL	(329,914)	(162,510)	(8,033)	(30,439)	(28,504)	(93,354)	(6,984)	(89)	-	-
Adj 6 - Big Sandy Unit 1 Operation Rider Deferrals - Energy	(297,971)	PROD_ENERGY	TOTAL	(297,971)	(111,807)	(7,246)	(25,154)	(28,226)	(116,502)	(6,103)	(109)	(2,358)	(467)
Adj 7 - Fuel Under (Over) Revenue & Expense	276,493	PROD_ENERGY	TOTAL	276,493	103,748	6,724	23,341	26,192	108,104	5,663	101	2,188	433

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
FEBRUARY 28, 2017

Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	SGS 3	Total MGS	Total LGS	Total IGS	Total PS	MW 17	OL 18	SL 19
Adj 8 - System Sales Clause - reset OSS Margin Baseline	21,734	PROD_ENERGY	TOTAL	21,734	8,155	529	1,835	2,059	8,498	445	8	172	34
Adj 9 - PPA Rider Sync	46,568	PROD_ENERGY	TOTAL	46,568	17,474	1,132	3,931	4,411	18,207	954	17	368	73
Adj 10 - Remove DSM Rider	(882,525)	CUST_TOTAL	TOTAL	(882,525)	(562,338)	(98,397)	(27,981)	(2,739)	(276)	(667)	(41)	(189,858)	(227)
Adj 11 - Remove HEAP Surcharge	(30,847)	CUST_TOTAL	TOTAL	(30,847)	(19,655)	(3,439)	(978)	(96)	(10)	(23)	(1)	(6,636)	(8)
Adj 12 - Remove Economic Development Surcharge	(37,876)	CUST_TOTAL	TOTAL	(37,876)	(24,134)	(4,223)	(1,201)	(118)	(12)	(29)	(2)	(8,148)	(10)
Adj 14 - Customer Annualization Adjustment	(241,462)	REVYEC_EXP_OM	TOTAL	(241,462)	(36,713)	(4,681)	(24,472)	55,463	(245,716)	(3,039)	-	19,927	(2,231)
Adj 15 - Weather Normalization Adjustment	734,037	WEATHER_FXNL_OM	TOTAL	734,037	734,037	-	-	-	-	-	-	-	-
Adj 17 - Normalization of Major Storms	74,492	TDOMX	TOTAL	74,492	48,633	2,839	8,250	6,664	5,189	1,827	23	667	400
Adj 18 - Amortization of Storm Cost Deferral	109,324	EXP_OM_DIST	TOTAL	109,324	74,016	4,394	12,421	9,838	4,083	2,740	34	1,124	674
Adj 19 - Rate Case Expense	47,075	RSALE	TOTAL	47,075	20,352	1,753	5,032	4,846	13,079	1,085	18	776	133
Adj 20 - Postage Rate Decrease	(832)	CUST_TOTAL	TOTAL	(832)	(530)	(93)	(26)	(3)	(0)	(1)	(0)	(179)	(0)
Adj 21 - Eliminate Advertising Expense A&G	(3,986)	LABOR_M	TOTAL	(3,986)	(2,250)	(144)	(376)	(329)	(756)	(84)	(1)	(37)	(9)
Adj 21 - Eliminate Advertising Expense O&M	(8,569)	CUST_TOTAL	TOTAL	(8,569)	(5,460)	(955)	(272)	(27)	(3)	(6)	(0)	(1,843)	(2)
Adj 22 - Annualization of Lease Costs	(5,018)	RB_GUP_EPIS_P	TOTAL	(5,018)	(2,472)	(122)	(463)	(434)	(1,420)	(106)	(1)	-	-
Adj 23 - Pension & OPEB Expense Adjustment	18,585	LABOR_M	TOTAL	18,585	10,492	669	1,754	1,535	3,523	390	5	172	44
Adj 24 - Employee Related Group Benefit Expenses	53,655	LABOR_M	TOTAL	53,655	30,291	1,932	5,065	4,433	10,172	1,125	15	496	127
Adj 25 - Remove PJM BLIs from base for FAC inclusion	(106,021)	PROD_ENERGY	TOTAL	(106,021)	(39,782)	(2,578)	(8,950)	(10,043)	(41,452)	(2,171)	(39)	(839)	(166)
Adj 26 - Peaking Unit Equivalent	393,823	PROD_ENERGY	TOTAL	393,823	147,773	9,577	33,246	37,306	153,978	8,066	144	3,116	617
Adj 27 - Forced Outage Adjustment	110,276	PROD_ENERGY	TOTAL	110,276	41,379	2,682	9,309	10,446	43,116	2,259	40	873	173
Adj 28 - PJM LSE OATT Expense	66,094	TRAN_LSE	TOTAL	66,094	32,557	1,609	6,098	5,710	18,702	1,399	18	-	-
Adj 29 - Annualize PJM Admin Fees	14,826	TRAN_LSE	TOTAL	14,826	7,303	361	1,368	1,281	4,195	314	4	-	-
Adj 31 - Severance Related Payroll Expenses - Big Sandy Plant	(4,429)	LABOR_PROD	TOTAL	(4,429)	(2,073)	(108)	(401)	(390)	(1,353)	(93)	(1)	(7)	(1)
Adjs 32-39 - Total Incentive Compensation & Payroll Adjustment	(103,283)	LABOR_M	TOTAL	(103,283)	(58,308)	(3,720)	(9,750)	(8,533)	(19,580)	(2,165)	(29)	(954)	(244)
Adj 40 - Remove Non-Recoverable Business Expenses	(1,864)	RB_GUP	TOTAL	(1,864)	(1,032)	(60)	(180)	(157)	(360)	(40)	(1)	(30)	(4)
Adj 41 - Plant Maintenance Normalization	(34,292)	PROD_DEMAND	TOTAL	(34,292)	(16,892)	(835)	(3,164)	(2,963)	(9,703)	(726)	(9)	-	-
Adj 52 - Employee Complement Increase	21,574	TDOMX	TOTAL	21,574	14,085	822	2,389	1,930	1,503	529	7	193	116
Adj 56 - Reduce base forestry expense	(849,286)	TOTOHLINES	TOTAL	(849,286)	(587,455)	(27,892)	(97,865)	(78,304)	(31,854)	(22,150)	(276)	(2,970)	(521)
Total Cash Working Capital Adjustments	(1,524,002)		TOTAL	(1,524,002)	(558,642)	(141,470)	(166,122)	(43,160)	(394,575)	(29,358)	(376)	(188,333)	(1,967)
Working Capital - Materials & Supplies													
Fuel / Allowance Inventory	28,853,245	PROD_ENERGY	TOTAL	28,853,245	10,826,519	701,628	2,435,753	2,733,233	11,281,134	590,939	10,558	228,302	45,179
Production - Demand Related	11,446,678	PROD_DEMAND	TOTAL	11,446,678	5,638,439	278,728	1,056,115	988,986	3,238,988	242,329	3,093	-	-
Emissions - Energy Related	1,941,575	PROD_ENERGY	TOTAL	1,941,575	728,532	47,214	163,905	183,923	759,123	39,765	710	15,363	3,040
Transmission & Distribution	2,422,380	TDPLANT	TOTAL	2,422,380	1,430,881	88,471	241,563	201,229	334,889	53,377	671	63,401	7,898
Total Working Cap - Materials & Supplies	44,663,878		TOTAL	44,663,878	18,624,370	1,116,041	3,897,337	4,107,370	15,614,134	926,410	15,033	307,066	56,117
Working Capital - Materials & Supplies Adjustments													
Adj 4 - Move FGD from Base Rates to Environmental (Mitchell)	(1,610,192)	PROD_ENERGY	TOTAL	(1,610,192)	(604,188)	(39,155)	(135,930)	(152,532)	(629,558)	(32,978)	(589)	(12,741)	(2,521)
Adj 51 - Mitchell Coal Stock Adjustment	(6,709,111)	PROD_ENERGY	TOTAL	(6,709,111)	(2,517,440)	(163,146)	(566,374)	(635,546)	(2,623,150)	(137,408)	(2,455)	(53,086)	(10,505)
Total Working Cap - Materials & Supplies Adjustments	(8,319,303)		TOTAL	(8,319,303)	(3,121,628)	(202,302)	(702,305)	(788,078)	(3,252,708)	(170,386)	(3,044)	(65,827)	(13,027)
Working Capital - Prepayments													
Working Capital - Prepayments	49,905,719	RB_GUP_EPIS	TOTAL	49,905,719	27,640,230	1,598,253	4,832,395	4,206,274	9,628,768	1,082,331	13,709	802,193	101,568
Total Working Capital	105,944,978		TOTAL	105,944,978	54,439,654	3,169,363	9,826,411	9,203,338	25,645,694	2,243,017	31,213	1,194,515	191,773
Construction Work-In-Progress excluding AFUD(													
Production	6,214,592	RB_GUP_EPIS_P	TOTAL	6,214,592	3,061,202	151,326	573,383	536,937	1,758,501	131,564	1,679	-	-
Transmission	9,206,639	RB_GUP_EPIS_T	TOTAL	9,206,639	4,525,724	222,793	843,228	791,101	2,626,963	192,612	2,470	1,438	310
Distribution	7,479,716	RB_GUP_EPIS_D	TOTAL	7,479,716	4,953,241	339,693	789,785	605,925	240,114	170,829	2,121	336,202	41,805
General	3,043,956	RB_GUP_EPIS_G	TOTAL	3,043,956	1,718,450	109,632	287,349	251,492	577,060	63,820	852	28,118	7,183
Total CWIP	25,944,903		TOTAL	25,944,903	14,258,618	823,444	2,493,744	2,185,455	5,202,638	558,825	7,123	365,757	49,298
Adjustments to CWIP	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-	-
Total Adjusted CWIP	25,944,903		TOTAL	25,944,903	14,258,618	823,444	2,493,744	2,185,455	5,202,638	558,825	7,123	365,757	49,298
Rate Base Offsets													
Accumulated Deferred FIT	(495,215,435)	RB_GUP	TOTAL	(495,215,435)	(274,274,546)	(15,859,492)	(47,951,953)	(41,738,939)	(95,546,451)	(10,739,988)	(136,030)	(7,960,177)	(1,007,859)
Customer Advances	(159,526)	TDPLANT	TOTAL	(159,526)	(94,231)	(5,826)	(15,908)	(13,252)	(22,054)	(3,515)	(44)	(4,175)	(520)
Customer Deposits	(26,917,350)	CUST_DEP_FXNL	TOTAL	(26,917,350)	(19,624,030)	(1,307,089)	(2,932,548)	(1,967,116)	(938,246)	(28,934)	-	(119,386)	-
Adjustments to Rate Base Offsets													
Adj 4 - Move FGD from Base Rates to Environmental (Mitchell)	29,690,336	PROD_DEMAND	TOTAL	29,690,336	14,624,954	722,964	2,739,347	2,565,226	8,401,272	628,551	8,022	-	-
Adj 53 - Remove Decommissioning Rider ADIT from Rate Base	81,440,991	PROD_DEMAND	TOTAL	81,440,991	40,116,447	1,983,099	7,514,065	7,036,449	23,044,801	1,724,125	22,005	-	-
Total Adjustments to Rate Base Offsets	111,131,327		TOTAL	111,131,327	54,741,401	2,706,063	10,253,412	9,601,675	31,446,073	2,352,676	30,027	-	-
Total Rate Base Offsets	(411,160,984)		TOTAL	(411,160,984)	(239,251,405)	(14,466,344)	(40,646,998)	(34,117,633)	(65,060,678)	(8,419,761)	(106,048)	(8,083,738)	(1,008,379)
Total Rate Base	1,194,888,447		TOTAL	1,194,888,447	652,486,366	37,514,381	114,971,829	101,363,382	240,509,510	26,428,694	337,885	18,839,286	2,437,113

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
FEBRUARY 28, 2017

Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	SGS 3	Total MGS	Total LGS	Total IGS	Total PS	MW 17	OL 18	SL 19
Operating Revenues													
Year End Migration Revenue	493,721,226		TOTAL	493,721,226	206,885,811	18,695,980	53,816,462	50,763,337	142,362,507	11,576,823	194,881	7,983,833	1,441,591
Adj 14 - Year End Customer Annualization	(3,274,059)	REVYEC_FXNL	TOTAL	(3,274,059)	(497,806)	(63,473)	(331,825)	752,041	(3,331,736)	(41,204)	-	270,192	(30,248)
Adj 15 - Weather Normalization Adjustment	9,953,044	WEATHER_FXNL	TOTAL	9,953,044	9,953,044	-	-	-	-	-	-	-	-
Total Firm Sales	500,400,211	RSALE	TOTAL	500,400,211	216,341,050	18,632,507	53,484,637	51,515,378	139,030,771	11,535,619	194,881	8,254,025	1,411,343
Non-Firm Sales: Energy	46,350,789	PROD_ENERGY	TOTAL	46,350,789	17,392,072	1,127,119	3,912,873	4,390,754	18,122,380	949,303	16,961	366,751	72,577
Non-Firm Sales: Demand	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-	-
Adjs 8, 25 - Non-Firm Sales: Energy Adjustment - reset OSS mar	(3,993,185)	PROD_ENERGY	TOTAL	(3,993,185)	(1,498,351)	(97,103)	(337,099)	(378,270)	(1,561,268)	(81,784)	(1,461)	(31,596)	(6,253)
Total Sales of Electricity Adjustments	(3,993,185)		TOTAL	(3,993,185)	(1,498,351)	(97,103)	(337,099)	(378,270)	(1,561,268)	(81,784)	(1,461)	(31,596)	(6,253)
Sales of Electricity	542,757,815		TOTAL	542,757,815	232,234,770	19,662,523	57,060,411	55,527,863	155,591,882	12,403,138	210,380	8,589,180	1,477,667
Other Operating Revenues													
450-Forfeited Discounts	4,111,894	FORF_DISC_FXNL	TOTAL	4,111,894	2,830,518	250,487	413,355	249,714	346,467	-	-	21,353	-
451-Miscellaneous Service Revenue	785,136	MISC_SERV_REV	TOTAL	785,136	719,544	45,681	15,159	1,248	12	-	-	3,492	-
454x-Rent from Electric Prop - Poles	5,808,789	DIST_POLES	TOTAL	5,808,789	4,081,911	194,429	661,976	509,427	177,180	150,907	1,819	26,604	4,536
454x-Rent from Electric Prop - Production	61,946	RB_GUP_EPIS_P	TOTAL	61,946	30,514	1,508	5,715	5,352	17,528	1,311	17	-	-
454x-Rent from Electric Prop - Transmission	(50,577)	TRANS_TOTAL	TOTAL	(50,577)	(24,861)	(1,224)	(4,632)	(4,345)	(14,434)	(1,058)	(14)	(8)	(2)
454x-Rent from Electric Prop - Other Dist	951,923	RB_GUP_EPIS_D	TOTAL	951,923	630,385	43,232	100,514	77,114	30,559	21,741	270	42,788	5,320
456-Other Electric Revenue - Production Energy	(513,342)	PROD_ENERGY	TOTAL	(513,342)	(192,620)	(12,483)	(43,336)	(48,628)	(200,708)	(10,514)	(188)	(4,062)	(804)
456-Other Electric Revenue - Transmission	59,610,175	TRANS_TOTAL	TOTAL	59,610,175	29,301,529	1,442,345	5,458,874	5,121,602	17,011,485	1,246,818	15,992	9,485	2,045
456-Other Electric Revenue - Dist	223,318	RB_GUP_EPIS_D	TOTAL	223,318	147,886	10,142	23,580	18,091	7,169	5,100	63	10,038	1,248
456-Other Electric LSE Charge	(42,605,780)	TRAN_LSE	TOTAL	(42,605,780)	(20,986,883)	(1,037,457)	(3,930,976)	(3,681,112)	(12,055,867)	(901,974)	(11,512)	-	-
456-Other Electric Revenues DSM	12,563,568	PROD_DEMAND	TOTAL	12,563,568	6,188,600	305,925	1,159,164	1,085,484	3,555,027	265,974	3,395	-	-
Total Other Operating Revenues	40,947,050		TOTAL	40,947,050	22,726,524	1,242,585	3,859,394	3,333,946	8,874,419	778,306	9,842	109,690	12,344
Other Operating Revenue Adjustments													
Adj 10 - Remove DSM Rider	(12,563,569)	PROD_DEMAND	TOTAL	(12,563,569)	(6,188,600)	(305,925)	(1,159,164)	(1,085,484)	(3,555,027)	(265,974)	(3,395)	-	-
Adj 28 - PJM LSE OATT Expense	(3,297,104)	TRAN_LSE	TOTAL	(3,297,104)	(1,624,097)	(80,285)	(304,204)	(284,868)	(932,959)	(69,800)	(891)	-	-
Adj 46 - Rent from Electric Prop - Poles -CATV Adj.	532,369	DIST_POLES	TOTAL	532,369	374,103	17,819	60,669	46,688	16,238	13,830	167	2,438	416
Total Other Operating Revenue Adjustments	(15,328,304)		TOTAL	(15,328,304)	(7,438,595)	(368,390)	(1,402,698)	(1,323,664)	(4,471,748)	(321,944)	(4,119)	2,438	416
Total Other Operating Revenues	25,618,746		TOTAL	25,618,746	15,287,929	874,195	2,456,695	2,010,283	4,402,671	456,362	5,723	112,128	12,760
Total Operating Revenues	568,376,561		TOTAL	568,376,561	247,522,700	20,536,717	59,517,106	57,538,146	159,994,553	12,859,500	216,104	8,701,308	1,490,427
Operating Expense													
O&M Expense													
Production													
500-Supervision & Engineering	3,540,991	LABOR_PROD	TOTAL	3,540,991	1,657,633	86,199	320,917	312,086	1,081,680	74,455	1,027	5,839	1,155
501-Fuel Delivered and Consumed	107,534,921	PROD_ENERGY	TOTAL	107,534,921	40,350,015	2,614,942	9,077,958	10,186,653	42,044,347	2,202,405	39,349	850,871	168,380
502-Steam / Consumables	6,255,757	PROD_ENERGY	TOTAL	6,255,757	2,347,329	152,122	528,103	592,600	2,445,896	128,123	2,289	49,499	9,795
503-Steam other Sources	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-	-
504-Steam Transferred Credit	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-	-
505-Electric	110,662	PROD_DEMAND	TOTAL	110,662	54,510	2,695	10,210	9,561	31,313	2,343	30	-	-
506-Misc. Steam Power Expenses	10,846,903	PROD_DEMAND	TOTAL	10,846,903	5,343,000	264,124	1,000,778	937,165	3,069,274	229,631	2,931	-	-
507-Rents	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-	-
508-IPP Operations	19	PROD_DEMAND	TOTAL	19	9	0	2	2	5	0	0	-	-
509-Allowances	385,332	PROD_ENERGY	TOTAL	385,332	144,587	9,370	32,529	36,502	150,658	7,892	141	3,049	603
510-Supervision & Engineering	2,559,143	LABOR_PROD	TOTAL	2,559,143	1,198,003	62,298	231,933	225,550	781,751	53,810	743	4,220	835
511-Structures	1,612,431	PROD_DEMAND	TOTAL	1,612,431	794,256	39,263	148,769	139,313	456,259	34,136	436	-	-
512-Boiler Plant	14,474,666	PROD_ENERGY	TOTAL	14,474,666	5,431,287	351,982	1,221,932	1,371,168	5,659,351	296,453	5,297	114,531	22,665
513-Electric Plant	4,640,309	PROD_DEMAND	TOTAL	4,640,309	2,285,737	112,992	428,133	400,920	1,313,037	98,236	1,254	-	-
514-Misc Steam Plant	1,806,779	PROD_DEMAND	TOTAL	1,806,779	889,989	43,995	166,701	156,105	511,252	38,250	488	-	-
555-Purchased Power Expense Demand	53,409,161	PROD_DEMAND	TOTAL	53,409,161	26,308,444	1,300,520	4,927,738	4,614,517	15,112,826	1,130,684	14,431	-	-
555-Purchased Power Expense Energy	97,062,507	PROD_ENERGY	TOTAL	97,062,507	36,420,482	2,360,283	8,193,890	9,194,614	37,949,809	1,987,921	35,517	768,008	151,983
556-Sys Control & Load Dispatching	571,585	PROD_DEMAND	TOTAL	571,585	281,553	13,918	52,737	49,385	161,738	12,101	154	-	-
557- Other Expenses	1,465,560	PROD_DEMAND	TOTAL	1,465,560	721,910	35,687	135,218	126,623	414,700	31,026	396	-	-
Total Production Expenses	306,276,726		TOTAL	306,276,726	124,228,745	7,450,390	26,477,547	28,352,765	111,183,896	6,327,467	104,482	1,796,017	355,417
Transmission													
560-Supervision & Engineering	1,449,820	EXP_OM_TRAN	TOTAL	1,449,820	712,663	35,080	132,769	124,566	413,748	30,325	389	231	50
561-Load Dispatching - Company	834,780	TRANS_TOTAL	TOTAL	834,780	410,338	20,199	76,446	71,723	238,229	17,460	224	133	29
561-Load Dispatching - PJM	1,391,646	TRAN_LSE	TOTAL	1,391,646	685,501	33,887	128,399	120,237	393,785	29,461	376	-	-
562-Station Equipment	234,457	TRANS_TOTAL	TOTAL	234,457	115,248	5,673	21,471	20,144	66,909	4,904	63	37	8
563-Overhead Lines	159,380	TRANS_TOTAL	TOTAL	159,380	78,344	3,856	14,595	13,694	45,484	3,334	43	25	5
564-Underground Lines	-	TRANS_TOTAL	TOTAL	-	-	-	-	-	-	-	-	-	-
565 LSE Transmission Purchases	27,040,523	TRAN_LSE	TOTAL	27,040,523	13,319,702	658,440	2,494,865	2,336,284	7,651,472	572,454	7,306	-	-
565 LSE Transmission Purchases - Retail Energy	-	PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-	-
565 Transmission by Others	116,830	TRANS_TOTAL	TOTAL	116,830	57,428	2,827	10,699	10,038	33,341	2,444	31	19	4

KENTUCKY POWER COMPANY
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Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	SGS 3	Total MGS	Total LGS	Total IGS	Total PS	MW 17	OL 18	SL 19
565 Transmission Purchases - Non-Juris	-	TRANS_TOTAL	TOTAL	-	-	-	-	-	-	-	-	-	-
566-Misc Transmission	1,392,007	TRANS_TOTAL	TOTAL	1,392,007	684,244	33,681	127,475	119,599	397,249	29,115	373	222	48
567-Rents	41,897	TRANS_TOTAL	TOTAL	41,897	20,595	1,014	3,837	3,600	11,957	876	11	7	1
Total Transmission Expenses	32,661,340		TOTAL	32,661,340	16,084,062	794,657	3,010,555	2,819,884	9,252,173	690,374	8,817	673	145
568-Supervision & Engineering	24,563	EXP_OM_TRAN	TOTAL	24,563	12,074	594	2,249	2,110	7,010	514	7	4	1
569-Structures	142,273	TRANS_TOTAL	TOTAL	142,273	69,935	3,442	13,029	12,224	40,602	2,976	38	23	5
570-Station Equipment	717,706	TRANS_TOTAL	TOTAL	717,706	352,790	17,366	65,725	61,664	204,818	15,012	193	114	25
571-Overhead Lines	1,834,884	TRANS_TOTAL	TOTAL	1,834,884	901,942	44,397	168,032	157,650	523,637	38,379	492	292	63
572-Underground Lines	168	TRANS_TOTAL	TOTAL	168	83	4	15	14	48	4	0	0	0
573-Misc Transmission Expenses	449,711	TRANS_TOTAL	TOTAL	449,711	221,057	10,881	41,183	38,638	128,338	9,406	121	72	15
575- PJM Admin	992,259	TRAN_LSE	TOTAL	992,259	488,770	24,162	91,550	85,731	280,773	21,006	268	-	-
Total Transmission Maintenance	4,161,564		TOTAL	4,161,564	2,046,650	100,847	381,783	358,032	1,185,225	87,296	1,118	504	109
Total Transmission O&M	36,822,904		TOTAL	36,822,904	18,130,712	895,505	3,392,337	3,177,916	10,437,398	777,670	9,935	1,177	254
Distribution Operation													
580 Supervision & Engineering	699,997	TOTOXEXP	TOTAL	699,997	434,510	50,183	75,026	56,416	25,298	14,589	181	23,923	19,871
581 Load Dispatching	2,197	DIST_CPD	TOTAL	2,197	1,468	69	259	224	115	58	1	3	1
582 Station Expenses	246,722	DIST_CPD	TOTAL	246,722	164,895	7,773	29,095	25,104	12,922	6,488	86	296	64
583 Overhead Lines	976,519	DIST_OHLINES	TOTAL	976,519	665,576	31,504	113,667	94,077	42,918	25,560	328	2,442	449
584 Underground Lines	123,066	DIST_UGLINES	TOTAL	123,066	84,111	3,984	14,298	11,761	5,261	3,219	41	330	60
585 Street Lighting	203,417	DIST_SL	TOTAL	203,417	-	-	-	-	-	-	-	-	203,417
586 Meters	1,065,113	DIST_METERS	TOTAL	1,065,113	477,551	282,962	143,213	89,071	60,972	11,226	118	-	-
587 Customer Installs	149,538	DIST_PCUST	TOTAL	149,538	95,308	16,677	4,738	451	27	113	7	32,178	38
588 Miscellaneous Distribution	3,793,319	RB_GUP_EPIS_D	TOTAL	3,793,319	2,512,024	172,274	400,537	307,293	121,773	86,635	1,076	170,504	21,201
589 Rents	1,711,104	RB_GUP_EPIS_D	TOTAL	1,711,104	1,133,133	77,710	180,676	138,615	54,930	39,080	485	76,912	9,564
Total Distribution Operations Expenses	8,970,992		TOTAL	8,970,992	5,568,575	643,136	961,510	723,012	324,217	186,968	2,324	306,587	254,665
Distribution Maintenance													
590 Supervision & Engineering	4,096	TOTMXEXP	TOTAL	4,096	2,824	136	471	377	154	106	1	21	5
591 Structures	27,595	DIST_CPD	TOTAL	27,595	18,443	869	3,254	2,808	1,445	726	10	33	7
592 Station Equipment	430,037	DIST_CPD	TOTAL	430,037	287,412	13,548	50,713	43,756	22,522	11,308	150	515	111
593 Overhead Lines	36,475,999	TOTOHLINES	TOTAL	36,475,999	25,230,604	1,197,919	4,203,190	3,363,076	1,368,118	951,323	11,847	127,544	22,378
5930010 Storm Expense Amortization	2,426,771	TOTOHLINES	TOTAL	2,426,771	1,678,608	79,698	279,641	223,748	91,022	63,292	788	8,486	1,489
593-Forestry Direct Assigned	743,471	TOTOHLINES	TOTAL	743,471	514,262	24,417	85,671	68,548	27,886	19,390	241	2,600	456
594 Underground Lines	86,140	TOTUGLINES	TOTAL	86,140	58,873	2,788	10,008	8,232	3,683	2,253	29	231	42
595 Line Transformers	52,685	DIST_TRANSF	TOTAL	52,685	38,549	1,851	5,828	3,996	636	1,355	15	392	64
596 Street Lighting	25,214	DIST_SL	TOTAL	25,214	-	-	-	-	-	-	-	-	25,214
597 Meters	77,653	DIST_METERS	TOTAL	77,653	34,816	20,630	10,441	6,494	4,445	818	9	-	-
598 Miscellaneous Distribution	61,150	DIST_OL	TOTAL	61,150	-	-	-	-	-	-	-	61,150	-
Total Distribution Maintenance Expenses	40,410,811		TOTAL	40,410,811	27,864,392	1,341,856	4,649,218	3,721,035	1,519,911	1,050,572	13,090	200,971	49,766
Total Distribution O&M	49,381,803		TOTAL	49,381,803	33,432,967	1,984,992	5,610,728	4,444,047	1,844,128	1,237,540	15,414	507,558	304,431
Customer Accounts													
901 Supervision	202,236	TOTOX234	TOTAL	202,236	174,444	21,757	6,452	672	71	157	9	(1,373)	46
902 Meter Read	367,489	CUST_902	TOTAL	367,489	290,620	50,852	21,736	3,227	428	605	21	-	-
903 Customer Records	5,356,255	CUST_903	TOTAL	5,356,255	4,607,083	565,619	160,847	15,746	1,585	3,836	237	-	1,302
904 Uncollectibles	(175,137)	CUST_TOTAL	TOTAL	(175,137)	(111,596)	(19,527)	(5,553)	(544)	(55)	(132)	(8)	(37,677)	(45)
905 Miscellaneous	16,984	TOTOX234	TOTAL	16,984	14,650	1,827	542	56	6	13	1	(115)	4
Total	5,767,827		TOTAL	5,767,827	4,975,201	620,529	184,024	19,158	2,035	4,479	260	(39,166)	1,307
907 - 910 Total Customer Services Expenses	8,570,068	CUST_TOTAL	TOTAL	8,570,068	5,460,778	955,523	271,721	26,600	2,680	6,480	400	1,843,686	2,200
911 - 916 Total Sales Expenses	95,534	CUST_TOTAL	TOTAL	95,534	60,873	10,652	3,029	297	30	72	4	20,552	25
Administrative & General Expense													
920-Salaries	9,272,353	LABOR_M	TOTAL	9,272,353	5,234,660	333,956	875,309	766,082	1,757,813	194,406	2,597	85,650	21,881
921-Office Supplies	699,376	LABOR_M	TOTAL	699,376	394,829	25,189	66,021	57,782	132,585	14,663	196	6,460	1,650
922-Administrative Expense Transferred	(1,339,452)	LABOR_M	TOTAL	(1,339,452)	(756,181)	(48,242)	(126,444)	(110,666)	(253,928)	(28,083)	(375)	(12,373)	(3,161)
923-Outside Services	1,276,264	LABOR_M	TOTAL	1,276,264	720,508	45,966	120,479	105,445	241,949	26,758	357	11,789	3,012
924-Property Insurance	725,506	RB_GUP_EPIS	TOTAL	725,506	401,821	23,235	70,251	61,149	139,979	15,734	199	11,662	1,477
925-Injuries & Damages	2,098,337	LABOR_M	TOTAL	2,098,337	1,184,606	75,574	198,083	173,365	397,794	43,994	588	19,383	4,952
926-Employee Pension & Benefits	3,349,051	LABOR_M	TOTAL	3,349,051	1,890,690	120,620	316,150	276,699	634,899	70,217	938	30,936	7,903
9260057 Post Ret Medicare Subsidy Direct	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-	-
927-Franchise Requirements	139,012	LABOR_M	TOTAL	139,012	78,479	5,007	13,123	11,485	26,353	2,915	39	1,284	328
928-Regulatory Commission Expense Allocated	112	LABOR_M	TOTAL	112	63	4	11	9	21	2	0	1	0
928- Rate Case Expense	951,455	RSALE	TOTAL	951,455	411,348	35,428	101,695	97,951	264,351	21,934	371	15,694	2,684
930-General Advertising Expense	634,789	LABOR_M	TOTAL	634,789	358,367	22,863	59,924	52,446	120,341	13,309	178	5,864	1,498
931-Rent	349,368	LABOR_M	TOTAL	349,368	197,234	12,583	32,980	28,865	66,232	7,325	98	3,227	824
Total A&G Operation	18,156,171		TOTAL	18,156,171	10,116,423	652,183	1,727,581	1,520,612	3,528,388	383,175	5,185	179,577	43,048
Total A&G Maintenance	2,685,047	LABOR_M	TOTAL	2,685,047	1,515,830	96,705	253,468	221,839	509,020	56,295	752	24,802	6,336

KENTUCKY POWER COMPANY
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Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	SGS 3	Total MGS	Total LGS	Total IGS	Total PS	MW 17	OL 18	SL 19
Total A&G Expenses	20,841,218		TOTAL	20,841,218	11,632,253	748,888	1,981,049	1,742,450	4,037,408	439,470	5,937	204,379	49,384
Total O&M Expenses	427,756,080		TOTAL	427,756,080	197,921,529	12,666,479	37,920,436	37,763,232	127,507,574	8,793,178	136,432	4,334,203	713,017
O&M Adjustments													
Adj 2 - Decommissioning Rider Removal	53	PROD_DEMAND	TOTAL	53	26	1	5	5	15	1	0	-	-
Adj 3 - Env Surcharge - Remove Mitchell FGD Expenses	(3,927,716)	PROD_ENERGY	TOTAL	(3,927,716)	(1,473,785)	(95,511)	(331,573)	(372,068)	(1,535,671)	(80,443)	(1,437)	(31,078)	(6,150)
Adj 5 - Environmental Surcharge Revenue Sync - remove FGD re	(667,403)	PROD_ENERGY	TOTAL	(667,403)	(250,428)	(16,229)	(56,341)	(63,222)	(260,943)	(13,669)	(244)	(5,281)	(1,045)
Adj 6 - Big Sandy Unit 1 Operation Rider Deferrals - Demand	(2,639,313)	PROD_DEMAND	TOTAL	(2,639,313)	(1,300,081)	(64,268)	(243,513)	(228,035)	(746,828)	(55,875)	(713)	-	-
Adj 6 - Big Sandy Unit 1 Operation Rider Deferrals - Energy	(2,383,768)	PROD_ENERGY	TOTAL	(2,383,768)	(894,454)	(57,966)	(201,235)	(225,811)	(932,013)	(48,822)	(872)	(18,862)	(3,733)
Adj 7 - Fuel Under (Over) Revenue & Expense	2,211,942	PROD_ENERGY	TOTAL	2,211,942	829,981	53,788	186,729	209,535	864,832	45,302	809	17,502	3,464
Adj 8 - System Sales Clause - reset OSS Margin Baseline	173,875	PROD_ENERGY	TOTAL	173,875	65,243	4,228	14,678	16,471	67,982	3,561	64	1,376	272
Adj 9 - PPA Rider Sync	372,542	PROD_ENERGY	TOTAL	372,542	139,788	9,059	31,450	35,290	145,658	7,630	136	2,948	583
Adj 10 - Remove DSM Rider	(7,060,189)	CUST_TOTAL	TOTAL	(7,060,189)	(4,498,695)	(787,179)	(223,849)	(21,914)	(2,208)	(5,338)	(330)	(1,518,864)	(1,812)
Adj 11 - Remove HEAP Surcharge	(246,772)	CUST_TOTAL	TOTAL	(246,772)	(157,241)	(27,514)	(7,824)	(766)	(77)	(187)	(12)	(53,088)	(63)
Adj 12 - Remove Economic Development Surcharge	(303,011)	CUST_TOTAL	TOTAL	(303,011)	(193,076)	(33,784)	(9,607)	(940)	(95)	(229)	(14)	(65,187)	(78)
Adj 14 - Customer Annualization Adjustment	(1,931,695)	REVYEC_EXP_OM	TOTAL	(1,931,695)	(293,705)	(37,449)	(195,777)	443,704	(1,965,724)	(24,310)	-	159,413	(17,847)
Adj 15 - Weather Normalization Adjustment	5,872,296	WEATHER_FXNL_OM	TOTAL	5,872,296	5,872,296	-	-	-	-	-	-	-	-
Adj 17 - Normalization of Major Storms	595,932	TDOMX	TOTAL	595,932	389,062	22,712	65,998	53,314	41,515	14,613	183	5,339	3,198
Adj 18 - Amortization of Storm Cost Deferral	874,592	EXP_OM_DIST	TOTAL	874,592	592,125	35,156	99,371	78,708	32,661	21,918	273	8,989	5,392
Adj 19 - Rate Case Expense	376,599	RSALE	TOTAL	376,599	162,817	14,023	40,252	38,770	104,634	8,682	147	6,212	1,062
Adj 20 - Postage Rate Decrease	(6,656)	CUST_TOTAL	TOTAL	(6,656)	(4,241)	(742)	(211)	(21)	(2)	(5)	(0)	(1,432)	(2)
Adj 21 - Eliminate Advertising Expense A&G	(31,889)	LABOR_M	TOTAL	(31,889)	(18,003)	(1,149)	(3,010)	(2,635)	(6,045)	(669)	(9)	(295)	(75)
Adj 21 - Eliminate Advertising Expense O&M	(68,555)	CUST_TOTAL	TOTAL	(68,555)	(43,683)	(7,644)	(2,174)	(213)	(21)	(52)	(3)	(14,748)	(18)
Adj 22 - Annualization of Lease Costs	(40,146)	RB_GUP	TOTAL	(40,146)	(22,235)	(1,286)	(3,887)	(3,384)	(7,746)	(871)	(11)	(645)	(82)
Adj 23 - Pension & OPEB Expense Adjustment	148,679	LABOR_M	TOTAL	148,679	83,936	5,355	14,035	12,284	28,186	3,117	42	1,373	351
Adj 24 - Employee Related Group Benefit Expenses	429,241	LABOR_M	TOTAL	429,241	242,326	15,460	40,520	35,464	81,374	9,000	120	3,965	1,013
Adj 25 - Remove PJM BLIs from base for FAC inclusion	(848,165)	PROD_ENERGY	TOTAL	(848,165)	(318,254)	(20,625)	(71,601)	(80,346)	(331,618)	(17,371)	(310)	(6,711)	(1,328)
Adj 26 - Peaking Unit Equivalent	3,150,582	PROD_ENERGY	TOTAL	3,150,582	1,182,184	76,613	265,968	298,451	1,231,825	64,527	1,153	24,929	4,933
Adj 27 - Forced Outage Adjustment	882,204	PROD_ENERGY	TOTAL	882,204	331,027	21,453	74,475	83,570	344,927	18,068	323	6,980	1,381
Adj 28 - PJM LSE OATT Expense	528,754	TRAN_LSE	TOTAL	528,754	260,455	12,875	48,785	45,684	149,618	11,194	143	-	-
Adj 29 - Annualize PJM Admin Fees	118,606	TRAN_LSE	TOTAL	118,606	58,423	2,888	10,943	10,247	33,561	2,511	32	-	-
Adj 31 - Severance Related Payroll Expenses - Big Sandy Plant	(35,433)	LABOR_PROD	TOTAL	(35,433)	(16,587)	(863)	(3,211)	(3,123)	(10,824)	(745)	(10)	(58)	(12)
Adjs 32-39 - Total Incentive Compensation & Payroll Adjustment	(826,263)	LABOR_M	TOTAL	(826,263)	(466,463)	(29,759)	(77,999)	(68,266)	(156,639)	(17,324)	(231)	(7,632)	(1,950)
Adj 40 - Remove Non-Recoverable Business Expenses	(14,914)	RB_GUP	TOTAL	(14,914)	(8,260)	(478)	(1,444)	(1,257)	(2,877)	(323)	(4)	(240)	(30)
Adj 41 - Plant Maintenance Normalization	(274,334)	PROD_DEMAND	TOTAL	(274,334)	(135,132)	(6,680)	(25,311)	(23,702)	(77,626)	(5,808)	(74)	-	-
Adj 52 - Employee Complement Increase	172,594	TDOMX	TOTAL	172,594	112,680	6,578	19,114	15,441	12,023	4,232	53	1,546	926
Adj 56 - Reduce base forestry expense	(6,794,282)	TOTOHLINES	TOTAL	(6,794,282)	(4,699,634)	(223,133)	(782,916)	(626,431)	(254,835)	(177,200)	(2,207)	(23,757)	(4,168)
Total Operations and Maintenance Expense Adjustments	(12,192,013)		TOTAL	(12,192,013)	(4,471,590)	(1,132,068)	(1,329,162)	(345,196)	(3,152,985)	(234,885)	(3,005)	(1,507,306)	(15,817)
Adjusted Operating & Maintenance Expense	415,564,067		TOTAL	415,564,067	193,449,939	11,534,411	36,591,274	37,418,036	124,354,589	8,558,293	133,426	2,826,898	697,200
Depreciation, Amortization & Reg. Debits Expense													
Production	34,972,487	RB_GUP-Land_P	TOTAL	34,972,487	17,226,852	851,585	3,226,699	3,021,600	9,895,926	740,376	9,449	-	-
Transmission & Reg. Debits	17,157,409	RB_GUP-Land_T	TOTAL	17,157,409	8,433,080	415,043	1,570,752	1,473,814	4,897,972	358,698	4,602	2,836	611
Distribution	27,081,260	RB_GUP-Land_D	TOTAL	27,081,260	17,932,243	1,233,528	2,856,299	2,188,421	864,079	617,605	7,663	1,228,671	152,750
General & Intangible	4,994,825	RB_GUP-Land_G	TOTAL	4,994,825	2,819,803	179,895	471,511	412,672	946,898	104,723	1,399	46,138	11,787
Total Depreciation & Amort Expense	84,205,981		TOTAL	84,205,981	46,411,979	2,680,051	8,125,261	7,096,508	16,604,874	1,821,402	23,112	1,277,645	165,148
Depreciation & Amortization Adjustments													
Adj 2 - Decommissioning Rider Removal	(1,987,451)	RB_GUP-Land_T	TOTAL	(1,987,451)	(976,857)	(48,077)	(181,950)	(170,721)	(567,363)	(41,550)	(533)	(329)	(71)
Adj 3 - Env Surcharge - Remove Mitchell FGD Expenses	(9,192,378)	RB_GUP-Land_P	TOTAL	(9,192,378)	(4,528,009)	(223,836)	(848,125)	(794,216)	(2,601,104)	(194,605)	(2,484)	-	-
Adj 5 - Environmental Surcharge Revenue Sync - remove FGD re	42,028	RB_GUP-Land_P	TOTAL	42,028	20,702	1,023	3,878	3,631	11,892	890	11	-	-
Adj 6 - Big Sandy Unit 1 Operation Rider Deferrals	347,890	RB_GUP-Land_P	TOTAL	347,890	171,365	8,471	32,098	30,057	98,440	7,365	94	-	-
Adj 30 - NERC Compliance & Cyber Security	14,275	RB_GUP-Land_P	TOTAL	14,275	7,032	348	1,317	1,233	4,039	302	4	-	-
Adj 42 - Annualization Depreciation/Amortization Expense Produ	1,390,210	RB_GUP-Land_P	TOTAL	1,390,210	684,794	33,852	128,266	120,113	393,378	29,431	376	-	-
Adj 42 - Annualization Depreciation/Amortization Expense Transi	52,403	RB_GUP-Land_T	TOTAL	52,403	25,757	1,268	4,797	4,501	14,960	1,096	14	9	2
Adj 42 - Annualization Depreciation/Amortization Expense Distrib	513,467	RB_GUP-Land_D	TOTAL	513,467	340,000	23,388	54,156	41,493	16,383	11,710	145	23,296	2,896
Adj 42 - Annualization Depreciation/Amortization Expense Gener	81,279	RB_GUP-Land_G	TOTAL	81,279	45,886	2,927	7,673	6,715	15,409	1,704	23	751	192
Adj 43 - Update Big Sandy Unit 1 Depreciation Rates	3,076,557	RB_GUP-Land_P	TOTAL	3,076,557	1,515,460	74,915	283,855	265,813	870,552	65,131	831	-	-
Adj 44 - ARO Depreciation	(3,818)	RB_GUP-Land_P	TOTAL	(3,818)	(1,881)	(93)	(352)	(330)	(1,080)	(81)	(1)	-	-
Total Depreciation & Amort Adjustments	(5,665,538)		TOTAL	(5,665,538)	(2,695,753)	(125,814)	(514,387)	(491,709)	(1,744,494)	(118,607)	(1,520)	23,727	3,019
Adjusted Depreciation & Amortization Expense	78,540,443		TOTAL	78,540,443	43,716,226	2,554,237	7,610,874	6,604,799	14,860,380	1,702,795	21,593	1,301,372	168,167
Taxes Other Than Income													
Federal Insurance Contribution Excise	1,963,938	LABOR_M	TOTAL	1,963,938	1,108,731	70,734	185,395	162,261	372,315	41,176	550	18,141	4,634
Federal Unemployment Tax	11,346	LABOR_M	TOTAL	11,346	6,405	409	1,071	937	2,151	238	3	105	27
Kentucky Unemployment	24,039	LABOR_M	TOTAL	24,039	13,571	866	2,269	1,986	4,557	504	7	222	57
Kentucky Real & Personal Property	13,834,817	RB_GUP	TOTAL	13,834,817	7,662,399	443,066	1,339,632	1,166,059	2,669,278	300,043	3,800	222,383	28,157
Municipal License	734	RB_GUP	TOTAL	734	407	24	71	62	142	16	0	12	1
Kentucky PSC Maintenance	1,128,601	RSALE	TOTAL	1,128,601	487,935	42,024	120,629	116,188	313,570	26,017	440	18,616	3,183
Kentucky Sales & Use	11,568	TDPLANT	TOTAL	11,568	6,833	422	1,154	961	1,599	255	3	303	38

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
FEBRUARY 28, 2017

Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	SGS 3	Total MGS	Total LGS	Total IGS	Total PS	MW 17	OL 18	SL 19
Regis Fee	80	LABOR_M	TOTAL	80	45	3	8	7	15	2	0	1	0
Kentucky Business Occup Taxes	4,237,868	LABOR_M	TOTAL	4,237,868	2,392,467	152,632	400,054	350,133	803,397	88,852	1,187	39,146	10,000
Gross Receipts Tax	(58,848)	RSALE	TOTAL	(58,848)	(25,442)	(2,191)	(6,290)	(6,058)	(16,350)	(1,357)	(23)	(971)	(166)
Federal Excise	6,551	LABOR_M	TOTAL	6,551	3,698	236	618	541	1,242	137	2	61	15
Taxes on Capital Leases	461,801	RB_GUP	TOTAL	461,801	255,768	14,789	44,716	38,923	89,099	10,015	127	7,423	940
Total Taxes Other Than Income	21,622,495		TOTAL	21,622,495	11,912,817	723,013	2,089,328	1,831,999	4,241,015	465,899	6,096	305,441	46,887
Taxes Other Than Income Adjustments													
Adj 3 - Env Surcharge - Remove Mitchell FGD Expenses	(188,103)	RB_GUP	TOTAL	(188,103)	(104,181)	(6,024)	(18,214)	(15,854)	(36,292)	(4,079)	(52)	(3,024)	(383)
Adj 5 - Environmental Surcharge Revenue Sync - remove FGD re	(4,282)	RB_GUP	TOTAL	(4,282)	(2,372)	(137)	(415)	(361)	(826)	(93)	(1)	(69)	(9)
Adj 6 - Big Sandy Unit 1 Operation Rider Deferrals	341,289	RB_GUP	TOTAL	341,289	189,023	10,930	33,047	28,765	65,848	7,402	94	5,486	695
Adj 31 - Severance Related Payroll Expenses - Big Sandy Plant	2,363	LABOR_PROD	TOTAL	2,363	1,106	58	214	208	722	50	1	4	1
Adjs 32-39 - Total Incentive Compensation & Payroll Adjustment	(33,388)	LABOR_M	TOTAL	(33,388)	(18,849)	(1,203)	(3,152)	(2,759)	(6,330)	(700)	(9)	(308)	(79)
Adj 47 - KPSC Maintenance Assessment	(1,801)	RSALE	TOTAL	(1,801)	(779)	(67)	(192)	(185)	(500)	(42)	(1)	(30)	(5)
Adj 48 - Kentucky Sales & Use Tax	78,776	TDPLANT	TOTAL	78,776	46,532	2,877	7,856	6,544	10,891	1,736	22	2,062	257
Adj 57 - Annualization of Property Tax Expense	595,507	RB_GUP	TOTAL	595,507	329,821	19,071	57,663	50,192	114,897	12,915	164	9,572	1,212
Total Adjustments to Taxes Other Than Income	790,361		TOTAL	790,361	440,302	25,505	76,807	66,551	148,409	17,188	217	13,693	1,689
Adjusted Taxes Other Than Incom	22,412,856		TOTAL	22,412,856	12,353,119	748,519	2,166,135	1,898,549	4,389,423	483,087	6,313	319,135	48,576
Other Expenses													
Gain/Loss on Disposition of Utility Plant	(5,318)	RB_GUP_EPIS_D	TOTAL	(5,318)	(3,522)	(242)	(562)	(431)	(171)	(121)	(2)	(239)	(30)
A/R Factoring	1,636,590	RB_GUP	TOTAL	1,636,590	906,424	52,413	158,472	137,939	315,762	35,494	450	26,307	3,331
Gain/Loss on Disposition of Allowances	(176,704)	PROD_ENERGY	TOTAL	(176,704)	(66,304)	(4,297)	(14,917)	(16,739)	(69,088)	(3,619)	(65)	(1,398)	(277)
Accretion	884,391	PROD_DEMAND	TOTAL	884,391	435,636	21,535	81,597	76,411	250,250	18,723	239	-	-
Interest Income - Corp. Borrowing Program	(18,037)	RB_GUP	TOTAL	(18,037)	(9,990)	(578)	(1,747)	(1,520)	(3,480)	(391)	(5)	(290)	(37)
Interest Expense - Corp. Borrowing Program	67,056	RB_GUP	TOTAL	67,056	37,139	2,147	6,493	5,652	12,938	1,454	18	1,078	136
Other Interest Expense	370,911	RB_GUP	TOTAL	370,911	205,429	11,879	35,915	31,262	71,563	8,044	102	5,962	755
Interest on Customer Deposits	110,400	CUST_DEP_FXNL	TOTAL	110,400	80,487	5,361	12,028	8,068	3,848	119	-	490	-
Total Other Expenses	2,869,289		TOTAL	2,869,289	1,585,298	88,218	277,280	240,642	581,622	59,702	738	31,909	3,879
Other Expense Adjustments													
Adj 5 - Environmental Surcharge Revenue Sync - remove FGD re	91,240	PROD_ENERGY	TOTAL	91,240	34,236	2,219	7,702	8,643	35,673	1,869	33	722	143
Adj 16 - Adjustment to Interest on Customer Deposits	67,254	CUST_DEP_FXNL	TOTAL	67,254	49,031	3,266	7,327	4,915	2,344	72	-	298	-
Adj 45 - ARO Accretion	(109,495)	PROD_DEMAND	TOTAL	(109,495)	(53,935)	(2,666)	(10,102)	(9,460)	(30,983)	(2,318)	(30)	-	-
Total Adjustments to Other Expenses	48,999		TOTAL	48,999	29,332	2,818	4,927	4,098	7,034	(377)	4	1,020	143
Total Adjusted Other Expenses	2,918,288		TOTAL	2,918,288	1,614,630	91,037	282,207	244,739	588,657	59,325	741	32,930	4,022
Total Operating Expense Before Income Ta	519,435,654		TOTAL	519,435,654	251,133,914	14,928,204	46,650,490	46,166,124	144,193,049	10,803,500	162,073	4,480,334	917,965
Gross Operating Income	48,940,907		TOTAL	48,940,907	(3,611,215)	5,608,514	12,866,616	11,372,022	15,801,504	2,056,000	54,030	4,220,974	572,462
Allowance for Borrowed Funds Used During Construction	516,882	RATEBASE	TOTAL	516,882	282,251	16,228	49,734	43,848	104,039	11,432	146	8,149	1,054
Interest Synchronization Tax	(35,421,259)	RATEBASE	TOTAL	(35,421,259)	(19,342,298)	(1,112,076)	(3,408,224)	(3,004,815)	(7,129,661)	(783,452)	(10,016)	(558,472)	(72,246)
Taxable Income Before Schedule M Adjustment	14,036,530		TOTAL	14,036,530	(22,671,262)	4,512,666	9,508,126	8,411,055	8,775,882	1,283,981	44,160	3,670,652	501,270
Schedule M Income Adjustment													
Book vs. Tax Depreciation - Normalized	(54,883,025)	RB_GUP	TOTAL	(54,883,025)	(30,396,905)	(1,757,653)	(5,314,350)	(4,625,783)	(10,589,085)	(1,190,276)	(15,076)	(882,199)	(111,698)
AFUDC - HR/J	11,364	BULK_TRANS	TOTAL	11,364	5,598	277	1,048	982	3,216	241	3	-	-
ABFUDC	(516,882)	RB_GUP_CWIP	TOTAL	(516,882)	(284,064)	(16,405)	(49,681)	(43,539)	(103,648)	(11,133)	(142)	(7,287)	(982)
ABFUDC - HR/J	21,713	BULK_TRANS	TOTAL	21,713	10,695	529	2,003	1,876	6,144	460	6	-	-
Interest Capitalization	1,085,613	RB_GUP	TOTAL	1,085,613	601,266	34,767	105,120	91,500	209,457	23,544	298	17,450	2,209
Book/Tax Unit of Property - DFIT FBK	(471,155)	RB_GUP	TOTAL	(471,155)	(260,949)	(15,089)	(45,622)	(39,711)	(90,904)	(10,218)	(129)	(7,573)	(959)
Book/Tax Unit of Property	9,231,420	RB_GUP	TOTAL	9,231,420	5,112,812	295,640	893,883	778,065	1,781,102	200,206	2,536	148,387	18,788
Book/Tax Unit of Property - SEC 481	4,938,790	RB_GUP	TOTAL	4,938,790	2,735,344	158,167	478,225	416,263	952,886	107,110	1,357	79,387	10,051
Removal Costs	(5,671,630)	RB_GUP	TOTAL	(5,671,630)	(3,141,226)	(181,636)	(549,187)	(478,030)	(1,094,280)	(123,004)	(1,558)	(91,167)	(11,543)
Tax Amortization of Pollution Control	7,468,270	PROD_DEMAND	TOTAL	7,468,270	3,678,743	181,853	689,052	645,254	2,113,245	158,105	2,018	-	-
Property Tax - State 2- Old Method	3,313,757	RB_GUP	TOTAL	3,313,757	1,835,321	106,125	320,873	279,298	639,353	71,867	910	53,266	6,744
Provision for Possible Revenue Refunds	1,015,169	REV	TOTAL	1,015,169	442,097	36,680	106,303	102,768	285,764	22,968	386	15,541	2,662
Deferred Fuel	(2,385,816)	FUELREV	TOTAL	(2,385,816)	(822,633)	(56,190)	(195,992)	(217,082)	(1,024,489)	(47,370)	(843)	(17,620)	(3,597)
Provision for Workers Comp	32,807	LABOR_M	TOTAL	32,807	18,521	1,182	3,097	2,711	6,219	688	9	303	77
Accrued Book Pension Expense	1,066,272	LABOR_M	TOTAL	1,066,272	601,958	38,403	100,656	88,095	202,139	22,356	299	9,849	2,516
Accrued Book Pension Costs - SFAS 158	1,486,483	LABOR_M	TOTAL	1,486,483	839,186	53,538	140,324	122,813	281,801	31,166	416	13,731	3,508
Supplemental Executive Retirement	4,805	LABOR_M	TOTAL	4,805	2,713	173	454	397	911	101	1	44	11
Accrd Supplemental Exec Retirement SFAS 158	(5,917)	LABOR_M	TOTAL	(5,917)	(3,340)	(213)	(559)	(489)	(1,122)	(124)	(2)	(55)	(14)
Accrd Supplemental Savings Plan Exp	2,852	LABOR_M	TOTAL	2,852	1,610	103	269	236	541	60	1	26	7
Accrued PSI Plan Expenses	64,783	LABOR_M	TOTAL	64,783	36,573	2,333	6,116	5,352	12,281	1,358	18	598	153
Book Provision for Uncollectible Accounts	(207,245)	CUST_TOTAL	TOTAL	(207,245)	(132,055)	(23,107)	(6,571)	(643)	(65)	(157)	(10)	(44,585)	(53)
Accrued Companywide Incentive Plan	499,348	LABOR_M	TOTAL	499,348	281,904	17,985	47,138	41,256	94,664	10,469	140	4,613	1,178
Accrued Book Vacation Pay	74,755	LABOR_M	TOTAL	74,755	42,203	2,692	7,057	6,176	14,172	1,567	21	691	176
(ICDP) Incentive Comp Deferral Plan	4,503	LABOR_M	TOTAL	4,503	2,542	162	425	372	854	94	1	42	11

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
FEBRUARY 28, 2017

Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	SGS 3	Total MGS	Total LGS	Total IGS	Total PS	MW 17	OL 18	SL 19
Accrued Book Severance Benefits	(391,926)	LABOR_M	TOTAL	(391,926)	(221,260)	(14,116)	(36,998)	(32,381)	(74,300)	(8,217)	(110)	(3,620)	(925)
Reg Asset on Deferred RTO Costs	76,513	TRANS_TOTAL	TOTAL	76,513	37,610	1,851	7,007	6,574	21,835	1,600	21	12	3
Customer Adv Inc for Tax	(3,611)	TDPLANT	TOTAL	(3,611)	(2,133)	(132)	(360)	(300)	(499)	(80)	(1)	(95)	(12)
Deferred Book Contract Revenue	476	REV	TOTAL	476	207	17	50	48	134	11	0	7	1
Deferred Storm Damage	2,392,762	EXP_OM_DIST	TOTAL	2,392,762	1,619,972	96,181	271,864	215,333	89,356	59,964	747	24,593	14,751
Deferred Demand Side Management Exp	(2,403,838)	CUST_TOTAL	TOTAL	(2,403,838)	(1,531,706)	(268,017)	(76,216)	(7,461)	(752)	(1,818)	(112)	(517,140)	(617)
Advance Rental Income	(238,712)	REV_RENT	TOTAL	(238,712)	(166,410)	(8,358)	(26,937)	(20,727)	(7,421)	(6,102)	(74)	(2,347)	(336)
Deferred Rev - Bonus Lease - Long-Term	(428,111)	REV	TOTAL	(428,111)	(186,438)	(15,469)	(44,829)	(43,339)	(120,511)	(9,686)	(163)	(6,554)	(1,123)
Reg Asset - SFAS 158 Pensions	(1,486,483)	LABOR_M	TOTAL	(1,486,483)	(839,186)	(53,538)	(140,324)	(122,813)	(281,801)	(31,166)	(416)	(13,731)	(3,508)
Reg Asset - SFAS 158 SERP	5,917	LABOR_M	TOTAL	5,917	3,340	213	559	489	1,122	124	2	55	14
Reg Asset - SFAS 158 OPEB	(3,337,578)	LABOR_M	TOTAL	(3,337,578)	(1,884,213)	(120,207)	(315,067)	(275,751)	(632,724)	(69,976)	(935)	(30,830)	(7,876)
NET CCS FEED STUDY COSTS	34,390	PROD_DEMAND	TOTAL	34,390	16,940	837	3,173	2,971	9,731	728	9	-	-
REMOVAL CST - BIG SANDY	(17,397,041)	PROD_DEMAND	TOTAL	(17,397,041)	(8,569,486)	(423,620)	(1,605,119)	(1,503,093)	(4,922,722)	(368,299)	(4,700)	-	-
SPENT ARO - BIG SANDY	(10,388,239)	PROD_DEMAND	TOTAL	(10,388,239)	(5,117,070)	(252,955)	(958,460)	(897,537)	(2,939,489)	(219,921)	(2,807)	-	-
NBV - ARO - RETIRED PLANTS	8,886,294	PROD_DEMAND	TOTAL	8,886,294	4,377,237	216,382	819,884	767,770	2,514,494	188,125	2,401	-	-
BIG SANDY U1 OR-UNDER RECOV	5,023,081	PROD_DEMAND	TOTAL	5,023,081	2,474,284	122,313	463,449	433,991	1,421,347	106,340	1,357	-	-
BIG SANDY RETIRE COSTS RECOV	2,006,790	PROD_DEMAND	TOTAL	2,006,790	988,511	48,866	185,154	173,385	567,848	42,484	542	-	-
BIG SANDY RETIRE RIDER U2 O&M	(86,099)	PROD_ENERGY	TOTAL	(86,099)	(32,307)	(2,094)	(7,268)	(8,156)	(33,663)	(1,763)	(32)	(681)	(135)
UND RECOV-PURCH PWR PPA	(372,542)	PROD_ENERGY	TOTAL	(372,542)	(139,788)	(9,059)	(31,450)	(35,290)	(145,658)	(7,630)	(136)	(2,948)	(583)
DEFD DEPREC-ENVIRONMENTAL	42,028	RB_GUP	TOTAL	42,028	23,277	1,346	4,070	3,542	8,109	911	12	676	86
DEFD O&M-ENVIRONMENTAL CSTS	143,739	RB_GUP	TOTAL	143,739	79,610	4,603	13,918	12,115	27,733	3,117	39	2,310	293
DEFD CONSUM EXP-ENVIRON CSTS	614,837	PROD_ENERGY	TOTAL	614,837	230,703	14,951	51,904	58,243	240,391	12,592	225	4,865	963
DEFD PROP TAX EXP-ENVIRON CSTS	4,283	RB_GUP	TOTAL	4,283	2,372	137	415	361	826	93	1	69	9
NERC COMPL/CYBER SEC-DEF DEPR	(52,958)	PROD_DEMAND	TOTAL	(52,958)	(26,086)	(1,290)	(4,886)	(4,576)	(14,985)	(1,121)	(14)	-	-
CAPACITY CHARGE TARIFF REV	(249,701)	PROD_DEMAND	TOTAL	(249,701)	(122,998)	(6,080)	(23,038)	(21,574)	(70,656)	(5,286)	(67)	-	-
DEFD DEPR-BIG SANDY U1 GAS	(347,890)	PROD_DEMAND	TOTAL	(347,890)	(171,365)	(8,471)	(32,098)	(30,057)	(98,440)	(7,365)	(94)	-	-
DEFD PROP TAX-BIG SANDY U1 GAS	(341,290)	PROD_DEMAND	TOTAL	(341,290)	(168,114)	(8,310)	(31,489)	(29,487)	(96,573)	(7,225)	(92)	-	-
M&S RETIRING PLANTS	718,799	PROD_DEMAND	TOTAL	718,799	354,068	17,503	66,319	62,104	203,394	15,217	194	-	-
Book Amortization Loss on Reacquired Debt	33,146	RB_GUP	TOTAL	33,146	18,358	1,062	3,210	2,794	6,395	719	9	533	67
Accrued SFAS 106 Post Retirement Exp	(2,234,839)	LABOR_M	TOTAL	(2,234,839)	(1,261,667)	(80,491)	(210,968)	(184,642)	(423,671)	(46,856)	(626)	(20,644)	(5,274)
Accrued OPEB Costs SFAS 158	3,337,578	LABOR_M	TOTAL	3,337,578	1,884,213	120,207	315,067	275,751	632,724	69,976	935	30,830	7,876
Accrd SFAS 112 Post Employment Benefits	(1,664,432)	LABOR_M	TOTAL	(1,664,432)	(939,647)	(59,947)	(157,122)	(137,515)	(315,536)	(34,897)	(466)	(15,375)	(3,928)
Accrued Book ARO Expense - SFAS 143	(11,076,598)	RB_GUP	TOTAL	(11,076,598)	(6,134,762)	(354,733)	(1,072,552)	(933,584)	(2,137,110)	(240,224)	(3,043)	(178,047)	(22,543)
Reg Asset Medicare Subsidy Flow Thru	214,887	LABOR_M	TOTAL	214,887	121,313	7,739	20,285	17,754	40,737	4,505	60	1,985	507
SFAS 109 - Deferred SIT Liability	6,519,181	RB_GUP	TOTAL	6,519,181	3,610,642	208,780	631,255	549,465	1,257,805	141,385	1,791	104,790	13,268
Reg Asset - SFAS 109 - Deferred SIT Liability	(6,519,181)	RB_GUP	TOTAL	(6,519,181)	(3,610,642)	(208,780)	(631,255)	(549,465)	(1,257,805)	(141,385)	(1,791)	(104,790)	(13,268)
Regulatory Asset Accrued SFAS 112	1,332,259	LABOR_M	TOTAL	1,332,259	752,120	47,983	125,765	110,071	252,564	27,932	373	12,306	3,144
IRS Capitalization Adjustment	(52,323)	RB_GUP	TOTAL	(52,323)	(28,979)	(1,676)	(5,066)	(4,410)	(10,095)	(1,135)	(14)	(841)	(106)
RESTRICTED STOCK PLAN	9,835	RB_GUP	TOTAL	9,835	5,447	315	952	829	1,898	213	3	158	20
Nontaxable Defd Compensation CSV Earn	27,104	LABOR_M	TOTAL	27,104	15,301	976	2,559	2,239	5,138	568	8	250	64
Nondeductible Meals and Travel & Entertainment	60,931	LABOR_M	TOTAL	60,931	34,398	2,195	5,752	5,034	11,551	1,277	17	563	144
Capitalized Software Costs Tax	(1,043)	RB_GUP	TOTAL	(1,043)	(578)	(33)	(101)	(88)	(201)	(23)	(0)	(17)	(2)
Book Leases Capitalized for Tax	(277,482)	RB_GUP	TOTAL	(277,482)	(153,683)	(8,886)	(26,869)	(23,387)	(53,537)	(6,018)	(76)	(4,460)	(565)
Capitalized Software Costs Book	(309,528)	RB_GUP	TOTAL	(309,528)	(171,432)	(9,913)	(29,972)	(26,088)	(59,720)	(6,713)	(85)	(4,975)	(630)
MTM Book Gain Above the Line Tax Deferral	1,569,522	PROD_ENERGY	TOTAL	1,569,522	588,927	38,166	132,497	148,679	613,657	32,145	574	12,419	2,458
Mark & Spread Deferral - 283 A/L	(262,547)	PROD_ENERGY	TOTAL	(262,547)	(98,515)	(6,384)	(22,164)	(24,871)	(102,651)	(5,377)	(96)	(2,077)	(411)
Mark & Spread Deferral - 190 A/L	343,281	PROD_ENERGY	TOTAL	343,281	128,808	8,348	28,979	32,519	134,217	7,031	126	2,716	538
Provision for Trading Credit Risk (Above Line)	(12,744)	PROD_ENERGY	TOTAL	(12,744)	(4,782)	(310)	(1,076)	(1,207)	(4,983)	(261)	(5)	(101)	(20)
Provision for FAS 157 A/L	1,172	PROD_ENERGY	TOTAL	1,172	440	28	99	111	458	24	0	9	2
Reg Liability - Unrealized MTM Gain Deferral	(606,571)	PROD_ENERGY	TOTAL	(606,571)	(227,602)	(14,750)	(51,206)	(57,460)	(237,159)	(12,423)	(222)	(4,799)	(950)
Book > Tax Basis - EMA A/C 283	391,182	PROD_ENERGY	TOTAL	391,182	146,782	9,512	33,023	37,056	152,946	8,012	143	3,095	613
Total Schedule M Adjustments - Per Books	(60,572,286)		TOTAL	(60,572,286)	(33,088,053)	(2,086,790)	(5,615,599)	(4,877,897)	(12,125,094)	(1,245,793)	(15,928)	(1,418,386)	(98,746)
Adjustments to Per Books Schedule M													
Adj 2 - Decommissioning Rider Removal	(1,920,691)	PROD_DEMAND	TOTAL	(1,920,691)	(946,100)	(46,769)	(177,210)	(165,946)	(543,485)	(40,661)	(519)	-	-
Adj 5 - Environmental Surcharge Revenue Sync - remove FGD re	(804,887)	PROD_ENERGY	TOTAL	(804,887)	(302,015)	(19,573)	(67,948)	(76,246)	(314,697)	(16,485)	(295)	(6,369)	(1,260)
Adj 6 - Big Sandy Unit 1 Operation Rider Deferrals	(4,333,901)	PROD_DEMAND	TOTAL	(4,333,901)	(2,134,806)	(105,531)	(399,863)	(374,446)	(1,226,334)	(91,750)	(1,171)	-	-
Adj 7 - Fuel Under (Over) Revenue & Expense	2,385,816	PROD_ENERGY	TOTAL	2,385,816	895,223	58,016	201,407	226,005	932,814	48,864	873	18,878	3,736
Adj 9 - PPA Rider Sync	372,542	PROD_ENERGY	TOTAL	372,542	139,788	9,059	31,450	35,290	145,658	7,630	136	2,948	583
Adj 10 - Remove DSM Rider	2,403,838	CUST_TOTAL	TOTAL	2,403,838	1,531,706	268,017	76,216	7,461	752	1,818	112	517,140	617
Adj 18 - Amortization of Storm Cost Deferral	874,592	EXP_OM_DIST	TOTAL	874,592	592,125	35,156	99,371	78,708	32,661	21,918	273	8,989	5,392
Adj 23 - Pension & OPEB Expense Adjustment	148,679	LABOR_M	TOTAL	148,679	83,936	5,355	14,035	12,284	28,186	3,117	42	1,373	351
Adj 30 - NERC Compliance & Cyber Security	67,233	RB_GUP-Land_P	TOTAL	67,233	33,118	1,637	6,203	5,809	19,024	1,423	18	-	-
Adjs 32-39 - Total Incentive Compensation & Payroll Adjustment	(499,348)	LABOR_M	TOTAL	(499,348)	(281,904)	(17,985)	(47,138)	(41,256)	(94,664)	(10,469)	(140)	(4,613)	(1,178)
Adj 42 - Annualization Depreciation/Amortization Expense Produ	4,466,767	RB_GUP-Land_P	TOTAL	4,466,767	2,200,253	108,766	412,121	385,926	1,263,931	94,562	1,207	-	-
Adj 42 - Annualization Depreciation/Amortization Expense Transı	52,403	RB_GUP-Land_T	TOTAL	52,403	25,757	1,268	4,797	4,501	14,960	1,096	14	9	2
Adj 42 - Annualization Depreciation/Amortization Expense Distrib	513,467	RB_GUP-Land_D	TOTAL	513,467	340,000	23,388	54,156	41,493	16,383	11,710	145	23,296	2,896
Adj 42 - Annualization Depreciation/Amortization Expense Gener	81,279	RB_GUP-Land_G	TOTAL	81,279	45,886	2,927	7,673	6,715	15,409	1,704	23	751	192
Adj 44 - ARO Depreciation	(3,818)	RB_GUP-Land_P	TOTAL	(3,818)	(1,881)	(93)	(352)	(330)	(1,080)	(81)	(1)	-	-
Adj 45 - ARO Accretion	(109,495)	PROD_DEMAND	TOTAL	(109,495)	(53,935)	(2,666)	(10,102)	(9,460)	(30,983)	(2,318)	(30)	-	-
Total Adjustments to Per Books Schedule M	3,694,476		TOTAL	3,694,476	2,167,149	320,973	204,816	136,508	258,532	32,077	688	562,402	11,330
Adjusted Schedule M	(56,877,810)		TOTAL	(56,877,810)	(30,920,903)	(1,765,817)	(5,410,784)	(4,741,389)	(11,866,562)	(1,213,715)	(15,239)	(855,984)	(87,416)

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
FEBRUARY 28, 2017

Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	SGS 3	Total MGS	Total LGS	Total IGS	Total PS	MW 17	OL 18	SL 19
Kentucky Taxable Income Before Adjustments	(42,841,280)		TOTAL	(42,841,280)	(53,592,165)	2,746,849	4,097,343	3,669,665	(3,090,680)	70,265	28,921	2,814,667	413,854
JCWA Depreciation Adjustment	40,363,921	RB_GUP	TOTAL	40,363,921	22,355,515	1,292,672	3,908,458	3,402,049	7,787,781	875,393	11,087	648,817	82,148
Kentucky Taxable Income	(2,477,359)		TOTAL	(2,477,359)	(31,236,650)	4,039,521	8,005,801	7,071,715	4,697,101	945,658	40,009	3,463,484	496,003
Tax Factor (Tax Rate x Apportionment)	4.32381%												
Kentucky Tax	(107,116)		TOTAL	(107,116)	(1,350,613)	174,661	346,156	305,768	203,094	40,888	1,730	149,754	21,446
West Virginia Taxable Income Before Adjustments	(42,841,280)		TOTAL	(42,841,280)	(53,592,165)	2,746,849	4,097,343	3,669,665	(3,090,680)	70,265	28,921	2,814,667	413,854
Federal Domestic Production Activity	-	RB_GUP_EPIS_P	TOTAL	-	-	-	-	-	-	-	-	-	-
West Virginia Taxable Income	(42,841,280)		TOTAL	(42,841,280)	(53,592,165)	2,746,849	4,097,343	3,669,665	(3,090,680)	70,265	28,921	2,814,667	413,854
Apportionment Factor	21.6208%												
Apportioned West Virginia Taxable Income	(9,262,628)		TOTAL	(9,262,628)	(11,587,055)	593,891	885,878	793,411	(668,230)	15,192	6,253	608,554	89,479
Post Apportionment Schedule M Adjustments	6,879,634	RB_GUP	TOTAL	6,879,634	3,810,278	220,323	666,158	579,846	1,327,351	149,202	1,890	110,584	14,001
Post Apportionment Taxable Income	(2,382,994)		TOTAL	(2,382,994)	(7,776,777)	814,214	1,552,037	1,373,257	659,121	164,394	8,143	719,138	103,480
Tax Rate	6.50%												
West Virginia Tax	(154,895)		TOTAL	(154,895)	(505,490)	52,924	100,882	89,262	42,843	10,686	529	46,744	6,726
Illinois Taxable Income Before Depreciation Adjustment	(42,841,280)		TOTAL	(42,841,280)	(53,592,165)	2,746,849	4,097,343	3,669,665	(3,090,680)	70,265	28,921	2,814,667	413,854
JCWA Depreciation Adjustment	43,065,542	RB_GUP	TOTAL	43,065,542	23,851,805	1,379,193	4,170,058	3,629,754	8,309,030	933,984	11,830	692,243	87,647
Illinois Taxable Income	224,262		TOTAL	224,262	(29,740,360)	4,126,042	8,267,400	7,299,419	5,218,350	1,004,250	40,751	3,506,910	501,501
Apportionment Factor	1.807%												
Apportioned Illinois State Taxable Income	4,052		TOTAL	4,052	(537,408)	74,558	149,392	131,901	94,296	18,147	736	63,370	9,062
Post Apportionment Schedule M Adjustments	47,002	RB_GUP	TOTAL	47,002	26,032	1,505	4,551	3,962	9,069	1,019	13	756	96
Post Apportionment Taxable Income	51,054		TOTAL	51,054	(511,376)	76,063	153,943	135,862	103,364	19,166	749	64,125	9,158
Tax Rate	7.75%												
Illinois Tax	3,957		TOTAL	3,957	(39,632)	5,895	11,931	10,529	8,011	1,485	58	4,970	710
Michigan Taxable Income Before Depreciation Adjustment	(42,841,280)		TOTAL	(42,841,280)	(53,592,165)	2,746,849	4,097,343	3,669,665	(3,090,680)	70,265	28,921	2,814,667	413,854
JCWA Depreciation Adjustment	41,365,075	RB_GUP	TOTAL	41,365,075	22,910,003	1,324,735	4,005,400	3,486,431	7,980,943	897,105	11,363	664,909	84,186
Michigan Taxable Income	(1,476,205)		TOTAL	(1,476,205)	(30,682,162)	4,071,583	8,102,743	7,156,096	4,890,263	967,371	40,284	3,479,577	498,040
Tax Factor (Tax Rate x Apportionment)	0.005016%												
Michigan Tax	(74)		TOTAL	(74)	(1,539)	204	406	359	245	49	2	175	25
Total Current State Income Tax	(258,128)		TOTAL	(258,128)	(1,897,275)	233,684	459,375	405,917	254,193	53,108	2,319	201,643	28,907
Deferred State Income Tax													
Deferred State Income Tax - WVA Pollution Control	(447,176)		TOTAL	(447,176)	(247,668)	(14,321)	(43,300)	(37,690)	(86,278)	(9,698)	(123)	(7,188)	(910)
Deferred State Income Tax - Mitchell Plant	(1,551,003)	RB_GUP_EPIS_P	TOTAL	(1,551,003)	(763,998)	(37,767)	(143,102)	(134,006)	(438,877)	(32,835)	(419)	-	-
Adj 55 - Mitchell Plant DSIT Amortization Adjustment	1,292,491	RB_GUP_EPIS_P	TOTAL	1,292,491	636,659	31,472	119,250	111,670	365,727	27,362	349	-	-
Total Adjusted Deferred State Income Tax	(705,688)		TOTAL	(705,688)	(375,007)	(20,616)	(67,152)	(60,025)	(159,427)	(15,171)	(193)	(7,188)	(910)
Total State Income Tax (Current + Deferred	(963,816)		TOTAL	(963,816)	(2,272,281)	213,068	392,223	345,892	94,765	37,937	2,127	194,455	27,997
Federal Taxable Income	(42,583,152)		TOTAL	(42,583,152)	(51,694,891)	2,513,164	3,637,968	3,263,748	(3,344,873)	17,157	26,602	2,613,025	384,947
Tax Factor (Tax Rate x Apportionment)	35.00%												
Gross Current FIT	(14,904,103)		TOTAL	(14,904,103)	(18,093,212)	879,608	1,273,289	1,142,312	(1,170,705)	6,005	9,311	914,559	134,732
Deferred FIT													
DFIT for Book vs Tax Depreciation Normalized	20,339,527	RB_GUP	TOTAL	20,339,527	11,265,026	651,382	1,969,486	1,714,305	3,924,291	441,114	5,587	326,941	41,395
DFIT ABFUDC	(67,118)	RB_GUP_CWIP	TOTAL	(67,118)	(36,886)	(2,130)	(6,451)	(5,654)	(13,459)	(1,446)	(18)	(946)	(128)
Interest Capitalization	37,162	RB_GUP	TOTAL	37,162	20,582	1,190	3,598	3,132	7,170	806	10	597	76
Property Tax - State 2- Old Method	(1,159,815)	RB_GUP	TOTAL	(1,159,815)	(642,362)	(37,144)	(112,305)	(97,754)	(223,774)	(25,153)	(319)	(18,643)	(2,360)
Removal Costs	304,759	RB_GUP	TOTAL	304,759	168,790	9,760	29,510	25,686	58,800	6,609	84	4,899	620
Percent Repair Allowance	(5,260,400)	RB_GUP	TOTAL	(5,260,400)	(2,913,467)	(168,467)	(509,367)	(443,370)	(1,014,937)	(114,085)	(1,445)	(84,557)	(10,706)
Tax Amortization of Pollution Control Equip.	(2,613,895)	PROD_DEMAND	TOTAL	(2,613,895)	(1,287,560)	(63,649)	(241,168)	(225,839)	(739,636)	(55,337)	(706)	-	-
Provision for Possible Revenue Refunds	(355,309)	REV	TOTAL	(355,309)	(154,734)	(12,838)	(37,206)	(35,969)	(100,017)	(8,039)	(135)	(5,439)	(932)
Deferred Fuel Costs	835,035	FUELREV	TOTAL	835,035	287,921	19,666	68,597	75,979	358,571	16,580	295	6,167	1,259
Provision for Workers Comp	(11,482)	LABOR_M	TOTAL	(11,482)	(6,482)	(414)	(1,084)	(949)	(2,177)	(241)	(3)	(106)	(27)
Accrued Book Pension Expense	(373,195)	LABOR_M	TOTAL	(373,195)	(210,685)	(13,441)	(35,230)	(30,833)	(70,749)	(7,824)	(105)	(3,447)	(881)
Accrued Book Pension Costs - SFAS 158	(520,268)	LABOR_M	TOTAL	(520,268)	(293,715)	(18,738)	(49,113)	(42,985)	(98,630)	(10,908)	(146)	(4,806)	(1,228)
Supplemental Executive Retirement	(1,681)	LABOR_M	TOTAL	(1,681)	(949)	(61)	(159)	(139)	(319)	(35)	(0)	(16)	(4)
Accrd Suppl Executive Retirement - SFAS 158	2,071	LABOR_M	TOTAL	2,071	1,169	75	196	171	393	43	1	19	5
Accrd Book Supplemental Savings Plan	(998)	LABOR_M	TOTAL	(998)	(563)	(36)	(94)	(82)	(189)	(21)	(0)	(9)	(2)
Accrued PSI Plan Expenses	(22,674)	LABOR_M	TOTAL	(22,674)	(12,800)	(817)	(2,140)	(1,873)	(4,298)	(475)	(6)	(209)	(54)
Book Provision - Uncollectible Accounts	72,536	CUST_TOTAL	TOTAL	72,536	46,219	8,087	2,300	225	23	55	3	15,605	19
Accrd Companywide Incentive Plan	(174,772)	LABOR_M	TOTAL	(174,772)	(98,667)	(6,295)	(16,498)	(14,440)	(33,133)	(3,664)	(49)	(1,614)	(412)
Accrd Book Vacation Pay	(26,165)	LABOR_M	TOTAL	(26,165)	(14,771)	(942)	(2,470)	(2,162)	(4,960)	(549)	(7)	(242)	(62)
(IDCP) Incentive Comp Deferral Plan	(1,576)	LABOR_M	TOTAL	(1,576)	(890)	(57)	(149)	(130)	(299)	(33)	(0)	(15)	(4)
Accrd Book Severance Benefits	137,174	LABOR_M	TOTAL	137,174	77,441	4,941	12,949	11,333	26,005	2,876	38	1,267	324
Reg Asset on Deferred RTO Costs	(26,779)	TRANS_TOTAL	TOTAL	(26,779)	(13,163)	(648)	(2,452)	(2,301)	(7,642)	(560)	(7)	(4)	(1)
Customer Adv Inc for Tax	1,265	TDPLANT	TOTAL	1,265	747	46	126	105	175	28	0	33	4
Deferred Book Contract Revenue	(167)	REV	TOTAL	(167)	(73)	(6)	(17)	(17)	(47)	(4)	(0)	(3)	(0)
Deferred Storm Damage	(837,467)	EXP_OM_DIST	TOTAL	(837,467)	(566,990)	(33,664)	(95,152)	(75,367)	(31,275)	(20,987)	(261)	(8,608)	(5,163)

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
FEBRUARY 28, 2017

Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	SGS 3	Total MGS	Total LGS	Total IGS	Total PS	MW 17	OL 18	SL 19
Deferred Demand Side Management Exp	841,343	CUST_TOTAL	TOTAL	841,343	536,097	93,806	26,675	2,611	263	636	39	180,999	216
Advance Rental Income	83,549	REV_RENT	TOTAL	83,549	58,243	2,925	9,428	7,254	2,597	2,136	26	822	117
Deferred Revenue - Bonus Lease Long-Term	149,839	REV	TOTAL	149,839	65,253	5,414	15,690	15,169	42,179	3,390	57	2,294	393
Reg Asset SFAS 158 Pensions	520,268	LABOR_M	TOTAL	520,268	293,715	18,738	49,113	42,985	98,630	10,908	146	4,806	1,228
Reg Asset SFAS 158 SERP	(2,071)	LABOR_M	TOTAL	(2,071)	(1,169)	(75)	(196)	(171)	(393)	(43)	(1)	(19)	(5)
Reg Asset SFAS 158 OPEB	1,168,152	LABOR_M	TOTAL	1,168,152	659,474	42,073	110,273	96,513	221,453	24,492	327	10,790	2,757
NET CCS FEED STUDY COSTS	(12,037)	PROD_DEMAND	TOTAL	(12,037)	(5,929)	(293)	(1,111)	(1,040)	(3,406)	(255)	(3)	-	-
REMOVAL CST - BIG SANDY	6,088,965	PROD_DEMAND	TOTAL	6,088,965	2,999,321	148,267	561,792	526,083	1,722,953	128,905	1,645	-	-
SPENT ARO - BIG SANDY	3,635,884	PROD_DEMAND	TOTAL	3,635,884	1,790,975	88,534	335,461	314,138	1,028,821	76,973	982	-	-
NBV - ARO - RETIRED PLANTS	(3,110,203)	PROD_DEMAND	TOTAL	(3,110,203)	(1,532,033)	(75,734)	(286,960)	(268,720)	(880,073)	(65,844)	(840)	-	-
BIG SANDY U1 OR-UNDER RECOV	(1,758,079)	PROD_DEMAND	TOTAL	(1,758,079)	(866,000)	(42,809)	(162,207)	(151,897)	(497,472)	(37,219)	(475)	-	-
BIG SANDY RETIRE COSTS RECOV	(702,376)	PROD_DEMAND	TOTAL	(702,376)	(345,978)	(17,103)	(64,804)	(60,685)	(198,747)	(14,869)	(190)	-	-
BIG SANDY RETIRE RIDER U2 O&M	30,135	PROD_ENERGY	TOTAL	30,135	11,307	733	2,544	2,855	11,782	617	11	238	47
UND RECOV-PURCH PWR PPA	130,389	PROD_ENERGY	TOTAL	130,389	48,925	3,171	11,007	12,352	50,980	2,670	48	1,032	204
DEFD DEPREC-ENVIRONMENTAL	(14,710)	RB_GUP	TOTAL	(14,710)	(8,147)	(471)	(1,424)	(1,240)	(2,838)	(319)	(4)	(236)	(30)
DEFD O&M-ENVIRONMENTAL CSTS	(50,309)	RB_GUP	TOTAL	(50,309)	(27,864)	(1,611)	(4,871)	(4,240)	(9,707)	(1,091)	(14)	(809)	(102)
DEFD CONSUM EXP-ENVIRON CSTS	(215,193)	PROD_ENERGY	TOTAL	(215,193)	(80,746)	(5,233)	(18,166)	(20,385)	(84,137)	(4,407)	(79)	(1,703)	(337)
DEFD PROP TAX EXP-ENVIRON CSTS	(1,498)	RB_GUP	TOTAL	(1,498)	(830)	(48)	(145)	(126)	(289)	(32)	(0)	(24)	(3)
NERC COMPL/CYBER SEC-DEF DEPR	18,535	PROD_DEMAND	TOTAL	18,535	9,130	451	1,710	1,601	5,245	392	5	-	-
CAPACITY CHARGE TARIFF REV	87,395	PROD_DEMAND	TOTAL	87,395	43,049	2,128	8,063	7,551	24,730	1,850	24	-	-
DEFD DEPR-BIG SANDY U1 GAS	121,761	PROD_DEMAND	TOTAL	121,761	59,977	2,965	11,234	10,520	34,454	2,578	33	-	-
DEFD PROP TAX-BIG SANDY U1 GAS	119,451	PROD_DEMAND	TOTAL	119,451	58,840	2,909	11,021	10,320	33,800	2,529	32	-	-
M&S RETIRING PLANTS	(251,580)	PROD_DEMAND	TOTAL	(251,580)	(123,924)	(6,126)	(23,212)	(21,736)	(71,188)	(5,326)	(68)	-	-
Book Amortization Loss on Reacquired Debt	(11,600)	RB_GUP	TOTAL	(11,600)	(6,425)	(371)	(1,123)	(978)	(2,238)	(252)	(3)	(186)	(24)
Accrued SFAS 106 Post Retirement Expense	782,194	LABOR_M	TOTAL	782,194	441,584	28,172	73,839	64,625	148,285	16,400	219	7,225	1,846
Accrued OPEB Costs SFAS 158	(1,168,152)	LABOR_M	TOTAL	(1,168,152)	(659,474)	(42,073)	(110,273)	(96,513)	(221,453)	(24,492)	(327)	(10,790)	(2,757)
Accrued SFAS 112 Post Employment Benefits	582,551	LABOR_M	TOTAL	582,551	328,876	20,981	54,993	48,130	110,438	12,214	163	5,381	1,375
Accrued Book ARO Expense SFAS 143	3,876,809	RB_GUP	TOTAL	3,876,809	2,147,167	124,157	375,393	326,755	747,988	84,078	1,065	62,316	7,890
Medicare Subsidy (PPACA) Reg Asset	(75,210)	LABOR_M	TOTAL	(75,210)	(42,459)	(2,709)	(7,100)	(6,214)	(14,258)	(1,577)	(21)	(695)	(177)
Deferred State Income Taxes	699,362	RB_GUP	TOTAL	699,362	387,341	22,397	67,720	58,945	134,934	15,167	192	11,242	1,423
Reg Asset - Accrued SFAS 112	(466,291)	LABOR_M	TOTAL	(466,291)	(263,242)	(16,794)	(44,018)	(38,525)	(88,397)	(9,776)	(131)	(4,307)	(1,100)
IRS Capitalization Adjustment	18,313	RB_GUP	TOTAL	18,313	10,143	586	1,773	1,544	3,533	397	5	294	37
Restricted Stock Plan	(3,443)	RB_GUP	TOTAL	(3,443)	(1,907)	(110)	(333)	(290)	(664)	(75)	(1)	(55)	(7)
Capitalized Software Costs Tax	365	RB_GUP	TOTAL	365	202	12	35	31	70	8	0	6	1
Book Leases Capitalized for Tax	97,118	RB_GUP	TOTAL	97,118	53,789	3,110	9,404	8,186	18,738	2,106	27	1,561	198
Capitalized Software Costs Book	108,335	RB_GUP	TOTAL	108,335	60,001	3,469	10,490	9,131	20,902	2,350	30	1,741	220
MTM Book Gain Above the Line Tax Deferral	(549,332)	PROD_ENERGY	TOTAL	(549,332)	(206,124)	(13,358)	(46,374)	(52,038)	(214,780)	(11,251)	(201)	(4,347)	(860)
Mark & Spread Deferral - 283 A/L	91,891	PROD_ENERGY	TOTAL	91,891	34,480	2,235	7,757	8,705	35,928	1,882	34	727	144
Mark & Spread Deferral - 190 A/L	(120,148)	PROD_ENERGY	TOTAL	(120,148)	(45,083)	(2,922)	(10,143)	(11,381)	(46,976)	(2,461)	(44)	(951)	(188)
Prov for Trading Credit Risk - Above the Line	4,460	PROD_ENERGY	TOTAL	4,460	1,674	108	377	422	1,744	91	2	35	7
Provision for FAS 157 A/L	(410)	PROD_ENERGY	TOTAL	(410)	(154)	(10)	(35)	(39)	(160)	(8)	(0)	(3)	(1)
Reg Liability - Unrealized MTM Gain Deferral	212,300	PROD_ENERGY	TOTAL	212,300	79,661	5,163	17,922	20,111	83,006	4,348	78	1,680	332
Book > Tax Basis - EMA A/C 283	(136,914)	PROD_ENERGY	TOTAL	(136,914)	(51,374)	(3,329)	(11,558)	(12,970)	(53,531)	(2,804)	(50)	(1,083)	(214)
Total Per Books DFIT	21,095,576		TOTAL	21,095,576	11,523,498	727,128	1,955,368	1,698,423	4,222,634	433,765	5,546	494,845	34,368
DFIT Adjustments													
Adj 2 - Decommissioning Rider Removal	672,242	PROD_DEMAND	TOTAL	672,242	331,135	16,369	62,024	58,081	190,220	14,232	182	-	-
Adj 5 - Environmental Surcharge Revenue Sync - remove FGD re	281,710	PROD_ENERGY	TOTAL	281,710	105,705	6,850	23,782	26,686	110,144	5,770	103	2,229	441
Adj 6 - Big Sandy Unit 1 Operation Rider Deferrals	1,516,866	PROD_DEMAND	TOTAL	1,516,866	747,182	36,936	139,952	131,056	429,217	32,112	410	-	-
Adj 7 - Fuel Under (Over) Revenue & Expense	(774,180)	PROD_ENERGY	TOTAL	(774,180)	(290,493)	(18,826)	(65,355)	(73,337)	(302,691)	(15,856)	(283)	(6,126)	(1,212)
Adj 8 - System Sales Clause - reset OSS Margin Baseline	(60,856)	RB_GUP-Land_P	TOTAL	(60,856)	(29,977)	(1,482)	(5,615)	(5,258)	(17,220)	(1,288)	(16)	-	-
Adj 9 - PPA Rider Sync	(130,390)	PROD_ENERGY	TOTAL	(130,390)	(48,926)	(3,171)	(11,007)	(12,352)	(50,980)	(2,670)	(48)	(1,032)	(204)
Adj 10 - Remove DSM Rider	(841,343)	CUST_TOTAL	TOTAL	(841,343)	(536,097)	(93,806)	(26,675)	(2,611)	(263)	(636)	(39)	(180,999)	(216)
Adj 18 - Amortization of Storm Cost Deferral	(306,107)	EXP_OM_DIST	TOTAL	(306,107)	(207,244)	(12,305)	(34,780)	(27,548)	(11,431)	(7,671)	(96)	(3,146)	(1,887)
Adj 23 - Pension & OPEB Expense Adjustment	(52,038)	LABOR_M	TOTAL	(52,038)	(29,378)	(1,874)	(4,912)	(4,299)	(9,865)	(1,091)	(15)	(481)	(123)
Adj 30 - NERC Compliance & Cyber Security	(23,532)	RB_GUP-Land_P	TOTAL	(23,532)	(11,591)	(573)	(2,171)	(2,033)	(6,659)	(498)	(6)	-	-
Adjs 32-39 - Total Incentive Compensation & Payroll Adjustment	174,772	LABOR_M	TOTAL	174,772	98,667	6,295	16,498	14,440	33,133	3,664	49	1,614	412
Adj 42 - Annualization Depreciation/Amortization Expense Produ	(441,136)	RB_GUP-Land_P	TOTAL	(441,136)	(217,296)	(10,742)	(40,701)	(38,114)	(124,825)	(9,339)	(119)	-	-
Adj 42 - Annualization Depreciation/Amortization Expense Transi	(16,628)	RB_GUP-Land_T	TOTAL	(16,628)	(8,173)	(402)	(1,522)	(1,428)	(4,747)	(348)	(4)	(3)	(1)
Adj 42 - Annualization Depreciation/Amortization Expense Distrib	(162,931)	RB_GUP-Land_D	TOTAL	(162,931)	(107,887)	(7,421)	(17,185)	(13,166)	(5,199)	(3,716)	(46)	(7,392)	(919)
Adj 42 - Annualization Depreciation/Amortization Expense Gener	(25,791)	RB_GUP-Land_G	TOTAL	(25,791)	(14,560)	(929)	(2,435)	(2,131)	(4,889)	(541)	(7)	(238)	(61)
Adj 43 - Update Big Sandy Unit 1 Depreciation Rates	(942,303)	RB_GUP-Land_P	TOTAL	(942,303)	(464,162)	(22,945)	(86,941)	(81,414)	(266,637)	(19,949)	(255)	-	-
Adj 44 - ARO Depreciation	1,336	RB_GUP-Land_P	TOTAL	1,336	658	33	123	115	378	28	0	-	-
Adj 45 - ARO Accretion	38,323	PROD_DEMAND	TOTAL	38,323	18,877	933	3,536	3,311	10,844	811	10	-	-
Adj 50 - AFUDC Offset	73,381	PROD_DEMAND	TOTAL	73,381	36,146	1,787	6,770	6,340	20,764	1,553	20	-	-
Adj 55 - Mitchell Plant DSIT Amortization Adjustment	(452,372)	RB_GUP	TOTAL	(452,372)	(250,546)	(14,487)	(43,803)	(38,128)	(87,280)	(9,811)	(124)	(7,272)	(921)
Total Adjustments to DFIT	(1,470,978)		TOTAL	(1,470,978)	(877,960)	(119,760)	(90,417)	(61,790)	(97,988)	(15,243)	(285)	(202,844)	(4,690)
Total Deferred FIT	19,624,598		TOTAL	19,624,598	10,645,538	607,368	1,864,951	1,636,633	4,124,646	418,522	5,261	292,001	29,678
Feedback Prior ITC Normalization Tax	(2,327)	RB_GUP	TOTAL	(2,327)	(1,289)	(75)	(225)	(196)	(449)	(50)	(1)	(37)	(5)
Total Federal Income Tax	4,718,168		TOTAL	4,718,168	(7,448,962)	1,486,901	3,138,014	2,778,748	2,953,492	424,477	14,571	1,206,522	164,405

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
FEBRUARY 28, 2017

Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	SGS 3	Total MGS	Total LGS	Total IGS	Total PS	MW 17	OL 18	SL 19
Total Income Tax	3,754,351		TOTAL	3,754,351	(9,721,244)	1,699,969	3,530,238	3,124,640	3,048,257	462,414	16,698	1,400,977	192,402
Total Expenses	523,190,005		TOTAL	523,190,005	241,412,671	16,628,173	50,180,728	49,290,764	147,241,306	11,265,914	178,771	5,881,311	1,110,367
Net Operating Income	45,186,556		TOTAL	45,186,556	6,110,029	3,908,545	9,336,378	8,247,381	12,753,247	1,593,587	37,333	2,819,997	380,060
AFUDC Offset													
Production	550,246	PROD_DEMAND	TOTAL	550,246	271,042	13,399	50,768	47,541	155,699	11,649	149	-	-
Transmission	280,347	RB_GUP_EPIS_T	TOTAL	280,347	137,811	6,784	25,677	24,089	79,992	5,865	75	44	9
Distribution	349,881	RB_GUP_EPIS_D	TOTAL	349,881	231,699	15,890	36,944	28,344	11,232	7,991	99	15,727	1,956
General	38,477	LABOR_M	TOTAL	38,477	21,722	1,386	3,632	3,179	7,294	807	11	355	91
Total Per Books AFUDC Offset	1,218,951		TOTAL	1,218,951	662,274	37,458	117,021	103,153	254,218	26,312	334	16,126	2,056
Adj 50 - AFUDC Offset	561,041	PROD_DEMAND	TOTAL	561,041	276,359	13,661	51,764	48,474	158,754	11,877	152	-	-
Total AFUDC Offset Adjustments	561,041		TOTAL	561,041	276,359	13,661	51,764	48,474	158,754	11,877	152	-	-
Total Adjusted AFUDC Offsets	1,779,992		TOTAL	1,779,992	938,633	51,120	168,785	151,626	412,972	38,189	485	16,126	2,056
Adjusted Net Operating Income	46,966,548		TOTAL	46,966,548	7,048,662	3,959,664	9,505,162	8,399,008	13,166,219	1,631,776	37,818	2,836,123	382,116
Current Rate of Return				3.93%	1.08%	10.56%	8.27%	8.29%	5.47%	6.17%	11.19%	15.05%	15.68%
O&M Labor													
Production Demand	12,848,663	PROD_DEMAND	TOTAL	12,848,663	6,329,033	312,867	1,185,468	1,110,116	3,635,698	272,009	3,472	-	-
Production Energy	3,382,469	PROD_ENERGY	TOTAL	3,382,469	1,269,194	82,252	285,544	320,417	1,322,489	69,276	1,238	26,764	5,296
Transmission	57,273	EXP_OM_TRAN	TOTAL	57,273	28,153	1,386	5,245	4,921	16,345	1,198	15	9	2
Distribution	9,850,666	EXP_OM_DIST	TOTAL	9,850,666	6,669,197	395,966	1,119,226	886,497	367,866	246,864	3,075	101,247	60,728
Customer Accounts	1,386,556	EXP_OM_CUSTACCT	TOTAL	1,386,556	1,196,013	149,172	44,238	4,605	489	1,077	63	(9,415)	314
Customer Service	658,852	EXP_OM_CUSTSERV	TOTAL	658,852	419,815	73,459	20,889	2,045	206	498	31	141,739	169
Total	28,184,479		TOTAL	28,184,479	15,911,405	1,015,101	2,660,610	2,328,602	5,343,093	590,922	7,893	260,344	66,509
Calculation of Proposed Revenues													
Proposed Operating Income	86,761,984	RATEBASE	TOTAL	86,761,984	29,709,448	5,084,816	13,084,966	11,554,148	20,990,688	2,482,329	47,844	3,358,778	448,967
					29,709,448	5,084,816	13,084,966	11,554,148	20,990,688	2,482,329	47,844	3,358,778	448,967
Proposed Rate of Return				7.26%	4.55%	13.55%	11.38%	11.40%	8.73%	9.39%	14.16%	17.83%	18.42%
Income Increase	39,795,436		TOTAL	39,795,436	22,660,786	1,125,152	3,579,804	3,155,140	7,824,469	850,553	10,026	522,655	66,851
Gross Revenue Conversion Factor	1.64325												
Revenue Increase	65,393,881		TOTAL	65,393,881	37,237,355	1,848,906	5,882,515	5,184,686	12,857,565	1,397,673	16,475	858,854	109,853
Percent Revenue Increase				13.07%	17.21%	9.92%	11.00%	10.06%	9.25%	12.12%	8.45%	10.41%	7.78%
Proposed Sales Revenue	565,794,092		TOTAL	565,794,092	253,578,405	20,481,413	59,367,152	56,700,064	151,888,336	12,933,292	211,356	9,112,879	1,521,196

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
FEBRUARY 28, 2017

Allocation Factor	Total Retail 1	RS 2	SGS 3	MGS-SEC 4	MGS-PRI 5	MGS-SUB 6	LGS-SEC 7	LGS-PRI 8	LGS-SUB 9	LGS-TRA 10	IGS-SEC 11	IGS-PRI 12	IGS-SUB 13	IGS-TRA 14	PS-SEC 15	PS-PRI 16	MW 17	OL 18	SL 19
XXXXXXXXXXXXXXXXXXXXXXXXX																			
BULK_TRANS PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS BULKTRAN	1.00000000	0.49258299	0.02435014	0.08919316	0.00280748	0.00026328	0.06780067	0.01263324	0.00570873	0.00025672	0.00236845	0.03875930	0.20484399	0.03699143	0.02082148	0.00034875	0.00027019	-	-
BULK_TRANS SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS TOTAL	1.00000000	0.49258299	0.02435014	0.08919316	0.00280748	0.00026328	0.06780067	0.01263324	0.00570873	0.00025672	0.00236845	0.03875930	0.20484399	0.03699143	0.02082148	0.00034875	0.00027019	-	-
CUST_902 PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902 BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902 SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902 DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902 DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902 ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902 CUSTOMER	1.00000000	0.79082539	0.13837808	0.05829570	0.00079072	0.00006082	0.00765227	0.00085444	0.00024619	0.00002896	0.00006951	0.00060824	0.00043446	0.00005214	0.00163357	0.00001159	0.00005793	-	-
CUST_902 TOTAL	1.00000000	0.79082539	0.13837808	0.05829570	0.00079072	0.00006082	0.00765227	0.00085444	0.00024619	0.00002896	0.00006951	0.00060824	0.00043446	0.00005214	0.00163357	0.00001159	0.00005793	-	-
CUST_903 PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903 BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903 SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903 DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903 DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903 ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903 CUSTOMER	1.00000000	0.86013133	0.10559973	0.02965798	0.00034501	0.00002667	0.00259493	0.00026079	0.00007517	0.00000882	0.00001764	0.00015454	0.00011045	0.00001323	0.00071184	0.00000441	0.00004431	-	0.00024316
CUST_903 TOTAL	1.00000000	0.86013133	0.10559973	0.02965798	0.00034501	0.00002667	0.00259493	0.00026079	0.00007517	0.00000882	0.00001764	0.00015454	0.00011045	0.00001323	0.00071184	0.00000441	0.00004431	-	0.00024316
CUST_DEP_FXNL PRODUCTION	0.35389035	0.24973551	0.01422052	0.03094022	0.00380337	0.00535263	0.01457257	0.00887942	0.00757986	-	-	0.00690110	0.00629604	0.00520581	0.00040329	-	-	-	-
CUST_DEP_FXNL BULKTRAN	0.18756968	0.13236532	0.00753719	0.01639900	0.00201587	0.00283701	0.00772378	0.00470629	0.00401749	-	-	0.00365774	0.00333704	0.00275919	0.00021375	-	-	-	-
CUST_DEP_FXNL SUBTRAN	0.04042765	0.02873930	0.00159768	0.00345242	0.00041647	0.00077842	0.00161613	0.00098247	0.00110433	-	-	0.00076530	0.00092037	-	0.00004383	-	-	0.00001092	-
CUST_DEP_FXNL DISTPRI	0.23547603	0.18101649	0.00982872	0.02119865	0.00255858	-	0.00984869	0.00599850	-	-	-	0.00469077	-	-	0.00026763	-	-	0.00006800	-
CUST_DEP_FXNL DISTSEC	0.12486240	0.10420884	0.00578706	0.01037220	-	-	0.00409505	-	-	-	-	-	-	-	0.00013612	-	-	0.00026314	-
CUST_DEP_FXNL ENERGY	0.00254819	0.00160742	0.00011999	0.00023914	0.00002968	0.00004106	0.00013509	0.00008189	0.00007029	-	-	0.00007530	0.00007380	0.00006411	0.00000330	-	-	0.00000711	-
CUST_DEP_FXNL CUSTOMER	0.05522571	0.03137474	0.00946820	0.00159649	0.00201257	0.00490262	0.00028072	0.00027183	0.00111545	-	-	0.00004085	0.00003797	0.00003116	0.00000700	-	-	0.00408610	-
CUST_DEP_FXNL TOTAL	1.00000000	0.72904762	0.04855935	0.08419810	0.01083654	0.01391175	0.03827204	0.02092041	0.01388742	-	-	0.01613107	0.01066522	0.00806028	0.00107493	-	-	0.00443527	-
CUST_TOTAL PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL CUSTOMER	1.00000000	0.63719189	0.11149540	0.03131374	0.00036406	0.00002800	0.00273978	0.00027538	0.00007935	0.00000933	0.00001867	0.00016336	0.00011669	0.00001400	0.00075146	0.00000467	0.00004667	0.21513085	0.00025671
CUST_TOTAL TOTAL	1.00000000	0.63719189	0.11149540	0.03131374	0.00036406	0.00002800	0.00273978	0.00027538	0.00007935	0.00000933	0.00001867	0.00016336	0.00011669	0.00001400	0.00075146	0.00000467	0.00004667	0.21513085	0.00025671
DIST_CPD PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD DISTPRI	1.00000000	0.66834265	0.03150393	0.11439270	0.00353533	-	0.08577453	0.01597551	-	-	0.00305781	0.04931554	-	-	0.02586496	0.00043153	0.00034961	0.00119772	0.00025819
DIST_CPD DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD TOTAL	1.00000000	0.66834265	0.03150393	0.11439270	0.00353533	-	0.08577453	0.01597551	-	-	0.00305781	0.04931554	-	-	0.02586496	0.00043153	0.00034961	0.00119772	0.00025819
DIST_METERS PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS CUSTOMER	1.00000000	0.44835694	0.26566362	0.07611716	0.05018844	0.00815221	0.03719914	0.01303120	0.02840351	0.00499202	0.00025638	0.00773037	0.04176984	0.00748805	0.01031906	0.00022087	0.00011120	-	-
DIST_METERS TOTAL	1.00000000	0.44835694	0.26566362	0.07611716	0.05018844	0.00815221	0.03719914	0.01303120	0.02840351	0.00499202	0.00025638	0.00773037	0.04176984	0.00748805	0.01031906	0.00022087	0.00011120	-	-
DIST_OHLINES PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHLINES BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHLINES SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHLINES DISTPRI	0.83320000	0.55686310	0.02624907	0.09531199	0.00294564	-	0.07146734	0.01331080	-	-	0.00254777	0.04108971	-	-	0.02155069	0.00035955	0.00029130	0.00099794	0.00021512
DIST_OHLINES DISTSEC	0.16680000	0.12471660	0.00601263	0.01814260	-	-	0.01156054	-	-	-	0.00031257	-	-	-	0.00426404	-	0.00004425	0.00150239	0.00024439
DIST_OHLINES ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHLINES CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHLINES TOTAL	1.00000000	0.68157970	0.03226170	0.11345460	0.00294564	-	0.08302787	0.01331080	-	-	0.00286034	0.04108971	-	-	0.02581472	0.00035955	0.00033554	0.00250033	0.00045951
DIST_OL PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL CUSTOMER	1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.00000000	-
DIST_OL TOTAL	1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.00000000	-

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
FEBRUARY 28, 2017

Allocation Factor	Total Retail 1	RS 2	SGS 3	MGS-SEC 4	MGS-PRI 5	MGS-SUB 6	LGS-SEC 7	LGS-PRI 8	LGS-SUB 9	LGS-TRA 10	IGS-SEC 11	IGS-PRI 12	IGS-SUB 13	IGS-TRA 14	PS-SEC 15	PS-PRI 16	MW 17	OL 18	SL 19
DIST_PCUST PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST CUSTOMER	1.00000000	0.63734956	0.11152298	0.03132149	0.00036415	-	0.00274046	0.00027545	-	-	0.00001867	0.00016340	-	-	0.00075164	0.00000467	0.00004669	0.21518408	0.00025677
DIST_PCUST TOTAL	1.00000000	0.63734956	0.11152298	0.03132149	0.00036415	-	0.00274046	0.00027545	-	-	0.00001867	0.00016340	-	-	0.00075164	0.00000467	0.00004669	0.21518408	0.00025677
DIST_POLES PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES DISTPRI	0.56690000	0.37888345	0.01785958	0.06484922	0.00200418	-	0.04862558	0.00905652	-	-	0.00173347	0.02795698	-	-	0.01466285	0.00024463	0.00019819	0.00067899	0.00014637
DIST_POLES DISTSEC	0.43310000	0.32382950	0.01561192	0.04710768	-	-	0.03001720	-	-	-	0.00081160	-	-	-	0.01107167	-	0.00011489	0.00390099	0.00063455
DIST_POLES ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES TOTAL	1.00000000	0.70271295	0.03347150	0.11195690	0.00200418	-	0.07864278	0.00905652	-	-	0.00254507	0.02795698	-	-	0.02573451	0.00024463	0.00031309	0.00457998	0.00078092
DIST_SERV PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV CUSTOMER	1.00000000	0.63786474	0.11161313	0.03134681	-	-	0.00274267	-	-	-	0.00001869	-	-	-	0.00075225	-	0.00004672	0.21535802	0.00025698
DIST_SERV TOTAL	1.00000000	0.63786474	0.11161313	0.03134681	-	-	0.00274267	-	-	-	0.00001869	-	-	-	0.00075225	-	0.00004672	0.21535802	0.00025698
DIST_SL PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL CUSTOMER	1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.00000000
DIST_SL TOTAL	1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.00000000
DIST_TRANSF PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_TRANSF BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_TRANSF SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_TRANSF DISTPRI	0.20176000	0.13484481	0.00635623	0.02307987	0.00071329	-	0.01730587	0.00322322	-	-	0.00061694	0.00994990	-	-	0.00521851	0.00008707	0.00007054	0.00024165	0.00005209
DIST_TRANSF DISTSEC	0.79824000	0.59684521	0.02877410	0.08682344	-	-	0.05532424	-	-	-	0.00149585	-	-	-	0.02040602	-	0.00021175	0.00718986	0.00116953
DIST_TRANSF ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_TRANSF CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_TRANSF TOTAL	1.00000000	0.73169002	0.03513033	0.10990331	0.00071329	-	0.07263010	0.00322322	-	-	0.00211279	0.00994990	-	-	0.02562453	0.00008707	0.00028229	0.00743151	0.00122163
DIST_UGLINES PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES DISTPRI	0.80950000	0.54102338	0.02550243	0.09260089	0.00286185	-	0.06943448	0.01293218	-	-	0.00247530	0.03992093	-	-	0.02093769	0.00034932	0.00028301	0.00096955	0.00020900
DIST_UGLINES DISTSEC	0.19050000	0.14243713	0.00686694	0.02072042	-	-	0.01320313	-	-	-	0.00035698	-	-	-	0.00486990	-	0.00005054	0.00171586	0.00027911
DIST_UGLINES ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES TOTAL	1.00000000	0.68346050	0.03236937	0.11332130	0.00286185	-	0.08263761	0.01293218	-	-	0.00283228	0.03992093	-	-	0.02580758	0.00034932	0.00033354	0.00268541	0.00048811
EXP_OM_CUSTACCT PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT CUSTOMER	1.00000000	0.86257803	0.10758458	0.03150242	0.00037392	0.00002889	0.00292531	0.00029965	0.00008637	0.00001014	0.00002104	0.00018431	0.00013171	0.00001578	0.00077163	0.00000488	0.00004514	(0.00679042)	0.00022663
EXP_OM_CUSTACCT TOTAL	1.00000000	0.86257803	0.10758458	0.03150242	0.00037392	0.00002889	0.00292531	0.00029965	0.00008637	0.00001014	0.00002104	0.00018431	0.00013171	0.00001578	0.00077163	0.00000488	0.00004514	(0.00679042)	0.00022663
EXP_OM_CUSTSERV PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV CUSTOMER	1.00000000	0.63719189	0.11149540	0.03131374	0.00036406	0.00002800	0.00273978	0.00027538	0.00007935	0.00000933	0.00001867	0.00016336	0.00011669	0.00001400	0.00075146	0.00000467	0.00004667	0.21513085	0.00025671
EXP_OM_CUSTSERV TOTAL	1.00000000	0.63719189	0.11149540	0.03131374	0.00036406	0.00002800	0.00273978	0.00027538	0.00007935	0.00000933	0.00001867	0.00016336	0.00011669	0.00001400	0.00075146	0.00000467	0.00004667	0.21513085	0.00025671
EXP_OM_DIST PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_DIST BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_DIST SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_DIST DISTPRI	0.67163568	0.44888277	0.02115916	0.07683022	0.00237445	-	0.05760923	0.01072972	-	-	0.00205373	0.03312208	-	-	0.01737183	0.00028983	0.00023481	0.00080443	0.00017341
EXP_OM_DIST DISTSEC	0.27719230	0.20725709	0.00999193	0.03014982	-	-	0.01921158	-	-	-	0.00051944	-	-	-	0.00708608	-	0.00007353	0.00249671	0.00040613
EXP_OM_DIST ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_DIST CUSTOMER	0.05117202	0.02089023	0.00904574	0.00258385	0.00144628	0.00023473	0.00110540	0.00037611	0.00081783	0.00014374	0.00000762	0.00022312	0.00120269	0.00021560	0.00030653	0.00000637	0.00000379	0.00697710	0.00558530
EXP_OM_DIST TOTAL	1.00000000	0.67703009	0.04019683	0.10956388	0.00382073	0.00023473	0.07792621	0.01110584	0.00081783	0.00014374	0.00258079	0.03334519	0.00120269	0.00021560	0.02476444	0.00029620	0.00031213	0.01027824	0.00616484

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
FEBRUARY 28, 2017

Allocation Factor	Total Retail 1	RS 2	SGS 3	MGS-SEC 4	MGS-PRI 5	MGS-SUB 6	LGS-SEC 7	LGS-PRI 8	LGS-SUB 9	LGS-TRA 10	IGS-SEC 11	IGS-PRI 12	IGS-SUB 13	IGS-TRA 14	PS-SEC 15	PS-PRI 16	MW 17	OL 18	SL 19
EXP_OM_TRAN PRODUCTION	0.00000000	0.00000000	0.00000000	0.00000000	-	-	-	0.00000000	-	-	(0.00000000)	0.00000000	-	-	(0.00000000)	-	0.00000000	-	-
EXP_OM_TRAN BULKTRAN	0.81970000	0.40377028	0.01995981	0.07311163	0.00230129	0.00021581	0.05557621	0.01035547	0.00467944	0.00021043	0.00194142	0.03177100	0.16791062	0.03032188	0.01706737	0.00028587	0.00022147	-	-
EXP_OM_TRAN SUBTRAN	0.18030000	0.08778220	0.00423648	0.01541212	0.00047607	0.00005929	0.01164410	0.00216462	0.00128798	-	0.00040659	0.00665614	0.04637123	-	0.00350453	0.00005842	0.00004680	0.00015912	0.00003430
EXP_OM_TRAN DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_TRAN DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_TRAN ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_TRAN CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_TRAN TOTAL	1.00000000	0.49155248	0.02419629	0.08852375	0.00277736	0.00027510	0.06722031	0.01252009	0.00596742	0.00021043	0.00234801	0.03842714	0.21428185	0.03032188	0.02057190	0.00034429	0.00026827	0.00015912	0.00003430
EXP_OM_LPP PRODUCTION	0.38144820	0.18777760	0.00930139	0.03405480	0.00107143	0.00010050	0.02588861	0.00482476	0.00217942	0.00009799	0.00090334	0.01478889	0.07816980	0.01410671	0.00794668	0.00013305	0.00010324	-	-
EXP_OM_LPP BULKTRAN	0.03658983	0.01796788	0.00089725	0.00327877	0.00010308	0.00000987	0.00249231	0.00046485	0.00020972	0.00000942	0.00008662	0.00142065	0.00751052	0.00135240	0.00076376	0.00001277	0.00000997	-	-
EXP_OM_LPP SUBTRAN	0.00804997	0.00390726	0.00019040	0.00069109	0.00002132	0.00000272	0.00052212	0.00009715	0.00005772	-	0.00001814	0.00029763	0.00207415	-	0.00015682	0.00000261	0.00000211	0.00000719	0.00000155
EXP_OM_LPP DISTPRI	0.22342867	0.14926117	0.00704821	0.02558277	0.00079039	-	0.01918325	0.00357348	-	-	0.00068323	0.01102298	-	-	0.00578241	0.00009644	0.00007824	0.00026827	0.00005783
EXP_OM_LPP DISTSEC	0.09230981	0.06898853	0.00333323	0.01005303	-	-	0.00640605	-	-	-	0.00017301	-	-	-	0.00236172	-	0.00002454	0.00083403	0.00013567
EXP_OM_LPP ENERGY	0.14757672	0.05538610	0.00358852	0.01204015	0.00038214	0.00003501	0.01098018	0.00203594	0.00092467	0.00004284	0.00042063	0.00738332	0.04192959	0.00795067	0.00297412	0.00004841	0.00005401	0.00116935	0.00023107
EXP_OM_LPP CUSTOMER	0.11059680	0.07543236	0.01328904	0.00379700	0.00051683	0.00008116	0.00063238	0.00015221	0.00028057	0.00004886	0.00000438	0.00009048	0.00041261	0.00007324	0.00017329	0.00000257	0.00000557	0.01371723	0.00188702
EXP_OM_LPP TOTAL	1.00000000	0.55872089	0.03764803	0.08949761	0.00288519	0.00022926	0.06610490	0.01114838	0.00365210	0.00019911	0.00228935	0.03500396	0.13009667	0.02348301	0.02015880	0.00029586	0.00027767	0.01599607	0.00231314
EXP_OTHTAX_PSC PRODUCTION	0.44886785	0.20017735	0.01326170	0.04578679	0.00135291	0.00013172	0.03510166	0.00671140	0.00288962	0.00012691	0.00104558	0.01815100	0.09773244	0.01596052	0.01012442	0.00016051	0.00015333	-	-
EXP_OTHTAX_PSC BULKTRAN	(0.03516041)	(0.02724751)	0.00026481	(0.00042317)	(0.00003632)	0.00003230	(0.00033218)	0.00001924	(0.00005051)	(0.00000372)	(0.00009131)	(0.00092502)	(0.00446979)	(0.00149920)	(0.00039210)	(0.00001082)	0.00000490	-	-
EXP_OTHTAX_PSC SUBTRAN	(0.00738036)	(0.00573594)	0.00004906	(0.00010081)	(0.00000776)	0.00001094	(0.00007796)	0.00000153	(0.00001478)	-	(0.00001865)	(0.00019159)	(0.00122352)	-	(0.00008025)	(0.00000217)	0.00000094	0.00000858	0.00000202
EXP_OTHTAX_PSC DISTPRI	0.11813783	0.06722776	0.00538626	0.01782530	0.00050702	-	0.01347989	0.00261745	-	-	0.00036637	0.00662511	-	-	0.00366808	0.00005555	0.00006369	0.00025935	0.00005600
EXP_OTHTAX_PSC DISTSEC	0.05026682	0.03193862	0.00283710	0.00771898	-	-	0.00495758	-	-	-	0.00009861	-	-	-	0.00163079	-	0.00002236	0.00091316	0.00014962
EXP_OTHTAX_PSC ENERGY	0.38025008	0.14469868	0.00922499	0.03099848	0.00089135	0.00004239	0.02879910	0.00541411	0.00238707	0.00011061	0.00107648	0.01849092	0.10679770	0.01948536	0.00766945	0.00012476	0.00014148	0.00330348	0.00059368
EXP_OTHTAX_PSC CUSTOMER	0.04501818	0.02127709	0.00621130	0.00164990	0.00040208	0.00010162	0.00041089	0.00012244	0.00023790	0.00004011	0.00000222	0.00006021	0.00031767	0.00004802	0.00010294	0.00000165	0.00000275	0.01201028	0.00201912
EXP_OTHTAX_PSC TOTAL	1.00000000	0.43233605	0.03723521	0.10345548	0.00310928	0.00031897	0.08233897	0.01488617	0.00544931	0.00027391	0.00247931	0.04221064	0.19915450	0.03399471	0.02272331	0.00032947	0.00038945	0.01649485	0.00282043
FORF_DISC_FXNL PRODUCTION	0.45094970	0.31872603	0.02169642	0.04382113	0.00059382	0.00006108	0.01467173	0.00976943	0.00239806	0.00005678	0.00056875	0.01460277	0.02312573	0.00085797	-	-	-	-	-
FORF_DISC_FXNL BULKTRAN	(0.04544325)	(0.04338399)	0.00043323	(0.00040500)	(0.00001594)	0.00001498	(0.00013885)	0.00002801	(0.00004192)	(0.00000166)	(0.00004967)	(0.00074419)	(0.00105766)	(0.00008059)	-	-	-	-	-
FORF_DISC_FXNL SUBTRAN	(0.00964113)	(0.00913286)	0.00008026	(0.00009649)	(0.00000340)	0.00000507	(0.00003259)	0.00000223	(0.00001226)	-	(0.00001014)	(0.00015413)	(0.00028951)	-	-	-	-	0.00000270	-
FORF_DISC_FXNL DISTPRI	0.14819123	0.10704127	0.00881204	0.01706005	0.00022254	-	0.00563430	0.00381009	-	-	0.00019929	0.00533000	-	-	-	-	-	0.00008165	-
FORF_DISC_FXNL DISTSEC	0.06529569	0.05085325	0.00464155	0.00738760	-	-	0.00207216	-	-	-	0.00005364	-	-	-	-	-	-	0.00028748	-
FORF_DISC_FXNL ENERGY	0.34033168	0.23039188	0.01509228	0.02966769	0.00039123	0.00001966	0.01203739	0.00788103	0.00198099	0.00004949	0.00058556	0.01487624	0.02527078	0.00104746	-	-	-	0.00104000	-
FORF_DISC_FXNL CUSTOMER	0.05031608	0.03387777	0.01016182	0.00157907	0.00017648	0.00004712	0.00017174	0.00017823	0.00019743	0.00001794	0.00000121	0.00004844	0.00007517	0.00000258	-	-	-	0.00378107	-
FORF_DISC_FXNL TOTAL	1.00000000	0.68837336	0.06091760	0.09901406	0.00136472	0.00014791	0.03441589	0.02166901	0.00452230	0.00012254	0.00134864	0.03395913	0.04712451	0.00182742	-	-	-	0.00519290	-
FUELREV PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV ENERGY	1.00000000	0.34480142	0.02355168	0.07894598	0.00286893	0.00033392	0.07093082	0.01338580	0.00637274	0.00029942	0.00275178	0.05144452	0.31632383	0.05888802	0.01952591	0.00032904	0.00035322	0.00738526	0.00150774
FUELREV CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV TOTAL	1.00000000	0.34480142	0.02355168	0.07894598	0.00286893	0.00033392	0.07093082	0.01338580	0.00637274	0.00029942	0.00275178	0.05144452	0.31632383	0.05888802	0.01952591	0.00032904	0.00035322	0.00738526	0.00150774
LABOR_M PRODUCTION	0.45587726	0.22455738	0.01110067	0.04066113	0.00127987	0.00012002	0.03090879	0.00575921	0.00260248	0.00011703	0.00107972	0.01766948	0.09338372	0.01686355	0.00949204	0.00015899	0.00012317	-	-
LABOR_M BULKTRAN	0.00166569	0.00082049	0.00004056	0.00014857	0.00000468	0.00000044	0.00011294	0.00002104	0.00000951	0.00000043	0.00000395	0.00006456	0.00034121	0.00006162	0.00003468	0.00000058	0.00000045	-	-
LABOR_M SUBTRAN	0.00036638	0.00017838	0.00000861	0.00003132	0.00000097	0.00000012	0.00002366	0.00000440	0.00000262	-	0.00000083	0.00001353	0.00009423	-	0.00000712	0.00000012	0.00000010	0.00000032	0.00000007
LABOR_M DISTPRI	0.23474121	0.15688756	0.00739527	0.02685268	0.00082989	-	0.02013482	0.00375011	-	-	0.00071779	0.01157639	-	-	0.00607157	0.00010130	0.00008207	0.00028115	0.00006061
LABOR_M DISTSEC	0.09688058	0.07243775	0.00349225	0.01053757	-	-	0.00671458	-	-	-	0.00018155	-	-	-	0.00247663	-	0.00002570	0.00087262	0.00014194
LABOR_M ENERGY	0.12001176	0.04503166	0.00291834	0.00979136	0.00031119	0.00002869	0.00892692	0.00165488	0.00075193	0.00003484	0.00034210	0.00600670	0.03410355	0.00647024	0.00241857	0.00003937	0.00004391	0.00094959	0.00018792
LABOR_M CUSTOMER	0.09045711	0.06463169	0.01106061	0.00318486	0.00053239	0.00008412	0.00059430	0.00015263	0.00029194	0.00005095	0.00000413	0.00009087	0.00042955	0.00007646	0.00016266	0.00000258	0.00000464	0.00713347	0.00196925
LABOR_M TOTAL	1.00000000	0.56454493	0.03601631	0.09120748	0.00295898	0.00023338	0.06741600	0.01134227	0.00365848	0.00020325	0.00233007	0.03542153	0.12835225	0.02347187	0.02066328	0.00030293	0.00028004	0.00923716	0.00235979
LABOR_PROD PRODUCTION	0.79160609	0.38993170	0.01927572	0.07060585	0.00222242	0.00020841	0.05367143	0.01000055	0.00451906	0.00020322	0.00187488	0.03068210	0.16215575	0.02928264	0.01648241	0.00027607	0.00021388	-	-
LABOR_PROD BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD ENERGY	0.20839391	0.07819504	0.00506754	0.01700216	0.00054037	0.00004982	0.01550111	0.00287361	0.00130569	0.00006050	0.00059403	0.01043031	0.05921895	0.01123522	0.00419972	0.00006836	0.00007626	0.00164892	0.00032631
LABOR_PROD CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD TOTAL	1.00000000	0.46812674	0.02434326	0.08760801	0.00276279	0.00025823	0.06917253	0.01287416	0.00582476	0.00026372	0.00246891	0.04111241	0.22137471	0.04051786	0.02068213	0.00034444	0.00029014	0.00164892	0.00032631
MISC_SERV_REV PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MISC_SERV_REV BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MISC_SERV_REV SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MISC_SERV_REV DISTPRI	0.56154671	0.52518103	0.02291681	0.01196138	0.00028947	-	0.00105430	0.00006070	-	-	-	0.00001573	-	-	-	-	-	0.00006730	-
MISC_SERV_REV DISTSEC	0.32442196	0.30425074	0.01357848	0.00588952	-	-	0.00044115	-	-	-	-	-	-	-	-	-	-	0.00026207	-
MISC_SERV_REV ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MISC_SERV_REV CUSTOMER	0.11403132	0.08702610	0.02168676	0.00088429	0.00022903	0.00005370	0.00003002	0.00000276	-	-	-	0.00000014	-	-	-	-	-	0.00411853	-
MISC_SERV_REV TOTAL	1.00000000	0.91645786	0.05818206	0.01873519	0.00051850	0.00005370	0.00152547	0.00006346	-	-	-	0.00001586	-	-	-	-	-	0.00444790	-
PROD_DEMAND PRODUCTION	1.00000000	0.49258299	0.02435014	0.08919316	0.00280748	0.00026328	0.06780067	0.01263324	0.00570873	0.00025672	0.00236845	0.03875930	0.20484399	0.03699143	0.02082148	0.00034875	0.00027019	-	-
PROD_DEMAND BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND TOTAL	1.00000000	0.49258299	0.02435014	0.08919316	0.00280748	0.00026328	0.06780067	0.01263324	0.00570873	0.00025672	0.00236845	0.03875930	0.20484399	0.03699143	0.02082148	0.00034875	0.00027019	-	-

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
FEBRUARY 28, 2017

Allocation Factor	Total Retail 1	RS 2	SGS 3	MGS-SEC 4	MGS-PRI 5	MGS-SUB 6	LGS-SEC 7	LGS-PRI 8	LGS-SUB 9	LGS-TRA 10	IGS-SEC 11	IGS-PRI 12	IGS-SUB 13	IGS-TRA 14	PS-SEC 15	PS-PRI 16	MW 17	OL 18	SL 19
PROD_ENERGY PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY ENERGY	1.00000000	0.37522709	0.02431714	0.08158664	0.00259301	0.00023905	0.07438368	0.01378930	0.00626551	0.00029031	0.00285052	0.05005092	0.28416836	0.05391339	0.02015278	0.00032806	0.00036592	0.00791251	0.00156582
PROD_ENERGY CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY TOTAL	1.00000000	0.37522709	0.02431714	0.08158664	0.00259301	0.00023905	0.07438368	0.01378930	0.00626551	0.00029031	0.00285052	0.05005092	0.28416836	0.05391339	0.02015278	0.00032806	0.00036592	0.00791251	0.00156582
RATEBASE PRODUCTION	0.40296310	0.19690456	0.00968220	0.03594287	0.00106487	(0.00001354)	0.02753372	0.00499407	0.00217447	0.00010546	0.00097297	0.01575768	0.08398373	0.01506187	0.00854389	0.00014327	0.00011100	-	-
RATEBASE BULKTRAN	0.18413645	0.08980679	0.00441678	0.01643081	0.00048325	(0.00001438)	0.01259734	0.00227380	0.00098479	0.00004835	0.00044611	0.00721765	0.03850715	0.00690441	0.00391702	0.00006569	0.00005089	-	-
RATEBASE SUBTRAN	0.03863960	0.01860933	0.00089330	0.00330292	0.00009501	(0.00000455)	0.00251787	0.00045274	0.00025764	-	0.00008919	0.00144268	0.01015046	-	0.00076773	0.00001281	0.00001027	0.00003467	0.00000752
RATEBASE DISTPRI	0.19946522	0.13280120	0.00622731	0.02293848	0.00066502	-	0.01733979	0.00313670	-	-	0.00062593	0.00998577	-	-	0.00528835	0.00008833	0.00007157	0.00024391	0.00005283
RATEBASE DISTSEC	0.10130639	0.07550909	0.00362156	0.01108757	-	-	0.00712292	-	-	-	0.00019505	-	-	-	0.00265768	-	0.00002761	0.00093244	0.00015246
RATEBASE ENERGY	0.02426108	0.00930138	0.00058325	0.00196324	0.00005691	0.00000285	0.00181339	0.00034043	0.00014988	0.00000702	0.00006891	0.00118391	0.00679542	0.00125260	0.00048571	0.00000793	0.00000885	0.00020247	0.00003692
RATEBASE CUSTOMER	0.04922817	0.02313231	0.00597131	0.00172031	0.00051753	(0.00001948)	0.00049013	0.00014080	0.00029351	0.00005599	0.00000342	0.00008618	0.00046766	0.00008323	0.00013722	0.00000249	0.00000259	0.01435307	0.00178989
RATEBASE TOTAL	1.00000000	0.54606467	0.03139572	0.09338620	0.00288260	(0.00004908)	0.06941516	0.01133855	0.00386030	0.00021682	0.00240157	0.03567387	0.13990442	0.02330211	0.02179760	0.00032053	0.00028278	0.01576657	0.00203962
RB_GUP_CWIP PRODUCTION	0.29930055	0.14743036	0.00728801	0.02669556	0.00084028	0.00007880	0.02029278	0.00378114	0.00170862	0.00007683	0.00070888	0.01160068	0.06130992	0.01107156	0.00623188	0.00010438	0.00008087	-	-
RB_GUP_CWIP BULKTRAN	0.28598469	0.14087119	0.00696377	0.02550788	0.00080290	0.00007529	0.01938995	0.00361291	0.00163261	0.00007342	0.00067734	0.01108457	0.05858225	0.01057898	0.00595462	0.00009974	0.00007727	-	-
RB_GUP_CWIP SUBTRAN	0.06282229	0.03058613	0.00147613	0.00537008	0.00016588	0.00002066	0.00405718	0.00075422	0.00044877	-	0.00014167	0.00231921	0.01615722	-	0.00122109	0.00002036	0.00001631	0.00005544	0.00001195
RB_GUP_CWIP DISTPRI	0.19123551	0.12781085	0.00602467	0.02187595	0.00067608	-	0.01640314	0.00305509	-	-	0.00058476	0.00943088	-	-	0.00494630	0.00008252	0.00006686	0.00022905	0.00004937
RB_GUP_CWIP DISTSEC	0.09613371	0.07187931	0.00346532	0.01045633	-	-	0.00666281	-	-	-	0.00018015	-	-	-	0.00245754	-	0.00002550	0.00086589	0.00014085
RB_GUP_CWIP ENERGY	0.01408024	0.00528329	0.00034239	0.00114876	0.00003651	0.00000337	0.00104734	0.00019416	0.00008822	0.00000409	0.00004014	0.00070473	0.00400116	0.00075911	0.00028376	0.00000462	0.00000515	0.00011141	0.00002205
RB_GUP_CWIP CUSTOMER	0.05044302	0.02571186	0.00617790	0.00175801	0.00052036	0.00008425	0.00046948	0.00013680	0.00029339	0.00005152	0.00000324	0.00008119	0.00043149	0.00007729	0.00012979	0.00000232	0.00000259	0.01283568	0.00167588
RB_GUP_CWIP TOTAL	1.00000000	0.54957299	0.03173819	0.09281256	0.00304200	0.00026236	0.06832267	0.01153431	0.00417162	0.00020586	0.00233617	0.03522126	0.14048203	0.02248694	0.02122498	0.00031394	0.00027454	0.01409747	0.00190010
RB_GUP_EPIS_D PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D DISTPRI	0.56780830	0.37949051	0.01788819	0.06495312	0.00200739	-	0.04870349	0.00907103	-	-	0.00173625	0.02800177	-	-	0.01468634	0.00024503	0.00019851	0.00068007	0.00014660
RB_GUP_EPIS_D DISTSEC	0.29403248	0.21984851	0.01059897	0.03198150	-	-	0.02037874	-	-	-	0.00055100	-	-	-	0.00751658	-	0.00007800	0.00264839	0.00043080
RB_GUP_EPIS_D ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D CUSTOMER	0.13815922	0.06288418	0.01692805	0.00480191	0.00158831	0.00025799	0.00138661	0.00041240	0.00089888	0.00015798	0.00000954	0.00024464	0.00132188	0.00023697	0.00038399	0.00000699	0.00000709	0.04162009	0.00501171
RB_GUP_EPIS_D TOTAL	1.00000000	0.66222320	0.04541521	0.10173653	0.00359570	0.00025799	0.07046884	0.00948342	0.00089888	0.00015798	0.00229679	0.02824642	0.00132188	0.00023697	0.02258691	0.00025202	0.00028360	0.04494855	0.00558912
RB_GUP_EPIS_G PRODUCTION	0.45587726	0.22455738	0.01110067	0.04066113	0.00127987	0.00012002	0.03090879	0.00575921	0.00260248	0.00011703	0.00107972	0.01766948	0.09338372	0.01686355	0.00949204	0.00015899	0.00012317	-	-
RB_GUP_EPIS_G BULKTRAN	0.00166569	0.00082049	0.00004056	0.00014857	0.00000468	0.00000044	0.00011294	0.00002104	0.00000951	0.00000043	0.00000395	0.00006456	0.00034121	0.00006162	0.00003468	0.00000058	0.00000045	-	-
RB_GUP_EPIS_G SUBTRAN	0.00036638	0.00017838	0.00000861	0.00003132	0.00000097	0.00000012	0.00002366	0.00000440	0.00000262	-	0.00000083	0.00001353	0.00009423	-	0.00000712	0.00000012	0.00000010	0.00000032	0.00000007
RB_GUP_EPIS_G DISTPRI	0.23474121	0.15688756	0.00739527	0.02685268	0.00082989	-	0.02013482	0.00375011	-	-	0.00071779	0.01157639	-	-	0.00607157	0.00010130	0.00008207	0.00028115	0.00006061
RB_GUP_EPIS_G DISTSEC	0.09688058	0.07243775	0.00349225	0.01053757	-	-	0.00671458	-	-	-	0.00018155	-	-	-	0.00247663	-	0.00002570	0.00087262	0.00014194
RB_GUP_EPIS_G ENERGY	0.12001176	0.04503166	0.00291834	0.00979136	0.00031119	0.00002869	0.00892692	0.00165488	0.00075193	0.00003484	0.00034210	0.00600670	0.03410355	0.00647024	0.00241857	0.00003937	0.00004391	0.00094959	0.00018792
RB_GUP_EPIS_G CUSTOMER	0.09045711	0.06463169	0.01106061	0.00318486	0.00053239	0.00008412	0.00059430	0.00015263	0.00029194	0.00005095	0.00000413	0.00009087	0.00042955	0.00007646	0.00016266	0.00000258	0.00000464	0.00713347	0.00196925
RB_GUP_EPIS_G TOTAL	1.00000000	0.56454493	0.03601631	0.09120748	0.00295898	0.00023338	0.06741600	0.01134227	0.00365848	0.00020325	0.00233007	0.03542153	0.12835225	0.02347187	0.02066328	0.00030293	0.00028004	0.00923716	0.00235979
RB_GUP_EPIS_P PRODUCTION	1.00000000	0.49258299	0.02435014	0.08919316	0.00280748	0.00026328	0.06780067	0.01263324	0.00570873	0.00025672	0.00236845	0.03875930	0.20484399	0.03699143	0.02082148	0.00034875	0.00027019	-	-
RB_GUP_EPIS_P BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P TOTAL	1.00000000	0.49258299	0.02435014	0.08919316	0.00280748	0.00026328	0.06780067	0.01263324	0.00570873	0.00025672	0.00236845	0.03875930	0.20484399	0.03699143	0.02082148	0.00034875	0.00027019	-	-
RB_GUP_EPIS_T PRODUCTION	0.01771128	0.00872427	0.00043127	0.00157972	0.00004972	0.00000466	0.00120084	0.00022375	0.00010111	0.00000455	0.00004195	0.00068648	0.00362805	0.00065517	0.00036877	0.00000618	0.00000479	-	-
RB_GUP_EPIS_T BULKTRAN	0.80537259	0.39671284	0.01961093	0.07183372	0.00226107	0.00021204	0.05460481	0.01017447	0.00459765	0.00020675	0.00190749	0.03121568	0.16497574	0.02979188	0.01676905	0.00028088	0.00021760	-	-
RB_GUP_EPIS_T SUBTRAN	0.17691613	0.08613470	0.00415697	0.01512287	0.00046713	0.00005818	0.01142556	0.00212400	0.00126380	-	0.00039896	0.00653122	0.04550093	-	0.00343876	0.00005732	0.00004592	0.00015614	0.00003366
RB_GUP_EPIS_T DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_T DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_T ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_T CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_T TOTAL	1.00000000	0.49157182	0.02419918	0.08853632	0.00277793	0.00027488	0.06723120	0.01252222	0.00596257	0.00021130	0.00234839	0.03843337	0.21410472	0.03044705	0.02057658	0.00034438	0.00026831	0.00015614	0.00003366
RB_GUP-Land_P PRODUCTION	1.00000000	0.49258299	0.02435014	0.08919316	0.00280748	0.00026328	0.06780067	0.01263324	0.00570873	0.00025672	0.00236845	0.03875930	0.20484399	0.03699143	0.02082148	0.00034875	0.00027019	-	-
RB_GUP-Land_P BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_P SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_P DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_P DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_P ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_P CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_P TOTAL	1.00000000	0.49258299	0.02435014	0.08919316	0.00280748	0.00026328	0.06780067	0.01263324	0.00570873	0.00025672	0.00236845	0.03875930	0.20484399	0.03699143	0.02082148	0.00034875	0.00027019	-	-
RB_GUP-Land_T PRODUCTION	0.01875108	0.00923646	0.00045659	0.00167247	0.00005264	0.00000494	0.00127134	0.00023689	0.00010704	0.00000481	0.00004441	0.00072678	0.00384105	0.00069363	0.00039043	0.00000654	0.00000507	-	-
RB_GUP-Land_T BULKTRAN	0.79394632	0.39108445	0.01933270	0.07081458	0.00222899	0.00020903	0.05383010	0.01003012	0.00453242	0.00020382	0.00188042	0.03077280	0.16263513	0.02936921	0.01653114	0.00027689	0.00021452	-	-
RB_GUP-Land_T SUBTRAN	0.18730260	0.09119154	0.00440102	0.01601071	0.00049456	0.00006159	0.01209634	0.00224870	0.00133800	-	0.00042238	0.00691466	0.04817222	-	0.00364064	0.00006069	0.00004862	0.00016530	0.00003563
RB_GUP-Land_T DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_T DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_T ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_T CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_T TOTAL	1.00000000	0.49151245	0.02419032	0.08849775	0.00277619	0.00027556	0.06719777	0.01251570	0.00597747	0.00020863	0.00234722	0.03841424	0.21464840	0.03006284	0.02056221	0.00034412	0.00026820	0.00016530	0.00003563

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
FEBRUARY 28, 2017

Allocation Factor	Total Retail 1	RS 2	SGS 3	MGS-SEC 4	MGS-PRI 5	MGS-SUB 6	LGS-SEC 7	LGS-PRI 8	LGS-SUB 9	LGS-TRA 10	IGS-SEC 11	IGS-PRI 12	IGS-SUB 13	IGS-TRA 14	PS-SEC 15	PS-PRI 16	MW 17	OL 18	SL 19
RB_GUP-Land_D PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_D BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_D SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_D DISTPRI	0.56364713	0.37670942	0.01775710	0.06447711	0.00199268	-	0.04834657	0.00900455	-	-	0.00172353	0.02779656	-	-	0.01457871	0.00024323	0.00019706	0.00067509	0.00014553
RB_GUP-Land_D DISTSEC	0.29686345	0.22196523	0.01070101	0.03228942	-	-	0.02057494	-	-	-	0.00055630	-	-	-	0.00758895	-	0.00007875	0.00267389	0.00043495
RB_GUP-Land_D ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_D CUSTOMER	0.13948942	0.06348963	0.01709103	0.00484814	0.00160360	0.00026048	0.00139996	0.00041637	0.00090754	0.00015950	0.00000963	0.00024700	0.00133461	0.00023925	0.00038769	0.00000706	0.00000715	0.04202081	0.00505997
RB_GUP-Land_D TOTAL	1.00000000	0.66216428	0.04554915	0.10161468	0.00359628	0.00026048	0.07032147	0.00942092	0.00090754	0.00015950	0.00228946	0.02804356	0.00133461	0.00023925	0.02255535	0.00025029	0.00028296	0.04536979	0.00564044
RB_GUP-Land_G PRODUCTION	0.45587726	0.22455738	0.01110067	0.04066113	0.00127987	0.00012002	0.03090879	0.00575921	0.00260248	0.00011703	0.00107972	0.01766948	0.09338372	0.01686355	0.00949204	0.00015899	0.00012317	-	-
RB_GUP-Land_G BULKTRAN	0.00166569	0.00082049	0.00004056	0.00014857	0.00000468	0.00000044	0.00011294	0.00002104	0.00000951	0.00000043	0.00000395	0.00006456	0.00034121	0.00006162	0.00003468	0.00000058	0.00000045	-	-
RB_GUP-Land_G SUBTRAN	0.00036638	0.00017838	0.00000861	0.00003132	0.00000097	0.00000012	0.00002366	0.00000440	0.00000262	-	0.00000083	0.00001353	0.00009423	-	0.00000712	0.00000012	0.00000010	0.00000032	0.00000007
RB_GUP-Land_G DISTPRI	0.23474121	0.15688756	0.00739527	0.02685268	0.00082989	-	0.02013482	0.00375011	-	-	0.00071779	0.01157639	-	-	0.00607157	0.00010130	0.00008207	0.00028115	0.00006061
RB_GUP-Land_G DISTSEC	0.09688058	0.07243775	0.00349225	0.01053757	-	-	0.00671458	-	-	-	0.00018155	-	-	-	0.00247663	-	0.00002570	0.00087262	0.00014194
RB_GUP-Land_G ENERGY	0.12001176	0.04503166	0.00291834	0.00979136	0.00031119	0.00002869	0.00892692	0.00165488	0.00075193	0.00003484	0.00034210	0.00600670	0.03410355	0.00647024	0.00241857	0.00003937	0.00004391	0.00094959	0.00018792
RB_GUP-Land_G CUSTOMER	0.09045711	0.06463169	0.01106061	0.00318486	0.00053239	0.00008412	0.00059430	0.00015263	0.00029194	0.00005095	0.00000413	0.00009087	0.00042955	0.00007646	0.00016266	0.00000258	0.00000464	0.00713347	0.00196925
RB_GUP-Land_G TOTAL	1.00000000	0.56454493	0.03601631	0.09120748	0.00295898	0.00023338	0.06741600	0.01134227	0.00365848	0.00020325	0.00233007	0.03542153	0.12835225	0.02347187	0.02066328	0.00030293	0.00028004	0.00923716	0.00235979
RB_GUP_EPIS PRODUCTION	0.38515569	0.18972114	0.00937859	0.03435325	0.00108132	0.00010140	0.02611382	0.00486576	0.00219875	0.00009888	0.00091222	0.01492837	0.07889683	0.01424746	0.00801951	0.00013432	0.00010407	-	-
RB_GUP_EPIS BULKTRAN	0.20414100	0.10055638	0.00497086	0.01820798	0.00057312	0.00005375	0.01384090	0.00257896	0.00116539	0.00005241	0.00048350	0.00791236	0.04181706	0.00755147	0.00425052	0.00007119	0.00005516	-	-
RB_GUP_EPIS SUBTRAN	0.04484365	0.02183291	0.00105368	0.00383325	0.00011841	0.00001475	0.00289608	0.00053838	0.00032034	-	0.00010113	0.00165549	0.01153331	-	0.00087164	0.00001453	0.00001164	0.00003958	0.00000853
RB_GUP_EPIS DISTPRI	0.20575689	0.13751611	0.00648215	0.02353709	0.00072742	-	0.01764870	0.00328707	-	-	0.00062917	0.01014701	-	-	0.00532189	0.00008879	0.00007193	0.00024644	0.00005312
RB_GUP_EPIS DISTSEC	0.10587947	0.07916623	0.00381663	0.01151636	-	-	0.00733827	-	-	-	0.00019841	-	-	-	0.00270668	-	0.00002809	0.00095367	0.00015513
RB_GUP_EPIS ENERGY	0.00325440	0.00122114	0.00007914	0.00026552	0.00000844	0.00000078	0.00024207	0.00004488	0.00002039	0.00000094	0.00000928	0.00016289	0.00092480	0.00017546	0.00006559	0.00000107	0.00000119	0.00002575	0.00000510
RB_GUP_EPIS CUSTOMER	0.05096889	0.02383502	0.00624438	0.00177260	0.00057219	0.00009288	0.00050304	0.00014896	0.00032357	0.00005686	0.00000346	0.00008837	0.00047584	0.00008529	0.00013925	0.00000252	0.00000261	0.01480873	0.00181331
RB_GUP_EPIS TOTAL	1.00000000	0.55384894	0.03202544	0.09348605	0.00308089	0.00026355	0.06858288	0.01146401	0.00402843	0.00020908	0.00233716	0.03489449	0.13364783	0.02205967	0.02137508	0.00031243	0.00027469	0.01607417	0.00203519
RB_GUP PRODUCTION	0.38515569	0.18972114	0.00937859	0.03435325	0.00108132	0.00010140	0.02611382	0.00486576	0.00219875	0.00009888	0.00091222	0.01492837	0.07889683	0.01424746	0.00801951	0.00013432	0.00010407	-	-
RB_GUP BULKTRAN	0.20414100	0.10055638	0.00497086	0.01820798	0.00057312	0.00005375	0.01384090	0.00257896	0.00116539	0.00005241	0.00048350	0.00791236	0.04181706	0.00755147	0.00425052	0.00007119	0.00005516	-	-
RB_GUP SUBTRAN	0.04484365	0.02183291	0.00105368	0.00383325	0.00011841	0.00001475	0.00289608	0.00053838	0.00032034	-	0.00010113	0.00165549	0.01153331	-	0.00087164	0.00001453	0.00001164	0.00003958	0.00000853
RB_GUP DISTPRI	0.20575689	0.13751611	0.00648215	0.02353709	0.00072742	-	0.01764870	0.00328707	-	-	0.00062917	0.01014701	-	-	0.00532189	0.00008879	0.00007193	0.00024644	0.00005312
RB_GUP DISTSEC	0.10587947	0.07916623	0.00381663	0.01151636	-	-	0.00733827	-	-	-	0.00019841	-	-	-	0.00270668	-	0.00002809	0.00095367	0.00015513
RB_GUP ENERGY	0.00325440	0.00122114	0.00007914	0.00026552	0.00000844	0.00000078	0.00024207	0.00004488	0.00002039	0.00000094	0.00000928	0.00016289	0.00092480	0.00017546	0.00006559	0.00000107	0.00000119	0.00002575	0.00000510
RB_GUP CUSTOMER	0.05096889	0.02383502	0.00624438	0.00177260	0.00057219	0.00009288	0.00050304	0.00014896	0.00032357	0.00005686	0.00000346	0.00008837	0.00047584	0.00008529	0.00013925	0.00000252	0.00000261	0.01480873	0.00181331
RB_GUP TOTAL	1.00000000	0.55384894	0.03202544	0.09348605	0.00308089	0.00026355	0.06858288	0.01146401	0.00402843	0.00020908	0.00233716	0.03489449	0.13364783	0.02205967	0.02137508	0.00031243	0.00027469	0.01607417	0.00203519
REV_RENT PRODUCTION	0.00848058	0.00417739	0.00020650	0.00075641	0.00002381	0.00000223	0.00057499	0.00010714	0.00004841	0.00000218	0.00002009	0.00032870	0.00173720	0.00031371	0.00017658	0.00000296	0.00000229	-	-
REV_RENT BULKTRAN	(0.00567571)	(0.00279576)	(0.00013820)	(0.00050623)	(0.00001593)	(0.00000149)	(0.00038482)	(0.00007170)	(0.00003240)	(0.00000146)	(0.00001344)	(0.00021999)	(0.00116264)	(0.00020995)	(0.00011818)	(0.00000198)	(0.00000153)	-	-
REV_RENT SUBTRAN	(0.00124842)	(0.00060782)	(0.00002933)	(0.00010672)	(0.00000330)	(0.00000041)	(0.00008063)	(0.00001499)	(0.00000892)	-	(0.00000282)	(0.00004609)	(0.00032108)	-	(0.00002427)	(0.00000040)	(0.00000032)	(0.00000110)	(0.00000024)
REV_RENT DISTPRI	0.56613602	0.37837285	0.01783551	0.06476183	0.00200148	-	0.04856005	0.00904431	-	-	0.00173114	0.02791930	-	-	0.01464309	0.00024430	0.00019793	0.00067807	0.00014617
REV_RENT DISTSEC	0.41430249	0.30977457	0.01493433	0.04506310	-	-	0.02871438	-	-	-	0.00077638	-	-	-	0.01059113	-	0.00010990	0.00373168	0.00060701
REV_RENT ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REV_RENT CUSTOMER	0.01800504	0.00819513	0.00220608	0.00062579	0.00020699	0.00003362	0.00018070	0.00005374	0.00011714	0.00002059	0.00000124	0.00003188	0.00017227	0.00003088	0.00005004	0.00000091	0.00000092	0.00542397	0.00065313
REV_RENT TOTAL	1.00000000	0.69711636	0.03501488	0.11059417	0.00221305	0.00003395	0.07756468	0.00911850	0.00012424	0.00002131	0.00251258	0.02801381	0.00042575	0.00013464	0.02531839	0.00024579	0.00030919	0.00983262	0.00140608
REV PRODUCTION	0.31779440	0.13881446	0.00986870	0.03343419	0.00096897	0.00009517	0.02554144	0.00496051	0.00210096	0.00009144	0.00073363	0.01295980	0.06969004	0.01107444	0.00723426	0.00011318	0.00011320	-	-
REV BULKTRAN	0.05461145	0.01800803	0.00232784	0.00728580	0.00020905	0.00005116	0.00553032	0.00110228	0.00044558	0.00001876	0.00012269	0.00250948	0.01365231	0.00185692	0.00144326	0.00002043	0.00002753	-	-
REV SUBTRAN	0.01232602	0.00408260	0.00048771	0.00152556	0.00004303	0.00001588	0.00115130	0.00022819	0.00012187	-	0.00002612	0.00052770	0.00377991	-	0.00029658	0.00000421	0.00000573	0.00002424	0.00000537
REV DISTPRI	0.11335539	0.06569909	0.00507372	0.01669119	0.00047490	-	0.01255315	0.00245185	-	-	0.00034692	0.00624115	-	-	0.00342334	0.00005214	0.00005869	0.00023800	0.00005124
REV DISTSEC	0.05061546	0.03297445	0.00274622	0.00744909	-	-	0.00475729	-	-	-	0.00009740	-	-	-	0.00157481	-	0.00002113	0.00085539	0.00013969
REV ENERGY	0.41085595	0.15668432	0.01002113	0.03351223	0.00097848	0.00005506	0.03091806	0.00583879	0.00257718	0.00011911	0.00116183	0.02007186	0.11512846	0.02113168	0.00823587	0.00013399	0.00015150	0.00349844	0.00063795
REV CUSTOMER	0.04044133	0.01922773	0.00560692	0.00147515	0.00035887	0.00009042	0.00036590	0.00010994	0.00021274	0.00003577	0.00000198	0.00005387	0.00028295	0.00004279	0.00009142	0.00000146	0.00000244	0.01069298	0.00178800
REV TOTAL	1.00000000	0.43549069	0.03613224	0.10137322	0.00303331	0.00030769	0.08081746	0.01469156	0.00545833	0.00026508	0.00249057	0.04236386	0.20253367	0.03410583	0.02229954	0.00032542	0.00038021	0.01530906	0.00262225
RSALE PRODUCTION	0.44886785	0.20017735	0.01326170	0.04578679	0.00135291	0.00013172	0.03510166	0.00671140	0.00288962	0.00012691	0.00104558	0.01815100	0.09773244	0.01596052	0.01012442	0.00016051	0.00015333	-	-
RSALE BULKTRAN	(0.03516041)	(0.02724751)	0.00026481	(0.00042317)	(0.00003632)	0.00003230	(0.00033218)	0.00001924	(0.00005051)	(0.00000372)	(0.00009131)	(0.00092502)	(0.00446979)	(0.00149920)	(0.00039210)	(0.00001082)	0.00000490	-	-
RSALE SUBTRAN	(0.00738036)	(0.00573594)	0.00004906	(0.00010081)	(0.00000776)	0.00001094	(0.00007796)	0.00000153	(0.00001478)	-	(0.00001865)	(0.00019159)	(0.00122352)	-	(0.00008025)	(0.00000217)	0.00000094	0.00000858	0.00000202
RSALE DISTPRI	0.11813783	0.06722776	0.00538626	0.01782530	0.00050702	-	0.01347989	0.00261745	-	-	0.00036637	0.00662511	-	-	0.00366808	0.00005555	0.00006369	0.00025935	0.00005600
RSALE DISTSEC	0.05026682	0.03193862	0.00283710	0.00771898	-	-	0.00495758	-	-	-	0.00009861	-	-	-	0.00163079	-	0.00002236	0.00091316	0.00014962
RSALE ENERGY	0.38025008	0.14469868	0.00922499	0.03099848	0.00089135	0.00004239	0.02879910	0.00541411	0.00238707	0.00011061	0.00107648	0.01849092	0.10679770	0.01948536	0.00766945	0.00012476	0.00014148	0.00330348	0.00059368
RSALE CUSTOMER	0.04501818	0.02127709	0.00621130	0.00164990	0.00040208	0.00010162	0.00041089	0.00012244	0.00023790	0.00004011	0.00000222	0.00006021	0.00031767	0.00004802	0.00010294	0.00000165	0.00000275	0.01201028	0.00201912
RSALE TOTAL	1.00000000	0.43233605	0.03723521	0.10345548	0.00310928	0.00031897	0.08233897	0.01488617	0.00544931	0.00027391	0.00247931	0.04221064	0.19915450	0.03399471	0.02272331	0.00032947	0.00038945	0.01649485	0.00282043
REVYEC_FXNL PRODUCTION	0.50803528	0.07039904	0.00690473	0.01519181	0.02120782	0.00755040	(0.06640495)	(0.03333061)	-	-	-	0.08082299	0.24404855	0.15603825	0.00560725	-	-	-	-
REVYEC_FXNL BULKTRAN	(0.03792488)	(0.00958250)	0.00013787	(0.00014041)	(0.00056942)	0.00185126	0.00062842	(0.00009556)	-	-	-	(0.00411893)	(0.01116156)	(0.01465691)	(0.00021716)	-	-	-	-
REVYEC_FXNL SUBTRAN	(0.00536894)	(0.00201723)	0.00002554	(0.00003345)	(0.00012157)	0.00062699	0.00014749	(0.00000759)	-	-	-	(0.00085310)	(0.00305527)	-	(0.00004445)	-	-	(0.00004291)	0.00000662
REVYEC_FXNL DISTPRI	0.03222714	0.02364288	0.00280437	0.00591434	0.00794788	-	(0.02550112)	(0.01299897)	-	-	-	0.02950036	-	-	0.00203151	-	-	(0.00129755)	0.00018344
REVYEC_FXNL DISTSEC	0.00271650	0.01123228	0.00147714	0.00256112	-	-	(0.00937869)	-	-	-	-	-	-	-	0.00090319	-	-	(0.00456862)	0.00049009
REVYEC_FXNL ENERGY	0.53019480	0.05088812	0.00480301	0.01028513	0.01397260	0.00242999	(0.05448184)	(0.02688791)	-	-	-	0.08233660	0.26668549	0.19049889	0.00424761	-	-	(0.01652757)	0.00194469
REVYEC_FXNL CUSTOMER	(0.02987990)	0.00748280	0.00323392	0.00054743	0.00630285	0.00582507	(0.00077732)	(0.00060808)	-	-	-	0.00026812	0.00079325	0.00046951	0.00005701	-	-	(0.06008843)	0.00661397
REVYEC_FXNL TOTAL	1.00000000	0.15204539	0.01938658	0.03432596	0.04874018	0.01828371	(0.15576802)	(0.07392871)	-	-	-	0.18795604	0.49731046	0.33234975	0.01258496	-	-	(0.08252509)	0.00923880
REVYEC_EXP_OM PRODUCTION	0.28379745	0.04617534	0.00473266	0.00999103	0.01382221	0.00551292	(0.04167245)	(0.02049258)	-	-	-	0.04708796	0.13055753	0.08448739	0.00359546	-	-	-	-
REVYEC_EXP_OM BULKTRAN	0.01535871	0.00248817	0.00025820	0.00054349	0.00075088	0.00030798	(0.00226672)	(0.00111600)	-	-	-	0.00255251	0.00707951	0.00456563	0.00019507	-	-	-	-
REVYEC_EXP_OM SUBTRAN	0.00273797	0.00054113	0.00005479	0.00011455	0.00015532	0.00008511	(0.00047484)	(0.00023323)	-	-	-	0.00053478	0.00195514	-	0.00004005	-	-	(0.00003828)	0.00000345
REVYEC_EXP_OM DISTPRI	0.02380019	0.01845157	0.00180540	0.00377729	0.00513028	-	(0.01554097)	(0.00763988)	-	-	-	0.01765563	-	-	0.00131631	-	-	(0.00126974)	0.00011431
REVYEC_EXP_OM DISTSEC	0.00252948	0.00851588	0.00085276	0.00148244	-	-	(0.00518314)	-	-	-	-	-	-	-	0.00053691	-	-	(0.00394328)	0.00026790
REVYEC_EXP_OM ENERGY	0.67341125	0.06945673	0.00931756	0.01802355	0.02518095	0.00986155	(0.09016376)	(0.04410725)	-	-	-	0.11997381	0.35732807	0.24304738	0.00686526	-	-	(0.05599977)	0.00462716
REVYEC_EXP_OM CUSTOMER	(0.00163505)	0.00641657	0.00236521	0.00039361	0.00370055	0.00251615	(0.00046613)	(0.00033977)	-	-	-	0.00015135	0.00039021	0.00024935	0.00003589	-	-	(0.02127402)	0.00422597
REVYEC_EXP_OM TOTAL	1.00000000	0.15204539	0.01938658	0.03432596	0.04874018	0.01828371	(0.15576802)	(0.07392871)	-	-	-	0.18795604	0.49731046	0.33234975	0.01258496	-	-	(0.08252509)	0.00923880

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
FEBRUARY 28, 2017

Allocation Factor	Total Retail 1	RS 2	SGS 3	MGS-SEC 4	MGS-PRI 5	MGS-SUB 6	LGS-SEC 7	LGS-PRI 8	LGS-SUB 9	LGS-TRA 10	IGS-SEC 11	IGS-PRI 12	IGS-SUB 13	IGS-TRA 14	PS-SEC 15	PS-PRI 16	MW 17	OL 18	SL 19
TDOMX PRODUCTION	-	0.00000000	0.00000000	0.00000000	-	-	-	0.00000000	-	-	(0.00000000)	0.00000000	-	-	(0.00000000)	-	0.00000000	-	-
TDOMX BULKTRAN	0.10680699	0.05261131	0.00260076	0.00952645	0.00029986	0.00002812	0.00724159	0.00134932	0.00060973	0.00002742	0.00025297	0.00413976	0.02187877	0.00395094	0.00222388	0.00003725	0.00002886	-	-
TDOMX SUBTRAN	0.02349311	0.01143803	0.00055201	0.00200820	0.00006203	0.00000773	0.00151723	0.00028205	0.00016782	-	0.00005298	0.00086730	0.00604218	-	0.00045664	0.00000761	0.00000610	0.00002073	0.00000447
TDOMX DISTPRI	0.58412148	0.39039330	0.01840212	0.06681923	0.00206506	-	0.05010274	0.00933164	-	-	0.00178613	0.02880627	-	-	0.01510828	0.00025207	0.00020422	0.00069961	0.00015081
TDOMX DISTSEC	0.24107412	0.18025147	0.00868998	0.02622129	-	-	0.01670831	-	-	-	0.00045176	-	-	-	0.00616276	-	0.00006395	0.00217139	0.00035321
TDOMX ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TDOMX CUSTOMER	0.04450430	0.01816823	0.00786708	0.00224717	0.00125783	0.00020414	0.00096136	0.00032711	0.00071126	0.00012501	0.00000662	0.00019405	0.00104598	0.00018751	0.00026659	0.00000554	0.00000329	0.00606798	0.00485754
TDOMX TOTAL	1.00000000	0.65286234	0.03811196	0.10682235	0.00368478	0.00023999	0.07653123	0.01129011	0.00148882	0.00015243	0.00255046	0.03400737	0.02896692	0.00413845	0.02421815	0.00030247	0.00030642	0.00895971	0.00536603
TDPLANT PRODUCTION	0.00742395	0.00365691	0.00018077	0.00066217	0.00002084	0.00000195	0.00050335	0.00009379	0.00004238	0.00000191	0.00001758	0.00028775	0.00152075	0.00027462	0.00015458	0.00000259	0.00000201	-	-
TDPLANT BULKTRAN	0.33758424	0.16628826	0.00822022	0.03011020	0.00094776	0.00008888	0.02288844	0.00426478	0.00192718	0.00008666	0.00079955	0.01308453	0.06915210	0.01248772	0.00702900	0.00011773	0.00009121	-	-
TDPLANT SUBTRAN	0.07415710	0.03610468	0.00174246	0.00633898	0.00019581	0.00002439	0.00478920	0.00089031	0.00052974	-	0.00016723	0.00273766	0.01907241	-	0.00144141	0.00002403	0.00001925	0.00006545	0.00001411
TDPLANT DISTPRI	0.32980277	0.22042126	0.01039008	0.03772703	0.00116596	-	0.02828868	0.00526877	-	-	0.00100847	0.01626440	-	-	0.00853034	0.00014232	0.00011530	0.00039501	0.00008515
TDPLANT DISTSEC	0.17078427	0.12769565	0.00615625	0.01857596	-	-	0.01183668	-	-	-	0.00032004	-	-	-	0.00436589	-	0.00004530	0.00153828	0.00025022
TDPLANT ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TDPLANT CUSTOMER	0.08024767	0.03652531	0.00983240	0.00278911	0.00092254	0.00014985	0.00080539	0.00023953	0.00052210	0.00009176	0.00000554	0.00014210	0.00076780	0.00013764	0.00022304	0.00000406	0.00000412	0.02417439	0.00291098
TDPLANT TOTAL	1.00000000	0.59069206	0.03652219	0.09620346	0.00325291	0.00026507	0.06911173	0.01075718	0.00302140	0.00018033	0.00231842	0.03251644	0.09051307	0.01289999	0.02174425	0.00029073	0.00027719	0.02617313	0.00326046
TOTMXEXP PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTMXEXP BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTMXEXP SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTMXEXP DISTPRI	0.70565675	0.47162050	0.02223096	0.08072198	0.00249473	-	0.06052737	0.01127323	-	-	0.00215776	0.03479984	-	-	0.01825178	0.00030451	0.00024671	0.00084518	0.00018219
TOTMXEXP DISTSEC	0.29002474	0.21685192	0.01045450	0.03154558	-	-	0.02010097	-	-	-	0.00054349	-	-	-	0.00741412	-	0.00007694	0.00261229	0.00042493
TOTMXEXP ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTMXEXP CUSTOMER	0.00431852	0.00091670	0.00054317	0.00015563	0.00010261	0.00001667	0.00007606	0.00002664	0.00005807	0.00001021	0.00000052	0.00001581	0.00008540	0.00001531	0.00002110	0.00000045	0.00000023	0.00161006	0.00066388
TOTMXEXP TOTAL	1.00000000	0.68938912	0.03322863	0.11242319	0.00259734	0.00001667	0.08070440	0.01129987	0.00005807	0.00001021	0.00270178	0.03481565	0.00008540	0.00001531	0.02568701	0.00030496	0.00032387	0.00506753	0.00127100
TOTOHLINES PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES DISTPRI	0.70562025	0.47159611	0.02222981	0.08071780	0.00249460	-	0.06052424	0.01127264	-	-	0.00215765	0.03479804	-	-	0.01825084	0.00030450	0.00024669	0.00084513	0.00018218
TOTOHLINES DISTSEC	0.29437975	0.22010817	0.01061148	0.03201927	-	-	0.02040280	-	-	-	0.00055165	-	-	-	0.00752545	-	0.00007809	0.00265152	0.00043131
TOTOHLINES ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES TOTAL	1.00000000	0.69170427	0.03284129	0.11273707	0.00249460	-	0.08092705	0.01127264	-	-	0.00270930	0.03479804	-	-	0.02577629	0.00030450	0.00032478	0.00349665	0.00061349
TOTOX234 PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234 BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234 SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234 DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234 DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234 ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234 CUSTOMER	1.00000000	0.86257803	0.10758458	0.03150242	0.00037392	0.00002889	0.00292531	0.00029965	0.00008637	0.00001014	0.00002104	0.00018431	0.00013171	0.00001578	0.00077163	0.00000488	0.00004514	(0.00679042)	0.00022663
TOTOX234 TOTAL	1.00000000	0.86257803	0.10758458	0.03150242	0.00037392	0.00002889	0.00292531	0.00029965	0.00008637	0.00001014	0.00002104	0.00018431	0.00013171	0.00001578	0.00077163	0.00000488	0.00004514	(0.00679042)	0.00022663
TOTOXEXP PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOXEXP BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOXEXP SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOXEXP DISTPRI	0.51839394	0.34646478	0.01633145	0.05930048	0.00183269	-	0.04446499	0.00828161	-	-	0.00158515	0.02556488	-	-	0.01340824	0.00022370	0.00018124	0.00062089	0.00013384
TOTOXEXP DISTSEC	0.21820913	0.16315528	0.00786577	0.02373430	-	-	0.01512359	-	-	-	0.00040891	-	-	-	0.00557825	-	0.00005789	0.00196544	0.00031971
TOTOXEXP ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOXEXP CUSTOMER	0.26339694	0.11111117	0.04749342	0.01356413	0.00752673	0.00122151	0.00576274	0.00195755	0.00425593	0.00074800	0.00003970	0.00116126	0.00625872	0.00112200	0.00159800	0.00003318	0.00001988	0.03158904	0.02793400
TOTOXEXP TOTAL	1.00000000	0.62073122	0.07169063	0.09659891	0.00935942	0.00122151	0.06535132	0.01023916	0.00425593	0.00074800	0.00203376	0.02672614	0.00625872	0.00112200	0.02058448	0.00025688	0.00025900	0.03417537	0.02838755
TOTUGLINES PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES DISTPRI	0.80950000	0.54102338	0.02550243	0.09260089	0.00286185	-	0.06943448	0.01293218	-	-	0.00247530	0.03992093	-	-	0.02093769	0.00034932	0.00028301	0.00096955	0.00020900
TOTUGLINES DISTSEC	0.19050000	0.14243713	0.00686694	0.02072042	-	-	0.01320313	-	-	-	0.00035698	-	-	-	0.00486990	-	0.00005054	0.00171586	0.00027911
TOTUGLINES ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES TOTAL	1.00000000	0.68346050	0.03236937	0.11332130	0.00286185	-	0.08263761	0.01293218	-	-	0.00283228	0.03992093	-	-	0.02580758	0.00034932	0.00033354	0.00268541	0.00048811
TRAN_LSE PRODUCTION	1.00000000	0.49258299	0.02435014	0.08919316	0.00280748	0.00026328	0.06780067	0.01263324	0.00570873	0.00025672	0.00236845	0.03875930	0.20484399	0.03699143	0.02082148	0.00034875	0.00027019	-	-
TRAN_LSE BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRAN_LSE SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRAN_LSE DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRAN_LSE DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRAN_LSE ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRAN_LSE CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRAN_LSE TOTAL	1.00000000	0.49258299	0.02435014	0.08919316	0.00280748	0.00026328	0.06780067	0.01263324	0.00570873	0.00025672	0.00236845	0.03875930	0.20484399	0.03699143	0.02082148	0.00034875	0.00027019	-	-
TRANS_TOTAL PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL BULKTRAN	0.81970000	0.40377028	0.01995981	0.07311163	0.00230129	0.00021581	0.05557621	0.01035547	0.00467944	0.00021043	0.00194142	0.03177100	0.16791062	0.03032188	0.01706737	0.00028587	0.00022147	-	-
TRANS_TOTAL SUBTRAN	0.18030000	0.08778220	0.00423648	0.01541212	0.00047607	0.00005929	0.01164410	0.00216462	0.00128798	-	0.00040659	0.00665614	0.04637123	-	0.00350453	0.00005842	0.00004680	0.00015912	0.00003430
TRANS_TOTAL DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL TOTAL	1.00000000	0.49155248	0.02419629	0.08852375	0.00277736	0.00027510	0.06722031	0.01252009	0.00596742	0.00021043	0.00234801	0.03842714	0.21428185	0.03032188	0.02057190	0.00034429	0.00026827	0.00015912	0.00003430

KENTUCKY POWER COMPANY
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Allocation Factor	Total Retail 1	RS 2	SGS 3	MGS-SEC 4	MGS-PRI 5	MGS-SUB 6	LGS-SEC 7	LGS-PRI 8	LGS-SUB 9	LGS-TRA 10	IGS-SEC 11	IGS-PRI 12	IGS-SUB 13	IGS-TRA 14	PS-SEC 15	PS-PRI 16	MW 17	OL 18	SL 19
WEATHER_FXNL PRODUCTION	0.46301331	0.46301331	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL BULKTRAN	(0.06302392)	(0.06302392)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL SUBTRAN	(0.01326731)	(0.01326731)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL DISTPRI	0.15549886	0.15549886	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL DISTSEC	0.07387452	0.07387452	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL ENERGY	0.33469029	0.33469029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL CUSTOMER	0.04921424	0.04921424	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL TOTAL	1.00000000	1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL_OM PRODUCTION	0.30369444	0.30369444	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL_OM BULKTRAN	0.01636462	0.01636462	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL_OM SUBTRAN	0.00355900	0.00355900	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL_OM DISTPRI	0.12135564	0.12135564	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL_OM DISTSEC	0.05600883	0.05600883	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL_OM ENERGY	0.45681577	0.45681577	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL_OM CUSTOMER	0.04220170	0.04220170	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL_OM TOTAL	1.00000000	1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

KENTUCKY POWER COMPANY
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INPUTS FROM WORKPAPERS

ALLOCATOR	FUNCTION		Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
CPG - 12 CP		Same as CPT	998,890	492,036	24,323	89,094	2,804	263	67,725	12,619	5,702	256	2,366	38,716	204,617	36,950	20,798	348	270	0	0
PROD_DEMAND	PRODUCTION		1.00000000	0.49258299	0.02435014	0.08919316	0.00280748	0.00026328	0.06780067	0.01263324	0.00570873	0.00025672	0.00236845	0.03875930	0.20484399	0.03699143	0.02082148	0.00034875	0.00027019	-	-
PROD_DEMAND	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND	TOTAL		1.00000000	0.49258299	0.02435014	0.08919316	0.00280748	0.00026328	0.06780067	0.01263324	0.00570873	0.00025672	0.00236845	0.03875930	0.20484399	0.03699143	0.02082148	0.00034875	0.00027019	-	-
ENER			5,981,505,922	2,244,423,054	145,453,117	488,010,975	15,510,097	1,429,850	444,926,415	82,480,796	37,477,163	1,736,472	17,050,423	299,379,891	1,699,754,726	322,483,254	120,543,977	1,962,264	2,188,747	47,328,732	9,365,970
PROD_ENERGY	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY	ENERGY		1.00000000	0.37522709	0.02431714	0.08158664	0.00259301	0.00023905	0.07438368	0.01378930	0.00626551	0.00029031	0.00285052	0.05005092	0.28416836	0.05391339	0.02015278	0.00032806	0.00036592	0.00791251	0.00156582
PROD_ENERGY	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY	TOTAL		1.00000000	0.37522709	0.02431714	0.08158664	0.00259301	0.00023905	0.07438368	0.01378930	0.00626551	0.00029031	0.00285052	0.05005092	0.28416836	0.05391339	0.02015278	0.00032806	0.00036592	0.00791251	0.00156582
CPT - 12 CP		Same as CPG	998,890	492,036	24,323	89,094	2,804	263	67,725	12,619	5,702	256	2,366	38,716	204,617	36,950	20,798	348	270	0	0
BULK_TRANS	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS	BULKTRAN		1.00000000	0.49258299	0.02435014	0.08919316	0.00280748	0.00026328	0.06780067	0.01263324	0.00570873	0.00025672	0.00236845	0.03875930	0.20484399	0.03699143	0.02082148	0.00034875	0.00027019	-	-
BULK_TRANS	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS	TOTAL		1.00000000	0.49258299	0.02435014	0.08919316	0.00280748	0.00026328	0.06780067	0.01263324	0.00570873	0.00025672	0.00236845	0.03875930	0.20484399	0.03699143	0.02082148	0.00034875	0.00027019	-	-
CPST - 12 CP			768,537	374,175	18,058	65,695	2,029	253	49,633	9,227	5,490	0	1,733	28,372	197,659	0	14,938	249	199	678	146
SUB_TRANS	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUB_TRANS	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUB_TRANS	SUBTRAN		1.00000000	0.48686743	0.02349686	0.08548042	0.00264041	0.00032885	0.06458180	0.01200568	0.00714352	-	0.00225509	0.03691704	0.25718929	-	0.01943723	0.00032402	0.00025956	0.00088255	0.00019025
SUB_TRANS	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUB_TRANS	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUB_TRANS	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUB_TRANS	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUB_TRANS	TOTAL		1.00000000	0.48686743	0.02349686	0.08548042	0.00264041	0.00032885	0.06458180	0.01200568	0.00714352	-	0.00225509	0.03691704	0.25718929	-	0.01943723	0.00032402	0.00025956	0.00088255	0.00019025
CPD - 12 CP			729,403	487,491	22,979	83,438	2,579	0	62,564	11,653	0	0	2,230	35,971	0	0	18,866	315	255	874	188
DIST_CPD	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD	DISTPRI		1.00000000	0.66834265	0.03150393	0.11439270	0.00353533	-	0.08577453	0.01597551	-	-	0.00305781	0.04931554	-	-	0.02586496	0.00043153	0.00034961	0.00119772	0.00025819
DIST_CPD	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD	TOTAL		1.00000000	0.66834265	0.03150393	0.11439270	0.00353533	-	0.08577453	0.01597551	-	-	0.00305781	0.04931554	-	-	0.02586496	0.00043153	0.00034961	0.00119772	0.00025819
SECDEM		**(NCP + SNCP) / 2**	1,470,167	1,099,246	52,995	159,908	0	0	101,894	0	0	0	2,755	0	0	0	37,583	0	390	13,242	2,154
DISTSEC	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISTSEC	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISTSEC	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISTSEC	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISTSEC	DISTSEC		1.00000000	0.74770145	0.03604693	0.10876860	-	-	0.06930777	-	-	-	0.00187394	-	-	-	0.02556376	-	0.00026528	0.00900714	0.00146514
DISTSEC	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISTSEC	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISTSEC	TOTAL		1.00000000	0.74770145	0.03604693	0.10876860	-	-	0.06930777	-	-	-	0.00187394	-	-	-	0.02556376	-	0.00026528	0.00900714	0.00146514
TOTCUST			214,251	136,519	23,888	6,709	78	6	587	59	17	2	4	35	25	3	161	1	10	46,092	55
CUST_TOTAL	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL	CUSTOMER		1.00000000	0.63719189	0.11149540	0.03131374	0.00036406	0.00002800	0.00273978	0.00027538	0.00007935	0.00000933	0.00001867	0.00016336	0.00011669	0.00001400	0.00075146	0.00000467	0.00004667	0.21513085	0.00025671
CUST_TOTAL	TOTAL		1.00000000	0.63719189	0.11149540	0.03131374	0.00036406	0.00002800	0.00273978	0.00027538	0.00007935	0.00000933	0.00001867	0.00016336	0.00011669	0.00001400	0.00075146	0.00000467	0.00004667	0.21513085	0.00025671
PRICUST		TOTCust excl Sub. & Tran.	214,198	136,519	23,888	6,709	78	0	587	59	0	0	4	35	0	0	161	1	10	46,092	55
DIST_PCUST	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST	CUSTOMER		1.00000000	0.63734956	0.11152298	0.03132149	0.00036415	-	0.00274046	0.00027545	-	-	0.00001867	0.00016340	-	-	0.00075164	0.00000467	0.00004669	0.21518408	0.00025677
DIST_PCUST	TOTAL		1.00000000	0.63734956	0.11152298	0.03132149	0.00036415	-	0.00274046	0.00027545	-	-	0.00001867	0.00016340	-	-	0.00075164	0.00000467	0.00004669	0.21518408	0.00025677
SECCUST		TOTCust excl Pri., Sub. & Tran.	214,025	136,519	23,888	6,709	0	0	587	0	0	0	4	0	0	0	161	0	10	46,092	55
DIST_SERV	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV	CUSTOMER		1.00000000	0.63786474	0.11161313	0.03134681	-	-	0.00274267	-	-	-	0.00001869	-	-	-	0.00075225	-	0.00004672	0.21535802	0.00025698
DIST_SERV	TOTAL		1.00000000	0.63786474	0.11161313	0.03134681	-	-	0.00274267	-	-	-	0.00001869	-	-	-	0.00075225	-	0.00004672	0.21535802	0.00025698

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
FEBRUARY 28, 2017

ALLOCATOR	FUNCTION		Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
METER			32,580,972	14,607,905	8,655,579	2,479,971	1,635,188	265,607	1,211,984	424,569	925,414	162,645	8,353	251,863	1,360,902	243,968	336,205	7,196	3,623	0	0
DIST_METERS	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS	CUSTOMER		1.00000000	0.44835694	0.26566362	0.07611716	0.05018844	0.00815221	0.03719914	0.01303120	0.02840351	0.00499202	0.00025638	0.00773037	0.04176984	0.00748805	0.01031906	0.00022087	0.00011120	-	-
DIST_METERS	TOTAL		1.00000000	0.44835694	0.26566362	0.07611716	0.05018844	0.00815221	0.03719914	0.01303120	0.02840351	0.00499202	0.00025638	0.00773037	0.04176984	0.00748805	0.01031906	0.00022087	0.00011120	-	-
DIR371			1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0
DIST_OL	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL	CUSTOMER		1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.00000000	-
DIST_OL	TOTAL		1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.00000000	-
DIR373			1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
DIST_SL	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL	CUSTOMER		1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.00000000
DIST_SL	TOTAL		1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.00000000
DIR902		Weighted TOTCUST	345,257	273,038	47,776	20,127	273	21	2,642	295	85	10	24	210	150	18	564	4	20	0	0
CUST_902	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902	CUSTOMER		1.00000000	0.79082539	0.13837808	0.05829570	0.00079072	0.00006082	0.00765227	0.00085444	0.00024619	0.00002896	0.00006951	0.00060824	0.00043446	0.00005214	0.00163357	0.00001159	0.00005793	-	-
CUST_902	TOTAL		1.00000000	0.79082539	0.13837808	0.05829570	0.00079072	0.00006082	0.00765227	0.00085444	0.00024619	0.00002896	0.00006951	0.00060824	0.00043446	0.00005214	0.00163357	0.00001159	0.00005793	-	-
DIR903		Calculated	4,536,148	3,901,683	479,016	134,533	1,565	121	11,771	1,183	341	40	80	701	501	60	3,229	20	201	0	1,103
CUST_903	PRODUCTION	Weighted	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903	BULKTRAN	Average	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903	CUSTOMER		1.00000000	0.86013133	0.10559973	0.02965798	0.00034501	0.00002667	0.00259493	0.00026079	0.00007517	0.00000882	0.00001764	0.00015454	0.00011045	0.00001323	0.00071184	0.00000441	0.00004431	-	0.00024316
CUST_903	TOTAL		1.00000000	0.86013133	0.10559973	0.02965798	0.00034501	0.00002667	0.00259493	0.00026079	0.00007517	0.00000882	0.00001764	0.00015454	0.00011045	0.00001323	0.00071184	0.00000441	0.00004431	-	0.00024316
CUST451		Spread by class; alloc. to	819,420	750,964	47,676	15,352	425	44	1,250	52	0	0	0	13	0	0	0	0	0	3,645	0
CUST_451	PRODUCTION	functions below:	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_451	BULKTRAN	MISC_SERV_REV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_451	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_451	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_451	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_451	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_451	CUSTOMER		1.00000000	0.91645786	0.05818206	0.01873519	0.00051850	0.00005370	0.00152547	0.00006346	-	-	-	0.00001586	-	-	-	-	-	0.00444790	-
CUST_451	TOTAL		1.00000000	0.91645786	0.05818206	0.01873519	0.00051850	0.00005370	0.00152547	0.00006346	-	-	-	0.00001586	-	-	-	-	-	0.00444790	-
CUSTDEP		Spread by class; alloc. to	26,429,740	19,268,539	1,283,411	2,225,334	286,407	367,684	1,011,520	552,921	367,041	0	0	426,340	281,879	213,031	28,410	0	0	117,223	0
CUST_DEP	PRODUCTION	functions below:	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_DEP	BULKTRAN	CUST_DEP_FXNL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_DEP	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_DEP	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_DEP	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_DEP	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_DEP	CUSTOMER		1.00000000	0.72904762	0.04855935	0.08419810	0.01083654	0.01391175	0.03827204	0.02092041	0.01388742	-	-	0.01613107	0.01066522	0.00806028	0.00107493	-	-	0.00443527	-
CUST_DEP	TOTAL		1.00000000	0.72904762	0.04855935	0.08419810	0.01083654	0.01391175	0.03827204	0.02092041	0.01388742	-	-	0.01613107	0.01066522	0.00806028	0.00107493	-	-	0.00443527	-
FORF DISCOUNTS		Spread by class; alloc. to	4,063,217	2,797,010	247,521	402,316	5,545	601	139,839	88,046	18,375	498	5,480	137,983	191,477	7,425	0	0	0	21,100	0
FORF_DISC	PRODUCTION	functions below:	1.00000000	0.68837336	0.06091760	0.09901406	0.00136472	0.00014791	0.03441589	0.02166901	0.00452230	0.00012254	0.00134864	0.03395913	0.04712451	0.00182742	-	-	-	0.00519290	-
FORF_DISC	BULKTRAN	FORF_DISC_FXNL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORF_DISC	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORF_DISC	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORF_DISC	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORF_DISC	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORF_DISC	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORF_DISC	TOTAL		1.00000000	0.68837336	0.06091760	0.09901406	0.00136472	0.00014791	0.03441589	0.02166901	0.00452230	0.00012254	0.00134864	0.03395913	0.04712451	0.00182742	-	-	-	0.00519290	-
YEAR END CUST ADJ		Spread by class; alloc. to	(3,275,101)	(497,964)	(63,493)	(112,421)	(159,629)	(59,881)	510,156	242,124	-	-	-	(615,575)	(1,628,742)	(1,088,479)	(41,217)	-	-	270,278	(30,258)
REVYEC	PRODUCTION	functions below:	1.00000000	0.15204539	0.01938658	0.03432596	0.04874018	0.01828371	(0.15576802)	(0.07392871)	-	-	-	0.18795604	0.49731046	0.33234975	0.01258496	-	-	(0.08252509)	0.00923880
REVYEC	BULKTRAN	REVYEC_FXNL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVYEC	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVYEC	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVYEC	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVYEC	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVYEC	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVYEC	TOTAL		1.00000000	0.15204539	0.01938658	0.03432596	0.04874018	0.01828371	(0.15576802)	(0.07392871)	-	-	-	0.18795604	0.49731046	0.33234975	0.01258496	-	-	(0.08252509)	0.00923880

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
FEBRUARY 28, 2017

ALLOCATOR	FUNCTION		Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
FUELR			9,014,177	3,108,101	212,299	711,633	25,861	3,010	639,383	120,662	57,445	2,699	24,805	463,730	2,851,399	530,827	176,010	2,966	3,184	66,572	13,591
FUELREV	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV	ENERGY		1.00000000	0.34480142	0.02355168	0.07894598	0.00286893	0.00033392	0.07093082	0.01338580	0.00637274	0.00029942	0.00275178	0.05144452	0.31632383	0.05888802	0.01952591	0.00032904	0.00035322	0.00738526	0.00150774
FUELREV	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV	TOTAL		1.00000000	0.34480142	0.02355168	0.07894598	0.00286893	0.00033392	0.07093082	0.01338580	0.00637274	0.00029942	0.00275178	0.05144452	0.31632383	0.05888802	0.01952591	0.00032904	0.00035322	0.00738526	0.00150774
WEATHER		Spread by class; alloc. to	9,956,443	9,956,443	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_NORM	PRODUCTION	functions below:	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_NORM	BULKTRAN	WEATHER_FXNL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_NORM	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_NORM	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_NORM	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_NORM	ENERGY		1.00000000	1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_NORM	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_NORM	TOTAL		1.00000000	1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

INTERNALLY DERIVED

Bulk Transmission Plant	$456,191,059
Subtransmission Plant	$100,333,074
Total Transmisison Plant	$556,524,133

ALLOCATOR	FUNCTION		Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
BULK_TRANS	BULKTRAN	81.97%	1.00000000	0.49258299	0.02435014	0.08919316	0.00280748	0.00026328	0.06780067	0.01263324	0.00570873	0.00025672	0.00236845	0.03875930	0.20484399	0.03699143	0.02082148	0.00034875	0.00027019	-	-
SUB_TRANS	SUBTRAN	18.03%	1.00000000	0.48686743	0.02349686	0.08548042	0.00264041	0.00032885	0.06458180	0.01200568	0.00714352	-	0.00225509	0.03691704	0.25718929	-	0.01943723	0.00032402	0.00025956	0.00088255	0.00019025
TRANS_TOTAL	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL	BULKTRAN		0.81970000	0.40	0.01995981	0.07311163	0.00230129	0.00021581	0.05557621	0.01035547	0.00467944	0.00021043	0.00194142	0.03177100	0.16791062	0.03032188	0.01706737	0.00028587	0.00022147	-	-
TRANS_TOTAL	SUBTRAN		0.18030000	0.09	0.00423648	0.01541212	0.00047607	0.00005929	0.01164410	0.00216462	0.00128798	-	0.00040659	0.00665614	0.04637123	-	0.00350453	0.00005842	0.00004680	0.00015912	0.00003430
TRANS_TOTAL	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL	TOTAL		1.00000000	0.49155248	0.02419629	0.08852375	0.00277736	0.00027510	0.06722031	0.01252009	0.00596742	0.00021043	0.00234801	0.03842714	0.21428185	0.03032188	0.02057190	0.00034429	0.00026827	0.00015912	0.00003430
DIST_CPD	DISTPRI	56.69%	1.00000000	0.66834265	0.03150393	0.11439270	0.00353533	-	0.08577453	0.01597551	-	-	0.00305781	0.04931554	-	-	0.02586496	0.00043153	0.00034961	0.00119772	0.00025819
DISTSEC	DISTSEC	43.31%	1.00000000	0.74770145	0.03604693	0.10876860	-	-	0.06930777	-	-	-	0.00187394	-	-	-	0.02556376	-	0.00026528	0.00900714	0.00146514
DIST_POLES	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES	DISTPRI		0.56690000	0.38	0.01785958	0.06484922	0.00200418	-	0.04862558	0.00905652	-	-	0.00173347	0.02795698	-	-	0.01466285	0.00024463	0.00019819	0.00067899	0.00014637
DIST_POLES	DISTSEC		0.43310000	0.32	0.01561192	0.04710768	-	-	0.03001720	-	-	-	0.00081160	-	-	-	0.01107167	-	0.00011489	0.00390099	0.00063455
DIST_POLES	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES	TOTAL		1.00000000	0.70271295	0.03347150	0.11195690	0.00200418	-	0.07864278	0.00905652	-	-	0.00254507	0.02795698	-	-	0.02573451	0.00024463	0.00031309	0.00457998	0.00078092
DIST_CPD	DISTPRI	83.32%	1.00000000	0.66834265	0.03150393	0.11439270	0.00353533	-	0.08577453	0.01597551	-	-	0.00305781	0.04931554	-	-	0.02586496	0.00043153	0.00034961	0.00119772	0.00025819
DISTSEC	DISTSEC	16.68%	1.00000000	0.74770145	0.03604693	0.10876860	-	-	0.06930777	-	-	-	0.00187394	-	-	-	0.02556376	-	0.00026528	0.00900714	0.00146514
DIST_OHLINES	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHLINES	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHLINES	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHLINES	DISTPRI		0.83320000	0.55686310	0.02624907	0.09531199	0.00294564	-	0.07146734	0.01331080	-	-	0.00254777	0.04108971	-	-	0.02155069	0.00035955	0.00029130	0.00099794	0.00021512
DIST_OHLINES	DISTSEC		0.16680000	0.12471660	0.00601263	0.01814260	-	-	0.01156054	-	-	-	0.00031257	-	-	-	0.00426404	-	0.00004425	0.00150239	0.00024439
DIST_OHLINES	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHLINES	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHLINES	TOTAL		1.00000000	0.68157970	0.03226170	0.11345460	0.00294564	-	0.08302787	0.01331080	-	-	0.00286034	0.04108971	-	-	0.02581472	0.00035955	0.00033554	0.00250033	0.00045951
DIST_CPD	DISTPRI	80.95%	1.00000000	0.66834265	0.03150393	0.11439270	0.00353533	-	0.08577453	0.01597551	-	-	0.00305781	0.04931554	-	-	0.02586496	0.00043153	0.00034961	0.00119772	0.00025819
DISTSEC	DISTSEC	19.05%	1.00000000	0.74770145	0.03604693	0.10876860	-	-	0.06930777	-	-	-	0.00187394	-	-	-	0.02556376	-	0.00026528	0.00900714	0.00146514
DIST_UGLINES	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES	DISTPRI		0.80950000	0.54102338	0.02550243	0.09260089	0.00286185	-	0.06943448	0.01293218	-	-	0.00247530	0.03992093	-	-	0.02093769	0.00034932	0.00028301	0.00096955	0.00020900
DIST_UGLINES	DISTSEC		0.19050000	0.14243713	0.00686694	0.02072042	-	-	0.01320313	-	-	-	0.00035698	-	-	-	0.00486990	-	0.00005054	0.00171586	0.00027911
DIST_UGLINES	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES	TOTAL		1.00000000	0.68346050	0.03236937	0.11332130	0.00286185	-	0.08263761	0.01293218	-	-	0.00283228	0.03992093	-	-	0.02580758	0.00034932	0.00033354	0.00268541	0.00048811
DIST_CPD	DISTPRI	20.18%	1.00000000	0.66834265	0.03150393	0.11439270	0.00353533	-	0.08577453	0.01597551	-	-	0.00305781	0.04931554	-	-	0.02586496	0.00043153	0.00034961	0.00119772	0.00025819
DISTSEC	DISTSEC	79.82%	1.00000000	0.74770145	0.03604693	0.10876860	-	-	0.06930777	-	-	-	0.00187394	-	-	-	0.02556376	-	0.00026528	0.00900714	0.00146514
DIST_TRANSF	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_TRANSF	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_TRANSF	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_TRANSF	DISTPRI		0.20176000	0.13484481	0.00635623	0.02307987	0.00071329	-	0.01730587	0.00322322	-	-	0.00061694	0.00994990	-	-	0.00521851	0.00008707	0.00007054	0.00024165	0.00005209
DIST_TRANSF	DISTSEC		0.79824000	0.59684521	0.02877410	0.08682344	-	-	0.05532424	-	-	-	0.00149585	-	-	-	0.02040602	-	0.00021175	0.00718986	0.00116953
DIST_TRANSF	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_TRANSF	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_TRANSF	TOTAL		1.00000000	0.73169002	0.03513033	0.10990331	0.00071329	-	0.07263010	0.00322322	-	-	0.00211279	0.00994990	-	-	0.02562453	0.00008707	0.00028229	0.00743151	0.00122163

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
FEBRUARY 28, 2017

ALLOCATOR	FUNCTION		Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
Show under production as it is capturing load (LSE) charges for transmission service, whereas the bulktran and subtran buckets are capturing the costs and revenues as a transmission owner (TO).																					
TRAN_LSE	PRODUCTION	Same as BULK_TR	1.00000000	0.49258299	0.02435014	0.08919316	0.00280748	0.00026328	0.06780067	0.01263324	0.00570873	0.00025672	0.00236845	0.03875930	0.20484399	0.03699143	0.02082148	0.00034875	0.00027019	-	-
TRAN_LSE	BULKTRAN																				
TRAN_LSE	SUBTRAN																				
TRAN_LSE	DISTPRI																				
TRAN_LSE	DISTSEC																				
TRAN_LSE	ENERGY																				
TRAN_LSE	CUSTOMER																				
TRAN_LSE	TOTAL		1.00000000	0.49258299	0.02435014	0.08919316	0.00280748	0.00026328	0.06780067	0.01263324	0.00570873	0.00025672	0.00236845	0.03875930	0.20484399	0.03699143	0.02082148	0.00034875	0.00027019	-	-
Total Firm Sales																					
SALES OF ELECTRICITY	PRODUCTION		224,613,568	100,168,786	6,636,156	22,911,721	676,996	65,913	17,564,876	3,358,385	1,445,969	63,505	523,209	9,082,764	48,905,334	7,986,648	5,066,261	80,318	76,726	-	-
	BULKTRAN		(17,594,275)	(13,634,661)	132,509	(211,754)	(18,177)	16,161	(166,224)	9,629	(25,274)	(1,861)	(45,691)	(462,879)	(2,236,685)	(750,198)	(196,208)	(5,415)	2,454	-	-
	SUBTRAN		(3,693,132)	(2,870,264)	24,550	(50,448)	(3,881)	5,473	(39,012)	765	(7,395)	-	(9,330)	(95,870)	(612,252)	-	(40,159)	(1,085)	472	4,292	1,011
	DISTPRI		59,116,193	33,640,787	2,695,286	8,919,786	253,712	-	6,745,341	1,309,773	-	-	183,332	3,315,206	-	-	1,835,506	27,795	31,868	129,779	28,022
	DISTSEC		25,153,525	15,982,092	1,419,684	3,862,582	-	-	2,480,772	-	-	-	49,346	-	-	-	816,046	-	11,189	456,946	74,868
	ENERGY		190,277,222	72,407,249	4,616,185	15,511,646	446,033	21,213	14,411,074	2,709,220	1,194,490	55,350	538,670	9,252,861	53,441,593	9,750,478	3,837,796	62,432	70,796	1,653,061	297,075
	CUSTOMER		22,527,109	10,647,060	3,108,136	825,609	201,200	50,851	205,611	61,270	119,046	20,070	1,110	30,130	158,961	24,031	51,509	824	1,376	6,009,947	1,010,367
	TOTAL		500,400,211	216,341,050	18,632,507	51,769,142	1,555,884	159,611	41,202,438	7,449,041	2,726,835	137,064	1,240,647	21,122,212	99,656,952	17,010,960	11,370,750	164,869	194,881	8,254,025	1,411,343
REV_SALES	PRODUCTION		0.44886785	0.20017735	0.01326170	0.04578679	0.00135291	0.00013172	0.03510166	0.00671140	0.00288962	0.00012691	0.00104558	0.01815100	0.09773244	0.01596052	0.01012442	0.00016051	0.00015333	-	-
REV_SALES	BULKTRAN		(0.03516041)	(0.02724751)	0.00026481	(0.00042317)	(0.00003632)	0.00003230	(0.00033218)	0.00001924	(0.00005051)	(0.00000372)	(0.00009131)	(0.00092502)	(0.00446979)	(0.00149920)	(0.00039210)	(0.00001082)	0.00000490	-	-
REV_SALES	SUBTRAN		(0.00738036)	(0.00573594)	0.00004906	(0.00010081)	(0.00000776)	0.00001094	(0.00007796)	0.00000153	(0.00001478)	-	(0.00001865)	(0.00019159)	(0.00122352)	-	(0.00008025)	(0.00000217)	0.00000094	0.00000858	0.00000202
REV_SALES	DISTPRI		0.11813783	0.06722776	0.00538626	0.01782530	0.00050702	-	0.01347989	0.00261745	-	-	0.00036637	0.00662511	-	-	0.00366808	0.00005555	0.00006369	0.00025935	0.00005600
REV_SALES	DISTSEC		0.05026682	0.03193862	0.00283710	0.00771898	-	-	0.00495758	-	-	-	0.00009861	-	-	-	0.00163079	-	0.00002236	0.00091316	0.00014962
REV_SALES	ENERGY		0.38025008	0.14469868	0.00922499	0.03099848	0.00089135	0.00004239	0.02879910	0.00541411	0.00238707	0.00011061	0.00107648	0.01849092	0.10679770	0.01948536	0.00766945	0.00012476	0.00014148	0.00330348	0.00059368
REV_SALES	CUSTOMER		0.04501818	0.02127709	0.00621130	0.00164990	0.00040208	0.00010162	0.00041089	0.00012244	0.00023790	0.00004011	0.00000222	0.00006021	0.00031767	0.00004802	0.00010294	0.00000165	0.00000275	0.01201028	0.00201912
REV_SALES	TOTAL		1.00000000	0.43233605	0.03723521	0.10345548	0.00310928	0.00031897	0.08233897	0.01488617	0.00544931	0.00027391	0.00247931	0.04221064	0.19915450	0.03399471	0.02272331	0.00032947	0.00038945	0.01649485	0.00282043
Production EPIS	PRODUCTION		824,295,257	406,033,823	20,071,703	73,521,497	2,314,196	217,018	55,887,775	10,413,521	4,705,676	211,609	1,952,303	31,949,108	168,851,932	30,491,860	17,163,047	287,474	222,716	-	-
	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL		824,295,257	406,033,823	20,071,703	73,521,497	2,314,196	217,018	55,887,775	10,413,521	4,705,676	211,609	1,952,303	31,949,108	168,851,932	30,491,860	17,163,047	287,474	222,716	-	-
RB_GUP_EPIS_P	PRODUCTION		1.00000000	0.49258299	0.02435014	0.08919316	0.00280748	0.00026328	0.06780067	0.01263324	0.00570873	0.00025672	0.00236845	0.03875930	0.20484399	0.03699143	0.02082148	0.00034875	0.00027019	-	-
RB_GUP_EPIS_P	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P	TOTAL		1.00000000	0.49258299	0.02435014	0.08919316	0.00280748	0.00026328	0.06780067	0.01263324	0.00570873	0.00025672	0.00236845	0.03875930	0.20484399	0.03699143	0.02082148	0.00034875	0.00027019	-	-
Transmission EPIS	PRODUCTION		10,045,283	4,948,136	244,604	895,971	28,202	2,645	681,077	126,904	57,346	2,579	23,792	389,348	2,057,716	371,589	209,158	3,503	2,714	-	-
	BULKTRAN		456,782,174	225,003,129	11,122,709	40,741,844	1,282,409	120,260	30,970,140	5,770,639	2,607,644	117,263	1,081,866	17,704,558	93,569,085	16,897,026	9,510,881	159,304	123,418	-	-
	SUBTRAN		100,341,301	48,852,912	2,357,705	8,577,217	264,942	32,997	6,480,222	1,204,666	716,790	-	226,278	3,704,303	25,806,708	-	1,950,357	32,513	26,044	88,556	19,090
	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL		567,168,758	278,804,176	13,725,018	50,215,032	1,575,553	155,902	38,131,438	7,102,209	3,381,781	119,842	1,331,936	21,798,209	121,433,509	17,268,615	11,670,395	195,319	152,176	88,556	19,090
RB_GUP_EPIS_T	PRODUCTION		0.01771128	0.00872427	0.00043127	0.00157972	0.00004972	0.00000466	0.00120084	0.00022375	0.00010111	0.00000455	0.00004195	0.00068648	0.00362805	0.00065517	0.00036877	0.00000618	0.00000479	-	-
RB_GUP_EPIS_T	BULKTRAN		0.80537259	0.39671284	0.01961093	0.07183372	0.00226107	0.00021204	0.05460481	0.01017447	0.00459765	0.00020675	0.00190749	0.03121568	0.16497574	0.02979188	0.01676905	0.00028088	0.00021760	-	-
RB_GUP_EPIS_T	SUBTRAN		0.17691613	0.08613470	0.00415697	0.01512287	0.00046713	0.00005818	0.01142556	0.00212400	0.00126380	-	0.00039896	0.00653122	0.04550093	-	0.00343876	0.00005732	0.00004592	0.00015614	0.00003366
RB_GUP_EPIS_T	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_T	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_T	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_T	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_T	TOTAL		1.00000000	0.49157182	0.02419918	0.08853632	0.00277793	0.00027488	0.06723120	0.01252222	0.00596257	0.00021130	0.00234839	0.03843337	0.21410472	0.03044705	0.02057658	0.00034438	0.00026831	0.00015614	0.00003366
Distribution EPIS	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI		446,253,132	298,250,001	14,058,726	51,048,099	1,577,652	-	38,277,152	7,129,122	-	-	1,364,557	22,007,214	-	-	11,542,320	192,571	156,015	534,485	115,218
	DISTSEC		231,086,643	172,783,818	8,329,963	25,134,970	-	-	16,016,100	-	-	-	433,042	-	-	-	5,907,444	-	61,302	2,081,430	338,574
	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER		108,582,391	49,422,070	13,304,130	3,773,926	1,248,285	202,761	1,089,770	324,111	706,451	124,161	7,498	192,269	1,038,898	186,243	301,789	5,493	5,569	32,710,149	3,938,817
	TOTAL		785,922,166	520,455,890	35,692,819	79,956,994	2,825,937	202,761	55,383,022	7,453,233	706,451	124,161	1,805,097	22,199,484	1,038,898	186,243	17,751,553	198,064	222,886	35,326,064	4,392,609
RB_GUP_EPIS_D	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D	DISTPRI		0.56780830	0.37949051	0.01788819	0.06495312	0.00200739	-	0.04870349	0.00907103	-	-	0.00173625	0.02800177	-	-	0.01468634	0.00024503	0.00019851	0.00068007	0.00014660
RB_GUP_EPIS_D	DISTSEC		0.29403248	0.21984851	0.01059897	0.03198150	-	-	0.02037874	-	-	-	0.00055100	-	-	-	0.00751658	-	0.00007800	0.00264839	0.00043080
RB_GUP_EPIS_D	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D	CUSTOMER		0.13815922	0.06288418	0.01692805	0.00480191	0.00158831	0.00025799	0.00138661	0.00041240	0.00089888	0.00015798	0.00000954	0.00024464	0.00132188	0.00023697	0.00038399	0.00000699	0.00000709	0.04162009	0.00501171
RB_GUP_EPIS_D	TOTAL		1.00000000	0.66222320	0.04541521	0.10173653	0.00359570	0.00025799	0.07046884	0.00948342	0.00089888	0.00015798	0.00229679	0.02824642	0.00132188	0.00023697	0.02258691	0.00025202	0.00028360	0.04494855	0.00558912

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
FEBRUARY 28, 2017

ALLOCATOR	FUNCTION	Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
Gen & Int Plant	PRODUCTION	27,667,549	13,628,564	673,709	2,467,756	77,676	7,284	1,875,878	349,531	157,946	7,103	65,529	1,072,375	5,667,531	1,023,462	576,079	9,649	7,475	-	-
	BULKTRAN	101,092	49,796	2,462	9,017	284	27	6,854	1,277	577	26	239	3,918	20,708	3,740	2,105	35	27	-	-
	SUBTRAN	22,236	10,826	522	1,901	59	7	1,436	267	159	-	50	821	5,719	-	432	7	6	20	4
	DISTPRI	14,246,628	9,521,629	448,825	1,629,710	50,367	-	1,221,998	227,597	-	-	43,563	702,580	-	-	368,488	6,148	4,981	17,063	3,678
	DISTSEC	5,879,759	4,396,304	211,947	639,533	-	-	407,513	-	-	-	11,018	-	-	-	150,309	-	1,560	52,960	8,615
	ENERGY	7,283,608	2,733,007	177,117	594,245	18,886	1,741	541,782	100,436	45,635	2,114	20,762	364,551	2,069,771	392,684	146,785	2,389	2,665	57,632	11,405
	CUSTOMER	5,489,913	3,922,548	671,277	193,292	32,311	5,105	36,069	9,263	17,718	3,092	251	5,515	26,070	4,640	9,872	156	281	432,936	119,515
	TOTAL	60,690,785	34,262,675	2,185,858	5,535,454	179,583	14,164	4,091,530	688,371	222,036	12,336	141,414	2,149,760	7,789,799	1,424,526	1,254,071	18,385	16,996	560,610	143,217
RB_GUP_EPIS_G	PRODUCTION	0.45587726	0.22455738	0.01110067	0.04066113	0.00127987	0.00012002	0.03090879	0.00575921	0.00260248	0.00011703	0.00107972	0.01766948	0.09338372	0.01686355	0.00949204	0.00015899	0.00012317	-	-
RB_GUP_EPIS_G	BULKTRAN	0.00166569	0.00082049	0.00004056	0.00014857	0.00000468	0.00000044	0.00011294	0.00002104	0.00000951	0.00000043	0.00000395	0.00006456	0.00034121	0.00006162	0.00003468	0.00000058	0.00000045	-	-
RB_GUP_EPIS_G	SUBTRAN	0.00036638	0.00017838	0.00000861	0.00003132	0.00000097	0.00000012	0.00002366	0.00000440	0.00000262	-	0.00000083	0.00001353	0.00009423	-	0.00000712	0.00000012	0.00000010	0.00000032	0.00000007
RB_GUP_EPIS_G	DISTPRI	0.23474121	0.15688756	0.00739527	0.02685268	0.00082989	-	0.02013482	0.00375011	-	-	0.00071779	0.01157639	-	-	0.00607157	0.00010130	0.00008207	0.00028115	0.00006061
RB_GUP_EPIS_G	DISTSEC	0.09688058	0.07243775	0.00349225	0.01053757	-	-	0.00671458	-	-	-	0.00018155	-	-	-	0.00247663	-	0.00002570	0.00087262	0.00014194
RB_GUP_EPIS_G	ENERGY	0.12001176	0.04503166	0.00291834	0.00979136	0.00031119	0.00002869	0.00892692	0.00165488	0.00075193	0.00003484	0.00034210	0.00600670	0.03410355	0.00647024	0.00241857	0.00003937	0.00004391	0.00094959	0.00018792
RB_GUP_EPIS_G	CUSTOMER	0.09045711	0.06463169	0.01106061	0.00318486	0.00053239	0.00008412	0.00059430	0.00015263	0.00029194	0.00005095	0.00000413	0.00009087	0.00042955	0.00007646	0.00016266	0.00000258	0.00000464	0.00713347	0.00196925
RB_GUP_EPIS_G	TOTAL	1.00000000	0.56454493	0.03601631	0.09120748	0.00295898	0.00023338	0.06741600	0.01134227	0.00365848	0.00020325	0.00233007	0.03542153	0.12835225	0.02347187	0.02066328	0.00030293	0.00028004	0.00923716	0.00235979
Production Land	Allocate on PROD_DEMAND	4,785,016																		
Prod. GUP less Land	PRODUCTION	819,510,241	403,676,805	19,955,187	73,094,706	2,300,762	215,758	55,563,347	10,353,070	4,678,360	210,381	1,940,970	31,763,644	167,871,751	30,314,856	17,063,416	285,806	221,423	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	819,510,241	403,676,805	19,955,187	73,094,706	2,300,762	215,758	55,563,347	10,353,070	4,678,360	210,381	1,940,970	31,763,644	167,871,751	30,314,856	17,063,416	285,806	221,423	-	-
RB_GUP-Land_P	PRODUCTION	1.00000000	0.49258299	0.02435014	0.08919316	0.00280748	0.00026328	0.06780067	0.01263324	0.00570873	0.00025672	0.00236845	0.03875930	0.20484399	0.03699143	0.02082148	0.00034875	0.00027019	-	-
RB_GUP-Land_P	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_P	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_P	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_P	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_P	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_P	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_P	TOTAL	1.00000000	0.49258299	0.02435014	0.08919316	0.00280748	0.00026328	0.06780067	0.01263324	0.00570873	0.00025672	0.00236845	0.03875930	0.20484399	0.03699143	0.02082148	0.00034875	0.00027019	-	-
Transmission Land	Allocate on BULK_TRANS	31,451,154																		
Trans. GUP less Land	PRODUCTION	10,045,283	4,948,136	244,604	895,971	28,202	2,645	681,077	126,904	57,346	2,579	23,792	389,348	2,057,716	371,589	209,158	3,503	2,714	-	-
	BULKTRAN	425,331,020	209,510,826	10,356,869	37,936,617	1,194,110	111,980	28,837,730	5,373,309	2,428,098	109,189	1,007,376	16,485,533	87,126,505	15,733,603	8,856,021	148,335	114,920	-	-
	SUBTRAN	100,341,301	48,852,912	2,357,705	8,577,217	264,942	32,997	6,480,222	1,204,666	716,790	-	226,278	3,704,303	25,806,708	-	1,950,357	32,513	26,044	88,556	19,090
	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	535,717,604	263,311,873	12,959,178	47,409,804	1,487,254	147,622	35,999,029	6,704,879	3,202,235	111,768	1,257,446	20,579,185	114,990,929	16,105,192	11,015,536	184,351	143,679	88,556	19,090
RB_GUP-Land_T	PRODUCTION	0.01875108	0.00923646	0.00045659	0.00167247	0.00005264	0.00000494	0.00127134	0.00023689	0.00010704	0.00000481	0.00004441	0.00072678	0.00384105	0.00069363	0.00039043	0.00000654	0.00000507	-	-
RB_GUP-Land_T	BULKTRAN	0.79394632	0.39108445	0.01933270	0.07081458	0.00222899	0.00020903	0.05383010	0.01003012	0.00453242	0.00020382	0.00188042	0.03077280	0.16263513	0.02936921	0.01653114	0.00027689	0.00021452	-	-
RB_GUP-Land_T	SUBTRAN	0.18730260	0.09119154	0.00440102	0.01601071	0.00049456	0.00006159	0.01209634	0.00224870	0.00133800	-	0.00042238	0.00691466	0.04817222	-	0.00364064	0.00006069	0.00004862	0.00016530	0.00003563
RB_GUP-Land_T	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_T	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_T	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_T	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_T	TOTAL	1.00000000	0.49151245	0.02419032	0.08849775	0.00277619	0.00027556	0.06719777	0.01251570	0.00597747	0.00020863	0.00234722	0.03841424	0.21464840	0.03006284	0.02056221	0.00034412	0.00026820	0.00016530	0.00003563
Distribution Land	Allocate on DIST_CPD	7,494,757																		
Dist. GUP less Land	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	438,758,375	293,240,935	13,822,612	50,190,753	1,551,155	-	37,634,292	7,009,389	-	-	1,341,639	21,637,606	-	-	11,348,469	189,337	153,395	525,509	113,283
	DISTSEC	231,086,643	172,783,818	8,329,963	25,134,970	-	-	16,016,100	-	-	-	433,042	-	-	-	5,907,444	-	61,302	2,081,430	338,574
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	108,582,391	49,422,070	13,304,130	3,773,926	1,248,285	202,761	1,089,770	324,111	706,451	124,161	7,498	192,269	1,038,898	186,243	301,789	5,493	5,569	32,710,149	3,938,817
	TOTAL	778,427,409	515,446,824	35,456,705	79,099,649	2,799,440	202,761	54,740,163	7,333,501	706,451	124,161	1,782,179	21,829,876	1,038,898	186,243	17,557,701	194,830	220,265	35,317,088	4,390,674
RB_GUP-Land_D	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_D	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_D	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_D	DISTPRI	0.56364713	0.37670942	0.01775710	0.06447711	0.00199268	-	0.04834657	0.00900455	-	-	0.00172353	0.02779656	-	-	0.01457871	0.00024323	0.00019706	0.00067509	0.00014553
RB_GUP-Land_D	DISTSEC	0.29686345	0.22196523	0.01070101	0.03228942	-	-	0.02057494	-	-	-	0.00055630	-	-	-	0.00758895	-	0.00007875	0.00267389	0.00043495
RB_GUP-Land_D	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_D	CUSTOMER	0.13948942	0.06348963	0.01709103	0.00484814	0.00160360	0.00026048	0.00139996	0.00041637	0.00090754	0.00015950	0.00000963	0.00024700	0.00133461	0.00023925	0.00038769	0.00000706	0.00000715	0.04202081	0.00505997
RB_GUP-Land_D	TOTAL	1.00000000	0.66216428	0.04554915	0.10161468	0.00359628	0.00026048	0.07032147	0.00942092	0.00090754	0.00015950	0.00228946	0.02804356	0.00133461	0.00023925	0.02255535	0.00025029	0.00028296	0.04536979	0.00564044
General Land	Allocate on LABOR_M	1,501,860																		
Gen. GUP less Land	PRODUCTION	26,982,885	13,291,310	657,037	2,406,689	75,754	7,104	1,829,458	340,881	154,038	6,927	63,908	1,045,838	5,527,282	998,135	561,824	9,410	7,290	-	-
	BULKTRAN	98,591	48,564	2,401	8,794	277	26	6,685	1,246	563	25	234	3,821	20,196	3,647	2,053	34	27	-	-
	SUBTRAN	21,686	10,558	510	1,854	57	7	1,401	260	155	-	49	801	5,577	-	422	7	6	19	4
	DISTPRI	13,894,080	9,286,006	437,718	1,589,381	49,120	-	1,191,758	221,965	-	-	42,485	685,194	-	-	359,370	5,996	4,858	16,641	3,587
	DISTSEC	5,734,258	4,287,513	206,702	623,707	-	-	397,429	-	-	-	10,746	-	-	-	146,589	-	1,521	51,649	8,401
	ENERGY	7,103,367	2,665,376	172,734	579,540	18,419	1,698	528,375	97,950	44,506	2,062	20,248	355,530	2,018,552	382,967	143,153	2,330	2,599	56,205	11,123
	CUSTOMER	5,354,059	3,825,480	654,666	188,508	31,512	4,979	35,176	9,034	17,280	3,016	245	5,378	25,425	4,526	9,628	153	274	422,222	116,558
	TOTAL	59,188,925	33,414,807	2,131,767	5,398,473	175,139	13,814	3,990,280	671,337	216,541	12,030	137,914	2,096,562	7,597,032	1,389,275	1,223,037	17,930	16,575	546,737	139,673
RB_GUP-Land_G	PRODUCTION	0.45587726	0.22455738	0.01110067	0.04066113	0.00127987	0.00012002	0.03090879	0.00575921	0.00260248	0.00011703	0.00107972	0.01766948	0.09338372	0.01686355	0.00949204	0.00015899	0.00012317	-	-
RB_GUP-Land_G	BULKTRAN	0.00166569	0.00082049	0.00004056	0.00014857	0.00000468	0.00000044	0.00011294	0.00002104	0.00000951	0.00000043	0.00000395	0.00006456	0.00034121	0.00006162	0.00003468	0.00000058	0.00000045	-	-
RB_GUP-Land_G	SUBTRAN	0.00036638	0.00017838	0.00000861	0.00003132	0.00000097	0.00000012	0.00002366	0.00000440	0.00000262	-	0.00000083	0.00001353	0.00009423	-	0.00000712	0.00000012	0.00000010	0.00000032	0.00000007
RB_GUP-Land_G	DISTPRI	0.23474121	0.15688756	0.00739527	0.02685268	0.00082989	-	0.02013482	0.00375011	-	-	0.00071779	0.01157639	-	-	0.00607157	0.00010130	0.00008207	0.00028115	0.00006061
RB_GUP-Land_G	DISTSEC	0.09688058	0.07243775	0.00349225	0.01053757	-	-	0.00671458	-	-	-	0.00018155	-	-	-	0.00247663	-	0.00002570	0.00087262	0.00014194
RB_GUP-Land_G	ENERGY	0.12001176	0.04503166	0.00291834	0.00979136	0.00031119	0.00002869	0.00892692	0.00165488	0.00075193	0.00003484	0.00034210	0.00600670	0.03410355	0.00647024	0.00241857	0.00003937	0.00004391	0.00094959	0.00018792
RB_GUP-Land_G	CUSTOMER	0.09045711	0.06463169	0.01106061	0.00318486	0.00053239	0.00008412	0.00059430	0.00015263	0.00029194	0.00005095	0.00000413	0.00009087	0.00042955	0.00007646	0.00016266	0.00000258	0.00000464	0.00713347	0.00196925
RB_GUP-Land_G	TOTAL	1.00000000	0.56454493	0.03601631	0.09120748	0.00295898	0.00023338	0.06741600	0.01134227	0.00365848	0.00020325	0.00233007	0.03542153	0.12835225	0.02347187	0.02066328	0.00030293	0.00028004	0.00923716	0.00235979

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
FEBRUARY 28, 2017

ALLOCATOR	FUNCTION		Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
CWIP	PRODUCTION		7,765,324	3,825,066	189,087	692,614	21,801	2,044	526,494	98,101	44,330	1,993	18,392	300,979	1,590,680	287,250	161,686	2,708	2,098	-	-
	BULKTRAN		7,419,845	3,654,889	180,674	661,799	20,831	1,953	503,070	93,737	42,358	1,905	17,574	287,588	1,519,911	274,471	154,492	2,588	2,005	-	-
	SUBTRAN		1,629,918	793,554	38,298	139,326	4,304	536	105,263	19,568	11,643	-	3,676	60,172	419,198	-	31,681	528	423	1,438	310
	DISTPRI		4,961,587	3,316,040	156,309	567,569	17,541	-	425,578	79,264	-	-	15,172	244,683	-	-	128,331	2,141	1,735	5,943	1,281
	DISTSEC		2,494,180	1,864,902	89,908	271,288	-	-	172,866	-	-	-	4,674	-	-	-	63,761	-	662	22,465	3,654
	ENERGY		365,311	137,074	8,883	29,804	947	87	27,173	5,037	2,289	106	1,041	18,284	103,810	19,695	7,362	120	134	2,891	572
	CUSTOMER		1,308,739	667,092	160,285	45,611	13,501	2,186	12,181	3,549	7,612	1,337	84	2,106	11,195	2,005	3,367	60	67	333,020	43,481
	TOTAL		25,944,903	14,258,618	823,444	2,408,013	78,925	6,807	1,772,625	299,257	108,232	5,341	60,612	913,812	3,644,793	583,421	550,680	8,145	7,123	365,757	49,298
RB_GUP_CWIP	PRODUCTION		0.29930055	0.14743036	0.00728801	0.02669556	0.00084028	0.00007880	0.02029278	0.00378114	0.00170862	0.00007683	0.00070888	0.01160068	0.06130992	0.01107156	0.00623188	0.00010438	0.00008087	-	-
RB_GUP_CWIP	BULKTRAN		0.28598469	0.14087119	0.00696377	0.02550788	0.00080290	0.00007529	0.01938995	0.00361291	0.00163261	0.00007342	0.00067734	0.01108457	0.05858225	0.01057898	0.00595462	0.00009974	0.00007727	-	-
RB_GUP_CWIP	SUBTRAN		0.06282229	0.03058613	0.00147613	0.00537008	0.00016588	0.00002066	0.00405718	0.00075422	0.00044877	-	0.00014167	0.00231921	0.01615722	-	0.00122109	0.00002036	0.00001631	0.00005544	0.00001195
RB_GUP_CWIP	DISTPRI		0.19123551	0.12781085	0.00602467	0.02187595	0.00067608	-	0.01640314	0.00305509	-	-	0.00058476	0.00943088	-	-	0.00494630	0.00008252	0.00006686	0.00022905	0.00004937
RB_GUP_CWIP	DISTSEC		0.09613371	0.07187931	0.00346532	0.01045633	-	-	0.00666281	-	-	-	0.00018015	-	-	-	0.00245754	-	0.00002550	0.00086589	0.00014085
RB_GUP_CWIP	ENERGY		0.01408024	0.00528329	0.00034239	0.00114876	0.00003651	0.00000337	0.00104734	0.00019416	0.00008822	0.00000409	0.00004014	0.00070473	0.00400116	0.00075911	0.00028376	0.00000462	0.00000515	0.00011141	0.00002205
RB_GUP_CWIP	CUSTOMER		0.05044302	0.02571186	0.00617790	0.00175801	0.00052036	0.00008425	0.00046948	0.00013680	0.00029339	0.00005152	0.00000324	0.00008119	0.00043149	0.00007729	0.00012979	0.00000232	0.00000259	0.01283568	0.00167588
RB_GUP_CWIP	TOTAL		1.00000000	0.54957299	0.03173819	0.09281256	0.00304200	0.00026236	0.06832267	0.01153431	0.00417162	0.00020586	0.00233617	0.03522126	0.14048203	0.02248694	0.02122498	0.00031394	0.00027454	0.01409747	0.00190010
T&D Plant	PRODUCTION		10,045,283	4,948,136	244,604	895,971	28,202	2,645	681,077	126,904	57,346	2,579	23,792	389,348	2,057,716	371,589	209,158	3,503	2,714	-	-
	BULKTRAN		456,782,174	225,003,129	11,122,709	40,741,844	1,282,409	120,260	30,970,140	5,770,639	2,607,644	117,263	1,081,866	17,704,558	93,569,085	16,897,026	9,510,881	159,304	123,418	-	-
	SUBTRAN		100,341,301	48,852,912	2,357,705	8,577,217	264,942	32,997	6,480,222	1,204,666	716,790	-	226,278	3,704,303	25,806,708	-	1,950,357	32,513	26,044	88,556	19,090
	DISTPRI		446,253,132	298,250,001	14,058,726	51,048,099	1,577,652	-	38,277,152	7,129,122	-	-	1,364,557	22,007,214	-	-	11,542,320	192,571	156,015	534,485	115,218
	DISTSEC		231,086,643	172,783,818	8,329,963	25,134,970	-	-	16,016,100	-	-	-	433,042	-	-	-	5,907,444	-	61,302	2,081,430	338,574
	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER		108,582,391	49,422,070	13,304,130	3,773,926	1,248,285	202,761	1,089,770	324,111	706,451	124,161	7,498	192,269	1,038,898	186,243	301,789	5,493	5,569	32,710,149	3,938,817
	TOTAL		1,353,090,924	799,260,066	49,417,837	130,172,026	4,401,489	358,663	93,514,460	14,555,443	4,088,232	244,003	3,137,033	43,997,693	122,472,407	17,454,858	29,421,948	393,384	375,062	35,414,621	4,411,699
TDPLANT	PRODUCTION		0.00742395	0.00365691	0.00018077	0.00066217	0.00002084	0.00000195	0.00050335	0.00009379	0.00004238	0.00000191	0.00001758	0.00028775	0.00152075	0.00027462	0.00015458	0.00000259	0.00000201	-	-
TDPLANT	BULKTRAN		0.33758424	0.16628826	0.00822022	0.03011020	0.00094776	0.00008888	0.02288844	0.00426478	0.00192718	0.00008666	0.00079955	0.01308453	0.06915210	0.01248772	0.00702900	0.00011773	0.00009121	-	-
TDPLANT	SUBTRAN		0.07415710	0.03610468	0.00174246	0.00633898	0.00019581	0.00002439	0.00478920	0.00089031	0.00052974	-	0.00016723	0.00273766	0.01907241	-	0.00144141	0.00002403	0.00001925	0.00006545	0.00001411
TDPLANT	DISTPRI		0.32980277	0.22042126	0.01039008	0.03772703	0.00116596	-	0.02828868	0.00526877	-	-	0.00100847	0.01626440	-	-	0.00853034	0.00014232	0.00011530	0.00039501	0.00008515
TDPLANT	DISTSEC		0.17078427	0.12769565	0.00615625	0.01857596	-	-	0.01183668	-	-	-	0.00032004	-	-	-	0.00436589	-	0.00004530	0.00153828	0.00025022
TDPLANT	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TDPLANT	CUSTOMER		0.08024767	0.03652531	0.00983240	0.00278911	0.00092254	0.00014985	0.00080539	0.00023953	0.00052210	0.00009176	0.00000554	0.00014210	0.00076780	0.00013764	0.00022304	0.00000406	0.00000412	0.02417439	0.00291098
TDPLANT	TOTAL		1.00000000	0.59069206	0.03652219	0.09620346	0.00325291	0.00026507	0.06911173	0.01075718	0.00302140	0.00018033	0.00231842	0.03251644	0.09051307	0.01289999	0.02174425	0.00029073	0.00027719	0.02617313	0.00326046
Electric Plant in Service	PRODUCTION		862,008,089	424,610,522	20,990,015	76,885,223	2,420,074	226,947	58,444,730	10,889,956	4,920,968	221,290	2,041,624	33,410,831	176,577,179	31,886,912	17,948,284	300,627	232,906	-	-
	BULKTRAN		456,883,266	225,052,925	11,125,170	40,750,861	1,282,692	120,287	30,976,994	5,771,916	2,608,222	117,289	1,082,106	17,708,476	93,589,793	16,900,765	9,512,986	159,339	123,445	-	-
	SUBTRAN		100,363,537	48,863,738	2,358,228	8,579,118	265,001	33,004	6,481,658	1,204,933	716,949	-	226,328	3,705,124	25,812,427	-	1,950,789	32,520	26,050	88,576	19,094
	DISTPRI		460,499,760	307,771,630	14,507,551	52,677,809	1,628,018	-	39,499,149	7,356,719	-	-	1,408,120	22,709,795	-	-	11,910,809	198,719	160,996	551,549	118,896
	DISTSEC		236,966,402	177,180,122	8,541,910	25,774,503	-	-	16,423,613	-	-	-	444,060	-	-	-	6,057,753	-	62,861	2,134,390	347,189
	ENERGY		7,283,608	2,733,007	177,117	594,245	18,886	1,741	541,782	100,436	45,635	2,114	20,762	364,551	2,069,771	392,684	146,785	2,389	2,665	57,632	11,405
	CUSTOMER		114,072,304	53,344,619	13,975,407	3,967,217	1,280,596	207,866	1,125,839	333,375	724,169	127,254	7,749	197,784	1,064,968	190,883	311,661	5,650	5,850	33,143,085	4,058,333
	TOTAL		2,238,076,966	1,239,556,564	71,675,398	209,228,976	6,895,268	589,846	153,493,764	25,657,335	9,015,944	467,948	5,230,749	78,096,561	299,114,138	49,371,244	47,839,066	699,244	614,774	35,975,231	4,554,917
RB_GUP_EPIS	PRODUCTION		0.38515569	0.18972114	0.00937859	0.03435325	0.00108132	0.00010140	0.02611382	0.00486576	0.00219875	0.00009888	0.00091222	0.01492837	0.07889683	0.01424746	0.00801951	0.00013432	0.00010407	-	-
RB_GUP_EPIS	BULKTRAN		0.20414100	0.10055638	0.00497086	0.01820798	0.00057312	0.00005375	0.01384090	0.00257896	0.00116539	0.00005241	0.00048350	0.00791236	0.04181706	0.00755147	0.00425052	0.00007119	0.00005516	-	-
RB_GUP_EPIS	SUBTRAN		0.04484365	0.02183291	0.00105368	0.00383325	0.00011841	0.00001475	0.00289608	0.00053838	0.00032034	-	0.00010113	0.00165549	0.01153331	-	0.00087164	0.00001453	0.00001164	0.00003958	0.00000853
RB_GUP_EPIS	DISTPRI		0.20575689	0.13751611	0.00648215	0.02353709	0.00072742	-	0.01764870	0.00328707	-	-	0.00062917	0.01014701	-	-	0.00532189	0.00008879	0.00007193	0.00024644	0.00005312
RB_GUP_EPIS	DISTSEC		0.10587947	0.07916623	0.00381663	0.01151636	-	-	0.00733827	-	-	-	0.00019841	-	-	-	0.00270668	-	0.00002809	0.00095367	0.00015513
RB_GUP_EPIS	ENERGY		0.00325440	0.00122114	0.00007914	0.00026552	0.00000844	0.00000078	0.00024207	0.00004488	0.00002039	0.00000094	0.00000928	0.00016289	0.00092480	0.00017546	0.00006559	0.00000107	0.00000119	0.00002575	0.00000510
RB_GUP_EPIS	CUSTOMER		0.05096889	0.02383502	0.00624438	0.00177260	0.00057219	0.00009288	0.00050304	0.00014896	0.00032357	0.00005686	0.00000346	0.00008837	0.00047584	0.00008529	0.00013925	0.00000252	0.00000261	0.01480873	0.00181331
RB_GUP_EPIS	TOTAL		1.00000000	0.55384894	0.03202544	0.09348605	0.00308089	0.00026355	0.06858288	0.01146401	0.00402843	0.00020908	0.00233716	0.03489449	0.13364783	0.02205967	0.02137508	0.00031243	0.00027469	0.01607417	0.00203519
Gross Utility Plant	PRODUCTION	Same as	862,008,089	424,610,522	20,990,015	76,885,223	2,420,074	226,947	58,444,730	10,889,956	4,920,968	221,290	2,041,624	33,410,831	176,577,179	31,886,912	17,948,284	300,627	232,906	-	-
	BULKTRAN	RB_GUP_EPIS	456,883,266	225,052,925	11,125,170	40,750,861	1,282,692	120,287	30,976,994	5,771,916	2,608,222	117,289	1,082,106	17,708,476	93,589,793	16,900,765	9,512,986	159,339	123,445	-	-
	SUBTRAN		100,363,537	48,863,738	2,358,228	8,579,118	265,001	33,004	6,481,658	1,204,933	716,949	-	226,328	3,705,124	25,812,427	-	1,950,789	32,520	26,050	88,576	19,094
	DISTPRI		460,499,760	307,771,630	14,507,551	52,677,809	1,628,018	-	39,499,149	7,356,719	-	-	1,408,120	22,709,795	-	-	11,910,809	198,719	160,996	551,549	118,896
	DISTSEC		236,966,402	177,180,122	8,541,910	25,774,503	-	-	16,423,613	-	-	-	444,060	-	-	-	6,057,753	-	62,861	2,134,390	347,189
	ENERGY		7,283,608	2,733,007	177,117	594,245	18,886	1,741	541,782	100,436	45,635	2,114	20,762	364,551	2,069,771	392,684	146,785	2,389	2,665	57,632	11,405
	CUSTOMER		114,072,304	53,344,619	13,975,407	3,967,217	1,280,596	207,866	1,125,839	333,375	724,169	127,254	7,749	197,784	1,064,968	190,883	311,661	5,650	5,850	33,143,085	4,058,333
	TOTAL		2,238,076,966	1,239,556,564	71,675,398	209,228,976	6,895,268	589,846	153,493,764	25,657,335	9,015,944	467,948	5,230,749	78,096,561	299,114,138	49,371,244	47,839,066	699,244	614,774	35,975,231	4,554,917
RB_GUP	PRODUCTION		0.38515569	0.18972114	0.00937859	0.03435325	0.00108132	0.00010140	0.02611382	0.00486576	0.00219875	0.00009888	0.00091222	0.01492837	0.07889683	0.01424746	0.00801951	0.00013432	0.00010407	-	-
RB_GUP	BULKTRAN		0.20414100	0.10055638	0.00497086	0.01820798	0.00057312	0.00005375	0.01384090	0.00257896	0.00116539	0.00005241	0.00048350	0.00791236	0.04181706	0.00755147	0.00425052	0.00007119	0.00005516	-	-
RB_GUP	SUBTRAN		0.04484365	0.02183291	0.00105368	0.00383325	0.00011841	0.00001475	0.00289608	0.00053838	0.00032034	-	0.00010113	0.00165549	0.01153331	-	0.00087164	0.00001453	0.00001164	0.00003958	0.00000853
RB_GUP	DISTPRI		0.20575689	0.13751611	0.00648215	0.02353709	0.00072742	-	0.01764870	0.00328707	-	-	0.00062917	0.01014701	-	-	0.00532189	0.00008879	0.00007193	0.00024644	0.00005312
RB_GUP	DISTSEC		0.10587947	0.07916623	0.00381663	0.01151636	-	-	0.00733827	-	-	-	0.00019841	-	-	-	0.00270668	-	0.00002809	0.00095367	0.00015513
RB_GUP	ENERGY		0.00325440	0.00122114	0.00007914	0.00026552	0.00000844	0.00000078	0.00024207	0.00004488	0.00002039	0.00000094	0.00000928	0.00016289	0.00092480	0.00017546	0.00006559	0.00000107	0.00000119	0.00002575	0.00000510
RB_GUP	CUSTOMER		0.05096889	0.02383502	0.00624438	0.00177260	0.00057219	0.00009288	0.00050304	0.00014896	0.00032357	0.00005686	0.00000346	0.00008837	0.00047584	0.00008529	0.00013925	0.00000252	0.00000261	0.01480873	0.00181331
RB_GUP	TOTAL		1.00000000	0.55384894	0.03202544	0.09348605	0.00308089	0.00026355	0.06858288	0.01146401	0.00402843	0.00020908	0.00233716	0.03489449	0.13364783	0.02205967	0.02137508	0.00031243	0.00027469	0.01607417	0.00203519
Net EPIS	PRODUCTION		524,214,322	258,219,058	12,764,691	46,756,331	1,471,723	138,014	35,542,085	6,622,526	2,992,596	134,574	1,241,576	20,318,181	107,382,155	19,391,437	10,914,918	182,821	141,637	-	-
	BULKTRAN		307,000,764	151,223,354	7,475,511	27,382,367	861,900	80,826	20,814,859	3,878,415	1,752,583	78,812	727,116	11,899,135	62,887,263	11,356,397	6,392,210	107,067	82,948	-	-
	SUBTRAN		65,255,225	31,770,644	1,533,293	5,578,044	172,301	21,459	4,214,300	783,433	466,152	-	147,156	2,409,030	16,782,945	-	1,268,381	21,144	16,937	57,591	12,415
	DISTPRI		325,887,320	217,804,395	10,266,731	37,279,129	1,152,119	-	27,952,831	5,206,217	-	-	996,501	16,071,309	-	-	8,429,063	140,630	113,934	390,321	84,141
	DISTSEC		166,693,542	124,637,004	6,008,790	18,131,023	-	-	11,553,158	-	-	-	312,373	-	-	-	4,261,314	-	44,220	1,501,432	244,229
	ENERGY		4,478,879	1,680,597	108,914	365,417	11,614	1,071	333,156	61,761	28,062	1,300	12,767	224,172	1,272,756	241,472	90,262	1,469	1,639	35,439	7,013
	CUSTOMER		80,002,522	37,289,249	9,801,515	2,782,121	900,784	146,228	791,231	234,422	509,438	89,522	5,446	139,076	749,182	134,285	219,043	3,973	4,103	23,349,788	2,853,118
	TOTAL		1,473,532,574	822,624,301	47,959,443	138,274,431	4,570,440	387,598	101,201,618	16,786,773	5,748,832	304,208	3,442,936	51,060,902	189,074,300	31,123,591	31,575,191	457,104	405,419	25,334,571	3,200,916
NP	PRODUCTION		0.35575347	0.17523811	0.00866265	0.03173078	0.00099877	0.00009366	0.02412033	0.00449432	0.00203090	0.00009133	0.00084258	0.01378876	0.07287396	0.01315983	0.00740731	0.00012407	0.00009612	-	-
NP	BULKTRAN		0.20834338	0.10262641	0.00507319	0.01858280	0.00058492	0.00005485	0.01412582	0.00263205	0.00118938	0.00005348	0.00049345	0.00807524	0.04267789	0.00770692	0.00433802	0.00007266	0.00005629	-	-
NP	SUBTRAN		0.04428489	0.02156087	0.00104056	0.00378549	0.00011693	0.00001456	0.00286000	0.00053167	0.00031635	-	0.00009987	0.00163487	0.01138960	-	0.00086078	0.00001435	0.00001149	0.00003908	0.00000843
NP	DISTPRI		0.22116058	0.14781105	0.00696743	0.02529915	0.00078188	-	0.01896994	0.00353315	-	-	0.00067627	0.01090665	-	-	0.00572031	0.00009544	0.00007732	0.00026489	0.00005710
NP	DISTSEC		0.11312512	0.08458381	0.00407781	0.01230446	-	-	0.00784045	-	-	-	0.00021199	-	-	-	0.00289190	-	0.00003001	0.00101893	0.00016574
NP	ENERGY		0.00303955	0.00114052	0.00007391	0.00024799	0.00000788	0.00000073	0.00022609	0.00004191	0.00001904	0.00000088	0.00000866	0.00015213	0.00086374	0.00016387	0.00006126	0.00000100	0.00000111	0.00002405	0.00000476
NP	CUSTOMER		0.05429301	0.02530602	0.00665171	0.00188806	0.00061131	0.00009924	0.00053696	0.00015909	0.00034573	0.00006075	0.00000370	0.00009438	0.00050843	0.00009113	0.00014865	0.00000270	0.00000278	0.01584613	0.00193624
NP	TOTAL		1.00000000	0.55826679	0.03254726	0.09383873	0.00310169	0.00026304	0.06867959	0.01139220	0.00390139	0.00020645	0.00233652	0.03465203	0.12831362	0.02112175	0.02142823	0.00031021	0.00027513	0.01719309	0.00217227

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
FEBRUARY 28, 2017

ALLOCATOR	FUNCTION	Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
Rate Base	PRODUCTION	481,495,953	235,278,987	11,569,153	42,947,722	1,272,403	(16,174)	32,899,720	5,967,356	2,598,252	126,015	1,162,592	18,828,671	100,351,191	17,997,251	10,208,990	171,192	132,633	-	-
	BULKTRAN	220,022,522	107,309,093	5,277,560	19,632,990	577,428	(17,178)	15,052,414	2,716,942	1,176,708	57,778	533,050	8,624,288	46,011,744	8,250,000	4,680,402	78,491	60,812	-	-
	SUBTRAN	46,170,006	22,236,074	1,067,392	3,946,616	113,530	(5,431)	3,008,573	540,969	307,857	-	106,567	1,723,845	12,128,670	-	917,352	15,312	12,266	41,424	8,990
	DISTPRI	238,338,688	158,682,625	7,440,941	27,408,930	794,625	-	20,719,120	3,748,012	-	-	747,922	11,931,879	-	-	6,318,988	105,550	85,516	291,450	63,128
	DISTSEC	121,049,832	90,224,944	4,327,359	13,248,406	-	-	8,511,096	-	-	-	233,063	-	-	-	3,175,637	-	32,994	1,114,166	182,168
	ENERGY	28,989,278	11,114,108	696,921	2,345,849	68,005	3,410	2,166,804	406,780	179,089	8,386	82,337	1,414,643	8,119,770	1,496,716	580,371	9,476	10,570	241,934	44,111
	CUSTOMER	58,822,167	27,640,535	7,135,055	2,055,577	618,396	(23,275)	585,649	168,243	350,718	66,902	4,083	102,973	558,804	99,453	163,961	2,974	3,094	17,150,313	2,138,715
	TOTAL	1,194,888,447	652,486,366	37,514,381	111,586,090	3,444,388	(58,648)	82,943,376	13,548,303	4,612,624	259,080	2,869,612	42,626,300	167,170,178	27,843,420	26,045,700	382,994	337,885	18,839,286	2,437,113
RATEBASE	PRODUCTION	0.40296310	0.19690456	0.00968220	0.03594287	0.00106487	(0.00001354)	0.02753372	0.00499407	0.00217447	0.00010546	0.00097297	0.01575768	0.08398373	0.01506187	0.00854389	0.00014327	0.00011100	-	-
RATEBASE	BULKTRAN	0.18413645	0.08980679	0.00441678	0.01643081	0.00048325	(0.00001438)	0.01259734	0.00227380	0.00098479	0.00004835	0.00044611	0.00721765	0.03850715	0.00690441	0.00391702	0.00006569	0.00005089	-	-
RATEBASE	SUBTRAN	0.03863960	0.01860933	0.00089330	0.00330292	0.00009501	(0.00000455)	0.00251787	0.00045274	0.00025764	-	0.00008919	0.00144268	0.01015046	-	0.00076773	0.00001281	0.00001027	0.00003467	0.00000752
RATEBASE	DISTPRI	0.19946522	0.13280120	0.00622731	0.02293848	0.00066502	-	0.01733979	0.00313670	-	-	0.00062593	0.00998577	-	-	0.00528835	0.00008833	0.00007157	0.00024391	0.00005283
RATEBASE	DISTSEC	0.10130639	0.07550909	0.00362156	0.01108757	-	-	0.00712292	-	-	-	0.00019505	-	-	-	0.00265768	-	0.00002761	0.00093244	0.00015246
RATEBASE	ENERGY	0.02426108	0.00930138	0.00058325	0.00196324	0.00005691	0.00000285	0.00181339	0.00034043	0.00014988	0.00000702	0.00006891	0.00118391	0.00679542	0.00125260	0.00048571	0.00000793	0.00000885	0.00020247	0.00003692
RATEBASE	CUSTOMER	0.04922817	0.02313231	0.00597131	0.00172031	0.00051753	(0.00001948)	0.00049013	0.00014080	0.00029351	0.00005599	0.00000342	0.00008618	0.00046766	0.00008323	0.00013722	0.00000249	0.00000259	0.01435307	0.00178989
RATEBASE	TOTAL	1.00000000	0.54606467	0.03139572	0.09338620	0.00288260	(0.00004908)	0.06941516	0.01133855	0.00386030	0.00021682	0.00240157	0.03567387	0.13990442	0.02330211	0.02179760	0.00032053	0.00028278	0.01576657	0.00203962
CUST_451	TOTAL	1.00000000	0.91645786	0.05818206	0.01873519	0.00051850	0.00005370	0.00152547	0.00006346	-	-	-	0.00001586	-	-	-	-	-	0.00444790	-
RB_GUP_EPIS_D	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D	DISTPRI	0.56780830	0.37949051	0.01788819	0.06495312	0.00200739	-	0.04870349	0.00907103	-	-	0.00173625	0.02800177	-	-	0.01468634	0.00024503	0.00019851	0.00068007	0.00014660
RB_GUP_EPIS_D	DISTSEC	0.29403248	0.21984851	0.01059897	0.03198150	-	-	0.02037874	-	-	-	0.00055100	-	-	-	0.00751658	-	0.00007800	0.00264839	0.00043080
RB_GUP_EPIS_D	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D	CUSTOMER	0.13815922	0.06288418	0.01692805	0.00480191	0.00158831	0.00025799	0.00138661	0.00041240	0.00089888	0.00015798	0.00000954	0.00024464	0.00132188	0.00023697	0.00038399	0.00000699	0.00000709	0.04162009	0.00501171
RB_GUP_EPIS_D	TOTAL	1.00000000	0.66222320	0.04541521	0.10173653	0.00359570	0.00025799	0.07046884	0.00948342	0.00089888	0.00015798	0.00229679	0.02824642	0.00132188	0.00023697	0.02258691	0.00025202	0.00028360	0.04494855	0.00558912
MISC_SERV_REV	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MISC_SERV_REV	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MISC_SERV_REV	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MISC_SERV_REV	DISTPRI	0.56154671	0.52518103	0.02291681	0.01196138	0.00028947	-	0.00105430	0.00006070	-	-	-	0.00001573	-	-	-	-	-	0.00006730	-
MISC_SERV_REV	DISTSEC	0.32442196	0.30425074	0.01357848	0.00588952	-	-	0.00044115	-	-	-	-	-	-	-	-	-	-	0.00026207	-
MISC_SERV_REV	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MISC_SERV_REV	CUSTOMER	0.11403132	0.08702610	0.02168676	0.00088429	0.00022903	0.00005370	0.00003002	0.00000276	-	-	-	0.00000014	-	-	-	-	-	0.00411853	-
MISC_SERV_REV	TOTAL	1.00000000	0.91645786	0.05818206	0.01873519	0.00051850	0.00005370	0.00152547	0.00006346	-	-	-	0.00001586	-	-	-	-	-	0.00444790	-
364 Poles	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	113,968,509	76,170,015	3,590,456	13,037,165	402,916	-	9,775,595	1,820,705	-	-	348,494	5,620,419	-	-	2,947,791	49,181	39,845	136,502	29,425
	DISTSEC	87,069,609	65,102,073	3,138,592	9,470,439	-	-	6,034,601	-	-	-	163,163	-	-	-	2,225,827	-	23,097	784,248	127,569
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	201,038,118	141,272,088	6,729,047	22,507,604	402,916	-	15,810,196	1,820,705	-	-	511,657	5,620,419	-	-	5,173,618	49,181	62,942	920,750	156,995
365 Overhead Lines	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	182,131,798	121,726,449	5,737,867	20,834,547	643,896	-	15,622,269	2,909,649	-	-	556,924	8,981,928	-	-	4,710,832	78,595	63,675	218,142	47,025
	DISTSEC	36,461,335	27,262,193	1,314,319	3,965,848	-	-	2,527,054	-	-	-	68,326	-	-	-	932,089	-	9,672	328,412	53,421
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	218,593,133	148,988,642	7,052,186	24,800,395	643,896	-	18,149,323	2,909,649	-	-	625,250	8,981,928	-	-	5,642,921	78,595	73,348	546,555	100,445
TOTOHLINES	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES	DISTPRI	0.70562025	0.47159611	0.02222981	0.08071780	0.00249460	-	0.06052424	0.01127264	-	-	0.00215765	0.03479804	-	-	0.01825084	0.00030450	0.00024669	0.00084513	0.00018218
TOTOHLINES	DISTSEC	0.29437975	0.22010817	0.01061148	0.03201927	-	-	0.02040280	-	-	-	0.00055165	-	-	-	0.00752545	-	0.00007809	0.00265152	0.00043131
TOTOHLINES	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES	TOTAL	1.00000000	0.69170427	0.03284129	0.11273707	0.00249460	-	0.08092705	0.01127264	-	-	0.00270930	0.03479804	-	-	0.02577629	0.00030450	0.00032478	0.00349665	0.00061349
366 Underground Conduit	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	5,843,003	3,905,128	184,078	668,397	20,657	-	501,181	93,345	-	-	17,867	288,151	-	-	151,129	2,521	2,043	6,998	1,509
	DISTSEC	1,375,037	1,028,117	49,566	149,561	-	-	95,301	-	-	-	2,577	-	-	-	35,151	-	365	12,385	2,015
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	7,218,040	4,933,245	233,643	817,958	20,657	-	596,482	93,345	-	-	20,444	288,151	-	-	186,280	2,521	2,408	19,383	3,523
367 Underground Lines	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	8,972,306	5,996,575	282,663	1,026,366	31,720	-	769,595	143,337	-	-	27,436	442,474	-	-	232,068	3,872	3,137	10,746	2,317
	DISTSEC	2,111,457	1,578,739	76,112	229,660	-	-	146,340	-	-	-	3,957	-	-	-	53,977	-	560	19,018	3,094
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	11,083,763	7,575,314	358,774	1,256,027	31,720	-	915,936	143,337	-	-	31,392	442,474	-	-	286,045	3,872	3,697	29,764	5,410
TOTUGLINES	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES	DISTPRI	0.80950000	0.54102338	0.02550243	0.09260089	0.00286185	-	0.06943448	0.01293218	-	-	0.00247530	0.03992093	-	-	0.02093769	0.00034932	0.00028301	0.00096955	0.00020900
TOTUGLINES	DISTSEC	0.19050000	0.14243713	0.00686694	0.02072042	-	-	0.01320313	-	-	-	0.00035698	-	-	-	0.00486990	-	0.00005054	0.00171586	0.00027911
TOTUGLINES	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES	TOTAL	1.00000000	0.68346050	0.03236937	0.11332130	0.00286185	-	0.08263761	0.01293218	-	-	0.00283228	0.03992093	-	-	0.02580758	0.00034932	0.00033354	0.00268541	0.00048811

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
FEBRUARY 28, 2017

ALLOCATOR	FUNCTION		Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
		Excl. 580 -																			
Acct 581-589	PRODUCTION	Acct. 580 allocated	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	on this: TOTOXEXF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI		4,287,634	2,865,608	135,077	490,474	15,158	-	367,770	68,497	-	-	13,111	211,447	-	-	110,899	1,850	1,499	5,135	1,107
	DISTSEC		1,804,807	1,349,457	65,058	196,306	-	-	125,087	-	-	-	3,382	-	-	-	46,138	-	479	16,256	2,644
	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER		2,178,555	919,000	392,818	112,189	62,254	10,103	47,664	16,191	35,201	6,187	328	9,605	51,766	9,280	13,217	274	164	261,273	231,042
	TOTAL		8,270,995	5,134,065	592,953	798,969	77,412	10,103	540,520	84,688	35,201	6,187	16,821	221,052	51,766	9,280	170,254	2,125	2,142	282,664	234,793
TOTOXEXP	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOXEXP	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOXEXP	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOXEXP	DISTPRI		0.51839394	0.34646478	0.01633145	0.05930048	0.00183269	-	0.04446499	0.00828161	-	-	0.00158515	0.02556488	-	-	0.01340824	0.00022370	0.00018124	0.00062089	0.00013384
TOTOXEXP	DISTSEC		0.21820913	0.16315528	0.00786577	0.02373430	-	-	0.01512359	-	-	-	0.00040891	-	-	-	0.00557825	-	0.00005789	0.00196544	0.00031971
TOTOXEXP	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOXEXP	CUSTOMER		0.26339694	0.11111117	0.04749342	0.01356413	0.00752673	0.00122151	0.00576274	0.00195755	0.00425593	0.00074800	0.00003970	0.00116126	0.00625872	0.00112200	0.00159800	0.00003318	0.00001988	0.03158904	0.02793400
TOTOXEXP	TOTAL		1.00000000	0.62073122	0.07169063	0.09659891	0.00935942	0.00122151	0.06535132	0.01023916	0.00425593	0.00074800	0.00203376	0.02672614	0.00625872	0.00112200	0.02058448	0.00025688	0.00025900	0.03417537	0.02838755
		Excl. 590 -																			
Acct 591-598	PRODUCTION	Acct. 590 allocated	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	on this: TOTMXEXF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI		26,800,804	17,912,120	844,331	3,065,816	94,750	-	2,298,826	428,157	-	-	81,952	1,321,696	-	-	693,202	11,565	9,370	32,100	6,920
	DISTSEC		11,015,123	8,236,024	397,061	1,198,099	-	-	763,434	-	-	-	20,642	-	-	-	281,588	-	2,922	99,215	16,139
	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER		164,017	34,816	20,630	5,911	3,897	633	2,889	1,012	2,206	388	20	600	3,244	581	801	17	9	61,150	25,214
	TOTAL		37,979,944	26,182,960	1,262,021	4,269,826	98,647	633	3,065,149	429,168	2,206	388	102,613	1,322,296	3,244	581	975,591	11,582	12,301	192,465	48,272
TOTMXEXP	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTMXEXP	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTMXEXP	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTMXEXP	DISTPRI		0.70565675	0.47162050	0.02223096	0.08072198	0.00249473	-	0.06052737	0.01127323	-	-	0.00215776	0.03479984	-	-	0.01825178	0.00030451	0.00024671	0.00084518	0.00018219
TOTMXEXP	DISTSEC		0.29002474	0.21685192	0.01045450	0.03154558	-	-	0.02010097	-	-	-	0.00054349	-	-	-	0.00741412	-	0.00007694	0.00261229	0.00042493
TOTMXEXP	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTMXEXP	CUSTOMER		0.00431852	0.00091670	0.00054317	0.00015563	0.00010261	0.00001667	0.00007606	0.00002664	0.00005807	0.00001021	0.00000052	0.00001581	0.00008540	0.00001531	0.00002110	0.00000045	0.00000023	0.00161006	0.00066388
TOTMXEXP	TOTAL		1.00000000	0.68938912	0.03322863	0.11242319	0.00259734	0.00001667	0.08070440	0.01129987	0.00005807	0.00001021	0.00270178	0.03481565	0.00008540	0.00001531	0.02568701	0.00030496	0.00032387	0.00506753	0.00127100
Acct 560-574	PRODUCTION		-	0	0	0	-	-	-	0	-	-	(0)	0	-	-	(0)	-	0	-	-
	BULKTRAN		6,064,531	2,987,285	147,672	540,915	17,026	1,597	411,179	76,615	34,621	1,557	14,364	235,057	1,242,283	224,336	126,273	2,115	1,639	-	-
	SUBTRAN		1,333,945	649,454	31,344	114,026	3,522	439	86,149	16,015	9,529	-	3,008	49,245	343,076	-	25,928	432	346	1,177	254
	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL		7,398,476	3,636,739	179,016	654,941	20,548	2,035	497,328	92,630	44,150	1,557	17,372	284,302	1,585,359	224,336	152,201	2,547	1,985	1,177	254
EXP_OM_TRAN	PRODUCTION		0.00000000	0.00000000	0.00000000	0.00000000	-	-	-	0.00000000	-	-	(0.00000000)	0.00000000	-	-	(0.00000000)	-	0.00000000	-	-
EXP_OM_TRAN	BULKTRAN		0.81970000	0.40377028	0.01995981	0.07311163	0.00230129	0.00021581	0.05557621	0.01035547	0.00467944	0.00021043	0.00194142	0.03177100	0.16791062	0.03032188	0.01706737	0.00028587	0.00022147	-	-
EXP_OM_TRAN	SUBTRAN		0.18030000	0.08778220	0.00423648	0.01541212	0.00047607	0.00005929	0.01164410	0.00216462	0.00128798	-	0.00040659	0.00665614	0.04637123	-	0.00350453	0.00005842	0.00004680	0.00015912	0.00003430
EXP_OM_TRAN	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_TRAN	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_TRAN	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_TRAN	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_TRAN	TOTAL		1.00000000	0.49155248	0.02419629	0.08852375	0.00277736	0.00027510	0.06722031	0.01252009	0.00596742	0.00021043	0.00234801	0.03842714	0.21428185	0.03032188	0.02057190	0.00034429	0.00026827	0.00015912	0.00003430
Acct 580-598	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI		33,166,581	22,166,640	1,044,878	3,794,015	117,255	-	2,844,848	529,853	-	-	101,417	1,635,628	-	-	857,852	14,312	11,595	39,724	8,563
	DISTSEC		13,688,256	10,234,729	493,420	1,488,852	-	-	948,703	-	-	-	25,651	-	-	-	349,923	-	3,631	123,292	20,055
	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER		2,526,967	1,031,597	446,695	127,595	71,420	11,591	54,586	18,573	40,386	7,098	376	11,018	59,391	10,647	15,137	315	187	344,542	275,812
	TOTAL		49,381,803	33,432,967	1,984,992	5,410,462	188,675	11,591	3,848,137	548,426	40,386	7,098	127,444	1,646,646	59,391	10,647	1,222,913	14,627	15,414	507,558	304,431
EXP_OM_DIST	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_DIST	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_DIST	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_DIST	DISTPRI		0.67163568	0.44888277	0.02115916	0.07683022	0.00237445	-	0.05760923	0.01072972	-	-	0.00205373	0.03312208	-	-	0.01737183	0.00028983	0.00023481	0.00080443	0.00017341
EXP_OM_DIST	DISTSEC		0.27719230	0.20725709	0.00999193	0.03014982	-	-	0.01921158	-	-	-	0.00051944	-	-	-	0.00708608	-	0.00007353	0.00249671	0.00040613
EXP_OM_DIST	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_DIST	CUSTOMER		0.05117202	0.02089023	0.00904574	0.00258385	0.00144628	0.00023473	0.00110540	0.00037611	0.00081783	0.00014374	0.00000762	0.00022312	0.00120269	0.00021560	0.00030653	0.00000637	0.00000379	0.00697710	0.00558530
EXP_OM_DIST	TOTAL		1.00000000	0.67703009	0.04019683	0.10956388	0.00382073	0.00023473	0.07792621	0.01110584	0.00081783	0.00014374	0.00258079	0.03334519	0.00120269	0.00021560	0.02476444	0.00029620	0.00031213	0.01027824	0.00616484
Acct 560-598	PRODUCTION		-	0	0	0	-	-	-	0	-	-	(0)	0	-	-	(0)	-	0	-	-
	BULKTRAN		6,064,531	2,987,285	147,672	540,915	17,026	1,597	411,179	76,615	34,621	1,557	14,364	235,057	1,242,283	224,336	126,273	2,115	1,639	-	-
	SUBTRAN		1,333,945	649,454	31,344	114,026	3,522	439	86,149	16,015	9,529	-	3,008	49,245	343,076	-	25,928	432	346	1,177	254
	DISTPRI		33,166,581	22,166,640	1,044,878	3,794,015	117,255	-	2,844,848	529,853	-	-	101,417	1,635,628	-	-	857,852	14,312	11,595	39,724	8,563
	DISTSEC		13,688,256	10,234,729	493,420	1,488,852	-	-	948,703	-	-	-	25,651	-	-	-	349,923	-	3,631	123,292	20,055
	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER		2,526,967	1,031,597	446,695	127,595	71,420	11,591	54,586	18,573	40,386	7,098	376	11,018	59,391	10,647	15,137	315	187	344,542	275,812
	TOTAL		56,780,279	37,069,706	2,164,008	6,065,403	209,223	13,627	4,345,465	641,056	84,536	8,655	144,816	1,930,948	1,644,750	234,983	1,375,113	17,174	17,398	508,735	304,685
TDOMX	PRODUCTION		-	0.00000000	0.00000000	0.00000000	-	-	-	0.00000000	-	-	(0.00000000)	0.00000000	-	-	(0.00000000)	-	0.00000000	-	-
TDOMX	BULKTRAN		0.10680699	0.05261131	0.00260076	0.00952645	0.00029986	0.00002812	0.00724159	0.00134932	0.00060973	0.00002742	0.00025297	0.00413976	0.02187877	0.00395094	0.00222388	0.00003725	0.00002886	-	-
TDOMX	SUBTRAN		0.02349311	0.01143803	0.00055201	0.00200820	0.00006203	0.00000773	0.00151723	0.00028205	0.00016782	-	0.00005298	0.00086730	0.00604218	-	0.00045664	0.00000761	0.00000610	0.00002073	0.00000447
TDOMX	DISTPRI		0.58412148	0.39039330	0.01840212	0.06681923	0.00206506	-	0.05010274	0.00933164	-	-	0.00178613	0.02880627	-	-	0.01510828	0.00025207	0.00020422	0.00069961	0.00015081
TDOMX	DISTSEC		0.24107412	0.18025147	0.00868998	0.02622129	-	-	0.01670831	-	-	-	0.00045176	-	-	-	0.00616276	-	0.00006395	0.00217139	0.00035321
TDOMX	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TDOMX	CUSTOMER		0.04450430	0.01816823	0.00786708	0.00224717	0.00125783	0.00020414	0.00096136	0.00032711	0.00071126	0.00012501	0.00000662	0.00019405	0.00104598	0.00018751	0.00026659	0.00000554	0.00000329	0.00606798	0.00485754
TDOMX	TOTAL		1.00000000	0.65286234	0.03811196	0.10682235	0.00368478	0.00023999	0.07653123	0.01129011	0.00148882	0.00015243	0.00255046	0.03400737	0.02896692	0.00413845	0.02421815	0.00030247	0.00030642	0.00895971	0.00536603

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
FEBRUARY 28, 2017

ALLOCATOR	FUNCTION	Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
Acct 902-904	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	5,548,607	4,786,106	596,945	174,795	2,075	160	16,231	1,663	479	56	117	1,023	731	88	4,281	27	250	(37,677)	1,257
	TOTAL	5,548,607	4,786,106	596,945	174,795	2,075	160	16,231	1,663	479	56	117	1,023	731	88	4,281	27	250	(37,677)	1,257
TOTOX234	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234	CUSTOMER	1.00000000	0.86257803	0.10758458	0.03150242	0.00037392	0.00002889	0.00292531	0.00029965	0.00008637	0.00001014	0.00002104	0.00018431	0.00013171	0.00001578	0.00077163	0.00000488	0.00004514	(0.00679042)	0.00022663
TOTOX234	TOTAL	1.00000000	0.86257803	0.10758458	0.03150242	0.00037392	0.00002889	0.00292531	0.00029965	0.00008637	0.00001014	0.00002104	0.00018431	0.00013171	0.00001578	0.00077163	0.00000488	0.00004514	(0.00679042)	0.00022663
Acct 901-905	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	5,767,827	4,975,201	620,529	181,701	2,157	167	16,873	1,728	498	58	121	1,063	760	91	4,451	28	260	(39,166)	1,307
	TOTAL	5,767,827	4,975,201	620,529	181,701	2,157	167	16,873	1,728	498	58	121	1,063	760	91	4,451	28	260	(39,166)	1,307
EXP_OM_CUSTACCT	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT	CUSTOMER	1.00000000	0.86257803	0.10758458	0.03150242	0.00037392	0.00002889	0.00292531	0.00029965	0.00008637	0.00001014	0.00002104	0.00018431	0.00013171	0.00001578	0.00077163	0.00000488	0.00004514	(0.00679042)	0.00022663
EXP_OM_CUSTACCT	TOTAL	1.00000000	0.86257803	0.10758458	0.03150242	0.00037392	0.00002889	0.00292531	0.00029965	0.00008637	0.00001014	0.00002104	0.00018431	0.00013171	0.00001578	0.00077163	0.00000488	0.00004514	(0.00679042)	0.00022663
A&G Regulatory																				
Acct 907-910	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	8,570,068	5,460,778	955,523	268,361	3,120	240	23,480	2,360	680	80	160	1,400	1,000	120	6,440	40	400	1,843,686	2,200
	TOTAL	8,570,068	5,460,778	955,523	268,361	3,120	240	23,480	2,360	680	80	160	1,400	1,000	120	6,440	40	400	1,843,686	2,200
EXP_OM_CUSTSERV	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV	CUSTOMER	1.00000000	0.63719189	0.11149540	0.03131374	0.00036406	0.00002800	0.00273978	0.00027538	0.00007935	0.00000933	0.00001867	0.00016336	0.00011669	0.00001400	0.00075146	0.00000467	0.00004667	0.21513085	0.00025671
EXP_OM_CUSTSERV	TOTAL	1.00000000	0.63719189	0.11149540	0.03131374	0.00036406	0.00002800	0.00273978	0.00027538	0.00007935	0.00000933	0.00001867	0.00016336	0.00011669	0.00001400	0.00075146	0.00000467	0.00004667	0.21513085	0.00025671
O&M Expense	PRODUCTION	64,750,639	31,875,152	1,578,905	5,780,786	181,875	17,060	4,394,578	819,001	369,955	16,634	153,342	2,510,406	13,269,283	2,394,606	1,348,945	22,586	17,525	-	-
less Purch. Power & Fuel	BULKTRAN	6,211,105	3,050,038	152,308	556,569	17,497	1,675	423,069	78,907	35,600	1,600	14,703	241,155	1,274,907	229,569	129,648	2,168	1,692	-	-
	SUBTRAN	1,366,479	663,255	32,320	117,312	3,619	462	88,629	16,491	9,798	-	3,080	50,523	352,086	-	26,621	443	357	1,220	263
	DISTPRI	37,926,902	25,337,007	1,196,430	4,342,662	134,169	-	3,256,346	606,596	-	-	115,978	1,871,146	-	-	981,561	16,371	13,281	45,538	9,817
	DISTSEC	15,669,543	11,710,768	565,814	1,706,496	-	-	1,087,423	-	-	-	29,368	-	-	-	400,901	-	4,165	141,576	23,030
	ENERGY	25,051,074	9,401,762	609,150	2,043,809	64,868	5,942	1,863,881	345,599	156,962	7,273	71,402	1,253,315	7,117,526	1,349,622	504,855	8,218	9,169	198,497	39,224
	CUSTOMER	18,773,750	12,804,605	2,255,807	644,539	87,732	13,777	107,346	25,838	47,627	8,293	743	15,359	70,041	12,432	29,416	436	945	2,328,493	320,320
	TOTAL	169,749,491	94,842,587	6,390,734	15,192,174	489,759	38,916	11,221,273	1,892,432	619,942	33,799	388,615	5,941,904	22,083,844	3,986,229	3,421,946	50,221	47,135	2,715,324	392,654
EXP_OM_LPP	PRODUCTION	0.38144820	0.18777760	0.00930139	0.03405480	0.00107143	0.00010050	0.02588861	0.00482476	0.00217942	0.00009799	0.00090334	0.01478889	0.07816980	0.01410671	0.00794668	0.00013305	0.00010324	-	-
EXP_OM_LPP	BULKTRAN	0.03658983	0.01796788	0.00089725	0.00327877	0.00010308	0.00000987	0.00249231	0.00046485	0.00020972	0.00000942	0.00008662	0.00142065	0.00751052	0.00135240	0.00076376	0.00001277	0.00000997	-	-
EXP_OM_LPP	SUBTRAN	0.00804997	0.00390726	0.00019040	0.00069109	0.00002132	0.00000272	0.00052212	0.00009715	0.00005772	-	0.00001814	0.00029763	0.00207415	-	0.00015682	0.00000261	0.00000211	0.00000719	0.00000155
EXP_OM_LPP	DISTPRI	0.22342867	0.14926117	0.00704821	0.02558277	0.00079039	-	0.01918325	0.00357348	-	-	0.00068323	0.01102298	-	-	0.00578241	0.00009644	0.00007824	0.00026827	0.00005783
EXP_OM_LPP	DISTSEC	0.09230981	0.06898853	0.00333323	0.01005303	-	-	0.00640605	-	-	-	0.00017301	-	-	-	0.00236172	-	0.00002454	0.00083403	0.00013567
EXP_OM_LPP	ENERGY	0.14757672	0.05538610	0.00358852	0.01204015	0.00038214	0.00003501	0.01098018	0.00203594	0.00092467	0.00004284	0.00042063	0.00738332	0.04192959	0.00795067	0.00297412	0.00004841	0.00005401	0.00116935	0.00023107
EXP_OM_LPP	CUSTOMER	0.11059680	0.07543236	0.01328904	0.00379700	0.00051683	0.00008116	0.00063238	0.00015221	0.00028057	0.00004886	0.00000438	0.00009048	0.00041261	0.00007324	0.00017329	0.00000257	0.00000557	0.01371723	0.00188702
EXP_OM_LPP	TOTAL	1.00000000	0.55872089	0.03764803	0.08949761	0.00288519	0.00022926	0.06610490	0.01114838	0.00365210	0.00019911	0.00228935	0.03500396	0.13009667	0.02348301	0.02015880	0.00029586	0.00027767	0.01599607	0.00231314
O&M Labor	PRODUCTION	12,848,663	6,329,033	312,867	1,146,013	36,072	3,383	871,148	162,320	73,350	3,298	30,431	498,005	2,631,971	475,290	267,528	4,481	3,472	-	-
	BULKTRAN	46,947	23,125	1,143	4,187	132	12	3,183	593	268	12	111	1,820	9,617	1,737	977	16	13	-	-
	SUBTRAN	10,326	5,028	243	883	27	3	667	124	74	-	23	381	2,656	-	201	3	3	9	2
	DISTPRI	6,616,059	4,421,794	208,432	756,829	23,390	-	567,489	105,695	-	-	20,231	326,275	-	-	171,124	2,855	2,313	7,924	1,708
	DISTSEC	2,730,529	2,041,620	98,427	296,996	-	-	189,247	-	-	-	5,117	-	-	-	69,803	-	724	24,594	4,001
	ENERGY	3,382,469	1,269,194	82,252	275,964	8,771	809	251,600	46,642	21,193	982	9,642	169,296	961,191	182,360	68,166	1,110	1,238	26,764	5,296
	CUSTOMER	2,549,486	1,821,611	311,738	89,764	15,005	2,371	16,750	4,302	8,228	1,436	116	2,561	12,107	2,155	4,585	73	131	201,053	55,502
	TOTAL	28,184,479	15,911,405	1,015,101	2,570,635	83,397	6,578	1,900,085	319,676	103,112	5,729	65,672	998,337	3,617,541	661,542	582,384	8,538	7,893	260,344	66,509
LABOR_M	PRODUCTION	0.45587726	0.22455738	0.01110067	0.04066113	0.00127987	0.00012002	0.03090879	0.00575921	0.00260248	0.00011703	0.00107972	0.01766948	0.09338372	0.01686355	0.00949204	0.00015899	0.00012317	-	-
LABOR_M	BULKTRAN	0.00166569	0.00082049	0.00004056	0.00014857	0.00000468	0.00000044	0.00011294	0.00002104	0.00000951	0.00000043	0.00000395	0.00006456	0.00034121	0.00006162	0.00003468	0.00000058	0.00000045	-	-
LABOR_M	SUBTRAN	0.00036638	0.00017838	0.00000861	0.00003132	0.00000097	0.00000012	0.00002366	0.00000440	0.00000262	-	0.00000083	0.00001353	0.00009423	-	0.00000712	0.00000012	0.00000010	0.00000032	0.00000007
LABOR_M	DISTPRI	0.23474121	0.15688756	0.00739527	0.02685268	0.00082989	-	0.02013482	0.00375011	-	-	0.00071779	0.01157639	-	-	0.00607157	0.00010130	0.00008207	0.00028115	0.00006061
LABOR_M	DISTSEC	0.09688058	0.07243775	0.00349225	0.01053757	-	-	0.00671458	-	-	-	0.00018155	-	-	-	0.00247663	-	0.00002570	0.00087262	0.00014194
LABOR_M	ENERGY	0.12001176	0.04503166	0.00291834	0.00979136	0.00031119	0.00002869	0.00892692	0.00165488	0.00075193	0.00003484	0.00034210	0.00600670	0.03410355	0.00647024	0.00241857	0.00003937	0.00004391	0.00094959	0.00018792
LABOR_M	CUSTOMER	0.09045711	0.06463169	0.01106061	0.00318486	0.00053239	0.00008412	0.00059430	0.00015263	0.00029194	0.00005095	0.00000413	0.00009087	0.00042955	0.00007646	0.00016266	0.00000258	0.00000464	0.00713347	0.00196925
LABOR_M	TOTAL	1.00000000	0.56454493	0.03601631	0.09120748	0.00295898	0.00023338	0.06741600	0.01134227	0.00365848	0.00020325	0.00233007	0.03542153	0.12835225	0.02347187	0.02066328	0.00030293	0.00028004	0.00923716	0.00235979

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
FEBRUARY 28, 2017

ALLOCATOR	FUNCTION		Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
Production O&M Labor	PRODUCTION		12,848,663	6,329,033	312,867	1,146,013	36,072	3,383	871,148	162,320	73,350	3,298	30,431	498,005	2,631,971	475,290	267,528	4,481	3,472	-	-
	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY		3,382,469	1,269,194	82,252	275,964	8,771	809	251,600	46,642	21,193	982	9,642	169,296	961,191	182,360	68,166	1,110	1,238	26,764	5,296
	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL		16,231,132	7,598,227	395,119	1,421,977	44,843	4,191	1,122,749	208,962	94,542	4,280	40,073	667,301	3,593,162	657,651	335,694	5,591	4,709	26,764	5,296
LABOR_PROD	PRODUCTION		0.79160609	0.38993170	0.01927572	0.07060585	0.00222242	0.00020841	0.05367143	0.01000055	0.00451906	0.00020322	0.00187488	0.03068210	0.16215575	0.02928264	0.01648241	0.00027607	0.00021388	-	-
LABOR_PROD	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD	ENERGY		0.20839391	0.07819504	0.00506754	0.01700216	0.00054037	0.00004982	0.01550111	0.00287361	0.00130569	0.00006050	0.00059403	0.01043031	0.05921895	0.01123522	0.00419972	0.00006836	0.00007626	0.00164892	0.00032631
LABOR_PROD	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD	TOTAL		1.00000000	0.46812674	0.02434326	0.08760801	0.00276279	0.00025823	0.06917253	0.01287416	0.00582476	0.00026372	0.00246891	0.04111241	0.22137471	0.04051786	0.02068213	0.00034444	0.00029014	0.00164892	0.00032631
Rent Revenues	PRODUCTION		61,946	30,514	1,508	5,525	174	16	4,200	783	354	16	147	2,401	12,689	2,291	1,290	22	17	-	-
	BULKTRAN		(41,458)	(20,421)	(1,010)	(3,698)	(116)	(11)	(2,811)	(524)	(237)	(11)	(98)	(1,607)	(8,492)	(1,534)	(863)	(14)	(11)	-	-
	SUBTRAN		(9,119)	(4,440)	(214)	(779)	(24)	(3)	(589)	(109)	(65)	-	(21)	(337)	(2,345)	-	(177)	(3)	(2)	(8)	(2)
	DISTPRI		4,135,312	2,763,806	130,279	473,050	14,620	-	354,704	66,064	-	-	12,645	203,935	-	-	106,960	1,785	1,446	4,953	1,068
	DISTSEC		3,026,252	2,262,733	109,087	329,161	-	-	209,743	-	-	-	5,671	-	-	-	77,362	-	803	27,258	4,434
	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER		131,517	59,861	16,114	4,571	1,512	246	1,320	393	856	150	9	233	1,258	226	366	7	7	39,619	4,771
	TOTAL		7,304,450	5,092,052	255,764	807,830	16,165	248	566,567	66,606	907	156	18,353	204,625	3,110	983	184,937	1,795	2,258	71,822	10,271
REV_RENT	PRODUCTION		0.00848058	0.00417739	0.00020650	0.00075641	0.00002381	0.00000223	0.00057499	0.00010714	0.00004841	0.00000218	0.00002009	0.00032870	0.00173720	0.00031371	0.00017658	0.00000296	0.00000229	-	-
REV_RENT	BULKTRAN		(0.00567571)	(0.00279576)	(0.00013820)	(0.00050623)	(0.00001593)	(0.00000149)	(0.00038482)	(0.00007170)	(0.00003240)	(0.00000146)	(0.00001344)	(0.00021999)	(0.00116264)	(0.00020995)	(0.00011818)	(0.00000198)	(0.00000153)	-	-
REV_RENT	SUBTRAN		(0.00124842)	(0.00060782)	(0.00002933)	(0.00010672)	(0.00000330)	(0.00000041)	(0.00008063)	(0.00001499)	(0.00000892)	-	(0.00000282)	(0.00004609)	(0.00032108)	-	(0.00002427)	(0.00000040)	(0.00000032)	(0.00000110)	(0.00000024)
REV_RENT	DISTPRI		0.56613602	0.37837285	0.01783551	0.06476183	0.00200148	-	0.04856005	0.00904431	-	-	0.00173114	0.02791930	-	-	0.01464309	0.00024430	0.00019793	0.00067807	0.00014617
REV_RENT	DISTSEC		0.41430249	0.30977457	0.01493433	0.04506310	-	-	0.02871438	-	-	-	0.00077638	-	-	-	0.01059113	-	0.00010990	0.00373168	0.00060701
REV_RENT	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REV_RENT	CUSTOMER		0.01800504	0.00819513	0.00220608	0.00062579	0.00020699	0.00003362	0.00018070	0.00005374	0.00011714	0.00002059	0.00000124	0.00003188	0.00017227	0.00003088	0.00005004	0.00000091	0.00000092	0.00542397	0.00065313
REV_RENT	TOTAL		1.00000000	0.69711636	0.03501488	0.11059417	0.00221305	0.00003395	0.07756468	0.00911850	0.00012424	0.00002131	0.00251258	0.02801381	0.00042575	0.00013464	0.02531839	0.00024579	0.00030919	0.00983262	0.00140608
Total Revenues	PRODUCTION		180,626,886	78,898,887	5,609,136	19,003,211	550,740	54,095	14,517,158	2,819,436	1,194,136	51,971	416,976	7,366,047	39,610,184	6,294,454	4,111,785	64,330	64,340	-	-
	BULKTRAN		31,039,870	10,235,344	1,323,089	4,141,080	118,822	29,076	3,143,302	626,511	253,259	10,665	69,735	1,426,329	7,759,656	1,055,429	820,317	11,611	15,645	-	-
	SUBTRAN		7,005,820	2,320,455	277,203	867,095	24,460	9,026	654,371	129,699	69,266	-	14,845	299,933	2,148,410	-	168,569	2,395	3,260	13,780	3,054
	DISTPRI		64,428,545	37,341,820	2,883,786	9,486,881	269,923	-	7,134,917	1,393,577	-	-	197,184	3,547,323	-	-	1,945,746	29,634	33,358	135,273	29,122
	DISTSEC		28,768,644	18,741,902	1,560,885	4,233,886	-	-	2,703,932	-	-	-	55,361	-	-	-	895,087	-	12,009	486,184	79,398
	ENERGY		233,520,892	89,055,697	5,695,776	19,047,569	556,145	31,297	17,573,101	3,318,629	1,464,811	67,701	660,356	11,408,374	65,436,319	12,010,751	4,681,074	76,159	86,107	1,988,430	362,596
	CUSTOMER		22,985,904	10,928,594	3,186,842	838,440	203,972	51,390	207,970	62,489	120,914	20,330	1,126	30,617	160,824	24,321	51,961	832	1,384	6,077,642	1,016,257
	TOTAL		568,376,561	247,522,700	20,536,717	57,618,162	1,724,061	174,883	45,934,753	8,350,341	3,102,386	150,666	1,415,583	24,078,623	115,115,392	19,384,955	12,674,538	184,962	216,104	8,701,308	1,490,427
REV	PRODUCTION		0.31779440	0.13881446	0.00986870	0.03343419	0.00096897	0.00009517	0.02554144	0.00496051	0.00210096	0.00009144	0.00073363	0.01295980	0.06969004	0.01107444	0.00723426	0.00011318	0.00011320	-	-
REV	BULKTRAN		0.05461145	0.01800803	0.00232784	0.00728580	0.00020905	0.00005116	0.00553032	0.00110228	0.00044558	0.00001876	0.00012269	0.00250948	0.01365231	0.00185692	0.00144326	0.00002043	0.00002753	-	-
REV	SUBTRAN		0.01232602	0.00408260	0.00048771	0.00152556	0.00004303	0.00001588	0.00115130	0.00022819	0.00012187	-	0.00002612	0.00052770	0.00377991	-	0.00029658	0.00000421	0.00000573	0.00002424	0.00000537
REV	DISTPRI		0.11335539	0.06569909	0.00507372	0.01669119	0.00047490	-	0.01255315	0.00245185	-	-	0.00034692	0.00624115	-	-	0.00342334	0.00005214	0.00005869	0.00023800	0.00005124
REV	DISTSEC		0.05061546	0.03297445	0.00274622	0.00744909	-	-	0.00475729	-	-	-	0.00009740	-	-	-	0.00157481	-	0.00002113	0.00085539	0.00013969
REV	ENERGY		0.41085595	0.15668432	0.01002113	0.03351223	0.00097848	0.00005506	0.03091806	0.00583879	0.00257718	0.00011911	0.00116183	0.02007186	0.11512846	0.02113168	0.00823587	0.00013399	0.00015150	0.00349844	0.00063795
REV	CUSTOMER		0.04044133	0.01922773	0.00560692	0.00147515	0.00035887	0.00009042	0.00036590	0.00010994	0.00021274	0.00003577	0.00000198	0.00005387	0.00028295	0.00004279	0.00009142	0.00000146	0.00000244	0.01069298	0.00178800
REV	TOTAL		1.00000000	0.43549069	0.03613224	0.10137322	0.00303331	0.00030769	0.08081746	0.01469156	0.00545833	0.00026508	0.00249057	0.04236386	0.20253367	0.03410583	0.02229954	0.00032542	0.00038021	0.01530906	0.00262225
EXP_OTHTAX_PSC	PRODUCTION	Same as RSALE	0.44886785	0.20017735	0.01326170	0.04578679	0.00135291	0.00013172	0.03510166	0.00671140	0.00288962	0.00012691	0.00104558	0.01815100	0.09773244	0.01596052	0.01012442	0.00016051	0.00015333	-	-
EXP_OTHTAX_PSC	BULKTRAN		(0.03516041)	(0.02724751)	0.00026481	(0.00042317)	(0.00003632)	0.00003230	(0.00033218)	0.00001924	(0.00005051)	(0.00000372)	(0.00009131)	(0.00092502)	(0.00446979)	(0.00149920)	(0.00039210)	(0.00001082)	0.00000490	-	-
EXP_OTHTAX_PSC	SUBTRAN		(0.00738036)	(0.00573594)	0.00004906	(0.00010081)	(0.00000776)	0.00001094	(0.00007796)	0.00000153	(0.00001478)	-	(0.00001865)	(0.00019159)	(0.00122352)	-	(0.00008025)	(0.00000217)	0.00000094	0.00000858	0.00000202
EXP_OTHTAX_PSC	DISTPRI		0.11813783	0.06722776	0.00538626	0.01782530	0.00050702	-	0.01347989	0.00261745	-	-	0.00036637	0.00662511	-	-	0.00366808	0.00005555	0.00006369	0.00025935	0.00005600
EXP_OTHTAX_PSC	DISTSEC		0.05026682	0.03193862	0.00283710	0.00771898	-	-	0.00495758	-	-	-	0.00009861	-	-	-	0.00163079	-	0.00002236	0.00091316	0.00014962
EXP_OTHTAX_PSC	ENERGY		0.38025008	0.14469868	0.00922499	0.03099848	0.00089135	0.00004239	0.02879910	0.00541411	0.00238707	0.00011061	0.00107648	0.01849092	0.10679770	0.01948536	0.00766945	0.00012476	0.00014148	0.00330348	0.00059368
EXP_OTHTAX_PSC	CUSTOMER		0.04501818	0.02127709	0.00621130	0.00164990	0.00040208	0.00010162	0.00041089	0.00012244	0.00023790	0.00004011	0.00000222	0.00006021	0.00031767	0.00004802	0.00010294	0.00000165	0.00000275	0.01201028	0.00201912
EXP_OTHTAX_PSC	TOTAL		1.00000000	0.43233605	0.03723521	0.10345548	0.00310928	0.00031897	0.08233897	0.01488617	0.00544931	0.00027391	0.00247931	0.04221064	0.19915450	0.03399471	0.02272331	0.00032947	0.00038945	0.01649485	0.00282043
		Check (SB=0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RBASE			500,400,211	216,341,050	18,632,507	51,769,142	1,555,884	159,611	41,202,438	7,449,041	2,726,835	137,064	1,240,647	21,122,212	99,656,952	17,010,960	11,370,750	164,869	194,881	8,254,025	1,411,343
Initial Other Revenue			67,976,350	31,181,650	1,904,210	5,849,020	168,177	15,272	4,732,315	901,300	375,551	13,602	174,936	2,956,411	15,458,440	2,373,995	1,303,788	20,093	21,223	447,283	79,084
Initial Total Expense			523,190,005	241,412,671	16,628,173	48,588,033	1,466,147	126,548	39,301,642	7,118,741	2,736,876	133,506	1,319,439	21,768,652	105,654,699	18,498,515	11,097,773	168,140	178,771	5,881,311	1,110,367
		Check (SB=0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Net Operating Income			45,186,556	6,110,029	3,908,545	9,030,129	257,913	48,335	6,633,111	1,231,600	365,510	17,161	96,144	2,309,971	9,460,692	886,440	1,576,764	16,822	37,333	2,819,997	380,060
RATEBASE	PRODUCTION		0.40296310	0.19690456	0.00968220	0.03594287	0.00106487	(0.00001354)	0.02753372	0.00499407	0.00217447	0.00010546	0.00097297	0.01575768	0.08398373	0.01506187	0.00854389	0.00014327	0.00011100	-	-
RATEBASE	BULKTRAN		0.18413645	0.08980679	0.00441678	0.01643081	0.00048325	(0.00001438)	0.01259734	0.00227380	0.00098479	0.00004835	0.00044611	0.00721765	0.03850715	0.00690441	0.00391702	0.00006569	0.00005089	-	-
RATEBASE	SUBTRAN		0.03863960	0.01860933	0.00089330	0.00330292	0.00009501	(0.00000455)	0.00251787	0.00045274	0.00025764	-	0.00008919	0.00144268	0.01015046	-	0.00076773	0.00001281	0.00001027	0.00003467	0.00000752
RATEBASE	DISTPRI		0.19946522	0.13280120	0.00622731	0.02293848	0.00066502	-	0.01733979	0.00313670	-	-	0.00062593	0.00998577	-	-	0.00528835	0.00008833	0.00007157	0.00024391	0.00005283
RATEBASE	DISTSEC		0.10130639	0.07550909	0.00362156	0.01108757	-	-	0.00712292	-	-	-	0.00019505	-	-	-	0.00265768	-	0.00002761	0.00093244	0.00015246
RATEBASE	ENERGY		0.02426108	0.00930138	0.00058325	0.00196324	0.00005691	0.00000285	0.00181339	0.00034043	0.00014988	0.00000702	0.00006891	0.00118391	0.00679542	0.00125260	0.00048571	0.00000793	0.00000885	0.00020247	0.00003692
RATEBASE	CUSTOMER		0.04922817	0.02313231	0.00597131	0.00172031	0.00051753	(0.00001948)	0.00049013	0.00014080	0.00029351	0.00005599	0.00000342	0.00008618	0.00046766	0.00008323	0.00013722	0.00000249	0.00000259	0.01435307	0.00178989
RATEBASE	TOTAL		1.00000000	0.54606467	0.03139572	0.09338620	0.00288260	(0.00004908)	0.06941516	0.01133855	0.00386030	0.00021682	0.00240157	0.03567387	0.13990442	0.02330211	0.02179760	0.00032053	0.00028278	0.01576657	0.00203962
NOI - Functionalized	PRODUCTION		18,332,141	2,203,205	1,205,366	3,475,554	95,277	13,329	2,631,042	542,459	205,889	8,347	38,952	1,020,348	5,679,193	572,972	618,036	7,519	14,655	-	-
	BULKTRAN		8,394,075	1,004,866	549,858	1,588,804	43,237	14,158	1,203,765	246,982	93,244	3,827	17,859	467,361	2,603,951	262,652	283,344	3,448	6,719	-	-
	SUBTRAN		1,814,516	208,224	111,209	319,381	8,501	4,476	240,600	49,176	24,395	-	3,570	93,417	686,400	-	55,535	673	1,355	6,201	1,402
	DISTPRI		7,658,180	1,485,940	775,256	2,218,074	59,501	-	1,656,940	340,711	-	-	25,058	646,603	-	-	382,541	4,636	9,449	43,626	9,845
	DISTSEC		3,447,408	844,887	450,858	1,072,130	-	-	680,646	-	-	-	7,809	-	-	-	192,248	-	3,645	166,776	28,408
	ENERGY		1,260,219	104,075	72,611	189,838	5,092	(2,811)	173,283	36,978	14,191	555	2,759	76,661	459,524	47,650	35,135	416	1,168	36,214	6,879
	CUSTOMER		4,280,017	258,832	743,386	166,348	46,305	19,182	46,835	15,294	27,791	4,431	137	5,580	31,624	3,166	9,926	131	342	2,567,179	333,526
	TOTAL		45,186,556	6,110,029	3,908,545	9,030,129	257,913	48,335	6,633,111	1,231,600	365,510	17,161	96,144	2,309,971	9,460,692	886,440	1,576,764	16,822	37,333	2,819,997	380,060

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
FEBRUARY 28, 2017

ALLOCATOR	FUNCTION		Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
Total Expenses	PRODUCTION		162,294,745	76,695,682	4,403,770	15,527,657	455,463	40,765	11,886,117	2,276,977	988,247	43,624	378,024	6,345,698	33,930,991	5,721,482	3,493,749	56,811	49,686	-	-
	BULKTRAN		22,645,795	9,230,478	773,231	2,552,276	75,584	14,918	1,939,537	379,529	160,015	6,838	51,876	958,968	5,155,705	792,777	536,973	8,164	8,926	-	-
	SUBTRAN		5,191,304	2,112,232	165,994	547,715	15,959	4,549	413,771	80,522	44,871	-	11,274	206,516	1,462,010	-	113,034	1,722	1,904	7,580	1,652
	DISTPRI		56,770,365	35,855,881	2,108,530	7,268,808	210,422	-	5,477,977	1,052,866	-	-	172,126	2,900,720	-	-	1,563,204	24,998	23,910	91,646	19,278
	DISTSEC		25,321,236	17,897,016	1,110,026	3,161,756	-	-	2,023,287	-	-	-	47,552	-	-	-	702,839	-	8,364	319,407	50,989
	ENERGY		232,260,673	88,951,622	5,623,165	18,857,730	551,053	34,107	17,399,818	3,281,651	1,450,620	67,146	657,598	11,331,713	64,976,795	11,963,101	4,645,939	75,743	84,939	1,952,216	355,717
	CUSTOMER		18,705,887	10,669,761	2,443,456	672,092	157,667	32,208	161,135	47,195	93,123	15,898	989	25,037	129,199	21,154	42,035	702	1,043	3,510,462	682,731
	TOTAL		523,190,005	241,412,671	16,628,173	48,588,033	1,466,147	126,548	39,301,642	7,118,741	2,736,876	133,506	1,319,439	21,768,652	105,654,699	18,498,515	11,097,773	168,140	178,771	5,881,311	1,110,367
Total Revenue	PRODUCTION		180,626,886	78,898,887	5,609,136	19,003,211	550,740	54,095	14,517,158	2,819,436	1,194,136	51,971	416,976	7,366,047	39,610,184	6,294,454	4,111,785	64,330	64,340	-	-
	BULKTRAN		31,039,870	10,235,344	1,323,089	4,141,080	118,822	29,076	3,143,302	626,511	253,259	10,665	69,735	1,426,329	7,759,656	1,055,429	820,317	11,611	15,645	-	-
	SUBTRAN		7,005,820	2,320,455	277,203	867,095	24,460	9,026	654,371	129,699	69,266	-	14,845	299,933	2,148,410	-	168,569	2,395	3,260	13,780	3,054
	DISTPRI		64,428,545	37,341,820	2,883,786	9,486,881	269,923	-	7,134,917	1,393,577	-	-	197,184	3,547,323	-	-	1,945,746	29,634	33,358	135,273	29,122
	DISTSEC		28,768,644	18,741,902	1,560,885	4,233,886	-	-	2,703,932	-	-	-	55,361	-	-	-	895,087	-	12,009	486,184	79,398
	ENERGY		233,520,892	89,055,697	5,695,776	19,047,569	556,145	31,297	17,573,101	3,318,629	1,464,811	67,701	660,356	11,408,374	65,436,319	12,010,751	4,681,074	76,159	86,107	1,988,430	362,596
	CUSTOMER		22,985,904	10,928,594	3,186,842	838,440	203,972	51,390	207,970	62,489	120,914	20,330	1,126	30,617	160,824	24,321	51,961	832	1,384	6,077,642	1,016,257
	TOTAL		568,376,561	247,522,700	20,536,717	57,618,162	1,724,061	174,883	45,934,753	8,350,341	3,102,386	150,666	1,415,583	24,078,623	115,115,392	19,384,955	12,674,538	184,962	216,104	8,701,308	1,490,427
Total Other Revenue	PRODUCTION		(43,986,682)	(21,269,899)	(1,027,020)	(3,908,510)	(126,256)	(11,818)	(3,047,718)	(538,949)	(251,833)	(11,535)	(106,233)	(1,716,718)	(9,295,150)	(1,692,194)	(954,476)	(15,987)	(12,386)	-	-
	BULKTRAN		48,634,145	23,870,005	1,190,580	4,352,834	136,999	12,915	3,309,526	616,883	278,533	12,526	115,426	1,889,208	9,996,340	1,805,627	1,016,526	17,026	13,191	-	-
	SUBTRAN		10,698,952	5,190,719	252,653	917,543	28,340	3,552	693,384	128,933	76,661	-	24,175	395,803	2,760,661	-	208,729	3,480	2,787	9,488	2,043
	DISTPRI		5,312,351	3,701,034	188,500	567,095	16,210	-	389,576	83,804	-	-	13,852	232,117	-	-	110,239	1,839	1,490	5,493	1,100
	DISTSEC		3,615,119	2,759,810	141,201	371,304	-	-	223,161	-	-	-	6,015	-	-	-	79,041	-	820	29,237	4,530
	ENERGY		43,243,670	16,648,448	1,079,591	3,535,923	110,111	10,083	3,162,027	609,409	270,321	12,351	121,686	2,155,513	11,994,726	2,260,273	843,278	13,727	15,312	335,370	65,521
	CUSTOMER	Check (SB=0)	458,795	281,533	78,706	12,831	2,772	539	2,359	1,220	1,868	259	16	487	1,863	289	451	8	8	67,695	5,890
	TOTAL	-	67,976,350	31,181,650	1,904,210	5,849,020	168,177	15,272	4,732,315	901,300	375,551	13,602	174,936	2,956,411	15,458,440	2,373,995	1,303,788	20,093	21,223	447,283	79,084
Firm Sales Revenue	PRODUCTION		224,613,568	100,168,786	6,636,156	22,911,721	676,996	65,913	17,564,876	3,358,385	1,445,969	63,505	523,209	9,082,764	48,905,334	7,986,648	5,066,261	80,318	76,726	-	-
	BULKTRAN		(17,594,275)	(13,634,661)	132,509	(211,754)	(18,177)	16,161	(166,224)	9,629	(25,274)	(1,861)	(45,691)	(462,879)	(2,236,685)	(750,198)	(196,208)	(5,415)	2,454	-	-
	SUBTRAN		(3,693,132)	(2,870,264)	24,550	(50,448)	(3,881)	5,473	(39,012)	765	(7,395)	-	(9,330)	(95,870)	(612,252)	-	(40,159)	(1,085)	472	4,292	1,011
	DISTPRI		59,116,193	33,640,787	2,695,286	8,919,786	253,712	-	6,745,341	1,309,773	-	-	183,332	3,315,206	-	-	1,835,506	27,795	31,868	129,779	28,022
	DISTSEC		25,153,525	15,982,092	1,419,684	3,862,582	-	-	2,480,772	-	-	-	49,346	-	-	-	816,046	-	11,189	456,946	74,868
	ENERGY		190,277,222	72,407,249	4,616,185	15,511,646	446,033	21,213	14,411,074	2,709,220	1,194,490	55,350	538,670	9,252,861	53,441,593	9,750,478	3,837,796	62,432	70,796	1,653,061	297,075
	CUSTOMER		22,527,109	10,647,060	3,108,136	825,609	201,200	50,851	205,611	61,270	119,046	20,070	1,110	30,130	158,961	24,031	51,509	824	1,376	6,009,947	1,010,367
	TOTAL		500,400,211	216,341,050	18,632,507	51,769,142	1,555,884	159,611	41,202,438	7,449,041	2,726,835	137,064	1,240,647	21,122,212	99,656,952	17,010,960	11,370,750	164,869	194,881	8,254,025	1,411,343
RSALE	PRODUCTION		0.44886785	0.20017735	0.01326170	0.04578679	0.00135291	0.00013172	0.03510166	0.00671140	0.00288962	0.00012691	0.00104558	0.01815100	0.09773244	0.01596052	0.01012442	0.00016051	0.00015333	-	-
RSALE	BULKTRAN		(0.03516041)	(0.02724751)	0.00026481	(0.00042317)	(0.00003632)	0.00003230	(0.00033218)	0.00001924	(0.00005051)	(0.00000372)	(0.00009131)	(0.00092502)	(0.00446979)	(0.00149920)	(0.00039210)	(0.00001082)	0.00000490	-	-
RSALE	SUBTRAN		(0.00738036)	(0.00573594)	0.00004906	(0.00010081)	(0.00000776)	0.00001094	(0.00007796)	0.00000153	(0.00001478)	-	(0.00001865)	(0.00019159)	(0.00122352)	-	(0.00008025)	(0.00000217)	0.00000094	0.00000858	0.00000202
RSALE	DISTPRI		0.11813783	0.06722776	0.00538626	0.01782530	0.00050702	-	0.01347989	0.00261745	-	-	0.00036637	0.00662511	-	-	0.00366808	0.00005555	0.00006369	0.00025935	0.00005600
RSALE	DISTSEC		0.05026682	0.03193862	0.00283710	0.00771898	-	-	0.00495758	-	-	-	0.00009861	-	-	-	0.00163079	-	0.00002236	0.00091316	0.00014962
RSALE	ENERGY		0.38025008	0.14469868	0.00922499	0.03099848	0.00089135	0.00004239	0.02879910	0.00541411	0.00238707	0.00011061	0.00107648	0.01849092	0.10679770	0.01948536	0.00766945	0.00012476	0.00014148	0.00330348	0.00059368
RSALE	CUSTOMER		0.04501818	0.02127709	0.00621130	0.00164990	0.00040208	0.00010162	0.00041089	0.00012244	0.00023790	0.00004011	0.00000222	0.00006021	0.00031767	0.00004802	0.00010294	0.00000165	0.00000275	0.01201028	0.00201912
RSALE	TOTAL		1.00000000	0.43233605	0.03723521	0.10345548	0.00310928	0.00031897	0.08233897	0.01488617	0.00544931	0.00027391	0.00247931	0.04221064	0.19915450	0.03399471	0.02272331	0.00032947	0.00038945	0.01649485	0.00282043

Calculation of CUST_DEP Allocator

ALLOCATOR	FUNCTION	Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
CUST_DEP	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	1.00000000	0.72904762	0.04855935	0.08419810	0.01083654	0.01391175	0.03827204	0.02092041	0.01388742	-	-	0.01613107	0.01066522	0.00806028	0.00107493	-	-	0.00443527	-
	TOTAL	1.00000000	0.72904762	0.04855935	0.08419810	0.01083654	0.01391175	0.03827204	0.02092041	0.01388742	-	-	0.01613107	0.01066522	0.00806028	0.00107493	-	-	0.00443527	-
RB_GUP	PRODUCTION	0.38515569	0.18972114	0.00937859	0.03435325	0.00108132	0.00010140	0.02611382	0.00486576	0.00219875	0.00009888	0.00091222	0.01492837	0.07889683	0.01424746	0.00801951	0.00013432	0.00010407	-	-
	BULKTRAN	0.20414100	0.10055638	0.00497086	0.01820798	0.00057312	0.00005375	0.01384090	0.00257896	0.00116539	0.00005241	0.00048350	0.00791236	0.04181706	0.00755147	0.00425052	0.00007119	0.00005516	-	-
	SUBTRAN	0.04484365	0.02183291	0.00105368	0.00383325	0.00011841	0.00001475	0.00289608	0.00053838	0.00032034	-	0.00010113	0.00165549	0.01153331	-	0.00087164	0.00001453	0.00001164	0.00003958	0.00000853
	DISTPRI	0.20575689	0.13751611	0.00648215	0.02353709	0.00072742	-	0.01764870	0.00328707	-	-	0.00062917	0.01014701	-	-	0.00532189	0.00008879	0.00007193	0.00024644	0.00005312
	DISTSEC	0.10587947	0.07916623	0.00381663	0.01151636	-	-	0.00733827	-	-	-	0.00019841	-	-	-	0.00270668	-	0.00002809	0.00095367	0.00015513
	ENERGY	0.00325440	0.00122114	0.00007914	0.00026552	0.00000844	0.00000078	0.00024207	0.00004488	0.00002039	0.00000094	0.00000928	0.00016289	0.00092480	0.00017546	0.00006559	0.00000107	0.00000119	0.00002575	0.00000510
	CUSTOMER	0.05096889	0.02383502	0.00624438	0.00177260	0.00057219	0.00009288	0.00050304	0.00014896	0.00032357	0.00005686	0.00000346	0.00008837	0.00047584	0.00008529	0.00013925	0.00000252	0.00000261	0.01480873	0.00181331
	TOTAL	1.00000000	0.55384894	0.03202544	0.09348605	0.00308089	0.00026355	0.06858288	0.01146401	0.00402843	0.00020908	0.00233716	0.03489449	0.13364783	0.02205967	0.02137508	0.00031243	0.00027469	0.01607417	0.00203519
CUST_DEP_FXNL	PRODUCTION	0.35389035	0.24973551	0.01422052	0.03094022	0.00380337	0.00535263	0.01457257	0.00887942	0.00757986	-	-	0.00690110	0.00629604	0.00520581	0.00040329	-	-	-	-
CUST_DEP_FXNL	BULKTRAN	0.18756968	0.13236532	0.00753719	0.01639900	0.00201587	0.00283701	0.00772378	0.00470629	0.00401749	-	-	0.00365774	0.00333704	0.00275919	0.00021375	-	-	-	-
CUST_DEP_FXNL	SUBTRAN	0.04042765	0.02873930	0.00159768	0.00345242	0.00041647	0.00077842	0.00161613	0.00098247	0.00110433	-	-	0.00076530	0.00092037	-	0.00004383	-	-	0.00001092	-
CUST_DEP_FXNL	DISTPRI	0.23547603	0.18101649	0.00982872	0.02119865	0.00255858	-	0.00984869	0.00599850	-	-	-	0.00469077	-	-	0.00026763	-	-	0.00006800	-
CUST_DEP_FXNL	DISTSEC	0.12486240	0.10420884	0.00578706	0.01037220	-	-	0.00409505	-	-	-	-	-	-	-	0.00013612	-	-	0.00026314	-
CUST_DEP_FXNL	ENERGY	0.00254819	0.00160742	0.00011999	0.00023914	0.00002968	0.00004106	0.00013509	0.00008189	0.00007029	-	-	0.00007530	0.00007380	0.00006411	0.00000330	-	-	0.00000711	-
CUST_DEP_FXNL	CUSTOMER	0.05522571	0.03137474	0.00946820	0.00159649	0.00201257	0.00490262	0.00028072	0.00027183	0.00111545	-	-	0.00004085	0.00003797	0.00003116	0.00000700	-	-	0.00408610	-
CUST_DEP_FXNL	TOTAL	1.00000000	0.72904762	0.04855935	0.08419810	0.01083654	0.01391175	0.03827204	0.02092041	0.01388742	-	-	0.01613107	0.01066522	0.00806028	0.00107493	-	-	0.00443527	-

REVYEC_EXP_OM allocator is the basis to allocate the O&M portion of the Customer Annualization (Year End Customer) Adjustment. It is spread to the functions within each tariff class using total O&M.

ALLOCATOR	FUNCTION	Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
REVYEC Total	TOTAL	1.00000000	0.15204539	0.01938658	0.03432596	0.04874018	0.01828371	(0.15576802)	(0.07392871)	-	-	-	0.18795604	0.49731046	0.33234975	0.01258496	-	-	(0.08252509)	0.00923880
EXP_OM	PRODUCTION	0.28183566	0.14137332	0.00677581	0.02484464	0.00071895	0.00004784	0.01911575	0.00362153	0.00159300	0.00007163	0.00066042	0.01059207	0.05653510	0.00992077	0.00579212	0.00009727	0.00007545	-	-
	BULKTRAN	0.01524355	0.00761792	0.00036967	0.00135151	0.00003906	0.00000267	0.00103978	0.00019722	0.00008659	0.00000389	0.00003570	0.00057417	0.00306563	0.00053611	0.00031424	0.00000527	0.00000412	-	-
	SUBTRAN	0.00335639	0.00165675	0.00007844	0.00028486	0.00000808	0.00000074	0.00021782	0.00004122	0.00002383	-	0.00000748	0.00012029	0.00084663	-	0.00006452	0.00000108	0.00000087	0.00000316	0.00000063
	DISTPRI	0.08374901	0.05649247	0.00258481	0.00939298	0.00026685	-	0.00712887	0.00135015	-	-	0.00025120	0.00397150	-	-	0.00212051	0.00003546	0.00002879	0.00010467	0.00002076
	DISTSEC	0.03466881	0.02607277	0.00122091	0.00368638	-	-	0.00237758	-	-	-	0.00006352	-	-	-	0.00086494	-	0.00000902	0.00032505	0.00004865
	ENERGY	0.55369642	0.21265309	0.01334008	0.04481910	0.00130977	0.00008557	0.04135941	0.00779481	0.00344837	0.00015978	0.00156882	0.02698719	0.15473314	0.02853937	0.01105962	0.00018055	0.00020140	0.00461607	0.00084027
	CUSTOMER	0.02745016	0.01964539	0.00338631	0.00097878	0.00019248	0.00002183	0.00021382	0.00006005	0.00011615	0.00002031	0.00000147	0.00003405	0.00016897	0.00002928	0.00005782	0.00000099	0.00000142	0.00175362	0.00076742
	TOTAL	1.00000000	0.46551171	0.02775604	0.08535824	0.00253518	0.00015865	0.07145303	0.01306498	0.00526794	0.00025560	0.00258861	0.04227927	0.21534948	0.03902553	0.02027379	0.00032061	0.00032107	0.00680256	0.00167772
REVYEC_EXP_OM	PRODUCTION	0.28379745	0.04617534	0.00473266	0.00999103	0.01382221	0.00551292	(0.04167245)	(0.02049258)	-	-	-	0.04708796	0.13055753	0.08448739	0.00359546	-	-	-	-
REVYEC_EXP_OM	BULKTRAN	0.01535871	0.00248817	0.00025820	0.00054349	0.00075088	0.00030798	(0.00226672)	(0.00111600)	-	-	-	0.00255251	0.00707951	0.00456563	0.00019507	-	-	-	-
REVYEC_EXP_OM	SUBTRAN	0.00273797	0.00054113	0.00005479	0.00011455	0.00015532	0.00008511	(0.00047484)	(0.00023323)	-	-	-	0.00053478	0.00195514	-	0.00004005	-	-	(0.00003828)	0.00000345
REVYEC_EXP_OM	DISTPRI	0.02380019	0.01845157	0.00180540	0.00377729	0.00513028	-	(0.01554097)	(0.00763988)	-	-	-	0.01765563	-	-	0.00131631	-	-	(0.00126974)	0.00011431
REVYEC_EXP_OM	DISTSEC	0.00252948	0.00851588	0.00085276	0.00148244	-	-	(0.00518314)	-	-	-	-	-	-	-	0.00053691	-	-	(0.00394328)	0.00026790
REVYEC_EXP_OM	ENERGY	0.67341125	0.06945673	0.00931756	0.01802355	0.02518095	0.00986155	(0.09016376)	(0.04410725)	-	-	-	0.11997381	0.35732807	0.24304738	0.00686526	-	-	(0.05599977)	0.00462716
REVYEC_EXP_OM	CUSTOMER	(0.00163505)	0.00641657	0.00236521	0.00039361	0.00370055	0.00251615	(0.00046613)	(0.00033977)	-	-	-	0.00015135	0.00039021	0.00024935	0.00003589	-	-	(0.02127402)	0.00422597
REVYEC_EXP_OM	TOTAL	1.00000000	0.15204539	0.01938658	0.03432596	0.04874018	0.01828371	(0.15576802)	(0.07392871)	-	-	-	0.18795604	0.49731046	0.33234975	0.01258496	-	-	(0.08252509)	0.00923880

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
FEBRUARY 28, 2017

ALLOCATOR	FUNCTION	Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
REVYEC_FXNL is a spreading of the REVYEC allocator to each function within the tariff classes using the RSALE allocator.																				
REVYEC TOTAL		1.00000000	0.15204539	0.01938658	0.03432596	0.04874018	0.01828371	(0.15576802)	(0.07392871)	-	-	-	0.18795604	0.49731046	0.33234975	0.01258496	-	-	(0.08252509)	0.00923880
RSALE	PRODUCTION	0.44886785	0.20017735	0.01326170	0.04578679	0.00135291	0.00013172	0.03510166	0.00671140	0.00288962	0.00012691	0.00104558	0.01815100	0.09773244	0.01596052	0.01012442	0.00016051	0.00015333	-	-
	BULKTRAN	(0.03516041)	(0.02724751)	0.00026481	(0.00042317)	(0.00003632)	0.00003230	(0.00033218)	0.00001924	(0.00005051)	(0.00000372)	(0.00009131)	(0.00092502)	(0.00446979)	(0.00149920)	(0.00039210)	(0.00001082)	0.00000490	-	-
	SUBTRAN	(0.00738036)	(0.00573594)	0.00004906	(0.00010081)	(0.00000776)	0.00001094	(0.00007796)	0.00000153	(0.00001478)	-	(0.00001865)	(0.00019159)	(0.00122352)	-	(0.00008025)	(0.00000217)	0.00000094	0.00000858	0.00000202
	DISTPRI	0.11813783	0.06722776	0.00538626	0.01782530	0.00050702	-	0.01347989	0.00261745	-	-	0.00036637	0.00662511	-	-	0.00366808	0.00005555	0.00006369	0.00025935	0.00005600
	DISTSEC	0.05026682	0.03193862	0.00283710	0.00771898	-	-	0.00495758	-	-	-	0.00009861	-	-	-	0.00163079	-	0.00002236	0.00091316	0.00014962
	ENERGY	0.38025008	0.14469868	0.00922499	0.03099848	0.00089135	0.00004239	0.02879910	0.00541411	0.00238707	0.00011061	0.00107648	0.01849092	0.10679770	0.01948536	0.00766945	0.00012476	0.00014148	0.00330348	0.00059368
	CUSTOMER	0.04501818	0.02127709	0.00621130	0.00164990	0.00040208	0.00010162	0.00041089	0.00012244	0.00023790	0.00004011	0.00000222	0.00006021	0.00031767	0.00004802	0.00010294	0.00000165	0.00000275	0.01201028	0.00201912
	TOTAL	1.00000000	0.43233605	0.03723521	0.10345548	0.00310928	0.00031897	0.08233897	0.01488617	0.00544931	0.00027391	0.00247931	0.04221064	0.19915450	0.03399471	0.02272331	0.00032947	0.00038945	0.01649485	0.00282043
REVYEC_FXNL	PRODUCTION	0.50803528	0.07039904	0.00690473	0.01519181	0.02120782	0.00755040	(0.06640495)	(0.03333061)	-	-	-	0.08082299	0.24404855	0.15603825	0.00560725	-	-	-	-
REVYEC_FXNL	BULKTRAN	(0.03792488)	(0.00958250)	0.00013787	(0.00014041)	(0.00056942)	0.00185126	0.00062842	(0.00009556)	-	-	-	(0.00411893)	(0.01116156)	(0.01465691)	(0.00021716)	-	-	-	-
REVYEC_FXNL	SUBTRAN	(0.00536894)	(0.00201723)	0.00002554	(0.00003345)	(0.00012157)	0.00062699	0.00014749	(0.00000759)	-	-	-	(0.00085310)	(0.00305527)	-	(0.00004445)	-	-	(0.00004291)	0.00000662
REVYEC_FXNL	DISTPRI	0.03222714	0.02364288	0.00280437	0.00591434	0.00794788	-	(0.02550112)	(0.01299897)	-	-	-	0.02950036	-	-	0.00203151	-	-	(0.00129755)	0.00018344
REVYEC_FXNL	DISTSEC	0.00271650	0.01123228	0.00147714	0.00256112	-	-	(0.00937869)	-	-	-	-	-	-	-	0.00090319	-	-	(0.00456862)	0.00049009
REVYEC_FXNL	ENERGY	0.53019480	0.05088812	0.00480301	0.01028513	0.01397260	0.00242999	(0.05448184)	(0.02688791)	-	-	-	0.08233660	0.26668549	0.19049889	0.00424761	-	-	(0.01652757)	0.00194469
REVYEC_FXNL	CUSTOMER	(0.02987990)	0.00748280	0.00323392	0.00054743	0.00630285	0.00582507	(0.00077732)	(0.00060808)	-	-	-	0.00026812	0.00079325	0.00046951	0.00005701	-	-	(0.06008843)	0.00661397
REVYEC_FXNL	TOTAL	1.00000000	0.15204539	0.01938658	0.03432596	0.04874018	0.01828371	(0.15576802)	(0.07392871)	-	-	-	0.18795604	0.49731046	0.33234975	0.01258496	-	-	(0.08252509)	0.00923880
FORF_DISC_FXNL Calculation - In order to properly assign forfeited discounts to the various functions within the customer classes, allocate it using the RSALE allocator																				
FORF_DISC TOTAL		1.00000000	0.68837336	0.06091760	0.09901406	0.00136472	0.00014791	0.03441589	0.02166901	0.00452230	0.00012254	0.00134864	0.03395913	0.04712451	0.00182742	-	-	-	0.00519290	-
RSALE	PRODUCTION	0.44886785	0.20017735	0.01326170	0.04578679	0.00135291	0.00013172	0.03510166	0.00671140	0.00288962	0.00012691	0.00104558	0.01815100	0.09773244	0.01596052	0.01012442	0.00016051	0.00015333	-	-
	BULKTRAN	(0.03516041)	(0.02724751)	0.00026481	(0.00042317)	(0.00003632)	0.00003230	(0.00033218)	0.00001924	(0.00005051)	(0.00000372)	(0.00009131)	(0.00092502)	(0.00446979)	(0.00149920)	(0.00039210)	(0.00001082)	0.00000490	-	-
	SUBTRAN	(0.00738036)	(0.00573594)	0.00004906	(0.00010081)	(0.00000776)	0.00001094	(0.00007796)	0.00000153	(0.00001478)	-	(0.00001865)	(0.00019159)	(0.00122352)	-	(0.00008025)	(0.00000217)	0.00000094	0.00000858	0.00000202
	DISTPRI	0.11813783	0.06722776	0.00538626	0.01782530	0.00050702	-	0.01347989	0.00261745	-	-	0.00036637	0.00662511	-	-	0.00366808	0.00005555	0.00006369	0.00025935	0.00005600
	DISTSEC	0.05026682	0.03193862	0.00283710	0.00771898	-	-	0.00495758	-	-	-	0.00009861	-	-	-	0.00163079	-	0.00002236	0.00091316	0.00014962
	ENERGY	0.38025008	0.14469868	0.00922499	0.03099848	0.00089135	0.00004239	0.02879910	0.00541411	0.00238707	0.00011061	0.00107648	0.01849092	0.10679770	0.01948536	0.00766945	0.00012476	0.00014148	0.00330348	0.00059368
	CUSTOMER	0.04501818	0.02127709	0.00621130	0.00164990	0.00040208	0.00010162	0.00041089	0.00012244	0.00023790	0.00004011	0.00000222	0.00006021	0.00031767	0.00004802	0.00010294	0.00000165	0.00000275	0.01201028	0.00201912
	TOTAL	1.00000000	0.43233605	0.03723521	0.10345548	0.00310928	0.00031897	0.08233897	0.01488617	0.00544931	0.00027391	0.00247931	0.04221064	0.19915450	0.03399471	0.02272331	0.00032947	0.00038945	0.01649485	0.00282043
FORF_DISC_FXNL	PRODUCTION	0.45094970	0.31872603	0.02169642	0.04382113	0.00059382	0.00006108	0.01467173	0.00976943	0.00239806	0.00005678	0.00056875	0.01460277	0.02312573	0.00085797	-	-	-	-	-
FORF_DISC_FXNL	BULKTRAN	(0.04544325)	(0.04338399)	0.00043323	(0.00040500)	(0.00001594)	0.00001498	(0.00013885)	0.00002801	(0.00004192)	(0.00000166)	(0.00004967)	(0.00074419)	(0.00105766)	(0.00008059)	-	-	-	-	-
FORF_DISC_FXNL	SUBTRAN	(0.00964113)	(0.00913286)	0.00008026	(0.00009649)	(0.00000340)	0.00000507	(0.00003259)	0.00000223	(0.00001226)	-	(0.00001014)	(0.00015413)	(0.00028951)	-	-	-	-	0.00000270	-
FORF_DISC_FXNL	DISTPRI	0.14819123	0.10704127	0.00881204	0.01706005	0.00022254	-	0.00563430	0.00381009	-	-	0.00019929	0.00533000	-	-	-	-	-	0.00008165	-
FORF_DISC_FXNL	DISTSEC	0.06529569	0.05085325	0.00464155	0.00738760	-	-	0.00207216	-	-	-	0.00005364	-	-	-	-	-	-	0.00028748	-
FORF_DISC_FXNL	ENERGY	0.34033168	0.23039188	0.01509228	0.02966769	0.00039123	0.00001966	0.01203739	0.00788103	0.00198099	0.00004949	0.00058556	0.01487624	0.02527078	0.00104746	-	-	-	0.00104000	-
FORF_DISC_FXNL	CUSTOMER	0.05031608	0.03387777	0.01016182	0.00157907	0.00017648	0.00004712	0.00017174	0.00017823	0.00019743	0.00001794	0.00000121	0.00004844	0.00007517	0.00000258	-	-	-	0.00378107	-
FORF_DISC_FXNL	TOTAL	1.00000000	0.68837336	0.06091760	0.09901406	0.00136472	0.00014791	0.03441589	0.02166901	0.00452230	0.00012254	0.00134864	0.03395913	0.04712451	0.00182742	-	-	-	0.00519290	-
WEATHER_FXNL Calculation - In order to properly assign the weather normalization load adjustment to the various functions within the customer classes, allocate it using the RSALE allocator																				
WEATHER_NORM TOTAL		1.00000000	1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RSALE	PRODUCTION	0.44886785	0.20017735	0.01326170	0.04578679	0.00135291	0.00013172	0.03510166	0.00671140	0.00288962	0.00012691	0.00104558	0.01815100	0.09773244	0.01596052	0.01012442	0.00016051	0.00015333	-	-
	BULKTRAN	(0.03516041)	(0.02724751)	0.00026481	(0.00042317)	(0.00003632)	0.00003230	(0.00033218)	0.00001924	(0.00005051)	(0.00000372)	(0.00009131)	(0.00092502)	(0.00446979)	(0.00149920)	(0.00039210)	(0.00001082)	0.00000490	-	-
	SUBTRAN	(0.00738036)	(0.00573594)	0.00004906	(0.00010081)	(0.00000776)	0.00001094	(0.00007796)	0.00000153	(0.00001478)	-	(0.00001865)	(0.00019159)	(0.00122352)	-	(0.00008025)	(0.00000217)	0.00000094	0.00000858	0.00000202
	DISTPRI	0.11813783	0.06722776	0.00538626	0.01782530	0.00050702	-	0.01347989	0.00261745	-	-	0.00036637	0.00662511	-	-	0.00366808	0.00005555	0.00006369	0.00025935	0.00005600
	DISTSEC	0.05026682	0.03193862	0.00283710	0.00771898	-	-	0.00495758	-	-	-	0.00009861	-	-	-	0.00163079	-	0.00002236	0.00091316	0.00014962
	ENERGY	0.38025008	0.14469868	0.00922499	0.03099848	0.00089135	0.00004239	0.02879910	0.00541411	0.00238707	0.00011061	0.00107648	0.01849092	0.10679770	0.01948536	0.00766945	0.00012476	0.00014148	0.00330348	0.00059368
	CUSTOMER	0.04501818	0.02127709	0.00621130	0.00164990	0.00040208	0.00010162	0.00041089	0.00012244	0.00023790	0.00004011	0.00000222	0.00006021	0.00031767	0.00004802	0.00010294	0.00000165	0.00000275	0.01201028	0.00201912
	TOTAL	1.00000000	0.43233605	0.03723521	0.10345548	0.00310928	0.00031897	0.08233897	0.01488617	0.00544931	0.00027391	0.00247931	0.04221064	0.19915450	0.03399471	0.02272331	0.00032947	0.00038945	0.01649485	0.00282043
WEATHER_FXNL	PRODUCTION	0.46301331	0.46301331	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL	BULKTRAN	(0.06302392)	(0.06302392)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL	SUBTRAN	(0.01326731)	(0.01326731)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL	DISTPRI	0.15549886	0.15549886	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL	DISTSEC	0.07387452	0.07387452	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL	ENERGY	0.33469029	0.33469029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL	CUSTOMER	0.04921424	0.04921424	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL	TOTAL	1.00000000	1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL_OM	PRODUCTION	0.30369444	0.30369444	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL_OM	BULKTRAN	0.01636462	0.01636462	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL_OM	SUBTRAN	0.00355900	0.00355900	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL_OM	DISTPRI	0.12135564	0.12135564	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL_OM	DISTSEC	0.05600883	0.05600883	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL_OM	ENERGY	0.45681577	0.45681577	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL_OM	CUSTOMER	0.04220170	0.04220170	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL_OM	TOTAL	1.00000000	1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Kentucky Power Company
Proposed Revenue Allocation
Twelve Months Ended February, 28, 2017

					Proposed Revenue Allocation					
Current Class (1)	**Current Revenue** (2)	**Rate Base** (3)	**Current Income** (4)	**Current ROR %** (5)	**Income Increase** (6)	**Income** (7)	**ROR %** (8)	**Revenue Increase** (9)	**Sales Revenue** (10)	**Percent Increase** (11)
RS	216,341,050	652,486,366	7,048,662	1.08	22,660,786	29,709,448	4.55	37,237,355	253,578,405	17.21
SGS	18,632,507	37,514,381	3,959,664	10.56	1,125,152	5,084,816	13.55	1,848,907	20,481,414	9.92
MGS	53,484,637	114,971,829	9,505,162	8.27	3,579,804	13,084,966	11.38	5,882,515	59,367,152	11.00
LGS	51,515,378	101,363,382	8,399,008	8.29	3,155,140	11,554,148	11.40	5,184,686	56,700,064	10.06
IGS	139,030,771	240,509,510	13,166,219	5.47	7,824,469	20,990,688	8.73	12,857,564	151,888,335	9.25
PS	11,535,619	26,428,694	1,631,776	6.17	850,553	2,482,329	9.39	1,397,672	12,933,291	12.12
MW	194,881	337,885	37,818	11.19	10,026	47,844	14.16	16,476	211,357	8.45
OL	8,254,025	18,839,286	2,836,123	15.05	522,655	3,358,778	17.83	858,854	9,112,879	10.41
SL	1,411,343	2,437,113	382,116	15.68	66,851	448,967	18.42	109,853	1,521,196	7.78
Total	500,400,211	1,194,888,447	46,966,548	3.93	39,795,436	86,761,984	7.26	65,393,882	565,794,093	13.07

Gross Rev Conversion Factor: 1.64325

Kentucky Power Company
Proposed Revenue Allocation
Twelve Months Ended February, 28, 2017

					Current Equalized Rate of Return							
Current Class (1)	**Current Revenue** (2)	**Rate Base** (3)	**Current Income** (4)	**Current ROR %** (5)	**Percent Increase** (6)	**Revenue Increase** (7)	**Income Increase** (8)	**Income** (9)	**ROR %** (10)	**Sales Revenue** (11)	**Current Subsidy** (12)=(11)-(2)	**Relative ROR**
RS	216,341,050	652,486,366	7,048,662	1.08	14.13	30,561,361	18,598,111	25,646,773	3.93	246,902,411	30,561,361	0.27
SGS	18,632,507	37,514,381	3,959,664	10.56	-21.92	(4,083,670)	(2,485,116)	1,474,548	3.93	14,548,837	(4,083,670)	2.69
MGS	53,484,637	114,971,829	9,505,162	8.27	-15.32	(8,193,338)	(4,986,054)	4,519,108	3.93	45,291,299	(8,193,338)	2.10
LGS	51,515,378	101,363,382	8,399,008	8.29	-14.08	(7,254,618)	(4,414,797)	3,984,211	3.93	44,260,760	(7,254,618)	2.11
IGS	139,030,771	240,509,510	13,166,219	5.47	-4.39	(6,100,895)	(3,712,699)	9,453,520	3.93	132,929,876	(6,100,895)	1.39
PS	11,535,619	26,428,694	1,631,776	6.17	-8.45	(974,388)	(592,964)	1,038,812	3.93	10,561,231	(974,388)	1.57
MW	194,881	337,885	37,818	11.19	-20.69	(40,321)	(24,537)	13,281	3.93	154,560	(40,321)	2.85
OL	8,254,025	18,839,286	2,836,123	15.05	-41.72	(3,443,632)	(2,095,622)	740,501	3.93	4,810,393	(3,443,632)	3.83
SL	1,411,343	2,437,113	382,116	15.68	-33.34	(470,499)	(286,322)	95,794	3.93	940,844	(470,499)	3.99
Total	500,400,211	1,194,888,447	46,966,548	3.93	0.00	0	0	46,966,548	3.93	500,400,211	0	1.00

Gross Rev Conversion Factor: 1.643251

Kentucky Power Company
Proposed Revenue Allocation
Twelve Months Ended February, 28, 2017

					Equalized Rate of Return						95% of		
Current Class (1)	Current Revenue (2)	Rate Base (3)	Current Income (4)	Current ROR % (5)	Percent Increase (6)	Revenue Increase (7)	Income Increase (8)	Income (9)	ROR % (10)	Sales Revenue (11)	Current Subsidy (12)	Proposed Increase (13)=(7)-(12)	Percent Increase (14)
RS	216,341,050	652,486,366	7,048,662	1.08	30.63	66,270,648	40,328,992	47,377,654	7.26	282,611,698	29,033,293	37,237,355	17.21
SGS	18,632,507	37,514,381	3,959,664	10.56	-10.90	(2,030,580)	(1,235,709)	2,723,955	7.26	16,601,927	(3,879,487)	1,848,907	9.92
MGS	53,484,637	114,971,829	9,505,162	8.27	-3.55	(1,901,156)	(1,156,948)	8,348,214	7.26	51,583,481	(7,783,671)	5,882,515	11.00
LGS	51,515,378	101,363,382	8,399,008	8.29	-3.31	(1,707,201)	(1,038,917)	7,360,091	7.26	49,808,177	(6,891,887)	5,184,686	10.06
IGS	139,030,771	240,509,510	13,166,219	5.47	5.08	7,061,714	4,297,405	17,463,624	7.26	146,092,485	(5,795,850)	12,857,564	9.25
PS	11,535,619	26,428,694	1,631,776	6.17	4.09	472,003	287,237	1,919,013	7.26	12,007,622	(925,669)	1,397,672	12.12
MW	194,881	337,885	37,818	11.19	-11.20	(21,829)	(13,284)	24,534	7.26	173,052	(38,305)	16,476	8.45
OL	8,254,025	18,839,286	2,836,123	15.05	-29.23	(2,412,596)	(1,468,185)	1,367,938	7.26	5,841,429	(3,271,450)	858,854	10.41
SL	1,411,343	2,437,113	382,116	15.68	-23.89	(337,121)	(205,155)	176,961	7.26	1,074,222	(446,974)	109,853	7.78
Total	500,400,211	1,194,888,447	46,966,548	3.93	13.07	65,393,882	39,795,436	86,761,984 86,761,984	7.26	565,794,093	0	65,393,882	13.07

Gross Rev Conversion Factor: 1.643251

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; (4) An Order Approving Accounting Practices To Establish Regulatory Assets And Liabilities; And (5) An Order Granting All Other Required Approvals And Relief	)	Case No. 2017-00179

DIRECT TESTIMONY OF

ANDREW R. CARLIN

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Andrew R. Carlin, being duly sworn, deposes and says he is the Director, Compensation and Executive Benefits for American Electric Power Service Corporation and that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief.

Andrew R. Carlin

STATE OF OHIO	)
	) Case No. 2017-00179
COUNTY OF FRANKLIN	)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Andrew R. Carlin, this the 19th day of June 2017.

Notary Public

Cheryl L. Strawser
Notary Public, State of Ohio
My Commission Expires 10-01-2021

My Commission Expires: October 1st, 2021

DIRECT TESTIMONY OF
ANDREW R. CARLIN, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2017-00179

TABLE OF CONTENTS

DIRECT TESTIMONY OF
ANDREW R. CARLIN, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Andrew R. Carlin. My business address is American Electric Power, 15th Floor, One Riverside Plaza, Columbus, Ohio 43215. My position is Director of Compensation & Executive Benefits for the American Electric Power Service Corporation ("AEPSC"), a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP"). AEP is the parent company of Kentucky Power Company ("Kentucky Power" or the "Company"). AEPSC supplies engineering, financing, accounting and similar planning and advisory services to operating companies in eleven jurisdictions, including Kentucky Power. In this testimony I refer to Kentucky Power and AEPSC collectively as the "Companies".

Q. PLEASE DESCRIBE YOUR EDUCATION, PROFESSIONAL QUALIFICATIONS AND BUSINESS EXPERIENCE.

A. I received a Bachelor of Arts Degree from Bowdoin College in 1988 with majors in Economics and Government. I also received a Master's of Business Administration Degree from the J. L. Kellogg Graduate School of Management at Northwestern University in 1992, with concentrations in finance, management strategy, and accounting.

From 1987 to 1988, I worked for Putnam Investor Services as a Shareholder Services Representative. From 1988 to 1990 and in the summer of 1991, I worked as an Associate Consultant and Research Analyst in the U.S. Compensation Practice for William M. Mercer, a leading international human resource consulting firm. From 1992 to 2000, I worked for Bank One Corporation, now part of J.P. Morgan Chase, in multiple planning, finance and compensation capacities.

I joined AEPSC as the Director of Executive Compensation & Benefits in 2000. In 2002 I took on responsibility for employee compensation, in addition to my executive compensation and benefits responsibilities. In my current position, as a member of the AEPSC compensation group, I am responsible for, among other things, developing and maintaining effective and cost-efficient compensation programs for Kentucky Power and its affiliates.

Q. WHAT SERVICE DOES THE AEPSC COMPENSATION GROUP PROVIDE TO KENTUCKY POWER, AEP AND AEPSC?

A. The compensation group is a department within Human Resources that is responsible for the design, development, and administration of employee compensation program and some of the employee benefit plans for the AEP System, including for employees of Kentucky Power. The compensation group conducts ongoing research and recommends changes to compensation programs as necessary to prudently manage employee compensation. The compensation group also develops communications materials and manages compensation plans and programs in compliance with federal and state regulations related to employee pay. The compensation group works in coordination with the AEPSC team responsible for non-compensation employee benefits; to ensure that employee Total Compensation (defined below) and benefits, as a whole, is market-competitive. This is done by comparing the Companies' compensation to that of other employers, which is obtained through the use of third-party compensation surveys. The list of compensation surveys the compensation group utilizes is provided as Exhibit ARC-1. This coordination enables AEP and its subsidiaries to recruit and retain the qualified employees who are required to provide service to customers.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY BODY?

A. Yes. The list of regulatory proceedings is provided in Exhibit ARC-2.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to show that the compensation opportunity provided to employees is reasonable, customary, prudent, and market-competitive. My testimony also will demonstrate that the Companies' compensation strategy, which offers employees the basic ability to earn market comparable compensation, which includes a combination of base pay and incentive compensation, benefits customers through the cost and quality of the work that employees perform on behalf of customers. I will show that the compensation opportunity provided to Kentucky Power employees and Kentucky Power's allocated share of the compensation for AEPSC employees is vital for recruiting, engaging, retaining and directing the efforts of employees with the skills and experience necessary to efficiently and effectively provide electric services to Kentucky Power customers.

Q. WHAT ARE THE COMPENSATION TERMS USED IN THIS TESTIMONY?

A. The Companies compensates all employees with a combination of a fixed base compensation (“Base Pay”) and a variable annual or short-term incentive compensation opportunity (“STI”). I refer to the sum of these two types of compensation (Base Pay + STI) as Total Cash Compensation (“TCC”). Approximately 1,050 positions in the AEP system also have a long-term incentive (“LTI”) compensation opportunity. These 1,050 positions require unique skills and involve roles for which long-term continuity, prudency and vision are required. Total Compensation (“Total Compensation”) is comprised of Base Pay, STI and, for eligible positions, LTI (Base Pay + STI +LTI). Total Compensation and TCC are the same for employees who do not have an LTI opportunity.

Q. ARE YOU SPONSORING EXHIBITS IN THIS TESTIMONY?

A. Yes, I am sponsoring the following exhibits:

- Exhibit ARC-1 (Survey List for 2016)
- Exhibit ARC-2 (Witness Participation Proceeding List)
- Exhibit ARC-3 (Towers Watson 2010 Annual Incentive Plan Design Survey Findings Report)
- Exhibit ARC-4 (KPCO TCC vs. Market for Technical, Craft and Clerical Positions)
- Exhibit ARC-5 (KPCO TCC vs. Market for Exempt Positions)
- Exhibit ARC-6 (TCC vs. Market for Executive Positions)
- Exhibit ARC-7 (CAHRS, Evaluating the Utility of Performance-Based Pay)
- Exhibit ARC-8 (2016 ICP Goals for Distribution)

- Exhibit ARC-9 (2016 ICP Funding Measures)
- Exhibit ARC-10 (Benefit Plan Design and Employee Cost Summary Grid – 2016)

II. OVERVIEW OF COMPENSATION PRACTICES

Q. WHAT IS THE PURPOSE OF THE COMPANIES' EMPLOYEE COMPENSATION PLAN?

A. The Companies uses a Total Compensation strategy to recruit and retain employees with the skills needed for the service and support of our customers. The Companies' compensation strategy must be fair and market-competitive to enable the Companies to attract, retain and motivate employees with the abilities and experience necessary to provide reliable electric service, safely, efficiently and effectively, for Kentucky Power customers.

Q. WHAT ARE SOME OF THE COMPANIES' OPTIONS IN HOW IT PAYS COMPENSATION TO EMPLOYEES?

A. Realizing that the Companies' compensation strategy must allow employees to earn a market-competitive wage, the basic choices in employee pay strategy are: (1) to use a 100% fixed base pay to provide market-competitive compensation; or (2) a combination of lower fixed base pay with a variable pay opportunity tied to performance that, in combination with base pay, brings employee's compensation opportunity to market-competitive levels. Both of these pay strategies pay employees at the same market-competitive level for similar positions assuming target performance on average for the variable component of pay.

Q. WHAT IS THE COMPANIES' OVERALL APPROACH TO HOW AN EMPLOYEE EARNS PAYROLL COMPENSATION?

A. The Companies utilize the combination method which uses lower base pay and a variable incentive opportunity portion that varies based on performance. This compensation strategy is used for all levels of positions

Q. WHY DO THE COMPANIES PAY EMPLOYEES IN THIS MANNER?

A. The design of the Companies' compensation programs and, specifically, its annual and long-term incentive compensation programs, has been developed prudently and appropriately from a customer-focused and business perspective. The compensation strategy described in this testimony uses base pay and defined employee goals to foster efficiency, safety and improvement in the customer experience. This pay strategy motivates employees to lower costs and generate efficiencies that benefit customers while also maintaining employee compensation opportunity at reasonable market-competitive rates that enable the Companies to attract and retain the suitable employees needed to efficiently and effectively provide its electric service to customers.

Q. WHAT ARE THE CUSTOMER BENEFITS DRIVEN BY EMPLOYEES EARNING THEIR PAYROLL COMPENSATION USING THIS COMBINATION METHOD?

A. The Companies' compensation method creates a culture of high performance and cost consciousness which reduces the cost of service for customers. The continuous improvements this type of culture produces results in efficiencies that lower costs of service which benefits customers through lower rates.

Q. WHY IS TOTAL COMPENSATION CHOSEN AS THE PRIMARY POINT OF COMPARISON TO MARKET COMPENSATION RATHER THAN BASE SALARY LEVELS?

A. Total Compensation is chosen as the primary point of comparison because it includes all statistically significant types of compensation earned by employees in the market at the market-competitive level. Market compensation survey information provided in ARC Exhibit-4, ARC Exhibit-5, and ARC Exhibit-6, shows that the target level of annual incentive compensation is a statistically significant and often a substantial component of market-competitive compensation for nearly every position. This survey information also shows that the target level of long-term compensation is a statistically significant and often a substantial component of market-competitive compensation for those positions to which the Companies provides such compensation. Employees and prospective employees evaluate the sum of compensation packages in their entirety when evaluating pay rate. No understanding or assessment of market-competitive employee pay would be complete or valid unless all types of pay are included in the equation.

Q. IS IT APPROPRIATE FOR THE COMPANY TO RECOVER EMPLOYEE INCENTIVE EXPENSE THROUGH BASE RATES?

A. Yes. The Companies' compensation program has been in place for more than 20 years. Customers have and will continue to receive financial benefits due to the effective design and operation of the company's Total Compensation program, through a lower cost of service. These lower costs and efficiencies are fostered by incentive compensation and are achieved while maintaining employee compensation at market-competitive rates. This compensation strategy has historically provided advantages to customers and produced substantial additional benefits that have already been reflected in the Company's actual expenses for many prior years, including the test year. Because of these benefits, and because the incentive compensation opportunity serves only to bring employee compensation to market-competitive levels, it is reasonable for these employee expenses to be included in the cost of service.

Q. IS THE COMPANIES' EMPLOYEE COMPENSATION SHOWN TO BE CONSISTENT WITH THIRD PARTY SURVEY MARKET COMPENSATION STUDIES?

A. Yes. In fact target employee compensation is shown ranking below the market median as shown in ARC Exhibits 4, 5, and 6.

Q. WHY MUST THE COMPANIES PROVIDE EMPLOYEES WITH A MARKET-COMPETITIVE TOTAL COMPENSATION PACKAGE?

A. Like most other regulated utility employers, the Companies must provide a market-competitive Total Compensation opportunity to efficiently and effectively attract and retain an adequately skilled and experienced workforce. Attracting and retaining such a workforce is reasonable and necessary for the safe, efficient and effective provision of service to customers and the operation of most aspects of the Company's business.

Q. WHAT WOULD BE THE IMPLICATIONS TO THE COMPANY AND ITS CUSTOMERS IF THE COMPANIES WERE TO DECIDE TO REDUCE ITS COMPENSATION TO LESS THAN MARKET-COMPETITIVE LEVELS?

A. Reducing employees' target Total Compensation to less than the market-competitive range would have substantial negative implications for the Company and its cost of service to customers. It is likely that the compensation expense saved would be more than offset by increased hiring and training expense due to increased employee turnover, as well as lower employee productivity, as it would take new employees time to learn to perform their jobs safely, efficiently and effectively. This is particularly true for linemen and other craft positions that require lengthy apprenticeships to learn the skills needed to work independently and safely. It requires AEP's Lineman five years to reach the journeyman (Lineman A) level in which they are fully proficient in their job. It would not be economical for the Company and its customers to become a training ground for lineman or other positions for other companies.

Q. ARE THERE ANY STUDIES SUPPORTING YOUR TESTIMONY THAT USING AN INCENTIVE COMPENSATION STRATEGY BENEFITS CUSTOMERS?

A. Yes. Exhibit ARC-7 (CAHRS, *Evaluating the Utility of Performance Based Pay*) is an academic study that shows the substantial financial benefits that can result from linking pay to performance. The financial benefits shown in this study (see Exhibit ARC-7, page 37) are the result of improved employee performance provided by a workforce whose pay was closely linked to their performance.

Q. DOES THE INCENTIVE PORTION OF EMPLOYEES' TARGET TOTAL COMPENSATION CONTRIBUTE TO THE COMPANIES EXCEEDING A MARKET-COMPETITIVE PAY LEVEL?

A. No. The Companies' incentive compensation is not a 'bonus' plan. The target compensation opportunity that incentive compensation provides is merely a portion of employees' total pay that is at risk. It is designed to motivate employees and provide a needed compensation opportunity that, when it is combined with base pay, brings employee Total Compensation to a reasonable and market-competitive level. The target value of incentive compensation is a critical component of the market-competitive Total Compensation package that the Companies use to attract and retain qualified employees.

Q. DOES THE USE OF INCENTIVE COMPENSATION REDUCE THE COMPANIES' BASE PAY EXPENSE?

A. Yes. The variable incentive compensation component reduces the amount of base wages needed to provide prudent, effective and market-competitive employee compensation. Conversely, if the Companies eliminated incentive compensation, it would need to increase base pay to continue to attract and retain the suitably skilled and experienced employees it needs to efficiently and effectively provide service to customers.

Q. HOW DOES THE COMPANIES' INCENTIVE COMPENSATION PLAN TARGETS COMPARE TO OTHER COMPANIES' TARGETS?

A. Target 2016 STI for all AEP participants was 10.4 percent of base pay, including overtime, which is less than the 16 percent target typical of broad-based STI plans. (See Exhibit ARC-3 (Towers Watson 2010 Annual Incentive Plan Design Survey Findings Report).

Q. WILL THE ANNUAL INCENTIVE PROGRAM CONTINUE TO PRODUCE INCREMENTAL BENEFITS?

A. While the annual incentive program is expected to produce additional incremental benefits going forward, these benefits are likely to be small compared to the cumulative total of all ongoing benefits incentive compensation has produced in past years that have already been captured in rates or will be captured in rates through this proceeding. These ongoing benefits would likely erode over time if the Company or AEPSC were to eliminate annual incentive compensation for a portion of its workforce if, for example, the Company was not receiving adequate recovery of annual incentive expense in its rates.

Additionally, to the extent that annual incentive compensation produces substantial additional benefits going forward, customers would immediately receive the benefits of any *operational* improvements. Because the compensation opportunity that annual incentive compensation provides is a portion of customary employee wages, it is just and reasonable to include annual incentive compensation in the Company's cost of service for rate making purposes.

Q. WHAT ARE THE TRENDS IN INCENTIVE COMPENSATION AND ITS PREVALENCE IN THE EMPLOYMENT MARKET?

A. Incentive compensation withstood the pressures of the "Great Recession" and the unprecedented challenges of cost, risk, scrutiny and talent management issues facing employers today. It continues to be used nearly universally by public utilities and other U.S. companies to encourage desired behaviors and provide competitive Total

Compensation opportunities. The compensation analyses discussed above in this testimony (Exhibits ARC-4, ARC-5, and ARC-6) show that market median Total Compensation includes incentive compensation for 100 percent of the 102 Kentucky Power incumbent employees in the 11 technical, craft (traditionally hourly skilled labor, such as line servicers and other trades) and clerical positions.

To state simply and to avoid misinterpretation, the Companies provides both annual and long-term incentive compensation as part of a market-competitive Total Compensation package; it is not provided as a “bonus” on top of an already market-competitive compensation package. In other words, if incentive compensation were not provided, the same target value of incentive compensation would need to be added to base pay in order for the Companies to provide a market-competitive compensation package to its employees. Paying market-competitive compensation enables the Companies to attract, retain, and motivate the suitably knowledgeable and experienced employees it needs to efficiently and effectively provide its electric services to customers. Furthermore, incentive compensation provides many additional and substantial benefits to customers, which are described in detail later in this testimony.

Q. IN THE PAST, INTERVENER WITNESSES HAVE SUGGESTED EXCLUDING KENTUCKY POWER EMPLOYEE INCENTIVE COMPENSATION IN WHOLE OR SUBSTANTIAL PART. HOW WOULD DOING SO AFFECT THE COMPETIVENESS OF KENTUCKY POWER’S EMPLOYEE COMPENSATION FOR PHYSICAL AND CRAFT POSITIONS?

A. If Kentucky Power's annual incentive compensation were to be excluded and this prompted the Company to eliminate incentive compensation for physical/craft positions, then Total Compensation for 7 of 10 physical/craft positions (70 percent) would fall below the market-competitive range and Company's average employee Total Compensation for these high incumbent positions would fall 9.4 percent below the market median. This shows that the target annual incentive compensation provided by Kentucky Power is necessary to achieve market-competitive compensation for these positions and, thus, is a reasonable and appropriate cost of doing business that cannot be eliminated without an offsetting increase in base pay if Total Compensation is to remain competitive.

Q. DO YOU BELIEVE IT WOULD BE REASONABLE TO DISALLOW RECOVERY OF ANY PORTION OF THE REQUESTED AMOUNT OF EMPLOYEE INCENTIVE COMPENSATION EXPENSE?

A. No. The Total Compensation the Companies provide to employees is a just, reasonable and prudent cost of doing business in service to customers. Reducing or eliminating a portion of employees' compensation opportunity would reduce the Company's cost recovery for this expense to less than that required to maintain Total Compensation in the market-competitive range for a substantial number of Kentucky Power positions. (See Exhibit ARC-4.) Paying market-competitive compensation enables the Companies to attract, retain, and motivate the suitably knowledgeable, experienced and qualified employees it needs to efficiently and effectively provide services to customers, while minimizing overall expense, which is in the best interests of customers and the Company. For example, any compensation expense avoided by reducing employee compensation to less than the market-competitive range would likely be eliminated by additional hiring and training expense due to employee turnover, as well as lower employee productivity while new employees learn to perform their jobs safely, efficiently and effectively. This is particularly true for positions that require lengthy apprenticeships to achieve the skills needed to work independently and safely, such as Line Mechanics.

III. COMPETITIVENESS OF TOTAL COMPENSATION

Q. HOW DOES THE COMPANIES' TARGET TOTAL COMPENSATION FOR PHYSICAL AND CRAFT POSITIONS COMPARE WITH MARKET DATA?

A. As shown in Exhibit ARC-4 (Kentucky Power TCC vs. Market for Technical, Craft and Clerical Positions), Kentucky Power's average target Total Compensation for the physical and craft positions included in the EAP Data Information Solutions, LLC 2016 Energy Technical Craft and Clerical ("ETC&C') Survey is 5.4 percent below the market median. Table ARC-1 below illustrates the Total Compensation for line positions with Kentucky Power in comparison with the 2016 EAPDIS Energy Technical, Craft & Clerical (ET,C&C) Survey for the southeast region of the United States.

Table ARC-1

Survey Job	AEP Title	AEP Target Total Cash Compensation (TCC)	ETC&C Survey Total Cash Compensation (TCC)	% Difference AEP Target TCC vs. Survey TCC
Line Mechanic	Line Mechanic-A	$77,575	$83,726	-7.9%
Trouble Service Mechanic	Line Servicer	$79,934	$87,900	-10.0%

Assuming a market-competitive compensation range of +/- 10 percent of the survey median, which is typical practice for such positions, Kentucky Power's average target TCC is within, but in the lower half of the market-competitive range. TCC is the same as Total Compensation for this exhibit because neither AEP nor other companies that participated in this survey provide a significant amount of LTI to these positions.

However, if Kentucky Power's and AEPSC's annual incentive compensation were to be excluded, the average target TCC for these positions would fall to 10.7 percent below the market median, which is below the market competitive range and 8 of 10 positions (80 percent) would fall below the market-competitive range. This shows that the annual incentive compensation opportunity Kentucky Power provides to physical and craft positions is necessary to maintain the competitiveness of their Total Compensation.

Q. HOW DOES KENTUCKY POWER'S AND AEPSC'S TARGET TOTAL COMPENSATION FOR NON-MANAGERIAL EXEMPT POSITIONS COMPARE WITH MARKET DATA?

A. Exhibit ARC-5 (TCC vs. Market for Exempt Positions) compares Kentucky Power's and AEPSC's compensation for non-executive exempt positions to those of similar companies, based on applicable external survey data. Using +/- 15 percent of the market midpoint as the market-competitive range, which is typical for exempt positions, this exhibit indicates that, on average, Kentucky Power's and AEPSC's target TCC for these positions was 0.11 percent below the market median, which is well centered within the +/- 15 percent market-competitive range. Target TCC is the same as target Total Compensation for this exhibit because neither AEP nor other companies that participated in this survey provide a significant amount of LTI to these positions.

However, if Kentucky Power's and AEPSC's annual incentive compensation were to be excluded, target TCC for these positions would fall to 9.6 percent below the market median. While Kentucky Power's and AEPSC's average target TCC would remain at the low end of the market-competitive range, 6 of 22 individual positions (27.3 percent) would fall below the market-competitive range. This shows that the annual incentive compensation opportunity Kentucky Power and AEPSC provide to these positions is necessary to maintain the competitiveness of their Total Compensation and is a reasonable cost of doing business that, practically speaking, cannot be eliminated without a corresponding increase in base pay.

Q. HOW DOES KENTUCKY POWER'S AND AEPSC'S TARGET TOTAL COMPENSATION FOR MANAGEMENT AND LEADERSHIP POSITIONS COMPARE WITH MARKET DATA?

A. The Human Resources Committee of AEP's Board of Directors (HRC) routinely engages a nationally recognized, independent executive compensation consulting firm (Meridian Compensation Partners, LLC) to conduct a compensation study of the Companies' executive positions. The peer group used for this study consists of companies specifically selected by the HRC to represent the talent markets from which the AEP and its subsidiaries must compete to attract and retain executive employees. This study showed that target TCC for the 15 executive positions whose time and expense is generally allocated to Kentucky Power were within the +/- 15 percent market-competitive range on average as of July 1, 2016. However, AEP's target Total Compensation would be below the market-competitive range for 100 percent of these executive positions without either the annual incentive compensation or the long-term compensation portions of target Total Compensation, unless it was replaced with base salary (See Exhibit ARC-6). Obviously, if both annual incentive compensation and long-term compensation were eliminated, target Total Compensation for these executive positions would be far below market-competitive levels. This study shows that the compensation opportunity provided by annual and long-term incentive compensation for senior management and executive positions is necessary, both singularly and in combination, to maintain the competitiveness of the Companies' Total Compensation for these positions. As such, the cost of providing this compensation opportunity, irrespective of the form in which it is provided, is a necessary, reasonable and appropriate cost of doing business.

Q. HOW ARE BASE SALARIES DETERMINED FOR SALARIED EMPLOYEES?

A. Base salary offers for salaried positions are made by management within the salary range for the job grade assigned to each position based on the qualifications and experience of the prospective employee relative to the requirements for the position. For jobs with multiple incumbents, the base salaries of other employees in the same position are also a major factor.

The Companies provides a base salary merit increase program for all salaried positions. The amount budgeted annually for merit increases is established by senior

AEP management based on salary planning surveys, the market-competitiveness of the Companies' compensation and the budget dollars available for salary increases.

As part of the merit program, each employee's individual performance is evaluated on an annual basis. The amount of the "merit" increase awarded to each employee, if any, is based on a combination of factors, including their individual performance rating, their performance relative to their peers, the position of their salary within the salary range for their job, and the size of the merit budget.

Q. HOW DOES THE COMPANIES' OVERALL BASE SALARY INCREASE BUDGET COMPARE TO THE MARKET FOR THE YEARS 2009 THROUGH 2016?

A. Table ARC-2 below compares median utility industry base salary increase budgets for employees to the Companies' salary increase budget for the years 2009-2016. Hourly/craft positions are not paid a salary so they are not included in this table.

Table ARC-2

	Nonexempt Salaried		Exempt		Executive	
	Industry*	Companies	Industry*	Companies	Industry*	Companies
2009 Actual	2.750%	0.000%	2.500%	0.000%	2.000%	0.000%
2010 Actual	2.700%	2.000%	3.000%	2.000%	2.950%	0.000%
2011 Actual	3.000%	3.200%	2.900%	3.200%	3.000%	3.200%
2012 Actual	2.750%	2.675%	3.000%	2.675%	3.000%	2.675%
2013 Actual	3.000%	3.000%	3.000%	3.000%	3.000%	3.000%
2014 Actual**	3.000%	3.350%	3.000%	3.350%	3.000%	3.350%
2015 Actual***	3.000%	3.500%	3.000%	3.500%	3.000%	3.000%
2016 Actual***	3.000%	3.500%	3.000%	3.500%	3.000%	3.000%
Total	23.200%	21.225%	23.400%	21.225%	22.950%	19.225%
Difference		-1.975%		-2.175%		-3.725%

*The Conference Board Research Report, U.S. Salary Increase Budgets for 2010-2016
** Represents 3.00% merit budget for Company; .35% was Promotional & Equity Adjustments
*** Represents 3.00% merit budget for Company ; and .5% promotional budget

Also shown in Table ARC-2, the Companies' base pay increase budgets have substantially lagged the market median overall over these years. While many companies pared back their salary increase budgets in 2009 due to economic conditions, the Companies froze salaries, which was a far more substantial response. While utility companies generally returned to nearly 3 percent increase for 2010, the Companies increased base wages by only 2 percent and maintained a salary freeze for executive positions. For 2011, the amount of the Companies' base wage increases kept pace with the market median and did not make up a significant portion of the 2009 and 2010 shortfall. The Companies' 2012 salary increase budget of 2.675 percent again lagged the market before returning to market median levels for 2013. For 2014 the Companies budgeted a 3 percent merit budget and provided a .35% promotional budget for line of progression promotions, such as Accountant to Accountant Sr. In 2015 and 2016, the Companies allocated 3.00 percent and 0.50 percent promotional budget for a 3.5 percent total salary increase budget which was even with the market median of 3.00 percent. Overall, the Companies' total salary increase budgets for non-exempt salaried and exempt positions were below the market median by 1.975 percent and 2.175 percent over this period, while the salary increase budget for AEP executives was a total of 3.725 percent less than the utility industry market median.

Q. HOW ARE BASE PAY INCREASES ADMINISTERED FOR HOURLY/CRAFT EMPLOYEES?

A. Base pay increases for hourly/craft employees, such as line mechanics and meter readers, are provided as general increases, and expressed as percentages of current base pay rates. General increases are negotiated with the labor unions that represent the Companies' employees. The Companies based its position in these negotiations on survey projections for market median general increases and market median total cash compensation paid by similar companies for these types of positions. As shown in Table ARC-3 below, pay increases for these types of employees have also lagged the market overall.

Table ARC-3

Hourly/Craft Employees*

Year	Utility Industry Market Median*	The Company
2009	2.500%	0.000%
2010	2.850%	2.000%
2011	2.900%	3.000%
2012	3.000%	2.000%
2013	3.000%	2.500%
2014	3.000%	2.500%
2015	3.000%	3.500%
2016	3.000%	3.500%
Total Pay Increase	23.250%	19.000%
	Company Employee Pay Increases Compared to Market	**-4.250%**

* The Conference Board Research Report, U. S. Salary Increase Budgets Survey

The Companies' total base pay increase budget was 4.25 percent less than the market median for hourly/craft employees for the 2009 through 2016 period, including a 2.5 percent general increase that was negotiated with most bargaining units for 2014. Reducing the growth of base wages is one of several difficult steps the Companies have taken to address their financial situation and economic conditions in the Kentucky Power service territory and such actions directly benefit customers by reducing the cost of the Company's electric service.

Q. WHAT OTHER STEPS HAVE THE COMPANIES TAKEN TO CONTROL COMPENSATION EXPENSE IN LIGHT OF THE GREAT RECESSION AND WEAK RECOVERY?

A. In addition to constraining the growth of base pay through lower than market merit increase budgets and general increases, the Companies took the following additional steps to reduce the growth rate of compensation expense:

- Froze external hiring from November 2008 through 2009;
- Froze line of progression promotional increases, such as Accountant to Sr. Accountant, from November 2008 through 2010, other than for physical/craft positions;
- Reduced the use of external contractors and temporary employees;
- Reduced the employee workforce through staff reductions and severance programs;
- Implemented efficiency measures, such as LEAN and other continuous improvement initiatives; and
- Implemented measured steps to adjust lagging employee compensation to market over time.

Q. HOW HAVE THE STEPS TAKEN TO CONTROL THE COMPANIES' COMPENSATION EXPENSES AFFECTED THE COMPETITIVENESS OF THE COMPANIES' COMPENSATION?

A. The market merit and base pay increases for 2009 and 2012 caused the Companies' base pay, target TCC and target total direct compensation to decline relative to peer companies. As a result, base compensation levels for all types of positions (physical/craft, salaried and managerial) are below the market median on average, although the Companies' base compensation levels generally remain within the market-competitive range (typically considered to be +/- 10 percent of the median for hourly/craft employees and +/- 15 percent for other employees). The Companies' target annual incentive compensation has also fallen relative to market because these levels are calculated as a function of base compensation. As a result, the Companies' target TCC and target Total Compensation were also affected by the below market base pay increases.

IV. TYPES OF INCENTIVE COMPENSATION OFFERED BY KENTUCKY POWER, AND AEPSC

A. Annual Incentive Compensation

Q. WHAT ARE THE GENERAL BENEFITS OF ANNUAL INCENTIVE COMPENSATION?

A. The Companies provide employees the means to earn incentive compensation instead of larger base salaries because it improves the Companies' performance without increasing overall compensation expense, assuming target performance. It encourages cost control and aligns work with the Companies' objectives, thereby improving performance of both employees and the Companies in in providing service to customers.

Q. WHAT ADDITIONAL BENEFITS DOES ANNUAL INCENTIVE COMPENSATION PROVIDE?

A. Annual incentive compensation also:

- Helps to attract, retain and motivate the qualified employees the Companies needs to efficiently and effectively provide electric service to customers;

- Communicates goals and objectives to employees in a manner that is more effective than otherwise possible. This focuses and more closely aligns employee efforts with these goals and objectives;
- Aligns the goals and objectives of departments throughout the organization which better ensures that all groups are working towards the same objectives;
- Encourages and motivates employees to achieve goals and objectives;
- Rewards employees for their individual performance along with the Companies' performance, which improves performance and increases retention of strong performers and reduces retention of weaker performers, thereby further improving performance;
- Links some compensation for all employees to performance objectives so that all employees have a personal stake in achieving these objectives;
- Shifts a portion of compensation expense from a fixed to a variable expense that varies based on the performance of the Companies. This reduces earnings volatility, business risk, and borrowing costs as well as the difficulties caused by more frequent and extensive changes in the size of the Companies' work force that would be necessary without the earnings cushion that incentive compensation provides;
- Creates a culture of high performance and cost consciousness; and
- Reduces the Company's cost of service by virtue of the productivity increases, expense savings, and other benefits that it creates and that the Companies would otherwise need to incur additional expense to provide.

Q. DOES ANNUAL INCENTIVE COMPENSATION NEED TO PROVIDE A DIRECT OPERATIONAL AND COST SAVING RETURN ON INVESTMENT IN ORDER TO BE A JUSTIFIABLE EXPENSE FOR THE COMPANIES TO INCUR AND A REASONABLE EXPENSE TO BE INCLUDED IN THE COMPANY'S COST OF SERVICE CHARGED TO CUSTOMERS?

A. No. When incentive compensation is designed as part of a market-competitive compensation package, rather than a bonus on top of already market-competitive compensation, as the target level of the Companies' annual incentive program is designed, then a positive return on investment is achieved by the attraction and retention of employees in the same way that base pay provides a return on investment. This target level is also the level needed to maintain the market-competitiveness of the Companies' compensation.

Furthermore, because the target level of Companies' annual incentive compensation is such a large percentage of its compensation expense (10.4 percent in calendar year 2016) it is unreasonable to expect this expense to be offset by incremental and quantifiable cost savings driven by the annual incentive program each year. This expectation both dismisses the program's value to the Companies and Kentucky Power customers as a component of market-competitive compensation and implies that it is possible to create 10 percent annual productivity increases in perpetuity, or at least the 20 plus years that the Companies' annual incentive plan will have been in place when the rates established in this case are next replaced. This is an expectation unbound by reality as any calculator will show.

Q. DESCRIBE THE EMPLOYEE ANNUAL INCENTIVE COMPENSATION PLANS APPLICABLE TO THIS PROCEEDING.

A. The Companies' annual incentive plans cover all employees from hourly positions through executive management. The majority of the goals for Kentucky Power employees participating in this plan are measured at the Kentucky Power (operating company) level. For calendar year 2016 there were separate annual incentive plans for employees in Kentucky Power, Customer & Distribution Services; Generation; Transmission, and other smaller groups. The remaining employees and all staff function and shared services employees participated in an AEP Annual Incentive Compensation Plan for the Executive Council and Staff. Kentucky Power's annual incentive plan uses a balanced scorecard consisting of three categories of performance objectives: Infrastructure Development (25%), Customer Experience (40%) and Employee Experience (35%) as shown in Exhibit ARC-8.

Q. PLEASE DESCRIBE THE MECHANISM USED TO FUND THE ANNUAL INCENTIVE PLAN PROGRAM.

A. As shown in Exhibit ARC-9 (2016 ICP Funding Measures); the Companies' annual incentive plan budgets were primarily funded based on AEP's earnings per share (EPS). Of the remainder, 10% was funded by safety performance and 15% was funded by strategic initiative performance. AEP's EPS incentive funding measure is set annually by the HRC in consultation with AEP executive management and the HRC's independent compensation consultant. The EPS performance measure is generally set at levels that are intended to allow employees to earn a target payout on average and to only have about a 10 to 15 percent chance of producing either a zero or a maximum payout.

Q. WHAT ARE THE BENEFITS TO CUSTOMERS OF TYING THE FUNDING FOR THE COMPANIES' ANNUAL INCENTIVE PROGRAM TO EARNINGS AND OTHER FINANCIAL MEASURES?

A. Tying funding of the budget for annual incentive compensation to the Companies' earnings promotes cost control and efficient use of financial resources, which is vital to providing reliable service at a reasonable cost to customers. The earnings and O&M measures included in the Companies' incentive compensation programs convey the importance of maintaining financial discipline, and directly encourage employees to reduce expense, operate efficiently, and conserve financial resources. This has and will continue to directly benefit customers by reducing the Company's cost of service through cost savings that are passed on to customers in rates that are lower than they otherwise would be, if the Companies did not use such performance measures.

The EPS measure used to fund incentive compensation also helps ensure that delivering incentive compensation payments will not impair the Companies financially. This bolsters the Companies' financial stability and reduces its earnings volatility, which benefits customers by reducing its cost of capital and helping to preserve capital during periods of weak earnings for investment in and maintenance of the Companies' electric system. It would be imprudent and a deviation from US industry norms for the Companies not have a mechanism, such as the EPS funding measure, to reduce or eliminate incentive compensation at a time when the Companies cannot afford to pay it. This compensation strategy benefits customers by reducing the risk of economic volatility that would be caused by a 100 percent fixed base pay obligation, which would increase AEP's cost of capital and the cost of providing service to customers. This mechanism also benefits ratepayers by better balancing the interests of other constituents with those of employees, rather than paying 100 percent fixed pay to employees and leaving customers and shareholders to absorb the risk of economic volatility. Thus the EPS funding measure and incentive compensation budget in general, is a mechanism that better balances the interests of customers, employees, and shareholders.

Tying funding for the incentive compensation to the Companies' financial performance also sends a clear message to all employees that it is imperative for them to control costs and it provides a direct incentive for them to do so. This, in turn, enables the Companies to complete work less expensively. Past performance with respect to O&M expense performance measures shows that, when such incentive plan measures are in place, AEP's business units manage their costs sufficiently and make the tough decisions necessary to fund annual incentive compensation even when annual O&M budgets are particularly stringent.

Most of such savings have already reduced Kentucky Power's cost of service and rates for Kentucky customers on a dollar for dollar basis due to inclusion of this O&M savings in prior base rate proceedings. If only 1 percent of the Companies' O&M expense is saved each year due to the incentive compensation program, then millions of dollars per year has been saved by Kentucky customers by virtue of tying incentive compensation to the Companies' financial performance measures. These are not necessarily new cost savings each year and, as such, they are already imbedded in the Company's cost of service and customer rates.

As an example of the effectiveness of incentive compensation, according to Distribution Region Operations Witness Phillips testimony, at the start of 2016, Kentucky Power crews were in the bottom quartile compared to other districts within AEP in productive hours worked per FTE (full time employee). This metric was added as an incentive measure for 2016 and by the end of the year some of the crews were in the top 5 or top quartile . Reliability targets are based on improving reliability indices which lowers the duration of outages that customers experience and how many times per year they experience a power outage. This result shows that Kentucky employees were able to significantly improve the amount of work completed, per day, which increases reliability, customers' satisfaction and customers' experience. Customer satisfaction survey results are also a measure included in the Companies' Incentive Compensation Plan. This measure challenges employees to be more effective customer advocates in meeting customers' needs in a timely and efficient manner.

Q. IS THE COMPANY REQUESTING THE INCLUSION OF ALL TEST YEAR ANNUAL EMPLOYEE INCENTIVE COMPENSATION COSTS IN ITS REVENUE REQUIREMENT IN THIS CASE?

A. No. The Company is including in its cost of service only the *target* (1.0 payout amount) of direct Kentucky Power annual incentive compensation for the test year, not the actual amount, which includes a portion of the substantially above target score earned for calendar year 2016 by Kentucky Power distribution and staff employees. Direct annual incentive compensation during the test year was higher than the target amount requested in the cost of service, because employees achieved strong performance towards their annual incentive goals during calendar year 2016. The Company has normalized these direct costs to the target level in its requested cost of service, which is the amount of direct annual incentive compensation that the company expects to pay in an average year. It is also the direct amount of annual incentive compensation that the Company needs to pay its employees, on average, in order to provide reasonable and customary market-competitive Total Compensation. Direct annual incentive compensation was adjusted to this level as described in the testimony of Company Witness Ross.

Q. IS THE ANNUAL INCENTIVE PROGRAM POTENTIALLY DETRIMENTAL TO CUSTOMERS?

A. No, since the Company's revenue is regulated through this and other rate proceedings, the only way for the Companies' employees to achieve earnings objectives is through cost control, which benefits customers. Furthermore, the balanced scorecard of objectives that the Companies use in its annual incentive program are well-developed to help ensure that some measures are not achieved at the expense of other important objectives, such as safety, operations and environment objectives.

Q. DO THE BENEFITS OF THE COMPANIES' ANNUAL INCENTIVE PROGRAM EXCEED ITS COST FOR KENTUCKY POWER CUSTOMERS?

A. Yes. The target level of the Companies' incentive compensation program does not increase the Companies' compensation expense beyond the employee pay that is required to provide market-competitive Total Compensation. By the same token, any reduction or elimination of the annual incentive compensation portion of employee pay would need to be replaced with increases in base pay to maintain market-competitive Total Compensation. The Companies have achieved substantial cost savings through the financial discipline and other benefits that the Companies' annual incentive compensation program provides, which has reduced the overall cost of service to customers. Reducing or eliminating annual incentive compensation would not only eliminate the potential for future annual incentive compensation driven benefits to customers going forward but would also erode the benefits achieved to date that are already imbedded in the Company's cost of service and rates.

In summary, the Companies' annual incentive program provides substantial benefits to customers. Therefore, it is just and reasonable to include the cost of the

Company's requested level of annual employee incentive compensation in its cost of service.

B. Long-term Incentive Compensation

Q. EXPLAIN THE COMPANIES' LONG-TERM INCENTIVE PROGRAM

A. The primary purpose of the Companies' long-term incentive program is to encourage managers to make business decisions from a long-term perspective. For 2016, the company provided long-term incentive awards in the form of performance units and restricted stock units ("RSUs").

Performance units are generally similar in value to shares of AEP common stock, except that participants' must generally continue their AEP employment over a three-year period to earn a payout and the number of performance units that participants ultimately earn is tied to AEP's long-term performance. All performance units granted and outstanding in the test year were granted with two equally weighted performance measures: three-year total shareholder return ("TSR") measured relative to a peer group of similar utility companies and three-year cumulative EPS relative to a Board-approved target. Both the TSR and EPS measures are capped at reasonable and appropriate levels so that they do not encourage the Companies management to pursue these financial objectives at the expense of other objectives, such as safety.

RSUs are solely tied to the participants' continued AEP employment through vesting dates over a little more than a three year vesting period. Participants who remain employed with AEP through a vesting date receive a share of AEP common stock, or the cash equivalent, for each vesting RSU.

Q. WHAT ARE THE DIRECT BENEFITS TO CUSTOMERS OF THE COMPANIES' LONG-TERM INCENTIVE PROGRAM?

A. As with annual incentive compensation, tying the variable long-term incentive compensation portion of pay to financial performance measures promotes the efficient use of financial resources, which is paramount over the long term to providing reliable service at a reasonable cost. Maintaining long-term financial discipline is imperative for the Companies, its customers and shareholders, particularly given the very long-term nature of the assets that comprise the Company's electric system. The EPS and TSR measures associated with the performance units granted as part of the long-term incentive plan communicate this goal and strongly encourage its continued pursuit by tying a substantial portion of compensation for management and executive employees to both internal and external measures of the Companies' long-term financial performance. This encourages participating employees to reduce expense, operate efficiently, and conserve financial resources, which directly benefits customers by keeping rates low.

Tying funding for long-term incentive compensation to AEP's earnings also retains additional capital in the Companies during periods of weaker earnings performance, which bolsters the Companies' financial stability and provides more capital for system maintenance during periods in which other sources of capital may be overly expensive or inaccessible. My discussion above regarding the benefits of reduced earnings volatility is also one of the benefits of long term incentive compensation. Tying long-term compensation to the Companies' financial performance sends a clear message to participants that it is imperative for them to maintain financial discipline and it provides a direct incentive for them to do so. This, in turn, enables the Companies to complete work less expensively. As with annual incentive compensation, if the long-term incentive program results in only a 1 percent annual O&M expense savings, then millions of dollars per year has been saved by Kentucky customers by virtue of this program over the more than two decades and many base rate cases that it has been in place.

Q. IS THE COMPANY REQUESTING THAT LONG-TERM INCENTIVE COMPENSATION EXPENSE BE INCLUDED IN THE COST OF SERVICE IN THIS CASE?

A. Yes, the Company is requesting that the amount of long-term incentive compensation expense for the test year be included in its cost of service. A cost of service adjustment to long-term incentive compensation expense is provided by Company Witness Ross.

Q. IS THE LONG-TERM INCENTIVE PROGRAM REASONABLE AND NECESSARY TO EFFECTIVELY AND EFFICIENTLY SUPPORT RELIABLE ELECTRIC SERVICE?

A. Yes. The Companies' long-term incentive compensation is a substantial component of the market-competitive compensation for management employees and it is critical to maintaining the market-competitiveness of such compensation. As with annual incentive compensation, the target level of the Companies' long-term incentive compensation is not pay that is over and above an already market-competitive level of total direct compensation. Thus, any reduction in long-term incentive compensation would need to be replaced with increases in other types of compensation in order to maintain reasonable, market-competitive employee pay that attracts and retains the suitably skilled and experienced employees the Companies needs to efficiently and effectively provide its electric service to customers. A large majority of public companies of AEP's size and complexity have similar programs, as do a large majority of public utility companies. Long-term incentive compensation is a substantial component of market median compensation for 100 percent of the 14 executive positions included in Exhibit ARC-6. The Willis Towers Perrin 2016 CDB Energy Services Executive Compensation Survey Report[1], which includes compensation data from 111 employers, indicates that long-term incentive compensation is a significant component of compensation for all 135 positions for which a sufficient data sample was available to report results. AEP provides long-term compensation as part of a market-competitive compensation package to approximately 1,050 employees annually.

Q. ARE THERE ANY INDIRECT COSTS TO CUSTOMERS FOR THE COMPANIES' LONG-TERM INCENTIVE PROGRAM?

A. No. The Companies' long-term incentive goals are established at stretch but achievable targets. This ensures that customers are not paying for long-term incentive compensation that may encourage employees to generate excessive earnings. In addition, any increase in long-term incentive compensation expense above the amount requested would be borne entirely by shareholders, not customers.

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[1] Willis Towers Perrin, 2016 CDB Energy Services Executive Compensation Survey Report, U.S., Position Summary Spreadsheet, Total Sample Summaries.

The goals in the Companies' long-term incentive plan are also balanced by the scorecard goals in the annual incentive plan to assure that the EPS and TSR goals are not achieved at the expense of other important objectives. As with annual incentive compensation, any increase in long-term incentive compensation that might be achieved by reducing spending in operational areas, for example, would likely be at least partially offset by a decrease in annual incentive funding due to the decline in the operating performance scores. As a result of this balanced approach to incentive compensation, AEP's long-term incentive compensation does not encourage behaviors that would be counter to customers' interests and there are not any indirect costs that offset the benefits of long-term incentive compensation to customers.

Q. DO THE BENEFITS OF THE COMPANIES' LONG-TERM INCENTIVE PROGRAM EXCEED ITS COST TO KENTUCKY POWER CUSTOMERS?

A. Yes. Similar to annual incentive compensation, the target value of the Companies' long-term incentive compensation is a portion of market-competitive Total Compensation for employees. Therefore, the target value of Companies' long-term incentive compensation does not have an incremental cost to customers that is above or beyond the cost of providing market-competitive Total Compensation to employees through other types of compensation. As with annual incentive compensation, the long-term incentive program has been in place for many years, so its accumulated ongoing benefits are already reflected in the Company's expense for the test year and incorporated into rates in prior rate proceedings. Reducing or eliminating long-term incentive compensation would not only eliminate the potential for long-term incentive compensation to drive further incremental improvements but would also erode the benefits achieved to date that are already imbedded in the Company's cost of service and rates.

V. EMPLOYEE BENEFITS

Q. PLEASE DESCRIBE AEP'S EMPLOYEE BENEFIT PROGRAMS PROVIDED TO EMPLOYEES.

A. AEP operates an overall benefits program in which all eligible employees may participate.

The programs include medical, wellness, dental, sick pay, long-term disability (LTD), life insurance, accidental death and dismemberment, retirement pension, retirement savings (401k), vacation and holiday benefits. These programs are financed through a combination of employer and employee contributions. Many of AEP's benefit programs, including the medical, dental, and LTD programs, are self-funded using a Voluntary Employee Beneficiary Association Trust, as opposed to utilizing a fully-insured arrangement in which premiums are paid to an insurance company for coverage. Employee contributions, as well as monthly contributions from the AEP companies for each employee, are deposited to the trust and used to fund the actual claims and vendor administration expenses as allowed under law. A brief summary of each benefit plan is outlined in Exhibit ARC-10 (Benefit Plan Design and Employee Cost Summary Grid – 2016).

Q. HOW DOES AEP DETERMINE THAT THE EMPLOYEE BENEFIT PROGRAMS THAT IT OFFERS ARE REASONABLE AND NECESSARY?

A. AEP compares itself with companies from both the utility industry and general industry when benchmarking its total benefit value because AEP must attract employees from a mix of professions and industries. Job seekers often pursue opportunities both within the energy industry and elsewhere in the broad job market. Therefore, AEP's benefits need to be competitive with both the utility industry and broad labor market's benefits in order to attract and retain qualified and competent employees. AEP uses several nationally recognized third-party surveys to evaluate the value, competitiveness, and efficiency of AEP benefits plan offerings and costs. These surveys indicate that AEP employee benefit plans provide a level of employee value that is at or near the mid-range of value, making them both reasonable and competitive with other businesses such that Kentucky Power can attract and retain qualified and competent employees.

AEP performs annual reviews of the reasonableness of the costs associated with AEP benefit plans and continually considers what changes can be made to improve the overall efficiencies of the benefit programs.

Q. HAS AEP TAKEN STEPS TO CONTROL THE COST OF EMPLOYEE BENEFITS?

A. Yes. On an ongoing basis, AEP reviews its employee benefits in an effort to keep costs reasonable, while continuing to provide benefits that are sufficient to attract and retain employees. Periodically, benefit plan changes are made and other steps are taken to control costs.

In 2013, AEP changed its health & welfare and pension benefits by removing many of the incentives to remain on long-term disability (LTD). For example, instead of receiving free medical benefits into retirement, current LTD employees now pay benefit premiums at active employee rates. At the time of this change, current LTD employees were given an opportunity to retire to maintain their free medical benefits. In addition, annual company pension credits were eliminated for LTD employees. Also in 2013, AEP added a spousal surcharge, which is a participant charge assessed when an employee's covered spouse/domestic partner is eligible for medical coverage through another employer.

In 2014, the "Exclusive Home Delivery" feature for prescription drugs was extended beyond the PPO (preferred provider organization) medical plan option to the consumer driven health plan options. This promoted employee's use of the less costly mail-order pharmacy and reduced the number of prescriptions filled at retail pharmacies. In addition, the prescription drug "Member Pays Difference" feature was extended to all medical plan options. This requires plan participants to pay the difference between generic and brand name drugs when the participant purchases the brand name drug in lieu of a less expensive generic equivalent.

In 2015, a tobacco/nicotine product use surcharge was added to all medical plan options. This participant charge is assessed when an employee who uses these products elects coverage under the AEP medical plan. Also in 2015 the medical plan and prescription drug out of pocket maximums and copays were increased for tobacco/nicotine product users. In addition, AEP provided an LTD settlement opportunity that reduced the cost of claims and will save money on claims administration over time.

In 2016, in an effort to allow AEP to continue to offer quality market-competitive medical benefits while slowing the rising cost of health care, AEP moved to consumer-directed medical plans, administered by a single medical vendor to take advantage of provider scale. See Exhibit ARC-10 for the current medical plan options and associated monthly employee costs. In addition, a personal health care dashboard was introduced to help employees take control of their health care by providing them the ability to compare doctors and medical services based on quality, convenience and cost.

Finally, AEP is also an active member of the Health Action Council of Ohio, which is a group of multi-state employers that work to extend group purchasing power to affect the delivery and price of healthcare services in the states in which they operate.

Q. HAVE THE RECENT STEPS TAKEN HAD A DEMONSTRABLE IMPACT ON MEDICAL PLAN COSTS?

A. Yes, The introduction of the spousal surcharge lowered employer plan costs both through the collected premiums and through a reduction in the average number of dependents covered by the plan. Similarly, the tobacco/nicotine surcharge reduces employer cost-share, while promoting healthy behaviors associated with lower projected healthcare spend.

Perhaps most significantly, the move to fully replacing medical plan offerings with consumer-directed options, while also consolidating active employee plans to enable enhanced network discounts, has driven medical spend well below current market trends of a 5-6% cost increase. In fact, these efforts led to a slight year-over-year reduction in AEP'S medical plan cost on a per member basis. The cost per member declined from $13,789 in 2015 to $13,698 in 2016.

VI. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY WITH RESPECT TO COST RECOVERY FOR COMPENSATION EXPENSE.

A. The Companies' employee compensation programs including annual and long-term incentive compensation, are reasonable, appropriate and effective performance drivers that benefit customers. The compensation strategy described in my testimony fosters efficiency, safety and operational improvements. A prudent and market-competitive employee compensation and benefits strategy is necessary to ensure that the Companies is able to attract, engage, motivate and retain the suitably skilled and experienced employees needed to efficiently and effectively provide electric service to its customers. The compensation and benefits strategy that the Companies follow, including annual incentive compensation, long-term incentive compensation and employee benefits, achieves these goals and is a reasonable and customary cost of doing business. This testimony shows that employee Total Compensation and the employee benefits it provides are market-competitive. Annual and long-term incentive compensation is provided to employees as part of this market-competitive compensation package. Therefore, I respectfully submit that the Companies' compensation and benefits, including annual and long-term incentive compensation, should be recovered as requested in the Company's cost of service.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Surveys Completed and Used for Compensation Comparisons

For the Year 2016

Towers Watson U.S. Compensation Data Bank (CDB):

2016 Energy Services Industry - Executive Compensation Survey Report

2016 Energy Services Industry - Middle Management, Professional & Support Compensation Survey Report

2016 General Industry - Executive Compensation Survey Report

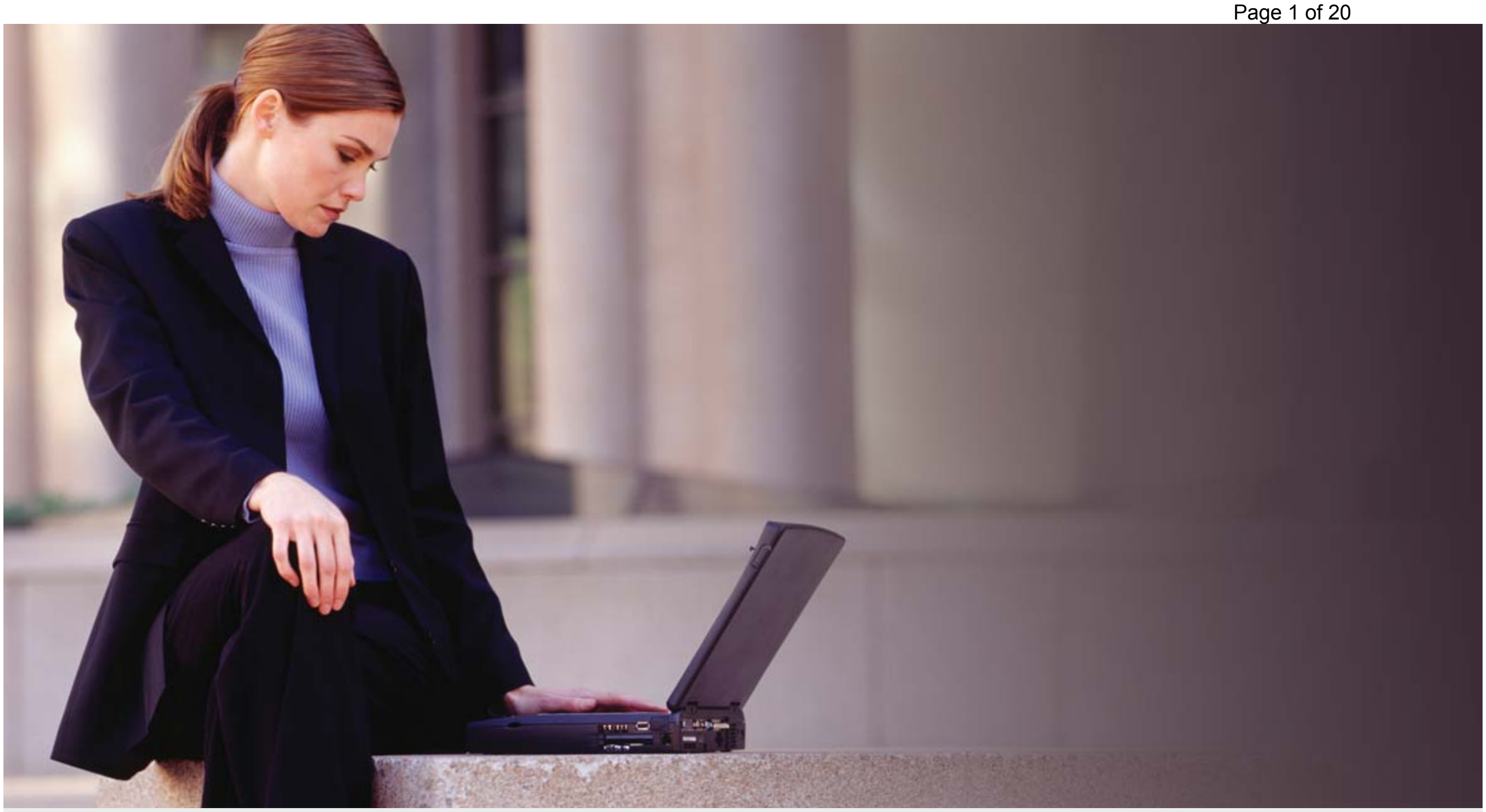
2016 General Industry - Middle Management, Professional and Support Compensation Survey Report

2016 Custom AEP Peer Group - Executive Compensation Surveys

EAPDIS, LLC, 2016 Energy Technical Craft Clerical Survey – ETCCS

Company Witness Andrew R. Carlin has submitted rate case testimony in the following regulatory proceedings:

- On behalf of IM in Michigan Case Nos. U-16180 and U- 16801;
- On behalf of Appalachian Power Company and Wheeling Power Company in West Virginia Case No. 10-0699-E-42T;
- On behalf of Appalachian Power Company in Virginia S.C.C. Case No. PUE-2011-00037;
- On behalf of Kentucky Power Company in Kentucky P.S.C. Case Number 2009-00459 and 2013-00197; 2014-00396;
- On behalf of Southwestern Electric Power Company in Texas Dockets No. 40443, 46449; and
- On behalf of Public Service Company of Oklahoma in Oklahoma Cause Nos. 201000050, 201300217, and 201500208.



2010 Annual Incentive Plan Design

Survey Findings Report

TOWERS WATSON

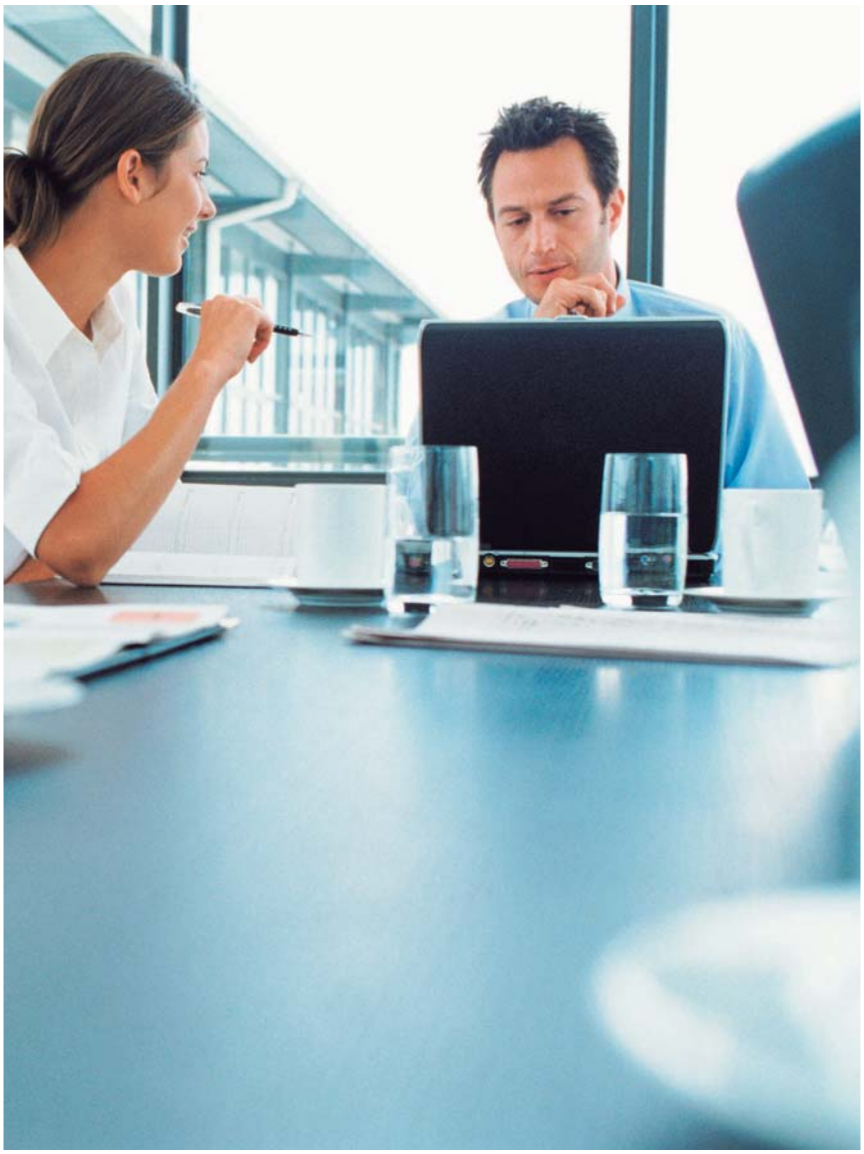
Key incentive plan changes clients have either discussed or implemented include:

- Discretionary awards, possible adjustments to plan metrics and associated communications
- Additional/new metrics (e.g., focus on expense management, use of capital)
- Broader performance ranges, through lower thresholds
- More emphasis on individual objectives
- More ongoing communication to help build employee line of sight

To help companies ensure that their annual incentive plans provide competitive reward opportunities and remain effective in supporting key business and talent goals, Towers Watson conducts ongoing research in annual incentive plan design and operations. Our latest survey of annual incentive plan practices highlights the continuing evolution in plan design, along with some emerging trends in plan management.

2010 Annual Incentive Plan Design

Survey Findings Report



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Overview

In today's turbulent economic environment, organizations face a "perfect storm" of cost, risk, scrutiny and talent management issues. Amid these unprecedented challenges, annual incentive plans continue to play an important role in communicating and reinforcing critical organizational objectives, encouraging desired behaviors and providing competitive total compensation opportunities.

As economic uncertainty continues to cloud the picture, Towers Watson's work with clients during 2009 and the first quarter of 2010 confirms that many pay interventions introduced in response to the current financial crisis have been temporary and tactical, rather than strategic.

Among most companies, decisions about cost still predominate, but the importance of weighing short- and long-term implications is growing. Given that financial and operational results are below historical norms, annual incentive compensation plans are under pressure to respond. But whether adjustments to overall plan design are warranted or have occurred is unclear.

Against this backdrop, Towers Watson's latest survey of annual incentive plan design practices has uncovered some areas where changes have occurred and others where previous plan designs remain the same.

The Towers Watson 2010 Annual Incentive Plan Design Survey is based on a profile of 212 large companies (see Appendix on page 19 for survey participant data). This survey provides detailed information about how organizations based in the U.S. and Canada design annual incentive plans for their top executives. U.S. companies represent 83% of the sample, and Canadian companies represent 17%. Although additional companies can and have joined the survey, the results in this report are based on participants as of December 1, 2009. Towers Watson first conducted the Annual Incentive Plan Design Survey in 1996, following up in 2001 and 2005.

Current plan design practice data are presented, by section, in the remainder of this report of survey findings. Highlights of key trends, developments and changes are organized into three groups:

1. Trends identified in our 2005 survey that remain stable and/or have expanded in practice/prevalence in 2010:

- There is continuing consistency in incentive plan designs within organizations, reflected by the finding that more companies are altering eligibility requirements and offering a single annual incentive plan for executives and other employees.
- Companies continue to be thoughtful about the specific definition of earnings used to measure performance, with relatively less use of earnings per share (EPS) and greater use of earnings before interest and taxes (EBIT or EBITDA) and operating earnings in their annual incentive plans.
- Most companies use two or more performance measures in their annual incentive plans, and the use of sales/revenue as a performance measure has maintained high prevalence.
- There is continued use of a broader and more complex range of performance measures to improve measurement and line of sight.
- Incentive zones and associated payout ranges remain largely unchanged over the past 10 years.
- There is a continued decrease in the use of voluntary deferred compensation arrangements, as companies have adjusted to the additional 409A restrictions that took effect in 2005.

"There is continued use of a broader and more complex range of performance measures to improve measurement and line of sight."

2. Practices identified as emerging/evolving in 2005 that have not taken a firm hold in the market and/or have retreated in 2010:

- The movement away from thresholds and maximum performance levels to mark the bottom and upper limits of bonus payout zones has not occurred.
- Tying target bonus opportunities to peer group or market is a near-universal practice, and the trend away from this approach, as reported in 2005, has reversed.
- In some areas, the use of discretion in annual incentive plan design remains steady. There has not been significant growth in this practice and, in some areas, the use of discretion has decreased. These findings suggest that even in the midst of economic uncertainty — and often increased pressure to exert more discretion — companies have not made significant changes in this area.

3. New approaches in designing annual incentive plans:

- Plan costs — spending on annual incentive plans as a percentage of net income or revenue — are mostly aligned with data collected in 2005, except that actual spending for the most recently completed year (as of October-November 2009) was below target and historical levels. In addition, actual spending for the current/ongoing year is generally expected to be 20% to 30% below target.
- Plan funding — the method used to determine aggregate spending — has seen continued growth in the use of financial results-based funding formulas; the most prevalent funding measures are cash flow and operating income (versus net income in 2005).
- While the number of performance measures used has not changed and there have been small adjustments to the overall list of measures, there has been an increase in the prevalence of cash flow and EBIT/EBITDA.
- The use of individual performance as a weighted measure has been stable for the CEO position at about one-third prevalence, and has increased from one-third to about half for positions below the CEO level.
- In addition to using individual performance, companies are showing increased use of measures at group/sector and business unit/division levels. Companies appear to be willing to increase the complexity and differentiation within the plans in exchange for greater line of sight and linkages to performance.
- The area of setting performance expectations has changed, with a majority of companies currently basing goals on "expected business conditions." In the past, this method was used less frequently and was less common than goal setting based on budgeted performance and year-over-year growth or improvement. This trend may be a temporary reaction to the current economic environment, or it may continue into the future.

Eligibility

"An increasing number of companies align their incentives across the organization, most likely to encourage greater consistency of focus and effort."

This study focuses on annual incentive plans that include the highest level of corporate management, typically the CEO and the company's senior management group. Over the past decade, a majority of companies have shifted away from offering an executive-only annual incentive plan and separate plans for other employees. Today, most companies offer an annual incentive plan to both executives and employees below the executive level.

All the surveyed plans are grouped into the following categories, according to the types of eligible participants:

- **Top-level executive plans** cover only the CEO, direct reports to the CEO and second-tier executives (i.e., direct reports to the CEO's direct reports) — 13% of the sample.
- **Middle management and above plans** cover not only the CEO and senior executives, but also middle managers — 25% of the sample.
- **Broad-based plans** typically extend to certain professional and administrative employees in addition to the CEO, other senior executives and middle management — 62% of the sample.

Continuing a trend started in 2005, a majority of the surveyed plans fall into the category of broad-based plans. In 2001, over half of the surveyed plans were top-level executive plans. An increasing number of companies align their incentives across the organization, most likely to encourage greater consistency of focus and effort.

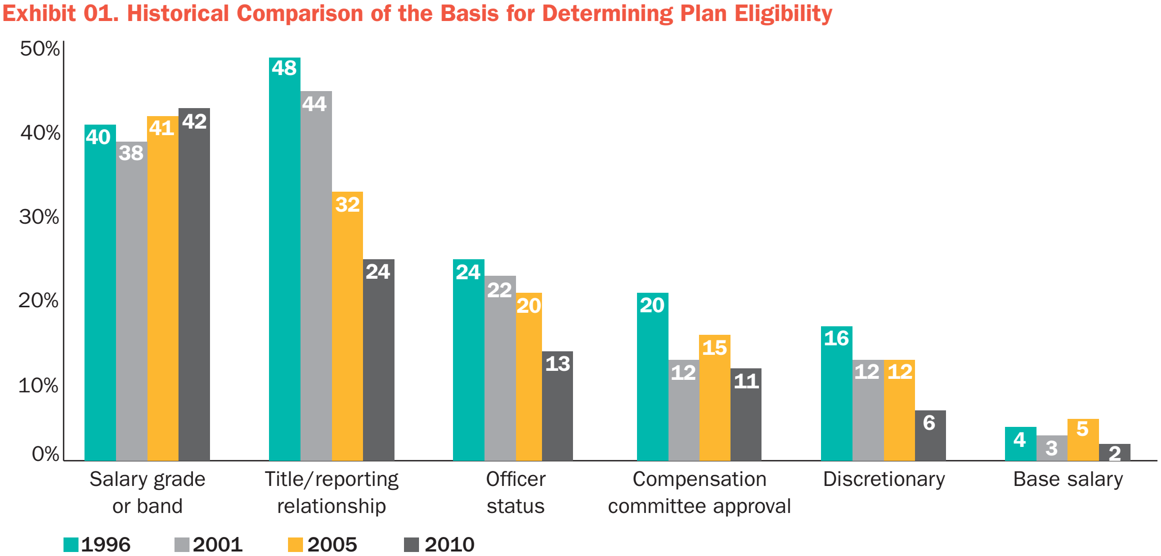
The number of plan participants, as a percentage of total employees, varies by the type of plan:

- **Top-level executive plans** — 0.4% of total employees at the median
- **Middle management and above plans** — 3.1% of total employees at the median
- **Broad-based plans** — over half of these plans include all (or all nonunion) employees in the company; of the broad-based plans that do not include all employees, the median participation is 20% of total employees

Eligibility Criteria

Eligibility to participate in an incentive plan is determined at each company by one or more factors *(Exhibit 1)*. In the 2010 survey, the most common factor for determining eligibility is an employee's salary grade or band. This differs from prior years, when position title, reporting relationship or officer status was a more common factor used to determine incentive plan eligibility. This finding is consistent with the trend toward including employees at various levels in the organization in one plan. In the past, when most survey plans were top-level executive plans that included only the CEO, direct reports to the CEO and their direct reports, an employee's reporting relationship was a simple, straightforward identifier of role and contribution. With plans now extending further into the organization, a more rigorous, contribution-based system (such as salary grades or bands) is used to determine eligibility.

Exhibit 01. Historical Comparison of the Basis for Determining Plan Eligibility



Plan Costs

Incentive plan costs are always a challenging issue for companies as they seek to strike a balance between cost management and competitive bonus levels that will motivate top performance. Given these pressures, often made more intense by heightened executive pay-level scrutiny by shareholders, analysts and the media, companies are carefully monitoring the cost of incentives.

In the 2010 survey, we collected information that allows us to summarize costs for the most recently completed fiscal year (both actual and target) and the current/ongoing fiscal year at target. Across all plans and comparison approaches, reflecting recent economic challenges among participants, actual plan costs are below target levels. These figures may not reflect the total costs of incentives for the companies, because costs may be incurred under other incentive plans not reported in this survey. However these figures do provide a comparison point against which to judge incentive spending.

One insightful way to assess plan costs is to compare the cost of an incentive plan in a given year to the net income generated by the company in that year. The percentage of net income spent on a particular incentive plan is a function of, among other things, how many people participate in the plan, the measures used for incentive purposes and the size of the organization.

Median Plan Cost as % of Net Income

In this year's survey, the portion of net income spent on incentive plans at all three levels is relatively closely aligned with the data in the 2005 survey, except for the actual most recent fiscal-year costs.

	2010 Survey Plan			2005 Survey Plan
	Most Recent Fiscal Year — Target	**Most Recent Fiscal Year — Actual**	**Current/Ongoing Fiscal Year — Target**	**Most Recent Fiscal Year — Actual**
Top-level executive plans	**1.9%**	**1.9%**	**1.7%**	**2.9%**
Middle management and above plans	**4.9%**	**2.8%**	**5.3%**	**5.5%**
Broad-based plans	**6.9%**	**5.0%**	**7.1%**	**6.9%**

Median Plan Cost as % of Revenue

Incentive plan costs as a percentage of company revenue provide an indication of how incentives relate to the size of the organization, with 2010 results similar to 2005 results.

	2010 Survey Plan			2005 Survey Plan
	Most Recent Fiscal Year — Target	**Most Recent Fiscal Year — Actual**	**Current/Ongoing Fiscal Year — Target**	**Most Recent Fiscal Year — Actual**
Top-level executive plans	**0.14%**	**0.12%**	**0.16%**	**0.13%**
Middle management and above plans	**0.29%**	**0.17%**	**0.34%**	**0.37%**
Broad-based plans	**0.63%**	**0.44%**	**0.69%**	**0.64%**

Median Plan Cost as % of Aggregate Base Salaries of Participants

It is important to evaluate the amount spent on incentives in relation to the aggregate base salaries of employees in the plan. Not surprisingly, top-level executive plans pay out the highest percentage of the aggregate base salaries of plan participants.

	2010 Survey Plan			2005 Survey Plan
	Most Recent Fiscal Year — Target	**Most Recent Fiscal Year — Actual**	**Current/Ongoing Fiscal Year — Target**	**Most Recent Fiscal Year — Actual**
Top-level executive plans	**41%**	**36%**	**41%**	**44%**
Middle management and above plans	**27%**	**24%**	**28%**	**32%**
Broad-based plans	**16%**	**12%**	**16%**	**17%**

Plan Costs for Current/Ongoing Fiscal Year

Since the survey data were collected during October-November 2009, we asked participants to report the anticipated/estimated plan costs for the current/ongoing fiscal year (generally, the 2009 fiscal year). This was a new data point in the survey and was not reported by a majority of participants. While we cannot report statistics similar to the plan cost tables above, we conclude that actual spending for the current/ongoing year is generally expected to be in the range of 20% to 30% below target.

Plan Funding

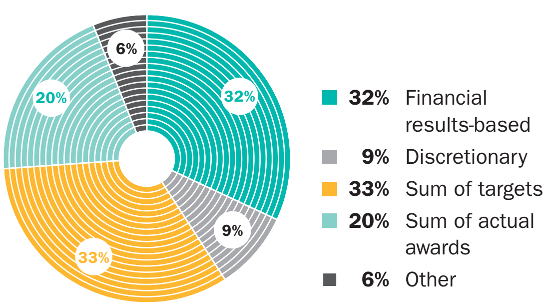
The method used to determine the aggregate size of an incentive pool from which all incentives will be paid plays an important role in achieving a fair balance between the interests of shareholders and plan participants.

Under the *sum-of-targets approach,* the aggregate amount of awards to be paid under the plan in a given year is determined by adding the target awards of all participants. The *sum-of-actual-awards method* is similar, except that actual awards are aggregated rather than target awards. Although over half of the survey plans use one of these approaches, the *financial results-based approach* has shown an increase in comparison to 2001 and 2005 survey findings.

Financial Results-Based Formula

As noted, the use of a funding formula based on financial results, which applies specific financial objectives designed to strengthen the link to company performance, is becoming more prevalent. Almost one-third (32%) of the survey respondents reported using this approach, compared to only 13% of companies in 2001 *(Exhibit 2).*

Exhibit 02. How Incentive Funding Is Determined



Companies that use this method will either create a bonus fund equal to a percentage of a financial measure (e.g., 3% of net income) or a percentage of a financial measure that exceeds a hurdle rate (e.g., 5% of net income in excess of an 8% return on net assets).

The most common performance measures used for plan funding are operating income and cash flow. Net income and pretax income are also used frequently *(Exhibit 3)*. In 2005, net income was the most common measure, and in 2001 EPS was the most commonly used measure in financial results-based formulas.

Exhibit 03. Measures Used in Incentive Plans With a Financial Results-Based Plan Funding Approach

	2010 Survey*	2005 Survey
Operating income	29%	21%
Cash flow	28%	20%
Net income	22%	25%
Pretax income	22%	16%

*Percentages total more than 100% due to multiple responses.

Almost one-half of companies that use a financial results-based formula allocate funds to business units based on performance (e.g., a corporate funding pool is allocated to business units based on business unit performance). The remaining companies are relatively evenly split between allocating at an individual level without first allocating to the business unit level and requiring business units to generate their own award pools.

When it comes to plan funding, it is less common to use a purely discretionary approach to determine the aggregate amount of award money (one unrelated to any established formula). For example, the board or management might look at the year's results and decide the company can afford to pay a total of $10 million in bonuses. Nine percent of companies reported using this approach in 2010, up from 5% in 2005, likely due to the difficulty of budgeting and setting performance expectations in the current economic environment.

"The use of a funding formula based on financial results, which applies specific financial objectives designed to strengthen the link to company performance, is becoming more prevalent."

Measuring Performance

In the drive to improve measurement and make compensation practices more effective, organizations continue to adjust their annual incentive plans by altering design features, usually in ways that are important to individual participants but don't involve a wholesale redesign. While cost is always a consideration for employers sponsoring these plans, typical design changes are made with an eye toward improving the line of sight between individual behavior and the organization's business objectives.

Consistent with our 2001 and 2005 findings, nearly nine out of 10 companies (89%) rely on two or more performance measures. Two-thirds of survey respondents (66%) reported that they currently use three or more performance measures.

While sales or revenue is the single most common annual incentive financial performance measure, four of the next five most common measures are earnings- or profit-based, and cash flow is now tied as the second-most prevalent performance measure (*Exhibit 4,* and *Exhibit 5* on page 11). Performance measures that show the largest increases in prevalence, compared to 2005, are cash flow and EBIT/EBITDA. The combination of sales or revenue with the other most common financial measures suggests that the drive for profitable growth is as strong as ever.

Use of Nonfinancial Performance Measures

Nonfinancial performance measures are often considered effective leading indicators of shareholder value creation and continue to gain in popularity (*Exhibit 6,* page 11). Due to the increasing prevalence of these measures, we have captured a wider range of metrics and categories.

Individual Performance and the Level of Performance Measurement

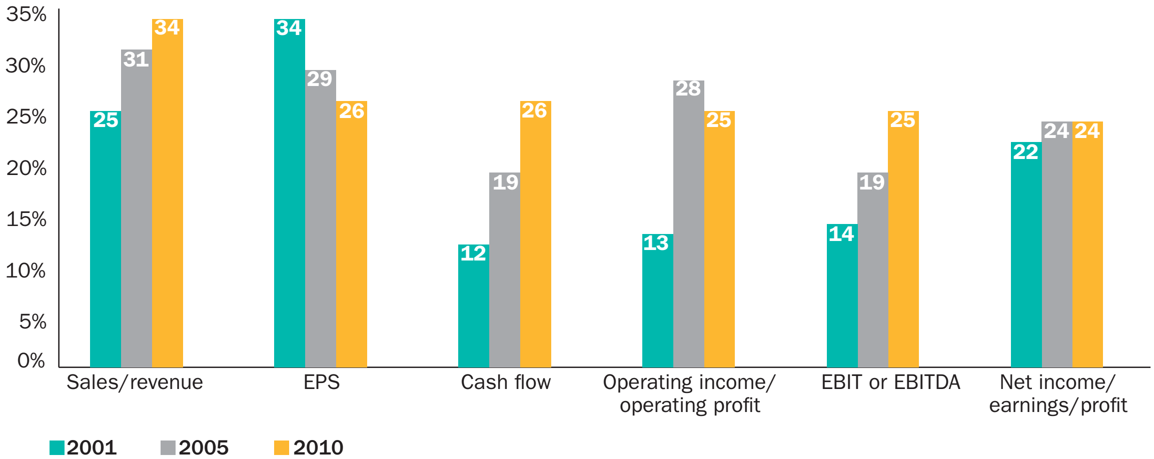
We asked survey participants to report the level at which performance is measured. While some organizations measure performance for the entire company, others measure performance at lower levels. In the latter approach, these companies possibly consider performance for each business unit or division, for the group (which includes several business units or divisions) and/or at the individual performance level.

Exhibit 04. Prevalence of Financial Performance Measures

	2010 Survey	2005 Survey
Sales/revenue	34%	31%
EPS	26%	29%
Cash flow	26%	19%
Operating income/operating profit	25%	28%
EBIT or EBITDA	25%	19%
Net income/earnings/profit	24%	24%
Cost/expense control/reduction	17%	—
Return on investment/return on invested capital (ROI/ROIC)	8%	7%
Return on equity (ROE)	7%	9%
Operating measures (e.g., operating margin)	7%	12%
Pretax income	5%	7%
Working capital	4%	—
Economic profit/economic value added (EP/EVA)	4%	3%
Gross margin	4%	—
Return on assets/return on net assets (ROA/RONA)	3%	4%
Total shareholder return	3%	—
Net operating profit after tax (NOPAT)	2%	—

Percentages total more than 100% due to multiple responses.

Exhibit 05. Historical Comparison of Most Prevalent Financial Performance Measures



A majority (61%) of the surveyed companies measure the CEO solely on corporate performance. In those cases where the CEO's award is based on more than corporate performance, it is usually based on a combination of corporate and individual performance. In short, the two most common CEO performance weightings and combinations are:

- 100% corporate performance
- 80% corporate, 20% individual performance

At lower levels in the organization, it is most common to base awards on two or more levels of performance. Performance measurement for non-CEOs generally depends on the employee's level within the organization.

At the group/sector executive level, common weightings and combinations are:

- 100% corporate performance
- 50% corporate, 50% individual performance
- 50% corporate, 50% group/sector performance

Common weightings and combinations for top business unit or division executives are:

- 25% corporate, 75% business unit/division performance
- 25% corporate, 25% business unit/division, 50% individual performance

Compared to our findings in 2005 and 2001, an increasing number of companies assign a specified weight to individual performance, especially below the CEO level *(Exhibit 7)*. When an individual performance component is included in the CEO's measurement calculation, which is used in 32% of the sample, it is typically assigned a weight of 20%. Individual performance is used below the CEO level by about half of companies, and the typical weighting is 50% of the total incentive opportunity.

Exhibit 06. Prevalence of Nonfinancial Performance Measures

	2010 Survey	2005 Survey
Strategic objectives	**27%**	—
Safety/environmental	**17%**	—
Customer satisfaction	**16%**	**14%**
Team/department objectives	**16%**	—
Volume/production	**7%**	—
Employee satisfaction	**4%**	**4%**

Exhibit 07. Level of Performance Measurement

	% of Organizations Using Measures at Each Level			
	Corporate Measures	**Group/ Sector Measures**	**Business Unit/Division Measures**	**Individual Measures**
CEO	**93%**	—	—	**32%**
Corporate staff	**92%**	**13%**	**5%**	**55%**
Top group/sector executive	**85%**	**46%**	—	**42%**
Group/sector staff	**47%**	**79%**	—	**67%**
Top business unit/ division executive	**52%**	**15%**	**71%**	**49%**
Business unit/ division staff	**38%**	**5%**	**65%**	**52%**

Calculating the Award

Companies that use more than one performance measure must define how these measures will be combined to calculate an individual's bonus. There are three principal approaches:

- The most common method is the *additive approach,* which calculates performance separately for each measure and then adds the associated incentive awards to determine the final award. The prevalence of this approach is 69% and is consistent with prior survey results.
- 16% of respondents use a *multiplicative method* to calculate individual awards, representing an increase over our 2005 and 2001 results. Under this approach, performance under one measure is adjusted by performance under another measure. For example, a bonus calculated on EPS growth is multiplied by a factor based on a second performance measure to determine the bonus award.
- Similar to 2005 and 2001, fewer than 10% of respondents use the *matrix approach,* in which the levels of performance for two separate measures are each assigned an axis on a matrix. The employee's annual award, usually expressed as a percentage of the target amount, is determined by the intersection of the performance levels for the two measures.

"Similar to our previous findings, the use of circuit breakers and/or modifiers was reported by approximately one-third of respondents."

Circuit Breakers

When several measures are used to calculate bonuses, employees generally do not have to meet all the measures to receive some level of bonus. Some plans designate one or more measure(s) as a "circuit breaker" that essentially requires the achievement of a certain minimum level of performance to receive any award payout. Similar to our findings in 2005 and 2001, plans with some sort of circuit-breaker feature were reported by about one-third of respondents. The four most common corporate performance measures used as a circuit breaker, in order of prevalence, are EPS, EBIT or EBITDA, operating income and cash flow. Individual performance is used as a circuit-breaker measure among 9% of companies. For example, some plans are structured so that, no matter how well the company performs, an individual will not receive any bonus unless his or her performance is at least at some threshold level.

Modifiers

Some plans incorporate a final adjustment to the award calculation by applying a modifier. For example, an otherwise determined award can be increased or decreased by a certain percentage based on how well a certain goal is achieved. While this might be similar to the multiplicative approach, typically the modifier makes a smaller adjustment to a calculated award (e.g., an award calculated using the additive approach is modified by 105% if the modifier goal is achieved).

This practice is reported by 30% of survey respondents, versus 20% in 2005. Most often, this modification is based on an individual performance rating. Other common modifiers are EBIT or EBITDA and sales/revenue.

Performance Incentive Zones and Bonus Payout Ranges

The *performance incentive zone* describes the range of performance outcomes for which incremental increases in performance will result in incremental increases in bonus awards. Some plans place no hard limits on performance that can earn a bonus, creating unlimited upside opportunities. Other plans have thresholds and maximums, creating an incentive zone that represents all possible performance levels between the floor and the maximum or cap.

The *bonus payout range* describes the actual dollar amount that can be earned at each level in the performance incentive zone. Like performance incentive zones, payout ranges can be uncapped if there is no maximum. *Exhibit 8* shows an example of an 80% to 120% performance incentive zone, tied to a bonus payout range of 50% to 200% of target bonus. As this example illustrates, an employee in this plan would receive no bonus for performance up to 80% of target and could not earn more than 200% of his or her target bonus even if performance exceeded 120% of target performance.

The size of performance incentive zones and bonus payout ranges varies considerably among survey participants. The median performance incentive zone for most measures is 40%. In other words, the difference between threshold performance as a percentage of target and maximum performance as a percentage of target is 40%. For example, if the performance threshold is 80% of target, the maximum would be 120% of target.

The median bonus payout range is 150% for most performance measures, indicating a payout range, for example, of 50% at the threshold level of performance and 200% at the maximum level of performance.

The 2010 findings regarding performance incentive zones and bonus payout ranges are consistent with our 2005 and 2001 results. This suggests that companies are comfortable with the leverage inherent in their existing plans.

In previous years, performance incentive zones and bonus payout ranges varied slightly according to the performance measure evaluated. In 2010, the median incentive zones and payout ranges were generally the same for all of the most prevalent performance measures. *Exhibit 9* shows slight differences in the median ranges reported for sales/revenue, EPS, cash flow, operating income/operating profit, EBIT or EBITDA, and net income/earnings/profit.

Exhibit 08. Sample Performance Incentive Zone

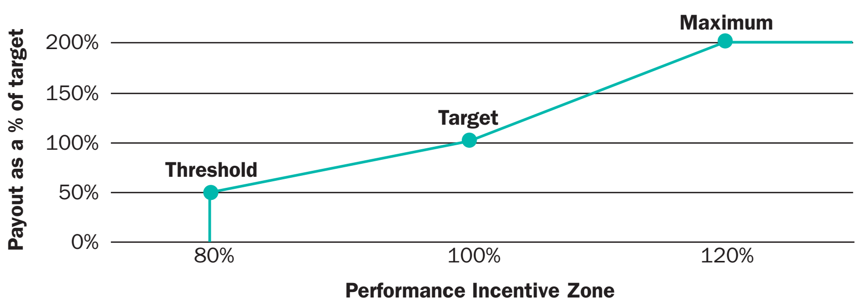


Exhibit 09. Performance Payout Zones

Median responses

	Performance as % of Target			Payout as % of Target		
Measure	**Threshold**	**Target**	**Maximum**	**Threshold**	**Target**	**Maximum**
Sales/revenue	**80%**	**100%**	**120%**	**50%**	**100%**	**200%**
EPS	**80%**	**100%**	**120%**	**50%**	**100%**	**200%**
Cash flow	**80%**	**100%**	**130%**	**50%**	**100%**	**200%**
Operating income/operating profit	**80%**	**100%**	**120%**	**35%**	**100%**	**200%**
EBIT or EBITDA	**80%**	**100%**	**120%**	**50%**	**100%**	**150%**
Net income/earnings/profit	**80%**	**100%**	**120%**	**50%**	**100%**	**200%**

Performance Expectations

Companies must manage performance expectations by establishing standards to identify what constitutes target performance and to assess the extent to which the target has been achieved. In prior years, budgeted performance was the most widely used approach. In 2010, however, the most common approach to establish a performance standard was based on expected business conditions. As many companies use more than one method to set performance expectations, other common approaches include budgeted performance, year-over-year growth or improvement, investor expectations and performance relative to a peer group.

> "In 2010, the most common approach to establish a performance standard is expected business conditions."

The approach used to establish performance standards usually varies, based on the performance measure. *Exhibit 10* shows the frequency with which various performance measures are used to set standards. As might be expected, the standards for financial measures are more likely to be based on budgeted performance or year-to-year growth than nonfinancial measures (e.g., customer satisfaction and employee satisfaction), which are often determined by a peer group comparison, or set by management or the board.

Exhibit 10. Factors That Determine Performance Expectations — by Performance Measure

	2010 Survey	2005 Survey
Determined by management/board based on business conditions	58%	25%
Based on budgeted performance	49%	37%
Year-to-year growth or improvement	30%	27%
Peer group performance or some other external standard	15%	1%
Achievement of strategic milestones	11%	1%
Based on expectations of investors	10%	3%
Timeless/absolute standard	5%	1%
Company's cost of capital	4%	—

Payout Levels

We asked survey participants to report the level of bonus payouts made over the past five years, generally covering the period between 2004 and 2008. The pattern of payout levels follows the general economic environment *(Exhibit 11)*. The prevalence of payments in the target-to-maximum range was consistent during the 2004-2007 time frame. In 2008, there was a sizable increase in the prevalence of payments between minimum and target.

Overriding Plan Design

To address unforeseen shifts in the business climate, many companies maintain a degree of flexibility in the administration of annual incentive awards. Companies also want the flexibility to retain key people and keep high performers motivated in difficult times. Generally, for those positions not subject to IRC Section 162(m), companies have the right to adjust individual awards under the established plan formula — either paying an extra reward as a portion of a bonus not warranted by the level of performance or declining to pay a portion of the bonus that was earned based on the level of achievement.

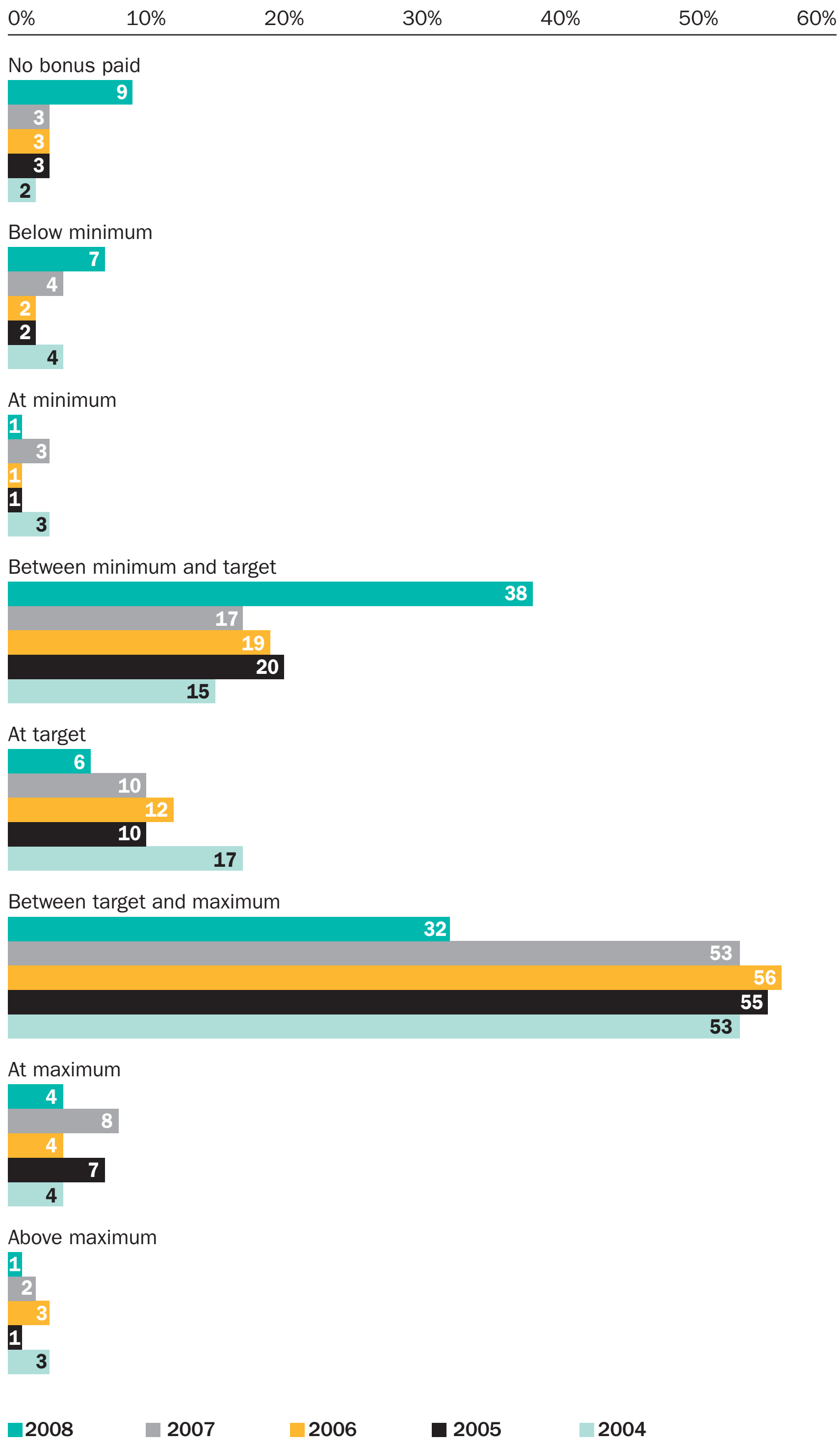
In this survey, we wanted to examine companies' experience with paying awards when performance thresholds were not reached. We learned that about 40% of survey participants had not been faced with such decisions in the previous five years because their organizations had met their thresholds each year.

Another 38% of participants reported they have not overridden the plan when threshold performance was not achieved. This finding suggests that more companies are deciding against overriding plan design. About 20% of survey respondents indicated they have overridden plan formulas and paid a portion of an award either to individuals or groups that did not meet the threshold level of performance. We found that this exception was usually made for a select few individuals rather than for the entire group.

Consistent with our findings in previous surveys, a much smaller percentage of companies (15%) have overridden their plans in the opposite direction, withholding a portion of an award that was earned under their formula. Again, if such an override does occur, it is usually done selectively for some participants.

Exhibit 11. Payout Levels Over Past Five Fiscal Years

% of companies paying out at each level



Award Payment

Size of Awards

The external market exerts considerable influence over incentive practices at individual companies as employers seek to balance their costs with their desire to attract and retain key talent. Of the companies using target bonuses, nearly all (91%) set target opportunities based on external market levels.

External Guidelines

Companies also often look at the bigger picture when trying to calculate the role bonuses will play in an overall compensation package. Again, this helps keep costs in line with objectives while ensuring the organization continues to attract, motivate and retain key talent.

We asked our survey respondents to tell us how competitive they would like to be in both base salary and total cash compensation (base salary plus annual bonus). *Exhibit 12* shows that most companies have targeted pay at the median for base salary and for total cash compensation. However, 26% of companies indicated that they target the 75th percentile for total cash compensation. (Note that target pay is different from actual pay levels.)

Exhibit 12. Desired Competitive Level of Each Compensation Component

	Base Salary	Target Total Cash
Below median	2%	0%
Median	89%	51%
60th percentile	2%	5%
75th percentile	3%	26%
90th percentile	0%	4%
Not specified	2%	12%
Other	2%	1%

Use of Discretion

The use of discretion in awarding incentive payments has become a common practice. Discretion is most likely to come into play with individual performance assessments, but payments can also be adjusted at the discretion of management or the board, or based on business circumstances. A few companies (5%) reported maintaining a special discretionary bonus fund outside the surveyed plans. Thirteen percent of companies reported that awards are not subject to discretion.

Payments in Cash

Most companies reported that their incentive payments are entirely or mostly in cash. About 5% of companies require an alternative, usually some combination of cash and stock. Thirteen percent of companies surveyed have a plan provision that allows bonuses to be paid totally or partially in stock. Among these organizations, it is slightly more common for the company to decide whether the bonus will be paid in stock, in lieu of cash. In some companies, however, participants are allowed to make that decision.

Deferred Payment Arrangements

One-third of the survey group offers plan participants the opportunity to defer payment for individual tax planning or other purposes. However, this practice has decreased significantly since 2001, when over two-thirds of companies reported offering deferral opportunities. This is most likely due to changes in U.S. tax rules, which impose additional restrictions on nonqualified deferred compensation.

"Most companies have targeted pay at the median for base salary and for total cash compensation."

Provisions for Employees Who Leave

Most companies have policies in place for employees who leave during the plan year or after the plan year has ended, but before bonus payments have been made.

If an employee leaves *during the plan year* due to disability, death or retirement, most companies pay a prorated portion of the award *(Exhibit 13)*. If, however, the employee is terminated (for cause) or resigns during the plan year, more than nine out of 10 companies will not pay any bonus. If a person is laid off without cause (e.g., due to a downsizing), companies are divided among paying a partial award, no award or making decisions on a case-by-case basis, with the most common choice being no award.

If an employee leaves *after plan year-end* (but before bonus payments are made) due to disability, death or retirement, most companies will pay the full award *(Exhibit 14)*. If the employee is terminated or resigns after plan year-end, companies are more likely to pay than if the termination occurred midyear. If the individual is laid off without cause after the end of the year, companies are again divided among partial award, no award or making decisions on a case-by-case basis, with the most common choice being to pay the full award.

For the most part, these practices are similar to those reported in the 2005 and 2001 surveys.

Exhibit 13. Bonus Treatment for Status Changes Occurring During Plan Year

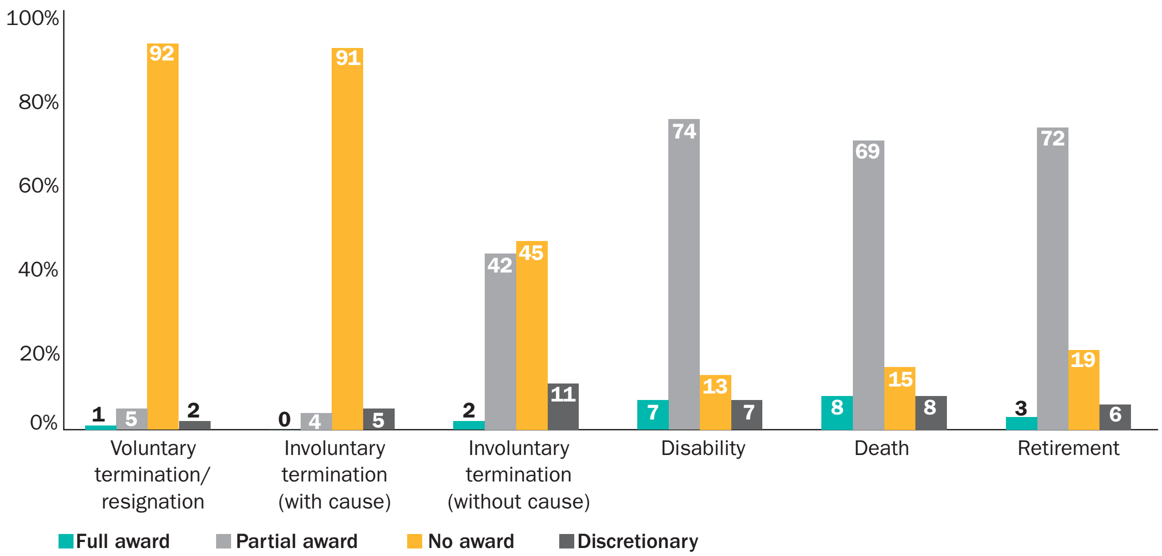
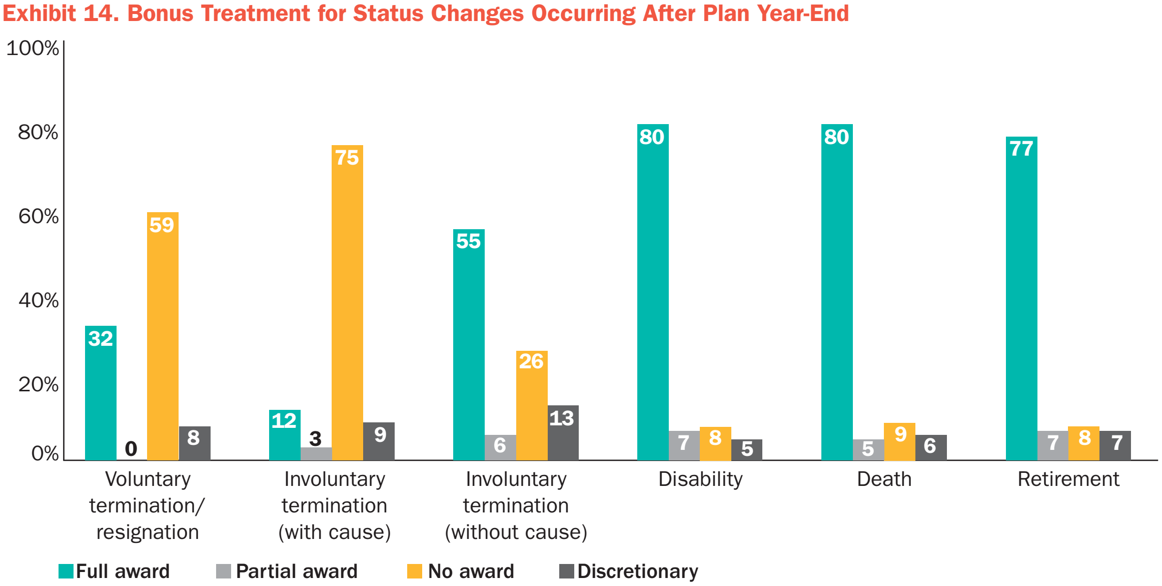


Exhibit 14. Bonus Treatment for Status Changes Occurring After Plan Year-End

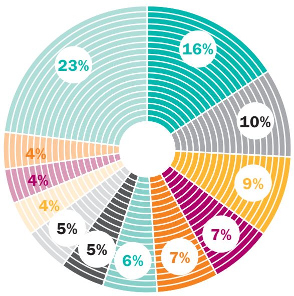


International Issues

About 60% of the companies surveyed include employees outside the home country (either the U.S. or Canada) in their surveyed incentive plan. Almost all of these companies (95%) use a similar plan design to deliver annual incentives to local and third-country national employees on a worldwide basis. Statutory restrictions and market practices are reasons cited by those companies that do not use a similar plan design in other countries.

Appendix

Exhibit A. Participants by Industry



- **16%** Energy services
- **10%** Insurance
- **9%** Food and beverage
- **7%** Financial services
- **7%** Oil and gas
- **6%** High tech
- **5%** Chemicals and gases
- **5%** Industrial manufacturing
- **4%** Pharmaceuticals and biotechnology
- **4%** Retail
- **4%** Telecommunications
- **23%** Other

Exhibit B. Participant List

Number of Participants: 212

Advanced Micro Devices
Agilent Technologies
AGL Resources
Agrium
AIG
Alberta Electric System Operator
Alberta Investment Management
Alliant Energy
Allstate
AMC Entertainment
American Airlines
American Commercial Lines
American Crystal Sugar
American Electric Power
American Family Insurance
American United Life
American Water Works
AMETEK
Anheuser-Busch
A.O. Smith
A&P
ARC Resources
A.T. Cross
Atomic Energy of Canada
AT&T
Automatic Data Processing
Avaya
Avista

BB&T
BC Transmission
Black Hills Power and Light
Blockbuster
Boeing
BOK Financial
BP
Bremer Financial
Brown-Forman

Campbell Soup
Canadian Broadcasting
Canadian Oil Sands
Canadian Pacific Railway
Capital Power
Carlson Companies
Carpenter Technology
CBS
CDI
Century Aluminum
CF Industries
Chevron
Chicago Mercantile Exchange
Chrysler
Chubb
CIGNA
Clearwire
Cobank
Comerica
ConocoPhillips
Constellation Brands
CPP Investment Board
Crown Castle

Dana
Del Monte Foods
Dick's Sporting Goods
Dominion Resources
Domino's Pizza
Dow Chemical
Dow Corning
DPL
Duke Energy
DuPont
Duquesne Light

Eaton
EMC
Energy Future Holdings
Entergy
EQT
Equity Residential Properties
Expedia
Exterran
ExxonMobil

First American
FirstEnergy
First Solar

Genzyme
GNC
Great Canadian Gaming
Greene Tweed

Hanesbrands
Harris
Hayes Lemmerz
H.B. Fuller
Henry Schein
Herman Miller
Hertz
Hewlett-Packard
Hexion Specialty Chemicals
Hoffmann-La Roche
Horizon Blue Cross Blue Shield of New Jersey
Hormel Foods
Hospira
Houghton Mifflin
Humana

IAMGOLD
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IKON Office Solutions
IMS Health
Independent Electricity System Operator
Independent Order of Foresters
Insurance Corporation of British Columbia
International Flavors & Fragrances

J.M. Smucker

Kellogg
Kendle International
Kennametal
Koppers
Kroger

Land O'Lakes
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National Bank of Canada
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Nexen
Nicor
Nordstrom
Northeast Utilities
NRG Energy

Ontario Power Generation
Oshkosh Truck
Owens-Illinois

Pacific Gas & Electric
Pacific Life
Papa John's
Pennsylvania Real Estate Investment Trust
People's Bank
Petro-Canada
Plexus
PolyOne
Portland General Electric
Principal Financial
Prudential Financial

QUALCOMM

RGA Reinsurance Group of America
Royal & SunAlliance Canada

Schreiber Foods
Schwan's
S.C. Johnson
Securian Financial Group
Security Benefit Group
Shaw Group
Spirit AeroSystems
SPX
SRA International
Starbucks
Starwood Hotels & Resorts
Sunoco
Syncrude Canada

Takeda Pharmaceutical
Tarion
Teradata
Time Warner Cable
T-Mobile USA
Toro
Toronto Hydro Electric Systems
TransCanada
Trinity Industries
Tupperware

UniSource Energy
United States Steel
United Technologies
Unum Group

Valero Energy
Valmont
Vectren
Vermilion Energy Trust
Viacom
Viad
Vulcan Materials
VWR International

Warner Chilcott
Waste Management
Wells' Dairy
Western Digital
Western Union
Whirlpool
Williams Companies
Wm. Wrigley Jr.
World Color Press

Xcel Energy

Zale

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EXHIBIT ARC-4 (KPCO Target Total Compensation vs. Market for Technical, Craft and Clerical Jobs)

KPCO Target Total Compensation vs.
2016 EAPDIS Energy Technical, Craft & Clerical Survey (Southeast Region Data)

Survey Job	KPCO Title	EEs	Base[1]	Target Annual Incentive[2]	Target Total Compensation	ETC&C Survey Median Base[3]	ETC&C Survey Median Incentive	ETC&C Survey Median Total Compensation	% Difference KPCO Target Total Comp vs.Survey Total Comp	% Difference KPCO Base vs.Survey Total Comp
Line Mechanic	Line Mechanic-A	32	$73,881	$3,694	$77,575	$80,693	$3,033	$83,726	-7.9%	-13.3%
Storekeeper/Handler	Stores Attendant A	7	$57,990	$2,900	$60,890	$52,465	$1,683	$54,148	11.1%	6.6%
Substation Mechanic/Technician	Station Electrician A	6	$71,375	$3,569	$74,944	$80,693	$3,139	$83,832	-11.9%	-17.45%
Motor Vehicle Mechanic	Fleet Technician A	5	$67,384	$3,369	$70,753	$68,868	$1,717	$70,585	0.2%	-4.8%
Meter Mechanic	Meter Electrician-A	6	$72,991	$3,650	$76,640	$80,693	$3,033	$83,726	-9.2%	-14.7%
Trouble Service Mechanic	Line Servicer	26	$76,128	$3,806	$79,934	$84,800	$3,100	$87,900	-10.0%	-15.5%
Control Operator	Unit Operator	8	$76,196	$3,810	$80,005	$84,405	$3,500	$87,905	-9.9%	-15.4%
Certified Welder	Maintenance Welder	8	$75,878	$3,794	$79,672	$78,317	$5,197	$83,514	-4.8%	-10.1%
Instrument and Control Tech	Control Technician-Sr	3	$76,606	$3,830	$80,437	$80,608	$5,091	$85,699	-6.5%	-11.9%
Equipment Operator	Equipment Operator	1	$66,456	$3,323	$69,779	$72,123	$1,485	$73,608	-5.5%	-10.8%
	Total	102						**Average**	-5.4%	-10.71%
								% of Jobs Above Market Competitive Range[4]	0.0%	0.0%
								% of Jobs Below Market Competitive Range[4]	20.0%	80.0%

Notes

(1) As of November 30, 2016
(2) The Company's target payout is 5 percent of base earnings for all physical and craft jobs
(3) Annualized from April 2016 to November 2016 @ 2.0% salary growth rate
(4) A market competitive range of +/- 10 percent has been used for all physical and craft positions

EXHIBIT ARC-5 (Total Compensation vs. Market for Exempt Positions) Exhibit ARC-5

Compensation Survey Analysis- Exempt Positions

				AEP Incumbent Data			Survey Results[1]			% Difference AEP	% Difference AEP
Survey Job		**AEP Title**	**EE Count**	**Avg Base**	**Target Incentive (2)**	**Target Total Compensation**	**Base**	**Incentive**	**Total Compensation**	**Target Total Comp vs. Survey Total Comp**	**Base vs Survey Total Comp**
KPCO Positions (3)											
Electric Distribution Operations-Career Level	EDD010-P3	Dist Dispatcher Sr	5	$85,742	$8,574	$94,317	$89,352	$12,064	$101,416	-7.5%	-18.3%
Energy Delivery/Distribution Supervisor	EDD020-M1	Dist System Supv	3	$106,701	$10,670	$117,371	$99,780	$14,109	$113,889	3.0%	-6.7%
Energy Delivery/Distribution Generalist/Multidiscipline - Career (	EDD000-P3	Dist Line Coord Sr	3	$84,963	$8,496	$93,459	$85,570	$15,437	$101,007	-8.1%	-18.9%
Electric Distribution Engineering-Intermediate Level (P2)	AZE543-P2	Engineer	3	$81,484	$7,334	$88,818	$76,675	$5,419	$82,094	7.6%	-0.7%
Electric Distribution Engineering-Career Level (P3)	AZE543-P3	Engineer Sr	4	$102,520	$10,252	$112,772	$96,815	$7,770	$104,585	7.3%	-2.0%
Budget Analysis - Specialist (P4)	AFT020-P4	Bus Ops Suppt Analyst Prin	1	$101,866	$10,187	$112,053	$107,959	$13,086	$121,045	-8.0%	-18.8%
Land/Right of Way - Career (P3)	ARE040-P3	Right of Way Agent Sr	1	$81,611	$8,161	$89,772	$89,761	$8,895	$98,656	-9.9%	-20.9%
AEPSC Human Resources (4)											
Diversity/EEO-Multi - Specialist (P4)	AHR110-P4	Workforce Diversity Consult Sr	2	$107,259	$16,089	$123,348	$106,119	$6,952	$113,071	8.33%	-5.42%
HR Gnrlst/Consultant Gnrlst/MultiDisc - Intermediate (P2)	AHR000-P2	HR Representative Sr	10	$67,311	$5,385	$72,696	$69,519	$2,760	$72,279	0.57%	-7.38%
Recruitment Generalist/Multidiscipline - Career (P3)	AHR140-P3	Recruiter Sr	3	$84,531	$8,453	$92,984	$85,672	$5,214	$90,886	2.26%	-7.52%
AEPSC Regulatory (4)											
Regulatory Affairs and Compliance - Intermediate (P2)	ACA050-P2	Regulatory Consultant	6	$74,055	$6,665	$80,720	$73,404	$6,236	$79,640	1.34%	-7.54%
AEPSC Business Logistics (4)											
Materials Planning/Scheduling - Career (P3)	ASC015-P3	Material Coordinator Sr	6	$86,252	$8,625	$94,877	$80,969	$2,965	$83,934	11.53%	2.69%
AEPSC Information Technology (4)											
Database Design and Analysis - Career (P3)	AID060-P3	IT Analyst A	1	$90,867	$9,087	$99,953	$104,279	$8,689	$112,968	-13.02%	-24.32%
Application Development Support - Intermediate (P2)	AID055-P2	IT Analyst B	1	$81,250	$6,500	$87,750	$78,004	$2,659	$80,663	8.08%	0.72%
Application Development Support - Career (P3)	AID055-P3	IT Analyst C	17	$94,530	$9,453	$103,983	$100,189	$7,668	$107,857	-3.73%	-14.10%
Application Development - Specialist (P4)	AID010-P4	IT Software Developer Lead	41	$109,181	$10,918	$120,099	$115,422	$8,690	$124,112	-3.34%	-13.68%
Application Development - Career (P3)	AID010-P3	IT Software Developer Sr	49	$95,959	$9,596	$105,555	$94,464	$3,374	$97,838	7.31%	-1.96%
Application Development - Intermediate (P2)	AIT010-P2	IT Software Developer	9	$80,911	$6,473	$87,384	$78,413	$4,396	$82,809	5.24%	-2.35%
Business Systems Analysis - Career (P3)	AID020-P3	IT Business Syst Anlyst Sr	9	$96,819	$9,682	$106,501	$91,499	$4,601	$96,100	9.77%	0.74%
AEPSC Accounting/Finance/Audit/Legal (4)											
General Accounting - Career (P3)	AFB010-P3	Accountant Sr	24	$74,608	$6,715	$81,323	$83,423	$6,747	$90,170	-10.88%	-20.86%
General Accounting - Entry (P1)	AFB010-P1	Accountant Assc	17	$53,014	$3,181	$56,195	$55,411	$3,987	$59,398	-5.70%	-12.04%
General Accounting - Intermediate (P2)	AFB010-P2	Accountant	22	$62,917	$5,033	$67,950	$66,452	$4,498	$70,950	-4.41%	-12.77%
		Incumbent Count	237						Average	-0.11%	-9.6%
Notes:		Job Count	22								
(1) All survey data aged to November 2016 at 3% annual rate											
(2) Reflects annual target incentive potential for job									% of Jobs Above Market Competitive Range[5]	0.0%	0.0%
(3) Survey Data from March 2016 Towers Watson Energy Services Middle Management & Professional Survey									% of Jobs Below Market Competitive Range[5]	0.0%	27.3%
(4) Survey Data from March 2016 Towers Watson General Industry Middle Management & Professional Survey											
(5) A market competitive range of +/- 15 percent has been used for all exempt positions											

EXHIBIT ARC-6 (Target Total Compensation vs. Market for Executive Positions)
Compensation Survey Analysis- Executive Positions

	AEP Incumbent Data ($,000)[1]						Survey Results ($,000)[2]								
AEP Title	Avg Base	Target %	Target Short-Term Incentive	Target Total Cash Comp	Target LTI	Target Total Comp	Base	STI %	STI $	Total Cash Comp	LTI	Total Comp	% Difference AEP Target Total Comp vs Survey Total Comp	% Difference AEP Target Total Cash Comp vs Survey Total Comp	% Difference AEP Base vs Survey Total Comp
CEO	$1,320	125%	$1,650	$2,970	$6,900	$9,870	$1,252	120%	$1,503	$2,773	$6,624	$9,397	5%	-68%	-86%
COO[3]	$721	80%	$577	$1,298	$1,898	$3,196	$600	80%	$480	$1,123	$1,500	$2,623	22%	-51%	-73%
CFO	$728	80%	$582	$1,310	$1,898	$3,208	$646	75%	$484	$1,145	$1,596	$2,741	17%	-52%	-73%
General Counsel	$613	70%	$429	$1,042	$1,125	$2,167	$584	70%	$409	$992	$1,207	$2,199	-1%	-53%	-72%
Exec 5	$560	70%	$392	$952	$900	$1,852	$489	70%	$342	$831	$831	$1,661	11%	-43%	-66%
Exec 6	$530	70%	$371	$901	$1,000	$1,901	$519	68%	$353	$906	$834	$1,740	9%	-48%	-70%
Exec 7	$436	60%	$262	$698	$832	$1,530	$466	68%	$317	$748	$614	$1,362	12%	-49%	-68%
Exec 8	$357	50%	$179	$536	$344	$880	$330	45%	$149	$503	$322	$825	7%	-35%	-57%
Exec 9[4]	$366	55%	$201	$567	$355	$922	$364	60%	$218	$599	$425	$1,024	-10%	-45%	-64%
Exec 10	$370	55%	$204	$574	$440	$1,014	$426	58%	$247	$676	$522	$1,198	-15%	-52%	-69%
Exec 11	$375	50%	$188	$563	$360	$923	$370	50%	$185	$551	$347	$898	3%	-37%	-58%
Exec 12	$268	40%	$107	$375	$155	$530	$265	40%	$106	$380	$219	$560	-5%	-33%	-52%
Exec 13[5]	$460	70%	$322	$782	$832	$1,614	$429	54%	$231	$671	$442	$1,113	45%	-30%	-59%
Exec 15[5]	$380	50%	$190	$570	$344	$914	$387	50%	$194	$581	$289	$869	5%	-34%	-56%
Incumbent Count	14												7.5%	-45.0%	-65.9%
												% of Jobs Above Market Competitive Range[6]	21.4%	0.0%	0.0%
												% of Jobs Below Market Competitive Range[6]	7.1%	100.0%	100.0%

Notes:
(1) AEP data as of July 1, 2016
(2) Median AEP Compensation Peer Group data from March 2015 Towers Watson Energy Services Executive Survey or proxy filings, in either case aged to January 1 2016 at 3% annual rate
(3) Position benchmarked against the Median less 10% due to job scope
(4) Position benchmarked against the Median less 15% due to job scope
(5) Position benchmarked against the 75th percentile due to job scope
(6) A market competitive range of +/- 15 percent has been used for all exempt and executive positions

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September 2003

Abstract

While the business press suggests that "winning the talent war," the attraction and retention of key talent, is increasingly pivotal to organization success, executives often report that their organizations do not fare well on this dimension. We demonstrate how, through integrating turnover and compensation research, the Boudreau and Berger (1985) staffing utility framework can be used by industrial/organizational (I/O) psychologists and other human resource (HR) professionals to address this issue. Employing a step-by-step process that combines organization-specific information about pay and performance with research on the pay-turnover linkage, we estimate the effects of incentive pay on employee separation patterns at various performance levels. We then use the utility framework to evaluate the financial consequences of incentive pay as an employee retention vehicle. The demonstration illustrates the limitations of standard accounting and behavioral cost-based approaches and the importance of considering both the costs and benefits associated with pay-for-performance plans. Our results suggest that traditional accounting or behavioral cost-based approaches, used alone, would have supported rejecting a potentially lucrative pay-for-performance investment. Additionally, our approach should enable HR professionals to use research findings and their own data to estimate the retention patterns and subsequent financial consequences of their existing, and potential, company-specific performance-based pay policies.

Is it Worth it to Win the Talent War? Evaluating the Utility of Performance-Based Pay

The ability to achieve competitive advantage through people depends in large part on the composition of the work force. This, in turn, is a function of who is hired, how they are developed, and who is retained—the latter of which is the focus of this study. Voluntary employee turnover can be either dysfunctional or functional for the organization, depending on who leaves (Boudreau, 1991; Boudreau & Berger, 1985; Hollenbeck & Williams, 1986; Trevor, 2001). Both low and high performers are generally more likely to leave an organization than are average performers (Jackofsky, 1984; Trevor, Gerhart, & Boudreau, 1997; Williams & Livingstone, 1994). Thus, organizations often will shed poor employees (functional turnover), but will also fail to retain star employees (dysfunctional turnover). It appears, however, that organizational practices can influence the performance distribution of leavers. Specifically, though high performers typically may leave the organization more often than do average performers, they do not necessarily do so. While research consistently reports that an organization's pay system affects the probability of voluntary turnover (Dreher, 1982; Gerhart & Milkovich, 1992; Griffeth, Hom, & Gaertner, 2000; Harrison, Virick, & William, 1996; Porter & Lawler, 1968; Schwab, 1991; Steers & Mowday, 1981; Trevor et al., 1997), the probability of high-performer turnover is particularly sensitive to the strength of the pay-for-performance link (Trevor et al., 1997). Consequently, organizations may be able to design compensation systems to enhance organizational value by targeting retention efforts at the dysfunctional high performer turnover.

This may in fact be increasingly happening as organizations in the United States and abroad are progressing toward linking pay more strongly to performance (Milkovich & Newman, 2002). Although many organizations have expanded their use of plans that reward team, business unit, and corporate performance (Milkovich & Newman, 2002), the predominant basis for pay-for-performance continues to be individual performance (IOMA, 2002; Hewitt Associates, 2002), and survey data indicate that companies believe individual pay-for-performance programs are effective (IOMA, 2002). While there are concerns about the wisdom of pay-for-performance (e.g., Kohn, 1993; Pfeffer, 1998), particularly for individual performance, research reviews find ample evidence that pay-for-performance is associated with higher performance at both the individual (Jenkins, Mitra, Gupta, & Shaw, 1998) and organizational levels of analysis (Gerhart, 2000). Such research, however, has not explicitly examined the mechanisms through which pay-for-performance plans affect individual behaviors to influence the organizational bottom line. One such mechanism involves pay-for-performance's effects on performance-specific turnover, and the associated costs and benefits that contribute to organizational financial performance.

The professional HR literature suggests that influencing the retention of high performers in particular is a crucial matter. Many articles cite the increasing difficulty in obtaining and keeping top talent (e.g., Bartlett & Ghoshal, 2002; Branch, 1998; Chambers, 1998; Rich, 1999). A report based on interviews of over 5,000 executives and managers (McKinsey & Company, 1998), for example, found that 65% of executives believed that they had insufficient talent in the ranks of their top 300 leaders and only 10% strongly believed that their companies retained most of their high performers. Even with the recent economic slowdown, organizations face increased pressures to attract and retain top talent in their most pivotal talent areas. The Bureau of Labor Statistics projects that, by 2010, the labor supply will grow by 17 million (Fullerton & Toosi, 2001) while labor demand will increase by 22.2 million (Berman, 2001), indicating that labor shortages will play increasing roles in the future. Moreover, even if a company is reducing employee headcount, voluntary attrition is often the first and most attractive option (Sherwyn & Sturman, 2002). Each of these circumstances highlights the potential benefits of managerial investments that particularly facilitate top-performer retention.

Few would debate the merits of a performance-based pay practice that, all else equal, resulted in greater retention of high performers. Unfortunately, all else is far from equal when changing an organization's pay systems. Because such changes will affect total labor costs, individual employee pay levels, and subsequent employee behaviors, the critical question becomes one of whether the benefits of such a practice outweigh the costs. We propose that while the potential retention benefits of incentive pay have been recognized, they have yet to be quantified in dollar terms. Moreover, researchers have failed to adequately address actual costs of performance-based bay. Our goal here is to provide the first empirical cost-benefit assessment of the viability of performance-based pay. Our approach should contribute to the pay-for-performance literature by specifying the circumstances that affect the success of pay-for-performance plans.

Our results should also contribute to practice, as the likelihood that HR professionals would apply the research findings to their own organizations should increase if these professionals are provided with a viable technique for doing so. In this paper we demonstrate such a technique. The employee movement utility model of Boudreau and Berger (1985) provides the means to evaluate the dollar value implications of various pay-for-performance strategies, which we illustrate with a step-by-step application to a published turnover and pay-for-performance article. In doing so, we (a) demonstrate how organizational representatives can use research findings, publicly available compensation and turnover data, or their own data to diagnose, inform, and evaluate their own company-specific incentive pay decisions; and (b), demonstrate that this technique will often provide different conclusions from typical decision models that use only traditional cost or accounting analysis.

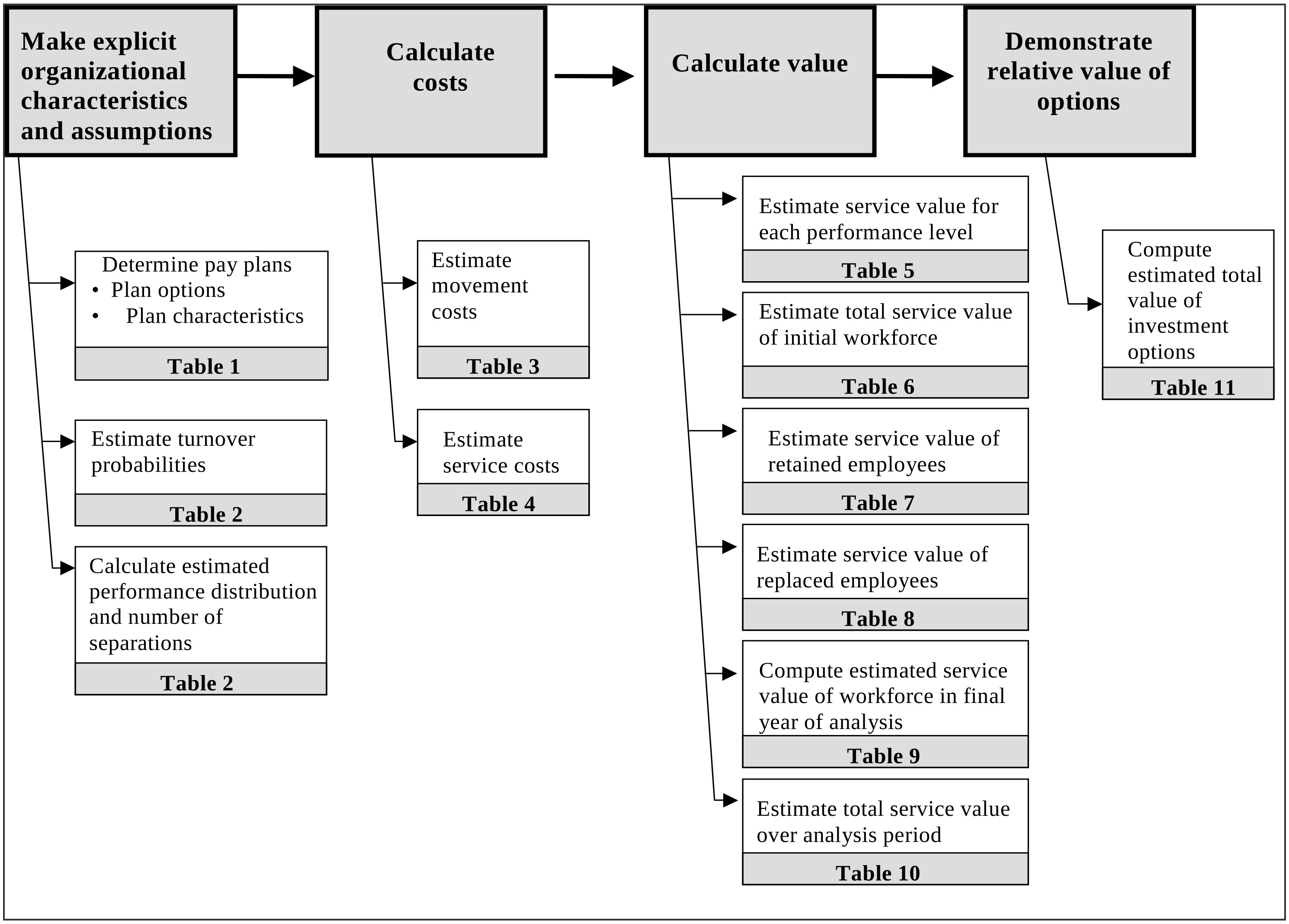
Utility Analysis Applied to Pay Decisions

Utility analysis is a tool for cost-benefit analysis that helps quantify the impact of human resource interventions (Cascio, 2000). While utility analysis has been applied to numerous human resource program areas, most applications have concentrated in the areas of employee selection and training (Boudreau & Ramstad, 2003b; 1999; Boudreau, 1991). The Boudreau and Berger (1985) framework represents one of the few applications to employee retention. Klass and McClendon (1996) used that framework to examine the pay policy decision of whether to lead, lag or match the market. They gathered parameter information from published studies and simulated effects on employee separation and offer acceptance patterns. Results for bank tellers suggested that a lag policy produced higher payoffs, although “leading the market” (paying higher than the average) did enhance retention and attraction of top candidates. The authors noted that these results did not necessarily suggest using a particular pay policy, and showed how simulated reductions in citizenship behavior due to low pay might change the results. This was an important initial application of employee movement utility principles to decisions about pay.

In this paper, we focus on a different type of pay decision – how to allocate pay increases across employees at different performance levels. Trevor et al. (1997) found that pay policies providing greater pay growth for high performers (and less for low performers) substantially increased retention among high performers, encouraged separation among low performers, and thus increased the value of the work force. This is an appealing prospect, but it is unclear whether the enhanced workforce value would offset the cost associated with such a reward system. Such costs are quite apparent using traditional accounting or behavioral costing models, but such models have limited ability to reflect effects on workforce value; furthermore, little data exists on the actual implications of these limitations (Boudreau & Ramstad, 2003a; 2003b). It is also unclear to what extent the enhanced workforce value would depend on such factors as the pay policy specifics, the retention pattern, and the variability in performance. The Boudreau-Berger utility framework provides a method to address these questions.

Using the Boudreau and Berger (1985) separation/acquisition utility model, our paper presents a model that captures the value associated with employee separations (turnover) and acquisitions (hires) over time. The model estimates three components in each time period: (a) movement costs—the costs associated with employee separations and acquisitions; (b) service costs—the pay, benefits, and associated expenses required to support the work force; and (c) service value—the value of the goods and services produced by the work force. The dollar-valued implications of a given pay plan, and of the subsequent separation and acquisition patterns over time, are estimated by subtracting the movement costs and service costs from the service value (i.e., subtracting the pay plan's costs from its benefits). Figure 1 shows the steps necessary to compute this estimate and the tables we employ here to illustrate these steps.

Figure 1
Flow Chart of Utility Analysis Procedure



The Illustrative Case Study

We illustrate our approach using a scenario in which a hypothetical company is considering implementing a pay-for-performance plan at the end of the year 2003. We assume that the company does not currently relate pay to performance, so under the current strategy all employees would receive the same pay increases over time. We compare the effects of this strategy with those of two alternative strategies that place different emphases on pay-for-performance. We choose to evaluate the implications of the three possible approaches over a four-year period (2004 to 2007). Thus, because pay-for-performance affects turnover differently at different levels of performance (Trevor et al., 1997), the 2007 workforce would reflect a different performance distribution under each of the three pay strategies. By calculating the movement costs, service costs, and service values from 2004 to 2007, we can estimate the cumulative effects of the pay strategies over the four-year period.[1]

We used a number of spreadsheets to make the necessary calculations, with each spreadsheet corresponding to a table in this paper. The spreadsheets are available from the lead author upon request, although the descriptions we provide here should be sufficient for many readers to create their own. We also make a number of assumptions to perform the necessary calculations. These assumptions are all based on published research (e.g., Trevor et al., 1997) or publicly available data (e.g., BLS, 2002). First, we draw directly from the Trevor et al. (1997) study to estimate (a) the relationship between pay growth, performance, and turnover that is captured in their survival analysis (see Appendix) and is used to calculate the turnover probabilities at each performance level under each pay strategy; (b) the baseline turnover probability necessary to compute those turnover probabilities that are specific to each performance level-pay strategy combination; and (c) the performance distribution at the beginning of our utility analysis timeframe.

It should be noted that the Trevor et al. (1997) data are from all 5,143 exempt employees hired by a large petrochemical organization between 1983 and 1988. Furthermore, Trevor et al. (1997) examined the effects of various strengths of pay-for-performance relationships based on archival data on individuals' performance and pay levels; they did not specifically manipulate the pay-for-performance link as part of either an experimental or quasi-experimental design. Nonetheless, these data represent a wide variety of exempt jobs over several years, and the results provide valuable insight into the relationships between turnover, pay, and performance. Thus, the results of the Trevor et al. (1997) study are useful for our purpose of illustrating our technique.

Second, we use published surveys (WorldatWork, 2002; BLS, 2002) to help generate realistic pay strategies, determine starting average pay levels, and estimate benefit costs. Finally, we employ the results of published research studies to help provide realistic estimates of the cost of turnover (e.g., Solomon, 1988; Johnson, 1995) and the value of different levels of employee performance (Becker and Huselid, 1992; Boudreau, 1991; Cascio, 2000; Schmidt and Hunter, 1983). We describe the rationale for our assumptions and suggest how professionals might apply each rationale or gather their own data to customize the application for their organizations. Thus, our demonstration is intended (a) to provide information on the value of pay-for-performance plans and the extent that they should ultimately lead to improved organizational financial success; and (b) to enable others to use the method with their own company's data, new research findings, and/or their own estimates to create company-specific evaluations to facilitate their own decision-making regarding the implementation of pay-for-performance policies.

Pay-For-Performance Plans and Performance-Specific Turnover

<u>Step 1: Specify the Pay-for-Performance Options</u>

As is evident in Figure 1, the first major phase in estimating the costs and benefits of performance-based pay is to make explicit the relevant organizational characteristics and assumptions. The initial step within this phase is to specify the pay policy scenarios to be considered. The two key parameters needed are: (a) the current pay level in each performance category for the employees to be considered; and (b) the relationship between pay growth and performance levels (usually expressed in terms of the percentage increase awarded for each performance level). For this second parameter, we constructed three hypothetical, but realistic, performance-based pay strategies. Because we intend to provide a broad range of potential outcomes, within which most particular organizational results should fall, the strategies were chosen to range from conservative to aggressive in terms of the pay-for-performance link. In terms of performance categories, we adopted the nine performance-rating categories used by Trevor et al. (1997), which range from 1.0 (lowest performance) to 5.0 (highest performance) in 0.5 increments, because this will facilitate using other aspects of the Trevor et al. situation as an illustration. Trevor et al. (1997) created the nine categories by computing average performance over time from a rating system in which "The performance scale ranged from 1 = lowest to 5 = highest, with the five categories representing levels of consistency in meeting and exceeding the basic requirements of the job" (p. 49). Professionals adopting our utility analysis framework should change the performance categories to reflect their own performance assessment approach.

Table 1
Pay Strategies and Estimated Four-Year Pay Levels for Each Strategy

Performance Ratings:	1.0	1.5	2.0	2.5	3.0	3.5	4.0	4.5	5.0
Pay Increase for Pay Strategy 1	**4%**	**4%**	**4%**	**4%**	**4%**	**4%**	**4%**	**4%**	**4%**
Pay Increase for Pay Strategy 2	**4%**	**4%**	**4%**	**4%**	**4%**	**5%**	**6%**	**7%**	**8%**
Pay Increase for Pay Strategy 3	**0%**	**1%**	**2%**	**3%**	**4%**	**5%**	**6%**	**7%**	**8%**
2003 Average Pay	**$47,983**	**$47,983**	**$47,983**	**$47,983**	**$47,983**	**$47,983**	**$47,983**	**$47,983**	**$47,983**
Pay Strategy 1: No pay/performance link									
2007 Average Pay	$56,133	$56,133	$56,133	$56,133	$56,133	$56,133	$56,133	$56,133	$56,133
Pay Strategy 2: Pay for performance e link for above average performer									
2007 Average Pay	$56,133	$56,133	$56,133	$56,133	$56,133	$58,324	$60,577	$62,896	$65,280
Pay Strategy 3: Pay for performance link for all performers									
2007 Average Pay	$47,983	$49,931	$51,938	$54,005	$56,133	$58,324	$60,577	$62,896	$65,280

Note: Data provided by the user are in bold.

The details of our three illustrative pay-for-performance plans are shown in Table 1. Pay strategy 1 gives all employees the same average pay increase, regardless of performance level. Data suggest that current pay increases average 4% (WorldatWork, 2002; BLS, 2002; Peck, 2002), so we used this value for all performance categories in pay strategy 1. Pay strategy 2 creates a pay-performance link (i.e., larger pay increases as performance improves) for performers above the middle "3.0" rating, and average pay increases (i.e., 4%) to those rated

3.0 and below. Pay strategy 3 maintains the positive reinforcement of pay strategy 2, and extends the pay-for-performance link to those below the middle rating (i.e., smaller pay increases as performance worsens). Thus, pay strategy 1 provides no performance link, pay strategy 2 is more aggressive, and pay strategy 3 is the most aggressive.

As noted above, in addition to the pay raise strategy, step one requires the setting of an initial pay level upon which the pay strategies will be applied. Because our example involves evaluating the pay-for-performance strategies for white-collar employees, we used the Bureau of Labor Statistics (BLS, 2002) estimate of average 2001 white collar (non-sales) pay, adjusted for the average salary increases of exempt workers for 2002 and 2003 (WorldatWork, 2002). This ultimately yielded a pay level of $47,983 for the year 2003.[2] For illustration, we simply assigned this same initial pay level to every performance category. Then, applying the percentage increase associated with each pay strategy and extrapolating for four future years, we projected the resulting performance-specific pay levels for the year 2007, as reported in Table 1.

In actual organizations, of course, the current pay levels would be available from company records. The same forward-projection method can be used based on these initial values. With observations of real data, it seems likely that initial pay levels will vary across performance categories, reflecting past pay policies, demographics, and performance distributions. While quite easy to observe in practice, pay-performance distributions are likely quite variable, so no obvious method exists to simulate them for our example. Our decision to begin with a uniform pay distribution across categories simplifies the presentation but does not otherwise reduce the generalizability of our approach.

Step 2: Determine Turnover Probabilities

The second step in the making explicit of organizational characteristics and assumptions (i.e., the first major phase in Figure 1) is to estimate the probability of separation at each performance level for each pay strategy. This step defines the key link between performance-based pay and workforce composition. For practitioners, this may represent the most novel element of the model, yet we believe it is quite feasible. We describe several methods for estimating these probabilities.

Estimation using existing research literature

Perhaps the most straightforward approach is to refer to existing empirical findings. For our hypothetical example, we use the performance level/pay strategy specific separation results generated by Trevor et al. (1997). Professionals employing utility analysis likely would prefer to access separation probabilities from a study of an employee population that resembled their own employees in terms of occupations, industry, and demographics. To date, however, the Trevor et al. (1997) study is the only published work from which the performance level/pay strategy specific separation probabilities can be estimated. While future research providing such information for different employee populations would be helpful, in their absence, the Trevor et al. (1997) results offer a useful starting point.

Estimation using organizational data

A second option for generating the performance level/pay strategy specific separation probabilities that are necessary for the cost-benefit analysis would be for professionals to estimate them using their own organization's data. In most companies, separation rates are customarily calculated for entire job categories and are seldom broken down by performance levels. Even when separation rates are reported by performance levels, they are rarely further broken down to reflect pay growth. Yet, if yearly individual-level information on performance, pay level, and separation is available, it can rather easily be converted into the required separation probabilities estimates.

First, professionals can compute each employee's average pay growth and average employee performance over a specified time period (e.g., over the last three years). These relatively continuous data can then be used to slot employees into performance level/pay strategy categories, such as Table 1's 27 categories that were created from all combinations of three pay strategies and nine performance levels. This approach would be repeated for all appropriate performance level and pay growth combinations, thus yielding counts of employees that fit each category. After compiling these counts, the second step would be simply to divide each category's number of voluntary separations by the number of employees in that category. This would yield the estimates of the separation probabilities specific to each performance level/pay strategy combination that are necessary for conducting the cost-benefit analysis of performance-based pay.

While relatively simple to describe, estimating category-specific separation probabilities from one's own organization involves two potentially difficult hurdles. First, to estimate the separation probabilities with any degree of reliability, there must be an adequate number of employees in the categories of interest. If the number of employees in a given category is low, then the resultant average rate of turnover may be strongly influenced by sampling error rather than reflecting an accurate estimate of that category's true turnover likelihood (e.g., a category with one employee mandates an unrealistic separation probability estimate of either one or zero). Thus, the HR professional or I/O psychologist must be working with relatively few categories and/or with large employee populations. A second serious problem with the approach described above is that it will produce separation probabilities that are likely to be confounded by other factors that are related to turnover, performance, and pay growth, such as pay level, age, gender, and tenure with the organization. Hence, though computing performance level/pay strategy specific separation probabilities for one's own organization is relatively simple, its value may be limited.

Fortunately, two statistical methods are available for dealing with the confounding and employee-per-category problems. While both of these methods require a statistical package and reasonable statistical sophistication, I/O psychologists may well have been exposed to one or both of the methods. If not, their training still may well have provided them with a methodological foundation sufficient to allow them to learn the techniques, particularly with the advances in user-friendly statistical software. Alternatively, HR professionals or I/O psychologists could simply hire a consultant to assist with the analyses.

Logistic regression and survival analysis can be used to estimate separation probabilities. Both explicitly account for the potential confound described above by statistically controlling for the effects of these other variables. The analyses yield partial coefficients that are net of the effects of the potentially confounding variables. The partial coefficients are then used to compute separation probabilities needed to conduct the cost-benefit analysis. Both methods also exploit the full range of the relatively continuous salary growth and performance data, rather than requiring pre-established categories that necessarily result in a loss of information. Logistic regression estimates the probability of separation over a specified time period. Survival analysis (Kalbfleisch & Prentice, 1980) computes the probability of survival (i.e., not separating) over a specified time span, and accounts for the length of time an individual stays before leaving the organization. In other words, survival analysis specifically models how long an individual remains with an employer before leaving, whereas logistic regression models whether a person leaves or not. While both methods are appropriate for estimating the separation probabilities specific to the performance level/pay strategy combinations of interest, each offers advantages under certain circumstances (for a complete discussion of this issue, see Morita, Lee, & Mowday, 1993). Our Appendix describes the use of survival analysis to calculate the required separation probabilities that are specific to each of our performance level/pay strategy combinations.

<u>Estimated separation probabilities for the example.</u>

For our example, we used the survival analysis results reported in Trevor et al. (1997), which estimated a survival model from data on a sample of exempt employees in one organization. The analysis produced a mathematical function describing survival probabilities as a function of salary growth and performance, which we present in the Appendix. Substituting a specific salary growth amount and performance level into the equation produces an estimated survival probability that is appropriate for that performance level and salary growth combination. Thus, we used the equation reported in Trevor et al.'s (1997) Table 4 (p. 54) to compute the separation probability (1.0 minus the survival probability), for each performance category under each pay strategy, at the end of our example's 4-year period. The estimated separation probabilities are presented in the top part of Table 2.

Table 2

Turnover Probabilities, and Estimate Number of Retained and Replaced Employees

Performance Ratings:	1	1.5	2	2.5	3	3.5	4	4.5	5	Total
Number of employees	**60**	**97**	**1171**	**1090**	**1667**	**672**	**317**	**46**	**23**	5143
Turnover Probabilities[1] (Probability of leaving the organization by 2007)										
Pay Strategy 1	**0.96**	**0.65**	**0.38**	**0.25**	**0.21**	**0.22**	**0.27**	**0.41**	**0.66**	
Pay Strategy 2	**0.96**	**0.65**	**0.38**	**0.25**	**0.21**	**0.14**	**0.11**	**0.11**	**0.14**	
Pay Strategy 3	**0.99**	**0.88**	**0.60**	**0.35**	**0.21**	**0.14**	**0.11**	**0.11**	**0.14**	
Retained Employees (2007)										
Pay Strategy 1	2	34	726	818	1317	524	231	27	8	3687
Pay Strategy 2	2	34	726	818	1317	578	282	41	20	3818
Pay Strategy 3	1	12	468	709	1317	578	282	41	20	3428
Replaced Employees (2004 - 2007)[2]										
Pay Strategy 1	58	63	445	273	350	148	86	19	15	1457
Pay Strategy 2	58	63	445	273	350	94	35	5	3	1326
Pay Strategy 3	59	85	703	382	350	94	35	5	3	1716

Notes: 1. These values were based on analyses from the Trevor et al. (1997) study. Those performing their own analyses would need to complete the table with their own company-specific data, or use approximations from the Trevor et al. results. See the Appendix for how we used the Trevor et al. results to obtain our values above.
2. Recall that we are evaluating the effects of the different pay policies going into effect at the end of 2004. Thus, while our data are based on the state of the workforce at the end of 2003, we are evaluating the effects of the programs in 2004-2007.
3. Data provided by the user **are in bold.**

We caution that our use of the Trevor et al. (1997) survival analysis provides reasonable separation probability estimates, rather than definitive ones. It is certainly probable that other factors could also influence the probability of turnover. For example, equity theory suggests that even when high performers receive the same pay increase (such as under Pay Strategy 2 and Pay Strategy 3), their turnover likelihoods may differ as a function of how referent others (e.g., low performers) are compensated. Our approach does not take this into consideration. Thus, the reader should keep in mind the imperfections associated with relying on any single study, model of turnover, or data set to estimate turnover probabilities.

Step 3: Determine Performance Distribution and Number of Separations

So far, we have established the pay increase that individuals in each performance level will receive under the different pay policies, and we have subsequently established the separation probabilities for each performance level/pay strategy category. Next, we need to project the number of separations in each performance level/pay strategy category over time. We specified our initial hypothetical employee group (those at the end of year 2003) to mirror in size and performance distribution the 5,143 employees analyzed by Trevor et al. (1997), which is shown in Table 2 (in actual organizations, the initial number of employees in each performance category would be identified through a straightforward count). We then multiplied the initial number of employees in each performance level/pay strategy category by the appropriate separation probability. Table 2 presents the resultant category-specific numbers of employees that separated (and will need to be replaced) and employees retained.

At this point, a traditional analysis of total separations would likely lead to a decision to adopt pay strategy 2, the moderately-aggressive policy through which performers above the midpoint receive higher pay increases. As Table 2 indicates, the number of separations over the four-year analysis period is 1,326 for pay strategy 2, while it is 1,457 for pay strategy 1 and 1,716 for pay strategy 3. Based only on separation rates, pay strategy 3 seems the least attractive policy. However, such conclusions are simplistic and superficial from a cost/benefits perspective; a more sophisticated and meaningful inference regarding the implications of the three pay strategies requires an analysis incorporating critical financial data.

Estimating the Cost of Pay-For-Performance Plans

Step 4: Determine Movement Costs

In steps one through three, we specified the pay-for-performance options, the estimated separation probabilities, and the subsequent numbers of separations and necessary replacements from each performance level/pay strategy combination. Hence, one key financial outcome to be considered is the projected cost of employee movements into and out of the workforce under each pay policy. As we see in Table 2, relative to the retention effects of simply providing everyone with the same salary increase (pay strategy 1), pay strategy 2 reduces overall separations, while pay strategy 3 increases them. We next translate these projected separations and replacements into financial costs.

We refer to the combined costs of employee separations and replacement acquisitions as movement costs. These costs include direct expenses, such as separation costs (e.g., exit interview, separation pay), replacement costs (e.g., advertising, travel expenses, interviewing and testing candidates), and training costs (e.g., informational literature costs, paying trainers). Movement costs also include indirect expenses, such as the lower productivity of new employees as they learn the job, time spent by managers having to supervise new employees more directly, and diminished productivity of veteran employees as they mentor and help new employees (Cascio, 2000). While such costs are not standard elements of traditional accounting systems, organizations increasingly employ software and reporting algorithms that calculate such metrics as turnover costs, costs per hire, etc. If these are available, one can simply multiply the relevant cost by the number of separations and/or replacements that emerge under each pay strategy.

Data available to calculate movement costs varies widely across companies. When movement costs are not readily available from the organization, one can turn to research. For example, Solomon (1988) suggested that movement costs range from 1.5 to 2.5 times the annual salary paid for a job (Solomon, 1988), while Johnson (1995) suggested that movement costs range from 93% to 200% of the position's salary. In our example, we estimated the movement cost associated with each separation as two times the average salary of all employees in the year of the separation (note that average salary will vary according to pay strategy). We also assumed that each separation is replaced, and thus we combined all separation and acquisition costs into a single estimate labeled movement costs. Should replacement not be expected, such as during a downsizing, separation cost estimates should be applied to the number of separations, and replacement acquisition costs should be applied to the number of replacements (Boudreau & Berger, 1985).

Table 3 provides the necessary information to estimate movement costs for our example. At the top of the table is the workforce's average salary in 2003 and in 2007 under each of the three pay strategies. As noted above, we multiplied this salary by 2.0 to estimate the average movement costs for each separation, which is shown for years 2003 and 2007. We then subtracted the 2003 average movement cost from the 2007 average movement cost and divided by four to get yearly movement cost increase, which we added to the 2003 average movement cost to get the 2004 average movement cost. This was added to the 2007 average movement cost and the sum was divided by two to compute the average (2004-2007) movement cost per separation. Table 3 also provides the total projected number of separations/replacements from Years 2004 to 2007, which were calculated in Table 2. Total movement costs for each pay strategy over the four-year period were then calculated by multiplying each pay strategy's total number of projected separations/replacements by each pay strategy's average movement cost per separation/replacement.

Table 3

Estimated Four-Year Movement Costs Under Different Pay Strategies

	Pay Strategy 1	Pay Strategy 2	Pay Strategy 3
Average Salary			
2003	$47,983	$47,983	$47,983
2007	$56,133	$56,914	$55,966
Movement Cost Multiplier (cost of separation as multiple of salary; same for all three Pay Strategies)	**2.0**		
Average Movement Costs (per separation)			
2003	$95,966	$95,966	$95,966
2007	$112,266	$113,828	$111,932
Yearly Increase in Average Movement Cost	$4,075	$4,466	$3,992
2004 Average Movement Cost	$100,041	$100,432	$99,958
Average Movement Cost (2004 - 2007)	$106,154	$107,130	$105,945
Number of Separations	1,457	1,326	1,716
Total Movement Costs[1]	$154,666,378	$142,054,380	$181,801,620

Notes: 1. Total Movement Costs were calculated assuming a linear growth in movement costs and an equal number of separations in each year. Thus, Total Movement Costs could be calculated as the number of separations times the average 2004 - 2007 movement costs. For simplicity, we assumed a constant rate of movement cost increase over time. This could easily be modified if an organization projected very significant increases or decreases in costs per movement in a given year, but such large discontinuities seem unlikely.
2. Data provided by the user **are in bold.**

Table 3's total estimated movement costs were $154.67 million, $142.05 million, and $181.80 million for pay strategies 1, 2, and 3, respectively. Compared to pay strategy 1 (giving equal pay increases to everyone), the turnover reduction associated with the policy of linking pay and performance for high performers (pay strategy 2) saves $12.61 million in movement costs over four years. Linking pay and performance for both high and low performers (pay strategy 3), however, creates additional separations among low performers and thus incurs four-year movement costs of $27.13 million and $39.75 million more than those incurred through pay strategies 1 and 2, respectively.

Some of these costs would be evident with standard accounting tools, to the extent that they represent “out-of-pocket” costs such as fees to search firms or consultants providing exit interviews. However, as mentioned above, many of these costs (e.g., staff time spent in processing separations and acquisitions) are “opportunity costs,” and only a portion of these savings (costs) would be recorded by the accounting system. Thus, our analytical approach offers the advantage of a more complete cost analysis for incentive pay strategies. Still, movement costs represent only one of the crucial financial implications of using pay-for-performance to manage performance and turnover. Hence, we next address the pay strategies’ substantial implications for differences in costs associated with pay levels, benefits, and other service costs.

Step 5: Estimate Future Service Costs

Service costs are the total costs required to retain and support the work force, and thus include pay and benefits (Boudreau & Berger, 1985), the latter of which is typically the largest service cost component other than pay. In some cases, service costs may vary with employee performance. For example, there may be significant bonuses or stock options, or higher performers may use significantly more materials or resources than lower performers. In these cases, which would tend to be of more relevance in executive populations, such variability in service costs should also be taken into account. Absent such factors, estimating service costs simply involves adjusting projected salary levels upward to reflect additional service costs (i.e., benefits), multiplying the resulting values by the number of employees in each year, and summing the products across years. Because we define total service costs as salary plus benefits in our example, we estimate each year’s service costs by estimating the ratio of total remuneration (employee benefits plus salary) to salary, and then multiplying this ratio by projected salary levels under each pay policy.

In Table 3 we had established, for each pay strategy, the average salary levels for the full work force in 2003 and 2007. Because we assumed that benefits were 37% of salary (U.S. Department of Labor, 2001), we multiplied Table 3’s average salary levels by 1.37 to reflect the

2003 and 2007 average service costs for each pay strategy (see Table 4). Using the assumption that service costs increased linearly from 2003 to 2007, we then computed, for each of the three pay strategies, (a) the average service cost increase (2007 service cost minus 2003 service cost, divided by four), (b) 2004 service cost (2003 service cost plus the average service cost increase), (c) the average 2004-2007 service cost (2004 service cost plus 2007 service cost, divided by two), and (d) the total 2004-2007 service cost (average 2004-2007 service cost times four, the number of years in our simulation, times 5143, the total number of employees in each year).

Table 4
Estimated Four-Year Service Costs Under Different Pay Strategies

	Pay Strategy 1	Pay Strategy 2	Pay Strategy 3
Average Service Cost Multiplier (per employee)	**1.37**	**1.37**	**1.37**
Average Service Cost			
2003	$65,737	$65,737	$65,737
2007	$76,902	$77,972	$76,673
Yearly Increase in Service Costs	$2,791	$3,059	$2,734
2004 Average Service Cost	$68,528	$68,796	$68,471
Average Service Cost (2004 - 2007)	$72,715	$73,384	$72,572
Total Service Costs (2004 - 2007)	$1,495,892,980	$1,509,655,648	$1,492,951,184

Notes: 1. Average service cost per employee is assumed to equal 1.37 times Table 3's average salary under each pay strategy. Total costs were calculated assuming a linear growth in service costs. Thus, it was estimated to equal the number of employees times the number of years times the average service costs (2004-2007).
2. Data provided by the user **are in bold.**

An implication of our decision to use the workforce average service costs to estimate total service costs is that it implicitly assumes that replacement employees will be paid at the average level of the workforce they enter. The framework of this model can certainly accommodate other assumptions (e.g., stronger pay-performance links will attract better performers who will be paid more), and would allow practitioners to incorporate such data when appropriate. We adopted the workforce-average assumption for simplicity.

Pay strategy 2 yielded the highest service costs; it is projected to cost $13.76 million more than pay strategy 1 (no performance-pay relationship). Under pay strategy 2, pay is always equal (for performers at or below the performance midpoint) or higher (for performers above the midpoint) than pay in strategy 1. Pay strategy 3 raises the pay for higher performers, but also lowers pay for lower performers, resulting in costs of $2.94 million less over four years than pay strategy 1, and $16.70 million less than pay strategy 2.

Service costs (i.e., pay and benefits) are highly visible to standard accounting systems. In fact, one could argue that they are the most visible elements of human capital in standard accounting. Thus, if standard accounting were used to evaluate these pay policies, the costs shown in Table 4 would likely be quite evident, and would perhaps suggest an argument for pay strategy 3 to organizational constituents who rely on accounting information for their decisions. Given that the movement costs analysis suggested pay strategy 3 as the least economical approach, however, it is clear that relying on only a single type of cost information may well provide an inaccurate basis for a decision. When we do aggregate the total movement and total service cost data from Tables 3 and 4, we see that pay strategy 3 is the most expensive, costing over $23 million more than pay strategy 2 and over $24 million more than pay strategy 1.

Consequently, from a cost-based perspective, we might conclude that undertaking an aggressive pay-for-performance system to “win the talent war” is not worth the investment. We instead caution that such an inference (and any decisions based on it) is at the least premature and is potentially detrimental to the organization. High performers provide greater value than do low performers, and any assessment of an HR program that differentially affects the performance distribution of the workforce must account for this. HR investments must be examined for both their “efficiency” and “effectiveness” (Boudreau & Ramstad, 2003b). Hence, having addressed the movement and service costs implications of the three pay strategies’ effects on turnover, we next turn to the strategies’ implications for workforce’s value, an often overlooked but absolutely essential consideration when assessing the financial practicality of human resource interventions.

Estimating the Value of Pay-For-Performance Plans

Step 6: Determine Service Value

Although our analyses have focused on the cost implications of the pay-for-performance strategies, such strategies also can produce value through the elimination of poor performers (and their subsequent replacement by average performers), and, in particular, the retention of high performers, whose retention is especially sensitive to pay-for-performance effects (Trevor et al., 1997). Moreover, when differences in individual performance are high (i.e., when a high performer is worth much more to the organization than an average performer), retaining top employees and eliminating poor employees may yield value that far outweighs the associated costs (Boudreau & Berger, 1985; Boudreau, 1991; Boudreau & Ramstad, 1999; 2003a; 2003b).

To examine the potential effects of performance-based pay on workforce value, we need to estimate the dollar value of individual performance variation. This will allow us to estimate the effect that changes in the workforce's performance distribution will have on workforce value. Our data provide estimates of changes in the performance ratings, so we must convert ratings to dollar values. This conversion method requires two components (Boudreau & Berger, 1985): (a) the dollar value of the average performance level; and (b) the incremental value of deviations from that average performance level.[3]

We employed the Schmidt and Hunter (1983) approach, which assumes that the value of the average performance level would equal 1.754 times the average wage at that level. For the 2003 work force, we multiplied Table 3's average salary of $47,983 by 1.754 to obtain a service value of $84,162 per person. For the 2007 work force, consistent with the estimate of average service costs above, we estimated average salary as that which would have been produced by four years of average salary increases, beginning in 2004. As noted in Table 3, the average 2007 salary under pay strategy 1, which allocates average salary increases across the performance distribution, is estimated to be $56,133. Multiplying this salary by 1.754 produces an average work force value estimate of $98,457 per person. These 2003 and 2007 average service value estimates are shown in “average service value” section of Table 5.

Table 5
Computations for Estimating Individual Service Value at Each Performance Level

Performance Ratings:	1	1.5	2	2.5	3	3.5	4	4.5	5
Number of employees	60	97	1171	1090	1667	672	317	46	23
Mean Performance		2.764							
Standard Dev. of Performance		0.668							
Z-Score of Performance Ratings	-2.641	-1.892	-1.144	-0.395	0.353	1.102	1.850	2.599	3.347
Average Service Value (assumed to equal 1.754 * average salary)									
2003	$84,162	$84,162	$84,162	$84,162	$84,162	$84,162	$84,162	$84,162	$84,162
2007	$98,457	$98,457	$98,457	$98,457	$98,457	$98,457	$98,457	$98,457	$98,457
Incremental Service Value **SDy =0.30**									
2003	-$38,017	-$27,235	-$16,468	-$5,686	$5,081	$15,863	$26,631	$37,412	$48,180
2007	-$44,474	-$31,861	-$19,265	-$6,652	$5,944	$18,558	$31,154	$43,767	$56,363
Incremental Service Value **SDy =0.60**									
2003	-$76,034	-$54,470	-$32,936	-$11,372	$10,163	$31,726	$53,261	$74,825	$96,359
2007	-$88,948	-$63,722	-$38,530	-$13,304	$11,889	$37,115	$62,308	$87,534	$112,726
Incremental Service Value **SDy =0.90**									
2003	-$114,051	-$81,705	-$49,403	-$17,058	$15,244	$47,590	$79,892	$112,237	$144,539
2007	-$133,423	-$95,583	-$57,795	-$19,955	$17,833	$55,673	$93,461	$131,301	$169,089
Total Individual Service Value (SDy = 30%)[1]									
2003	$46,145	$56,927	$67,694	$78,476	$89,243	$100,025	$110,793	$121,574	$132,342
2007	$53,983	$66,596	$79,192	$91,805	$104,401	$117,015	$129,611	$142,224	$154,820
Total Individual Service Value (SDy = 60%)									
2003	$8,128	$29,692	$51,226	$72,790	$94,325	$115,888	$137,423	$158,987	$180,521
2007	$9,509	$34,735	$59,927	$85,153	$110,346	$135,572	$160,765	$185,991	$211,183
Total Individual Service Value (SDy = 90%)									
2003	-$29,889	$2,457	$34,759	$67,104	$99,406	$131,752	$164,054	$196,399	$228,701
2007	-$34,966	$2,874	$40,662	$78,502	$116,290	$154,130	$191,918	$229,758	$267,546

Notes: 1. Total Individual Service Value is computed as the Average Service Value plus the Incremental Service Value, shown in the top portion of this table.
2. Data provided by the user **are in bold**.

For the second component necessary to estimate the value associated with each employee, we needed an estimate for the value of each performance level above and below the average. Combined with the estimate for the average value of individuals' performance, this will allow us to calculate the value of each of the nine performance levels, in both 2003 and 2007. In this study, and probably characteristic of most organizations, we had no direct estimates of the dollar value of particular performance levels. Hence, we used an estimation approach typical of utility analysis studies (e.g., Boudreau, 1991; Boudreau & Ramstad, 2003b). Utility analysis typically employs an estimate of the value of a one-standard-deviation difference in employee value, referred to as SDy, with SDy often approximated as equal to a given percentage of salary (Boudreau, 1991; Cascio, 2000). Thus, someone who performs one standard deviation above average (i.e., someone who is in the 84th percentile of performance) is estimated to be worth more than an average performer by a value equal to SDy. Using the SDy term, we can compute the value of each performance category relative to the average.

A recurring problem with using SDy is that it is unlikely to be estimated precisely (Boudreau, 1991; Cascio, 2000). Furthermore, its impact on final estimates of the value of a utility estimate is often quite significant (Boudreau, 1991). Thus, we investigated three potential values. As a very conservative approach, we assumed that SDy would equal 30% of average salary. This is substantially less than Schmidt and Hunter's (1983) 40% recommendation, which has been characterized as a conventional benchmark (Becker & Huselid, 1992), a safe estimate (Schmidt, Hunter, Outerbridge, & Trattner, 1986), and a conservative estimate (Judiesch, Schmidt, & Mount, 1992). We also used 60% of average salary as a somewhat conservative estimate, and we used 90% of average salary as what we believe to be a more realistic estimate.[4] In other words, our three estimates suggest that an employee performing better than 84 percent of the employee population is worth 30% of salary, 60% of salary, or 90% of salary more to the organization than an average performer (i.e., someone performing at the 50th percentile) in the same job.

In order to move from these SDy estimates to estimates of each employee's service value, we first used the observed distribution of employee performance to compute the standardized z-score corresponding to each of the nine performance ratings. This transformation, accomplished through subtracting the mean performance score from each performance category rating and then dividing by the performance standard deviation, produces a performance distribution with a mean of zero and a standard deviation of one. For example, performance category 1.5 received a z-score of -1.89 through subtracting the average performance rating of 2.764 from 1.5 and dividing by the standard deviation of 0.668. The z-scores, which represent the number of standard deviations that each performance category rating deviates from the performance mean, are listed in the fifth row of data in Table 5.

We assumed that the z-scores associated with each raw performance score would remain constant from 2003 to 2007. That is, although the actual distribution of workers across performance categories changes from 2003 to 2007, we assumed that the value of performance at each performance level did not change. For example, a performance rating of 4 in 2003, which was 1.850 standard deviations above the mean in 2003, provided value to the employer equal to mean performance's value plus the product of 1.850 and SDy. We assumed, regardless of the actual number of employees who received a score of 4 in 2007, the financial value of an individual with a performance rating of 4 in that year would be equal to 2007 mean performance's value plus the product of 1.850 and SDy.

For 2003, we estimated average salary as $47,983 (from Table 1), producing SDy estimates of $14,395 (i.e., 0.3 * $47,983), $28,790 (i.e., 0.6 * $47,983) and $43,185 (i.e., 0.9 * $47,983) for the 30%, 60% and 90% SDy scenarios, respectively. For 2007, estimated average salary was $56,133 (from Table 1), producing, at the 30%, 60%, and 90% SDy scenarios, estimated SDy levels of $16,840 (i.e., 0.3 * $56,133), $33,680 (i.e., 0.6 * $56,133), and $50,520 (i.e., 0.9 * $56,133). Multiplying these SDy estimates (i.e., the appropriate dollar value of a one standard deviation performance difference) by the z-scores (i.e., the number of standard deviations the performance category is from the mean) produced the "incremental" (beyond the average) dollar values corresponding to each performance rating level for each SDy assumption (see Table 5). Thus, under the 60% assumption in 2007, an employee at performance level 5.0 is worth $112,726 more than an average employee (i.e., $56,133 * 0.60 * 3.347). The sums of the average service values for the workforce, and the incremental service values for each performance category, produced the individual service values for each performance category that are reported in the bottom section of Table 5. Thus, the last six lines of data in Table 5 represent, for each unique combination of performance level (1.0 – 5.0 at half point intervals), year (2003 and 2007), and SDy scenario (30%, 60%, and 90%), the individual service value for each employee.

With individual service values determined for both 2003 and 2007, we can now compute the total service value for the workforce under each of the three pay strategies. For 2003 (for all three pay strategies), we calculated the total service value of the workforce by multiplying each performance category's individual service value by the corresponding quantity of employees in the performance category, and adding the products. Thus, for example, Table 5's individual service value of $115,888 for SDy = 60% and performance = 3.5 in 2003 is multiplied by 672 (the number of employees in that performance category) to yield the $77,876,736 figure in Table 6 (under SDy = 60% and performance = 3.5). This $77,876,736 is then added to the similarly computed values for the other eight performance categories to produce, when SDy = 60%, Table 6's total 2003 service value of $432,351,857. This is our estimate of what the workforce is worth to the employer in 2003 under the assumption that being one standard deviation above average in performance is worth 60% of an average performer's salary. We note that the total service values are the same in 2003 regardless of pay strategy (although they do differ across SDy assumptions) because the three pay strategies had yet to result in the different performance-specific turnover patterns that begin in 2004.

Table 6

Computing Total Service Value (2003 Employees)

Performance Ratings:	1	1.5	2	2.5	3	3.5	4	4.5	5	Total
Number of employees	60	97	1171	1090	1667	672	317	46	23	5143
2003 Total Service Value										
SDy = 30%	$2,768,700	$5,521,919	$79,269,674	$85,538,840	$148,768,081	$67,216,800	$35,121,381	$5,592,404	$3,043,866	$430,072,965
SDy = 60%	$487,680	$2,880,124	$59,985,646	$79,341,100	$157,239,775	$77,876,736	$43,563,091	$7,313,402	$4,151,983	$432,351,857
SDy = 90%	-$1,793,340	$238,329	$40,702,789	$73,143,360	$165,709,802	$88,537,344	$52,005,118	$9,034,354	$5,260,123	$434,631,219

Note: The total service values are the same in 2003 regardless of pay strategy (although they do differ across SDy assumptions) because the three pay strategies had yet to result in the different performance-specific turnover patterns that begin in 2004.

For 2007, calculation of the total service value of the workforce is slightly more complex, as the computations for those employees retained over the four-year analysis differ from the computations required for those hired as replacements during the four-year period. For the retained employees, 2007 total service value calculation closely resembles the approach to 2003, where Table 5's 2003 individual service values for each SDy level and performance category combination were multiplied by the quantity of retained employees for each performance category, and these products were summed. In 2007, however, the three pay strategies' different effects on performance-specific turnover result in pay strategy-specific numbers of retained employees in each performance category. Consequently, we need to conduct the individual service value by employee quantity multiplications separately for each pay strategy to get the 2007 estimates. Thus, Table 5's 2007 individual service values for each SDy level and performance category combination were multiplied by the quantity of retained employees for each performance category under each pay strategy, and these products were summed. For example, Table 5's individual service value of $129,611 for SDy = 30% and performance = 4.0 in 2007 is multiplied by 231, 282, and 282 (the number of retained employees in that performance category under the three pay strategies, as listed in Table 7) to yield the $29,940,141, $36,550,302, and $36,550,302 figures in Table 7 (under SDy = 30%, performance = 4.0, and pay strategies 1, 2, and 3, respectively). Thus, the final nine rows of data in Table 7 chronicle, for each SDy and pay strategy combination, the combined service value of all retained employees in 2007 at each performance level. The final column for each of these nine rows provides total service values across performance categories.

Table 7

Total Service Value of Retained Employees (2007)

Performance Ratings:	1	1.5	2	2.5	3	3.5	4	4.5	5	Total
Retained Employees										
Pay Strategy 1	2	34	726	818	1317	524	231	27	8	3687
Pay Strategy 2	2	34	726	818	1317	578	282	41	20	3818
Pay Strategy 3	1	12	468	709	1317	578	282	41	20	3428
Total Service Value (2007)										
SDy = 30%										
Pay Strategy 1	$107,966	$2,264,264	$57,493,392	$75,096,490	$137,496,117	$61,315,860	$29,940,141	$3,840,048	$1,238,560	$368,792,838
Pay Strategy 2	$107,966	$2,264,264	$57,493,392	$75,096,490	$137,496,117	$67,634,670	$36,550,302	$5,831,184	$3,096,400	$385,570,785
Pay Strategy 3	$53,983	$799,152	$37,061,856	$65,089,745	$137,496,117	$67,634,670	$36,550,302	$5,831,184	$3,096,400	$353,613,409
SDy = 60%										
Pay Strategy 1	$19,018	$1,180,990	$43,507,002	$69,655,154	$145,325,682	$71,039,728	$37,136,715	$5,021,757	$1,689,464	$374,575,510
Pay Strategy 2	$19,018	$1,180,990	$43,507,002	$69,655,154	$145,325,682	$78,360,616	$45,335,730	$7,625,631	$4,223,660	$395,233,483
Pay Strategy 3	$9,509	$416,820	$28,045,836	$60,373,477	$145,325,682	$78,360,616	$45,335,730	$7,625,631	$4,223,660	$369,716,961
SDy = 90%										
Pay Strategy 1	-$69,932	$97,716	$29,520,612	$64,214,636	$153,153,930	$80,764,120	$44,333,058	$6,203,466	$2,140,368	$380,357,974
Pay Strategy 2	-$69,932	$97,716	$29,520,612	$64,214,636	$153,153,930	$89,087,140	$54,120,876	$9,420,078	$5,350,920	$404,895,976
Pay Strategy 3	-$34,966	$34,488	$19,029,816	$55,657,918	$153,153,930	$89,087,140	$54,120,876	$9,420,078	$5,350,920	$385,820,200

Having computed 2007 service value for retained employees, we next address the 2007 value of those employees hired to replace the employees that separated during the 2004-2007 window. These replacement employees were assumed to have an individual service value equal to the average individual service value of retained employees under pay strategy 1 for each of the SDy assumptions. Thus, for example, Table 8's average individual replacement employee service value of $101,594 when SDy = 60% was computed by dividing Table 7's total retainee service value of $374,575,510, which is under pay strategy 1 with SDy = 60%, by 3687, which is Table 7's total retainees under pay strategy 1. We note that using pay strategy 1's retainee service value for all replacements assumes that the recruiting effectiveness and job performance of replacement employees are not affected by the compensation system. Because the average service value of retained employees under pay strategies 2 and 3 is greater than the average service value of employees retained under pay strategy 1, this provides a conservative estimate of replacement service value under the two pay strategies with pay-for-performance links. The total service value of replacement employees for each pay strategy and SDy combination is equal to the pay strategy-specific number of replacements times the SDy-specific average service value. These totals are reported in the bottom three rows of data in Table 8.

Table 8
Service Value of Replacement Employees (2007)

	Pay Strategy 1	Pay Strategy 2	Pay Strategy 3
Average Service Value			
SDy = 30%	$100,025	$100,025	$100,025
SDy = 60%	$101,594	$101,594	$101,594
SDy = 90%	$103,162	$103,162	$103,162
Number of Separations (2004-2007)	1457	1326	1716
Total Service Value of Replacements (2007)			
SDy = 30%	$145,736,425	$132,633,150	$171,642,900
SDy = 60%	$148,022,458	$134,713,644	$174,335,304
SDy = 90%	$150,307,034	$136,792,812	$177,025,992

Note: We are using the conservative assumption that replacement employees will have the service value of employees under the first pay strategy. Our approach implicitly assumes that the pay strategy has no effect on recruitment or job performance of new employees. If we assumed that new employees had service values equal to the average service values of employees under the new pay strategies, then the total service value of replacements would be higher under pay strategies 2 and 3.

Finally, Table 8's service values of the replacements and Table 7's service values of retained employees were added to produce the estimated 2007 total service value for each pay strategy and SDy level combination, as shown in Table 9. We used these 2007 total service values, as well as the 2003 total service values from Table 6, to compute total service value across all years in Table 10. As we had done with total service costs computations, we calculated the four-year stream of service value levels by assuming that service value rose linearly in each performance category between 2003 and 2007. Thus, for each pay strategy and SDy combination, we computed (a) the average service value increase (2007 service value minus 2003 service value, divided by four); (b) 2004 service value (2003 service value plus the average service value increase); (c) the average 2004-2007 service value (2004 service value plus 2007 service value, divided by 2); and (d), the total 2003-2007 service value (average 2003-2007 service value, times four, the number of years in our simulation).

Table 9
Total Service Value of the 2007 Workforce

	Value of Retained Employees	+	Value of Replaced Employees	=	Total Value (2007)
SDy = 30%					
Pay Strategy 1	$368,792,838	+	$145,736,425	=	$514,529,263
Pay Strategy 2	$385,570,785	+	$132,633,150	=	$518,203,935
Pay Strategy 3	$353,613,409	+	$171,642,900	=	$525,256,309
SDy = 60%					
Pay Strategy 1	$374,575,510	+	$148,022,458	=	$522,597,968
Pay Strategy 2	$395,233,483	+	$134,713,644	=	$529,947,127
Pay Strategy 3	$369,716,961	+	$174,335,304	=	$544,052,265
SDy = 90%					
Pay Strategy 1	$380,357,974	+	$150,307,034	=	$530,665,008
Pay Strategy 2	$404,895,976	+	$136,792,812	=	$541,688,788
Pay Strategy 3	$385,820,200	+	$177,025,992	=	$562,846,192

Table 10
Computing Four Year Total Service Value

	Pay Strategy 1	Pay Strategy 2	Pay Strategy 3
SDy = 30%			
2003 Service Value	$430,072,965	$430,072,965	$430,072,965
2007 Service Value	$514,529,263	$518,203,935	$525,256,309
Average Service Value Increase	$21,114,075	$22,032,743	$23,795,836
2004 Service Value	$451,187,040	$452,105,708	$453,868,801
Avg. (2004 - 2007 Service Value)	$482,858,152	$485,154,822	$489,562,555
Total Service Value (2004-2007)	$1,931,432,608	$1,940,619,288	$1,958,250,220
SDy = 60%			
2003 Service Value	$432,351,857	$432,351,857	$432,351,857
2007 Service Value	$522,597,968	$529,947,127	$544,052,265
Average Service Value Increase	$22,561,528	$24,398,818	$27,925,102
2004 Service Value	$454,913,385	$456,750,675	$460,276,959
Avg. (2004 - 2007 Service Value)	$488,755,677	$493,348,901	$502,164,612
Total Service Value (2004-2007)	$1,955,022,708	$1,973,395,604	$2,008,658,448
SDy = 90%			
2003 Service Value	$434,631,219	$434,631,219	$434,631,219
2007 Service Value	$530,665,008	$541,688,788	$562,846,192
Average Service Value Increase	$24,008,447	$26,764,392	$32,053,743
2004 Service Value	$458,639,666	$461,395,611	$466,684,962
Avg. (2004 - 2007 Service Value)	$494,652,337	$501,542,200	$514,765,577
Total Service Value (2004-2007)	$1,978,609,348	$2,006,168,800	$2,059,062,308

Under all assumptions about SDy, the 2007 and total service values are lowest when giving all employees average pay increases (pay strategy 1), are higher when giving high performers high pay increases and all others average increases (pay strategy 2), and are highest when the pay-for-performance link was strongest (pay strategy 3). Compared to pay strategy 1, which gives all employees average pay increases, pay strategy 2 prompts more high-performing and highly-paid employees to stay, and their value enhances the work force. Pay strategy 3 augments this effect by encouraging the turnover of low performers, who subsequently are replaced with workers whose expected value is that of average workers under pay strategy 1.

Hence, whereas our cost analysis suggested that pay strategy 3 was the least effective and pay strategy 1 was the most effective, our analysis of workforce value indicates the exact opposite. Obviously, relying only on either cost or value estimates would be shortsighted. The critical question is whether the service value benefits of a strong pay-for-performance link outweigh the costs (Boudreau, 1991; Boudreau & Ramstad, 2003a; 2003b).

Step 7: Determining the Final Utility—Is Pay-for-Performance Worth it?

At this point, we return to the flow chart in Figure 1 and the question that motivated this research effort: Is it worth it to use pay-for-performance in an attempt to win the war for talent? To speak to this, we began by specifying three pay plan strategies and estimating the subsequent turnover probabilities and performance distributions we would expect under each. Using this turnover and performance information, we then addressed costs for each pay plan through the estimation of expenses associated with employee movement out of and into the workforce and with the pay and benefits for the workforce. Having estimated costs, we turned to the benefits dimension of the cost-benefit analysis and estimated the value of the retained workforce and of the replacement employees. Thus, we have estimated the three components for the decision of whether pay-for-performance makes sense in our example: (a) the four-year stream of movement costs; (b) the four-year stream of service costs; and (c), the four-year stream of service value. Now, we combine these components to estimate the relative value of the three pay strategies by taking the stream of service value and subtracting the stream of service costs and movement costs (Boudreau & Berger, 1985). The relevant amounts are summarized in Table 11 for each pay strategy and SDy assumption combination.

Table 11
Computation of Four Year Investment Value of Different Pay Strategies (in $millions)

	Service Value (in $millions)	-	Service Costs (in $millions)	-	Movement Costs (in $millions)	=	Four Year Value (in $millions)	Difference from Pay Strategy 1	% Change from Pay Strategy 1
SDy = 30%									
Pay Strategy 1	$1,931.43		$1,495.89		$154.67		$280.87	--	--
Pay Strategy 2	$1,940.62		$1,509.66		$142.05		$288.91	$8.04	2.86%
Pay Strategy 3	$1,958.25		$1,492.95		$181.80		$283.50	$2.62	0.91%
SDy = 60%									
Pay Strategy 1	$1,955.02		$1,495.89		$154.67		$304.46	--	--
Pay Strategy 2	$1,973.40		$1,509.66		$142.05		$321.69	$17.22	5.66%
Pay Strategy 3	$2,008.66		$1,492.95		$181.80		$333.91	$29.44	9.15%
SDy = 90%									
Pay Strategy 1	$1,978.61		$1,495.89		$154.67		$328.05	--	--
Pay Strategy 2	$2,006.17		$1,509.66		$142.05		$354.46	$26.41	8.05%
Pay Strategy 3	$2,059.06		$1,492.95		$181.80		$384.31	$56.26	15.87%

These results suggest a different conclusion from the cost analysis presented earlier. Recall that traditional compensation-cost analyses may have led decision makers to the conclusion that a strong link between pay and performance would be unwise given its extreme cost, and that although a moderate pay-for-performance link was not much more expensive than having no link, there were no cost-based data to strongly suggest it as a compelling alternative. When the potential benefits of workforce value are accounted for, however, it becomes clear that investments in performance-based pay may hold the potential for significant organizational improvement. Table 11 indicates that even under our most conservative SDy assumption, pay-for-performance plans yielded greater net values than did the non-contingent pay strategy. That is, by fully incorporating both costs and benefits into our assessment, we find that, under all of our conditions, pay-for-performance is indeed a valuable investment. Moreover, as SDy (i.e., the value associated with performance differences) became larger, the payoff to pay-for-performance increased dramatically, ultimately (i.e., at SDy = 90%) resulting in advantages, relative to the non-contingent pay from pay strategy 1, of over $26 and $56 million dollars for the partially contingent and highly contingent pay strategies, respectively.

Discussion

This analysis suggests that even under conservative assumptions about the value of performance variability among employees, the four-year financial benefit of linking pay to performance in this company would be substantial. When these SDy assumptions are closer to what we believe to be more realistic (i.e., if job performance differences have greater value to an organization), the present model reveals the potentially high payoff from investments in performance-based pay. Moreover, our analysis vividly illustrates the limitations of standard accounting and behavioral cost-based approaches for identifying the critical variables and, thus, the appropriate pay strategy.

Simplifying decisions

Because utility analysis can be rather complex, we used a number of simplifying decisions here. First, we assumed that replacement employees would be of average performance level (and, thus, average service value). This implicitly assumes that pay-for-performance would not influence applicant attraction, even though research suggests that the degree to which pay and performance are linked does in fact matter to applicants (Cable & Judge, 1994). Second, in focusing on the relationship between pay-for-performance and turnover, we made no provisions for whether the performance-based pay would actually improve workforce performance (net of retention effects). This implicit modeling of no effect of performance-based pay on performance is particularly noteworthy given that the contingent pay plan in the Trevor et al. (1997) study was sufficiently well designed to elicit a performance-specific retention pattern. Third, we were working with the relatively normally distributed performance distribution from the Trevor et al. sample. While using this distribution simplified matters by allowing us to make use of other aspects of the Trevor et al. study, we recognize that many performance distributions may be characterized by a greater proportion of employees being rated in the top two or three performance categories and by the subsequent negative skew. The Trevor et al. distribution arose because the organization, consistent with its individualistic and hierarchical culture, encouraged differentiation among employees during performance appraisal. Additionally, because Trevor et al. used averaged performance levels (with a mean of 3.05 performance ratings per employee), such factors as change in performance over time and random error in ratings combined to reduce the likelihood of having an average rating in the very top or bottom performance levels. To the extent that an organization with an aggressive pay-for-performance plan does encourage or mandate a normal performance distribution, however, the implications are noteworthy. For example, the system allocates large raises to the relatively few high performers, who should then be satisfied, motivated, and likely to remain; in contrast, the system also may frustrate, de-motivate, and ultimately result in increased turnover among employees that might be reasonably high performers but were not rated as such as a result of the forced distribution.

We emphasize that each of the three simplifying decisions was made to facilitate our presentation rather than strengthen our results. Indeed, each decision actually weakens the results' apparent support for performance-based pay. In unreported analyses, we incorporated into the utility analysis improved applicant quality under pay strategies 2 and 3, improved performance (net of retention effects) under pay strategies 2 and 3, and a more negative skew in the performance distribution. In each case, these alternative approaches to the decision in question resulted in a larger net advantage for pay strategy 2 and, to an even greater extent, for pay strategy 3. Thus, the analyses we presented here are a simplified and conservative approach. The spreadsheets available from the first author can be adapted to test such alternative assumptions.

On Overcoming the "Futility of Utility"

Our simplifying decisions notwithstanding, the analyses presented here entail much detail and speculation that, according to utility analysis criticism, might hinder their acceptance in managerial ranks. Indeed, we are quite aware of the "futility of utility" (Latham & Whyte, 1997; Whyte & Latham, 1994) findings in which utility analysis appeared to reduce managerial support for an HR intervention. To a large extent, the futility of utility problem likely resides within the presenter and recipients of utility analysis data, rather than with utility analysis itself.

In defense of utility analysis, Sturman (2000) concludes that managers need to understand utility analysis and be trained in the use of the technology. Citing the necessity of managers making decisions based on the Merton and Scholes options pricing formula to have experience in finance and economics, Sturman (2000) argued that "For a complex decision making tool to be useful, the users of the decision aid must desire the information it provides and be trained in its use" (p. 297). Hence, rather than being apologists for the complexity of utility analysis, we believe that in-house I/O psychologists should attempt to convey that it is important for key stakeholders to have some basic grounding in sophisticated human resource decision-making. Given that labor costs often comprise over half of all operating costs (Milkovich & Newman, 2002), training decision makers in a decision tool designed to inform as to the optimal way to allocate these costs would appear to be a valid undertaking. On the presenter side, Cronshaw (1997), after participating as the expert utility presenter in the Whyte and Latham (1997) "futility" study, contended that "it is not utility analysis per se that imperils I/O psychologists, but the intemperate way it is often used. In effect, the messenger kills the message" (p. 614). Cronshaw advocated that utility analysis should be presented as an informational tool rather than as a "persuasive tool in a one-sided (and often self-serving) attempt to 'sell' innovations to managers" (p. 614).

Boudreau and Ramstad (1999; 2002) noted that the powerful influence of disciplines such as Finance and Marketing evolved from their focus on enhancing decisions about the key resource (money or customers), rather than on selling accounting or sales programs, and suggested that the influence of HR and I/O professionals will increase with a similar focus on talent decisions. They suggested (Boudreau & Ramstad, 2002, 2003a; 2003b) the HC BRidge® decision model for "talent" resources that draws upon well-developed decision models to delineate three fundamental elements: efficiency, effectiveness and impact. The present analysis vividly shows the value of integrating "efficiency" (payroll and movement costs); "effectiveness" (changes in movement patterns); and "impact" (value of improvements in performance) into a decision support model, and the dangers of decision frameworks based solely on efficiency or effectiveness alone.

In addition to these emphases on decision maker training and on presenting utility analysis as an informative tool rather than marketing it as a panacea, we also offer a few additional suggestions that might assist the I-O psychologist in communicating utility analyses. First, expectations should be set at the outset by affirming that the evaluation will be somewhat complex, just as would be expected from manufacturing, finance, or accounting. Any simplistic attempt to estimate performance-based pay's effects on the bottom line would be superficial and incomplete. Second, communicating the utility analysis would probably benefit from an initially broad explanation. Perhaps using something similar to our Figure 1 as a guide, the practitioner should emphasize the simple cost-benefit concepts of movement costs, service costs, performance-specific retention, and the critical, but often overlooked, workforce value. We believe that it would be wise to continually hearken back to these big picture concepts, with emphasis on effects rather than on measures (Cascio, 2000) and technical details (Hoffman, 1996). Third, acceptance may be facilitated via emphasis on the conservative nature of the assumptions, decisions, and subsequent estimates (Hoffman, 1996). Finally, highlighting the rationale for these assumptions and decisions should demystify them, and using the spreadsheets to instantaneously show the effects of changing them may provide valuable "best case" and "worse case" scenarios. Together, these recommendations should assist in indicating that well-designed performance-based pay is worth considering, and that HR is able to quantitatively evaluate the relevant alternatives.

Limitations and Conclusions

Several limitations are noteworthy. Our results reflect one organization's characteristics, such as plan specifics, the individual job performance distribution, and the relationship between pay-for-performance and turnover. The extent to which this organization, its employees, and our conclusions are representative of other firms and employees with regard to these factors is unknown. What is critical, however, is that the approach we took to finding these results can be applied in a wide variety of situations, thus enabling the examination of external validity. A second limiting factor in our study is that there may be additional pay strategy-specific training costs or administrative costs that we did not include. We believe, however, that such costs could easily be incorporated into this framework. Third, as discussed throughout this study, we made a number of assumptions and decisions in order to conduct the analyses. Although we believe that we took the most logical and conservative approaches at these junctures, viable arguments could be made for approaches different from our own. Fourth, although we modeled employees' performance levels as stable over time, research has shown that employee performance levels change over time (e.g., Deadrick, Bennett, & Russell, 1997; Ployhart & Hakel, 1998; Sturman & Trevor, 2001). Furthermore, changes in performance levels are related to the likelihood of turnover, even after controlling for the effects of current performance levels (Harrison et al., 1996; Sturman & Trevor, 2001). Considering the movement of employees between different performance categories across years, and the implications of these movements for forecasting turnover, would certainly add complexity to the model we presented. It may be valuable for future research to explore the implications of these model refinements.

The method we describe involves a significant amount of calculation, but is relatively simple to replicate on a spreadsheet. Actual replication may require some customization to fit a specific company's profile, but the basic premise of the methods should be the same. We hope that this demonstration will inspire organizations to more fully tap available research findings to help them enhance their HR policy decision-making. We also hope that this paper helps demonstrate the value of research findings like those reported in Trevor et al. (1997) and will be complemented by future research on additional factors that may influence the pay-for-performance link with turnover. For example, satisfaction with different types of pay-for-performance plans (e.g., raises versus bonuses) can have different effects on outcomes of organizational interest, such as job satisfaction and organizational commitment (Sturman & Short, 2000). Ideally, the research presented here will encourage extensions of this work that can prove valuable for both understanding HR practices in general and for evaluating specific HR policies.

Organizations of all types will likely respond to increasing pressures to “win the talent war” by employing all available tools to enhance attraction, selection, and retention processes. A formidable tool in this endeavor is the accumulated knowledge available from industrial/organizational psychology and human resources research. The method described here illustrates how utility analysis can be used to demystify and integrate this research, making it a more practical decision-making tool, and thus a more potent influence on significant strategic organizational goals (Boudreau, 1991; Boudreau & Ramstad, 1997; 1999; 2002; 2003a; 2003b).

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Footnotes

1. The Boudreau and Berger (1985) model in its purest form would calculate the work force value in each intervening year and apply a discount factor to equalize the time value of the dollar amounts. While these economic corrections can yield substantial changes to the estimated value (Sturman, 2000), such embellishments do not have a significant effect in this case because the changes in dollar amounts are assumed to be linear, the time frame is relatively short, and our focus is on the relative (versus absolute) value of the different strategies. We also did not have information about the organizational tax rate, so we report our results in pre-tax dollars. After-tax effects could be easily calculated by multiplying the final results by an appropriate after-tax proportion, but the relative effects of the options would not be altered.

2. The Bureau of Labor Statistics provides a wealth of information on hourly earnings for diverse groups and occupations (see BLS, 2002). We used the average hourly earnings and weekly hours of all white collar occupations, excluding sales jobs. The most recent information shows that white collar, full-time employees (excluding sales) earned an average hourly wage of $21.65 and worked an average of 39.4 hours per week in 2001. Based on the 29th Annual Report on the 2002-2003 Total Salary Increase Budget Survey (WorldatWork, 2002), salary increases averaged 3.9% for exempt salaried employees in 2002, and is projected to increase 4.1% for 2003. This led us to use an estimated hourly wage of $23.42, for a total salary for 2003 of $47,983. Note again that anyone employing the methods described in this paper can simply enter the data from other sources, such as their own company's data. The value we chose was intended to capture a broad, generalizable sample. More importantly, it is intended to be a reasonable estimate to help illustrate our technique.

3. There is no single accepted method of estimating the dollar value of average performance among workers or applicants. Some research has suggested that average performance value can be estimated equal to the average compensation of the work group (Boudreau, 1991, p. 654; Raju, Burke & Normand, 1990, p. 9). However, it seems unlikely that average-performing employees produce only enough value to offset their direct wage costs. Considering the other service costs that are incurred, and the need for organizations to obtain a positive return on costs, a higher level of average service value seems likely. Based on an analysis of wage and productivity estimates in the national income accounts of the United States, Schmidt and Hunter (1983) proposed assuming that the ratio of average dollar value to average wage is approximately 1.754.

4. Support of the 90% approach is provided by Becker and Huselid (1992), who found direct observations of SDy fell in the 74% to 100% of mean salary range. Moreover, because researchers generally contend that SDy increases as job complexity increases (e.g., Judiesch et al., 1992), our 30% and 60% SDy values would appear to have additional support as conservative estimates, given our sample of all exempt hires in a large company.

Appendix

Computing Separation Probabilities Using Survival Analysis Results

Our estimation uses the survival analysis from Trevor et al.'s (1997) Table 4 (model 1).

Probability of survival = $S(0)^{e^{(ßX)}}$,
where S(0) = baseline probability of survival, which was 0.77,
ß = a vector of survival analysis regression coefficients,
X = a vector of independent variables,
(ßX) = 4.941 + 0.314 * Salary Growth - 2.541 * Performance + 0.553 * Performance^2 - 0.020 * Performance^3 + 0.007 * Salary Growth^3 - 0.663 * Salary Growth * Performance + 0.071 * Salary Growth * Performance^2

The salary growth data used to estimate the equation above was measured in thousands of dollars. Thus, to use the equation, our example's percentage increases had to be converted to a parallel salary growth measure for each pay strategy and performance level combination. To do so, we determined the average pay growth under each strategy by subtracting 2003 pay from 2007 pay, dividing by 4, and then dividing this amount by 1000.

For example, under strategy 3 and performance level 2.5, the average pay increase was [($54,005 - $47,983) / 4]/1000 = 1.5055. The table below lists the salary growth for each pay strategy and performance level.

Performance Category	1.0	1.5	2.0	2.5	3.0	3.5	4.0	4.5	5.0
Strategy 1	2.0375	2.0375	2.0375	2.0375	2.0375	2.0375	2.0375	2.0375	2.0375
Strategy 2	2.0375	2.0375	2.0375	2.0375	2.0375	2.5853	3.1485	3.7283	4.3243
Strategy 3	0.000	0.4870	0.9888	1.5055	2.0375	2.5853	3.1485	3.7283	4.3243

Next, we need to estimate separation probability (i.e., 1 - probability of survival): 1 - $S(0)^{e^{(ßX)}}$. For example, for performers rated at 5.0 under Pay Strategy 2, the pay increase of 8% translates to an average dollar increase (in thousands) of 4.3243, which yields a separation probability = 1 - $.77^{e^{(ßX)}}$ = 1 - $.77^{e^{(4.941 – 5.467)}}$ = 1 - $.77^{e^{(-0.526)}}$ = 1 - $.77^{(0.5910)}$ = 1 - 0.86 = 0.14. See Table 2 for separation probabilities at each performance level/pay strategy combination.

The 4.941 constant in the (ßX) calculation resulted from adding the estimated model constant (6.810) from Trevor et al.'s equation to the sum of the model terms that included neither performance nor salary growth (e.g. age, promotions). These terms were evaluated at the means of the respective X variables. As an aside, we advocate centering variables prior to conducting hazard analyses, which causes the model constant and variables set at their means to drop out, thus simplifying the calculation of survival probabilities (Retherford & Choe, 1993; Trevor, 2001). See Trevor (2001) and Morita et al. (1993) for more on computing survival probabilities.

2016 OpCo ICP Framework

Infrastructure Development (25%)

- OpCo Net Income (10%)
- OpCo / AEPU Economic Development (5%)
- **Efficiency and Effectiveness Measures** (10%)
  - OpCo Cost per ASB Hour (5%)
  - OpCo ASB Hours per FTE Equivalent (2.5%)
  - OpCo MRO Cost per Order Completed (2.5%)

Customer Experience (40%)

- **Customer Reliability** *(Total 10%)*
  - OpCo SAIDI (5 %)
  - OpCo Reliability Work Plan Execution (5%)
- **Risk Mitigation Work Plan Execution** (5%)
  - Execution of Risk Mitigation plans (5 Components – Network, Poles, Overhead, Underground Transformer, Contact Voltage)
- **Regulatory Execution** (5%)
  - Pursuit of customer-driven programs with regulators (e.g., solar, AMI)
- **Customer Experience Work Plans** (10%)
  - OpCo –(5%) including Mobile Alert participation %
  - System-Wide (5%) – Outage Mapping & Data Analytics
- JDPA Residential Overall Customer Satisfaction Index (5%)
- Emergency Restoration Planning / ICS Execution (5%)

Employee Experience (35%)

- OpCo Employee Culture/ Experience Work Plan Execution (5%)
- OpCo DART Rate (10%)
  - Combined Employee and Contractor Rate
- Pro-Active Employee Safety Measure (20%)
  - Quality Assurance on Jobsite Observations
  - Engage Employees to identify and address top five high-risk activities
  - Good Catch Program
  - Site Inspection Program

OpCo ICP plans are subject to executive leadership discretion

AEP AMERICAN ELECTRIC POWER

AEP®

2016 Performance Measures and Weights

- **Continue the balanced scorecard of earnings, safety and strategic measures**

Performance Category	2016
Budget Funding Measures	
Operating Earnings Per Shares	**75%**
Safety	**10%**
Strategic Initiatives	**15%**

The funding measures above establish the aggregate funding available for all annual incentive groups

BENEFIT PLAN DESIGN AND EMPLOYEE COST SUMMARY GRIDS

January 1, 2016 - December 31, 2016

ELIGIBLE PARTICIPANTS

All full-time (scheduled to work an average of 40 hours per week) employees and their eligible dependents are eligible to participate in the following benefits: group medical, dental, life, accidental death & dismemberment, sick pay, long-term disability, retirement savings (401k), retirement (pension), holiday and vacation pay. All part-time (scheduled to work an average of 20 hours per week) employees are eligible to participate in the group medical, dental, retirement savings plan and retirement (pension) plan beginning the first day of service with AEP. Part-time employees are also eligible for holiday and vacation benefits according to a different schedule than full-time. Temporaries, co-ops and interns are eligible to participate in the pension plan and the 401k plan.

RETIREMENT ELIGIBLITY

Employees who are at least age 55 with at least 10 or more years of service when they terminate employment are eligible to enroll in retiree benefits. For benefit purposes, these employees are referred to as "retirees." Eligible retirees and their eligible dependents may elect retiree medical, dental, and vision coverage. Eligible retirees may elect life insurance. However, employees hired or rehired on or after January 1, 2011, are not eligible for company-paid life insurance upon retirement. Employees hired or rehired on or after January 1, 2014, are not eligible for retiree medical coverage.

Eligible surviving dependents of active and retired employees may continue medical and dental coverage until they reach the limiting age, or for surviving spouses of active employees, attain age 65, or remarry. Surviving spouse of retirees can continue coverage beyond age 65, if unmarried.

PARTICIPANT MEDICAL CONTRIBUTIONS

The pre-tax monthly cost to active full-time employees is calculated based on a percentage of the total cost of coverage. The pre-tax monthly costs to active part-time employees are two and one-half times the monthly costs of active full-time employees. Retiree contributions can vary depending on when the employee retired. The monthly costs for many retirees are a percentage of total premiums ranging from 20% - 46%, and are based on their age and years of service at retirement. Effective with retirements on or after January 1, 2013, company contributions for retiree medical coverage are capped at a fixed amount of $11,500 for under age 65 retirees and $3,800 for retirees age 65. Once this cap is exceeded, the retiree contributions will reflect the cost of coverage above the cap. Eligible surviving dependents generally pay 50% of the total monthly cost of coverage.

January 1, 2016 - December 31, 2016

MEDICAL PLAN SURCHARGES

Spousal Surcharge

Effective January 1, 2014, if an active employee covers his/her spouse/domestic partner on AEP's medical plan, and that spouse/domestic partner has access to medical coverage through his/her employer, the employee will be assessed a surcharge of $50.00 per month.

Tobacco Surcharge

Effective January 1, 2015, employees who use tobacco and nicotine products will have a surcharge, in the amount of $50.00 per month, assessed when they elect coverage under AEP's medical plan.

January 1, 2016 – December 31, 2016

GROUP MEDICAL PLANS

Health Savings Account (HSA) Plan Options	**HSA Basic**		**HSA Plus**	
	In-Network	**Out-of-Network**	**In-Network**	**Out-of-Network**
Company Annual Contribution to HSA	NA	NA	participant only: $500 participant + spouse/domestic partner or participant + child(ren): $750 participant + family: $1,000	
Annual Deductible (includes medical, prescription and behavioral health)	$2,700/participant $5,400/participant + spouse/domestic partner $5,400/participant + 1 child $8,100/participant + children $8,100/participant + family	$4,000/participant $8,000/participant + spouse/domestic partner $8,000/participant + 1 child $12,000/participant + children $12,000/participant + family	$2,000/participant $3,000/participant + spouse/domestic partner $3,000/participant + child(ren) $4,000/participant + family	$3,000/participant $4,500/participant + spouse/domestic partner $4,500/participant + child(ren) $6,000/participant + family
Annual out-of-pocket maximum	$4,000/participant $8,000/participant + spouse/domestic partner $8,000/participant + 1 child $12,000/participant + child(ren) $12,000/participant + family	$8,000/participant $16,000/participant + spouse/domestic partner $16,000/participant + 1 child $24,000/participant + child(ren) $24,000/participant + family	$4,000/participant $6,000/participant + spouse/domestic partner $6,000/participant + child(ren) $8,000/participant + family	$6,000/participant $9,000/participant + spouse/domestic partner $9,000/participant + child(ren) $12,000/participant + family
Co-Insurance	10% after deductible	30% after deductible	15% after deductible	30% after deductible
Preventive Care	$0%; no deductible	30% after deductible	$0%; no deductible	30% after deductible
Prescription Coverage	10% after deductible		15% after deductible	
2016 Full-Time Employee Monthly Cost	participant only $31.09 participant + spouse/domestic partner $63.89 participant + child(ren) $62.79 participant + family $95.52		participant only $88.56 participant + spouse/domestic partner: $191.99 participant + child(ren) $170.37 participant + family $273.73	

<u>January 1, 2016 – December 31, 2016</u>

<table>
<tr><th colspan="6">HRA Plan</th></tr>
<tr><th colspan="2"></th><th>Participant Only</th><th colspan="2">Participant + Spouse/Domestic Partner or Participant + Child(ren)</th><th>Participant + Family</th></tr>
<tr><td>Health Reimbursement Account (HRA)</td><td>AEP Annual Allocation</td><td>$1,000</td><td colspan="2">$1,500</td><td>$2,000</td></tr>
<tr><td rowspan="3">Traditional Health Coverage (Prescription coverage same as any other medical expense)</td><td>Annual Deductible (includes medical, prescription drug and behavioral health)</td><td>$1,500</td><td colspan="2">$2,250</td><td>$3,000</td></tr>
<tr><td>Then, employee pays coinsurance for covered services</td><td colspan="4">15% for in-network providers
30% for out-of-network providers</td></tr>
<tr><td>Annual Out-of-Pocket Maximum</td><td>$4,000 if in-network

$6,500 if out-of-network</td><td colspan="2">$6,000 if in-network

$9,750 if out-of-network</td><td>$8,000 if in-network

$13,000 if out-of-network</td></tr>
<tr><td>Annual Preventive (not applied to Company's HRA allocation)</td><td colspan="5">In-network: 0%; no deductible
Out-of-network: 30% after deductible</td></tr>
<tr><td colspan="2">2016 Full-Time Monthly Employee Cost</td><td>$132.37</td><td>$288.02</td><td>$250.61</td><td>$406.19</td></tr>
</table>

<u>Teladoc</u>

Teladoc provides employees and their eligible dependents with 24/7/365 access to US board-certified physicians by phone or online video. Teladoc can diagnose, recommend treatment and prescribe medication when appropriate, including sinus problem, bronchitis, allergies, poison ivy, cold and flu symptoms, urinary tract infection, respiratory infection and more. The cost to participants for each physician consultation is $40.

This program is available to participants enrolled in an AEP consumer-directed health plan. FirstCare HMO participants are not eligible for this benefit.

January 1, 2016 – December 31, 2016

HMO	FirstCare HMO
Office Visit Co-pay	Primary Care Physician: $20/visit Specialist: $30/visit
Deductible	N/A except for separate prescription drug benefit
Participant Coinsurance	15%
Annual Medical Out-Of-Pocket Maximum	$3,000/participant $6,000/family (includes medical coinsurance and co-pays; does not include prescription drugs)
Prescription Coverage	Deductible: $50/participant; $150/participant + family for retail (deductible waived for mail order) Generics: $10 co-pay retail; $20 co-pay mail Retail Preferred Brand: 20% coinsurance ($20 minimum; $100 maximum) Retail Non-Preferred Brand: 35% coinsurance ($35 minimum; $200 maximum) Mail Preferred Brand: 20% coinsurance ($50 minimum; $200 maximum) Mail Non-Preferred Brand: 35% coinsurance ($90 minimum; $300 maximum)
Annual Prescription Out-Of-Pocket Maximum	$1,000/individual $3,000/family (includes prescription deductible)
2016 Full-Time Employee Monthly Cost	Participant Only $118.42 Participant + Spouse/Domestic Partner $262.59 Participant + Child(ren) $184.10 Participant + Family $323.27

Wellness Program

Healthy living habits are an essential ingredient for healthy employees. For that reason, AEP sponsors a number of programs, including incentives, and initiatives designed to help employees achieve and maintain a healthy lifestyle. All active employees (regardless of whether they are enrolled in a medical plan) are eligible to participate in the following wellness programs along with spouses and domestic partners of active employees who are covered under an AEP medical plan.

- Rewards for preventive care
- Flu Shots
- Health Risk Assessments
- Life Style Coaching, including tobacco cessation

January 1, 2016 – December 31, 2016

GROUP DENTAL

DPPO option

Coverage Level	Participant Only	Participant + Spouse/Domestic Partner	Participant + Child(ren)	Participant + Family
Deductible (does not apply to preventive service)	$50/person	$50/person	$50/person $150/family	$150/Family
Annual Maximum	$1,500 per covered person			
Coinsurance				
Preventive	100%			
Basic Services	80% after deductible			
Major Services	50% after deductible			
Orthodontia	50% up to a lifetime maximum of $1,500 per covered child			
2016 Full-time Monthly Cost	$10.66	$21.05	$32.40	$42.79

DMO Option
A DMO option is available to employees who live within the same zip code area as a network DMO dentist. Similar to a medical Health Maintenance Organization (HMO), the DMO provides dental service through a group of network dentist. The DMO offers no deductibles or annual maximum, no co-pay for covered preventive services and low, fixed co-pays on other dental services.

The full-time 2016 monthly cost for the DMO option is:

Employee Only	$ 9.28
Employee + Spouse	$18.56
Employee + Child(ren)	$20.88
Employee & Family	$30.16

The pre-tax monthly costs to active part-time employees are two and one-half times the monthly costs to active full-time employees. The monthly costs to certain grandfathered retirees and surviving dependents are the same as active employees. The monthly cost to most other retirees and eligible surviving dependents are 100% of the total cost of coverage.

SICK PAY PLAN

The Sick Pay Plan provides full-time employees financial protection in the event of a short-term illness or injury that prevents employees from working. Benefits are payable for the first day of absence from work due to illness or injury and may continue up to 26 weeks.

Sick pay is determined according to the amount of the employee's base pay on the day before the absence begins and is paid at 100% or 60% depending on service with the Company.

The Company pays the full cost of coverage through normal salary allocations as this program is financed as a salary continuation plan.

January 1, 2016 – December 31, 2016

LONG-TERM DISABILITY

The AEP Long-Term Disability plan provides full-time employees financial protection in the event of an employee's illness or injury that prevents them from working for an extended period of time. To qualify for LTD benefits, the employee must be totally disabled because of illness or injury for 26 weeks (elimination period) and unable to perform the functions of their own occupation. After 2 years of approved disability, the employees must be unable to perform the duties of any occupation.

The plan's monthly total disability benefit pays 60% of the employee's base monthly pay in effect immediately before the disability begins. The Company pays the full cost of this coverage. Effective January 1, 2014, eligible employees have the opportunity to purchase additional 10% coverage.

LIFE INSURANCE PLAN

The company provides full-time employees two times their base annual pay in life insurance at no cost to the employee. Most employees can purchase up to eight times their base pay in supplemental coverage. The total amount of combined coverage for most employees cannot exceed $1 million.

AEP provides life insurance coverage equal to a flat $30,000 at no cost to retired employees (at least age 55 with 10 or more years of service). Certain grandfathered retirees are eligible for additional coverage, which reduces as the retiree gets older. However, employees hired or rehired on or after January 1, 2011, are not eligible for company-paid life insurance upon retirement.

The employee pays the total cost of supplemental and dependent life coverage. The monthly after-tax cost for the employee supplemental life coverage is based on the employee's age, tobacco use status, the employee's base pay and the level of coverage. Some active employees, who remained in grandfathered life plans (not open to new enrollments), pay between $0.20 - $0.35 per $1,000 for coverage.

ACCIDENTAL DEATH & DISMEMBERMENT (AD&D) INSURANCE

AEP'S AD&D benefit program offers help with the financial hardship a full-time employee's family may suffer should the employee become seriously injured or die in an accident.

The Company provides employees two times their base pay (up to $1.5 million) at no cost to the employee. For employees on an Emergency Response Team, the Company provides AD&D insurance of an additional two times their base pay (up to $1.5 million) at no cost to the employee. Employees can purchase up to ten times their base pay (up to $1.5 million) in supplemental coverage. Employees can purchase dependent AD&D insurance for their eligible dependents.

The 2016 pre-tax monthly costs of supplemental/dependent coverage are:

AD&D Option	**Cost per $1,000**
Participant Only	$.018
Participant + Spouse/Domestic Partner	$.024
Participant + Family	$.029

January 1, 2016 – December 31, 2016

AEP SYSTEM RETIREMENT SAVINGS PLAN (Qualified 401k Plan)

The AEP System Retirement Savings Plan is a 401(k) savings plan that gives employees an opportunity to save through payroll deductions on a pre-tax and after-tax basis. Generally, employees can contribute from 1% to 50% of their eligible compensation on a pre-tax basis, after-tax basis, including Roth 401(k) after-tax, or in a combination of any of the contribution options, up to the limits established by the IRS. The Company adds 100% to their account for every dollar they contribute up to the first 1% and 70% for every dollar they contribute up to the next 5% each pay period. All contribution sources are eligible for the match, but the 6% limit is applied to the total amount contributed each pay period. Employees can invest in any combination of the 19 investment options available and/or the self-directed brokerage account to design their own diversified portfolio. Employees are immediately 100% vested in the value of their contributions and AEP contributions.

AEP SYSTEM RETIREMENT PLAN (Qualified Pension Plan)

Each of the AEP affiliates establishes a recordkeeping account for their employees to track growth of a participant's benefit over time. The plan provides a cash balance benefit. The account balance grows through two annual credits: an interest credit and an annual employer company credit which is a percentage of a participant's pay, based on age and service. Employees are eligible to participate after completing one year of service with AEP. Employees are automatically enrolled in the AEP System Retirement Plan once eligible.

Participants are 100% vested in their accrued benefit after three years of service.

Participants of the AEP System Retirement Plan who were employed by the Company on 12/31/2000 and participants of the Central and South West Retirement Plan who were age 50 or older with at least 10 years of service as of June 30, 1997, are grandfathered in each plan's prior pension formula. Grandfathered participants receive the higher benefit from the prior formulas provided by the plans or the newer cash balance formula.

HOLIDAY

AEP provides pay for 9 holiday days per year for full-time employees and part-time employees who are regularly scheduled to work that day. An additional 24 hours of paid personal holiday time off can be scheduled by the employee with the approval from their supervisor to use throughout the year.

The following nine days* are scheduled by AEP

- New Year's Day
- Good Friday
- Memorial Day (last Monday in May)
- Independence Day (Fourth of July)
- Labor Day
- Thanksgiving Day
- Day after Thanksgiving
- Day before Christmas
- Christmas Day

* days may vary based on collective bargaining agreements

January 1, 2016 – December 31, 2016

VACATION

AEP provides paid vacation time off for all full-time and part-time employees who are scheduled to work an average of 20 hours per week. Part-time employees receive one-half the annual allocation as full-time employees. Refer to complete schedule below:

Group	Exempt Full-time Employees Salary Grades 8 and above	Exempt Full-time Employees Under Salary Grade 8 and all Non-Exempt Employees	Part-Time Employees
Years of Service	**Hours**	**Hours**	**Hours**
Year of hire	10 per month of service (max 120 hours)	8 per month of service (max 80 hours)	4 per month of service (max 40 hours)
1	120	80	40
2	120	88	44
3	120	96	48
4	120	104	52
5-6	120	120	60
7-8	128	128	64
9-10	136	136	68
11-12	144	144	72
13-14	152	152	76
15-23	160	160	80
24 +	200	200	100
	Employees hired on or before the 15th of the month will receive vacation service credit for that month.		

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power	)	
Company For (1) A General Adjustment Of Its	)	
Rates For Electric Service; (2) An Order	)	
Approving Its 2017 Environmental Compliance	)	
Plan; (3) An Order Approving Its Tariffs And	)	Case No. 2017-00179
Riders; (4) An Order Approving Accounting	)	
Practices To Establish Regulatory Assets And	)	
Liabilities; And (5) An Order Granting All Other	)	
Required Approvals And Relief	)	

DIRECT TESTIMONY OF

JASON A. CASH

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Jason A Cash, being duly sworn, deposes and says he is employed by American Electric Power as Accountant Policy and Research Staff, that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief

Jason A Cash

STATE OF OHIO)
) 2017-00179
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by (~~Insert Name~~), this the 20th day of June 2017.
Jason Cash

Notary Public

Notary ID Number: 2014-RE-488323

My Commission Expires: April 29, 2019

DIRECT TESTIMONY OF
JASON A. CASH ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2017-00179

TABLE OF CONTENTS

EXHIBITS

DIRECT TESTIMONY OF
JASON A. CASH ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jason A. Cash. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by American Electric Power Service Corporation ("AEPSC") as a Staff Accountant in Accounting Policy and Research ("AP&R"). AEPSC is a wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP").

My responsibilities include providing the AEP electric operating subsidiaries with accounting support, including the preparation of depreciation studies. I also monitor regulatory proceedings and legislation for accounting implications and assist in determining the appropriate regulatory accounting treatment.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I graduated with a Bachelor of Science degree with a major in accounting from The Ohio State University in 2000. In 2000, I joined AEPSC and have held several positions within the Accounting organization, including general ledger accounting and financial reporting for Ohio Power Company and AEPSC. From 2008 through 2013, I worked in AEPSC's Transmission Accounting department where I was promoted to Supervisor of

Transmission Accounting in 2013. I started my current position as Staff Accountant in AP&R in 2014.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY BEFORE ANY REGULATORY COMMISSIONS?

A. Yes. I have prepared a depreciation study and filed testimony before the Tennessee Regulatory Authority in Docket No. 16-00001 on behalf of AEP subsidiary, Kingsport Power Company. I have also prepared depreciation studies and filed testimony before the Federal Regulatory Energy Commission ("FERC') in Docket No. ER15-2114-000 on behalf of Transource West Virginia, LLC, and in Docket No. ER17-419-000 on behalf of Transource Pennsylvania, LLC and Transource Maryland, LLC. Transource West Virginia, LLC, Transource Pennsylvania, LLC and Transource Maryland, LLC are wholly owned subsidiaries of Transource Energy, LLC. Transource Energy is a joint venture between AEP and Great Plains Energy.

Q. HAVE YOU HAD ANY FORMAL TRAINING RELATING TO DEPRECIATION AND UTILITY ACCOUNTING?

A. Yes. I am a member of the Society of Depreciation Professionals ("SDP") and am currently serving as an at-large director for the SDP. I have completed training courses offered by the SDP, which include Depreciation Fundamentals, Life and Net Salvage Analysis, and Analyzing the Life of Real World Property. These training classes included topics such as introduction to plant and depreciation accounting, data requirements and collection, depreciation models, life cycle analysis, current regulatory issues, actuarial life analysis, net salvage analysis and simulation life analysis.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony supports the revised depreciation rates proposed by Kentucky Power Company ("Kentucky Power" or "Company") for Big Sandy Unit 1. The revised depreciation rates are based on my depreciation study of the electric utility plant values for Big Sandy Unit 1 in service at December 31, 2016. Schedules I and II in the Depreciation Study Report detail the results of the study. The depreciation rates determined by the study are intended to provide recovery of invested capital, cost of removal, and credit for salvage over the expected remaining life of Big Sandy Unit 1.

The revised depreciation rates are required due to changes in investment and expected life of Big Sandy Unit 1 following Unit 1's conversion to use natural gas in 2016.

Q. ARE YOU PROPOSING TO REVISE THE DEPRECIATION RATES FOR KENTUCKY POWER'S UNDIVIDED INTEREST IN THE MITCHELL PLANT OR ANY OF THE OTHER FUNCTIONAL PLANT GROUPS DURING THIS PROCEEDING?

A. No. Kentucky Power will continue to use the depreciation rates for its ownership share of the Mitchell Plant, and for the Transmission, Distribution, and General Plant functions as approved by the Commission in Case No. 2014-00396. The Distribution Plant function depreciation rates were first established in Case No. 91-066.

Q. ARE YOU SPONSORING ANY EXHIBITS IN THIS PROCEEDING?

A. Yes. I am sponsoring **EXHIBIT JAC-1**, which includes my depreciation study report, and **EXHIBIT JAC-2**, which is a copy of the Sargent & Lundy dismantling study performed for the Big Sandy Plant.

Q. WAS THE DEPRECIATION STUDY PREPARED OR ASSEMBLED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes.

III. DEFINITION OF DEPRECIATION

Q. PLEASE EXPLAIN THE DEFINITION OF DEPRECIATION AS USED IN PREPARING YOUR DEPRECIATION STUDY.

A. The definition of depreciation I used in preparing the study is the same that is used by the FERC and the National Association of Regulatory Utility Commissioners. That definition is:

> Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.
>
> Service value means the difference between original cost and the net salvage value (net salvage value means the salvage value of the property retired less the cost of removal) of the electric plant.

This is the same definition of depreciation that was used in preparing the Company's most recent depreciation study prepared for Case No. 2014-00396.

IV. DEPRECIATION STUDY OVERVIEW

Q. HOW DO THE DEPRECIATION RATES AND ANNUAL ACCRUALS CALCULATED IN YOUR 2016 DEPRECIATION STUDY COMPARE WITH KENTUCKY POWER'S CURRENT RATES AND ACCRUALS FOR BIG SANDY?

A. A comparison of Kentucky Power's current rates and accruals for Big Sandy and the study rates and accruals is shown below based on total Company depreciable plant balances at December 31, 2016:

Table 1 - Depreciation Rates and Accruals
Based on Depreciable Plant In Service at December 31, 2016

	Existing		Study		
Functional Plant Group	Rates	Accruals	Rates	Accruals	Difference
Big Sandy Unit 1	3.78%	5,886,810	5.78%	9,003,728	3,116,918

Based on results of the depreciation study, the Company proposes an increase in annual depreciation expense of $3,116,918 due to a change in depreciation rates using depreciable plant balances at December 31, 2016. The change in depreciation rates is necessary because of changes in investment and service life of Big Sandy Unit 1 after Unit 1 was converted to use natural gas in 2016.

It should be noted that the accrual amounts in the above table result from applying the applicable depreciation rates to depreciable balances at December 31, 2016. They do not represent the depreciation accruals that the Company is requesting to be included in its cost of service. The annual depreciation accruals that the Company requests in cost of service in this proceeding are calculated and supported by Company witness Tyler Ross and result from his application of my recommended depreciation rates to the adjusted plant in service balances at Test Year end.

Big Sandy Unit 1's current depreciation rates are based on a 1991 settlement agreement in Case No. 91-066 effective on April 1, 1991 and do not reflect changes in investment in Big Sandy Unit 1 or its service life following conversion to natural gas.

V. STUDY METHODS AND PROCEDURES

Q. PLEASE BRIEFLY DESCRIBE THE METHODS AND PROCEDURES USED IN THE STUDY.

A. The methods and procedures are fully described in my depreciation study report labeled **EXHIBIT JAC-1**. In summary, all of the property included in the depreciation report was considered using the group plan method. Under the group plan method, depreciation is accrued upon the basis of the original cost of all property included in each depreciable plant group instead of individual items of property. Upon retirement of any depreciable property, its full cost, less any net salvage realized, is charged to the accumulated provision for depreciation regardless of the age of the particular item retired. Also under the group plan method, the values in each primary plant account are considered as a separate group for depreciation accounting purposes and an annual depreciation rate for each account is determined.

In this study, the plant groups consisted of the individual primary plant accounts for Big Sandy Unit 1 Production plant property only. The depreciation rates were calculated by using the Average Remaining Life Method, which is the same method that was used to calculate Kentucky Power's current depreciation rates. The Average

Remaining Life Method recovers the original cost of the plant, adjusted for net salvage, less accumulated depreciation over the average remaining life of the plant.

The original cost, accumulated depreciation, and net salvage by plant account for Big Sandy Unit 1 were combined in the depreciation study. The combined amounts were used to establish depreciation rates for Big Sandy Unit 1 by plant account in order to fully depreciate each plant account by the estimated 2031 retirement year.

Q. YOU INDICATED ABOVE THAT THE AVERAGE REMAINING LIFE METHOD RECOVERS THE ORIGINAL COST OF THE PLANT, ADJUSTED FOR NET SALVAGE. HOW WAS THE NET SALVAGE AMOUNT FOR BIG SANDY UNIT 1 CALCULATED?

A. Net salvage for Big Sandy Unit 1 was determined based on actual historical experience for each Production Plant account, including the amounts related to interim retirements, and an estimate of end-of-life, or terminal, salvage amounts for each account. To determine this terminal salvage amount, Kentucky Power relied on a 2012 conceptual dismantling cost estimate for the Big Sandy Plant prepared by the independent engineering firm, Sargent & Lundy. The proposed depreciation rates for Big Sandy Unit 1 included the dismantling cost at its estimated retirement date.

Q. WHY DID KENTUCKY POWER USE THE SARGENT & LUNDY DISMANTLING STUDY TO DETERMINE THE TERMINAL NET SALVAGE AMOUNT FOR BIG SANDY UNIT 1?

A. The Sargent & Lundy dismantling study provides estimated removal cost and salvage amounts specific to Big Sandy and is therefore a reasonable method to arrive at future expected terminal net salvage amounts. A copy of the Sargent & Lundy dismantling study is included with my testimony as **<u>EXHIBIT JAC-2</u>**.

Q. WERE THERE ANY ADJUSTMENTS MADE TO THE RESULTS PROVIDED BY THE DISMANTLING STUDY WHEN ADDING THE SARGENT & LUNDY NET SALVAGE AMOUNTS TO THE DEPRECIATION STUDY?

A. Yes. Sargent & Lundy provided a terminal net salvage amount in 2013 dollars. I applied a 2.30% inflation rate factor to the net salvage amounts provided by the Sargent & Lundy study to determine the terminal net salvage amount at Big Sandy's retirement year. The terminal net salvage amount after inflation was used in the calculation of net salvage percentages in the depreciation study.

Q. WHAT IS THE SOURCE OF THE 2.30% INFLATION RATE USED FOR THIS PURPOSE?

A. The 2.30% inflation rate was taken from a publication titled "The Livingston Survey" dated December 9, 2016 and is the most recent rate provided by the survey. The Livingston Survey is published by the research department of the Federal Reserve Bank of Philadelphia and provides a long term inflation outlook projecting an inflation rate for a 10 year period.

Q. WERE THERE ANY OTHER ADJUSTMENTS MADE TO THE RESULTS PROVIDED BY THE DISMANTLING STUDY WHEN ADDING THE SARGENT & LUNDY NET SALVAGE AMOUNTS TO THE DEPRECIATION STUDY?

A. Yes. The terminal net salvage amount provided by Sargent & Lundy in the dismantling study was for the entire Big Sandy Plant, which included both Units 1 and 2. A calculation was made to allocate a portion of the total terminal net salvage to Unit 1 based on the generating capacity of each unit. The calculation resulted in 26.27% of the terminal net salvage costs identified in the Sargent & Lundy dismantling study being allocated to Big Sandy Unit 1 based on its relative generating capacity as compared to Big Sandy Unit 2.

Q. DO YOU RECOMMEND ANY CHANGES IN HOW THE DEPRECIATION RATES CALCULATED IN THIS DEPRECIATION STUDY ARE APPLIED TO BIG SANDY UNIT 1 FROM WHEN THE RATES WERE LAST UPDATED IN CASE NO. 91-066?

A. Yes. Kentucky Power currently applies depreciation rates and maintains accumulated depreciation for Big Sandy Unit 1 by functional plant classification (Production). The Company proposes to adopt and apply the proposed depreciation accrual rates at the primary plant account level, and that the accumulated depreciation by primary plant account be established as of the date the revised depreciation rates become effective. Maintaining accumulated depreciation at the primary account level will facilitate monitoring depreciation accruals and actual salvage and removal activity for future depreciation study purposes. In addition, the application of depreciation accrual rates at the primary account level has been applied to the Kentucky Power's undivided interest in the Mitchell Plant, the Transmission Plant function, and the General Plant function as a result of the settlement agreement in Case No. 2014-00396.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

KENTUCKY POWER COMPANY

DEPRECIATION STUDY REPORT

FOR

BIG SANDY UNIT 1

ELECTRIC PLANT IN SERVICE

AT

DECEMBER 31, 2016

DEPRECIATION STUDY REPORT

Table of Contents

I. <u>INTRODUCTION</u>

This report presents the results of a depreciation study of Kentucky Power Company's ("Kentucky Power" or "Company") depreciable Big Sandy Unit 1 electric utility plant in service at December 31, 2016 (the "Study"). The study was prepared by Jason A. Cash, Staff Accountant – Accounting Policy and Research at American Electric Power Service Corporation ("AEPSC"). The purpose of the Study was to develop updated annual depreciation accrual rates for Unit 1 of Kentucky Power's Big Sandy Plant.

The proposed depreciation rates are based on the Average Remaining Life Method of computing depreciation. Further explanation of this method is contained in Section II of this report.

The definition of depreciation used in the Study is the same used by the Federal Energy Regulatory Commission ("FERC") and the National Association of Regulatory Utility Commissioners and in preparing the Company's most recent depreciation study in Case No. 2014-00396:

> Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.
>
> Service value means the difference between original cost and the net salvage value (net salvage value means the salvage value of the property retired less the cost of removal) of the electric plant. (FERC <u>Accounting and Reporting Requirements for Public Utilities and Licensees</u>, ¶15.001.)

Schedule I of this report shows the proposed depreciation accrual rates for Big Sandy Unit 1. Schedule II compares depreciation expense of Big Sandy Unit 1 using rates approved by the Commission and rates recommended by the depreciation study. A comparison of Kentucky

Power's current rates and accruals for Big Sandy Unit 1 and the Study rates and accruals is shown below based on total Company depreciable plant balances at December 31, 2016:

Table 1 - Depreciation Rates and Accruals
Based on Depreciable Plant In Service at December 31, 2016

	Existing		Study		
Functional Plant Group	Rates	Accruals	Rates	Accruals	Difference
Big Sandy Unit 1	3.78%	5,886,810	5.78%	9,003,728	3,116,918

Based on Big Sandy Unit 1 Depreciable Plant In-Service as of December 31, 2016, the Company proposes an increase in depreciation rates that result in an increase in annual depreciation expense of $3,116,918. The depreciation rate changes are necessary because of changes in investment and the service life of Big Sandy Unit 1 after it was converted to use natural gas in 2016. Big Sandy Unit 1's current depreciation rates are based on a 1991 settlement agreement in Case No. 91-066 and were made effective on April 1, 1991.

II. DISCUSSION OF METHODS AND PROCEDURES USED IN THE STUDY

1. Group Method

All of the depreciable property included in the Study was considered using the group plan method. Under the group plan method, depreciation expense is accrued upon the basis of the original cost of all property included in each depreciable plant account. Upon retirement of any depreciable property, its full cost, less any net salvage realized, is charged to the accrued depreciation reserve regardless of the age of the particular item retired. Also, under the group plan method, the amount in each primary plant account are considered as a separate group for depreciation accounting purposes and an annual depreciation rate for each account is determined. The annual accruals by primary account were then summed, to arrive at the total accrual for each functional group. The total accrual divided by the original cost yields the functional group accrual rate.

2. Annual Depreciation Rates Using the Average Remaining Life Method

Kentucky Power's current depreciation rates are based on the Average Remaining Life Method. The Average Remaining Life Method recovers the original cost of the plant, adjusted for net salvage, less accumulated depreciation, over the average remaining life of the plant. By this method, the annual depreciation rate for each account is determined on the following basis:

$$\text{Annual Depreciation Expense} = \frac{\text{(Orig. Cost) (Net Salvage Ratio) - Accumulated Depreciation}}{\text{Average Remaining Life}}$$

$$\text{Annual Depreciation Rate} = \frac{\text{Annual Depreciation Expense}}{\text{Original Cost}}$$

3. Life Span Analysis

For Kentucky Power's Big Sandy Unit 1, a life span analysis was used to arrive at the historically realized mortality characteristics and service life of the depreciable plant investment. The life-span method of analysis is particularly suited to specific location property, such as generating plants, where all of the surviving investments are likely to be retired in total at a future date. The key elements in the life span analysis are the age of the surviving investments, the projected retirement date of the facility and the expected interim retirements. Interim retirements are those retirements that are expected to occur between the date of the depreciation study and the expected final retirement date of the generating plant. Examples of interim retirements include fans, pumps, motors, a set of boiler tubes, a turbine rotor, etc. The interim retirement history for each primary production plant account was analyzed and the results of those analyses were used to project future interim retirements. The age of Big Sandy's surviving investments at December 31, 2016 was obtained from the accounting records of Kentucky

Power. AEPSC engineering and Kentucky Power operational personnel provided the estimated retirement date used in the life-span analysis for Big Sandy Unit 1.

Big Sandy Unit 1

At December 31, 2016, Kentucky Power's depreciable investment in Steam Production Plant includes Big Sandy Unit 1. Big Sandy Unit 1 is located on Highway 23 near Louisa, Kentucky and was originally placed in service in 1963. Kentucky Power converted Big Sandy Unit 1 from a coal fired unit to a natural gas fired unit in 2016. Following the conversion to natural gas, Big Sandy Unit 1's capacity is 285 MW. The anticipated retirement date for Big Sandy Unit 1 as a natural gas unit is 2031. Additionally, since the last depreciation study performed for Kentucky Power (property investment dated December 31, 2013), Kentucky Power retired Big Sandy Unit 2 and the coal related assets of Big Sandy Unit 1 in 2015.

III. NET SALVAGE

1. Net Salvage - Steam Production Plant

The net salvage analysis for steam production plant included a review of the experienced functional interim retirement, salvage and removal history for Steam Production Plant for the period 2001-2016.

While the net salvage characteristics include interim retirements for the plants, the most significant net salvage amounts for generating plants occurs at the end of their life. Therefore, to assist in establishing total net salvage applicable to Kentucky Power's Big Sandy Unit 1, Kentucky Power relied on a conceptual demolition costs estimate prepared by Sargent & Lundy for the Big Sandy Plant. The Sargent & Lundy demolition cost estimates are based on 2013 price levels which were inflated to retirement date in the depreciation study. The terminal net salvage amount provided by Sargent & Lundy in the dismantling study was for the entire Big Sandy Plant, which included both Units 1 and 2. A portion of the terminal net salvage amount was allocated to Unit 1 based on the generating capacity of each unit. These estimates were incorporated into the calculation of net salvage ratios for Big Sandy's Production Plant.

2. Net Salvage – Ratios

The net salvage ratios shown on Schedule I of this report may be explained as follows:

a. Where the ratio is shown as unity (1.00), it was assumed that the net salvage in that particular account would be zero.

b. Where the ratio is less than unity, it was assumed that the salvage exceeded the removal costs. For example, if the net salvage were 20%, the net salvage ratio would be expressed as .80.

c. Where the ratio is greater than unity, it was assumed that the salvage was less than the cost of removal. For example, if the net salvage were minus 5%, the net salvage ratio would be expressed as 1.05.

IV. STUDY RESULTS

Steam Production Plant

Depreciation rates for Big Sandy Unit 1 were calculated by plant account with the expectation that the total cost including interim net salvage would be recovered by 2031, which is the estimated retirement date for the unit. A comparison of the Big Sandy Unit 1 steam production depreciation accruals is provided on Schedule II using the currently approved depreciation rates and the study depreciation rates. The original cost and accumulated depreciation amounts used for Big Sandy Plant are the plant's original cost and accumulated depreciation on Kentucky Power's books at December 31, 2016.

Depreciation rates for the Big Sandy Plant increased from 3.78% to 5.78%. As a result, depreciation expense increased by $3,116,918. The increase in steam production depreciation expense due to the change in depreciation rates was primarily because of the changes in investment and the service life of Big Sandy Unit 1 after it was converted to use natural gas in 2016.

SCHEDULE I – EXPLANATION OF COLUMN HEADINGS

Schedule I shows the determination of the recommended annual depreciation accrual rate by primary plant accounts by the straight line remaining life method. An explanation of the schedule follows:

Column I	-	Account number.
Column II	-	Account title.
Column III	-	Original Cost at December 31, 2016
Column IV	-	Net Salvage Ratio.
Column V	-	Total to be Recovered (Column III) * (Column IV).
Column VI	-	Calculated Depreciation Requirement.
Column VII	-	Accumulated Depreciation.
Column VIII	-	Remaining to be Recovered (Column V - Column VII).
Column IX	-	Average Remaining Life.
Column X	-	Recommended Annual Accrual Amount.
Column XI	-	Recommended Annual Accrual Percent or Depreciation Rate (Column X/Column III).

KENTUCKY POWER COMPANY
SCHEDULE I - CALCULATION OF BIG SANDY UNIT 1 DEPRECIATION RATES BY THE REMAINNG LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2016
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

									Annual Accrual	
Acct.	Title	Original Cost	Net Salvg. Ratio	Total to be Recovered	Calculated Depreciation Requirement	Accumulated Depreciation	Remaining to Be Recovered	Avg. Remain Life	Amount	Percent
(I)	(II)	(III)	(IV)	(V)	(VI)	(VII)	(VIII)	(IX)	(X)	(XI)
STEAM PRODUCTION PLANT										
Big Sandy Unit 1										
311.0	Structures & Improvements	11,756,127	1.09	12,814,178	7,526,502	4,805,397	8,008,781	14.10	567,999	4.83%
312.0	Boiler Plant Equipment	75,388,722	1.09	82,173,707	22,552,265	9,774,280	72,399,427	13.43	5,390,873	7.15%
314.0	Turbogenerator Units	61,392,346	1.09	66,917,657	36,338,075	28,424,981	38,492,676	13.86	2,777,249	4.52%
315.0	Accessory Electrical Equip.	3,877,136	1.09	4,226,078	2,964,549	2,578,951	1,647,127	14.03	117,400	3.03%
316.0	Misc. Power Plant Equip.	3,321,344	1.09	3,620,265	2,153,127	1,512,867	2,107,398	14.03	150,207	4.52%
	Total	155,735,675		169,751,885	71,534,518	47,096,476	122,655,409		9,003,728	5.78%
	Total Depreciable Plant	155,735,675	1.09	169,751,885	71,534,518	47,096,476	122,655,409	13.62	9,003,728	5.78%

N/A = Not Applicable

KENTUCKY POWER COMPANY
SCHEDULE II - COMPARE BIG SANDY UNIT 1 DEPRECIATION EXPENSE USING CURRENT AND STUDY RATES
ANNUAL DEPRECIATION RATES AND ACCRUALS BY THE REMAINNG LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2016

NO. (1)	TITLE (2)	ORIGINAL COST AT 12/31/2015 (3)	CURRENT APPROVED RATE (4)	ANNUAL ACCRUAL (5)	STUDY RATE (6)	STUDY ACCRUAL (7)	DIFFERENCE (DECREASE) (8)
STEAM PRODUCTION PLANT							
BIG SANDY UNIT 1							
311.0	Structures & Improvements	11,756,127	3.78%	444,382	4.83%	567,999	123,617
312.0	Boiler Plant Equipment	75,388,722	3.78%	2,849,694	7.15%	5,390,873	2,541,179
314.0	Turbogenerator Units	61,392,346	3.78%	2,320,631	4.52%	2,777,249	456,618
315.0	Accessory Electrical Equipment	3,877,136	3.78%	146,556	3.03%	117,400	(29,156)
316.0	Misc. Power Plant Equip.	3,321,344	3.78%	125,547	4.52%	150,207	24,660
	Total	155,735,675	3.78%	5,886,810	5.78%	9,003,728	3,116,918
	Total Depreciable Plant	155,735,675	3.78%	5,886,810	5.78%	9,003,728	3,116,918

Big Sandy Plant Unit 1 & 2

CONCEPTUAL DEMOLITION COST ESTIMATE

Prepared for:
American Electric Power Company

Project No. 11488-066
March 28, 2013
Revision 0

Sargent & Lundy LLC
55 East Monroe Street
Chicago, IL 60603-5780 USA

Issue Summary Page

Revision Number	Date	Purpose	Prepared By	Reviewed By	Approved By	Pages Affected
A	03/12/13	Comments	R. Kinsinger	J. A. Evanchik D. F. Franczak		All
0	03/28/13	Use	R. Kinsinger Robert Kinsinger	J. A. Evanchik J. A. Evanchik D. F. Franczak D. F. Franczak	S.R. Bertheau	All

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Section **Page**

1.0 INTRODUCTION

The Big Sandy Plant is located near Louisa, Kentucky in Lawrence County. The plant consists of two (2) generating units with a total generating capacity of 1,097 megawatts (Unit 1 = 281MW, Unit 2 = 816 MW). Units 1 & 2 were placed in operation in 1963 and 1969 respectively.

The American Electric Power Company (AEP) recently contracted Sargent & Lundy, LLC. to prepare a conceptual demolition cost estimate using 1st Quarter 2013 pricing levels. The objective of the conceptual demolition cost estimate is to determine the gross demolition costs for Big Sandy Plant Units 1 and 2 (including gross salvage credits and any other benefits). The cost estimate considers the demolition/dismantlement methodology which complies with current OSHA rules and regulations.

2.0 COST ESTIMATE SUMMARY

Conceptual Demolition Cost Estimate No. 31983B, dated March 28, 2013, was prepared and is included as Exhibit 1. The cost estimate is structured into a code of accounts as identified in Table 2-1.

Table 2-1
Cost Estimate Code of Accounts

Account Number	Description
10	Demolition Costs (including steel, equipment & piping scrap value)
18	Scrap Value Costs
91	Other Direct & Construction Indirect Costs
93	Indirect Costs
94	Contingency Costs
96	Escalation Costs

The results of the cost estimate are provided in Table 2-2 below:

Table 2-2
Cost Estimate Results Summary

Description	Total Cost
Demolition Cost	$38,725,498
Scrap Value	$(20,887,112)
Direct Cost Subtotal	$17,838,386
Indirect Cost	$ 1,783,800
Contingency Cost	$9,209,600
Total Project Cost	$28,831,786

3.0 TECHNICAL BASIS

The scope of dismantlement includes the complete Big Sandy Plant Units 1 & 2 generating facility and plant common services associated with both units. Common facilities include:

- 825 ft Chimney
- Various Buildings
- Coal Rail and Truck Unloading Facilities

The following are excluded from the scope of the conceptual demolition cost estimate.

- Bottom Ash Pond
- Asbestos Removal
- Switchyard

The scope of the demolition cost estimate is based on a review of the facility by two (2) S&L employees conducted in January 2013 for development of the demolition cost estimate.

4.0 COMMERCIAL BASIS

4.1 General Information

The Conceptual Demolition Cost Estimate prepared for the Big Sandy Plant is a conceptual estimate of the cost to dismantle Big Sandy Plant Units 1 and 2.

Costs were calculated for (1) demolition of existing plant structures and equipment and associated site restoration costs, (2) scrap value of steel and copper, (3) associated indirect costs, and (4) contingency. All units used in the cost estimate are U.S. Standard and all costs are in US Dollars (1st Quarter 2013 levels). A two (2) year demolition schedule is anticipated not including asbestos removal (to be performed prior to start of demolition work).

4.2 Quantities/Material Cost

Quantities of pieces of equipment and/or bulk material commodities used in this cost estimate were intended to be reasonable and representative of projects of this type. Material quantities were estimated from the site plot plan and other drawings and data provided by AEP and Plant Personnel.

4.3 Construction Labor Wages

Craft labor rates (Craft Hourly Rate) for the cost estimate were calculated as Non-Union Kentucky Craft Labor rates based on Personnel Administration Services (PAS) Inc. "2013 Merit Shop Wage and Benefit Survey". The craft rates were incorporated into work crews appropriate for the activities by adding allowances for small tools, construction equipment, insurance, and site overheads to arrive at crew hourly rates detailed in the cost estimate. A 1.05 regional labor productivity multiplier was included based on Compass International Global Construction Yearbook, 2013 Edition, for non-union work in Kentucky.

4.3.1 Labor Work Schedule and Incentives

The estimate assumed a 5x8 work week. No other labor incentives are included.

4.3.2 Construction Indirects

Allowances were included in the cost estimate as direct costs as noted for the following:

- Freight: Material and scrap freight included in the material and scrap costs.
- Additional Crane Allowance: None included. Cost of cranes and construction machinery are included in the labor wage rates.
- Mobilization and Demobilization: Included in labor wage rates.
- Scaffolding: Included in labor wage rates.
- Consumables: Included in material and labor costs.

- Per Diem Costs: Excluded from the estimate.
- Contractor's General and Administrative Costs and Profit: Included in the labor wage rates.

4.4 Scrap Value

The value of scrap was determined by a 12 month average (March 2012 through February of 2013) using Zone 4 (USA Midwest) of the "Scrap Metals Market Watch" (www.americanrecycler.com).

Since the values obtained are delivered pieces, 10% of the values obtained were deducted to pay for separation, preparation and shipping to the mills. This resulted in realized prices of:

- Mixed Steel Value @ $287/Ton
- Copper Value @ $6,091/Ton
- Stainless Steel @ $1,336/Ton

Note: 1 Ton = 2,000 Lbs

All steel is considered to be mixed steel unless otherwise noted.

4.5 Indirect Costs

Allowances were included in the cost estimate as indirect costs as noted for the following:

- Engineering, Procurement and Project Services: None included.
- Construction Management Support: None included.
- Owners Cost: Included as 10.0% of the total direct cost. Owners Costs include owner project engineering, administration and construction management, permits and fees, legal expenses, taxes, etc.

4.6 Escalation

No allowance for escalation was included in the cost estimate. All costs are determined in 1st Quarter 2013 levels.

4.7 Contingency

Allowances were included in the cost estimate as contingency as noted for the following:

- Scrap Value: Included as a 15.0% reduction in the salvage value resulting in a total net reduction in the salvage value. The contingency assumes a potential drop in salvage value thus increasing the project cost.

- Material: Included as 15.0% of the total material cost.
- Labor: Included as 15.0% of the total labor cost.
- Indirect: Included as 15.0% of the total indirect cost.

4.8 Assumptions

The following assumptions apply to the cost estimate.

- All chemicals will be removed by the Owner prior to demolition, from the facilities to be demolished.
- All coal and fuel oil will be consumed prior to demolition.
- Catalyst, if any, is assumed to be removed and returned to the OEM by others, prior to demolition.
- All electrical equipment and wiring is de-energized prior to start of dismantlement.
- No extraordinary environmental costs for demolition have been included. Removal of five (5) feet of fill inside the bermed areas around the oil tanks and metal cleaning waste tank is included.
- Asbestos and PCB's are removed from site by others prior to start of demolition.
- Bottom Ash Pond is not included. These costs will be determined by the Owner.
- Demolition of the chimney will be subcontracted. The chimney is 825 ft high and is located approximately 580 ft from the Big Sandy River to the South and 480 ft from the main switchyard to the North. Also, the main line for the Chesapeake and Ohio Railroad is approximately 825 ft North and US 29 is approximately 50 ft beyond the railroad. Therefore Careful Demolition (top down demolition process) will be used to dismantle the chimney. The chimney is demolished by breaking it up from the top and dropping the debris down the throat of the chimney and removing the debris periodically through the duct openings on the sides of the chimney (located 75 to 100 ft above grade). The remaining chimney below the duct openings is then demolished as any other structure.
- Switchyards within the plant boundaries are not part of the scope, neither are access roads to these facilities. Fences and gates needed to protect the switchyard will be left in place. The other site fences are removed.
- All items above grade and to a depth of 2 foot will be demolished. Any other items buried more than 2 foot will remain in place. All foundations are removed and buried on site with the exception of power block (turbine building, boiler building and service building), and the one (1) chimney thick mat foundation at grade. These foundations will have two (2) feet of soil spread over them and will be graded into the surrounding area.

- Underground piping, conduit and cable ducts will be abandoned in place.
- Underground piping larger than 4 feet diameter will be filled with sand or slurry and capped at the ends to prevent collapse. Non-metal pipe will be collapsed.
- All demolished materials are considered debris, except for organic combustibles and non-embedded metals which have scrap value.
- The basis for salvage estimating is for scrap value only. No resale of equipment or material is included.
- Handling, on-site and off-site disposal of hazardous materials would be performed in compliance with methods approved by Owner.
- Disturbed areas will be buried under 2 feet of topsoil mulched and seeded with grass – no other landscaping is included.
- All borrow material is assumed to be purchased from nearby (10 mile round trip) offsite sources.
- Debris not suitable for burial is to be disposed of off-site. Assumed distance to final disposal is within a 5 mile haul.

5.0 REFERENCES

Drawings utilized in the preparation of this demolition cost estimate are identified in Table 5-1.

Table 5-1

Reference Drawings

Unit	Document Number	Revision	Title
0	12-5030-2	0	Plot Plan
0	12-5030-10	0	Plot Plan
0	12-5030A-2	0	SCR Project Plot Plan
1	1-1200A-18	1	Auxiliary One Line
1	1-5031-2	1	General Cross Section
1	1-5032-2	1	Long Section Thru Turbine Room & Service Building Unit 1
1	1-5033-2	1	Long Section Thru Heater Bay & Service Building & Elev. South Side of Blr
2	2-1395	2	Fire Protection Foam House Electrical Assembly
2	2-1396	2	Fire Protection Sump F.O. Tank, & Truck Unloading Station Electrical Assemblies
2	2-3044-4-1	2	Concrete Stack Circular Steel Platforms
2	2-4101-2	2	Plumbing & Drainage, Roof & Drain System Sheet 1 of 6
2	2-4103-1	2	Plumbing & Drainage, Roof & Drain System Sheet 3 of 6
2	2-4107-2	2	Plumbing & Drainage, Floor Plan Service Building
2	2-4112-4	2	Plumbing & Drainage, Locomotive House & Tractor Shed Building
2	2-4122	2	Plumbing & Drainage, Service Building Annex Plans & Details
2	2-5001-3	2	Composite Cycle Diagram Unit 2
2	2-5050-15	2	Circulating Water Piping Sheet 1 of 3
2	2-5051-10	2	Circulating Water Piping Sheet 2 of 3
2	2-5109-1	2	Metal Cleaning Waste Treatment Facility General Arrangement & Yard Piping
2	2-5110-1	2	Metal Cleaning Waste Treatment Facility Piping Details
2	2-5135-32	2	Yard Piping Unit No 2, Sheet 1 of 3
2	2-536801-3	2	Urea Conversion Area Piping Composite
2	2-536802-0	2	Urea Preparation Area Piping Composite
2	2-536803-2	2	Urea Conversion Area Piping Composite
2	2-536804-2	2	Urea Conversion Area Piping Composite
2	2-538806-0	2	SCR Project Composite Piping Units 1 & 2 Precipitator Area
2	2-538807-1	2	SCR Project Piping Site Key Plan
2	2-538829-0	2	SCR Project Composite Piping Plans El. 116' 3"
2	Figure BS-2-3-15-1	2	Cooling Tower
2	2-MSK-459	2	Study of Revised River Water Makeup for Units 1 & 2
2	100109-9267512-02	2	SCR General Arrangement, Front Sectional View
2	100109-9267513-02	2	SCR General Arrangement, Unit 2 - Rear Sectional Views

Unit	Document Number	Revision	Title
2	100109-9267514-02	2	SCR General Arrangement, Unit 2 - Auxiliary Views
2	100109-9267520-02	2	SCR General Arrangement, SCR 2 - Plan View
2	100109-9267521-02	2	SCR General Arrangement, Unit 2 - Plan View
2	100109-9267530-02	2	SCR General Arrangement, Big Sandy 2, Isometric View
2	Training Document	2	Big Sandy Unit 2 Longitudinal Sections
2	Training Document	2	Big Sandy Unit 2 General Cross Section

0 = Common For Units 1& 2

1 = Unit 1

2 = Unit 2

EXHIBIT 1
Big Sandy Plant Units 1 & 2
Conceptual Demolition Cost Estimate No. 31983B

AMERICAN ELECTRIC POWER
Decommissioning Study Big Sandy
Units 1, 2 and Common Facilities

Project name	Big Sandy
Estimator	RCK
Labor rate table	13NUKY
Project No.	11488-066
Station Name	Big Sandy
Unit	1, 2 and Common
Location	Kentucky
Product Factor	1
Price Level	2013
Issue Date	3/28/2013
Estimate Date	3/28/2013
Reviewed By	JAE
Approved By	MNO
Estimate No.	31983B
Estimate Class	Conceptual
Report format	Sorted by 'Area/Group phase' 'Group phase' summary
Cost index	NUKY

ESTIMATE NO.: 31983B
PROJECT NO.: 11488-066
ISSUE DATE: 3/28/2013
PREP./REV.: RCK/JAE
APPROVED: MNO

AMERICAN ELECTRIC POWER
Decommissioning Study Big Sandy
Units 1, 2 and Common Facilities

Estimate Totals

Description	Amount	Totals	Hours
LABOR	29,540,432		357,986.217 hrs
MATERIAL	7,535,066		
SUBCONTRACT	1,650,000		
SCRAP RECOVERY	(20,887,112)		
	17,838,386	17,838,386	
91-1 SCAFFOLDING			
91-2 OT WORKING 5-10 HOUR DAYS			
91-3 OT Working 7-10 Hr Days			
91-2 PER DIEM			
91-5 CONSUMABLES			
91-6 FREIGHT ON EQUIPMENT			
91-7 FREIGHT ON SPECIAL EQUIP.			
91-8 FREIGHT ON MATERIAL			
91-9 FREIGHT ON SCRAP INCL			
91-10 SALES TAX			
91-11 CONTRACTOR'S G&A EXPENSE			
91-12 CONTRACTOR'S PROFIT			
		17,838,386	
93-1 EP&P SERVICES			
93-2 CM SUPPORT			
93-3 START-UP/COMMISSIONING			
93-4 START-UP/SPARE PARTS			
93-5 EXCESS LIABILITY INSUR.			
93-6 SALES TAX ON INDIRECTS			
93-7 OWNER'S COST	1,783,800		
93-8 EPC FEE			
	1,783,800	19,622,186	
94-3 CONTINGENCY ON MATERIAL	1,130,300		
94-4 CONTINGENCY ON LABOR	4,431,100		
94-5 CONTINGENCY ON SUB.	247,500		
94-6 CONTINGENCY ON SCRAP	3,133,100		
94-7 CONTINGENCY ON INDIRECTS	267,600		
	9,209,600	28,831,786	
96-3 ESCALATION ON MATERIAL			
96-4 ESCALATION ON LABOR			
96-5 ESCALATION ON SUB.			
96-6 ESCALATION ON SCRAP			
96-7 ESCALATION ON INDIRECTS			
		28,831,786	
98 INTEREST DURING CONSTR.			
		28,831,786	
Total		***28,831,786***	

PRINT DATE 3/26/2013 2:34 PM
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ESTIMATE NO.: 31983B
PROJECT NO.: 11488-066
ISSUE DATE: 3/28/2013
PREP./REV.: RCK/JAE
APPROVED: MNO

AMERICAN ELECTRIC POWER
Decommissioning Study Big Sandy
Units 1, 2 and Common Facilities

AREA	GROUP	PHASE	DESCRIPTION	SCRAP AMOUNT	MATERIAL AMOUNT	LABOR MAN HRS	LABOR AMOUNT	TOTAL AMOUNT
Common								
	10.00.00		WHOLE PLANT DEMOLITION		7,449,896	74,076	8,819,470	17,919,366
	18.00.00		SCRAP VALUE	(2,183,209)				(2,183,209)
			Common	**(2,183,209)**	**7,449,896**	**74,076**	**8,819,470**	**15,736,157**
Unit 1								
	10.00.00		WHOLE PLANT DEMOLITION		27,770	82,596	6,043,293	6,071,063
	18.00.00		SCRAP VALUE	(5,153,373)				(5,153,373)
			Unit 1	**(5,153,373)**	**27,770**	**82,596**	**6,043,293**	**917,690**
Unit 2								
	10.00.00		WHOLE PLANT DEMOLITION		57,400	201,314	14,677,668	14,735,068
	18.00.00		SCRAP VALUE	(13,550,530)				(13,550,530)
			Unit 2	**(13,550,530)**	**57,400**	**201,314**	**14,677,668**	**1,184,539**

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Area	Group	Phase	DESCRIPTION	TAKEOFF QUANTITY	SCRAP AMOUNT	MATERIAL AMOUNT	LABOR MAN HRS	LABOR PRICE	LABOR AMOUNT	TOTAL AMOUNT
Common										
	10.00.00		**WHOLE PLANT DEMOLITION**							
		10.21.00	**CIVIL WORK**							
			COVERED DISTURBED AREAS OF SITE W/2 FT TOPSOIL	296,500.00 CY	-	7,116,000	15,572	102.05 /MH	1,589,171	8,705,171
			SEED AND MULCH	92.00 AC	-	256,496	2,609	32.86 /MH	85,740	342,236
			PAVED SURFACES	15,400.00 SY	-	0	1,941	102.05 /MH	198,097	198,097
			DEMOLITION - 26450 TRACK FEET of 110# RAILROAD TRACK	26,450.00 TF	-	0	8,335	102.05 /MH	850,595	850,595
			DEMOLITION - PERIMETER FENCE	4,500.00 LF	-	0	189	102.05 /MH	19,295	19,295
			CIVIL WORK			**7,372,496**	**28,647**		**2,742,899**	**10,115,395**
		10.22.00	**CONCRETE**							
			BUILDING PAD FOUNDATION 110LB/CY, OUTBUILDINGS & MISC FDNS	2,555.00 CY	-	0	3,019	76.08 /MH	229,708	229,708
			EQUIPMENT FOUNDATION 110 LB/CY, MISC EQUIPMENT	1,300.00 CY	-		1,387	76.08 /MH	105,553	105,553
			INTAKE CLOSURE	800.00 CY	-	73,600	840	76.08 /MH	63,933	137,533
			CONCRETE			**73,600**	**5,247**		**399,194**	**472,794**
		10.24.00	**ARCHITECTURAL**							
			BUILDING, WAREHOUSE #4, 100 ' X 35' X 14' TALL	49,000.00 CF	-		309	74.88 /MH	23,125	23,125
			BUILDING, CHEMICAL BLDG. 3900 SF X 14' TALL	54,600.00 CF	-		344	74.88 /MH	25,768	25,768
			BUILDING, WAREHOUSE #5, 100' X50' X14' TALL	70,000.00 CF	-		441	74.88 /MH	33,035	33,035
			BUILDING, CONSTRUCTION OFFICES, 140' X 50' X 14' TALL	98,000.00 CF	-		618	74.88 /MH	46,249	46,249
			BUILDING, CONSTRUCTION LOCKERROOM / WAREHOUSE, 100' X 40' X 14' TALL	56,000.00 CF	-		353	74.88 /MH	26,428	26,428
			BUILDING, ANNEX, 85' X 48' 14' TALL	57,120.00 CF	-		360	74.88 /MH	26,957	26,957
			BUILDING, CAR DUMPER, 40' X68' X 22' TALL	59,840.00 CF	-		377	74.88 /MH	28,240	28,240
			BUILDING, SHOWER BLDG & COAL HANDLING OFFICE, 80' X 74' X 20' TALL	118,400.00 CF	-		746	74.88 /MH	55,877	55,877
			BUILDING, THAW-OUT SHED, 220' X 24' X 14' TALL	73,920.00 CF	-		466	74.88 /MH	34,885	34,885
			BUILDING, THAW-OUT SHED ELECTRICAL, 90' X 20' X 14' TALL	25,200.00 CF	-		159	74.88 /MH	11,893	11,893
			BUILDING, TRACTOR REPAIR BUILDING PART 1 88' X 25' X 14' TALL	30,800.00 CF	-		194	74.88 /MH	14,536	14,536
			BUILDING, TRACTOR REPAIR BUILDING PAR2 1 40' X 24' X 14' TALL	13,440.00 CF	-		85	74.88 /MH	6,343	6,343
			BUILDING, PICNIC SHELTER, 60' X 34' X 10' TALL	20,400.00 CF	-		129	74.88 /MH	9,627	9,627
			BUILDING, WAREHOUSE BOB AREA, 150' X 74' X 14' TALL	155,400.00 CF	-		979	74.88 /MH	73,338	73,338

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Area	Group	Phase	DESCRIPTION	TAKEOFF QUANTITY	SCRAP AMOUNT	MATERIAL AMOUNT	LABOR MAN HRS	LABOR PRICE	LABOR AMOUNT	TOTAL AMOUNT
		10.24.00	ARCHITECTURAL							
			BUILDING, OLD GATEHOUSE - TRAIONING BLDG, 35' X 30' X 12' TALL	12,600.00 CF	-		79	74.88 /MH	5,946	5,946
			BUILDING, RIVER SCREEN HOUSEM 50' X 30' X 14' TALL	21,000.00 CF	-		132	74.88 /MH	9,911	9,911
			BUILDING, FOAM HOUSE, 30' X 30' X 12' TALL	10,800.00 CF	-		68	74.88 /MH	5,097	5,097
			BUILDING, WATER TREATING BLDG, 40' X 30' X 14' TALL	16,800.00 CF	-		106	74.88 /MH	7,928	7,928
			BUILDING, GATEHOUSE - NORTH ENTRANCE, 20' X 16' X 14' TALL	4,480.00 CF	-		28	74.88 /MH	2,114	2,114
			BUILDING, FIREHOUSE, 30' X 15' X 12' TALL	5,400.00 CF	-		34	74.88 /MH	2,548	2,548
			BUILDING, UNIDENTIFED BLDG WEST OF FIRE HOUSE, 60' X 24' X 12' TALL	17,280.00 CF	-		109	74.88 /MH	8,155	8,155
			BUILDING, UNIDENTIFED BLDG EAST OF FIRE HOUSE, 60' X 24' X 12' TALL	17,280.00 CF	-		109	74.88 /MH	8,155	8,155
			BUILDING, SHED SW OF UNIT 1 SERVICE BLDG, 40' X 30' X 12' TALL	14,400.00 CF	-		91	74.88 /MH	6,796	6,796
			ARCHITECTURAL				6,316		472,952	472,952
		10.25.00	CONCRETE CHIMNEY & STACK							
			825' TALL CONCRETE CHIMNEY	825.00 VLF	-			76.08 /MH		1,650,000
			CONCRETE CHIMNEY & STACK							1,650,000
		10.31.00	MECHANICAL EQUIPMENT							
			TANKS, FUEL OIL TANK, 3,400,000 GALLONS, BOTTOM ONLY (TOP HAS BEEN REMOVED)	32.40 TN	-		91	65.32 /MH	5,940	5,940
			TANKS, FUEL OIL TANK, 500,000 GALLONS	50.00 TN	-		140	65.32 /MH	9,167	9,167
			TANKS, METAL CLEANING WASTE TANK 1,000,000 GALLONS	83.00 TN	-		233	65.32 /MH	15,217	15,217
			MECHANICAL EQUIPMENT				464		30,324	30,324
		10.33.00	MATERIAL HANDLING EQUIPMENT							
			MATERIAL HANDLING EQUIPMENT - COAL HANDLING SYSTEM	1,015.00 TN	-		2,159	65.32 /MH	141,026	141,026
			MATERIAL HANDLING EQUIPMENT				2,159		141,026	141,026
		10.35.00	PIPING							
			PIPING - CIRC WATER PIPING AND TUNNELS	1.00 LS	-		1,071	76.08 /MH	81,514	81,514
			PIPING - DEMO BOP PIPING AND HANGERS	1.00 LS	-		535	65.32 /MH	34,924	34,924
			PIPING				1,606		116,439	116,439
		10.41.00	ELECTRICAL EQUIPMENT							
			MISCELLANEOUS ELECTRICAL EQUIPMENT	75.00 TN	-		211	65.32 /MH	13,750	13,750
			MISCELLANEOUS ELECTRICAL EQUIPMENT, TRANSFORMERS	50.00 TN	-		140	65.32 /MH	9,167	9,167

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			ELECTRICAL EQUIPMENT				**351**		**22,917**	**22,917**
		10.42.00	**RACEWAY, CABLE TRAY, & CONDUIT**							
			RACEWAY, CABLE TRAY, & CONDUIT -	225.00 TN	-		479	65.32 /MH	31,262	31,262
			RACEWAY, CABLE TRAY, & CONDUIT				**479**		**31,262**	**31,262**
		10.86.00	**WASTE**							
			WASTE - OIL CONTAMINATED FILL, 3,400,000 GALLON OIL TANK COINTAINMENT	16,225.00 CY	-	0	20,179	168.94 /MH	3,409,039	3,409,039
			WASTE - METAL CLEANING TANK BERMED AREA CONTAMINATED FILL	3,889.00 CY	-	0	4,837	168.94 /MH	817,119	817,119
			WASTE - BUILDING WASTE - COMMON BLDGS	380.00 CY	-	3,800	40	65.32 /MH	2,607	6,407
			WASTE - OIL CONTAMINATED FILL, 500,000 GALLON OIL TANK COINTAINMENT	3,016.00 CY	-	0	3,751	168.94 /MH	633,693	633,693
			WASTE			**3,800**	**28,807**		**4,862,457**	**4,866,257**
			WHOLE PLANT DEMOLITION			**7,449,896**	**74,076**		**8,819,470**	**17,919,366**
	18.00.00		**SCRAP VALUE**							
		18.10.00	**MIXED STEEL**							
			MIXED STEEL REBAR RECOVERY FROM OUTBUILDINGS FOUNDATIONS & MISC FDNS	-164.00 TN	(47,068)	-		65.89 /MH		(47,068)
			MIXED STEEL REBAR RECOVERY FROM 825' CHIMNEY	-448.00 TN	(128,576)	-		65.89 /MH	0	(128,576)
			MIXED STEEL, STEEL LINER FROM 825' CHIMNEY	-278.00 TN	(79,786)	-		65.89 /MH	0	(79,786)
			MIXED STEEL, EQUIPMENT FOUNDATION110 LB/CY, MISC EQUIPMENT, REINFORCING	-72.00 TN	(20,664)	-		65.89 /MH		(20,664)
			MIXED STEEL, MATERIAL HANDLING EQUIPMENT - COAL HANDLING SYSTEM, COMMON	-1,015.00 TN	(291,305)	-		65.89 /MH		(291,305)
			MIXED STEEL, 26450 TF OF RAILROAD TRACK , 110# rRAIL	-970.00 TN	(278,390)	-		65.89 /MH	0	(278,390)
			MIXED STEEL, RACEWAY, CABLE TRAY, & CONDUIT -	-225.00 TN	(64,575)	-		65.89 /MH	0	(64,575)
			MIXED STEEL, MISCELLANEOUS ELECTRICAL EQUIPMENT, TRANSFORMERS	-25.00 TN	(7,175)	-		65.89 /MH		(7,175)
			MIXED STEEL, TANKS, FUEL OIL TANK, 3,400,000 GALLONS, BOTTOM ONLY (TOP HAS BEEN REMOVED)	-32.40 TN	(9,299)	-		65.89 /MH		(9,299)
			MIXED STEEL, TANKS, FUEL OIL TANK, 500,000 GALLONS	-50.00 TN	(14,350)	-		65.89 /MH		(14,350)

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		18.10.00	**MIXED STEEL**							
			MIXED STEEL, TANKS, METAL CLEANING WASTE TANK 1,000,000 GALLONS	-83.00 TN	(23,821)	-		65.89 /MH		(23,821)
			MIXED STEEL		**(965,009)**					**(965,009)**
		18.30.00	**COPPER**							
			COPPER SCRAP CABLE & COMMON	-150.00 TN	(913,650)	-		65.89 /MH		(913,650)
			COPPER, MISCELLANEOUS ELECTRICAL EQUIPMENT, TRANSFORMERS	-50.00 TN	(304,550)	-		65.89 /MH		(304,550)
			COPPER		**(1,218,200)**					**(1,218,200)**
			SCRAP VALUE		**(2,183,209)**					**(2,183,209)**
			Common		**(2,183,209)**	**7,449,896**	**74,076**		**8,819,470**	**15,736,157**
Unit 1										
	10.00.00		**WHOLE PLANT DEMOLITION**							
		10.22.00	**CONCRETE**							
			BUILDING PAD FOUNDATION 110 LB/CY, UNIT 1 COOLING TOWER BASIN	3,835.00 CY	-	0	4,532	76.08 /MH	344,787	344,787
			BUILDING PAD FOUNDATION 110LB/CY, OUTBUILDINGS & MISC FDNS	49.00 CY	-		58	76.08 /MH	4,405	4,405
			ELEVATED FOUNDATION 110/CY, UNIT 1 COOLING TOWER SHELL	7,112.00 CY	-	0	4,475	76.08 /MH	340,449	340,449
			ELEVATED FOUNDATION, UNIT 1 TURBINE AND BLR BLDGS	2,000.00 CY	-	0	1,258	76.08 /MH	95,739	95,739
			TURBINE PEDESTAL FOUNDATION 140 LB/CY, UNIT 1	1,911.00 CY	-	0	3,613	76.08 /MH	274,895	274,895
			CONCRETE				**13,936**		**1,060,276**	**1,060,276**
		10.23.00	**STEEL**							
			DUCTWORK W/BREECHINGS AND STEEL SUPPORTS, UNIT 1	537.00 TN	-	0	1,507	65.89 /MH	99,310	99,310
			STEEL				**1,507**		**99,310**	**99,310**
		10.24.00	**ARCHITECTURAL**							
			BUILDING, UNIT 1 POWER BLOCK, INCLUDING TURBINE BLDG, BOILER HOUSE PREHTR FAN ENCLOSURE & COAL BUNKERS	4,501,000.00 CF	-	0	47,279	74.88 /MH	3,540,282	3,540,282
			BUILDING, UNIT 1 THAW-OUT SHED, 60' X 22' X 16' TALL	21,120.00 CF	-		133	74.88 /MH	9,967	9,967
			ARCHITECTURAL				**47,413**		**3,550,250**	**3,550,250**
		10.31.00	**MECHANICAL EQUIPMENT**							
			MAIN BOILER AND APPURTENANCES, UNIT 1	3,218.00 TN	-	0	6,845	71.35 /MH	488,392	488,392
			FD & ID FANS, UNIT 1	214.00 TN	-	0	455	71.35 /MH	32,478	32,478
			FEEDWATER DEARATING EQUIPMENT, UNIT 1	100.00 TN	-	0	213	65.32 /MH	13,894	13,894
			TANKS, UNIT 1 CONDENSATE STORAGE TANK, 300,000 GALLONS	29.00 TN	-		81	65.32 /MH	5,317	5,317

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		10.31.00	MECHANICAL EQUIPMENT							
			WATER TREATMENT DEMINERALIZATION & CHEMICAL TREATMENT EQUIPMENT, UNIT 1	136.00 TN	-	0	289	65.32 /MH	18,896	18,896
			TURBINE GENERATOR, UNIT 1	750.00 TN	-	0	1,595	65.32 /MH	104,207	104,207
			CONDENSER, UNIT 1	423.00 TN	-	0	900	65.32 /MH	58,773	58,773
			CIRCULATING WATER EQUIPMENT, UNIT 1	69.00 TN	-	0	147	65.32 /MH	9,587	9,587
			COOLING TOWER, UNIT 1 REMOVE FILL	295,000.00 CF	-	0	1,859	65.32 /MH	121,446	121,446
			MECHANICAL EQUIPMENT - UNIT 1 MISC. POWER PLANT EQUIPMENT	155.00 TN	-	0	330	65.32 /MH	21,536	21,536
			MECHANICAL EQUIPMENT - DEMOLISH UNIT 1 TURBINE ROOM OVERHEAD CRANE	1.00 LS	-	0	331	65.32 /MH	21,613	21,613
			MECHANICAL EQUIPMENT - UNIT 1 DUST COLLECTORS	137.00 TN	-	0	291	65.32 /MH	19,035	19,035
			MECHANICAL EQUIPMENT - PRECIPITATORS UNIT 1	200.00 TN	-	0	425	65.32 /MH	27,788	27,788
			MECHANICAL EQUIPMENT				13,762		942,962	942,962
		10.33.00	MATERIAL HANDLING EQUIPMENT							
			MATERIAL HANDLING EQUIPMENT - UNIT 1 ASH HANDLING EQUIPMENT	77.00 TN	-	0	164	65.32 /MH	10,699	10,699
			MATERIAL HANDLING EQUIPMENT - UNIT 1 FUEL EQUIPMENT, CONVEYORS INCL TRUSSES & BENTS	837.00 TN	-	0	1,780	65.32 /MH	116,295	116,295
			MATERIAL HANDLING EQUIPMENT				1,944		126,993	126,993
		10.34.00	HVAC							
			HVAC - UNIT 1	1.00 LS	-		897	65.32 /MH	58,596	58,596
			HVAC				897		58,596	58,596
		10.35.00	PIPING							
			PIPING - UNIT 1 BOILER PLANT AND TURBINE PIPING	799.00 TN	-	0	1,784	65.32 /MH	116,552	116,552
			PIPING				1,784		116,552	116,552
		10.41.00	ELECTRICAL EQUIPMENT							
			GENERATOR BUS TRANSFORMERS UNIT 1 MAIN POWER TRANSFORMER	344.00 TN	-	0	966	65.32 /MH	63,067	63,067
			STATION AUXILIARY TRANSFORMERS, UNIT 1 MAIN AUX TRANSFORMERS	34.00 TN	-	0	95	65.32 /MH	6,233	6,233
			ELECTRICAL EQUIPMENT				1,061		69,301	69,301
		10.86.00	WASTE							
			WASTE - UNIT 1 COOLING TOWER FILL	1,094.00 CY	-	10,940	115	65.32 /MH	7,506	18,446
			WASTE - UNIT 1 BLDG WASTE	1,683.00 CY	-	16,830	177	65.32 /MH	11,548	28,378
			WASTE			27,770	292		19,054	46,824
			WHOLE PLANT DEMOLITION			27,770	82,596		6,043,293	6,071,063
	18.00.00		SCRAP VALUE							
		18.10.00	MIXED STEEL							

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		18.10.00	MIXED STEEL							
			MIXED STEEL, UNIT 1 POWER BLOCK, INCLUDING TURBINE BLDG, BOILER HOUSE PREHTR FAN ENCLOSURE & COAL BUNKERS & SERVICE BLDG	-2,251.00 TN	(646,037)	-		65.89 /MH		(646,037)
			MIXED STEEL, REBAR RECOVERED, TURBINE PEDESTAL FOUNDATION 140 LB/CY, UNIT 1	-105.00 TN	(30,135)	-		65.89 /MH	0	(30,135)
			MIXED STEEL, UNIT 1 COOLING TOWER REINFORCING RECOVERED	-603.00 TN	(173,061)	-		65.89 /MH	0	(173,061)
			MIXED STEEL, ELEVATED FOUNDATION, UNIT 1 TURBINE AND BLR BLDGS, REINFORCING	-110.00 TN	(31,570)	-		65.89 /MH		(31,570)
			MIXED STEEL, MAIN BOILER AND APPURTENANCES, UNIT 1	-3,218.00 TN	(923,566)	-		65.89 /MH	0	(923,566)
			MIXED STEEL, FD & ID FANS, UNIT 1	-214.00 TN	(61,418)	-		65.89 /MH	0	(61,418)
			MIXED STEEL, DUCTWORK W/BREECHINGS AND STEEL SUPPORTS, UNIT 1	-537.00 TN	(154,119)	-		65.89 /MH	0	(154,119)
			MIXED STEEL, FEEDWATER DEARATING EQUIPMENT, UNIT 1	-100.00 TN	(28,700)	-		65.89 /MH	0	(28,700)
			MIXED STEEL, WATER TREATMENT DEMINERALIZATION & CHEMICAL TREATMENT EQUIPMENT, UNIT 1	-136.00 TN	(39,032)	-		65.89 /MH	0	(39,032)
			MIXED STEEL, UNIT 1 CONDENSER	-287.00 TN	(82,369)	-		65.89 /MH	0	(82,369)
			MIXED STEEL, MATERIAL HANDLING EQUIPMENT - UNIT 1 ASH HANDLING EQUIPMENT	-77.00 TN	(22,099)	-		65.89 /MH	0	(22,099)
			MIXED STEEL, MATERIAL HANDLING EQUIPMENT - UNIT 1 FUEL EQUIPMENT, CONVEYORS INCL TRUSSES & BENTS	-837.00 TN	(240,219)	-		65.89 /MH	0	(240,219)
			MIXED STEEL, TURBINE GENERATOR, UNIT 1	-750.00 TN	(215,250)	-		65.89 /MH	0	(215,250)
			MIXED STEEL, CIRCULATING WATER EQUIPMENT, UNIT 1	-69.00 TN	(19,803)	-		65.89 /MH	0	(19,803)
			MIXED STEEL, MECHANICAL EQUIPMENT - UNIT 1 MISC. POWER PLANT EQUIPMENT	-155.00 TN	(44,485)	-		65.89 /MH	0	(44,485)
			MIXED STEEL, MECHANICAL EQUIPMENT - UNIT 1 DUST COLLECTORS	-137.00 TN	(39,319)	-		65.89 /MH	0	(39,319)
			MIXED STEEL, PIPING - UNIT 1 BOILER PLANT AND TURBINE PIPING	-799.00 TN	(229,313)	-		65.89 /MH		(229,313)
			MIXED STEEL, MECHANICAL EQUIPMENT - PRECIPITATORS UNIT 1	-200.00 TN	(57,400)	-		65.89 /MH	0	(57,400)
			MIXED STEEL, GENERATOR BUS TRANSFORMERS UNIT 1 MAIN POWER TRANSFORMER	-193.50 TN	(55,535)	-		65.89 /MH	0	(55,535)

Area	Group	Phase	DESCRIPTION	TAKEOFF QUANTITY	SCRAP AMOUNT	MATERIAL AMOUNT	LABOR MAN HRS	LABOR PRICE	LABOR AMOUNT	TOTAL AMOUNT
		18.10.00	MIXED STEEL							
			MIXED STEEL, STATION AUXILIARY TRANSFORMERS, UNIT 1 MAIN AUX TRANSFORMERS	-19.70 TN	(5,654)	-		65.89 /MH	0	(5,654)
			MIXED STEEL, TANKS, UNIT 1 CONDENSATE STORAGE TANK, 300,000 GALLONS	-29.00 TN	(8,323)	-		65.89 /MH		(8,323)
			MIXED STEEL		(3,107,406)					(3,107,406)
		18.30.00	COPPER							
			COPPER, UNIT 1 CONDENSER TUBES COPPER / NI	-135.40 TN	(824,721)	-		65.89 /MH		(824,721)
			COPPER, GENERATOR BUS TRANSFORMERS UNIT 1 MAIN POWER TRANSFORMER	-147.50 TN	(898,423)	-		65.89 /MH		(898,423)
			COPPER, STATION AUXILIARY TRANSFORMERS, UNIT 1 MAIN AUX TRANSFORMERS	-53.00 TN	(322,823)	-		65.89 /MH		(322,823)
			COPPER		(2,045,967)					(2,045,967)
			SCRAP VALUE		(5,153,373)					(5,153,373)
			Unit 1		**(5,153,373)**	**27,770**	**82,596**		**6,043,293**	**917,690**
Unit 2										
	10.00.00		WHOLE PLANT DEMOLITION							
		10.22.00	CONCRETE							
			BUILDING PAD FOUNDATION 110 LB/CY, UNIT 2 COOLING TOWER BASIN	9,583.00 CY	-		11,324	76.08 /MH	861,564	861,564
			BUILDING PAD FOUNDATION 110LB/CY, OUTBUILDINGS & MISC FDNS	363.00 CY	-		429	76.08 /MH	32,636	32,636
			ELEVATED FOUNDATION 110/CY, UNIT 2 COOLING TOWER SHELL	13,122.00 CY	-		8,256	76.08 /MH	628,146	628,146
			ELEVATED FOUNDATION , UNIT 2 TURBINE AND BLR BLDGS	2,035.00 CY	-		1,280	76.08 /MH	97,415	97,415
			TURBINE PEDESTAL FOUNDATION 140 LB/CY, UNIT 2	7,778.00 CY	-		14,706	76.08 /MH	1,118,856	1,118,856
			CONCRETE				35,997		2,738,616	2,738,616
		10.23.00	STEEL							
			DUCTWORK W/BREECHINGS AND STEEL SUPPORTS, UNIT 2	1,022.00 TN	-		2,868	65.89 /MH	189,004	189,004
			STEEL				2,868		189,004	189,004
		10.24.00	ARCHITECTURAL							
			BUILDING, UNIT 2 POWER BLOCK, INCLUDING TURBINE BLDG, BOILER HOUSE PREHTR FAN ENCLOSURE & COAL BUNKERS	8,863,000.00 CF	-	0	93,099	74.88 /MH	6,971,234	6,971,234
			BUILDING, UNIT 2, UREA SYSTEM BLDG, 60' 45' X 40' TALL	108,000.00 CF	-		681	74.88 /MH	50,969	50,969

AMERICAN ELECTRIC POWER
Decommissioning Study Big Sandy
Units 1, 2 and Common Facilities

Area	Group	Phase	DESCRIPTION	TAKEOFF QUANTITY	SCRAP AMOUNT	MATERIAL AMOUNT	LABOR MAN HRS	LABOR PRICE	LABOR AMOUNT	TOTAL AMOUNT
		10.24.00	ARCHITECTURAL							
			BUILDING, UNIT 2 UREA SYSTEM AMMONIOA ON DEMAND (AOD) BLDG, 60' X 40' X14' TALL	33,600.00 CF	-		212	74.88 /MH	15,857	15,857
			BUILDING, UNIT 2 SCR BLDG, 70' 67' X 20' TALL	93,800.00 CF	-		591	74.88 /MH	44,267	44,267
			ARCHITECTURAL				94,582		7,082,327	7,082,327
		10.31.00	MECHANICAL EQUIPMENT							
			MAIN BOILER AND APPURTENANCES, UNIT 2	12,160.00 TN	-		25,866	71.35 /MH	1,845,507	1,845,507
			FD & ID FANS, UNIT 2	6,135.00 TN	-		13,050	71.35 /MH	931,101	931,101
			FEEDWATER DEARATING EQUIPMENT, UNIT 2	215.00 TN	-		457	65.32 /MH	29,873	29,873
			TANKS, UNIT 2 CLEAN CONDENSATE TANK, 750,000 GALLONS	77.00 TN	-		216	65.32 /MH	14,117	14,117
			TANKS, UNIT 2 CONTAMINATED CONDENSATE TANK, 500,000 GALLONS	50.00 TN	-		140	65.32 /MH	9,167	9,167
			TANKS, UNIT 2 UREA SOLUTION STORAGE TANK, 200,000 GALLONS TK103-100	25.00 TN	-		70	65.32 /MH	4,583	4,583
			TANKS, UNIT 2 UREA SOLUTION STORAGE TANK, 200,000 GALLONS TK104-100	25.00 TN	-		70	65.32 /MH	4,583	4,583
			WATER TREATMENT DEMINERALIZATION & CHEMICAL TREATMENT EQUIPMENT, UNIT 2	269.00 TN	-		572	65.32 /MH	37,375	37,375
			TURBINE GENERATOR, UNIT 2	2,045.00 TN	-		4,350	65.32 /MH	284,137	284,137
			CONDENSER, UNIT 2	1,165.00 TN	-		2,478	65.32 /MH	161,868	161,868
			CIRCULATING WATER EQUIPMENT, UNIT 2	484.00 TN	-		1,030	65.32 /MH	67,248	67,248
			COOLING TOWER, UNIT 2 REMOVE FILL	664,000.00 CF	-		4,185	65.32 /MH	273,356	273,356
			MECHANICAL EQUIPMENT - UNIT 2 MISC. POWER PLANT EQUIPMENT	613.00 TN	-		1,304	65.32 /MH	85,172	85,172
			MECHANICAL EQUIPMENT - DEMOLISH UNIT 2 TURBINE ROOM OVERHEAD CRANE	1.00 LS	-		331	65.32 /MH	21,613	21,613
			MECHANICAL EQUIPMENT - UNIT 2 DUST COLLECTORS	269.00 TN	-		572	65.32 /MH	37,375	37,375
			MECHANICAL EQUIPMENT - PRECIPITATORS UNIT 2	600.00 TN	-		1,276	65.32 /MH	83,365	83,365
			MECHANICAL EQUIPMENT - SCR UNIT 2	664.00 TN	-		1,412	65.32 /MH	92,258	92,258
			MECHANICAL EQUIPMENT				57,380		3,982,698	3,982,698
		10.33.00	MATERIAL HANDLING EQUIPMENT							
			MATERIAL HANDLING EQUIPMENT - UNIT 2 ASH HANDLING EQUIPMENT	377.00 TN	-		802	65.32 /MH	52,381	52,381
			MATERIAL HANDLING EQUIPMENT - UNIT 2 FUEL EQUIPMENT, CONVEYORS INCL TRUSSES & BENTS	32.00 TN	-		68	65.32 /MH	4,446	4,446

AMERICAN ELECTRIC POWER
Decommissioning Study Big Sandy
Units 1, 2 and Common Facilities

Area	Group	Phase	DESCRIPTION	TAKEOFF QUANTITY	SCRAP AMOUNT	MATERIAL AMOUNT	LABOR MAN HRS	LABOR PRICE	LABOR AMOUNT	TOTAL AMOUNT
			MATERIAL HANDLING EQUIPMENT				**870**		**56,827**	**56,827**
		10.34.00	**HVAC**							
			HVAC - UNIT 2	1.00 LS	-		1,780	65.32 /MH	116,300	116,300
			HVAC				**1,780**		**116,300**	**116,300**
		10.35.00	**PIPING**							
			PIPING - UNIT 2 BOILER PLANT AND TURBINE PIPING	2,690.00 TN	-		6,007	65.32 /MH	392,396	392,396
			PIPING				**6,007**		**392,396**	**392,396**
		10.41.00	**ELECTRICAL EQUIPMENT**							
			GENERATOR BUS TRANSFORMERS UNIT 2 MAIN POWER TRANSFORMER	328.00 TN	-		921	65.32 /MH	60,134	60,134
			STATION AUXILIARY TRANSFORMERS, UNIT 2 MAIN AUX TRANSFORMERS	109.00 TN	-		306	65.32 /MH	19,984	19,984
			ELECTRICAL EQUIPMENT				**1,227**		**80,117**	**80,117**
		10.86.00	**WASTE**							
			WASTE - UNIT 2 COOLING TOWER FILL	2,460.00 CY	-	24,600	258	65.32 /MH	16,879	41,479
			WASTE - UNIT 2 BLDG WASTE	3,280.00 CY	-	32,800	345	65.32 /MH	22,505	55,305
			WASTE			**57,400**	**603**		**39,384**	**96,784**
			WHOLE PLANT DEMOLITION			**57,400**	**201,314**		**14,677,668**	**14,735,068**
	18.00.00		**SCRAP VALUE**							
		18.10.00	**MIXED STEEL**							
			MIXED STEEL, UNIT 2 POWER BLOCK, INCLUDING TURBINE BLDG, BOILER HOUSE PREHTR FAN ENCLOSURE & COAL BUNKERS & SERVICE BLDG	-4,431.50 TN	(1,271,841)	-		65.89 /MH		(1,271,841)
			MIXED STEEL, REBAR RECOVERED, TURBINE PEDESTAL FOUNDATION 140 LB/CY, UNIT 2	-467.00 TN	(134,029)	-		65.89 /MH		(134,029)
			MIXED STEEL, UNIT 2 COOLING TOWER REINFORCING RECOVERED	-1,249.00 TN	(358,463)	-		65.89 /MH		(358,463)
			MIXED STEEL, ELEVATED FOUNDATION , UNIT 2 TURBINE AND BLR BLDGS, REINFORCING	-112.00 TN	(32,144)	-		65.89 /MH		(32,144)
			MIXED STEEL, MAIN BOILER AND APPURTENANCES, UNIT 2	-12,160.00 TN	(3,489,920)	-		65.89 /MH		(3,489,920)
			MIXED STEEL, FD & ID FANS, UNIT 2	-6,135.00 TN	(1,760,745)	-		65.89 /MH		(1,760,745)
			MIXED STEEL, DUCTWORK W/BREECHINGS AND STEEL SUPPORTS, UNIT 2	-1,022.00 TN	(293,314)	-		65.89 /MH		(293,314)
			MIXED STEEL, FEEDWATER DEARATING EQUIPMENT, UNIT 2	-215.00 TN	(61,705)	-		65.89 /MH		(61,705)
			MIXED STEEL, WATER TREATMENT DEMINERALIZATION & CHEMICAL TREATMENT EQUIPMENT, UNIT 2	-269.00 TN	(77,203)	-		65.89 /MH		(77,203)
			MIXED STEEL, UNIT 2 CONDENSER	-792.00 TN	(227,304)	-		65.89 /MH		(227,304)

AMERICAN ELECTRIC POWER
Decommissioning Study Big Sandy
Units 1, 2 and Common Facilities

Area	Group	Phase	DESCRIPTION	TAKEOFF QUANTITY	SCRAP AMOUNT	MATERIAL AMOUNT	LABOR MAN HRS	LABOR PRICE	LABOR AMOUNT	TOTAL AMOUNT
		18.10.00	MIXED STEEL							
			MIXED STEEL, MATERIAL HANDLING EQUIPMENT - UNIT 2 ASH HANDLING EQUIPMENT	-377.00 TN	(108,199)	-		65.89 /MH		(108,199)
			MIXED STEEL, MATERIAL HANDLING EQUIPMENT - UNIT 2 FUEL EQUIPMENT, CONVEYORS INCL TRUSSES & BENTS	-35.00 TN	(10,045)	-		65.89 /MH		(10,045)
			MIXED STEEL, TURBINE GENERATOR, UNIT 2	-2,045.00 TN	(586,915)	-		65.89 /MH		(586,915)
			MIXED STEEL, CIRCULATING WATER EQUIPMENT, UNIT 2	-484.00 TN	(138,908)	-		65.89 /MH		(138,908)
			MIXED STEEL, MECHANICAL EQUIPMENT - UNIT 2 MISC. POWER PLANT EQUIPMENT	-613.00 TN	(175,931)	-		65.89 /MH		(175,931)
			MIXED STEEL, MECHANICAL EQUIPMENT - UNIT 2 DUST COLLECTORS	-269.00 TN	(77,203)	-		65.89 /MH		(77,203)
			MIXED STEEL, PIPING - UNIT 2 BOILER PLANT AND TURBINE PIPING	-2,690.00 TN	(772,030)	-		65.89 /MH		(772,030)
			MIXED STEEL, MECHANICAL EQUIPMENT - PRECIPITATORS UNIT 2	-600.00 TN	(172,200)	-		65.89 /MH		(172,200)
			MIXED STEEL, GENERATOR BUS TRANSFORMERS UNIT 2 MAIN POWER TRANSFORMERS	-180.50 TN	(51,804)	-		65.89 /MH		(51,804)
			MIXED STEEL, STATION AUXILIARY TRANSFORMERS, UNIT 2 MAIN AUX TRANSFORMERS	-56.00 TN	(16,072)	-		65.89 /MH		(16,072)
			MIXED STEEL, MECHANICAL EQUIPMENT - SCR UNIT 2	-664.00 TN	(190,568)	-		65.89 /MH		(190,568)
			MIXED STEEL, TANKS, UNIT 2 CLEAN CONDENSATE TANK, 750,000 GALLONS	-77.00 TN	(22,099)	-		65.89 /MH		(22,099)
			MIXED STEEL, TANKS, UNIT 2 CONTAMINATED CONDENSATE TANK, 500,000 GALLONS	-50.00 TN	(14,350)	-		65.89 /MH		(14,350)
			MIXED STEEL, TANKS, UNIT 2 UREA SOLUTION STORAGE TANK, 200,000 GALLONS TK103-100	-25.00 TN	(7,175)	-		65.89 /MH		(7,175)
			MIXED STEEL, TANKS, UNIT 2 UREA SOLUTION STORAGE TANK, 200,000 GALLONS TK104-100	-25.00 TN	(7,175)	-		65.89 /MH		(7,175)
			MIXED STEEL		(10,057,341)					(10,057,341)
		18.30.00	COPPER							
			COPPER, UNIT 2 CONDENSER TUBES COPPER / NI	-373.00 TN	(2,271,943)	-		65.89 /MH		(2,271,943)
			COPPER, GENERATOR BUS TRANSFORMERS UNIT 2 MAIN POWER TRANSFORMER	-147.50 TN	(898,423)	-		65.89 /MH		(898,423)

ESTIMATE NO.: 31983B
PROJECT NO.: 11488-066
ISSUE DATE: 3/28/2013
PREP./REV.: RCK/JAE
APPROVED: MNO

AMERICAN ELECTRIC POWER
Decommissioning Study Big Sandy
Units 1, 2 and Common Facilities

Area	Group	Phase	DESCRIPTION	TAKEOFF QUANTITY	SCRAP AMOUNT	MATERIAL AMOUNT	LABOR MAN HRS	LABOR PRICE	LABOR AMOUNT	TOTAL AMOUNT
		18.30.00	COPPER							
			COPPER, STATION AUXILIARY TRANSFORMERS, UNIT 2 MAIN AUX TRANSFORMERS	-53.00 TN	(322,823)	-		65.89 /MH		(322,823)
			COPPER		(3,493,189)					(3,493,189)
			SCRAP VALUE		(13,550,530)					(13,550,530)
			Unit 2		**(13,550,530)**	**57,400**	**201,314**		**14,677,668**	**1,184,539**

Sub Regional RTEP Committee: Western AEP Supplemental Projects

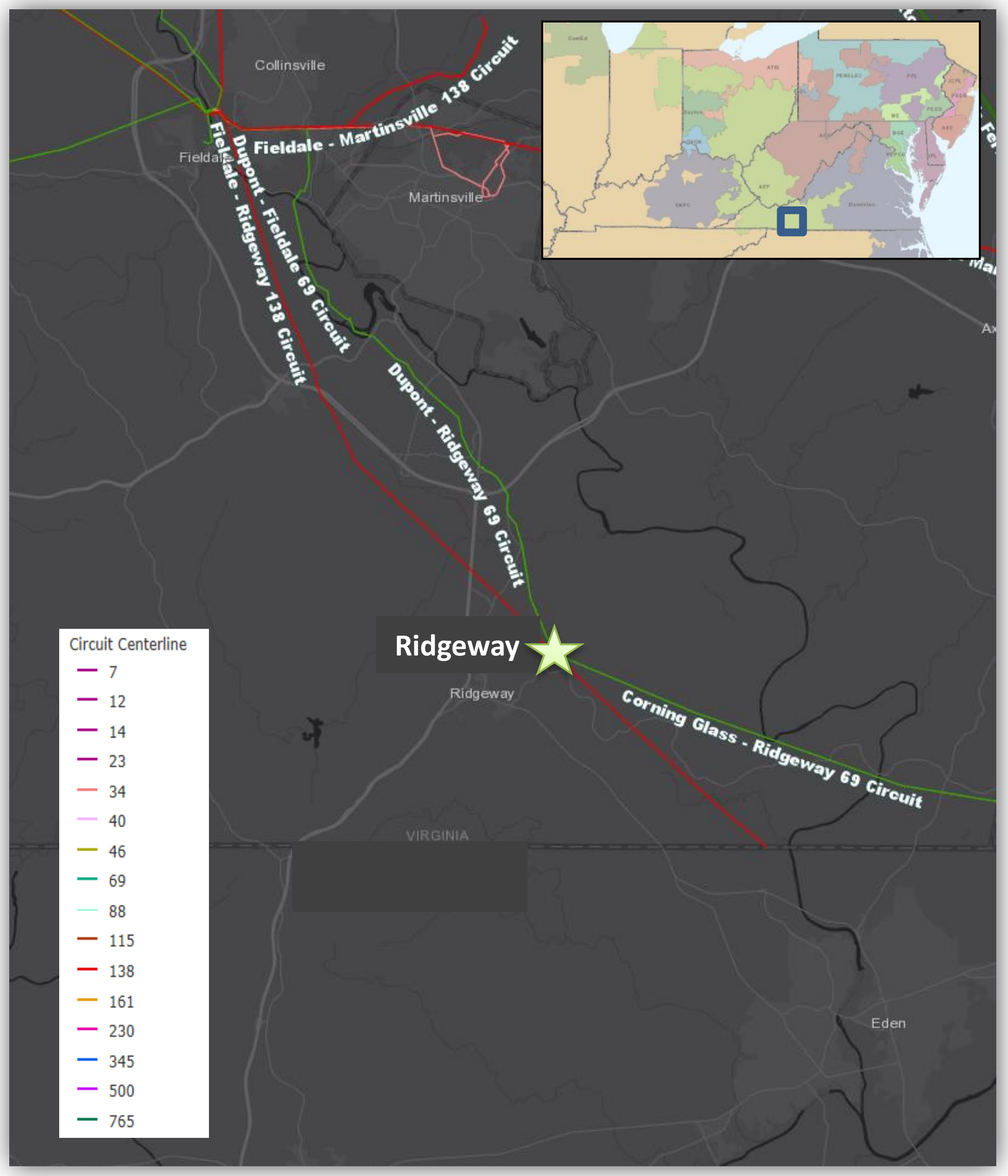
February 21, 2020

Needs

Stakeholders must submit any comments within 10 days of this meeting in order to provide time necessary to consider these comments prior to the next phase of the M-3 process

Need Number: AEP-2020-AP006
Process Stage: Needs Meeting 02/21/2020
Supplemental Project Driver: Equipment Material/Condition/Performance/Risk
Specific Assumptions Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)
Problem Statement:
<u>Ridgeway Station</u>

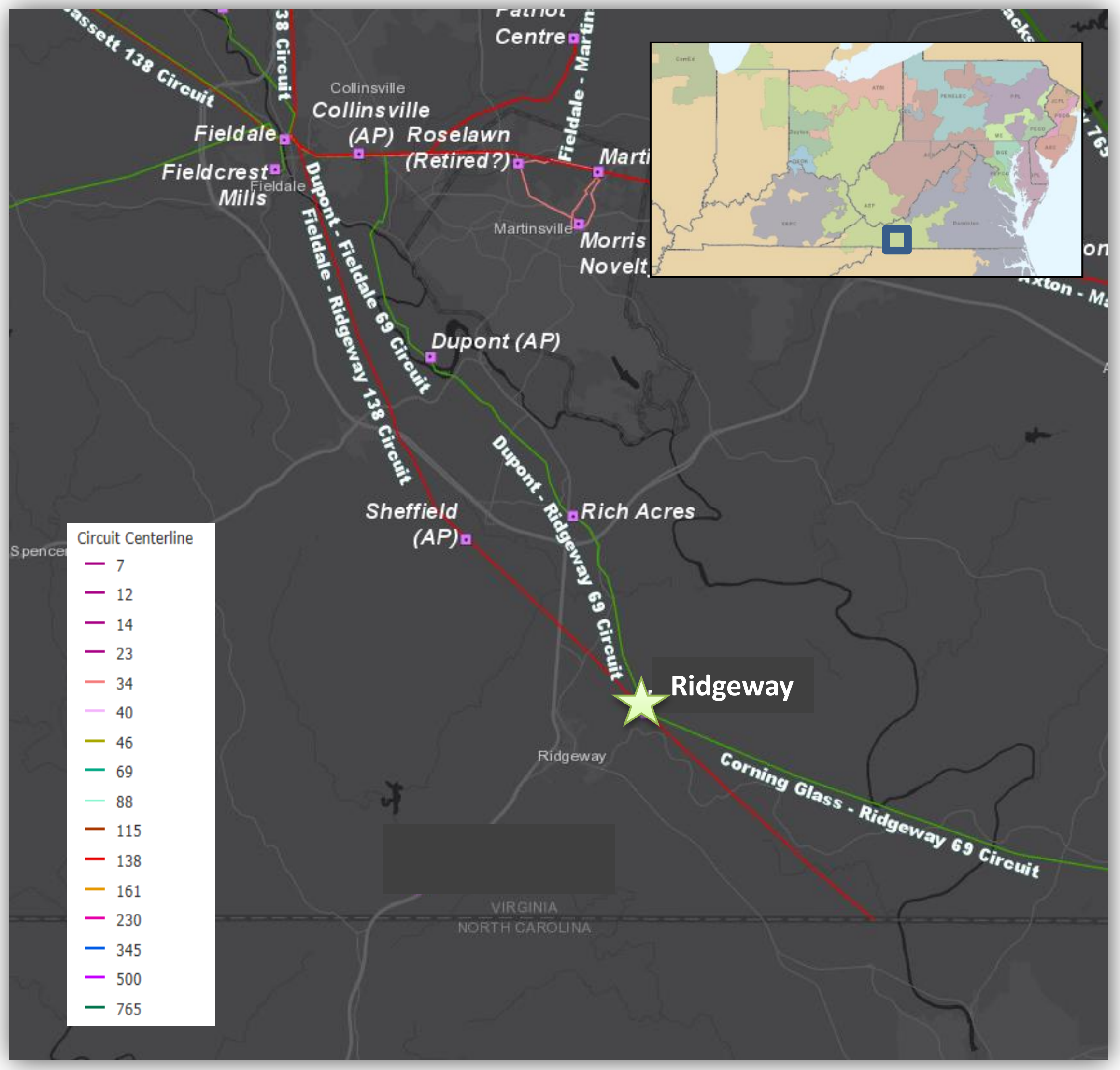
- **138/69 kV Transformer 2A**
  - Manufactured in 1960
  - Elevated levels of ethylene, CO_2, and CO due to insulating paper breakdown.
  - The existing foundations for the transformer are wood tie foundations. Wood tie foundations cannot be patched or fixed like their concrete counterparts.
- **138 kV Series Reactors #1, #2 and spare**
  - Manufactured in 1944
  - All of the Reactor 2 units are showing reduced interfacial tension levels in the oil, indicating the beginnings of sludge generation. There are leaks on Reactor 2 Phase 2. The dielectric strength of the oil in the spare unit has continued to decline.
  - Reactor 1 Phase 2 has declining dielectric strength and rising moisture content. The reactor bushings are subject to leakage. The foundations are built with wood ties with signs of rot.
  - The spare unit has low interfacial tension on the oil, indicating contaminates and sludge in the oil itself. If needed, this unit would have impaired circulation and cooling capability.
  - None of the reactors have oil containment.



Continued from previous slide …

- **<u>Ridgeway Station</u>**
  - **138/34.5 kV Transformer 1**
    - Manufactured in 1972
    - Increased acetylene levels due to through faults and increased moisture levels due to gasket leaks and insulating paper breakdown.
  - **138 kV circuit switchers U and V**
    - CS-U manufactured in 1979, CS-V manufactured in 1974
    - MARK V-138 model types lack a gas monitor and have a history of malfunction. Both of these circuit switcher models have presented AEP with a large amount of failures and mis-operations.
  - **Relaying**
    - Currently, 41 of the 61 relays (67% of all station relays) are electromechanical type which have significant limitations with regards to spare part availability and fault data collection and retention in addition to a lack of vendor support.

Model: N/A



AEP Transmission Zone M-3 Process
Wyoming County, WV

Need Number: AEP-2020-AP007

Process Stage: Need Meeting 2/21/2020

Supplemental Project Driver:

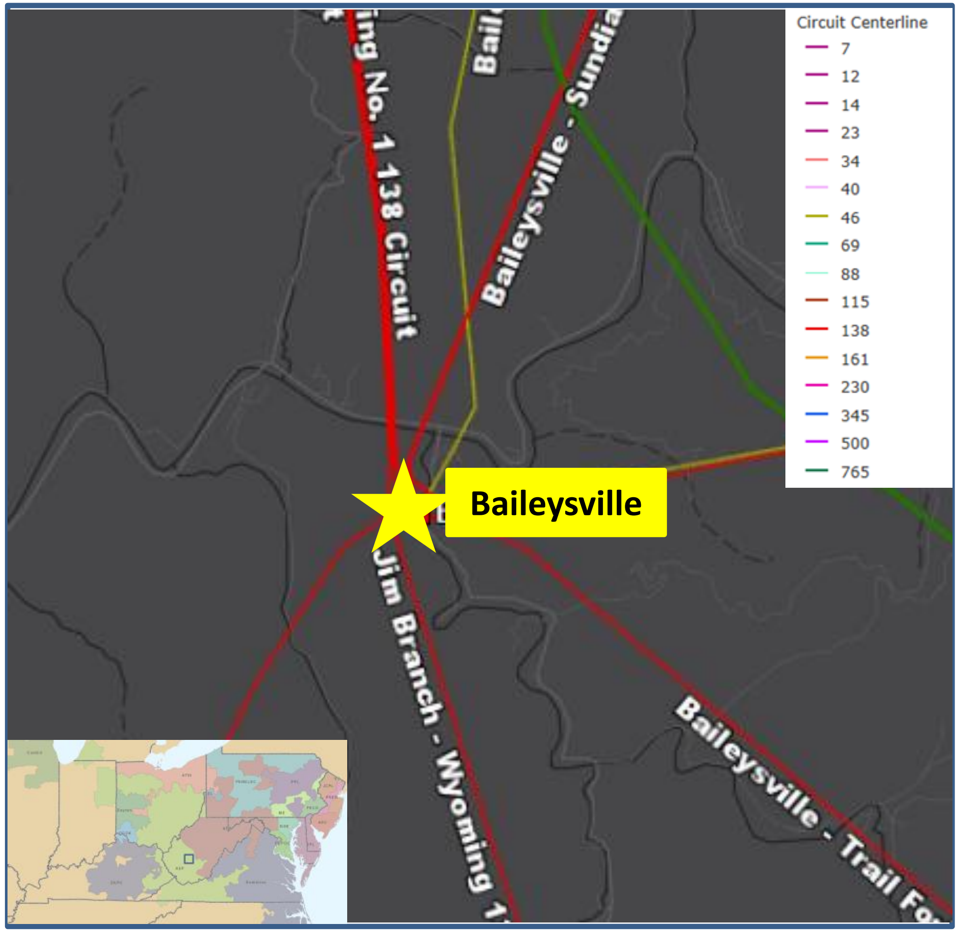
Equipment Material/Condition/Performance/Risk

Specific Assumption Reference:

AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

- Baileysville Station
    - 138 kV circuit breakers G, H, I, K, L and N are SF6 filled type breakers, the only 6 of this specific type on AEP's system
        - Vintage 1980s
        - Limited manufacturer support
        - Obsolete parts that are not available for replacmeent.
    - 46 kV CS AA is an SF6 filled 2030-69 type circuit switcher
        - Vintage 1990s
        - S&C 2030 circuit switcher has no gas monitor and sister units have a history of malfuncitons
    - 138 kV CS CC is an SF6 filled MARK V-138 type circuit switcher.
        - Vintage 1990s
        - This type of switcher have presented AEP with a large amount of failures and mis-operations.
        - Mark V family has no gas monitor
    - Currently 79% of the relays at Baileysville Station are in need of replacement
        - 28 electromechanical and 8 static type relays
            - – These type of relays have limitations with regard to fault data collection and retention.
    - Capacitor Bank BB, vintage 1976, has blown fuses and defective cans.
    - The station has seen significant flooding; as recently as 2009 the entire station flooded. In 2001, the control house was flooded with 1.5 feet of water.
    - The station has insufficient room for safe ingress/egress and for accessing equipment around the station.



Need Number: AEP-2020-AP008

Process Stage: Needs Meeting 02/21/2020

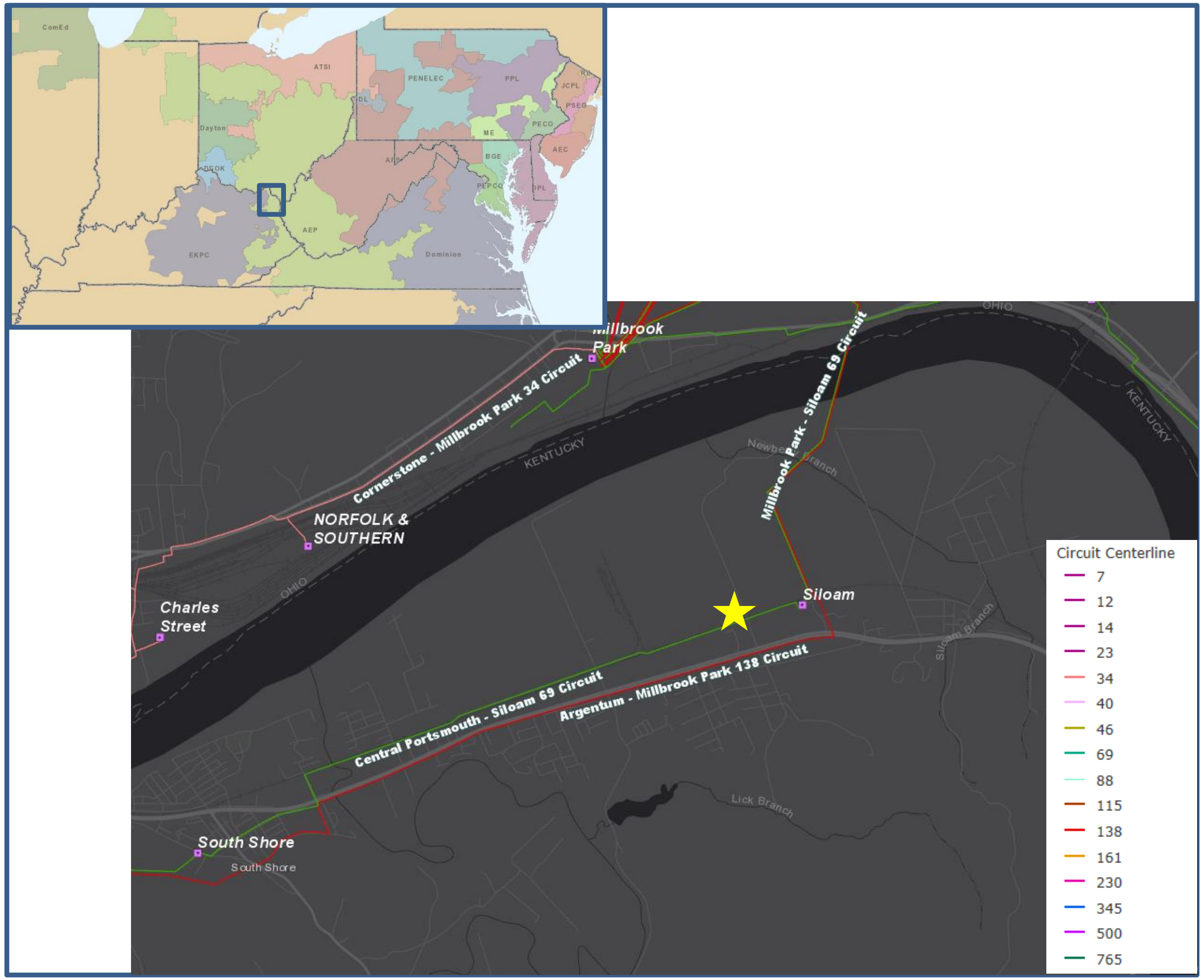
Supplemental Project Driver: Customer Service

Specific Assumption References: AEP Connection Requirements for the AEP Transmission System (AEP Assumptions Slide 7)

Problem Statement:

- Kentucky Power has requested a new 69kV Transmission delivery point in Siloam area with a projected load of 9 MW.

Model: 2024 RTEP



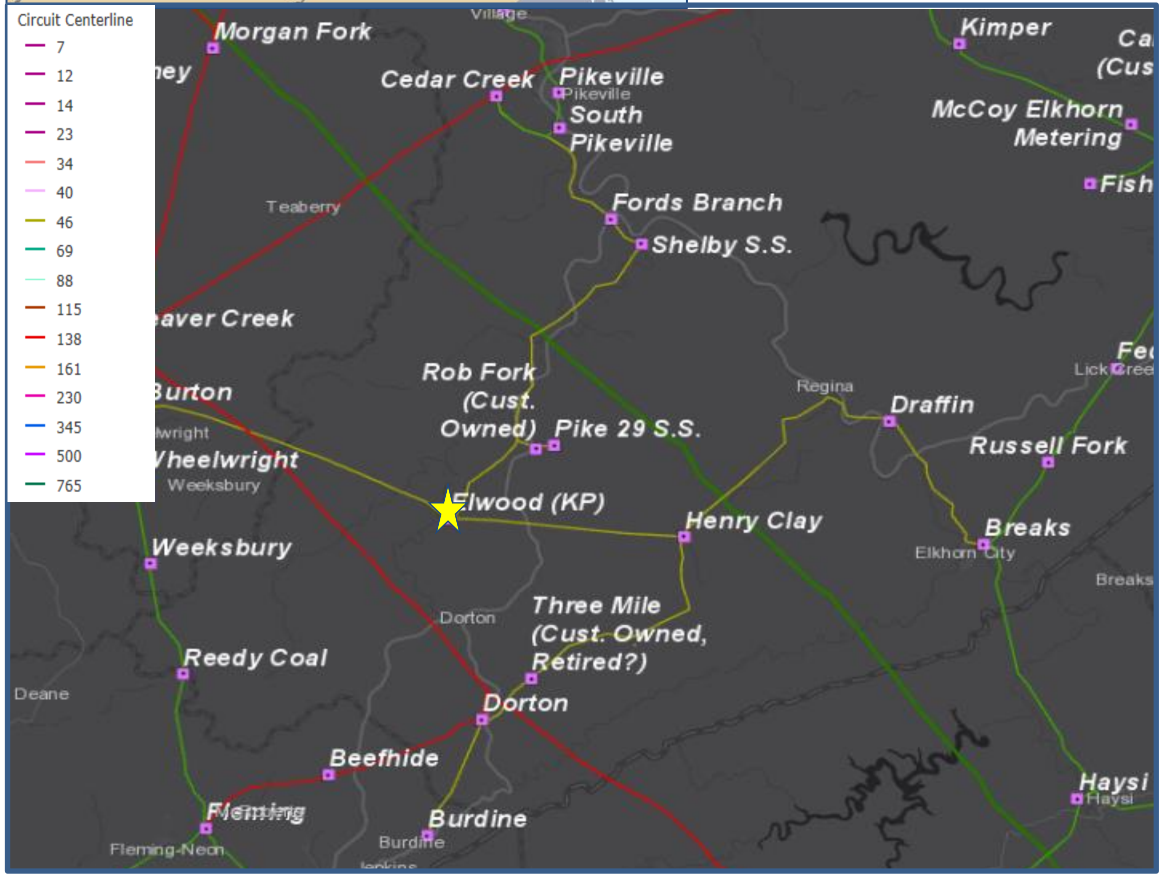
AEP Transmission Zone M-3 Process
Pike County, KY

Need Number: AEP-2020-AP009
Process Stage: Needs Meeting 02/21/2020
Supplemental Project Driver: Equipment Condition/Performance/Risk, Operational Flexibility
Specific Assumptions Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)
Problem Statement:

Elwood 46kV Station:

46 kV Circuit Breakers A,B, and C

- 1960's vintage FZO-69-1500P type oil circuit breakers.
- Fault Ops: CB A (33), CB B (83), and CB C (105). Recommended : 10
- Other drivers: damage to bushings, spare part availability, historical reliability, and lack of vendor support of the breakers.
- There are 8 remaining FZO-69-1500P circuit breakers on the AEP system, including the 3 at this station.
- 86% of the relays (36/42) at the station are electromechanical, which have significant limitations with regards to fault data collection and retention and have no spare part availability due to a lack vendor support.



AEP Transmission Zone M-3 Process
Pike County, Kentucky

Need Number: AEP–2020-AP011

Process Stage: Needs Meeting 02/21/2020

Supplemental Project Driver:

Equipment Material/ Condition/Performance/Risk, Operational Flexibility and Efficiency

Specific Assumption References:

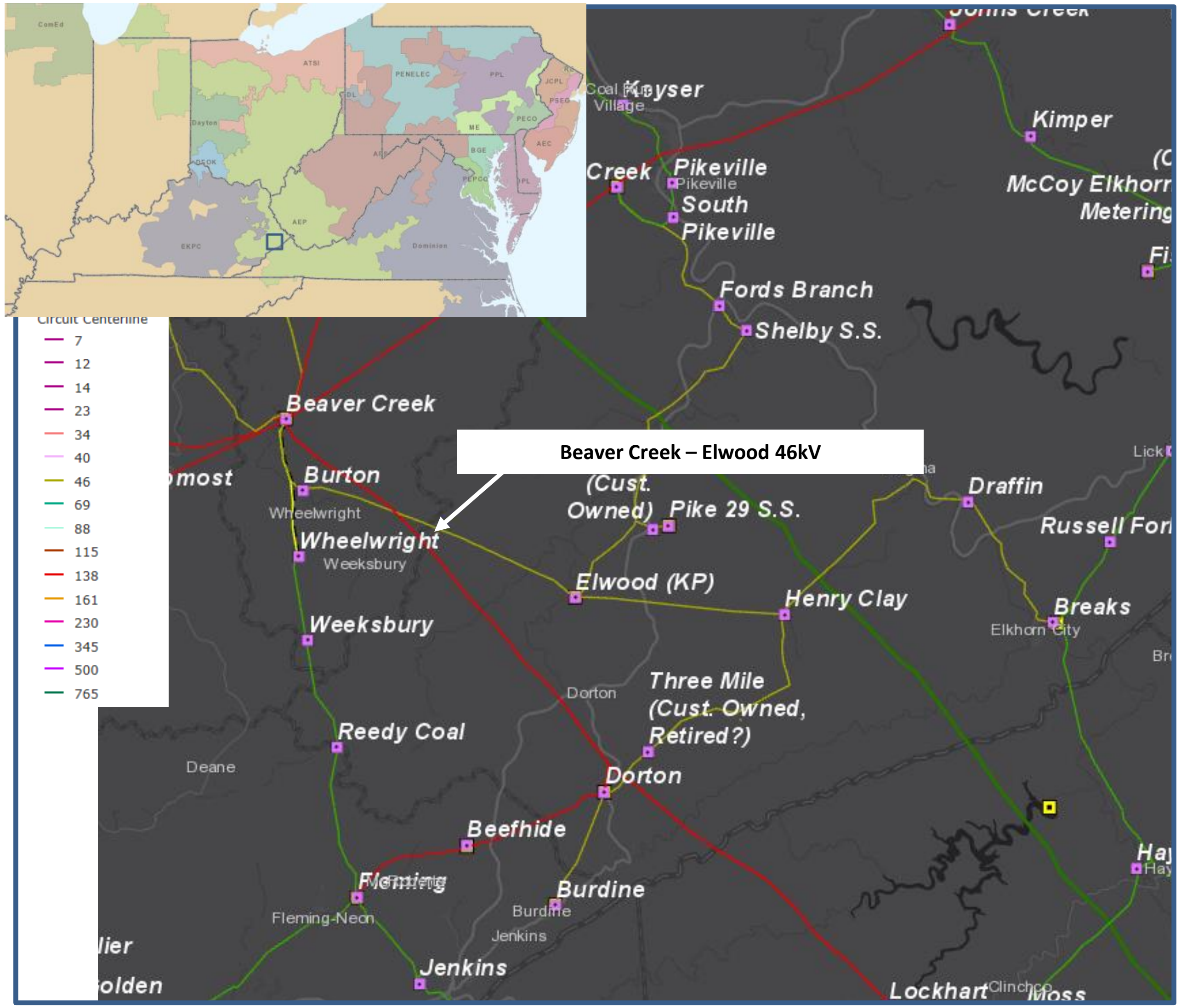
AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Model: N/A

Problem Statement:

Beaver Creek – Elwood 46kV:

- Original Install Date: 1930s vintage
- Length of Line: ~10.48 mi
- Total structure count: 60
- Original Line Construction Type: Wood
- Conductor Type: 336 ACSR
- Momentary/Permanent Outages and Duration: 18 Momentary and 1 permanent Outage
- CMI (last 5 years only): 269,070 minutes
- Number of open conditions: 34 open conditions on 20 unique structures.
- Open conditions include crossarms and poles with rot top, woodpecker damage and leaning-in-line conditions.



AEP Transmission Zone M-3 Process
Pike County, Kentucky

Need Number: AEP-2020-AP012

Process Stage: Needs Meeting 02/21/2020

Supplemental Project Driver:

Equipment Material/ Condition/Performance/Risk, Operational Flexibility and Efficiency

Specific Assumption References:

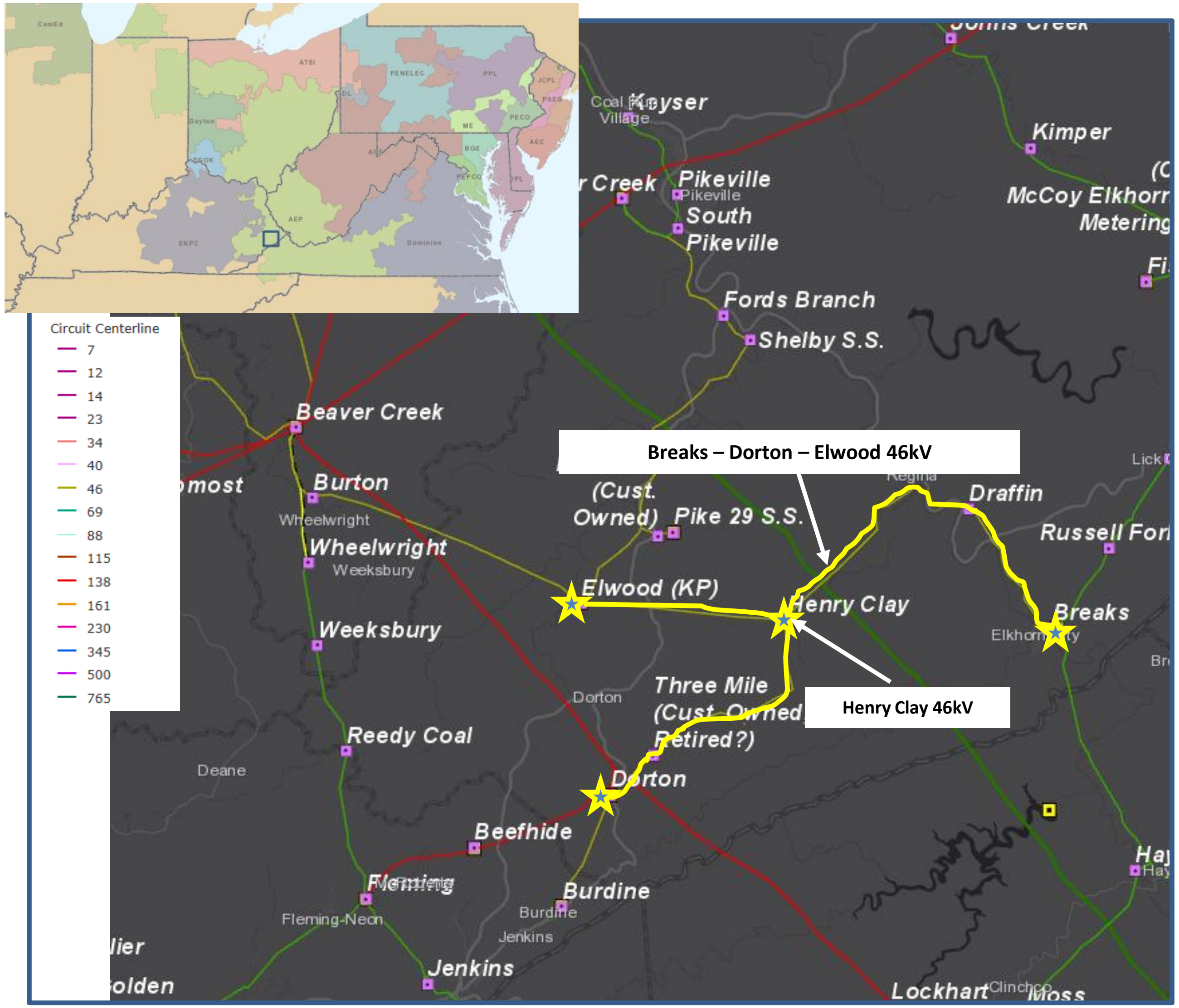
AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Model: N/A

Problem Statement:

Breaks– Dorton - Elwood 46kV:

- Original Install Date: 1960s
- Length of Line: ~26 mi
- Total structure count: 135
- Original Line Construction Type: Wood
- Conductor Type: 336 ACSR
- Momentary/Permanent Outages and Duration: 38 momentary and 4 permanent
- CMI (last 5 years only): 99,556
- Number of open conditions by type / defects / inspection failures: 191 open conditions on 74 unique structures
- Open conditions include: Crossarms or braces with rot, woodpecker damage, and bowed conditions.
- There is a three terminal line at Henry Clay substation



AEP Transmission Zone: Supplemental Sullivan County, TN

Need Number: AEP-2020-AP013

Process Stage: Needs Meeting 02/21/2020

Supplemental Project Driver: Equipment Condition/Performance/Risk

Specific Assumption Reference:

AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

Fort Robinson Station

Circuit Breaker E (69 KV):

- Circuit breaker E is 52 years old, CG/CF, oil filled type breaker without oil containment; oil filled breakers have much more maintenance required due to oil handling and spills can result in significant mitigation cost.
- It has experienced 113 fault operations — exceeding manufacturer's recommended number of 10.

Circuit Breaker D (34.5 KV) Concerns:

- Circuit breaker D is 36 years old, CG, oil filled without oil containment; oil filled breakers have much more maintenance required due to oil handling and spills can result in significant mitigation cost.
- It has experienced 33 fault operations — exceeding manufacturer's recommended number of 10.
- CB D is 1 of only 27 remaining of the CG-48-72.5-31.5-1200 models on the AEP system. The manufacturer provides no support for the CF/CG/CGH/CH family of circuit breakers and spare parts are increasingly more difficult to obtain. This model has experienced major malfunctions associated with their OA-3 hydraulic mechanism, which includes low-pressure readings, hydraulic leaks, pump lockouts, and failure to shut off.

Transformer 1 (138/69-34.5 KV) :

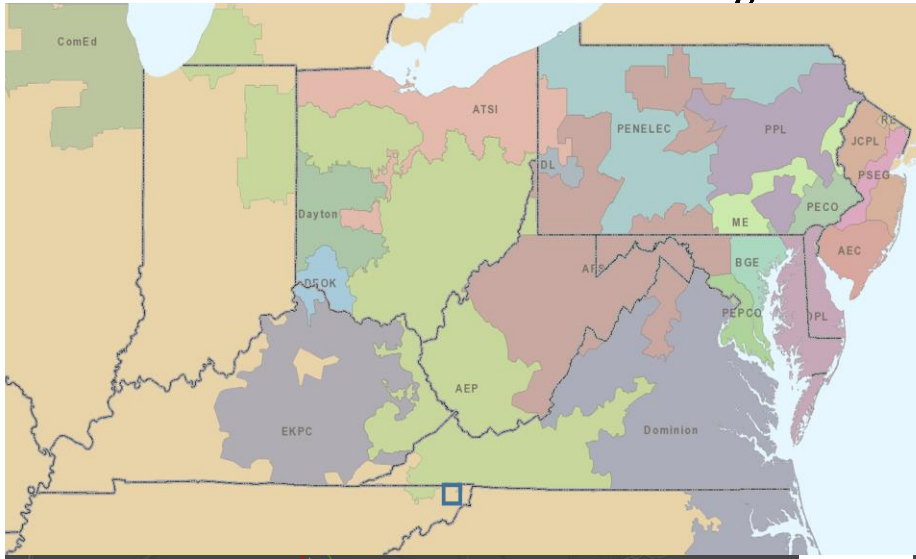
- The current low side GOAB switch on the tertiary side of 1 Bank is incapable of load breaking.
- MOAB/Ground SW configuration on the high side of the transformer.
- Grounding bank is 48 years old with elevated levels of acetylene. This concentration of acetylene indicates excessive internal component decomposition due to arcing within the tank.

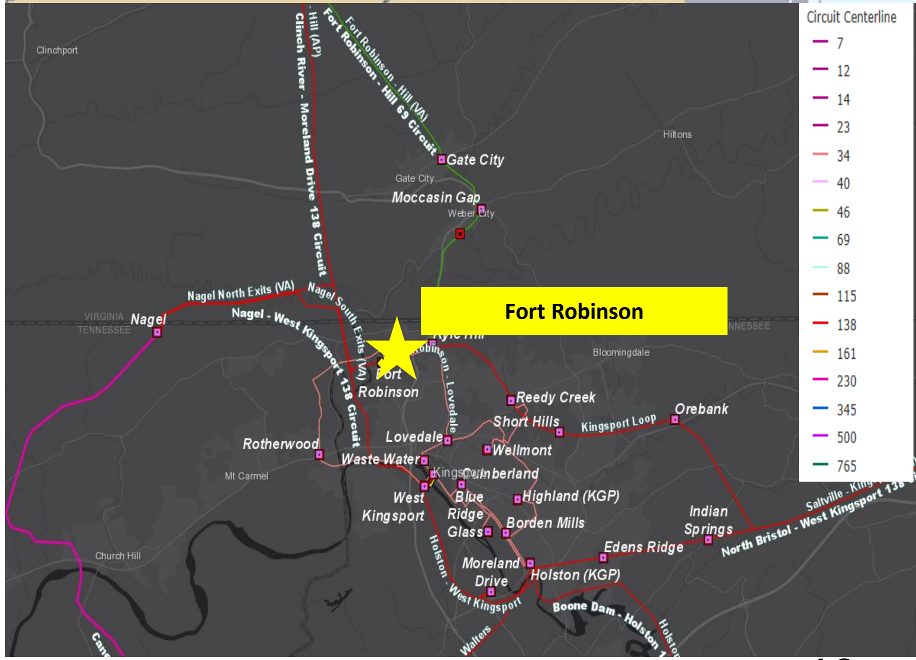
Relay Concerns:

- There are 33 electromechanical type relays (82% of all relays at the station) which have significant limitations with regards to fault data collection and retention.
- There are 4 microprocessor based relays with unsupported firmware and lack of vendor support.

Operations Concerns:

- Fort Robinson Station is served off of the Nagel – Wolf Hills 138 kV circuit which is 39.11 miles long without CB sectionalizing.





AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

AEP Transmission Zone: Supplemental
Scott County, VA

Need Number: AEP-2020-AP014

Process Stage: Needs Meeting 02/21/2020

Supplemental Project Driver: Equipment Condition/Performance/Risk

Specific Assumption Reference:

AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

Hill Station

Circuit Breaker H (69 KV):

- Circuit breaker H is 52 years old, CF model type, oil filled type breaker filled without oil containment; oil filled breakers have much more maintenance required due to oil handling and oil spills can result in significant mitigation cost. Spare parts for these units are difficult to impossible to procure.
- 91 fault operations — exceeding manufacturer's recommended number of 10.

Circuit Switcher AA (69 KV):

- Circuit switcher AA is 25 years old, 2030-69, SF6 type breaker. This type of circuit switcher has no gas monitor and sister units have a history of malfunctions, including gas loss, interrupter failures, and operating mechanism failures.

Transformer 1 (138/69-34.5 KV) Concerns:

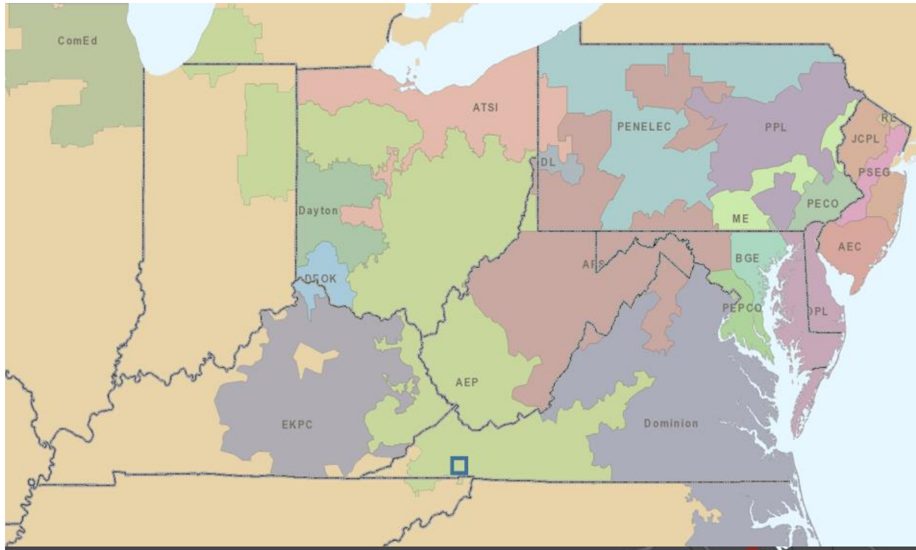
- Transformer bank 1 is 63 years old with elevated levels of carbon dioxide and moisture and a decrease in dielectric strength.
- The current MOAB/Ground SW configuration on the high side of the transformer

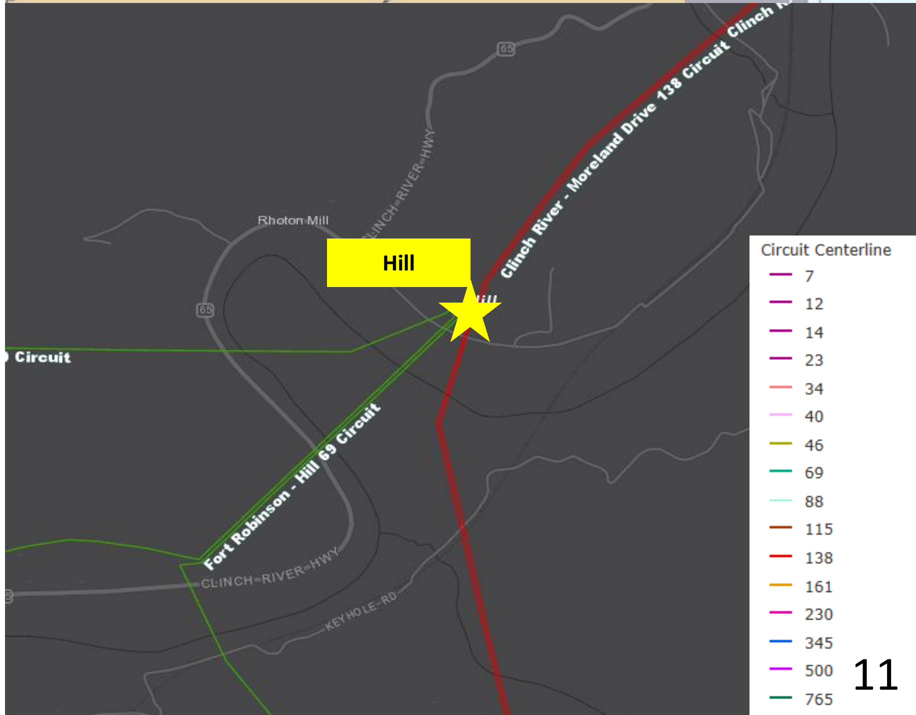
Relays

- 20 relays (53%) are of the electromechanical type which have limitations with regards to fault data collection and retention.
- These relays lack vendor support and have no access to spare parts.

Operations Concerns:

- Hill Station is served off of the Clinch River – Nagle 138 kV circuit which is 41.61 miles long without CB sectionalizing.





Need Number: AEP-2020-AP015

Process Stage: Needs Meeting 02/21/2020

Supplemental Project Driver: Equipment Condition/Performance/Risk

Specific Assumption Reference:

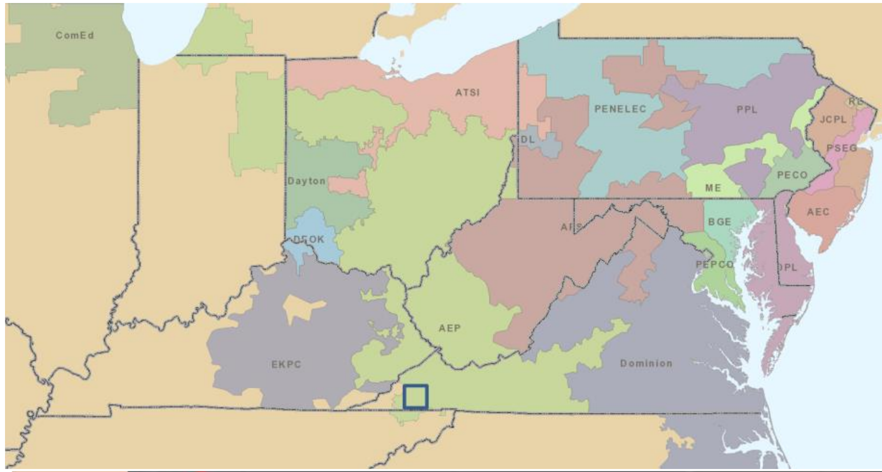
AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

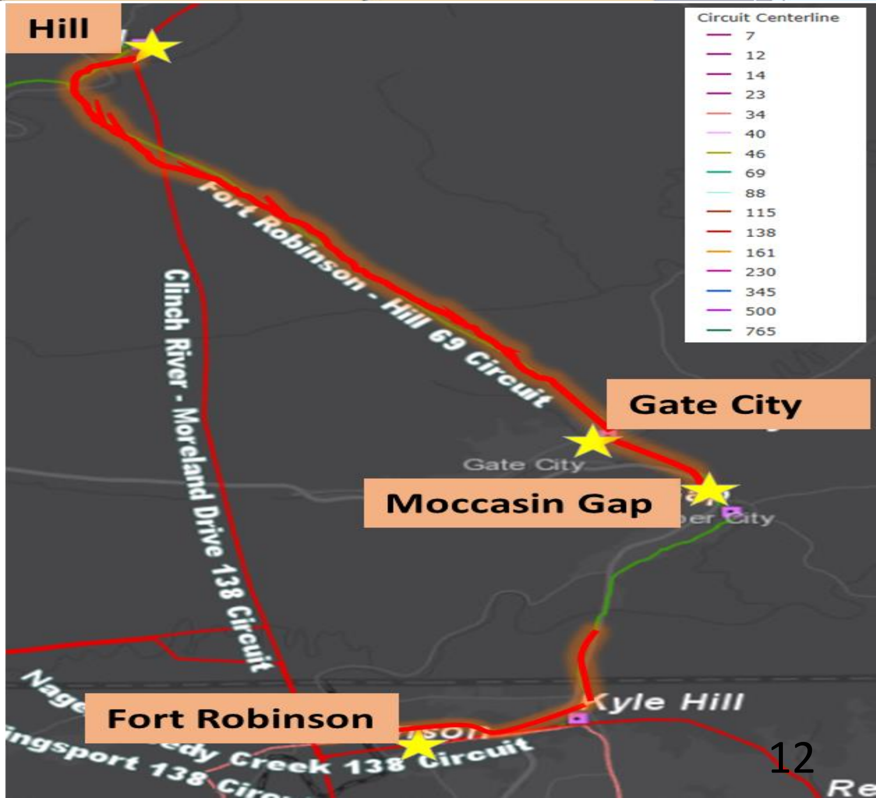
Problem Statement:

Fort Robinson —Hill 69 KV (installed in 1970)

- Length: 12.7 Miles
- Original Construction Type: Wood (86% original)
- Original Conductor Type (91% original): 219.9 ACSR, 1/0 CU, 336 ACSR, 4/0 ACSR, and 556 ACSR
- Momentary/Permanent Outages: 7 momentary, 8 permanent (5 years)
- CMI: 5,721,762
- Total structure count: 127
- Number of open conditions: 120
  - Open conditions include: broken conductor strands, broken/burnt insulators, split Bayonet, cracked X-Brace.
- Unique structure count with open conditions: 95 (44%)
- Additional Info:
  - There have been 5 weather related momentary outages, with 4 of those being attributed to lightning as well as 1 permanent outage. These lightning caused outages are indicative of insufficient shielding and/or insufficient grounding

Note: ~1.5 mile 1/0 Cu conductor section of the ~ 5 miles Fort Robinson – Moccasin Gap 69 KV line section was addressed under b3101





AEP Transmission Zone M-3 Process
Mason County, WV

Need Number: AEP-2020-AP016

Process Stage: Need Meeting 2/21/2020

Supplemental Project Driver: Equipment Condition/Performance/Risk

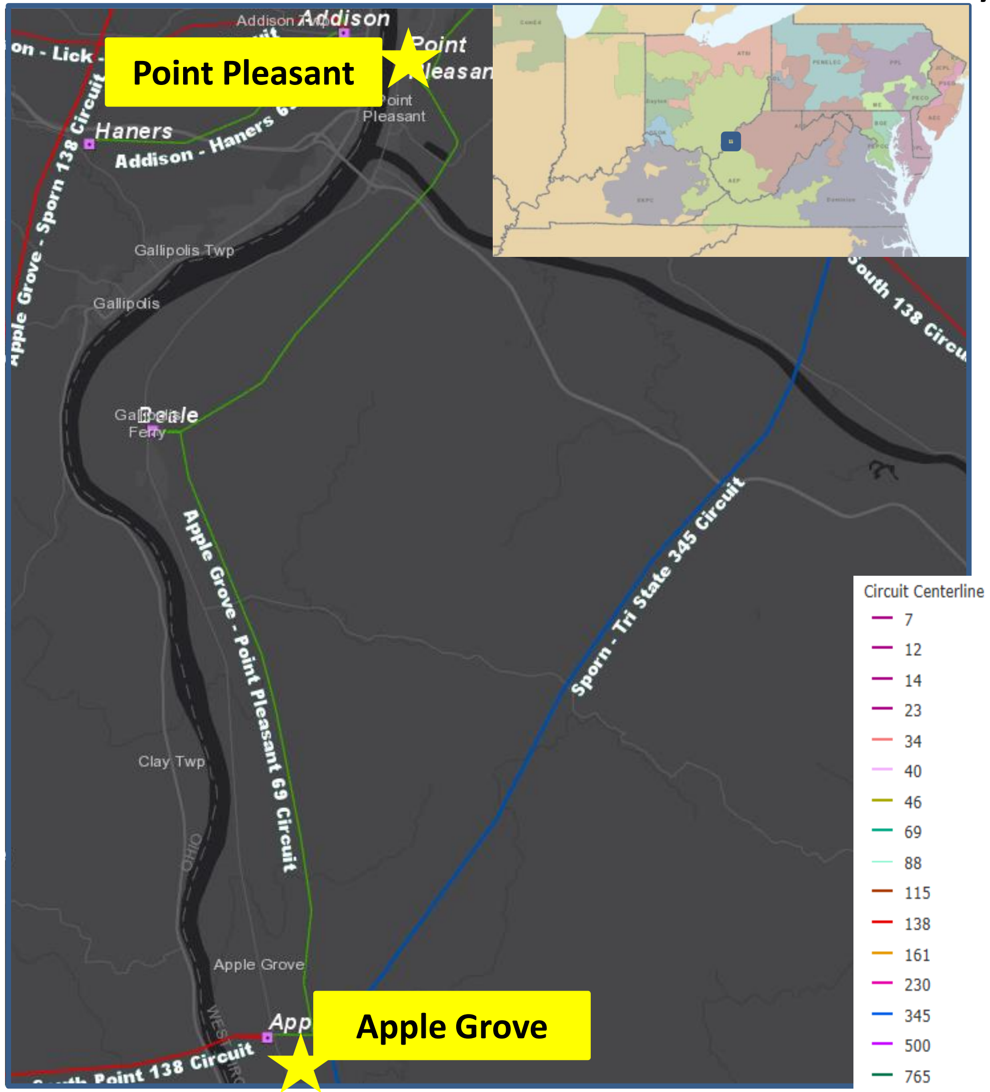
Specific Assumption Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

Apple Grove – Point Pleasant 69 kV (17 miles)

- The line consists of mainly 1960s wood pole structures. The circuit utilizes steel lattice towers with grillage foundations on the Big Sandy River Crossing.
    - The circuit was originally installed in 1960, primarily with 4/0 ACSR conductor and 5-bell porcelain insulators.
    - Structures on the line failed to meet 2017 NESC Grade B loading criteria, failed to meet current AEP structural strength requirements, and failed to meet current ASCE structural strength requirements
    - The insulators do not meet current AEP standards for CIFO and minimum leakage distance requirements.
    - There are currently 79 structures (61% of the line) with at least one open condition
        - A total of 171 open conditions on the line, related to damaged/worn shield wires, rotted crossarms and poles, woodpecker damage, broken or burnt insulators.
- Since 2014 there have been 6 momentary and 6 permanent outages on the circuit
- CMI: 1.5 million

Model: N/A



Need Number: AEP-2020-AP017

Process Stage: Need Meeting 2/21/2020

Supplemental Project Driver: Equipment Condition/Performance/Risk

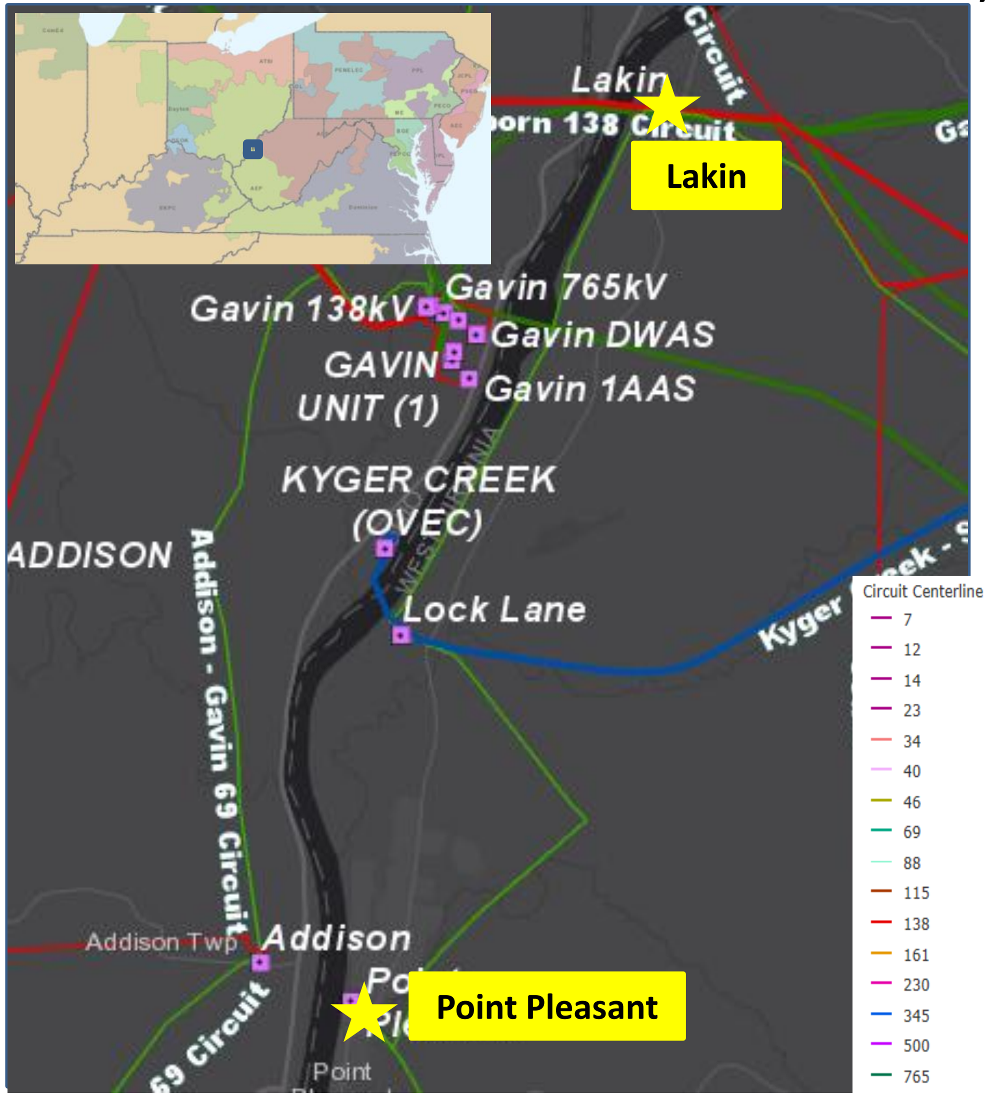
Specific Assumption Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

Lakin – Point Pleasant 69 kV (11 miles)

- The line entirely consists of 1960s wood pole structures with 4-bell porcelain insulators
    - Line was originally installed in 1966, with a combination of 556 ACSR and 3/0 ACSR conductor
    - Structures on the line failed to meet 2017 NESC Grade B loading criteria, failed to meet current AEP structural strength requirements, and failed to meet current ASCE structural strength requirements
    - The insulators do not meet current AEP standards for CIFO and minimum leakage distance requirements.
    - There are currently 95 structures (86% of the line) with at least one open condition
        - A total of 222 open conditions on the line, related to damaged/worn shield wires, rotted crossarms and poles, woodpecker damage, broken or missing ground wire leads, broken or loose guys.
- Since 2014 there have been 17 momentary and 7 permanent outages on the circuit
- CMI: 3.1M

Model: N/A



Need Number: AEP-2020-AP018

Process Stage: Need Meeting 2/21/2020

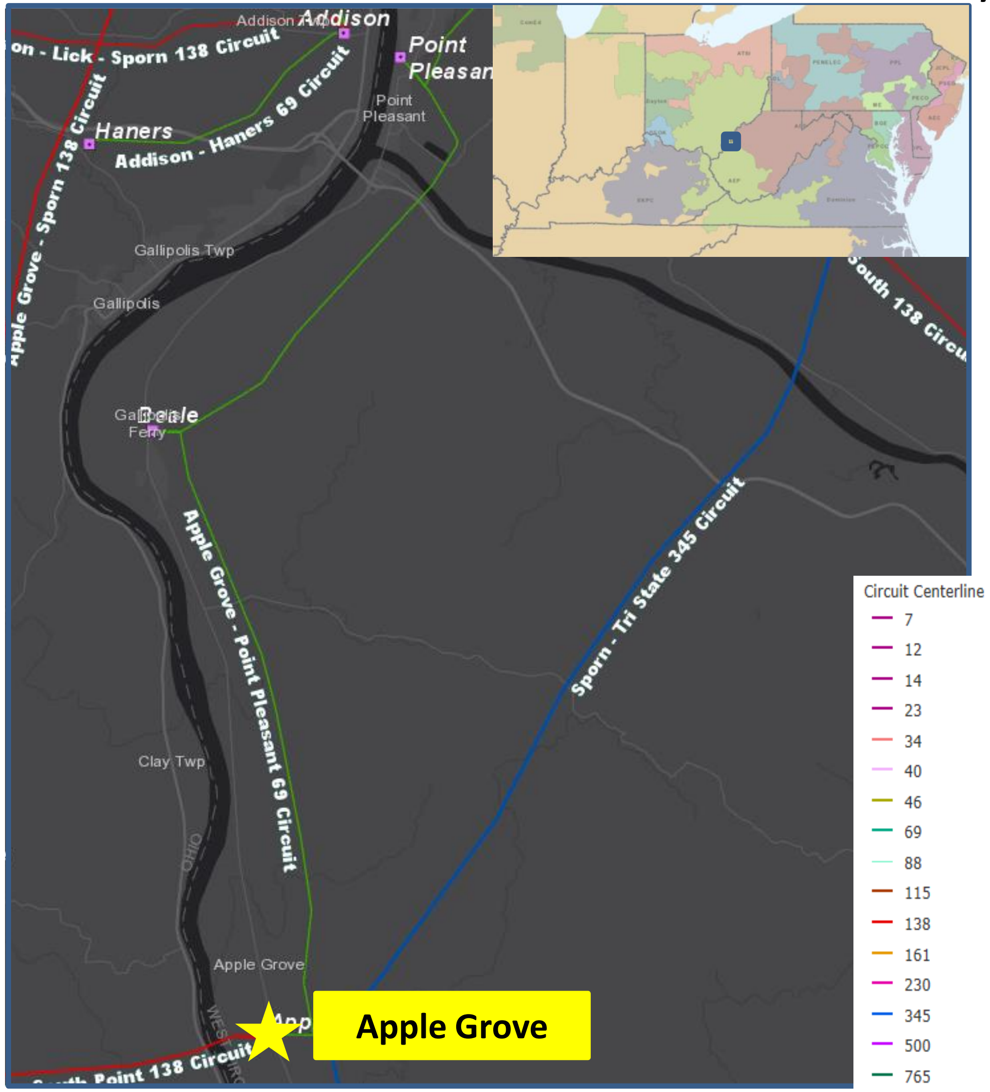
Supplemental Project Driver: Equipment Condition/Performance/Risk

Specific Assumption Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

Apple Grove Station

- 69 kV circuit breaker L is an FK type oil filled breaker, without oil containment.
  - 1960s vintage
  - Oil filled breakers need more maintenance due to the oil handling required and oil spills can result in significant cost associated with environmental mitigations
  - The manufacturer does not provide support for this type of breaker and spare parts are increasingly more difficult to obtain.
- 138/69 kV transformer bank #1 was manufactured in 1965
  - Elevated moisture levels
  - Elevated Carbon Monoxide and Carbon Dioxide levels
    - Indicates abnormal paper insulation deterioration
  - In 2004 one fan was destroyed by a failed fan blade
  - Oil containment inspection indicates deficiencies in the existing containment
  - The bank is connected directly to the 138 kV bus with a high side MOAB switch.
    - This can cause a fault in the station to signal the remote end breakers to open which is a known safety hazard in legacy station designs.
- 54 of the 66 relays (82% of all station relays) have needs associated with them
  - 51 are electromechanical type and 3 are static type which have significant limitations with regards to spare part availability and fault data collection/retention
- Overlapping zones of protection in existing station configuration
  - Apple Grove – Point Pleasant 69 kV line terminates directly into the 69 kV bus



Model: N/A

AEP Transmission Zone M-3 Process
Mason County, WV

Need Number: AEP-2020-AP019

Process Stage: Need Meeting 2/21/2020

Supplemental Project Driver: Equipment Condition/Performance/Risk

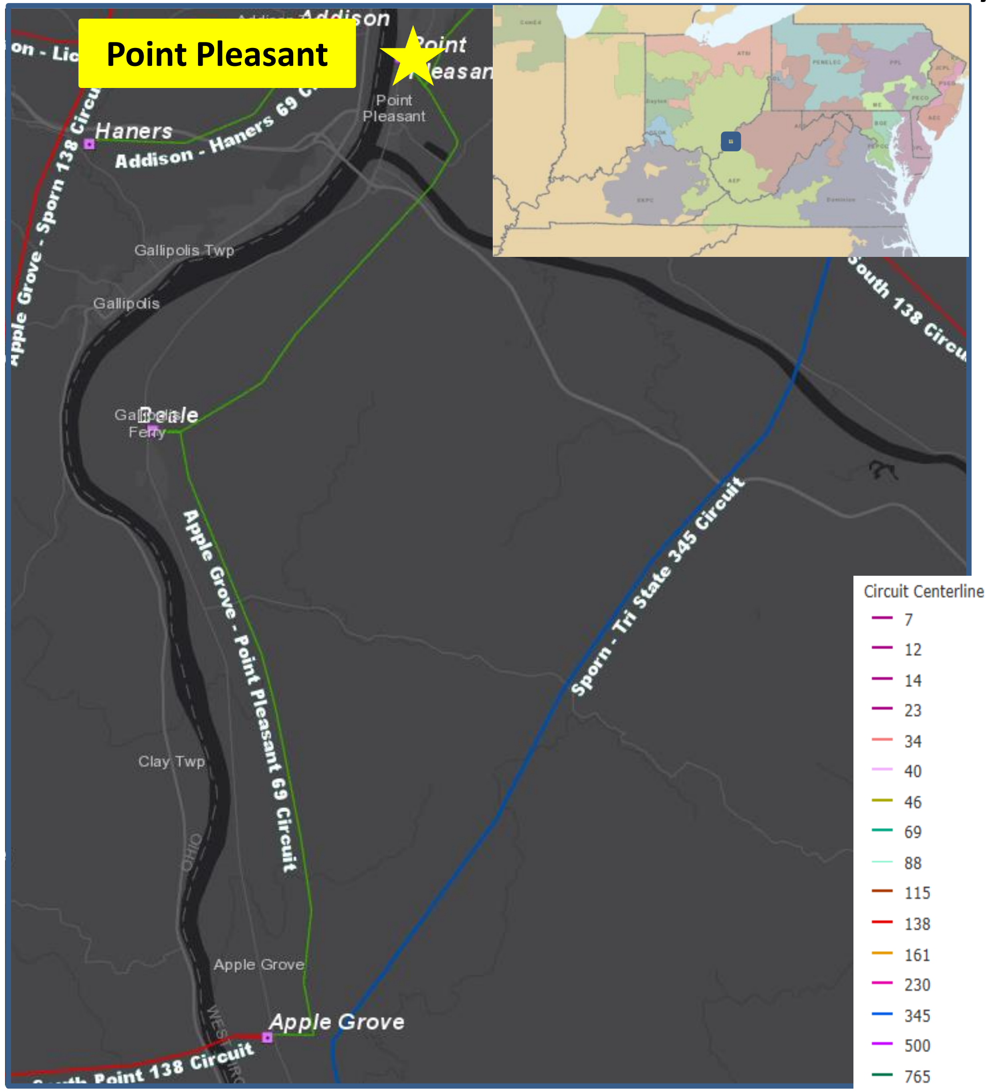
Specific Assumption Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

Point Pleasant Station

- 69 kV circuit breakers G and H are an CF type oil filled breaker, without oil containment.
  - 1968 vintage
  - Oil filled breakers need more maintenance due to the oil handling required
  - The manufacturer does not provide support for this type of breaker and spare parts not available.
  - Oil spills can result in significant mitigation costs.
- 69 kV circuit switcher AA is a 2030-69 type SF6 switcher.
  - 1991 vintage
  - S&C 2030 circuit switcher has no gas monitor and sister units have experienced numerous malfunctions
- 39 out of the 40 relays (98% of all station relays) are in need of replacement
  - 34 relays are electromechanical type and 5 static type which have significant limitations with regards to fault data collection and retention.

Model: N/A



Berrien Springs-Colby

Need Number: AEP-2020-IM001

Process Stage: Needs Meeting 02/21/2020

Supplemental Project Driver: Equipment Condition/Performance/Risk

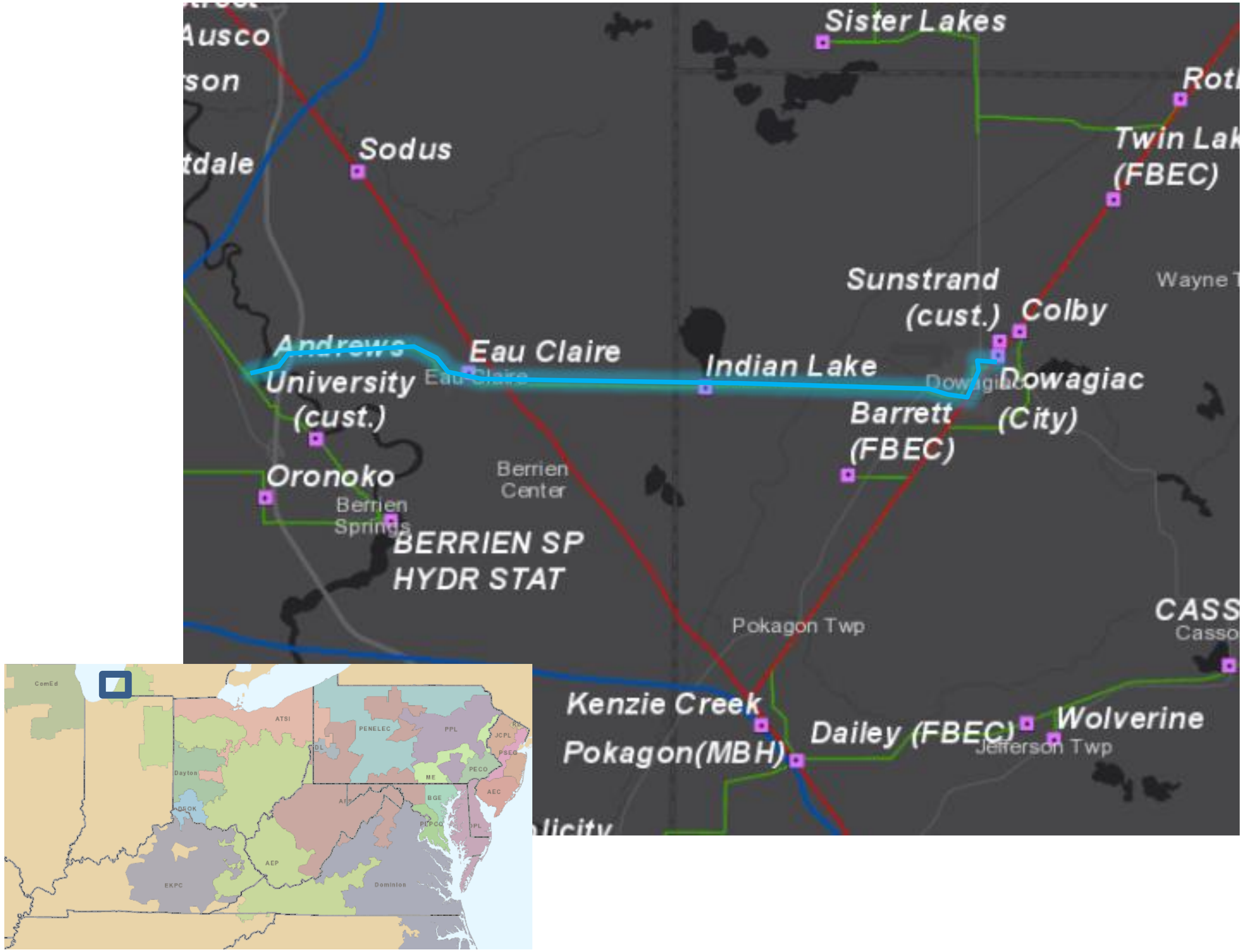
Specific Assumption Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Model: N/A

Problem Statement:

Berrien Springs-Colby 69kV line

- 15.72 miles of wood pole structures with horizontal insulators rebuilt in 1995
- 148 structures with at least one open condition, 31% of the structures on the line
    - Open conditions include insect or woodpecker damage, broken or stolen ground wire conditions, and broken or burnt insulators
- Outages: 2 permanent since 2015
- CMI: 297,132



Need Number: AEP-2020-IM002

Process Stage: Needs Meeting 02/21/2020

Supplemental Project Driver: Equipment Condition/Performance/Risk

Specific Assumption Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Model: 2024 RTEP

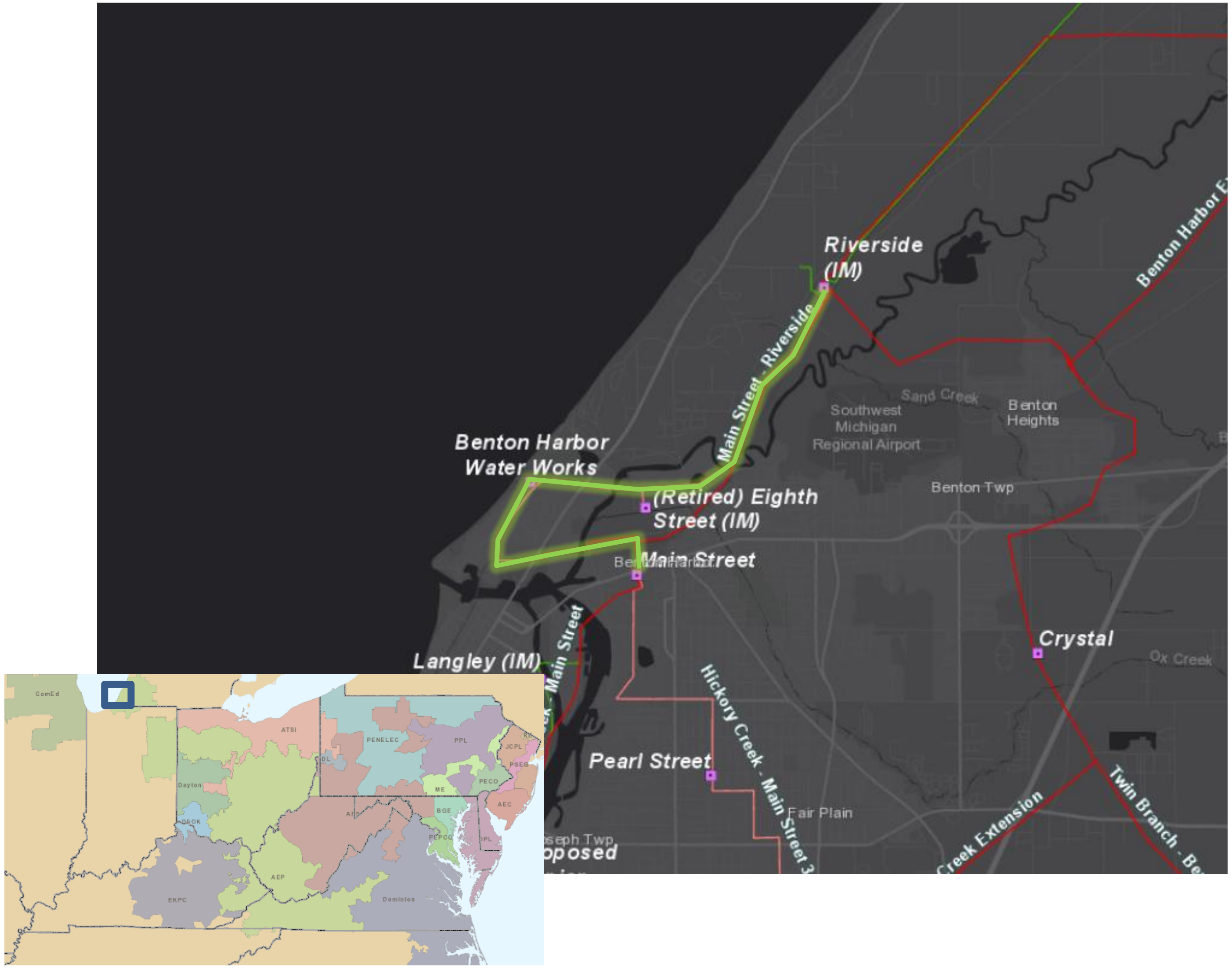
Problem Statement:

Main Street-Riverside 34.5kV line:

- 4.1 miles of the 4.6 mile 34.5kV line from Main St. –Riverside 34.5kV:
    - 1930's double circuit steal lattice towers and 1950's wood pole line with cross arm construction
    - 15 structures with at least one open condition (21% of the line)
        - Open conditions include pole leaning, rot, woodpecker or insect damage

Riverside Station:

- There are (2) 34.5kV oil filled breakers of FK-type 1960's vintage
    - Circuit breaker G has exceeded it's manufacturer designed number of fault operations
    - The common failure mode documented by AEP are compressor failures and valve defects which cause low pressure and oil leaks
    - The manufacturer no longer provides support for this fleet of circuit breakers. Spare parts are not available.



AEP Transmission Zone M-3 Process
Buchanan Hydro

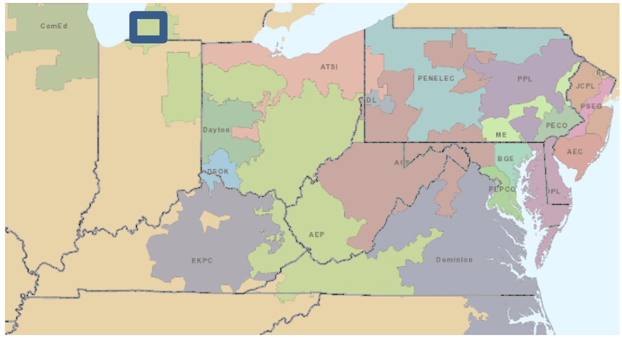
Need Number: AEP-2020-IM003
Process Stage: Needs Meeting 02/21/2020
Supplemental Project Driver: Equipment Condition/Performance/Risk
Specific Assumption Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)
Model: N/A
Problem Statement:

Buchanan Hydro Station:

- Buchanan Hydro station has flooded twice in the last 5 years causing the 12kV load to be dropped from the station.
- (2) FK-type Oil filled breakers, AEP has common failure modes for these types of breakers with compressor failures, valve defects, reclose failures and charging motor failures.
  - Both breakers installed in 2003
  - Breaker A has exceeded the designed number of fault operations
- (2) CF-Type oil filled breakers. This model family has experienced major malfunctions associated with their hydraulic mechanisms which have led to several failures to close and other types of mis-operations.
  - Both breakers have exceed the designed number of fault operations
- Transformer #1 was installed in 1964. The transformer has elevated levels of carbon dioxide and ethylene, there is indication of overheating faults occurring in the main tank which have further degraded the insulating paper materials. There is also indication of capacitive layer deterioration.
- Transformer #2 was installed in 1965. The age of the unit's insulation materials can lead to susceptibility of short circuit faults which may cause failure in the main tank. The transformer has elevated levels of carbon dioxide and ethylene, there is indication of overheating faults occurring in the main tank which have further degraded the insulating paper materials

Buchanan Hydro –Clark Equipment Tap 34.5kV:

- 1.36 miles of 1954 and 1984 wood pole cross arm line
- 10 unique structures (26%) with at least one open condition
- Open conditions include pole or cross arm with rot conditions



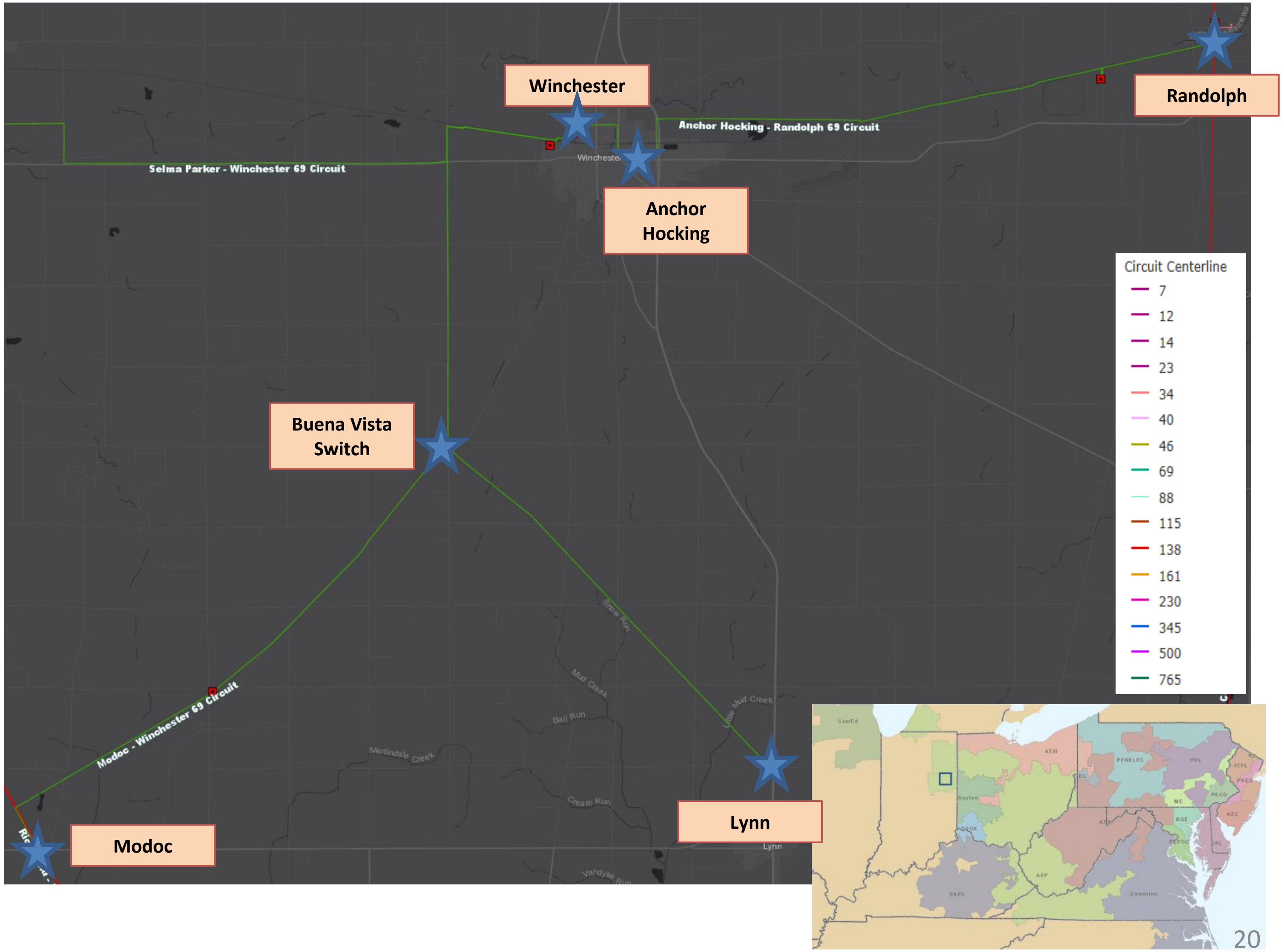
AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

AEP Transmission Zone: Supplemental
Winchester, Indiana and surrounding area

Need Number: AEP-2020-IM004
Meeting Date: Needs Meeting 02/21/20
Supplemental Project Driver: Equipment Material/Condition/Performance/Risk
Specific Assumptions Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)
Problem Statement:

Anchor Hocking – Winchester 69kV Line (~1.25 Miles)
- 1968 vintage wood pole, crossarm construction
- There are currently 12 open conditions on this line (11 structures with at least one open condition or 25% of the line).
- Open conditions include: Damaged pole, worn shield wires, stolen ground lead wires, and damaged jumpers.

Anchor Hocking 69kV station
- Breaker B 69kV
  - 1972 vintage oil filled, CF-type breaker. This type is oil filled without oil containment. Oil filled breakers have much more maintenance required due to oil handling that their modern, vacuum counterparts do not require. Finding spare parts for these units not possible as these models are no longer vendor supported



AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY™

AEP Transmission Zone: Supplemental Winchester, Indiana and surrounding area

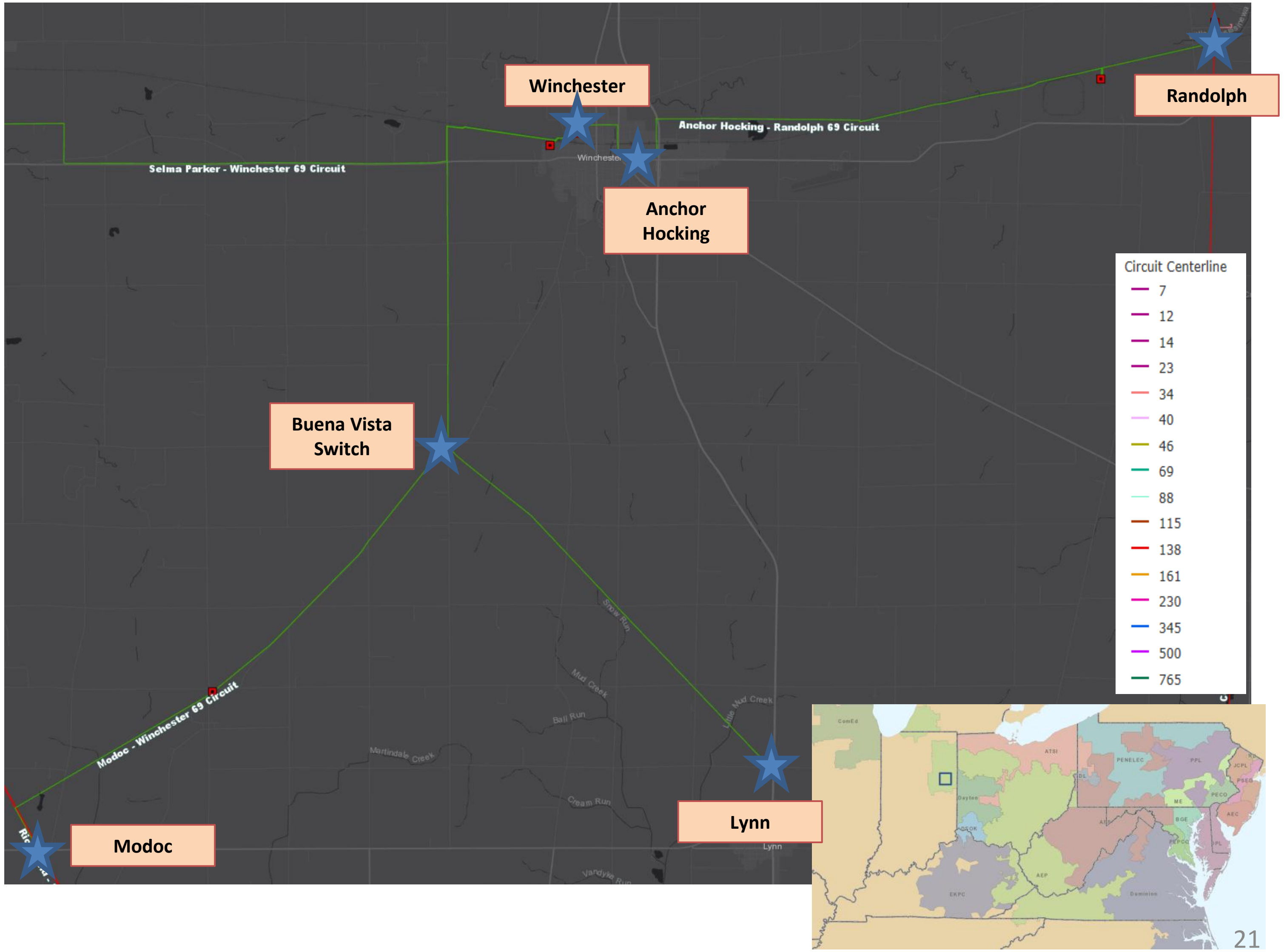
Need Number: AEP-2020-IM004
Meeting Date: Needs Meeting 02/21/20
Supplemental Project Driver: Equipment Material/Condition/Performance/Risk
Specific Assumptions Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)
Problem Statement:

Winchester 69kV station

- Breakers A and B 69kV
  - 1971 vintage oil filled, CF-type breaker. This type is oil filled without oil containment. Oil filled breakers have much more maintenance required due to oil handling that modern, vacuum counterparts do not require. Finding spare parts for these units not possible as these models are no longer vendor supported. Also, oil spills can result in significant cost to mitigate

Modoc 138/69/12kV station

- 138/69kV Transformer #1
  - 1965 vintage
  - Elevated moisture levels
  - Decrease in interfacial tension of the oil, reducing its insulating capabilities
  - Unit is showing signs of leaking

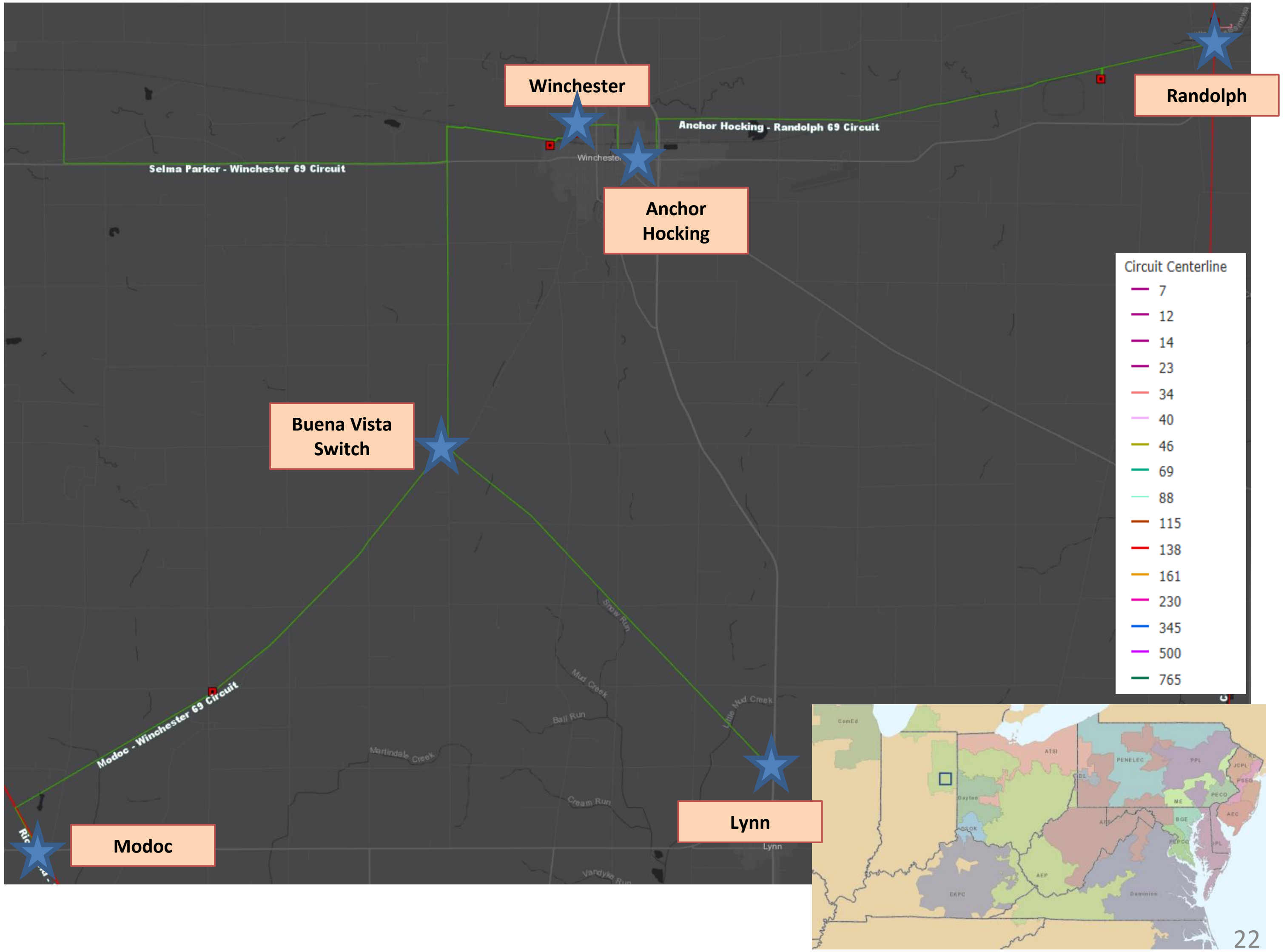


AEP Transmission Zone: Supplemental
Winchester, Indiana and surrounding area

Need Number: AEP-2020-IM004
Meeting Date: Needs Meeting 02/21/20
Supplemental Project Driver: Equipment Material/Condition/Performance/Risk
Specific Assumptions Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)
Problem Statement:

Randolph 138/69kV station

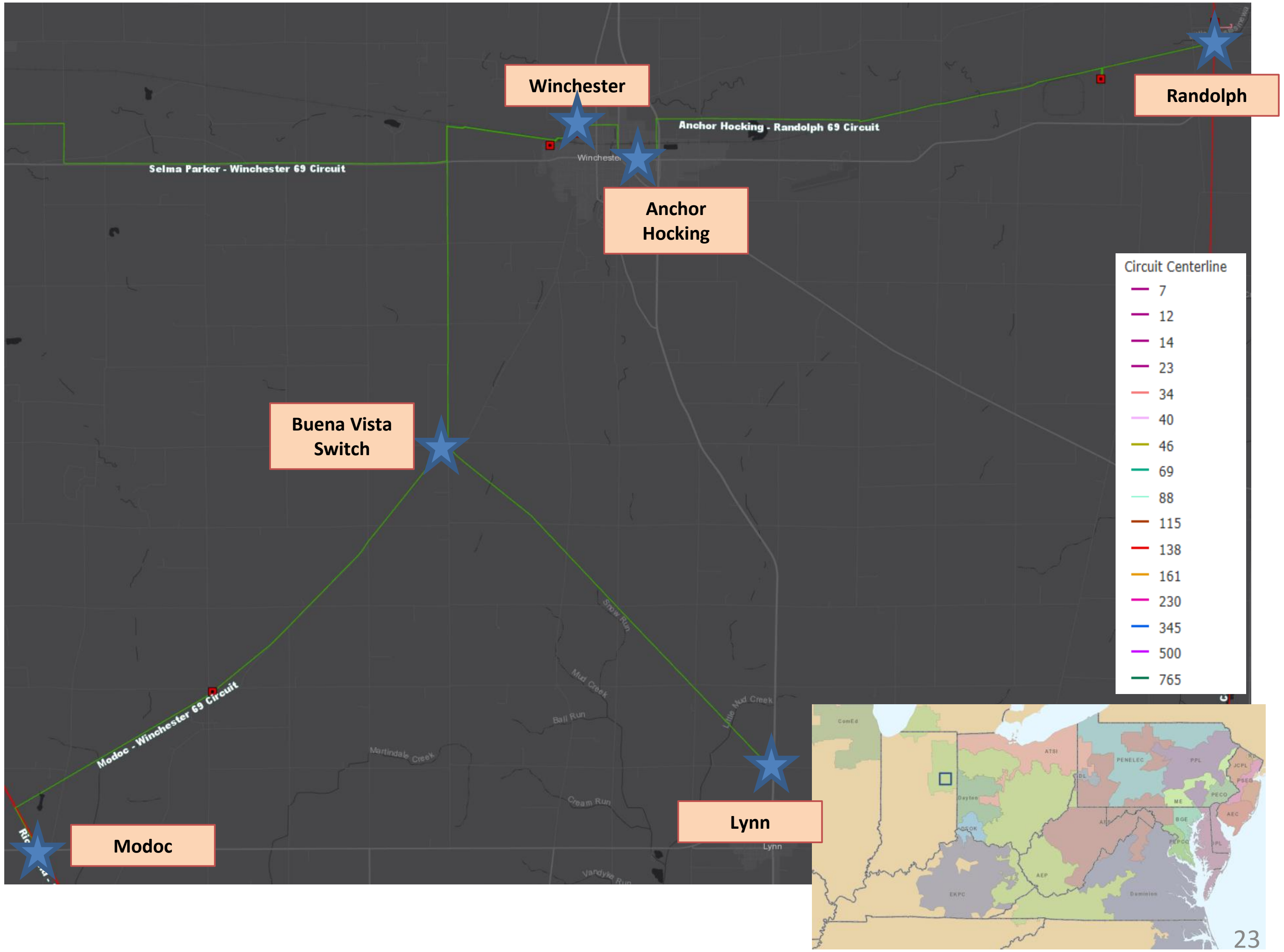
- 138/69/12 kV Transformer #1
    - 1970 vintage
    - Elevated carbon dioxide levels
    - Increased levels of decomposition of the paper insulating materials, leading to increased risk of failure
- Switcher V 138kV
    - Mark V S&C Electric type switcher
    - Failed operational components including high contact resistance, gas loss, and interrupter failure represent half of these malfunctions.
    - This model has no gas monitor and a history of malfunction
- Cap Switcher AA
    - 2030-69 S&C Electric type switcher.
    - This model has no gas monitor and a history of malfunction.
    - This particular switcher has exceeded the recommended number of switched operations with 5497 (5000 recommended)



Need Number: AEP-2020-IM004
Meeting Date: Needs Meeting 02/21/20
Supplemental Project Driver: Equipment Material/Condition/Performance/Risk
Specific Assumptions Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)
Problem Statement:

Modoc – Winchester 69kV Line (~13.4 Miles)
- 1967 vintage wood pole, horizontal insulator line
- There are currently 69 open conditions on this line (63 structures with at least one open condition or 26% of the line).
- Open conditions include: Damaged poles, damaged braces, broken guy wires, and damaged insulators.

Buena Vista – Lynn 69kV Line (~5.7 Miles)
- 1967 vintage wood pole, horizontal insulator line
- There are currently 31 open conditions on this line (28 structures with at least one open condition or 38% of the line).
- Open conditions include: Damaged poles, damaged shield wires, broken ground lead wires, and damaged insulators.



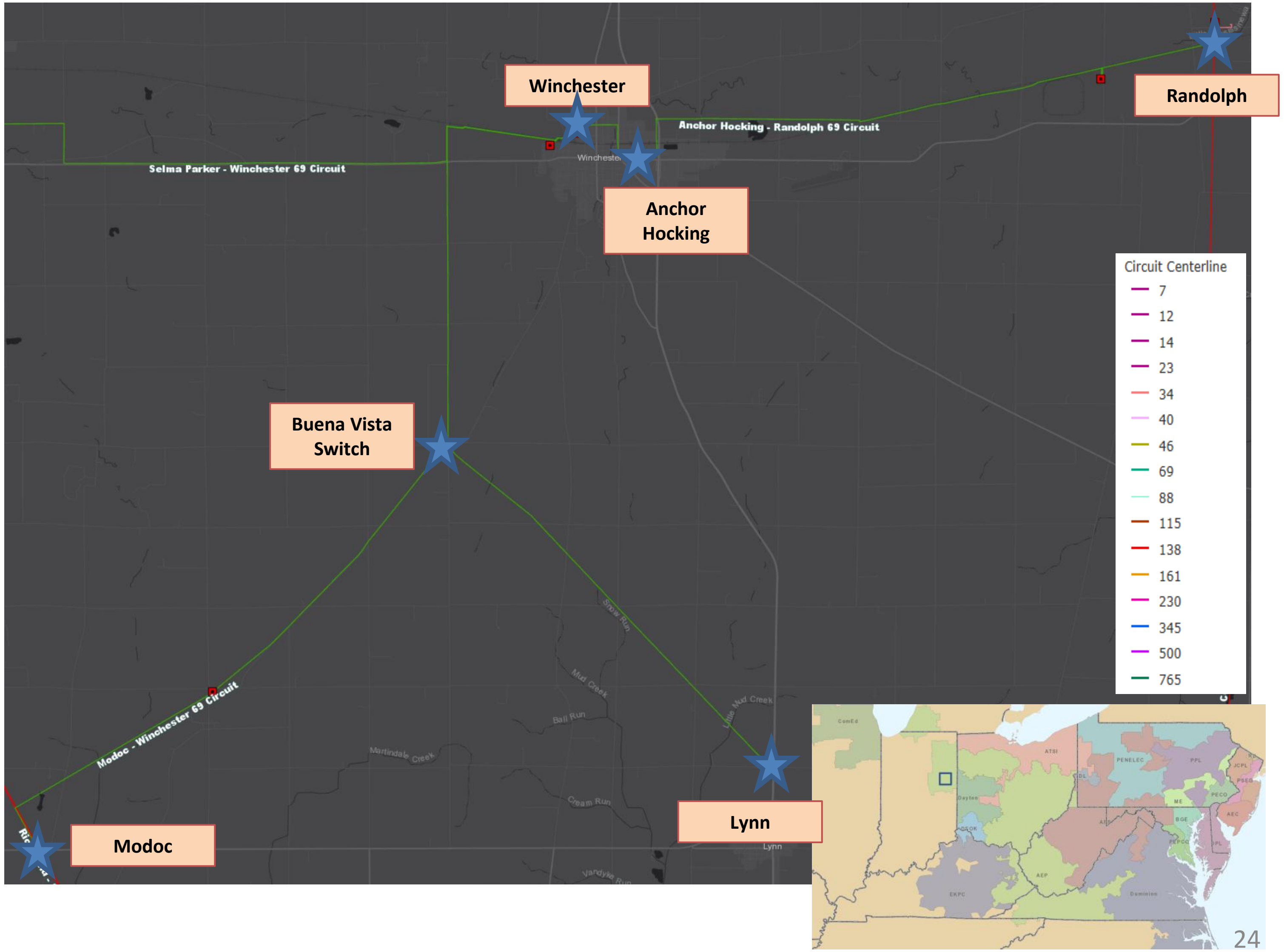
AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

AEP Transmission Zone: Supplemental
Winchester, Indiana and surrounding area

Need Number: AEP-2020-IM004
Meeting Date: Needs Meeting 02/21/20
Supplemental Project Driver: Operational Flexibility
Specific Assumptions Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)
Problem Statement:

Lynn 69/12kV station
- Radial circuit serving 7MW peak load to REMC and the distribution network for the city of Lynn.

Modoc 138/69/12kV station
- Modoc is a 3 terminal line off of the Desoto – College Corner 138kV circuit with high speed ground switch protection on the transformer



AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

AEP Transmission Zone: Supplemental Anderson, Indiana

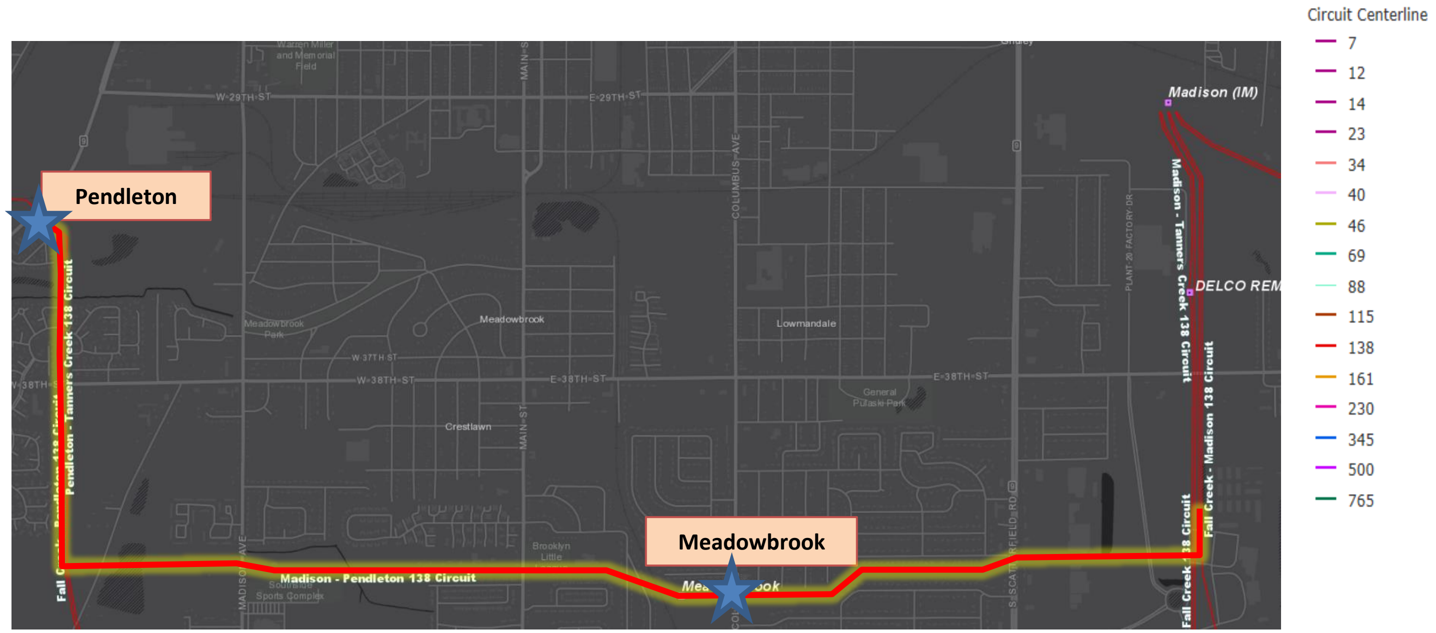
Need Number: AEP-2020-IM005
Meeting Date: Needs Meeting 02/21/2020
Supplemental Project Driver: Equipment Material/Condition/Performance/Risk/Operational
Specific Assumptions Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)
Problem Statement:

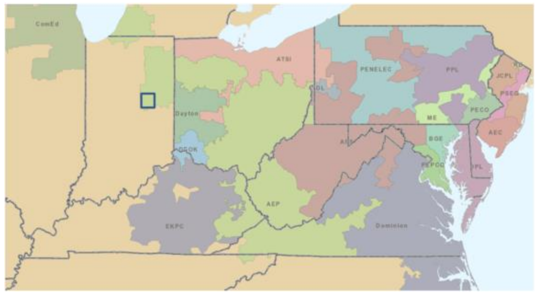
Madison – Pendleton 138kV Line (~4.2 Miles)

- 1967 vintage wood pole, H-Frame construction
- There are currently 16 open conditions on this line (9 structures with at least one open condition or 24% of the line).
- Open conditions include: Rotting or bowed crossarms or poles, broken shield wires, and stolen ground lead wires.

Meadowbrook 138/34.5kV station

- Three-terminal line and overlapping zones of protection on the bus, line, and transformer.



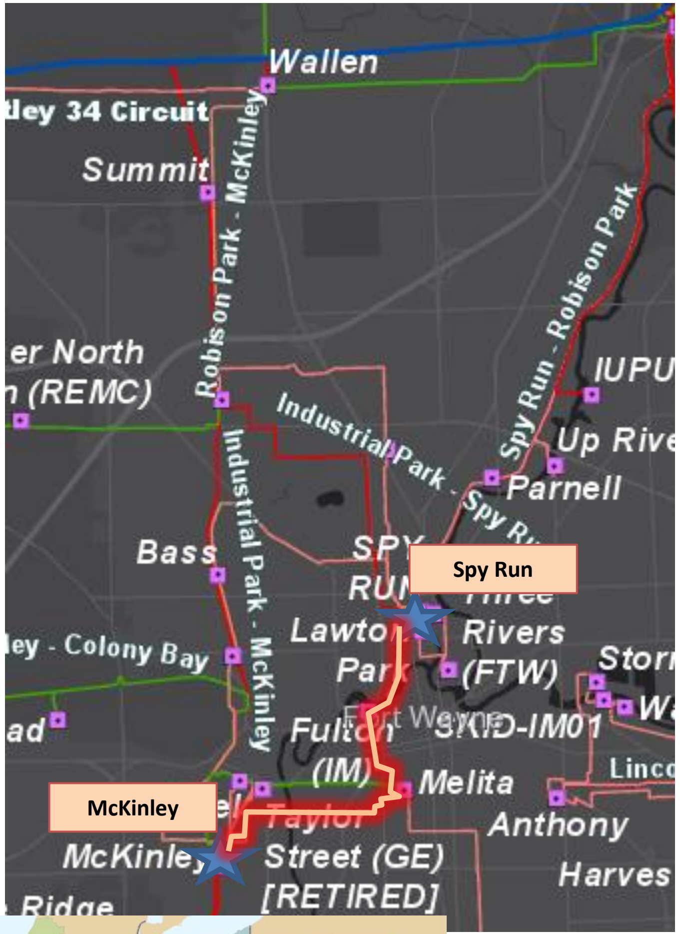


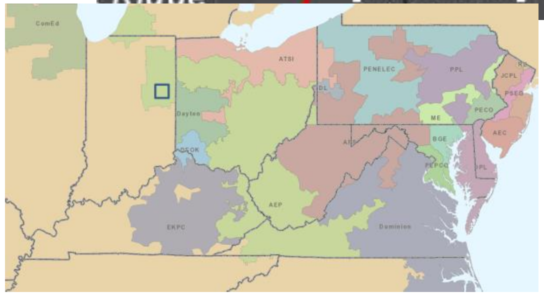
AEP Transmission Zone: Supplemental
Ft Wayne, IN

Need Number: AEP-2020-IM006
Process Stage: Needs Meeting 2/21/2020
Supplemental Project Driver: Equipment Condition/Performance/Risk
Specific Assumptions Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)
Problem Statement:

McKinley 138/69/34.5kV
- Breakers G 34kV
    - 1956 vintage Oil breakers
    - Fault Operations: G(10) – Recommended(10)
- Oil filled breakers have much more maintenance required due to oil handling that modern, vacuum counterparts do not require. Finding spare parts for these units is difficult or impossible, and these models are no longer vendor supported. Oil spills can result in significant costs associated with mitigation.

McKinley – Spy Run 34.5kV line asset (~5 miles)
- 1960 vintage wood crossarm construction
- There are currently 42 open conditions on this line across 37 unique structures (27% of the line) including, but not limited to, split crossarms, rot top, rot heart and broken grounds.
- Structures are in the river flood plains and in the flood control berm.





Need Number: AEP-2020-IM007

Process Stage: Needs Meeting 02/21/2020

Supplemental Project Driver: Equipment Condition/Performance/Risk

Specific Assumption Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Model: N/A

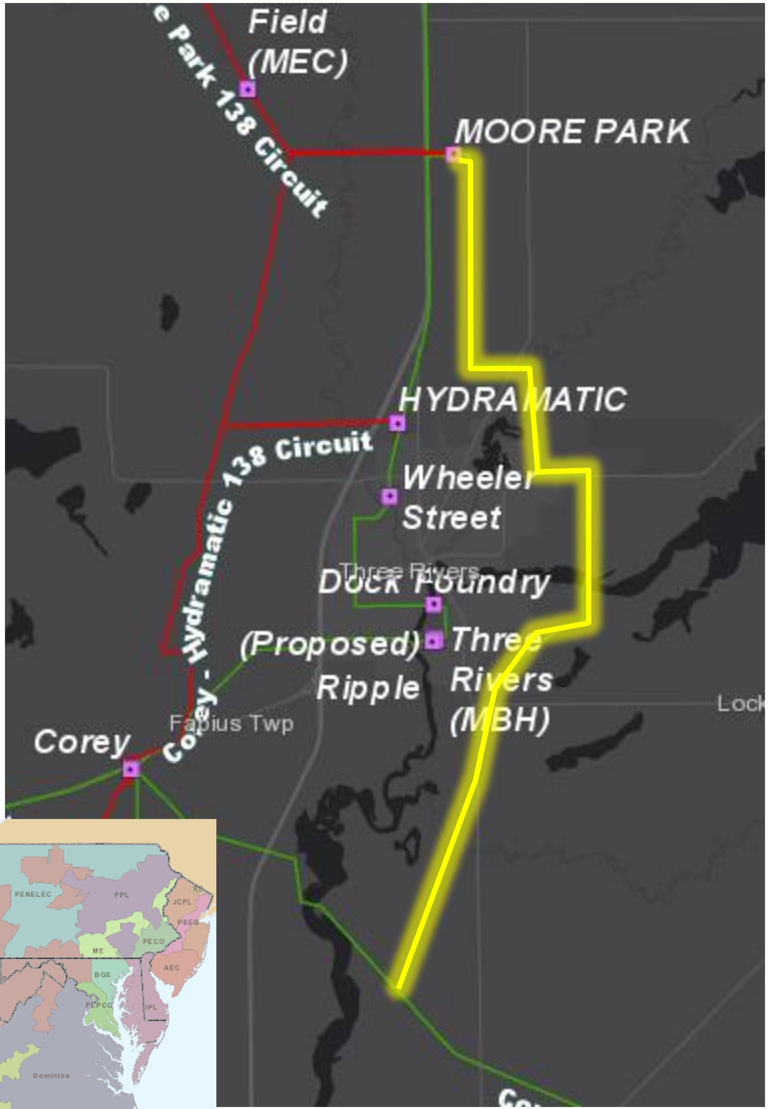
Problem Statement:

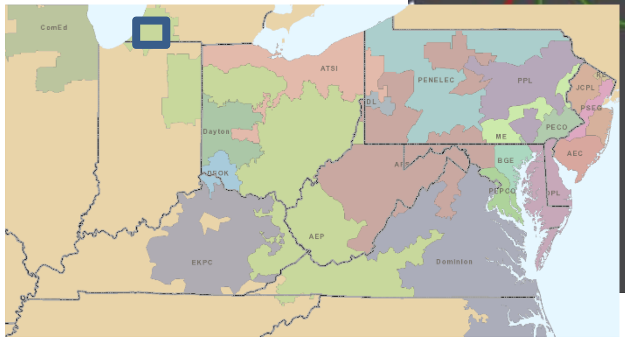
Moorepark 69kV Tap line:

- 9.02 miles of 1967 wood pole structure with horizontal insulators
- 94 structures with at least one open condition (52% of the line)
    - Open conditions include pole damage such as cracked, insect damage, rot heart and woodpecker holes, shielding/grounding conditions related to broken, missing or stolen ground wires, and broken or burnt insulators
- Since 2014 8 momentary and 1 permanent outages
    - 7 due to weather (lightning/thunderstorm) demonstrating poor shielding
- This line is a three terminal line which is hard to coordinate from a relaying perspective and is prone to misoperations

Moorepark (138/69kV) Station:

- 69kV circuit breaker (1) installed in 2006 with 41 documented malfunction records due to low SF6. This breaker has exceeded the designed number of fault operations.
- (1) 2030-69 Cap Switcher with no gas monitor. The AEP system has experienced numerous malfunctions of this type of cap switcher due to gas loss, interrupter failures, operating mechanism failures and trip or reclose failures.

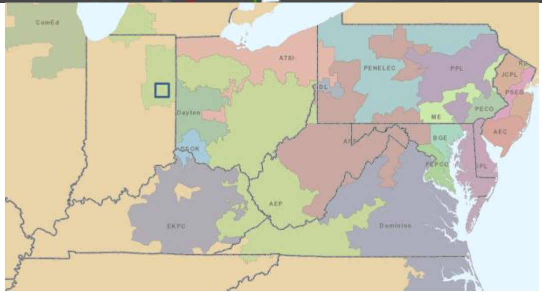




AEP Transmission Zone: Supplemental
Kendallville, IN

Need Number: AEP-2020-IM008
Process Stage: Needs Meeting 2/21/2020
Supplemental Project Driver: Customer Service
Specific Assumptions Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 7)
Model: 2024 RTEP
Problem Statement:

I&M Distribution has requested a expansion of their Bixler station and a rebuild of their North Kendallville stations in order to help address the loading and recoverability of the area. These stations serve sensitive customers, including industrial plants and the local hospital, and the load is not recoverable for an outage due to the radial nature of the transmission feeds as presented in need AEP-2019-IM015.

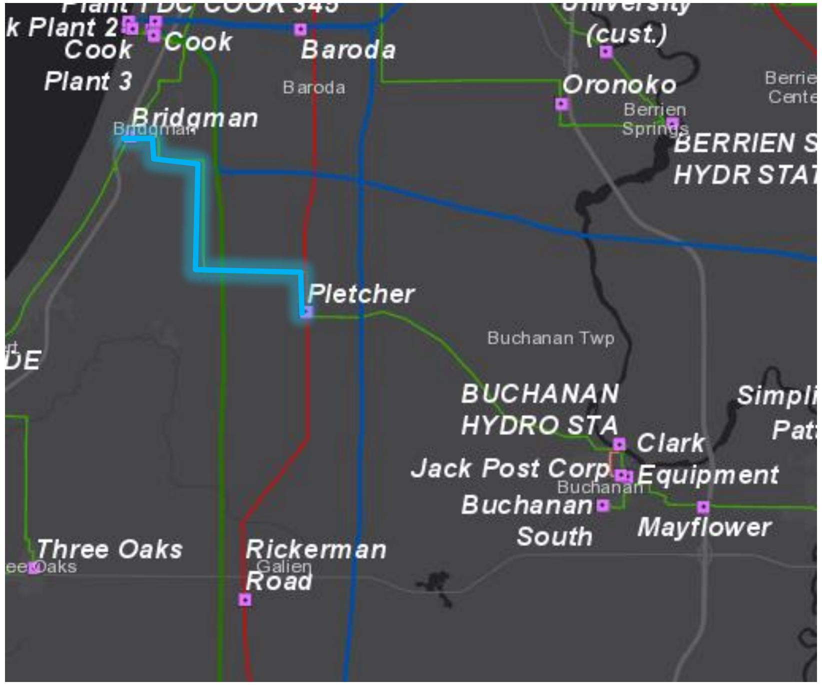


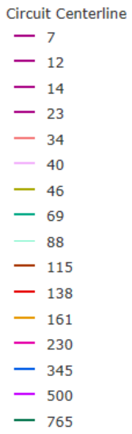
AEP Transmission Zone M-3 Process
Bridgman-Pletcher

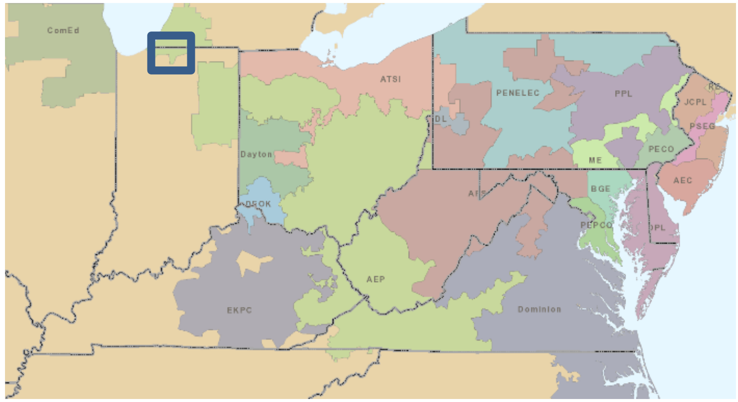
Need Number: AEP-2020-IM009
Process Stage: Needs Meeting 02/21/2020
Supplemental Project Driver: Equipment Condition/Performance/Risk
Specific Assumption Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)
Model: N/A
Problem Statement:

Bridgman-Pletcher 69kV line:

- 7.7 miles of 1964 wood pole line
- 57 unique structures (46%) with at least one open conditions relating to structure and conductor issues
- Open conditions include rotted poles, burnt or broken insulators, split or damaged poles or broken conductor strands, woodpecker damage and guy/ground wire damage







Need Number: AEP-2019-OH029 **Canceled**

Process Stage: Needs Meeting 06/17/2019

Supplemental Project Driver:

Customer Service

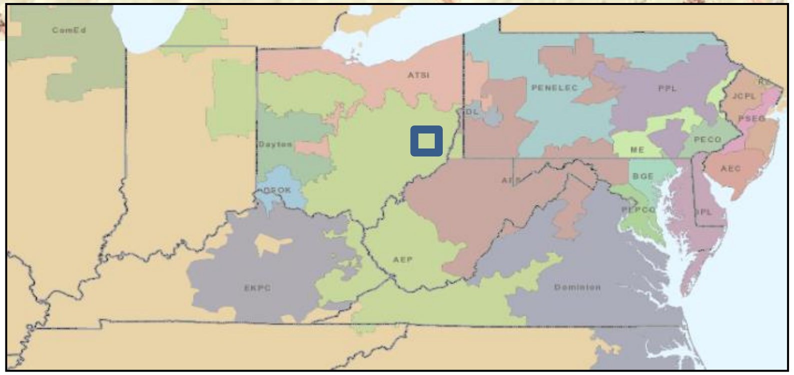
Specific Assumption References:

AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 7)

Model: 2023 RTEP

Problem Statement:

- Buckeye Power, on behalf of South Central Power Co-op, has requested transmission service in Stock Township of Harrison County, Ohio.
- The forecasted peak demand is 16 MVA, with an in-service date of 9/1/2020.
- This need has been cancelled by the customer.



AEP Transmission Zone M-3 Process
Crooksville / Harrison, Ohio

Need Number: AEP-2020-OH004

Process Stage: Need Meeting 02/21/2020

Supplemental Project Driver:

Equipment Material/Condition/Performance/Risk

Specific Assumption References:

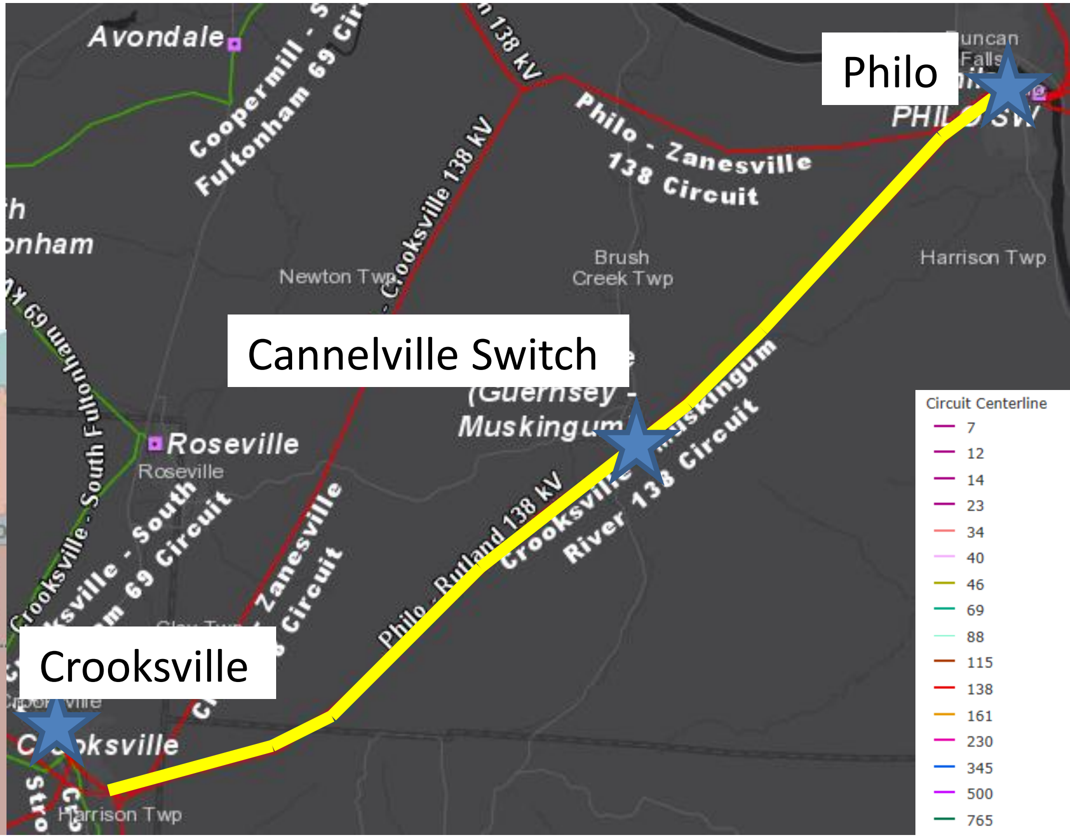
AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8), AEP Presentation on Pre-1930s Lines

Problem Statement:

Crooksville – Philo 138kV

- Length: 13 Miles
- Original Construction Type: Aluminum/Steel Lattice
- Original Conductor Type: 397.5 ACSR Lark / 636 ACSR Grosbeak (vintage 1926)
- Momentary/Permanent Outages: 1 total outages
    - CMI: 320,767
    - Number of open conditions: 5
    - Total structure count: 65
    - Open conditions include: Burnt insulators, damaged shield wire
- Please reference assumptions materials on pre-1930s era lattice lines

Model: N/A



AEP Transmission Zone M-3 Process
Winesburg, Ohio

Need Number: AEP-2020-OH005

Process Stage: Needs Meeting 2/21/2020

Supplemental Project Driver: Customer Service

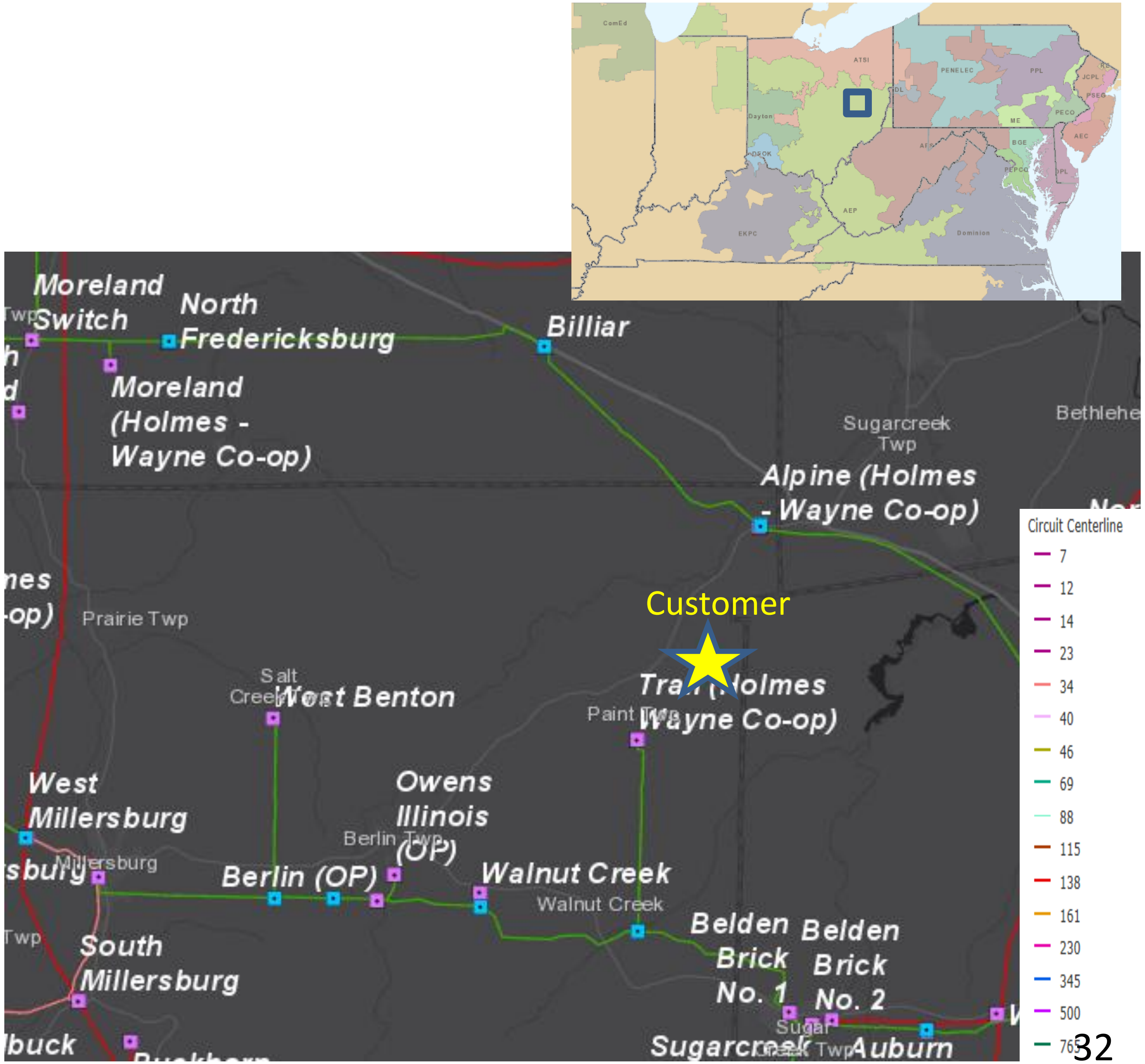
Specific Assumption Reference:

AEP Connection Requirements for the AEP Transmission System (AEP Assumptions Slide 7)

Problem Statement:

- Holmes-Wayne Electric Cooperative has requested service for a new delivery point near Winesburg, Ohio.
- The anticipated new load is 8 MW.

Model: PJM 2024 RTEP Base Case



Need Number: AEP-2020-OH006

Process Stage: Need Meeting 02/21/2020

Supplemental Project Driver:

Customer Service

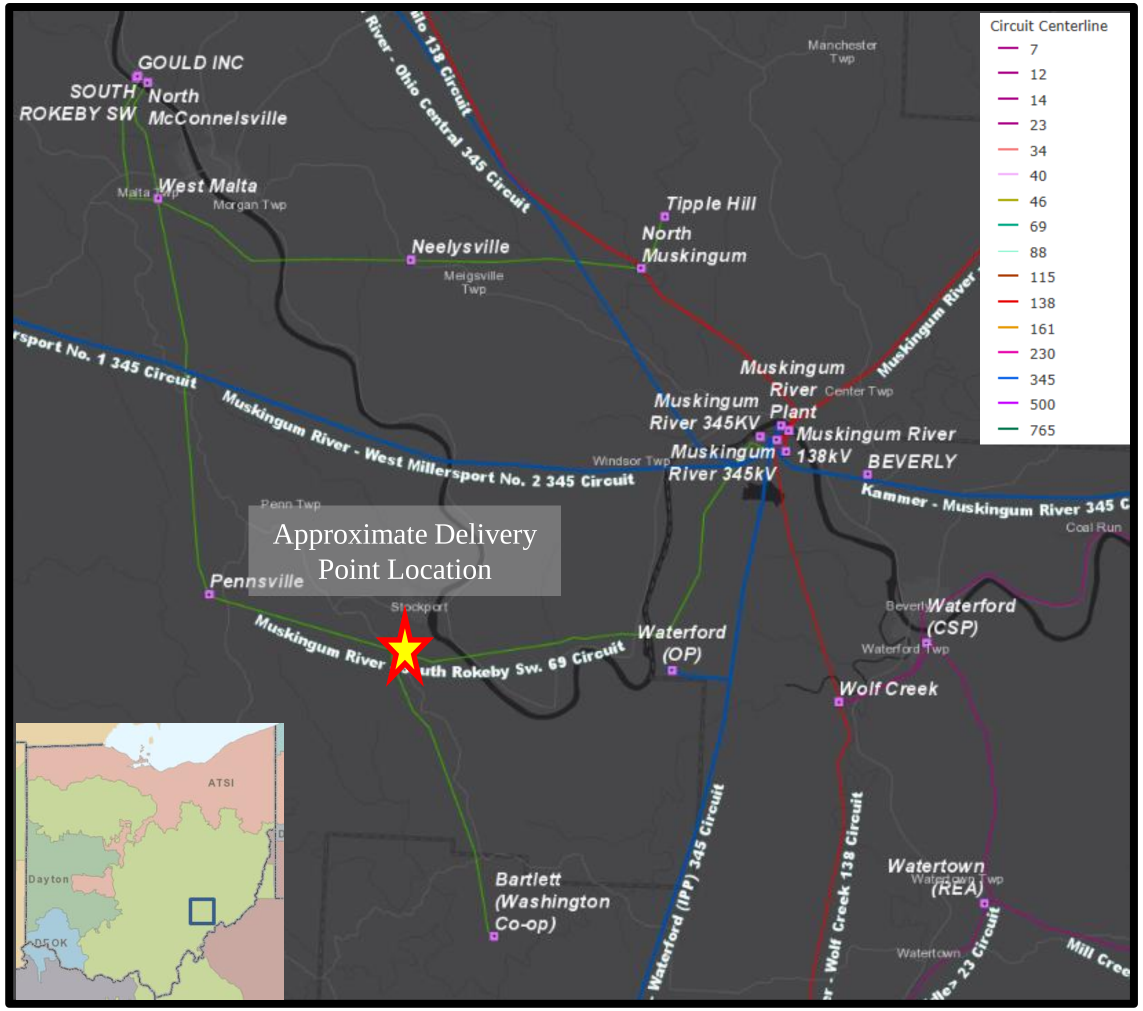
Specific Assumption Reference:

AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions slide 7)

Problem Statement:

- AEP Ohio is requesting a new 69kV delivery point on the Muskingum River – South Rokeby SW 69kV Circuit. Anticipated load is about 5 MVA.

Model: 2024 RTEP



AEP Transmission Zone M-3 Process
Adena, Ohio

Need Number: AEP-2020-OH007

Process Stage: Needs Meeting 2/21/2020

Supplemental Project Driver:

Equipment Material Condition, Performance and Risk; Operational Flexibility & Efficiency

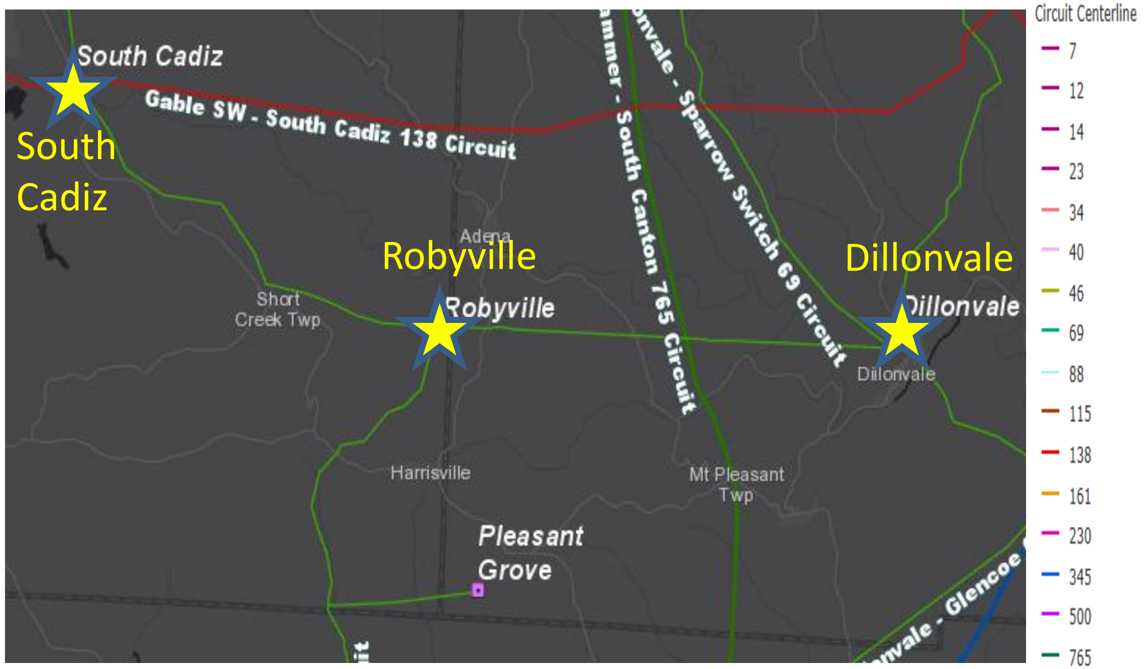
Specific Assumption Reference:

AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

Equipment Material Condition, Performance and Risk:

- The Robyville 69-12kV substation is in poor condition. The 69kV breaker 'C' is an oil-filled unit from 1965, has experienced 143 fault operations (manufacturer recommends 10), and has mechanical problems on the breaker's open/close mechanism.
- The station consists of deteriorating wooden 69kV & 12kV station structures. Foundations for the 2- transformers and voltage regulator are of wooden rail road tie construction. The station fence and retaining wall are in very poor condition. The two distribution transformers date to 1941 & 1947; both are showing signs of thermal degradation (due to past electrical faults), high carbon-monoxide levels (due to excessive heating), contaminated oil, and hot spots.
- The small control house dates to the 1940's. Of the 16 relays, 12 are original electromechanical models, which lack modern fault recording, no SCADA functionality, and have limited spare part availability.



Need Number: AEP-2020-OH007

Process Stage: Needs Meeting 2/21/2020

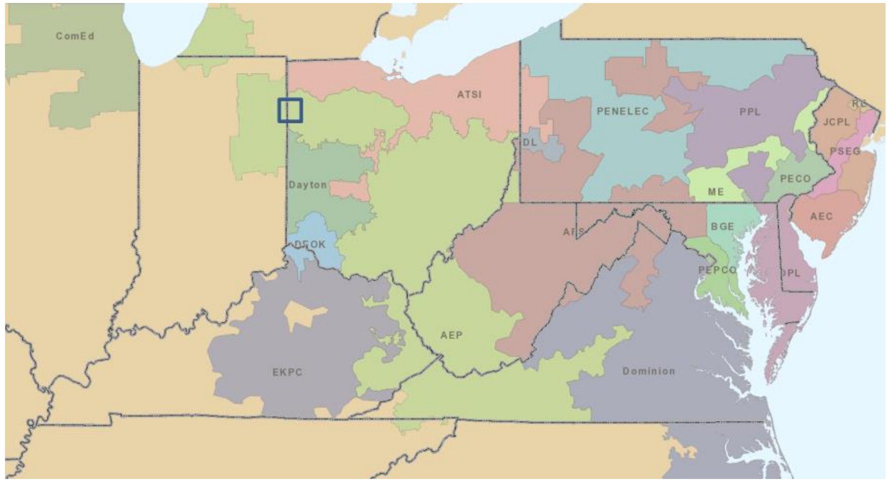
Operational Flexibility & Efficiency:

- Robyville Station contains dissimilar zones (2-lines, bus, and transformer) of protection that cause misoperations and over tripping.
- The distribution transformers at Robyville are in parallel (1.5 MVA each) and lack a high-side protective device. A fault on either transformer or the low-side 12kV bus will take out both 69-12kV transformers an outage 1,000+ customers served from this station.
- In the past 5 years, the Dillonvale-Robyville-South Cadiz 69kV circuit has experienced 10 momentary outages and 2 sustained outages. Distribution customers served from Robyville have experienced a CMI (customer-minutes-of-interruption) total of 610,598.
- South Cadiz 69 kV breaker D is an oil-filled unit from 1965, with 34 fault operations; it exhibits signs of mechanical degradation.
- Dillonvale 69 kV breaker B is an oil-filled unit from 1952, with 35 fault operations.

Need Number: AEP-2020-OH008
Process Stage: Needs Meeting 2/21/2020
Supplemental Project Driver: Equipment Condition/Performance/Risk
Specific Assumptions Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)
Problem Statement:

Rob Park – South Hicksville (OH) 34kV (~4.6 Miles)

- 1956 & 1962 vintage wood pole construction with 32 open conditions on 17 unique structures, approximately 17% of the line. These conditions include but not limited to damaged poles, broken insulators, broken shield wire, rot top and broken Knee/Vee braces
- The circuits on this line have had the following outages across the last 5 years.
  Rob Park – South Hicksville: 9 momentary and 6 permanent
  CMI: 526,269
  North Hicksville – Butler: 5 Momentary and 2 Permanent.
  CMI: 120 over the last 5 years.
- Related to previously shared need AEP-2019-IM014.



Need Number: AEP-2020-OH009

Process Stage: Need Meeting 02/21/2020

Supplemental Project Driver:

Equipment Material/Condition/Performance/Risk, Operational Flexibility and Efficiency, Customer Service

Specific Assumption Reference:

AEP Guidelines for Transmission Owner Identified Needs

Problem Statement:

Equipment Material/Condition/Performance/Risk:

- This line consists of 15 wood pole structures and has predominantly the original #2 ACSR/AW Sparrow conductors installed in 1943. 9 out of the 15 structures on this line were installed more than 60 years ago. 5 year CMI on this circuit is approximately 95,000. The existing construction is obsolete crossarm construction with 35 kV vertical stud post insulators.

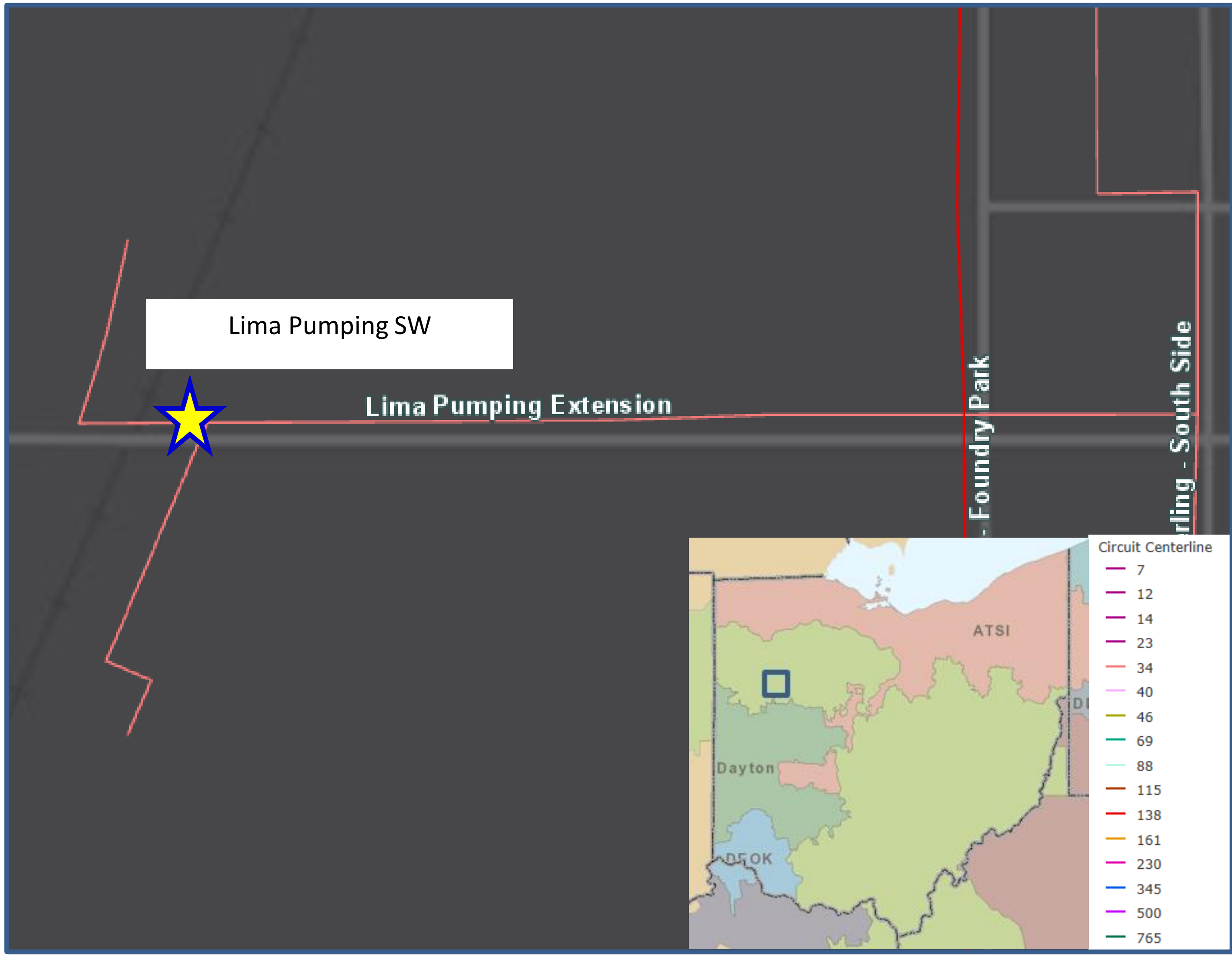
Operational Flexibility and Efficiency

- The line has experienced four (4) conductor failures since August 1, 2018. The first 8 spans of the line have 35 total splices. During these failures the 34 kV conductors end up falling into and faulting the AEP Ohio 3-phase distribution underbuild, interrupting several hundred additional distribution customers.

Customer Service:

- Both customers on this radial line experienced multiple outages due to geese contact on AEP's 34.5 kV transmission line. Additionally these two customers are connected via a hard tap at the end of the radial 34.5 kV line forcing both of them to be out when one of them requests an outage.

Model: N/A



Need Number: AEP-2020-OH010

Process Stage: Need Meeting 02/21/2020

Supplemental Project Driver: Customer Service

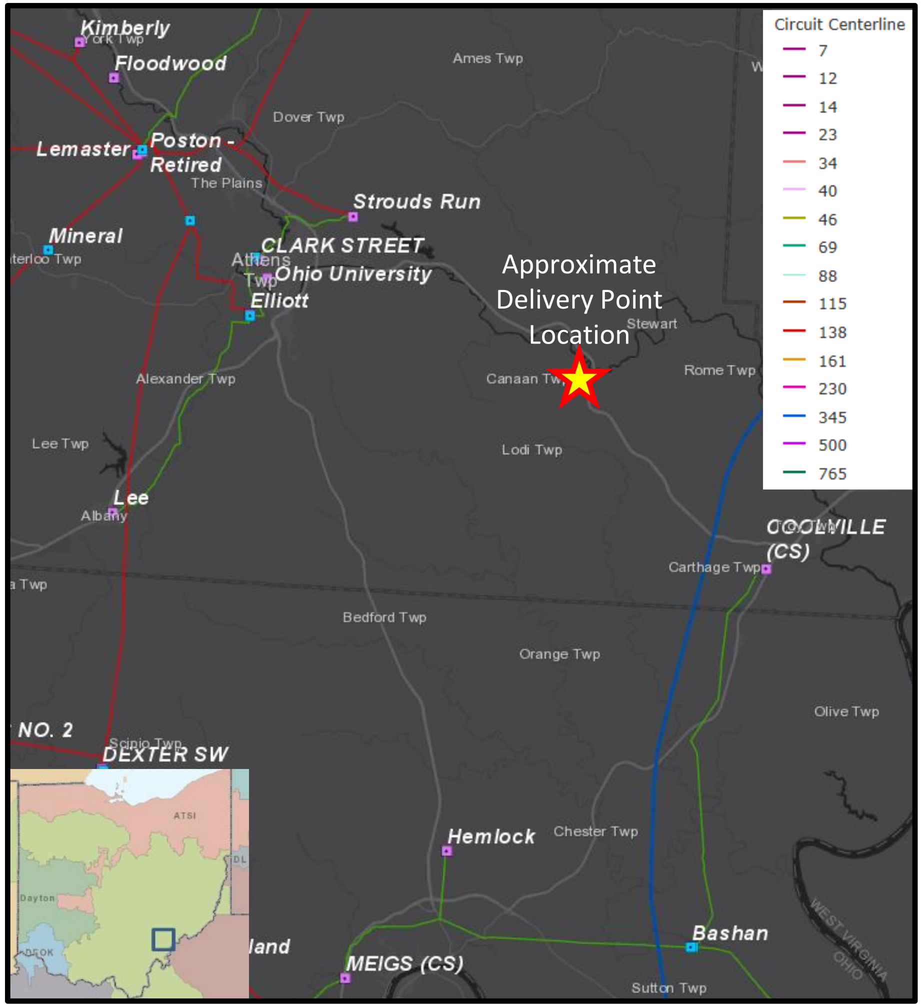
Specific Assumption Reference:

AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions slide 7)

Problem Statement:

- AEP Ohio has requested a new delivery point between Coolville and Elliott Stations. Anticipated peak load is approximately 7.5 MVA that will be transferred from nearby stations in the area.

Model: 2024 RTEP



AEP Transmission Zone M-3 Process
Athens Ohio

Need Number: AEP-2020-OH011

Process Stage: Need Meeting 02/21/2020

Supplemental Project Driver:
Equipment Material/Condition/Performance/Risk

Specific Assumption Reference:
AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8), AEP Presentation on Pre-1930s Lines

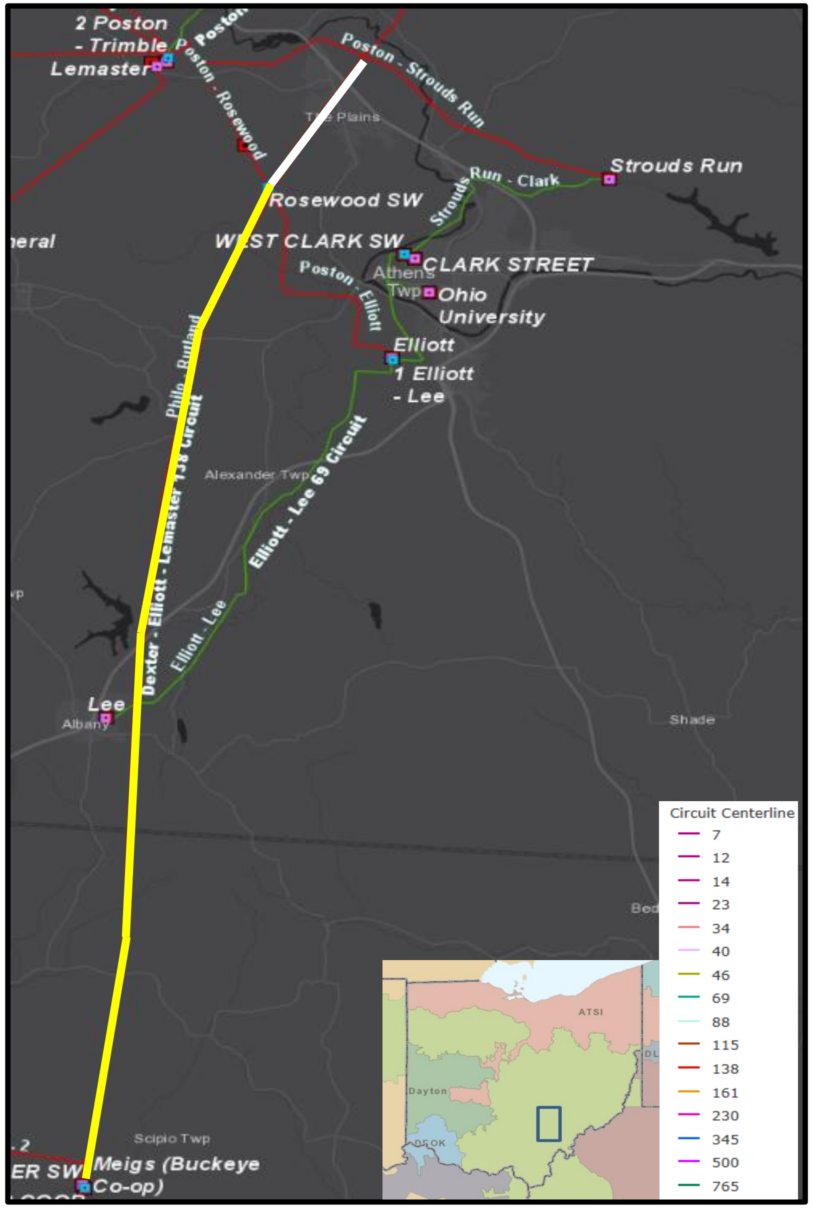
Problem Statement:

<u>Dexter – Rosewood 138kV (1927 Steel Lattice Line)</u>

- Length: ~~16.8~~ 8.8 Miles
- Original Construction Type: Aluminum/Steel Lattice
- Original Conductor Type: 397.5 CM ACSR 30/7 (1926 vintage)
- Momentary/Permanent Outages: 3 total outages over last 5 years
    - Total structure count: ~~68~~ 38
- Please reference needs materials on pre-1930s era lattice lines
- There is an additional 2.5 miles of the 1920's Philo - Rutland lattice line which is de-energized and runs through the middle of The Plains community north of Athens

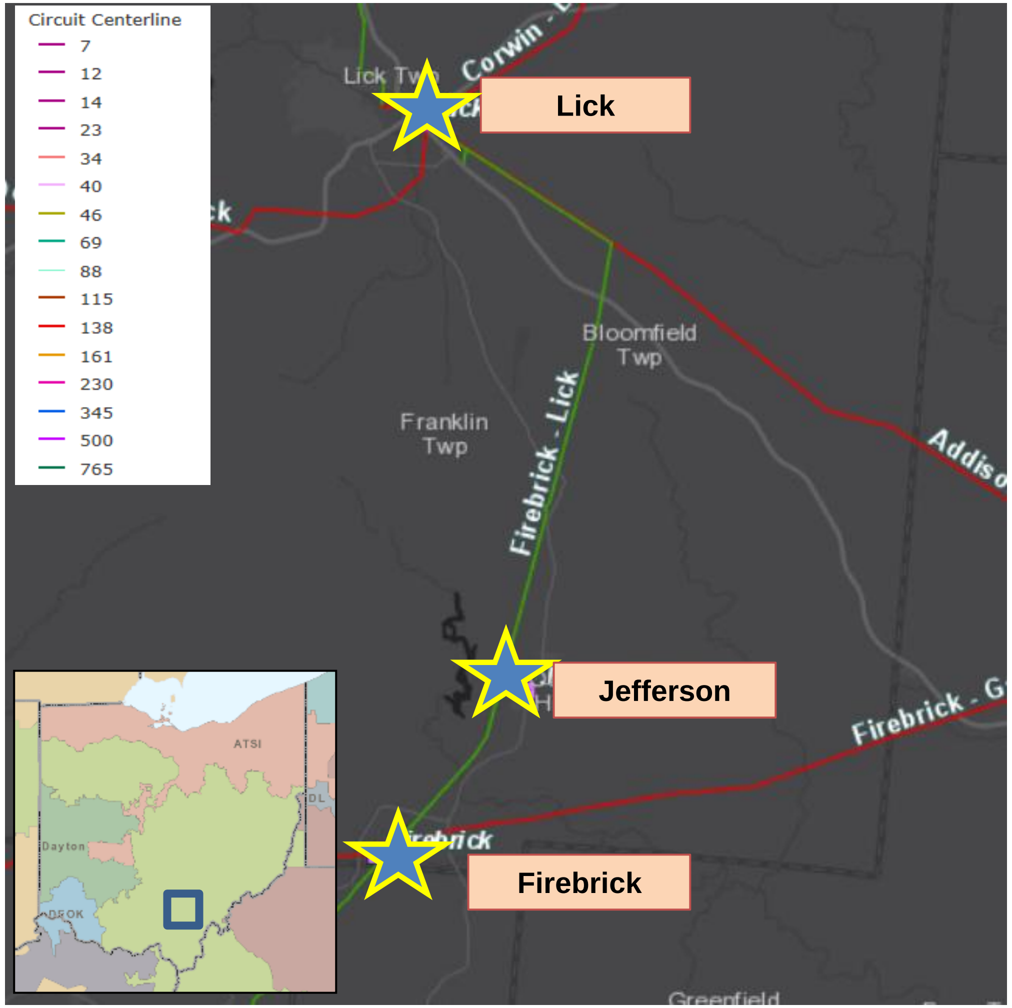
Model: N/A

The remaining 8 miles out of Dexter will be captured under Need Number: **AEP-2020-OH022**



AEP Transmission Zone M-3 Process
Jackson County, Ohio

Need Number: AEP-2020-OH012
Process Stage: Needs Meeting 02/21/2020
Process Chronology: Needs Meeting 02/21/2020
Supplemental Project Driver: Equipment Material/Condition/ Performance/Risk
Specific Assumptions Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions slide 8)
Problem Statement:
Jefferson-Lick 69 kV line
- Original Construction Date: 1927
- Length: 12.5 miles
- Original Construction Type: Wood (1927, 1953, and 1980s)
- Conductor Type: 8.5 miles of 4/0 ACSR conductor (1927 and 1967) with 4.0 miles of 336 ACSR conductor (1980s)
- Outages: 4 Permanent and 17 Momentary (5 years)
- 3.96 million customer minutes of interruption (CMI) associated with the Firebrick – Lick 69 kV circuit over the last 5 years.
- Conditions: 27 of 93 structures have at least one open condition including rot top pole, crossarm damage, and insulator issues.



Need Number: AEP-2020-OH013

Process Stage: Needs Meeting 02/21/2020

Supplemental Project Driver: Equipment Condition/Performance/Risk

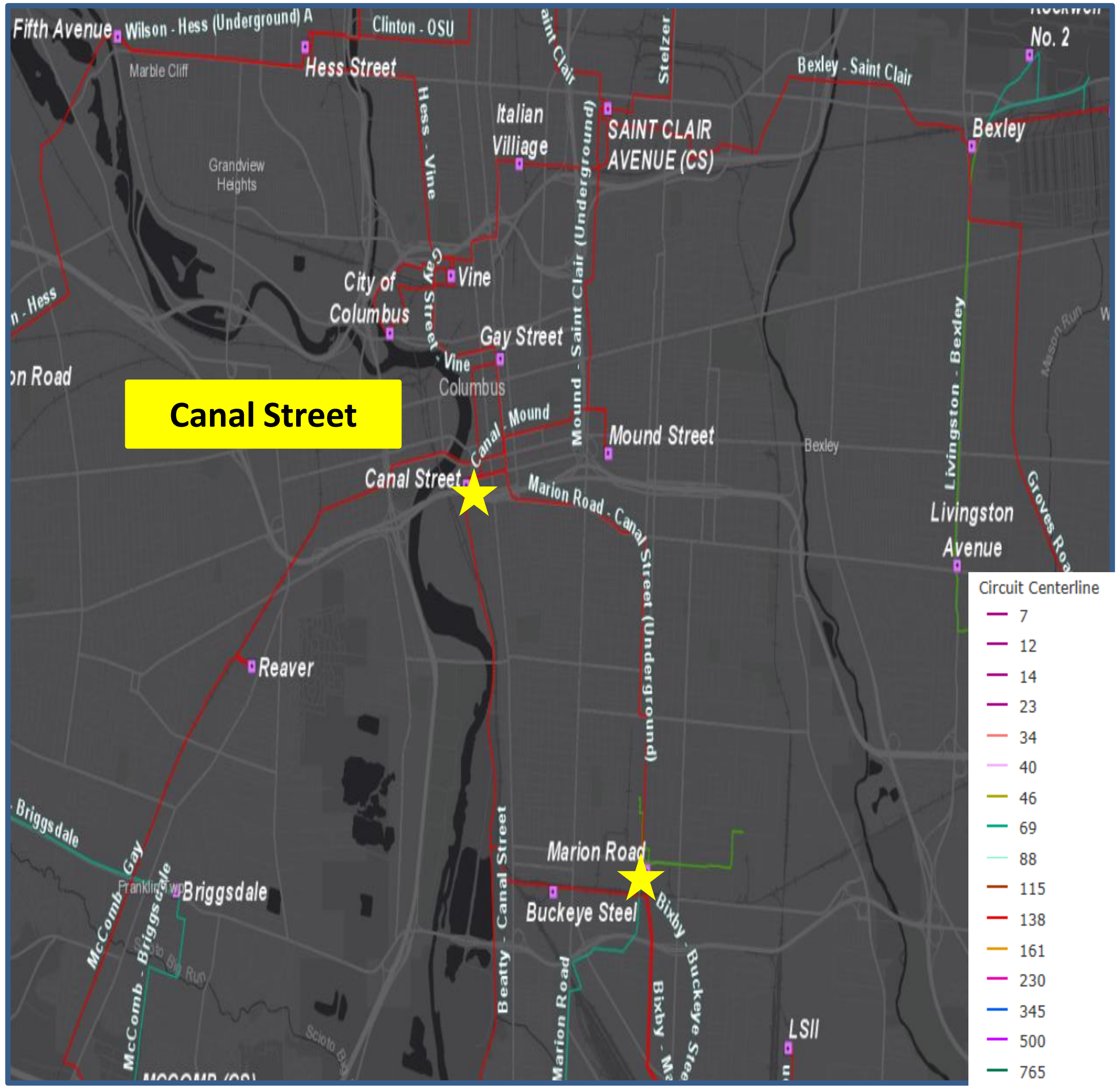
Specific Assumption Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8), Customer Service

Problem Statement:

Canal Street – Marion Road 138 kV Underground Circuit

- Ohio Department of Transportation (ODOT) has requested that approximately 1500 feet of the existing Canal – Marion 138 kV underground circuit be relocated as part of a planned Interstate improvement project.
- The existing Canal – Marion 138 kV underground circuit is approximately 3.8 miles long and was originally installed in the 1950's.
- The circuit utilizes an underground oil-filled pipe type cable design. Oil-filled pipe type underground cables come with several challenges/risks in densely populated urban areas. Lead times for replacement/repairs from the remaining single vendor can be 6 months to a year. Even minor issues with the cable could result in costly outages over an extended period of time due to this single remaining vendor.

Model: N/A



Need Number: AEP-2020-OH014

Process Stage: Need Meeting 02/21/2020

Supplemental Project Driver:
Equipment Material/Condition/Performance/Risk

Specific Assumption Reference:

AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions slide 8)

Problem Statement:

<u>Poston – Shrouds Run 138kV (1965)</u>

- Length 7.52 Miles
- Original Construction Type: Wood H-Frame
- Original Conductor Type: 636 ACSR Conductor (vintage 1966)
- Momentary/Permanent Outages: 3 total outages last 5 years
    - Number of open conditions: 62
    - Total structure count: 46
    - Open conditions include: rot top, woodpecker holes, bowed structures, and burnt poles
    - Unique structure count with open conditions: 31

Model: N/A

AEP Transmission Zone M-3 Process
Athens Area Improvements

Need Number: **AEP-2020-OH022**

(Remainder of need transferred from AEP-2020-OH011)

Process Stage: Need Meeting 02/21/2020

Supplemental Project Driver:

Equipment Material/Condition/Performance/Risk

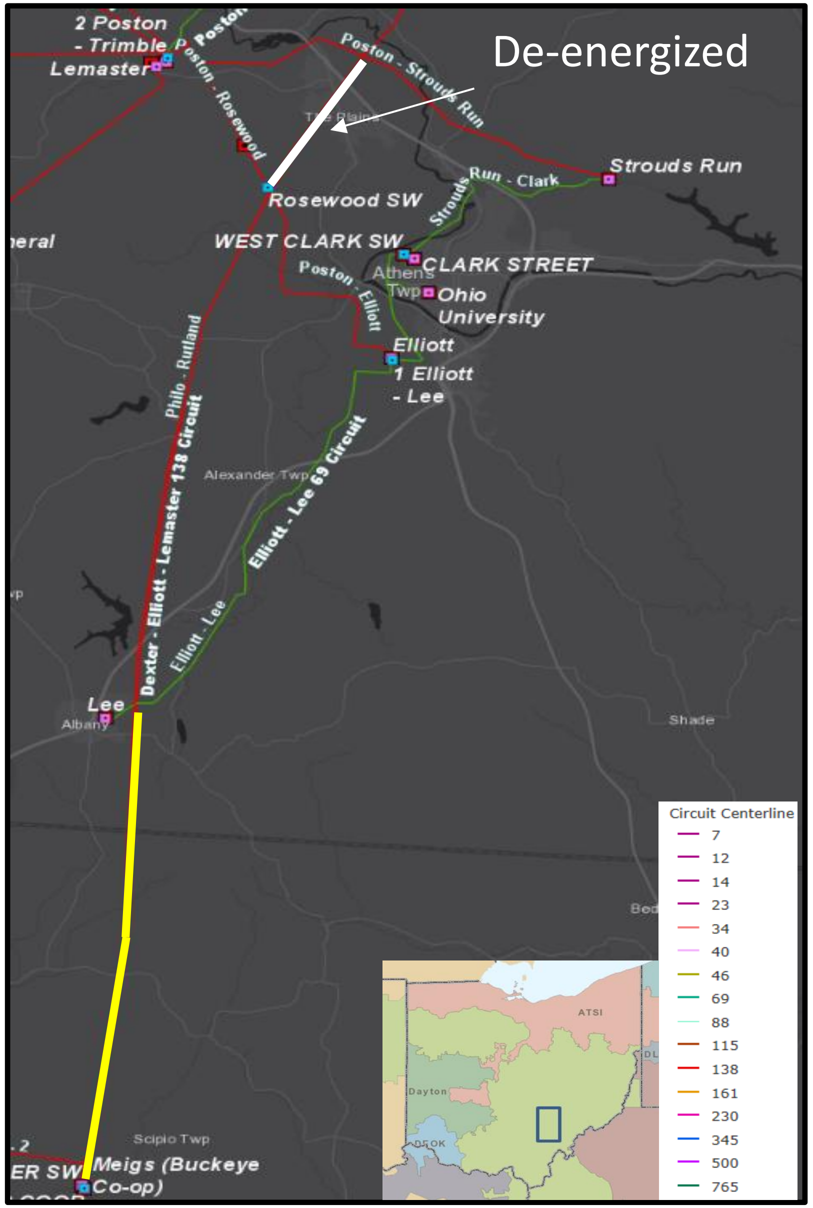
Specific Assumption Reference:

AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8), AEP Presentation on Pre-1930s Lines

Problem Statement:

Dexter – Rosewood 138kV (1927 Steel Lattice Line)

- Length: 8 Miles
- Original Construction Type: Aluminum/Steel Lattice
- Original Conductor Type: 397.5 CM ACSR 30/7 (1926 vintage)
- Momentary/Permanent Outages: 3 total outages over last 5 years
    - Total structure count: 30
- Please reference needs materials on pre-1930s era lattice lines
- There is an additional 2.5 miles of the 1920’s Philo - Rutland lattice line which is de-energized and runs through the middle of The Plains community north of Athens



Solutions

Stakeholders must submit any comments within 10 days of this meeting in order to provide time necessary to consider these comments prior to the next phase of the M-3 process

Need Number: AEP-2018-OH007
Process Stage: Solutions Meeting 02/21/2020
Previously Presented: Needs Meeting 10/26/2018
Supplemental Project Driver: Equipment Material/Condition/Performance/Risk, Operational Flexibility and Efficiency
Specific Assumption References:
AEP Guidelines for Transmission Owner Identified Needs
Problem Statement:
The 138/34kV transformers and 34kV circuit breakers at New Liberty, North Baltimore, and North Findlay Stations have significant asset renewal needs. Between these three stations seventeen (17) 34.5kV circuit breakers/ circuit switchers have been identified as needing replacement, fifteen (15) of which are oil filled (vintage 1950's) and have seen a high number of fault operations. Short circuit capability is also a concern for many of these 34.5 kV breakers at New Liberty and North Findlay stations.

North Findlay Station:

- 34.5kV CBs F, G, H, J, K, L
- 34.5kV circuit switcher BB
- Transformers #1 and 2

New Liberty Station:

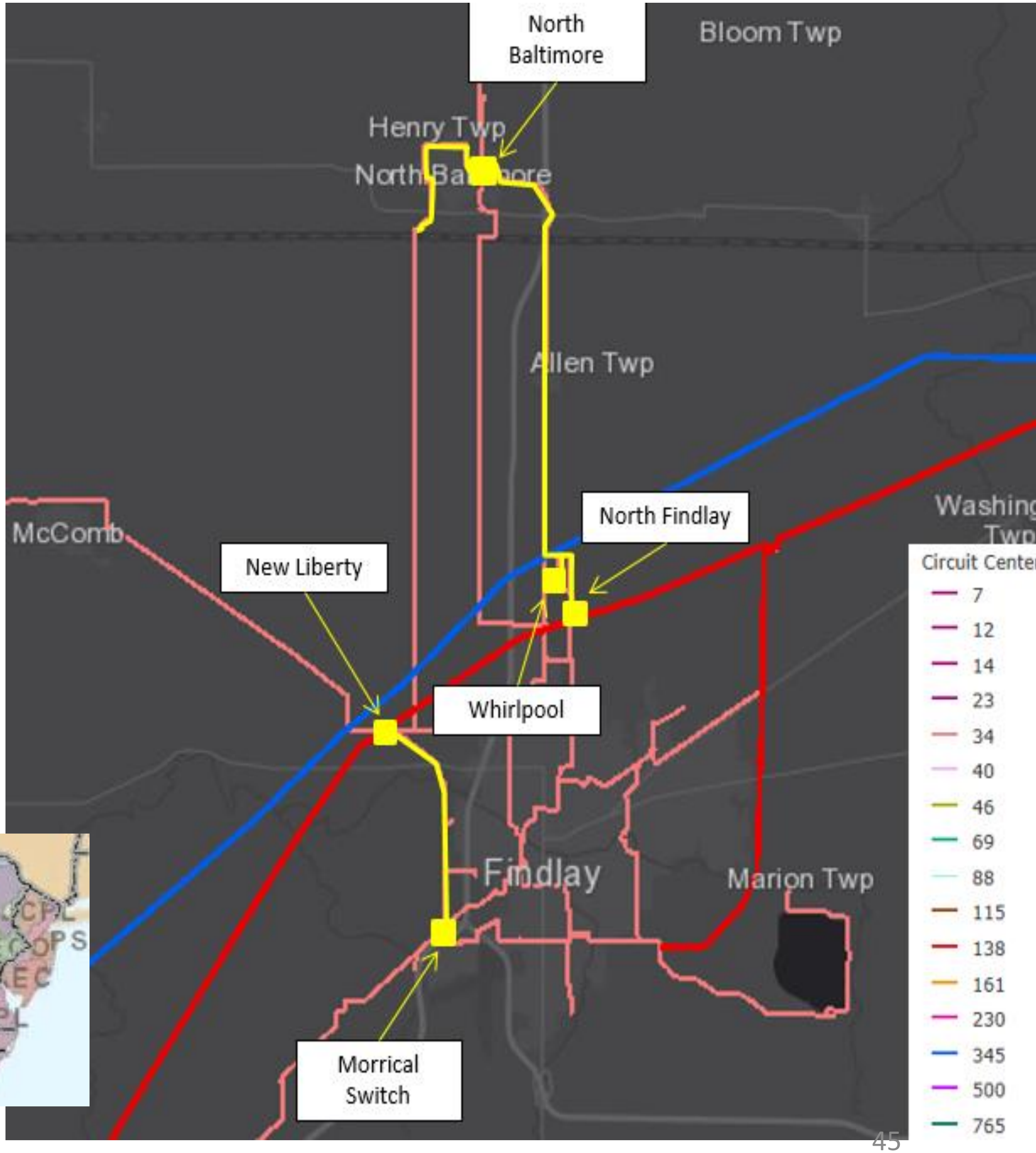
- 34.5kV CBs C, E, G, H, I, J
- Transformers #1 and 2

North Baltimore Station:

- 34.5kV CBs A, B, C, E

Morrical Switch

- 34.5kV CB A



Problem Statement (Continued):

Morrical Switch

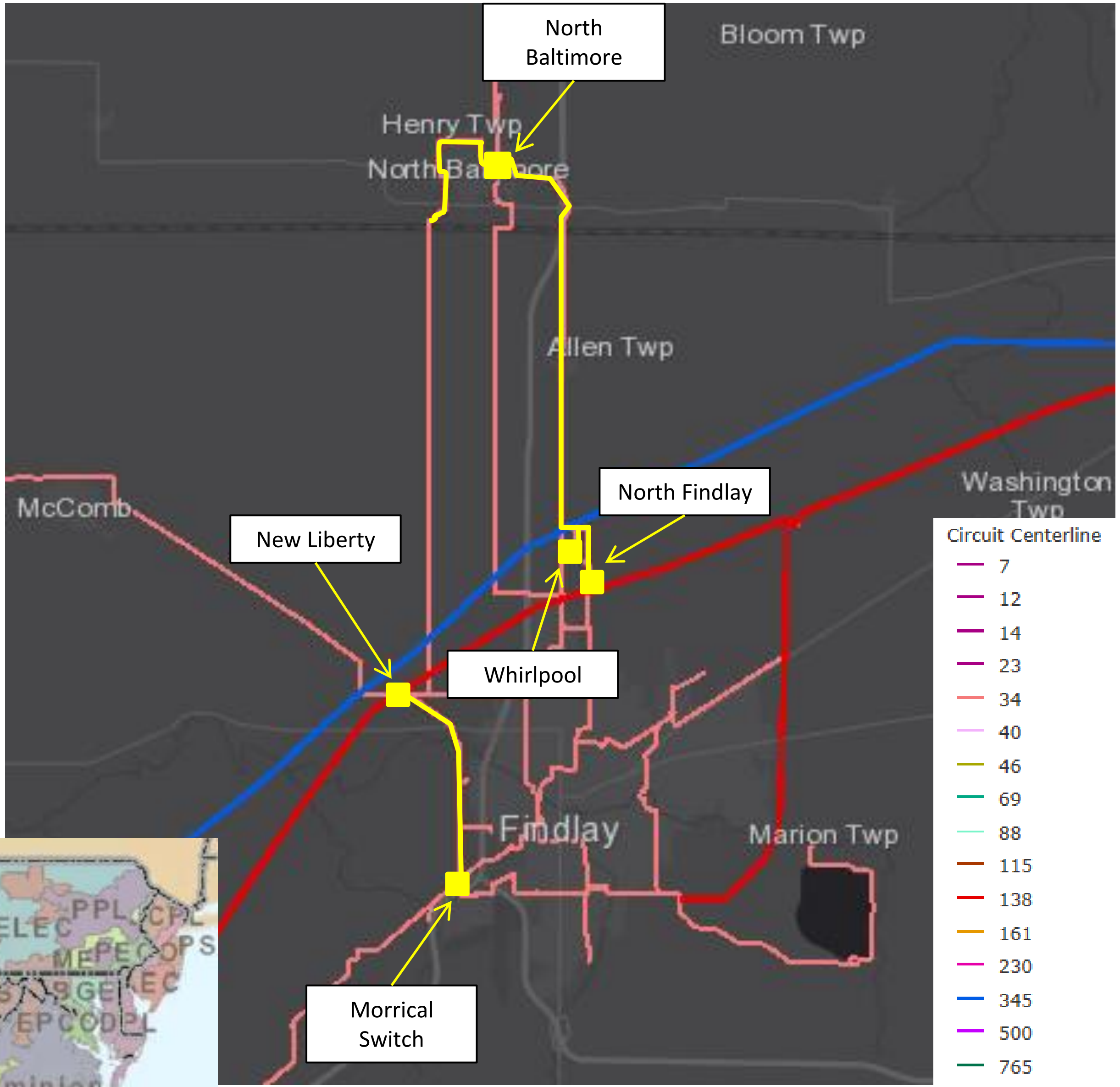
- Evaluation of the station has shown the wooden bay structures, the 34.5kV circuit breaker and all existing relaying (electromechanical) at the station are in need of replacement.

The following line sections have identified asset renewal concerns and many have seen loading greater than 90% under contingency conditions.
New Liberty – North Baltimore 34.5kV: The 10 mile circuit is a combination of 4/0 ACSR and 336 ACSR (circa 1940) with wood structures (Predominately pre-1980's). The line section has 30 open A conditions.
North Findlay – North Baltimore 34.5kV *#1:* The 8 mile circuit identified is predominately 4/0 ACSR (circa 1961) with small portions of 2/0 Copper, 336 ACSR, 556 ACSR, and 795 ACSR. This line has predominantly wood structures (ranging from 1920's – 2000's) with14 open A conditions.
New Liberty – Findlay Center 34.5kV: This 3.3 mile line has a combination of 4/0 Copper, 336 ACSR, and 556 ACSR (circa 1934-1964) with wood structures and 10 open A conditions.
Whirlpool Extension 34.5kV: This 0.15 miles of rebuild identified is 336 ACSR (circa 1967) with wood structures (circa 1967).

<u>Operational Flexibility and Efficiency</u>

There is an existing 34.5kV three terminal line at Morrical Switch and hard taps at in the area that increase outages to customers in the area (Totten and Centrex).

Model: 2022 Summer RTEP



AEP Transmission Zone M-3 Process
Findlay – North Baltimore

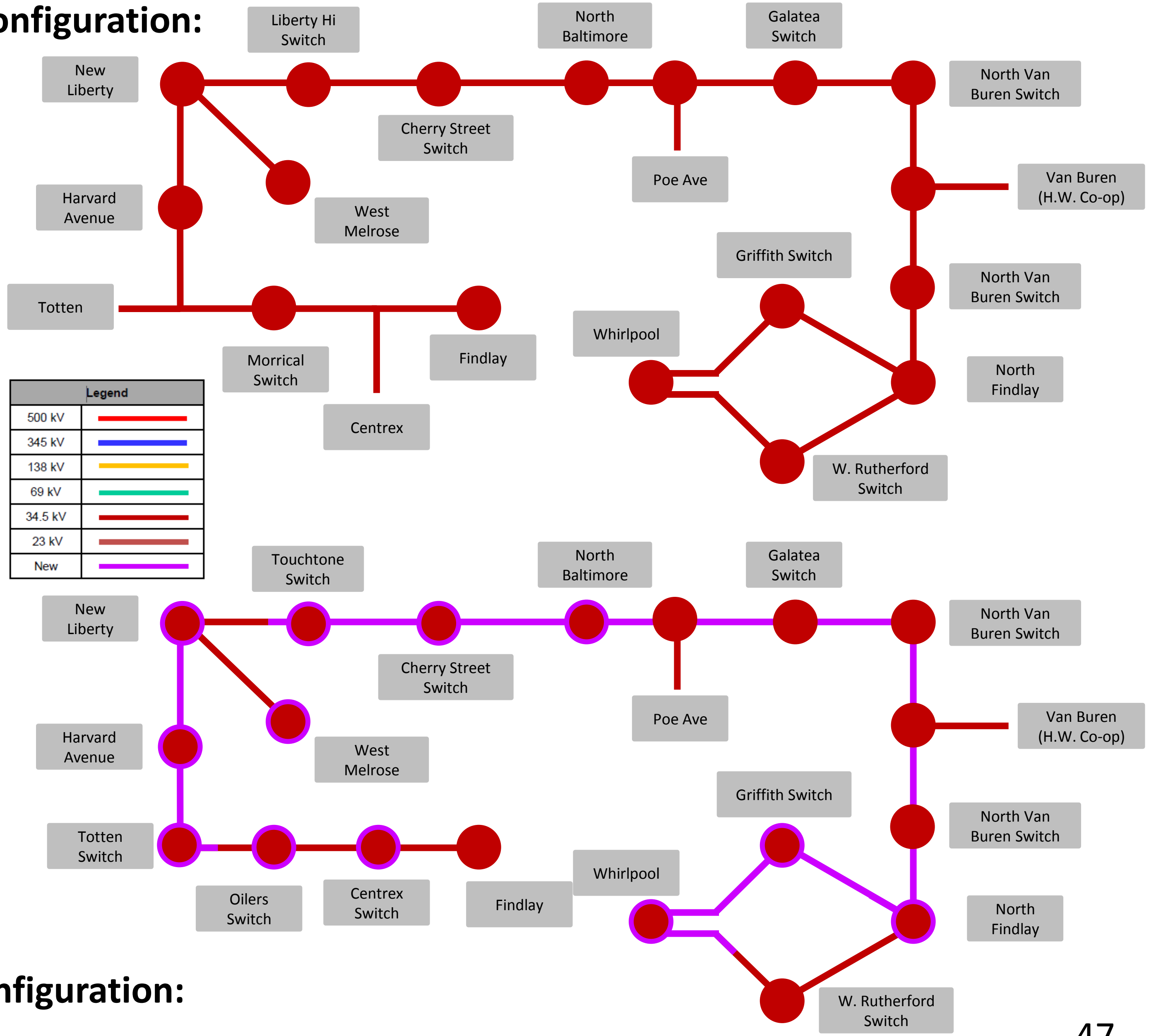
Existing Configuration:

Need Number: AEP-2018-OH007

Process Stage: Solutions Meeting 02/21/2020

Proposed Solution:

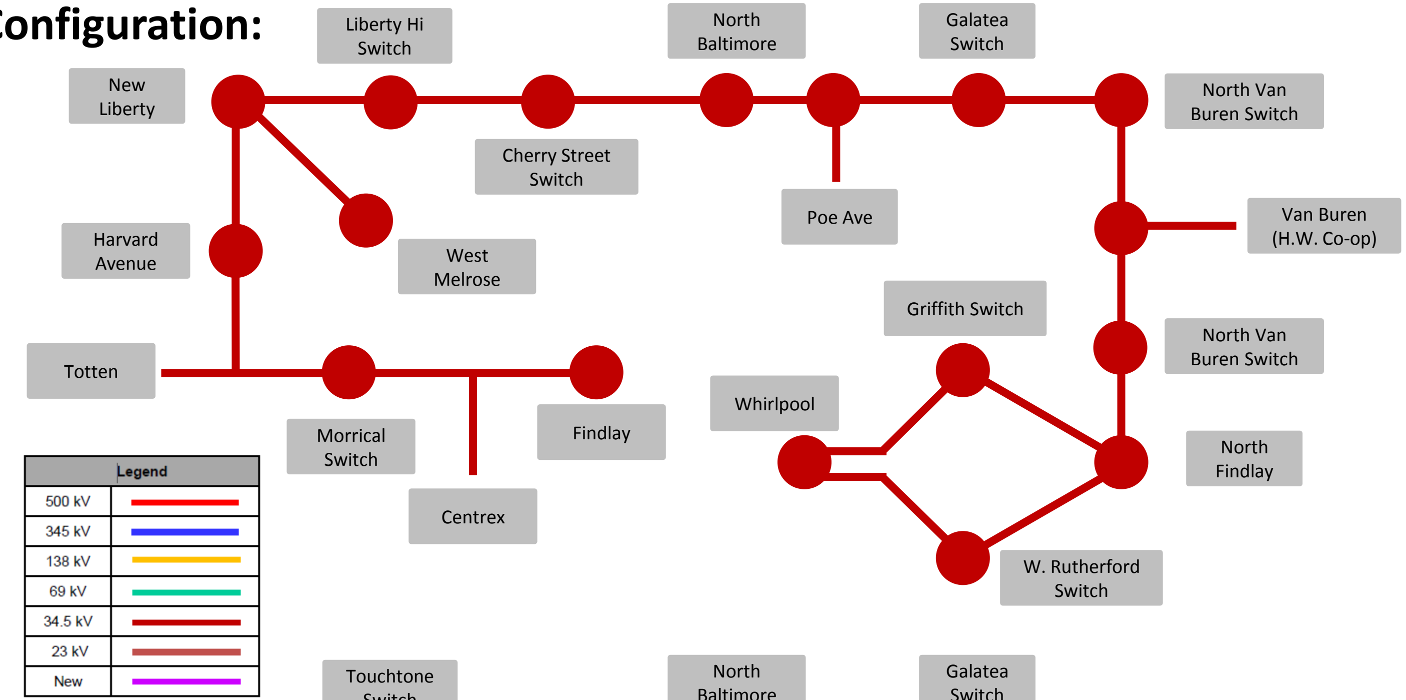
- Rebuild approximately 3.0 miles of New Liberty – North Baltimore 34kV line. **Estimated Cost: $9.3M**
- Rebuild 8.0 miles of North Findlay – North Baltimore #1 34kV line (advanced construction date due to imminent failure). **Estimated Cost: $25.3M**
- Rebuild 0.15 miles of Whirlpool Extension. **Estimated Cost: $0.8M**
- Build 1.0 mile of Oilers Switch Extension. **Estimated Cost: $2.2M**
- Rebuild 2.9 miles of New Liberty – Findlay Center 34kV line. **Estimated Cost: $10.4M**
- At North Findlay station, replace 34.5kV CBs F, G, H, J, K, L with 34.5kV 2000A 40kA breakers. Replace 34.5kV circuit switcher BB (40kA). Replace T1 and T2 with 90MVA 138/69/34kV transformers. **Estimated Cost: $12.1M**
- At New Liberty station, remove existing T1 and T2. Replace with one 90 MVA 138/69/34kV Transformer. Install High Side Circuit switcher for new Transformer. Expand station to build new 34.5 kV ring bus with (6) 2000A 40kA breakers. **Estimated Cost: $11.4M**
- At Oilers switch station, build new ring bus in the clear with (4) 2000A 40kA breakers to replace Morrical switch. **Estimated Cost: $5.3M**
- At North Baltimore station, rebuild station with (4) 2000A 40kA breakers. **Estimated Cost: $4.9M**
- Install three way 1200A switch called "Touchstone" to replace Liberty Hi switch. **Estimated Cost: $0.7M**



Future Configuration:

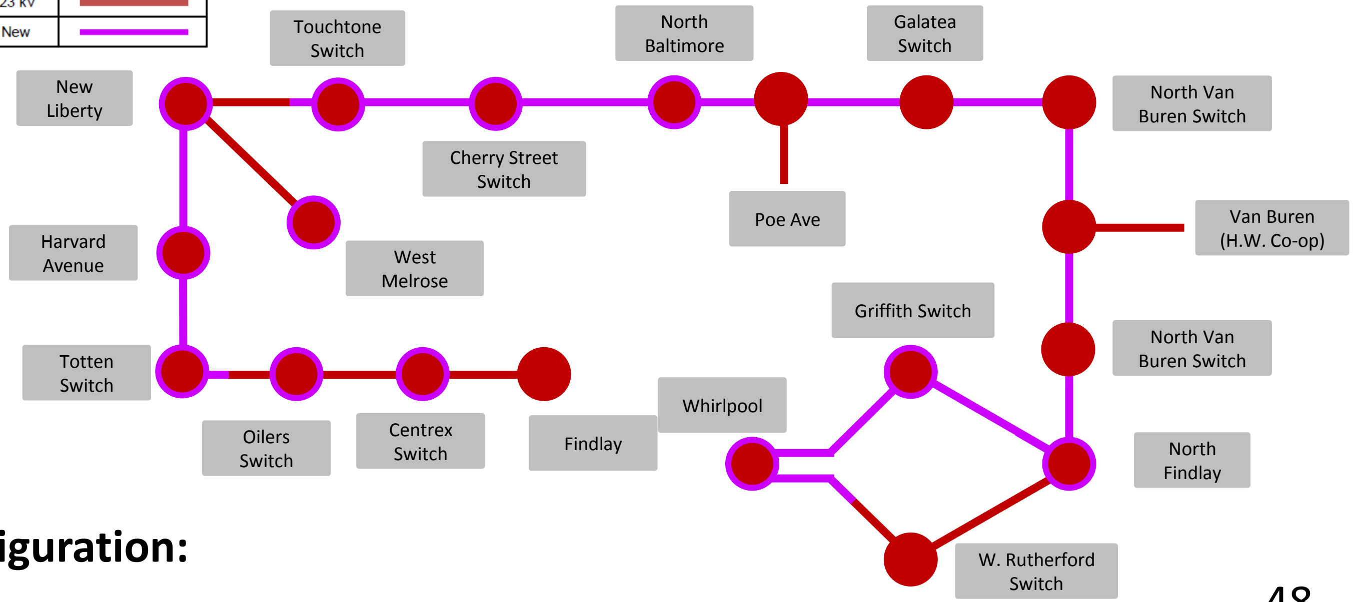
AEP Transmission Zone M-3 Process
Findlay – North Baltimore

Existing Configuration:



- Replace Cherry Street switch with a two way 1200A switch. **Estimated Cost: $0.6M**
- Replace West Melrose switch with 1200A switches. **Estimated Cost: $0.2M**
- Replace Harvard Avenue switch with a three way 1200A switch. **Estimated Cost: $0.6M**
- Install three way 1200A switch called "Totten" to eliminate the hard tap to the customer. **Estimated Cost: $0.6M**
- Install two way 1200A switch called "Centrex" to eliminate the hard tap to the customer. **Estimated Cost: $0.5M**
- Replace Griffith switch with a two way 1200A switch. **Estimated Cost: $0.6M**
- Replace Whirlpool MOABs with 1200A capability. **Estimated Cost: $0.4M**

Total Project Cost: $85.9M



Future Configuration:

Alternatives Considered:

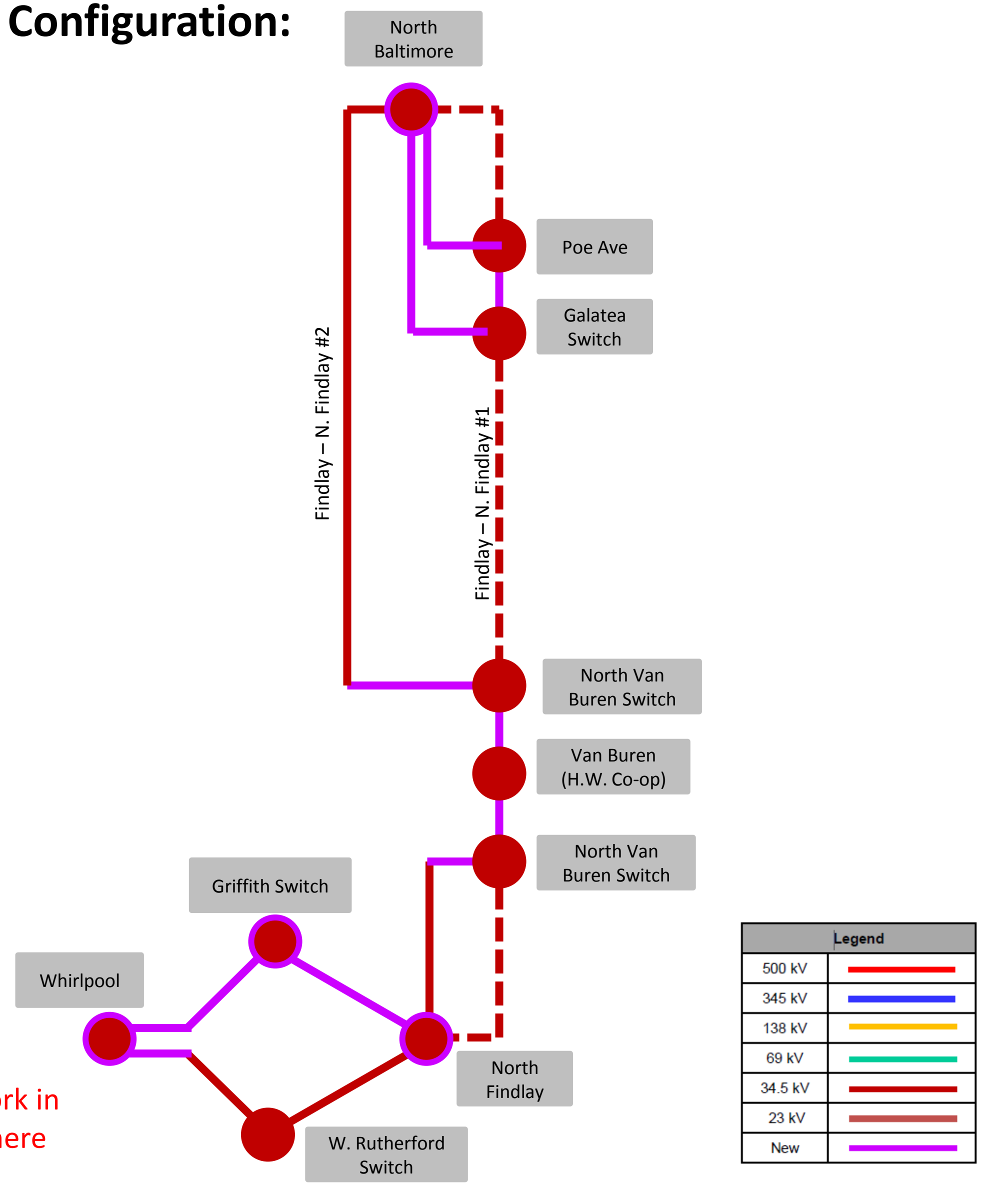
1. Alternate #1 **($98.3M)**

- Rebuild the approximately 1.5 miles of the North Baltimore – North Findlay #1 34.5 kV circuit that is currently double circuit out of North Findlay with the North Findlay #1 – North Findlay #2 34.5 kV circuit as single circuit to continue looped service to customers served out of Griffin, Whirlpool, and West Rutherford switches. This would involve retiring the rest of the 34.5 kV circuit that goes north towards North Baltimore via Van Buren . In order to provide service to the co-op served from the existing North Baltimore – North Findlay #1 circuit that would be retired, a new greenfield 1.1 mile double circuit 34.5 kV line would need to be constructed to loop the customers into the existing North Baltimore – North Findlay #2 circuit (a new crossing of I-75 would be required). An additional 1.6 miles of double circuit 34.5 kV line would be required to be constructed to serve the existing customer at Poe Avenue and service at Galatea switch (a new crossing of I-75 would be required). Under the current proposed solution only certain portions of the ~10 mile New Liberty – North Baltimore 34.5 kV circuit is being rebuilt to allow for flexibility in the future associated with potential developments to the north to address need AEP-2019-OH052 (North Baltimore – Portage 34.5 kV radial). This alternative would eliminate that flexibility and require the entire ~10 mile New Liberty – North Baltimore 34.5 kV circuit to be rebuilt to maintain the existing three sources to the northern Findlay network. The proposed station work would stay mostly unchanged under this alternative. The Whirlpool, Oilers, and New Liberty – Findlay Center line work would also remain unchanged. This alternative was not chosen due to it not being as cost effective as the proposed solution, along with the additional unknowns/impacts associated with the portions of greenfield line construction required.

Projected In-Service: 8/2022

Project Status: Engineering

Alternative Configuration:



**Costs include all the other work in the chosen option not shown here

AEP Transmission Zone M-3 Process
Pickaway, Ohio

Need Number: AEP-2019-OH012

Process Stage: Solutions Meeting 02/21/2020

Previously Presented: Needs Meeting 03/25/2019

Supplemental Project Driver:

Customer Service

Specific Assumption References:

AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions slide 7)

Problem Statement:

- South Central Power is rebuilding Lockbourne 138kV Station due to asset renewal conditions. Lockbourne is currently radially served via AEP's Harrison Station, this line is partially owned by AEP and South Central Power with the point of ownership change being Circleville. The current loading on this radial line is 65MW with plans for increased load. Total CMI 2.7M over 3 year period. (2015-2018).
- Radial service restricts the ability to perform routine maintenance and can cause extended outages to customers. The maintenance of radial transmission lines often requires cost-prohibitive temporary facilities or other labor-intensive measures.

AEP Transmission Zone M-3 Process
Pickaway, Ohio

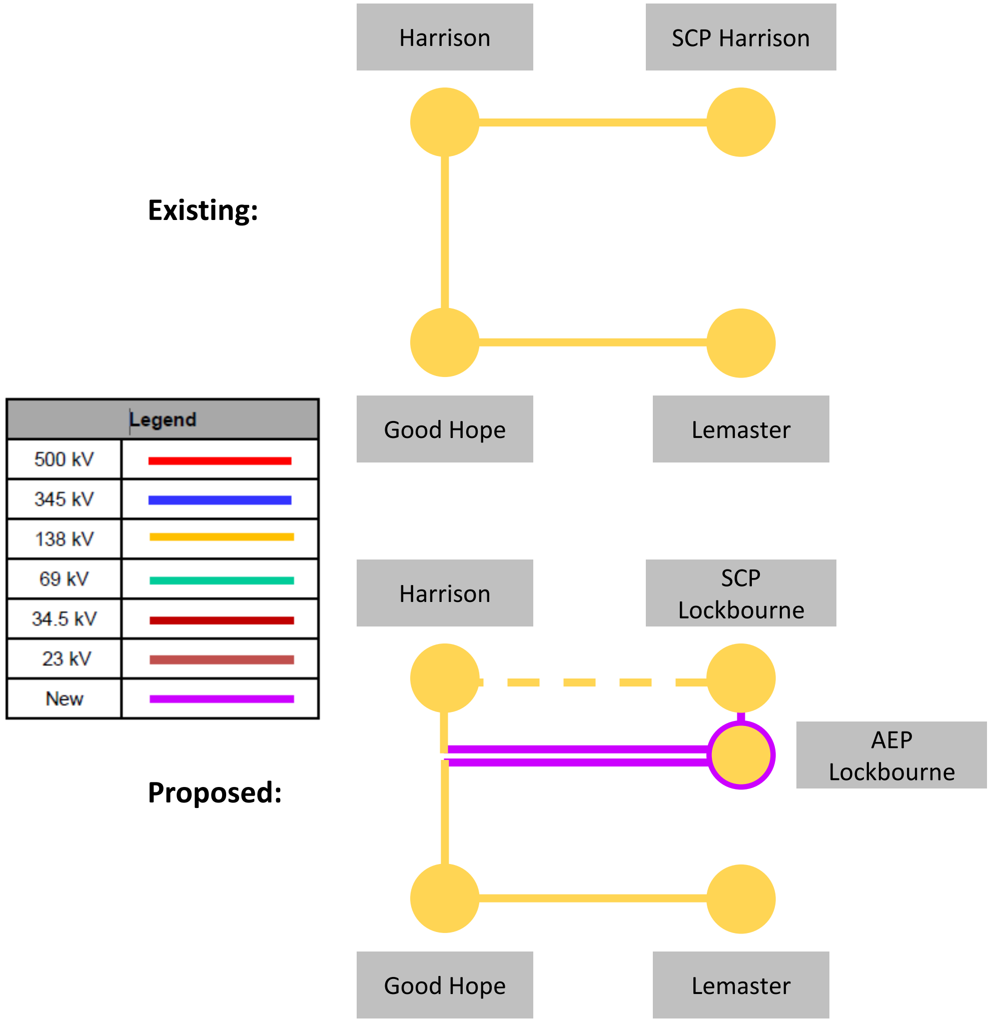
Need Number: AEP-2019-OH012

Process Stage: Solutions Meeting 02/21/2020

Proposed Solution:

- Build new 0.3 mile double circuit 138kV extension from the Harrison – Lemaster 138kV Circuit to the new Lockbourne 138kV station Fiber will also be installed on the line. **Cost: $2.0M**
- Remove the existing 138 kV radial line from AEP Harrison to SCP Harrison station. **Cost: $0.3M**
- Build three short lines to interconnect to SCP's Lockbourne station to serve their three transformers. **Cost: $0.1M**
- Build a new 138kV five (5) breaker switch station (Lockbourne) with 3000A 40kA breakers and a capacitor bank (28.8 MVAR) to provide service to three SCP deliveries at the site. **Cost: $11.1M**
- Remove existing breaker 3E from the ring bus at Harrison. **Cost: $0.3M**

Total Estimated Transmission Cost: $13.8M



Alternatives Considered:

No other alternates have been identified by the customer to serve their needs.

Projected In-Service: 09/23/2021

Project Status: Scoping

AEP Transmission Zone M-3 Process
Cameron Customer Service

Need Number: AEP-2018-OH032

Process Stage: Solutions Meeting 02/21/2020

Previously Presented: Needs Meeting 1/11/2019

Supplemental Project Driver:

Customer Service

Specific Assumption Reference:

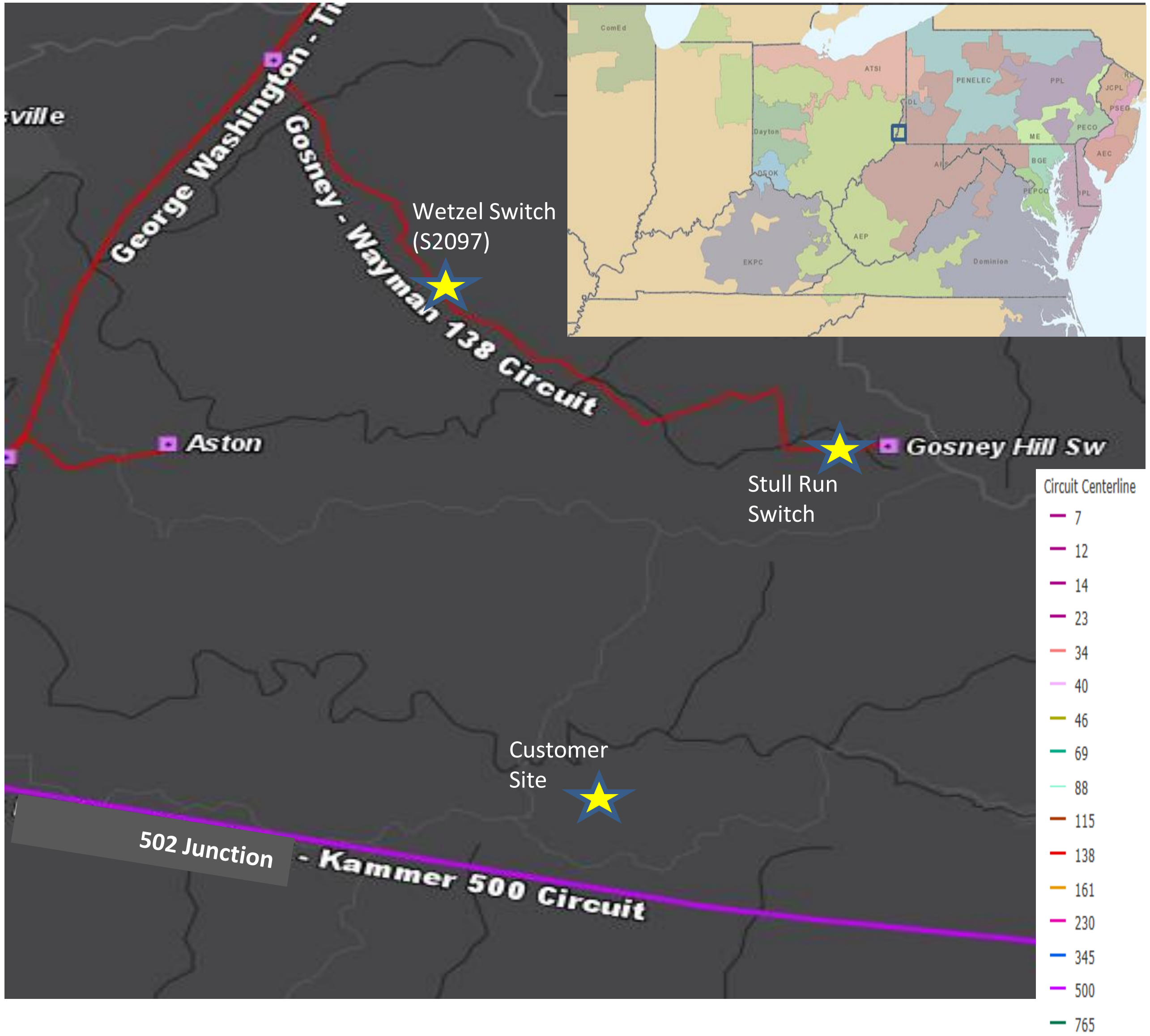
AEP Connection Requirements for the AEP Transmission System (AEP Assumptions Slide 7)

Problem Statement:

A customer has requested new service west of Cameron, West Virginia. The forecasted peak demand is 30 MW initially, with long-term prospects of 90 MW.

With the addition of this customer load, plus the new customer load on S2097 (AEP-2019-OH006), the Wayman-Gosney-Nauvoo Ridge 138kV radial line has an MVA-mile demand of 1142, far exceeding AEP's guideline of 75 MVA-miles.

Model: Summer RTEP 2024



Need Number: AEP-2018-OH032

Process Stage: Solutions Meeting 02/21/2020

Proposed Solution:

Construct a new 500-138kV station (Panhandle), connecting to the Kammer-502 Junction 500kV circuit (~10.3 miles from Kammer, 31.7 miles from 502 Junction). Install a 3-breaker 500kV ring bus; 450 MVA 500-138kV transformer; 3-breaker 138kV ring bus. **Estimated Cost: $25.0 M**

Construct a new 138kV switching station (Nauvoo Ridge) with 8- 138kV breakers in a breaker-and-a-half design. The station will have 1 circuit to Gosney Hill, 2 circuits to the customer's facility, 2 circuits to Panhandle, and a 23 MVAR 138kV cap bank. **Estimated Cost: $16.4 M**

At Gosney Hill, install a new 138kV breaker toward Nauvoo Ridge. Update station protection. **Estimated Cost: $1.0 M**

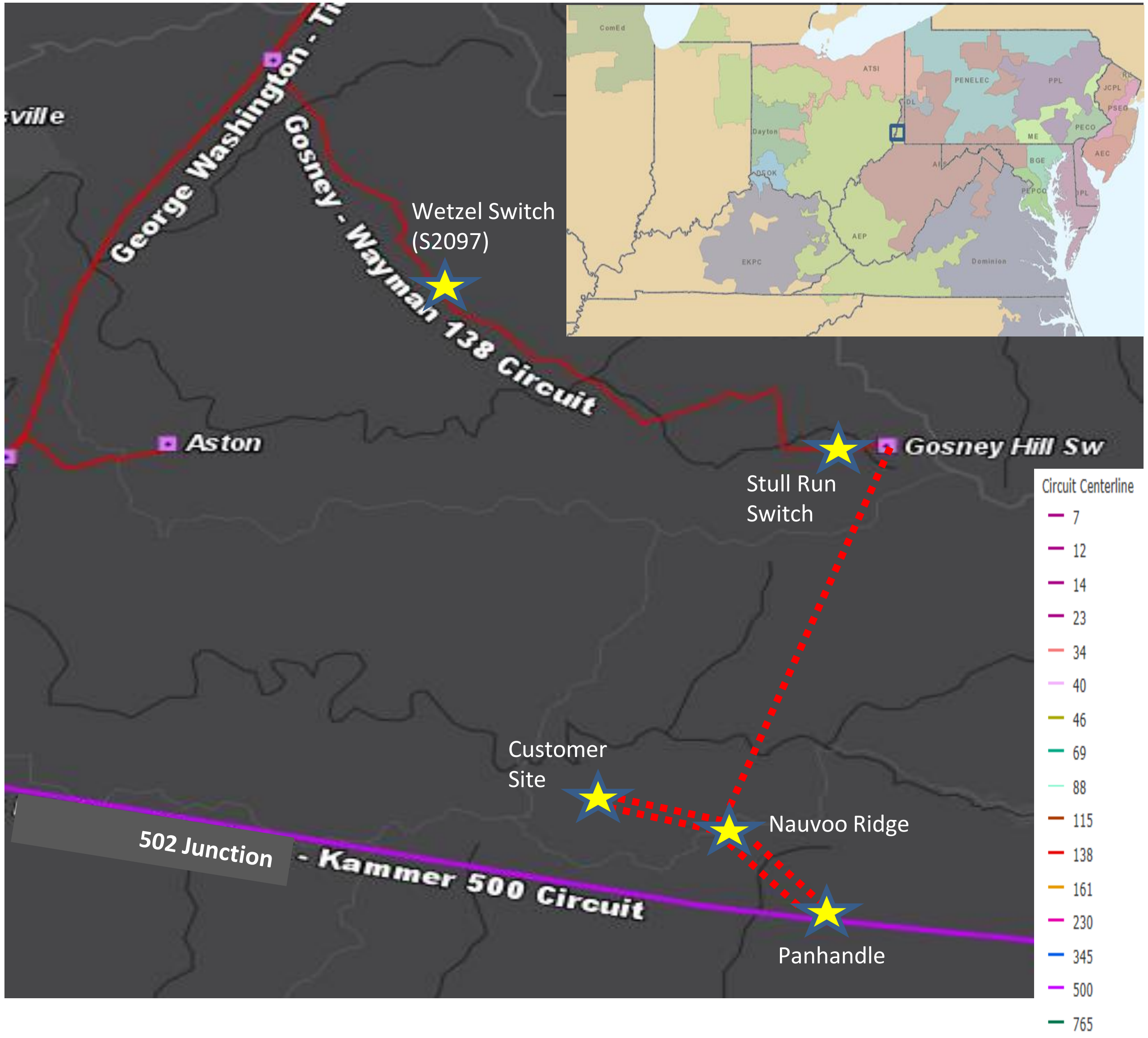
Construct a new 4.7-mile 138kV line south of Gosney Hill station to Nauvoo Ridge. Utilize 1033 ACSR conductor. Acquire new right-of-way. **Estimated Cost: $14.7 M**

Construct a new 1.3 mile double-circuit 138kV line from Nauvoo Ridge to the customer's substation. Acquire new right-of-way. **Estimated Cost: $4.8 M**

Construct a new 1.5 mile double-circuit 138kV line from Panhandle to Nauvoo Ridge. Utilize 1033 ACSR conductor for each circuit. Acquire new right-of-way. **Estimated Cost: $5.0 M**

Extend the Kammer-502 Junction 500kV transmission line 0.1-mile into Panhandle station (0.2 mile total). **Estimated Cost: $1.5 M**

Total Estimated Transmission Cost: $68.4 M



AEP Transmission Zone M-3 Process
Cameron Customer Service

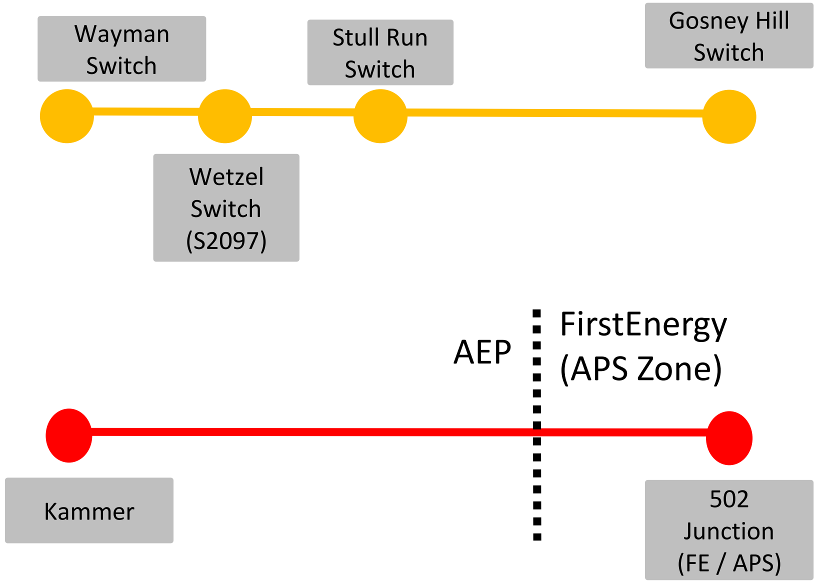
Need Number: AEP-2018-OH032

Process Stage: Solutions Meeting 02/21/2020

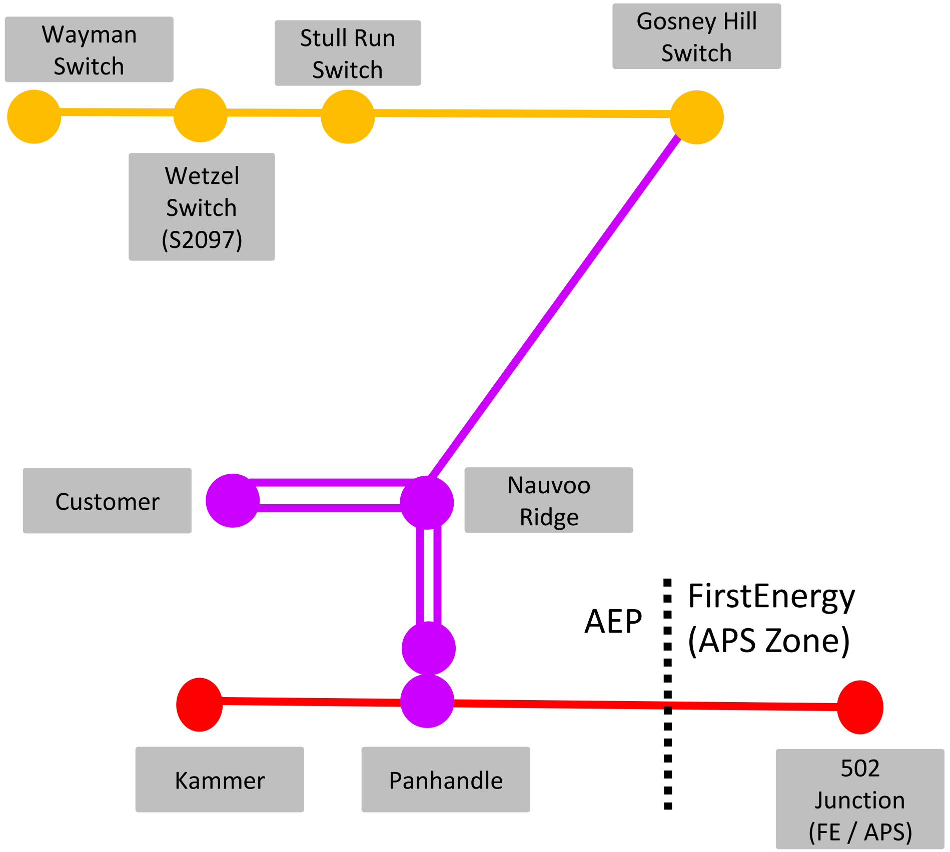
Proposed Solution:

Legend	
500 kV	
345 kV	
138 kV	
69 kV	
34.5 kV	
23 kV	
New	

Existing:



Proposed:



Need Number: AEP-2018-OH032

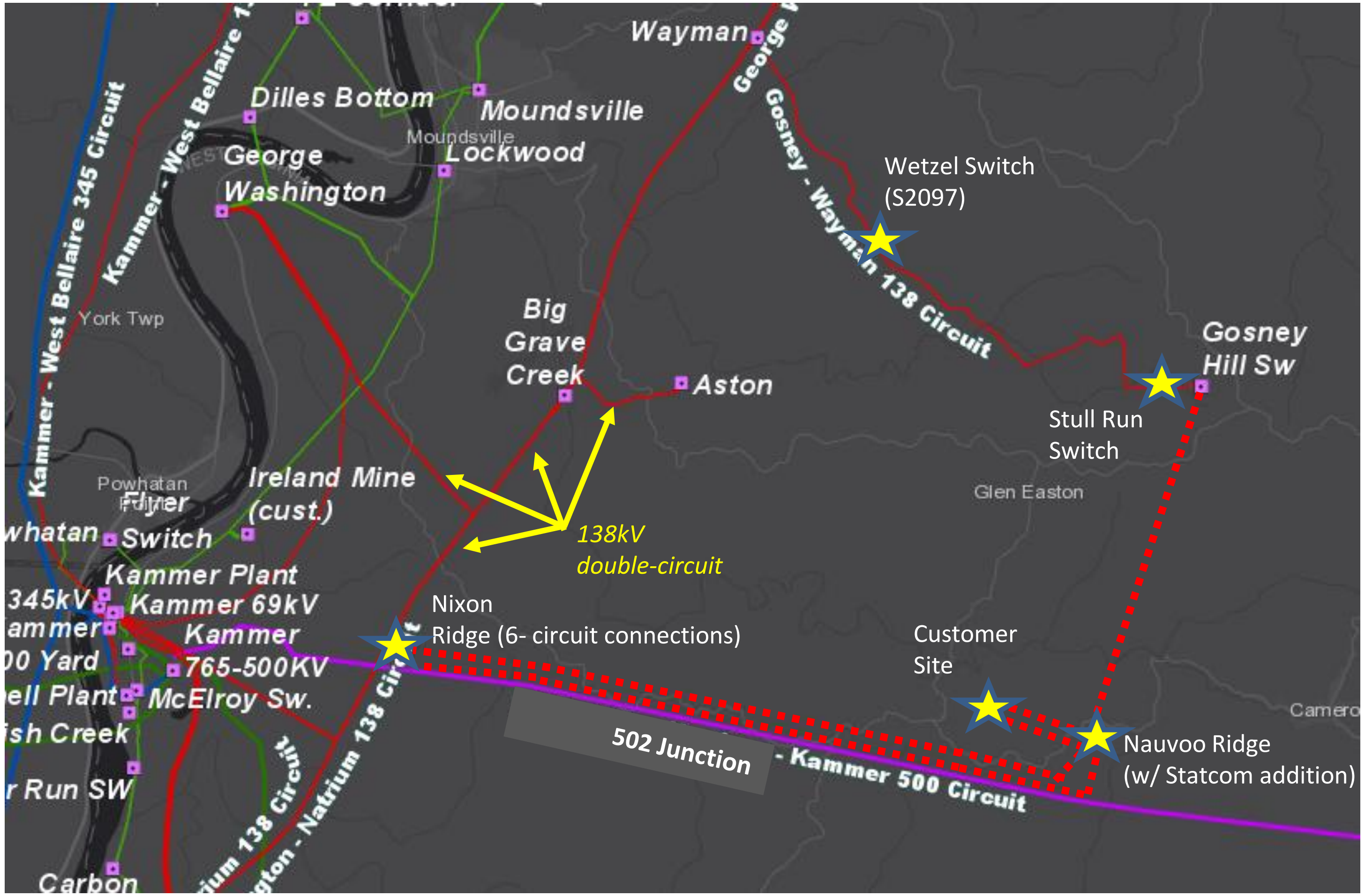
Process Stage: Solutions Meeting 02/21/2020

Alternatives Considered:

Construct a new 9-breaker switching station (Nixon Ridge, breaker-and-a-half) at the crossing of the Kammer-502 Junction 500kV line & 138kV double-circuit corridor (3 miles east of Kammer), looping in the Aston-Kammer 138kV & George Washington-Natrium 138kV circuits, plus 2 new circuits to Nauvoo Ridge. Remote-end 138kV protection & RTU updates at Aston, Kammer, George Washington & Natrium stations. Build a 9-mile 138kV double-circuit line from Nixon Ridge east to Nauvoo Ridge. *Keep the remaining scope between Gosney-Nauvoo-New Customer 138kV*. This solution resulted in several violations, as it strains the local 138kV system, as the only EHV sources in the region are at Kammer & West Bellaire. Overloads on Kammer-Nixon Ridge 138kV, near-overload on Kammer-Natrium 138kV (would overload with a pending customer project). In addition, N-1-1 voltage violations of 0.90-0.92 pu in the area; to rectify this, more cap banks could be placed, but due to 6 in the region already, switching conflicts (hunting) would likely arise. To mitigate these violations, this alternate would require a reconductor or rebuild 18 miles of 138kV lines and install a 138kV +/- 75 MVAR Statcom system in the area, for dynamic voltage support. **Total Cost of $120 Million**

Projected In-Service: 7/21/2020 (for initial 138kV service to the customer). 3/1/2022 (for the 2nd phase to construct Panhandle station and complete the 138kV loop).

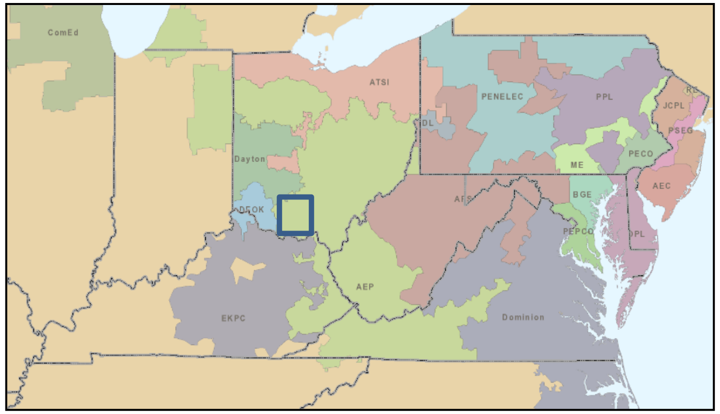
Project Status: Engineering (for initial customer service project); Scoping (for 2nd phase)

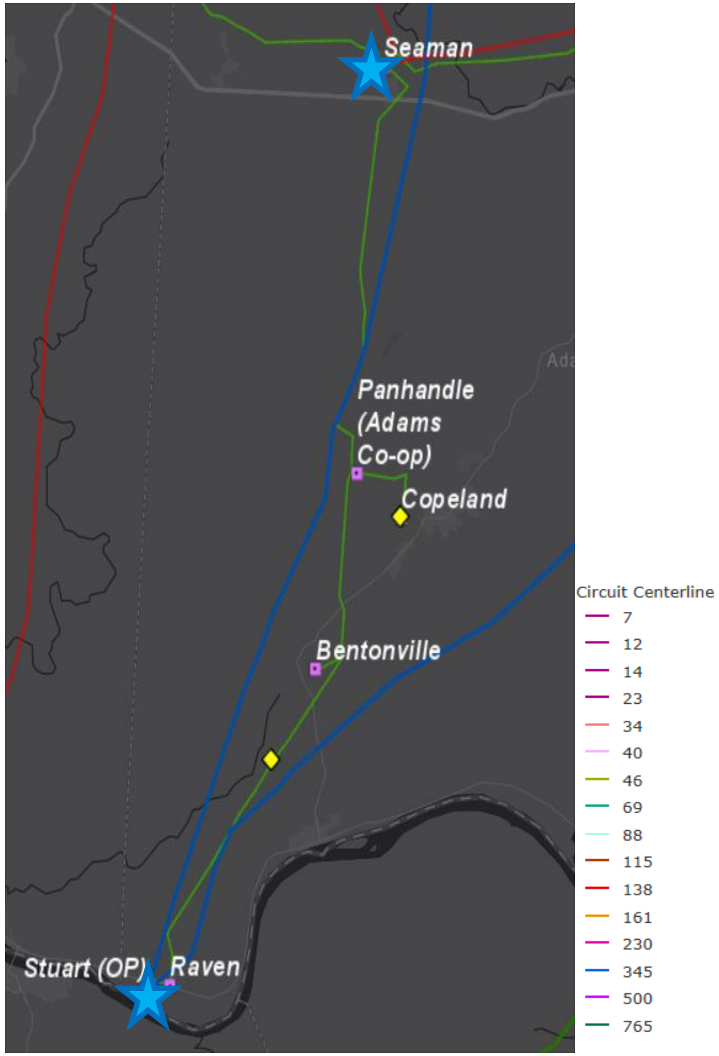


AEP Transmission Zone M-3 Process
Adams County, Ohio

Need Number: AEP-2019-OH014
Process Stage: Solutions Meeting 02/21/2020
Process Chronology: Needs Meeting 04/23/2019
Supplemental Project Driver: Equipment Material/Condition/ Performance/Risk
Specific Assumptions Reference: AEP Guidelines for Transmission Owner Identified Needs
Problem Statement:

- The existing 28.5 mile, 69 kV line section between Stuart (DP&L/Duke) and Seaman(AEP) was constructed in 1974 using wood pole structures with 636 ACSR conductor. There are 260 open conditions distributed across the 170 structures on this line.
- The Stuart-Seaman 69 kV circuit has experienced over 2.2 million customer minutes of interruption in the past three years: 753,716 for AEP and 1,517,618 for Adams Coop.





Need Number: AEP-2019-OH014
Process Stage: Solutions Meeting 02/21/2020
Proposed Solution:

Rebuild 22.0 miles of the existing 28.5 mile Stuart-Seaman 69kV circuit with 795 ACSR. Retire approximately 3 miles of the line between West Union and structure 86. 32 of the line's 170 structure were replaced since 2012 and will not be replaced as part of the rebuild
Estimated Cost: $48.5M

Construct approximately 2.5 miles of new line from structure 86 on the Stuart – Seaman 69 kV line to Copeland station utilizing 795 ACSR. **Estimated Cost: $5.0M**

Rebuild the 2.0 mile West Union – Copeland 69 kV line utilizing 795 ACSR. The line is part of the Stuart – Seaman 69 kV circuit and is currently radial fed from West Union switch. **Estimated Cost: $4.0M**

Establish a four breaker 69 kV ring (3000A, 40kA) at the existing Copeland station to serve the Adams Co-op and AEP Ohio customers currently served from a hard tap at the end of the radial. **Estimated Cost: $5.0M**

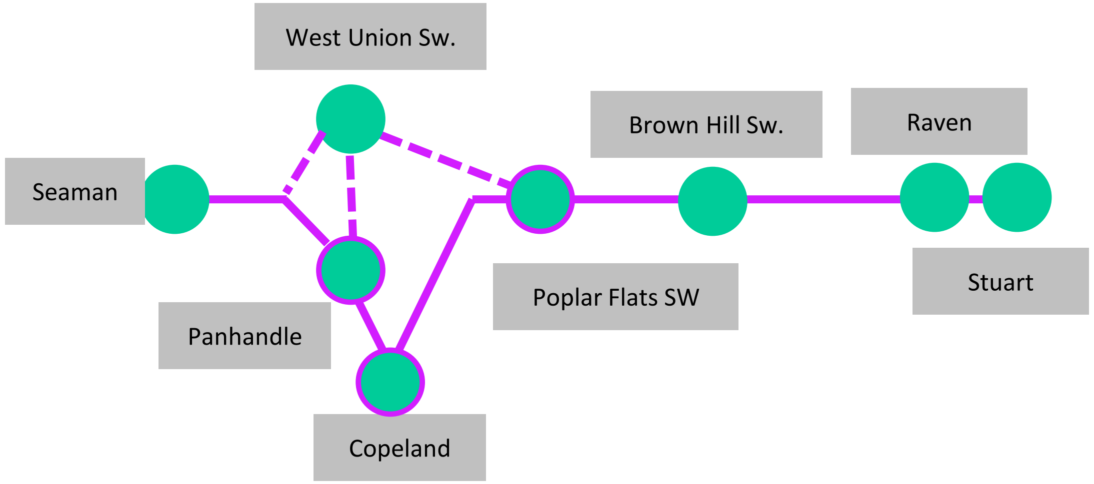
Retire existing West Union Switch
Estimated Cost: $0.1M

Install new 2000A 3-way phase over phase switch at Panhandle
Estimated Cost: $0.7M

Replace the existing Poplar Flats switch with a new 2000A 3-way phase over phase switch.
Estimated Cost: $0.7M

Remote end upgrade and equipment relocation work will be required at Seaman station to accommodate the new line at the station.
Estimated Cost: $1.0M

Total Estimated Transmission Cost: $65.0M

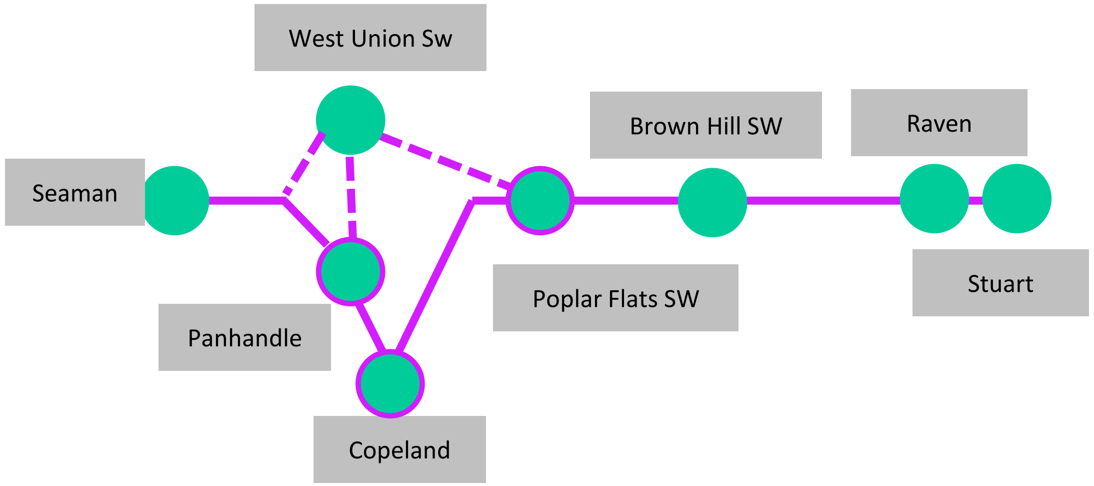


Legend	
500 kV	
345 kV	
138 kV	
69 kV	
34.5 kV	
23 kV	
New	

Need Number: AEP-2019-OH014
Process Stage: Solutions Meeting 02/21/2020
Proposed Solution:

Alternatives:
Alternate #1
Rebuild the existing 28.5 mile Stuart – Seaman 69 kV circuit leaving the existing configuration. The Panhandle and Poplar Flats switches would still require replacement. Station work would still be required at Seaman station. The existing West Union switch would require replacement rather than being retired. This alternative was not chosen as it would leave the existing radial and hard tapped configuration between West Union switch and Copeland station for a similar if not higher cost overall. In addition, rebuilding the line between West Union and Copeland would be difficult from a constructability perspective due to the radial nature of the line. **$65.9M**

Projected IS Date: 12/01/2024
Project Status: Scoping



Legend	
500 kV	
345 kV	
138 kV	
69 kV	
34.5 kV	
23 kV	
New	

Need Number: AEP-2019-OH024

Process Stage: Solutions Meeting 02/21/2020

Previously Presented: Needs Meeting 05/20/2019

Supplemental Project Driver:

Equipment Condition/Performance/Risk

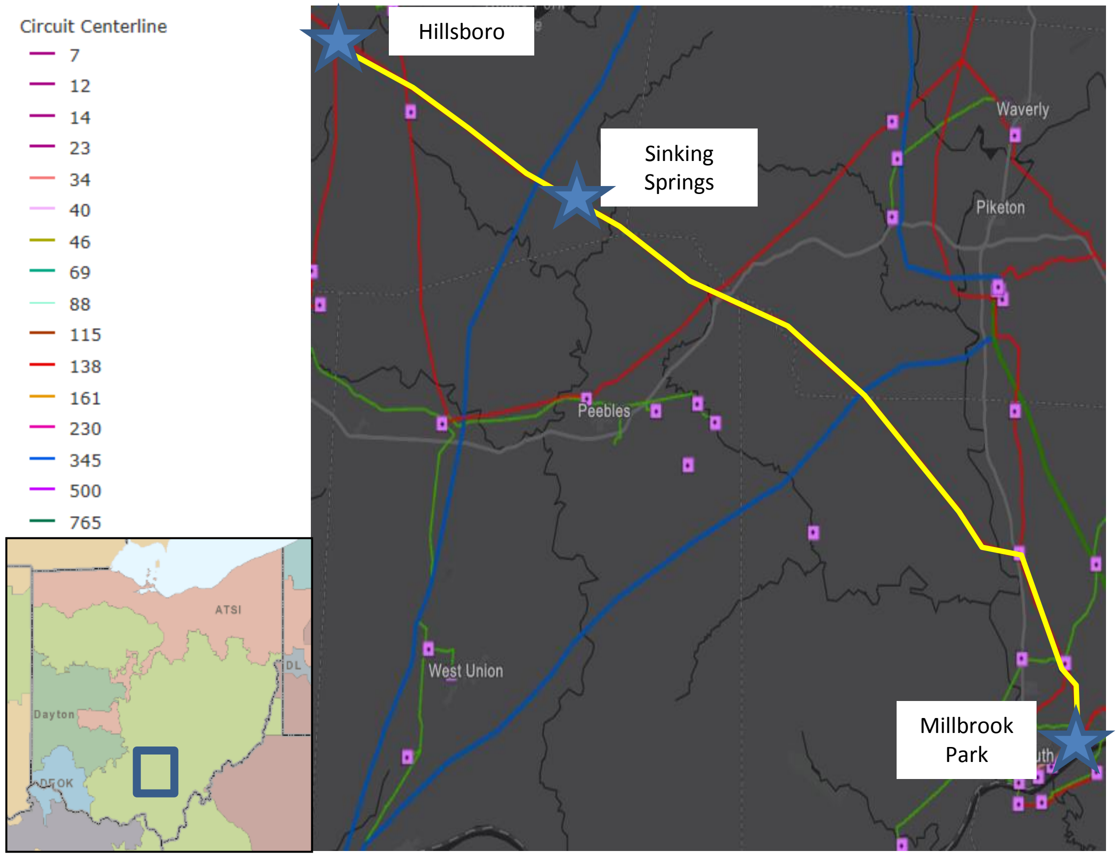
Specific Assumption Reference:

AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

- The 1943 Hillsboro – Millbrook Park 138 kV circuit (~52 miles) is wood pole construction and has 1,342 open conditions.
- The majority (93%) of the original conductor (vintage 1944 & 1948) is 477 MCM (26/7) ACSR and is still in-service.
- Half of the wood pole structures from the 1940's are still in-service; the remaining are a mixture from 1960's – 1980's.
- There are additional concerns with the shielding, grounding, and hardware along this 52 mile long line.
- Sinking Springs is in a remote part of AEP's service territory making manual switching difficult.
- Originally installed in 1942-1943 timeframe. 98% of the line is on wood structures.
- Age Profile: 53% from 1940's; 4.4% from 1960's; 13% from 1970's; 27% from 1980's; 2.6% from 2000's

Model: N/A



AEP Transmission Zone M-3 Process
Hillsboro – Millbrook Park 138 kV Line Rebuild

Need Number: AEP-2019-OH024

Process Stage: Solutions Meeting 02/21/2020

Proposed Solution:

Portsmouth – Trenton #1 & #2 138kV Cost: $126.1M

Rebuild 43.4 miles single circuit line between Hillsboro – South Lucasville with 1033 ACSR. **Estimated Cost:$92.5M**

Rebuild 8.5 miles double circuit between Millbrook Park – South Lucasville with 1033 ACSR. **Estimated Cost: $33.6M**

Install a new 3-way 2000A 138kV, phase over phase switch at Sinking Springs. **Estimated Cost: $0.7M**

Total Estimated Transmission Cost: $126.8M

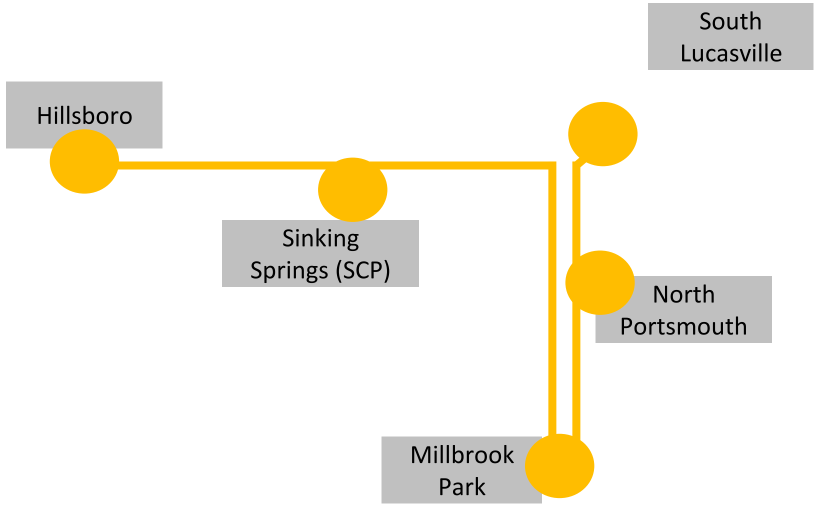
Alternatives Considered:

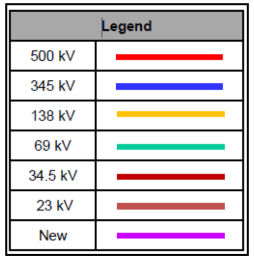
No viable cost-effective transmission alternative was identified.

Projected In-Service: 09/30/2022

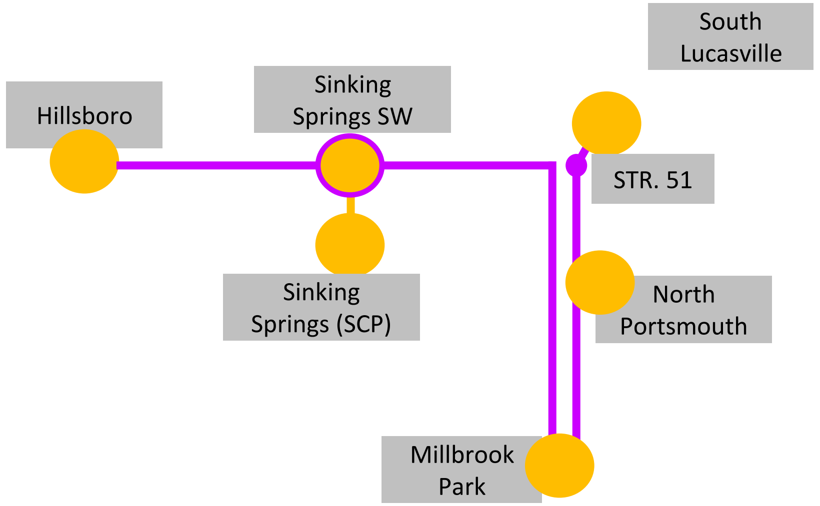
Project Status: Scoping

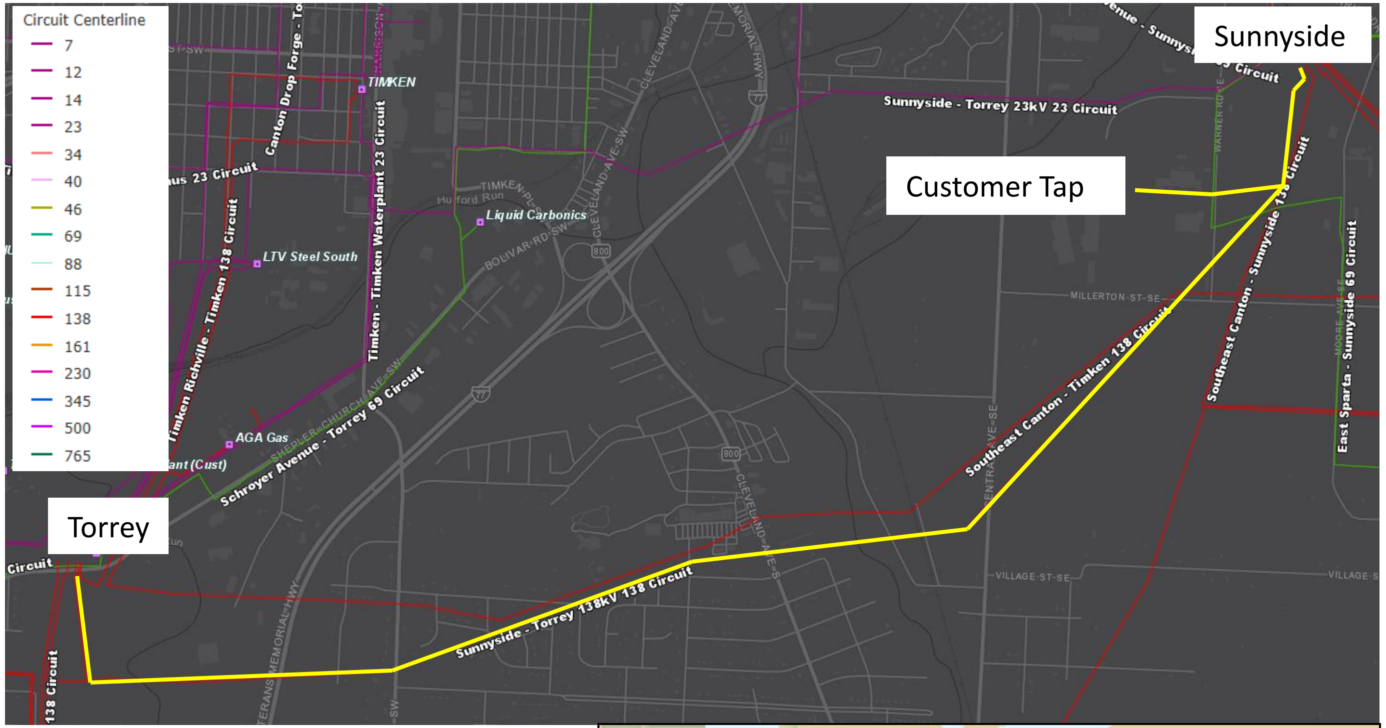
Existing:

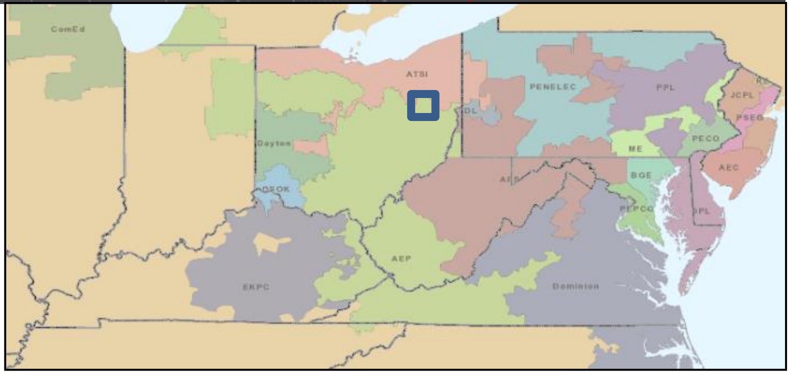




Proposed:







Need Number: AEP-2019-OH027

Process Stage: Solutions Meeting 2/21/2020

Previously Presented: Needs Meeting 5/20/2019

Supplemental Project Driver:

Equipment/Material/Condition/Performance/Risk

Specific Assumption Reference:

AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

- The majority (94%) of the Sunnyside-Torrey 138 kV line (4.3 miles) is comprised of steel lattice towers built in 1918, with the remaining 6%, dating back to 1954.
- The conductor is original vintage (1918), consisting of 6-wired 200 MCM copper & 250 MCM copper.
- Note that the 0.3-mile customer tap was built in 2007 and is in adequate condition.

Need Number: AEP-2019-OH027

Process Stage: Solutions Meeting 2/21/2020

Proposed Solution:

Rebuild the 4-mile Sunnyside-Torrey 138kV circuit. Supplement the existing right-of-way as needed, to resolve encroachments and other constraints.

Cost estimate: $12.7 Million

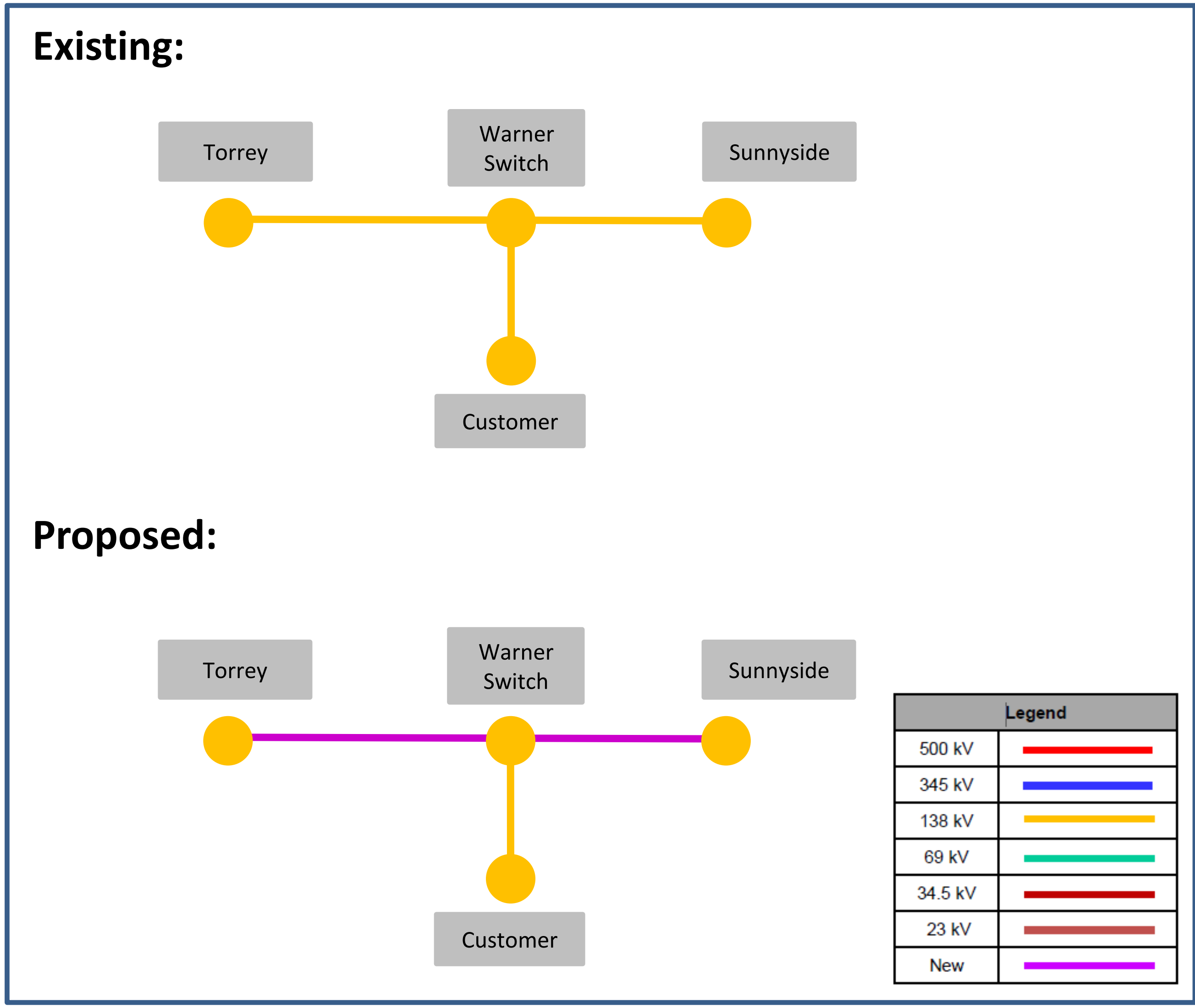
Ancillary Benefits: Improved reliability for the industrial customer served from the circuit.

Alternatives Considered:

No viable cost-effective alternative was identified.

Projected In-Service: 8/1/2022

Project Status: Scoping



Need Number: AEP-2019-OH043

Process Stage: Solutions Meeting 2/21/2020

Previously Presented: Need Meeting 7/24/2019

Supplemental Project Driver:
Equipment Material/Condition/Performance/Risk

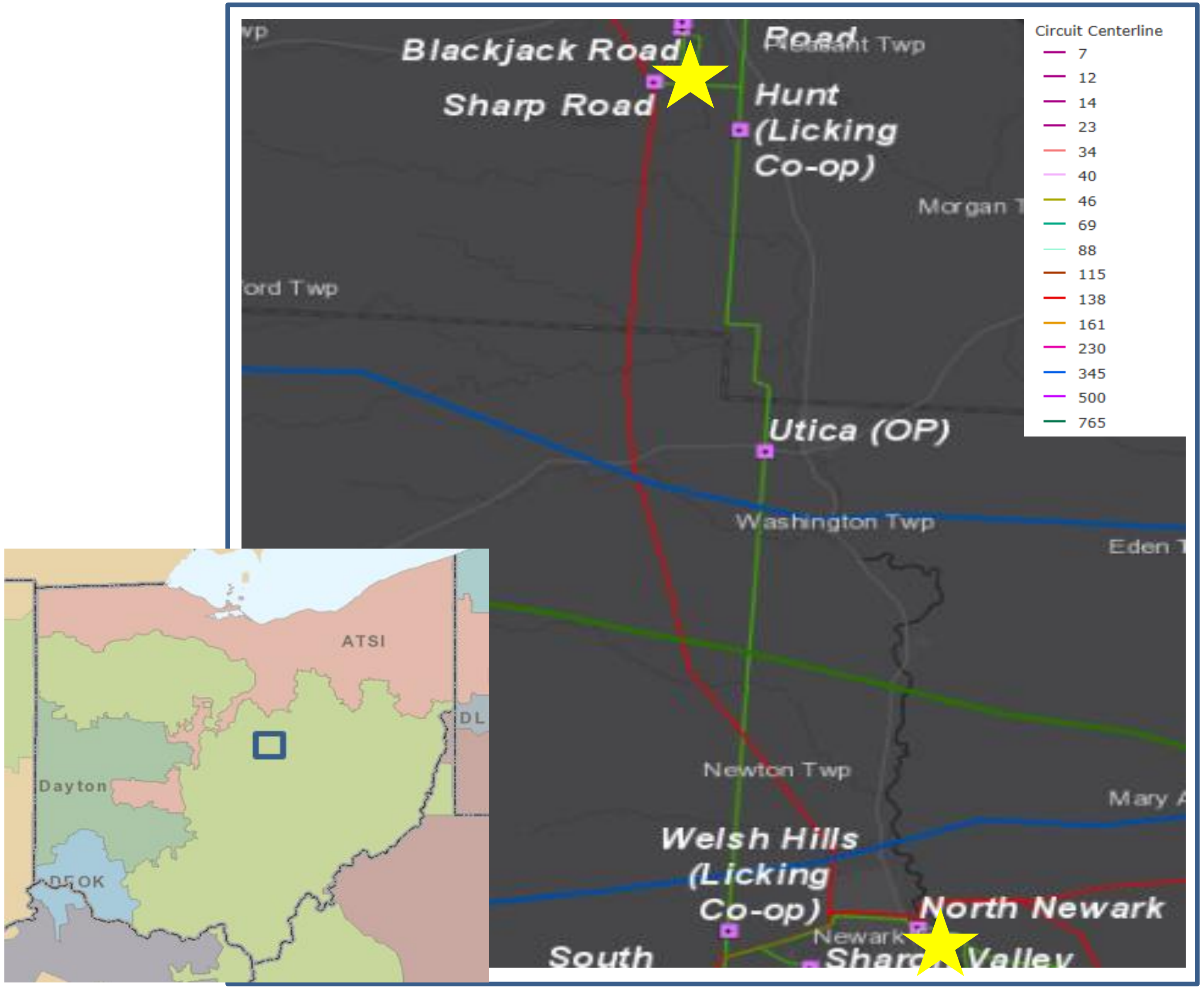
Specific Assumption References:
AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

North Newark – Sharp Road 138kV (vintage 1951)

- Length: 19.38 Miles
- Original Construction Type: Wood Pole
- Original Conductor Type: 477 KCM Hawk
- Number of open conditions: 68
  - Open conditions include: Burnt insulators, insect damage, pole rot, woodpecker damage

Model: N/A



Need Number: AEP-2019-OH043

Process Stage: Solutions Meeting 2/21/2020

Proposed Solution:

- Rebuild the existing 138kV line with 19.4 miles of new 1033 ACSR.

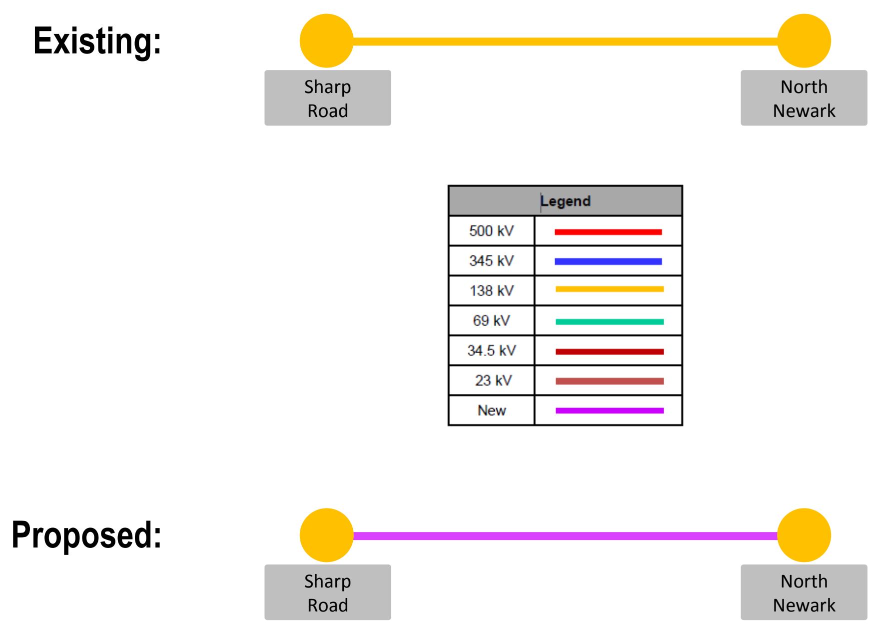
Estimated Cost: $42.2M

Alternatives Considered:

No viable cost-effective transmission alternative has been identified as this line helps support the New Albany area and has seen increased loading due to 1,600 MW of data center demand over the past 5 years with more expected in the coming years.

Projected In-Service: 7/1/2023

Project Status: Scoping



AEP Transmission Zone M-3 Process
Culbertson 138kV Greenfield Station

Need Number: AEP-2019-OH051

Process Stage: Solutions Meeting 02/21/2020

Previously Presented:

Need Meeting 9/25/2019

Supplemental Project Driver:

Customer Service

Specific Assumption Reference:

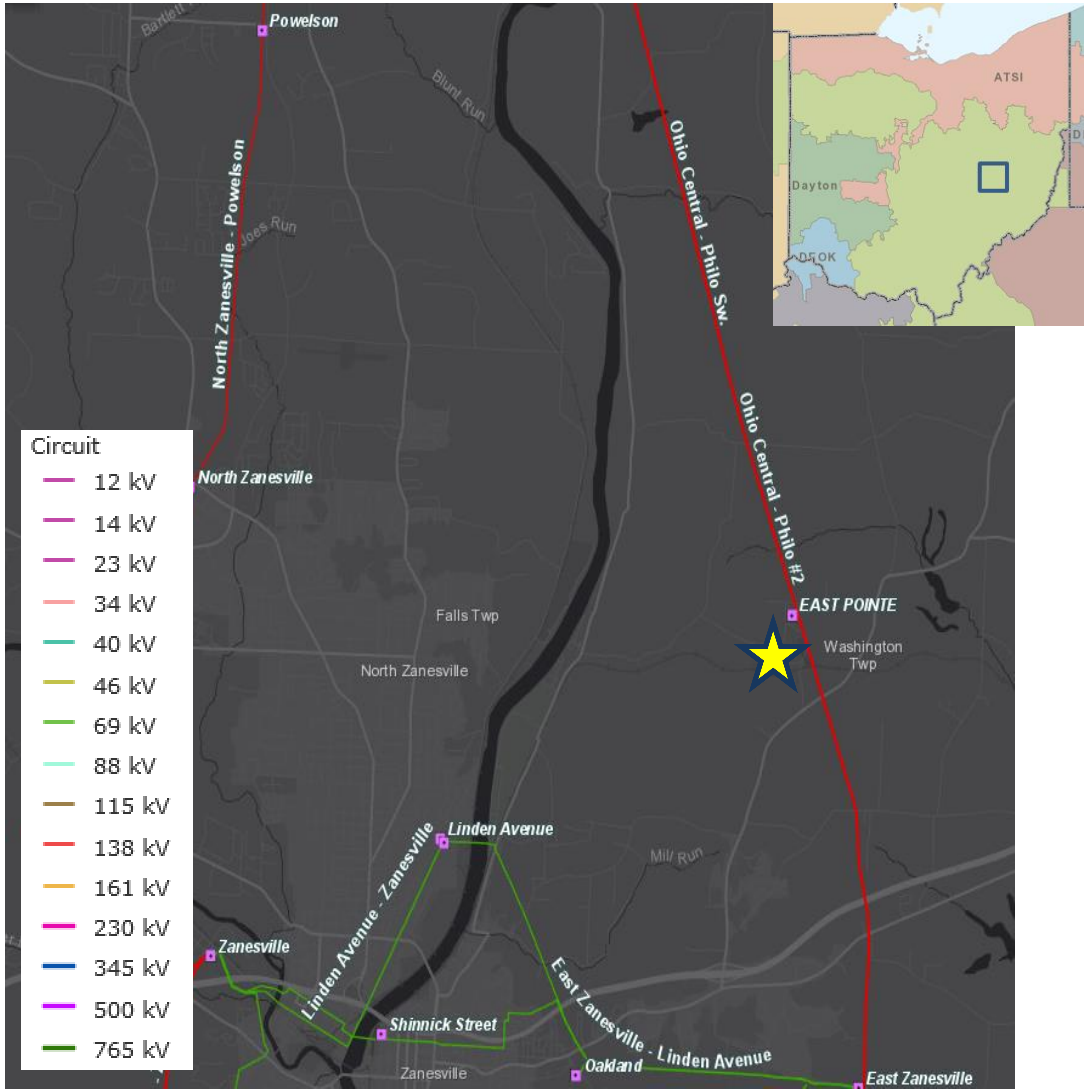
AEP Connection Requirements for the AEP Transmission System (AEP Assumptions Slide 7)

Problem Statement:

Customer Service:

- Peak load: 30MW
- A customer has requested new service on the Ohio Central – Philo #1 138 kV circuit.

Model: 2024 RTEP



Culbertson 138kV Greenfield Station

Need Number: AEP-2019-OH051

Process Stage: Solutions Meeting 02/21/2020

Proposed Solution:

- Install approximately 0.5 Miles of 138kV double circuit line to tie the greenfield Culbertson station to the Ohio Central – Philo #1 138kV circuit. **Estimated Cost: $1.9M**
- Culbertson 138kV: Install 4 greenfield 138kV 2000A 40kA CBs in a ring bus configuration to serve the new customer station. **Estimated Cost: $8.0M**

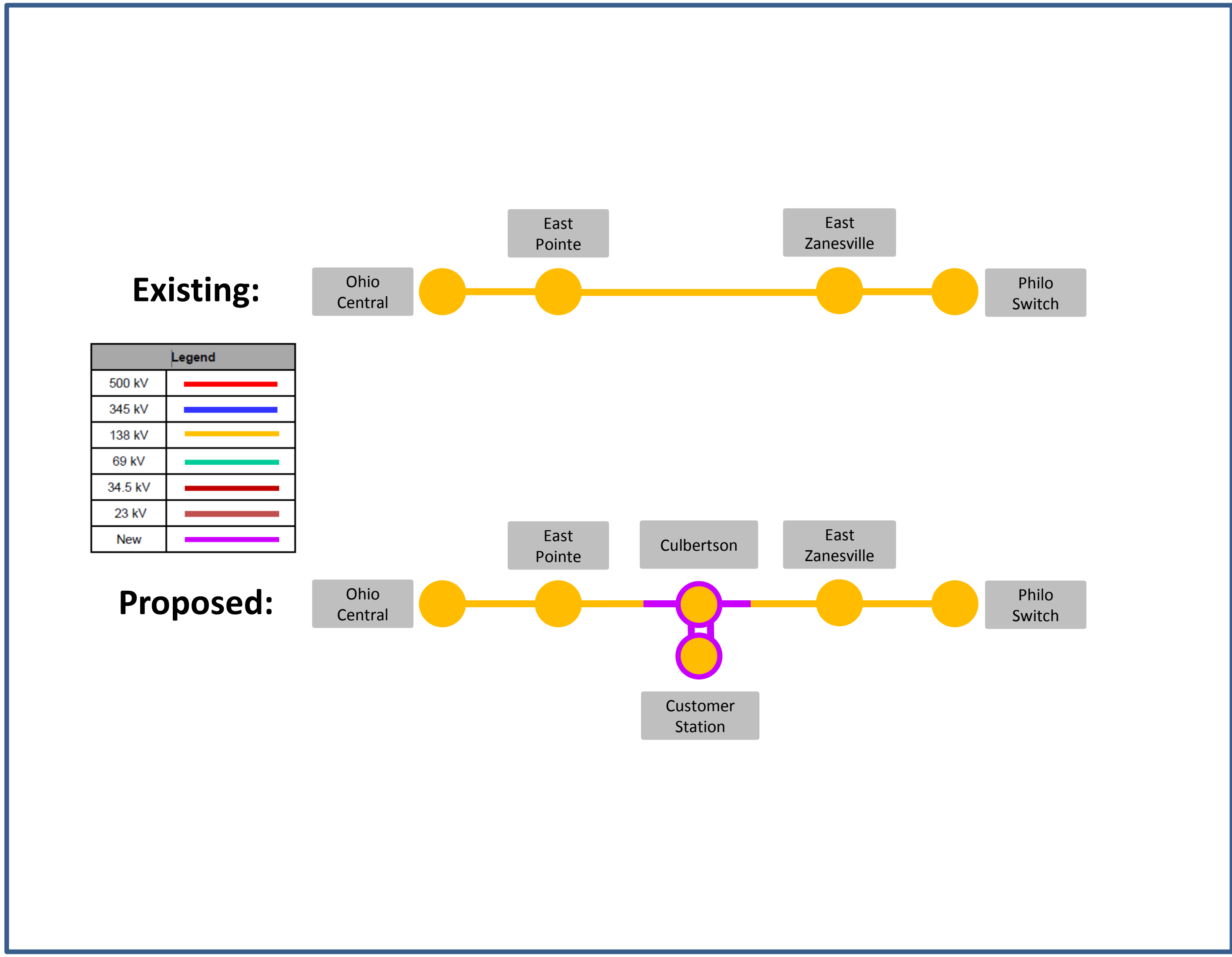
Total Estimated Transmission Cost: $9.9M

Alternatives Considered:

- No viable cost-effective transmission alternative was identified.

Projected In-Service: 09/01/2020

Project Status: Engineering



Need Number: AEP-2019-AP017

Process Stage: Solutions Meeting 02/21/2020

Previously presented: Need Meeting 06/17/2019

Supplemental Project Driver:

Equipment Material/ Condition/Performance/Risk, Operational Flexibility and Efficiency

Specific Assumption References:

AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

Beaver Creek – McKinney #1 46 kV Circuit

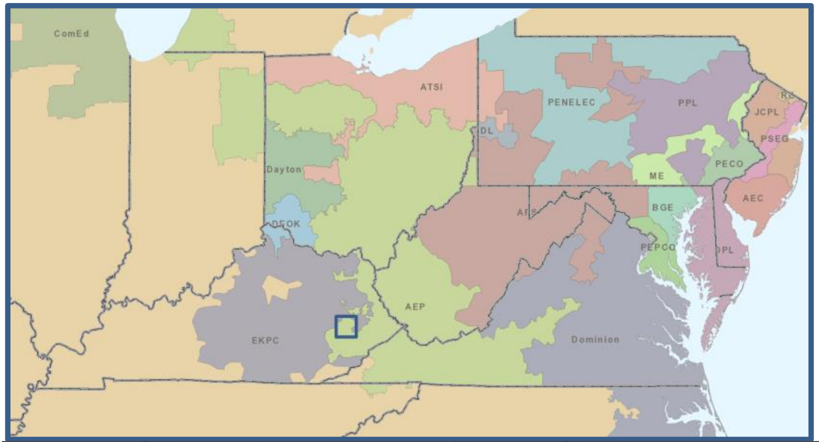
- From 2016-2018, the approximately 24.6 mile Beaver Creek – McKinney #1 46 kV circuit has experienced 22 outages.
- The circuit is comprised of 152 structures, the majority of which are wood structures dating back to 1929 (22/152, 14%) and 1949 (61/152, 40%).
- There are 142 open conditions along the 24.6 mile long line. These include damaged poles and cross-arms, conductor/shield wires, and guy anchor/knee/vee braces.

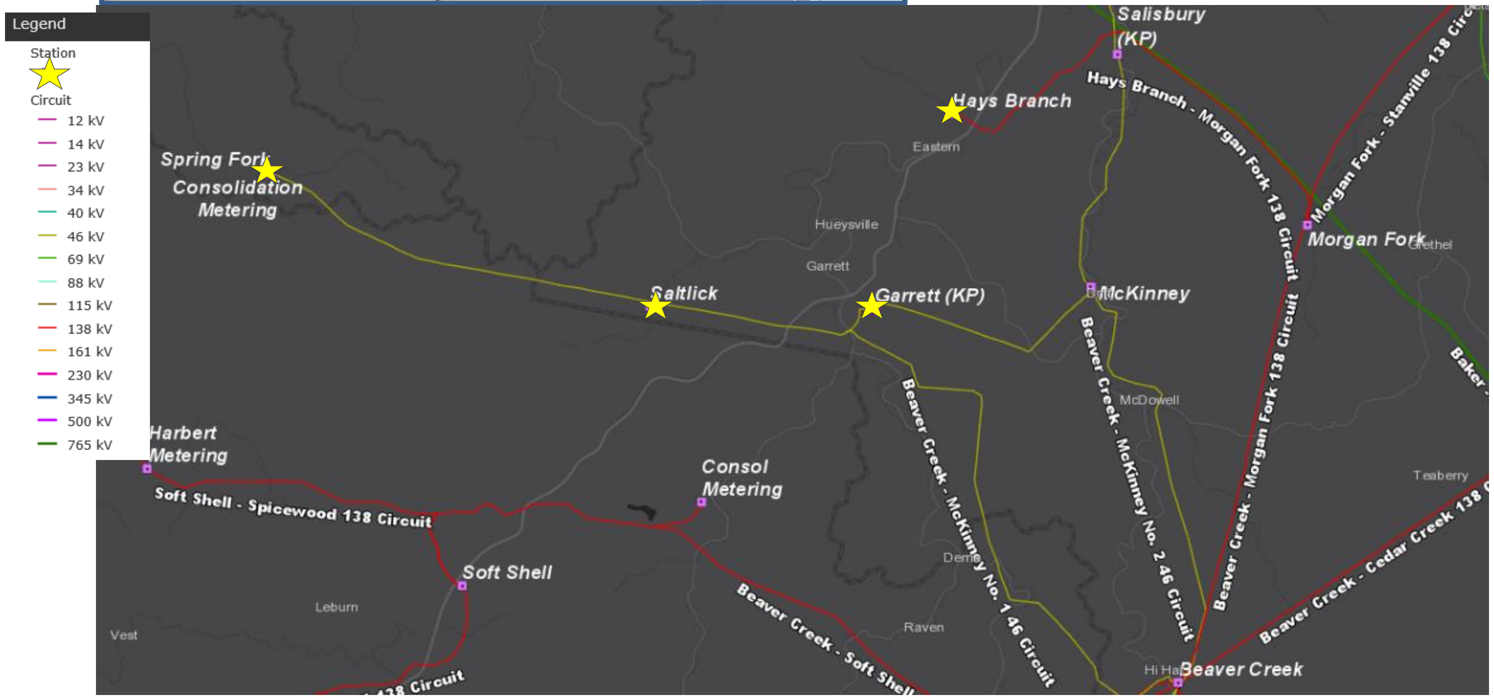
Hays Branch Station

- Hays Branch serves a ~30 MW gas compressing operation that is currently radially fed from a ~8.25 mile line out of Morgan Fork station.

Saltlick Station

- Saltlick serves an EKPC co-op that is currently radially fed off the Beaver Creek – McKinney 46 kV circuit.





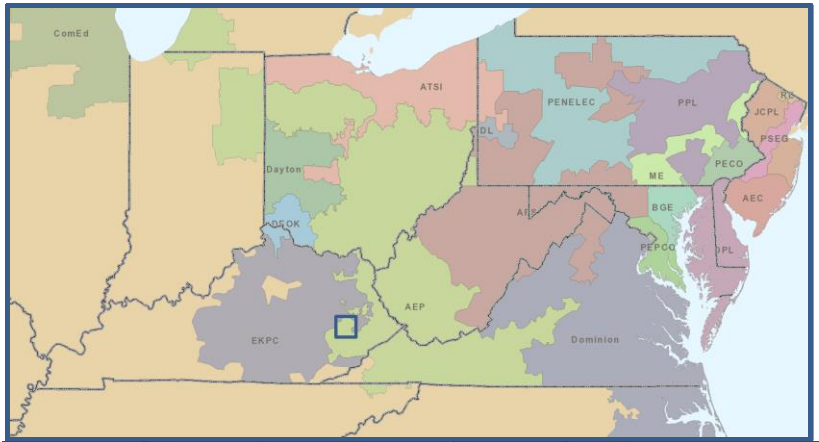
Continued from previous slide…

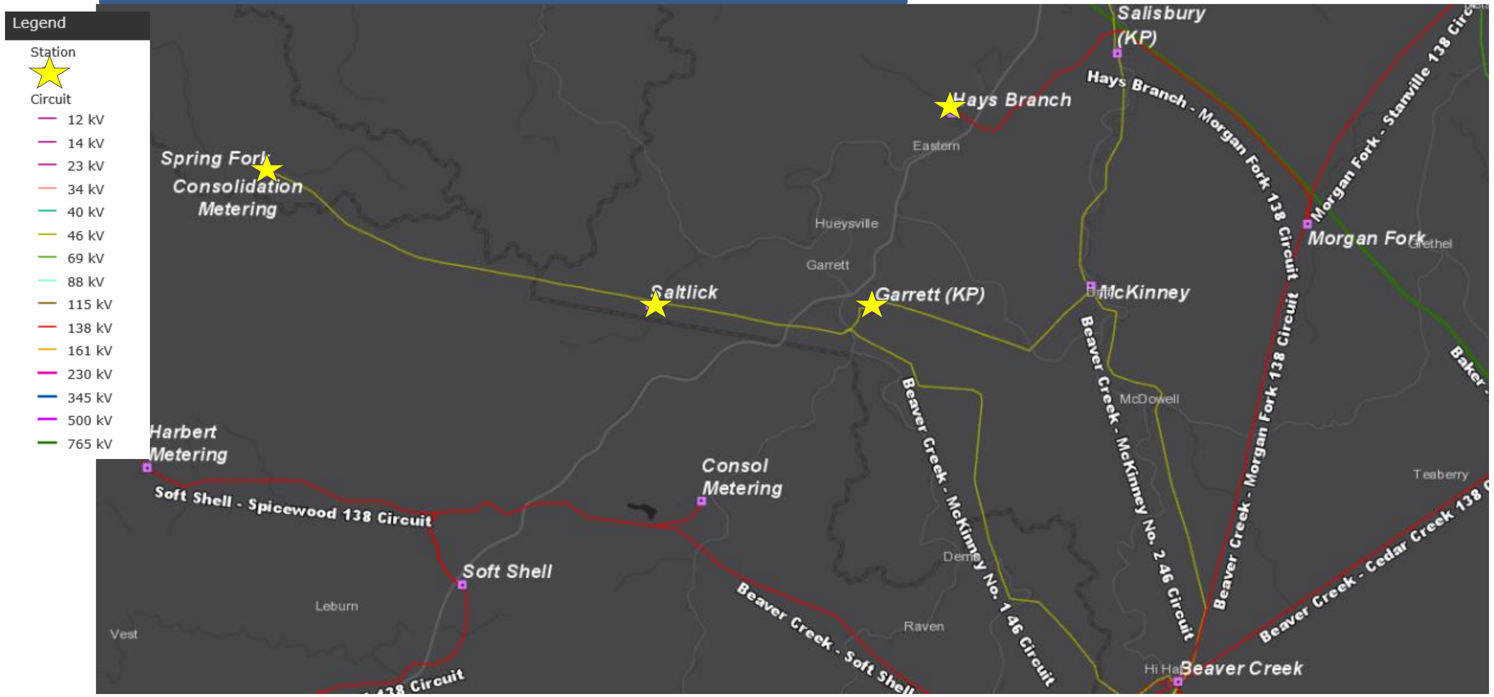
Spring Fork

- Spring Fork station serves KPCo distribution customers and is currently radially fed off the Beaver Creek – McKinney 46 kV circuit.

Consolidation Metering

- Consolidation Metering station serves a mining operation and is currently radially fed off the Beaver Creek – McKinney 46 kV circuit.





Proposed Solution:

Construct ~9.3 miles of single circuit 138kV from Soft Shell to Garrett picking up Salt Lick Co-op via Snag Fork along the way.
Estimated Cost: $35.3M

Construct ~3.5 miles of single circuit 138kV from the Eastern station to Garrett station. A short extensio will be required from the new station to the existing Hays Branch metering point. Construct short extension to existing Morgan Fork – Hays Branch 138 kV circuit from Eastern station
Estimated Cost: $11.5M

Double circuit cut into existing Hays Branch - Morgan Fork line to tie into new Hays Branch S.S PoP switch. Installation of a new heavy double circuit dead-end tap structure on the existing Hays Branch – Morgan Fork 138kV Line (Due to unequal loading on the transmission line).
Estimated Cost: $1.3M

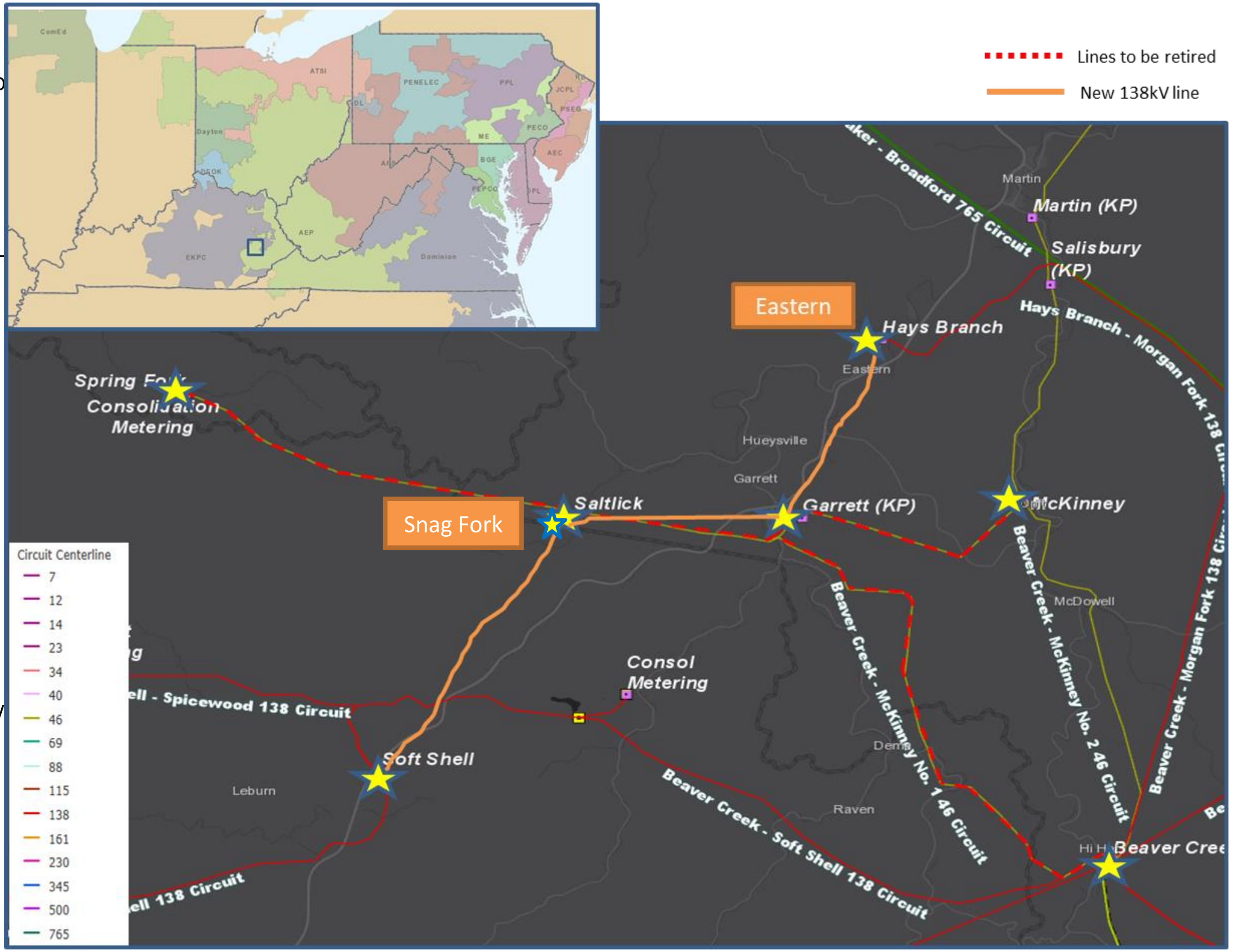
Construct ~0.25 mi of double circuit 138kV line Hays Branch S.S – Eastern. Installation of 3 double circuit suspension structures one of which is a custom pole structure.
Estimated Cost: $1.6M

New PoP switch structure at Hays Branch to accommodate new line from Eastern station
Estimated Cost: $0.5M

Expand the Garrett station, Install a 138kV three breaker ring bus (If space becomes a constraint, we should look at installing a straight bus arrangement with two 138 kV breakers and a circuit switcher on the high side of the transformer), 138/12kV 30 MVA transformer
Estimated Cost: $5.8M

Establish a new 138 kV substation Eastern south of the existing Hays Branch station. Install two 138kV breakers (3000A 40kA) at the new Eastern station on exits toward Morgan Fork and Garrett station.
Estimated Cost: $6 M

Establish Snag Fork S.S. Install a 3 way phase over phase motorized (automated) switching structure near Saltlick to serve the EKPC co-op.
Estimated Cost: $1.1 M



AEP Transmission Zone: Baseline Garrett Area Improvements

Proposed Solution (Cont.):

Move the existing 69kV rated CB G to the Beaver Creek – McKinney #2 circuit exit at McKinney substation.
Estimated Cost: $0.9 M

Install a 138kV breaker (3000A 40kA) with an exit towards Garrett station (via Snag Fork) at Softshell substation.
Estimated Cost: $0.8 M

Retire the ~25 miles of the 46kV Beaver Creek – McKinney #1 46 KV circuit. Retire Spring Fork Tap.
Estimated Cost: $17.3 M

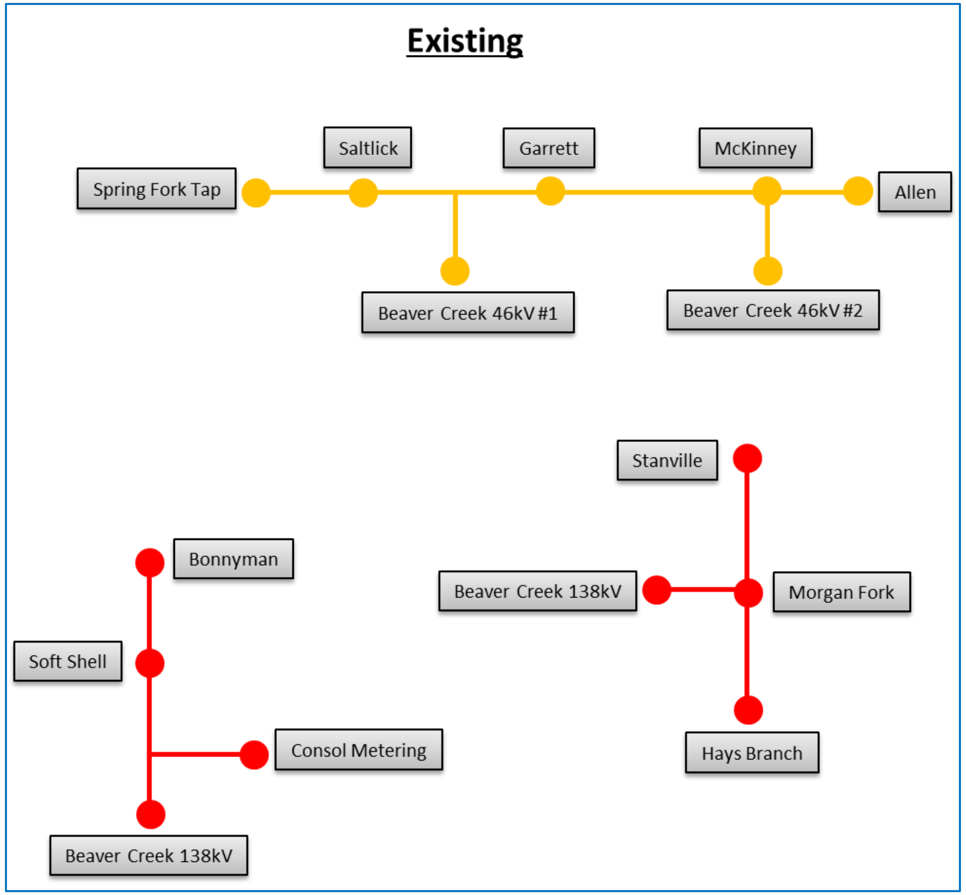
Total Estimated Transmission Cost: $81.9 M

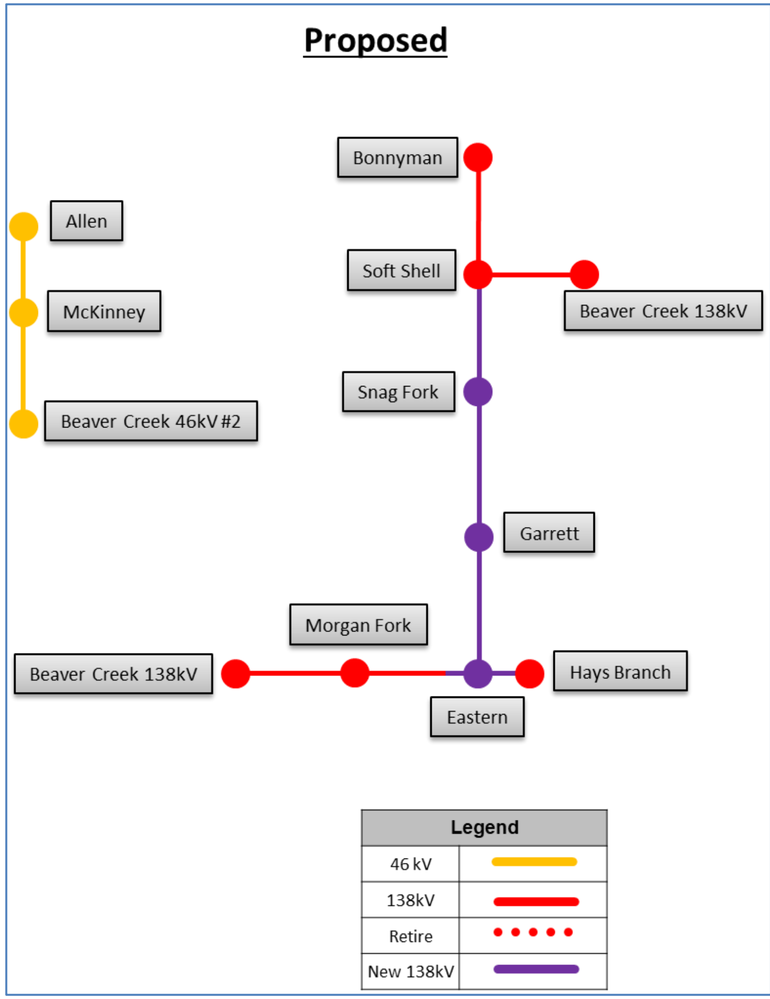
Ancillary Benefits: Removal of obsolete ~25 mi of 46kV network.

Alternative Solution:

Rebuild Beaver Creek – McKinney 46 kV #1 (approximately 25.0 miles) circuit keeping the system configuration as is. Construct new ~6.5 miles of 138kV line from Stanville station. Convert the ~3.5 mi 138kV existing single circuit to double circuit 138kV line from Hays Branch to newly constructed 138kV from Stanville making one feed for Hays Branch from Morgan Fork and other from Stanville.
Estimated Cost: $105 M

Projected In Service Date: 10/31/2023
Project Status: Scoping





AEP Transmission Zone M-3 Process
Wyoming/McDowel Counties, WV

Need Number: AEP-2019-AP024

Process Stage: Solutions Meeting: 02/21/2020

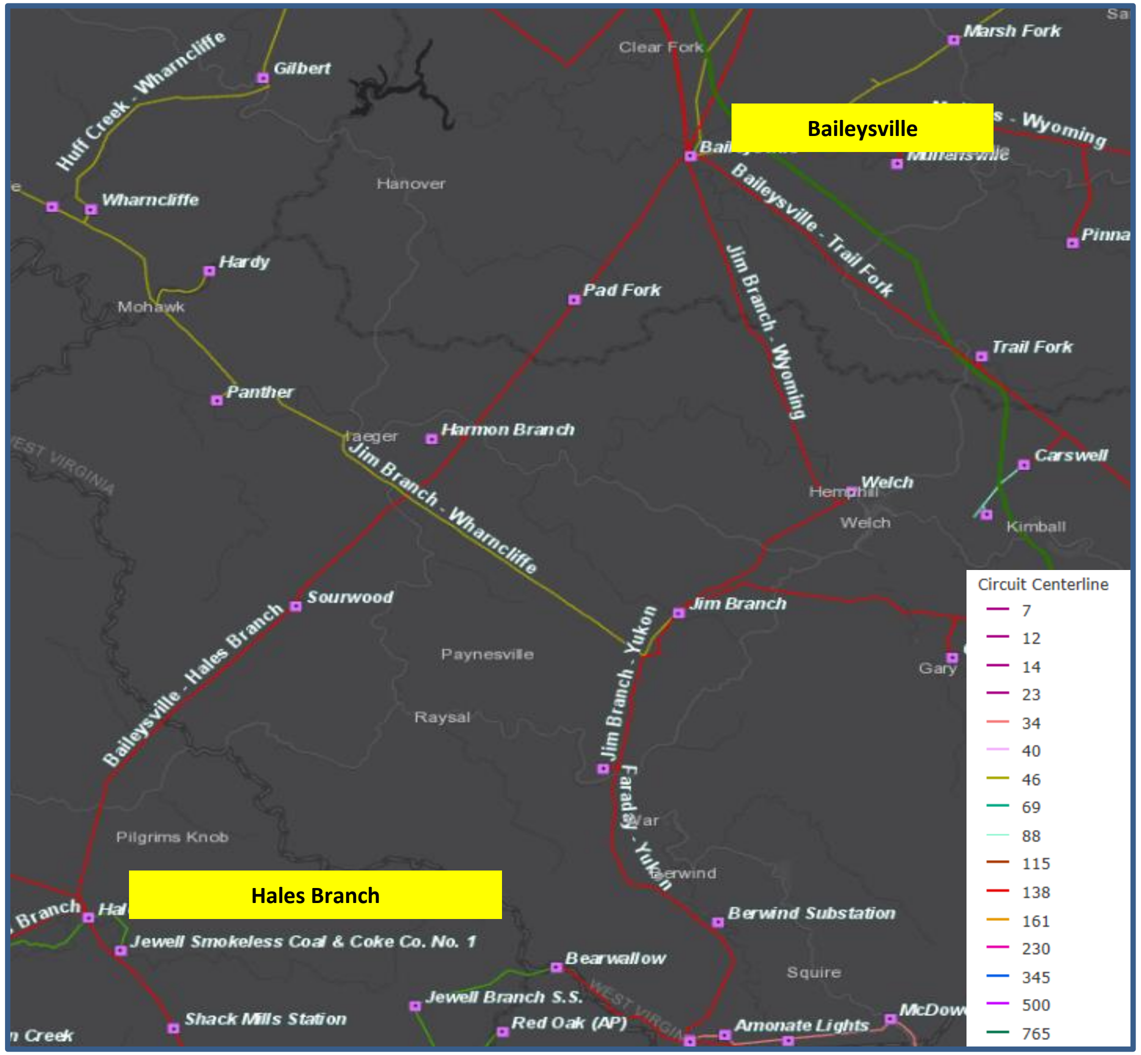
Previously Presented: Needs Meeting 7/24/2019

Supplemental Project Driver:
Equipment Condition/Performance/Risk

Specific Assumption Reference:
AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:
Baileysville – Hales Branch 138 kV (~27.8 miles)

- Majority of the circuit is constructed with 1970s wood structures.
- Between 2015-2018 the circuit experienced 24 momentary outages.
  - All momentary outages are attributed to lightening, insufficient shielding and aging towers as the structures, conductor, hardware, and insulators on the line are displaying issues associated with their age
- The circuit currently has 54 open conditions
  - Open conditions include: Rotten Tops, Woodpecker damage, Split Poles, Corroded Crossarms, Rotten Shells, Broken Ground Lead Wires, and Buildings Encroachment in Right Of Way
- Structures loading does not meet current NESC standards.



Need Number: AEP-2019-AP024

Process Stage: Solutions Meeting: 02/21/2020

Proposed Solution:

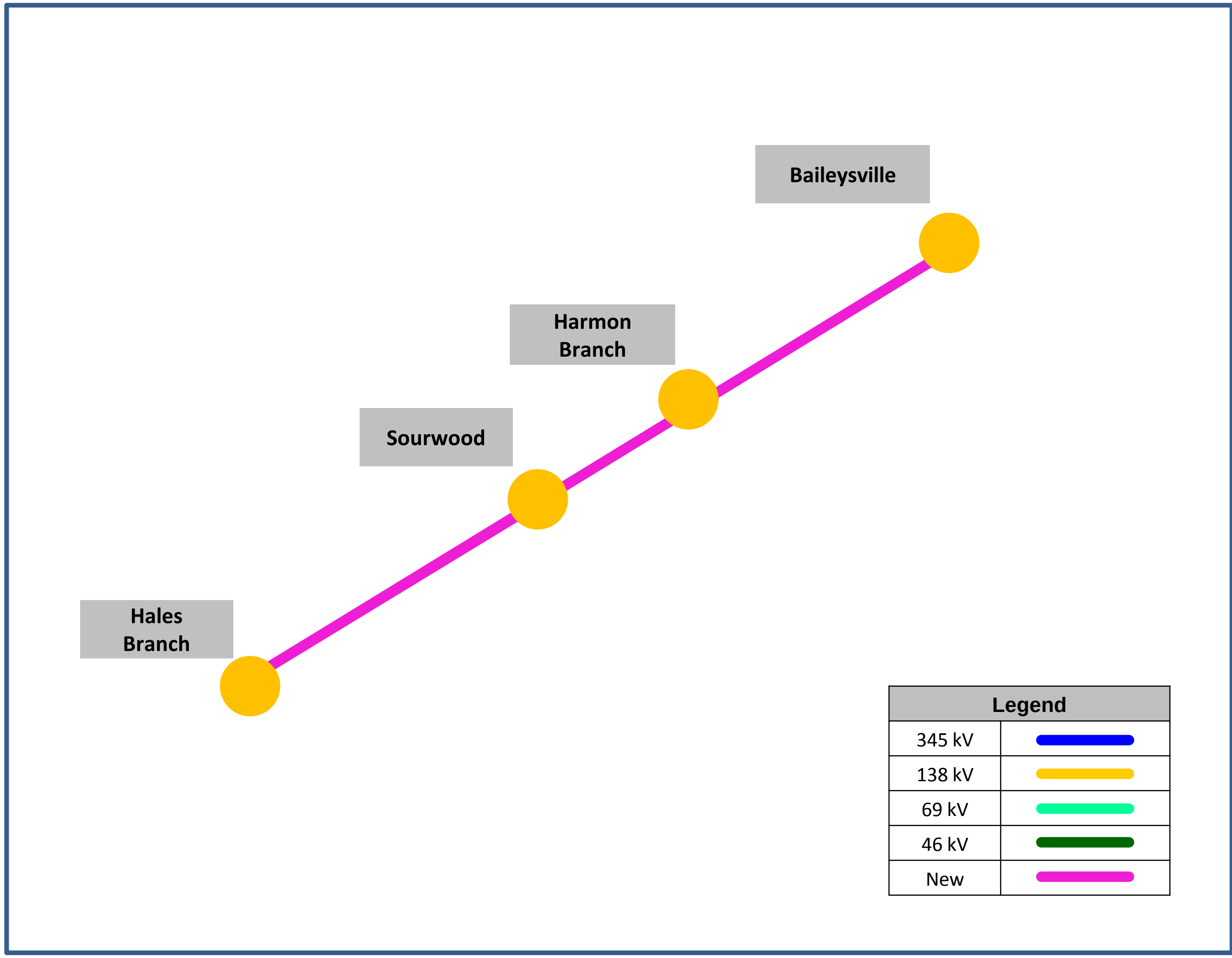
Rebuild ~27.8 miles of the existing Baileysville – Hales Branch 138kV circuit. **Estimated Cost: $98.5M**

Alternatives Considered:

Retire ~27.8 miles of Baileysville – Harmon Branch 138 KV. Build new ~ 5.2 mile 138 KV double circuit with in/out from Baileysville to Pad fork station. Construct a new ~ 8.6 mile 138 KV line from Jim Branch to Harmon Branch, a new ~ 7.7 138 KV line from Harmon Branch to Sourwood, and ~ 9.2 mile 138 KV from Sourwood to Yukon substation. Add 138 KV circuit breaker at Jim Branch for Jim Branch — Harmon Branch 138KV, 138 KV circuit breaker at Yukon substation for Sourwood – Yukon 138KV. Requires more new ROW and increases cost. **Estimated Cost: ~$126 M**

Project Status: Scoping

Projected In-Service: 8/01/2026



Need Number: AEP-2019-AP043

Process Stage: Solutions Meeting 02/21/2020

Previously Presented: Needs Meeting 11/22/2019

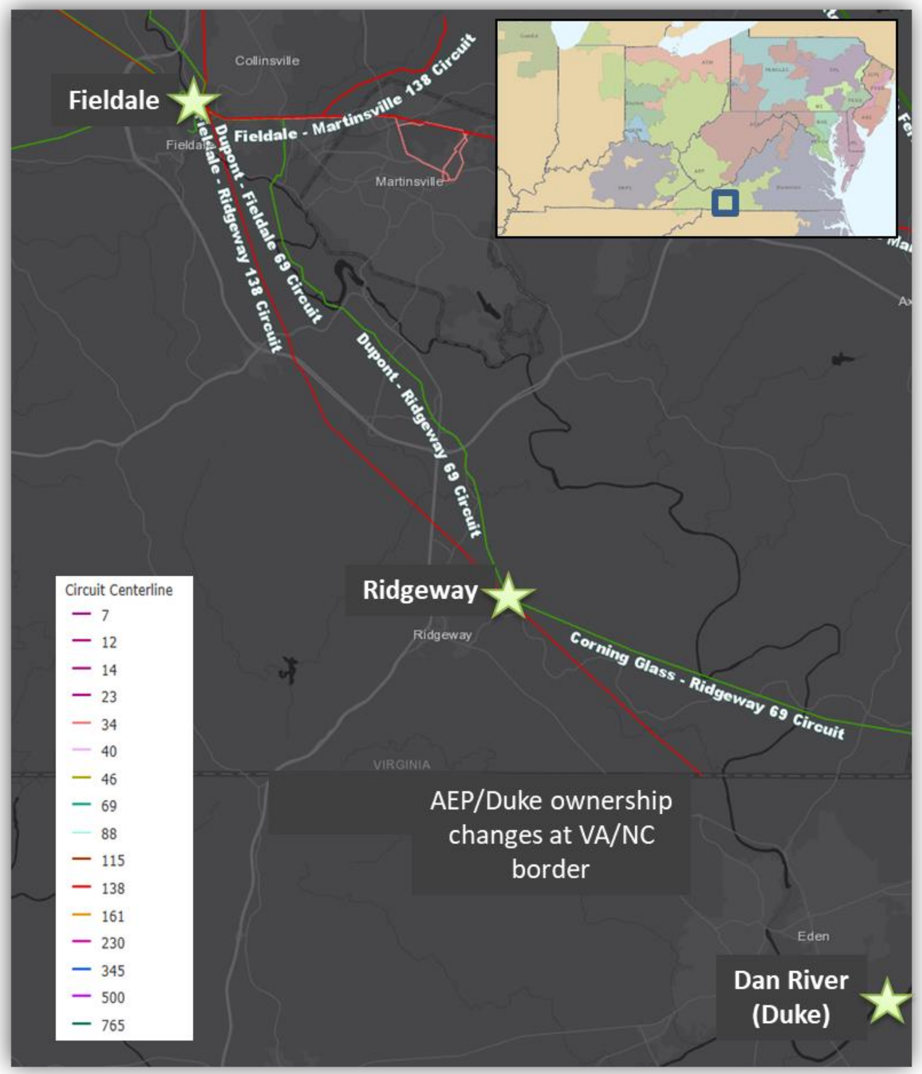
Supplemental Project Driver: Equipment Material/Condition/Performance/Risk

Specific Assumption Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

- **Fieldale-Ridgeway 138 kV Circuit (10.3 mi.)**
  - 1949 wood H-Frame construction
  - 58 Type A open conditions on 35 unique structures (51% of all structures on circuit)
  - From 2015-2018, a total of 4 permanent outages resulting in 241,094 customer minutes of interruption
- **Ridgeway-Dan River 138 kV Circuit (4.5 mi.)**
  - 1949 wood H-Frame construction
  - 40 Type A open conditions on 23 unique structures (68% of all structures on circuit (owned by AEP))
  - From 2015-2018, a total of 3 permanent outages occurred

Model: N/A



Need Number(s): AEP-2019-AP043

Process Stage: Solutions Meeting 02/21/2020

Proposed Solution:

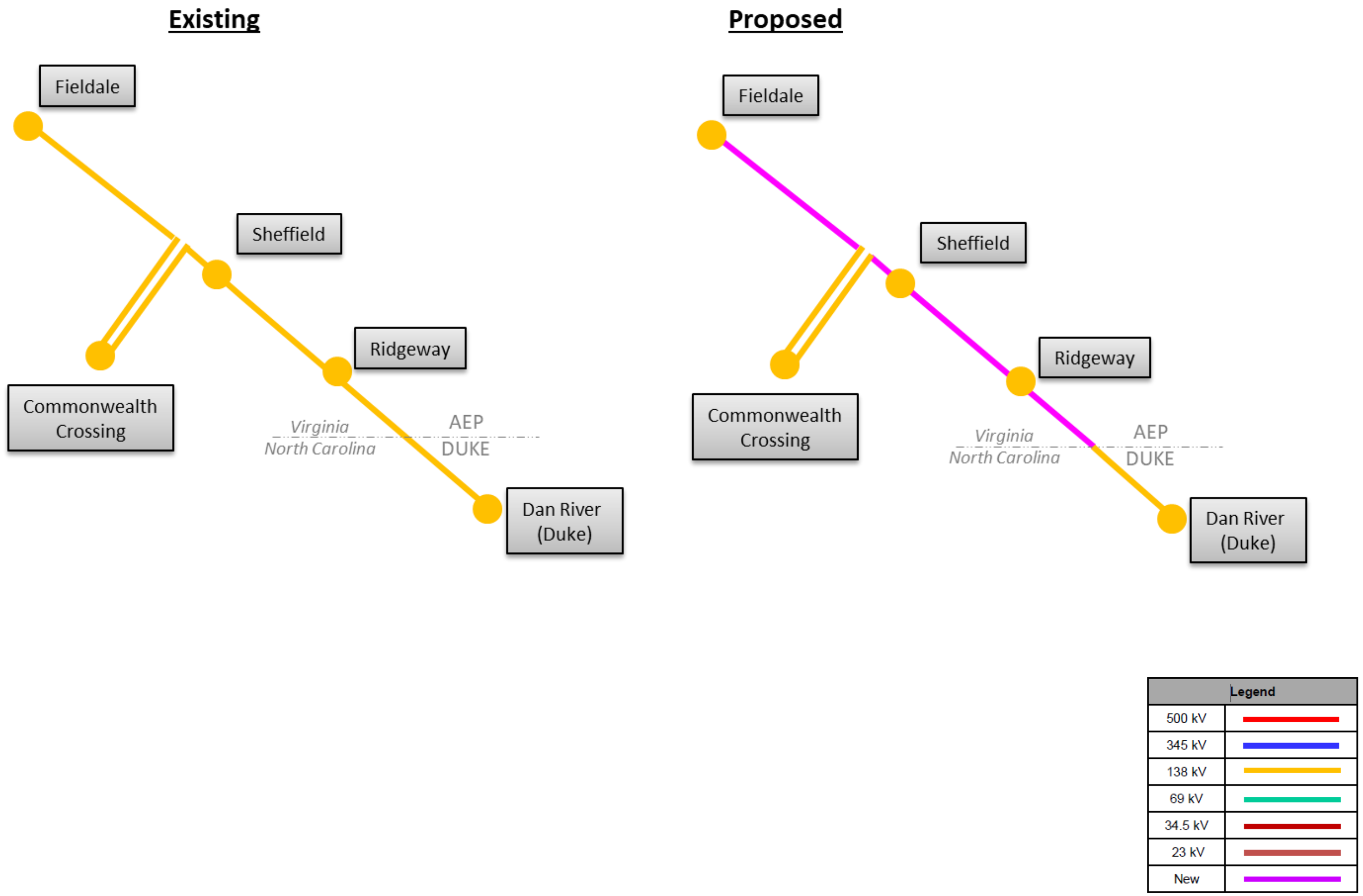
- Rebuild approximately 15 miles of the AEP-owned portion of the 138 kV line between Fieldale and Dan River stations (AEP/Duke ownership changes at the VA/NC border).
  Estimated Cost ($32.2 M)

Alternatives Considered:

No viable cost effective solution was identified.

Projected In-Service: 10/31/2022

Project Status: Scoping



Need Number: AEP-2019-AP045

Process Stage: Solutions Meeting 02/21/2020

Previously Presented: Needs Meeting 11/22/2019

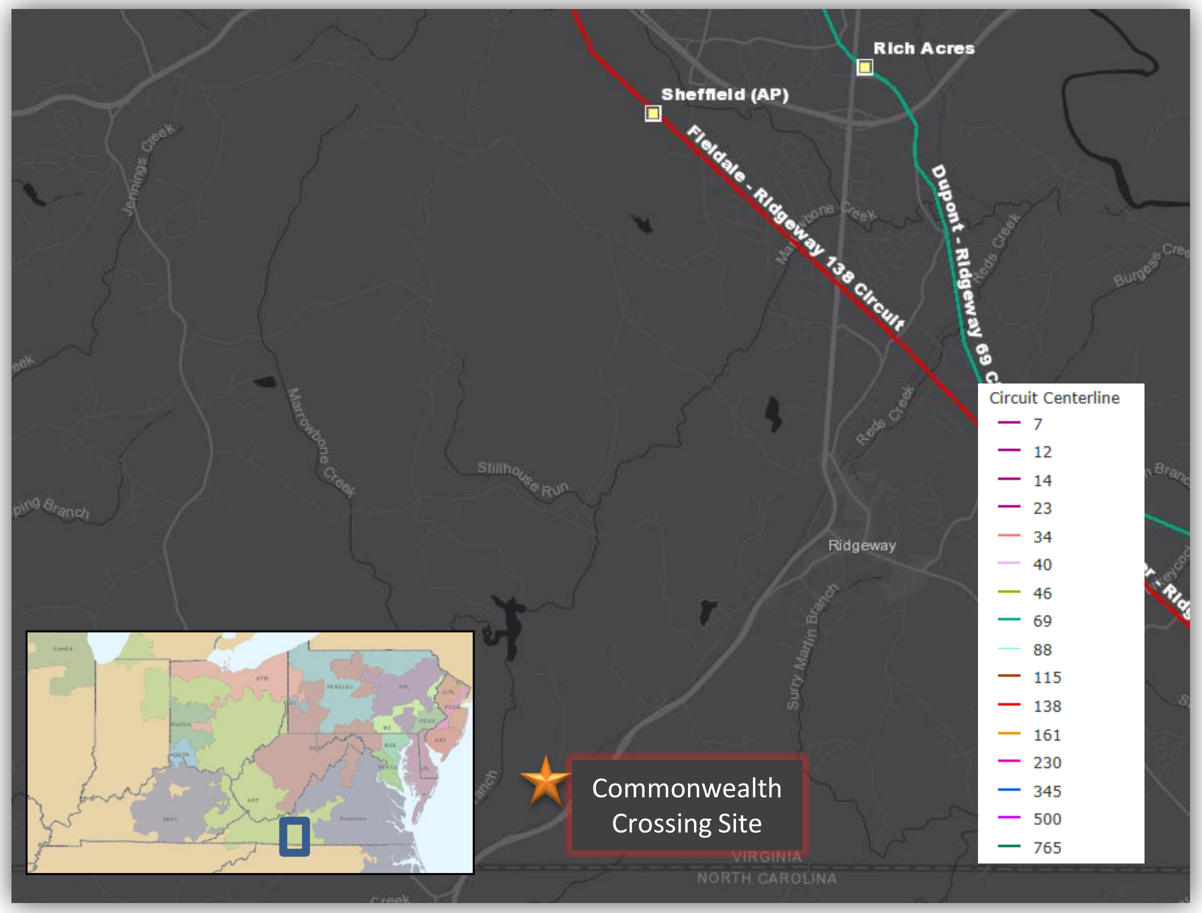
Supplemental Project Driver: Customer Service

Specific Assumption Reference: AEP Connection Requirements for the AEP Transmission System (AEP Assumptions Slide 7)

Problem Statement:

- Henry County VA (Customer) has requested that AEP construct a new 138 kV loop fed transmission line and a new 138-34.5kV (30 MVA) substation in its Commonwealth Crossing Business Centre (CCBC) to initially serve Press Glass (5 MVA). The CCBC is located roughly 5 miles from the Sheffield-Ridgeway 138kV line in Ridgeway VA.

Model: 2024 RTEP



Need Number(s): AEP-2019-AP045

Process Stage: Solutions Meeting 02/21/2020

Proposed Solution:

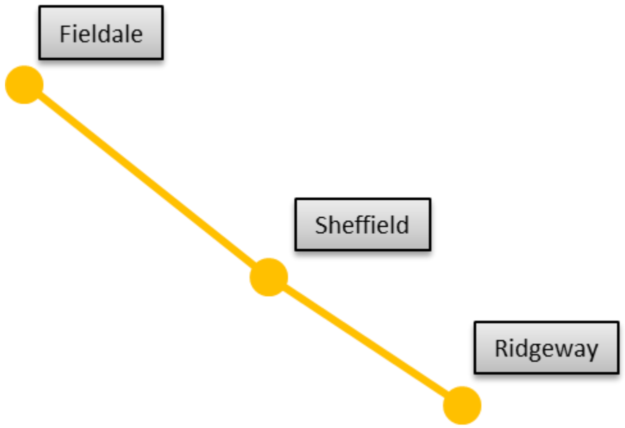
- Construct ~5.75 miles of new double circuit 138 kV line from the Fieldale-Ridgeway 138 kV circuit to a new Commonwealth Crossing station. **Estimated Cost: $14.8M**
- Establish a new 138/34.5 kV Commonwealth Crossing Station with 2-138 kV, 3000 A, 40 kA circuit breakers, high-side 3000 A, 40 kA circuit switcher, 138/34.5 kV, 30 MVA transformer, and 3-34.5 kV distribution feeders. **Estimated Cost: $0**
- Install 5.75 miles of 48 ct. fiber between Commonwealth Crossing station and Ridgeway station to support SCADA and relaying. **Estimated Cost: $0.4M**

Total Estimated Transmission Cost: $15.2M

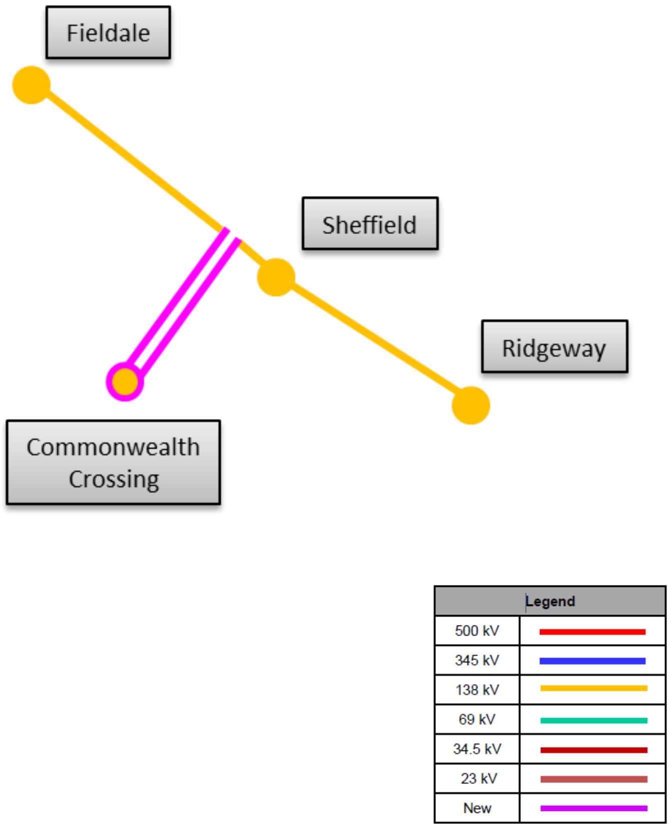
Ancillary Benefits:

The new station will provide a reliable source to the Commonwealth Crossing Business Centre (CCBC) which will be ready to accommodate new customers as needed.

Existing



Proposed



AEP Transmission Zone M-3 Process
Henry County, VA

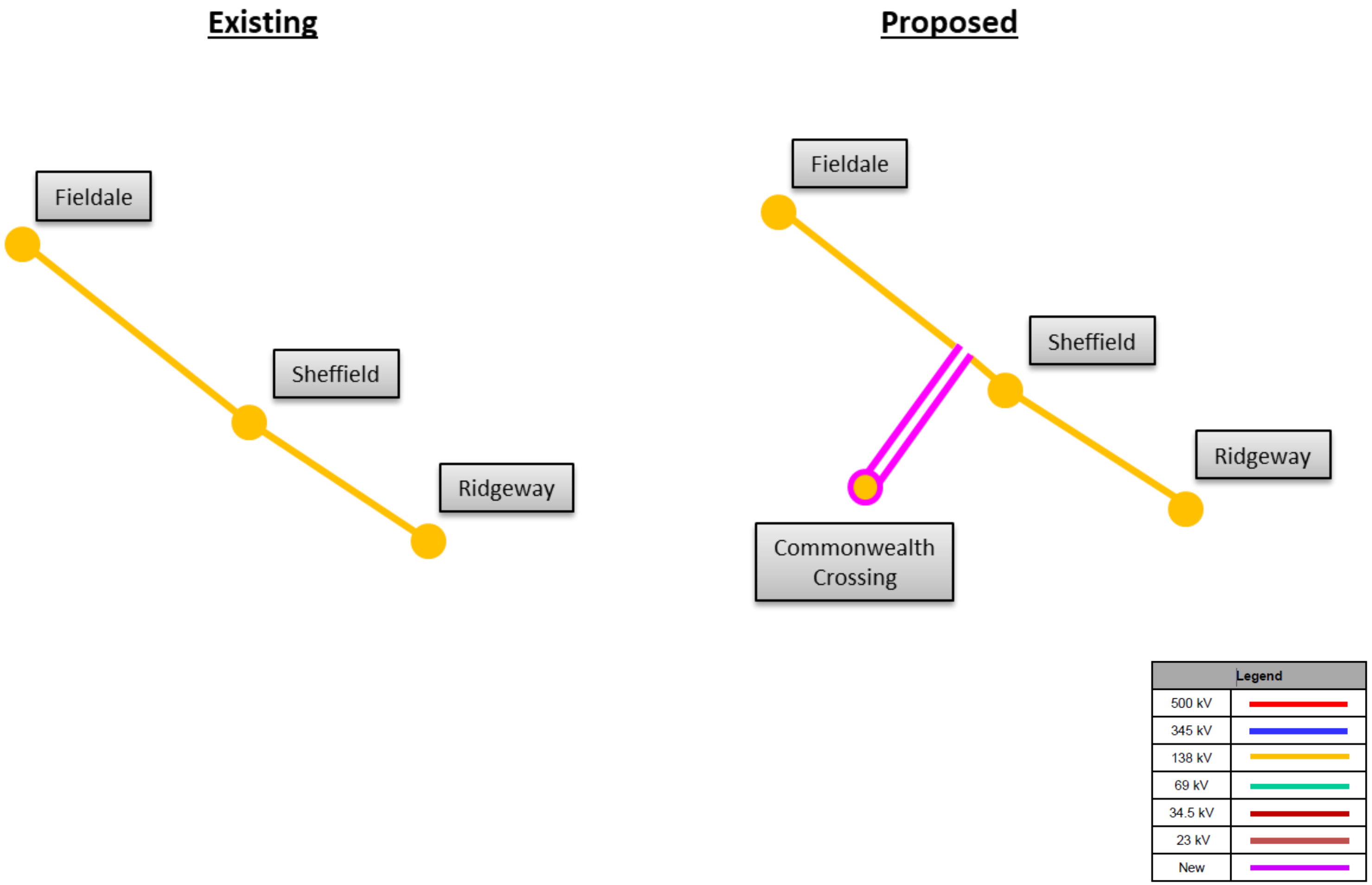
Alternatives Considered:

Establish a new 138 kV, 3 breaker ring station along the Fieldale-Ridgeway 138 kV circuit and extend a 5.75 mile, single circuit 138 kV line to a new Commonwealth Crossing station.

This alternative would adequately serve the load from a capacity perspective, however the reliability of a single circuit line is less due to the higher probability of experiencing a fault on the 5.75 mile radial line. In addition, it is AEP's guideline to provide loop service to 75 MVA-miles or more. If the existing customer or another customer requests service here it would only require ~13 MVA total to reach this threshold. **Estimated Cost: $18M**

Projected In-Service: 3/1/2020

Project Status: Construction



Need Number: AEP-2019-AP050

Process Stage: Solutions Meeting 02/21/2020

Previously Presented: Needs Meeting 11/22/2019

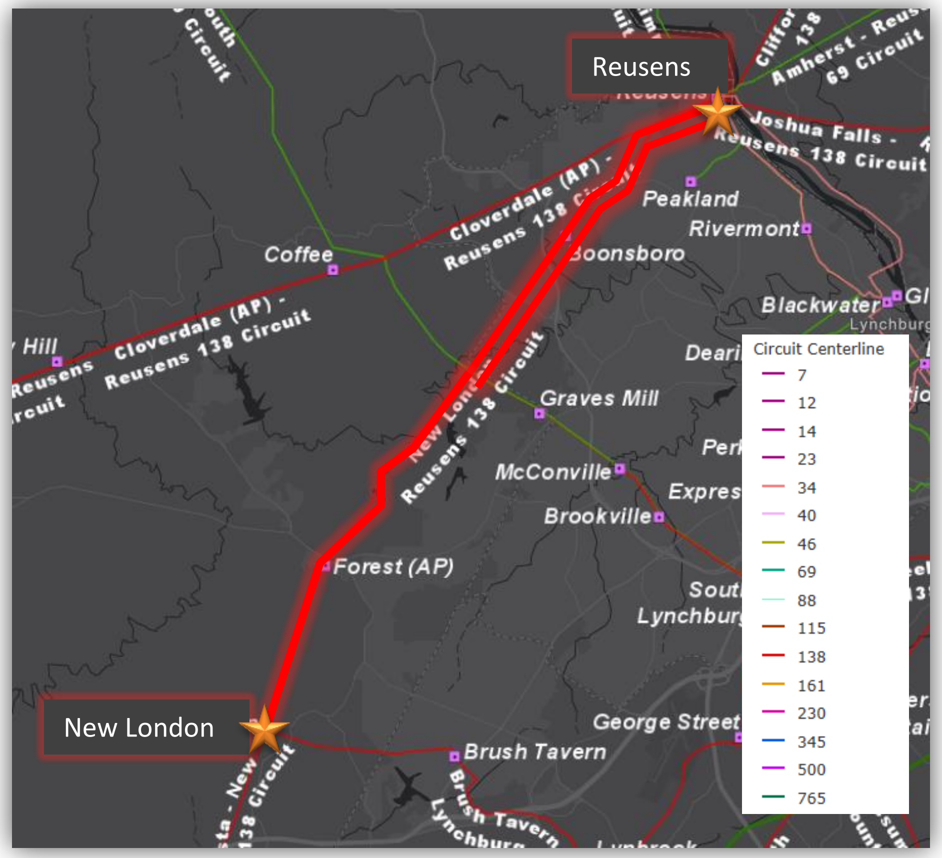
Supplemental Project Driver: Equipment Material/Condition/Performance/Risk

Specific Assumption Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

- <u>**Reusens-Altavista 138 kV Line Asset (11.6 mi.)**</u>
  - A total of 16 open conditions on 13 unique structures (comprising 18% of the line asset)
  - New London-Reusens 138 kV Circuit: From 2015-2018, a total of 2 permanent and 2 momentary outages occurred
  - McConville-Reusens 138 kV Circuit: From 2015-2018, a total of 2 permanent and 2 momentary outages occurred
    - **138 kV Double Circuit Section (5.5 mi.)**
      - Section exists between Reusens Station and structure 5-10
      - 1949 steel lattice structures
      - The lattice towers used on this line are approximately 70 years old, which exceeds the projected life span for that structure type. Structure loading does not comply with the NESC 250B and 250D standards for the line.
      - The shield wire and most of the conductor is 70 years old as well, which exceeds the expected life span of the conductor. The current shielding does not comply with the current standards, specifying a maximum of 30 degrees. The current shielding angle is approximately 50 degrees.
    - **138 kV Single Circuit Section (6.1 mi.)**
      - Section exists between structure 5-10 and New London Station
      - 1949 wood H-Frame construction
      - The wood structures used on this line are approximately 70 years old, which exceeds the projected life span for that structure type. Structure loading does not comply with the NESC 250B and 250D standards for the line.
      - The shield wire and most of the conductor is 70 years old as well, which exceeds the expected life span of the conductor.
      - The current shielding does not comply with the current standards, specifying a maximum of 30 degrees. The current shielding angle is approximately 50 degrees.

Model: N/A



AEP Transmission Zone M-3 Process
Lynchburg, VA

Need Number(s): AEP-2019-AP050

Process Stage: Solutions Meeting 02/21/2020

Proposed Solution:

- Rebuild 11.6 mile section of the Reusens-Altavista 138 kV line asset from Reusens to New London. Approximately 5.5 miles consists of double circuit 138 kV construction and approximately 6 miles consists of single circuit 138 kV construction between Reusens and New London **Estimated Cost: $36.2M**
- Install a 57.6 MVAR cap bank at Brush Tavern 138kV due to low voltage concerns from operations during construction outages in the area. **Estimated Cost: $0.0M**

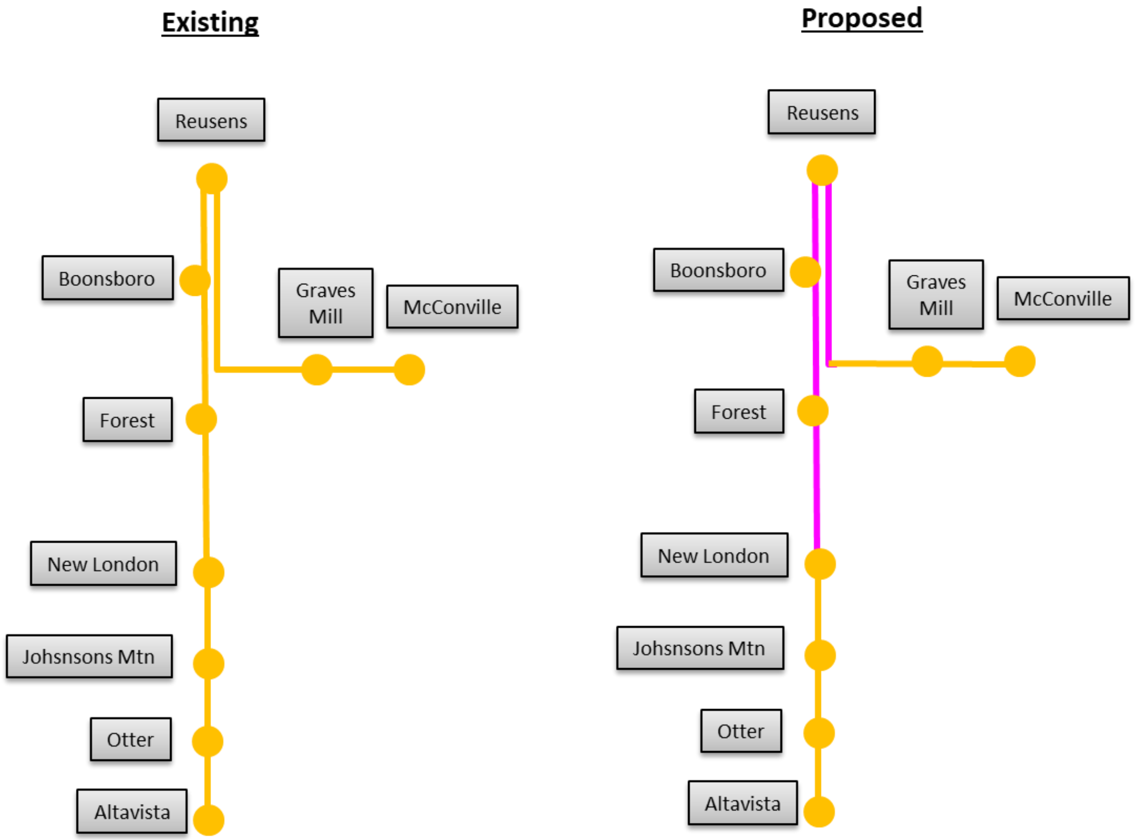
Total Estimated Transmission Cost: $36.2M

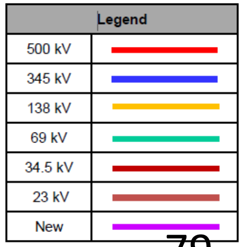
Alternatives Considered:

No cost effective alternative was identified.

Projected In-Service: 10/31/2022

Project Status: Scoping

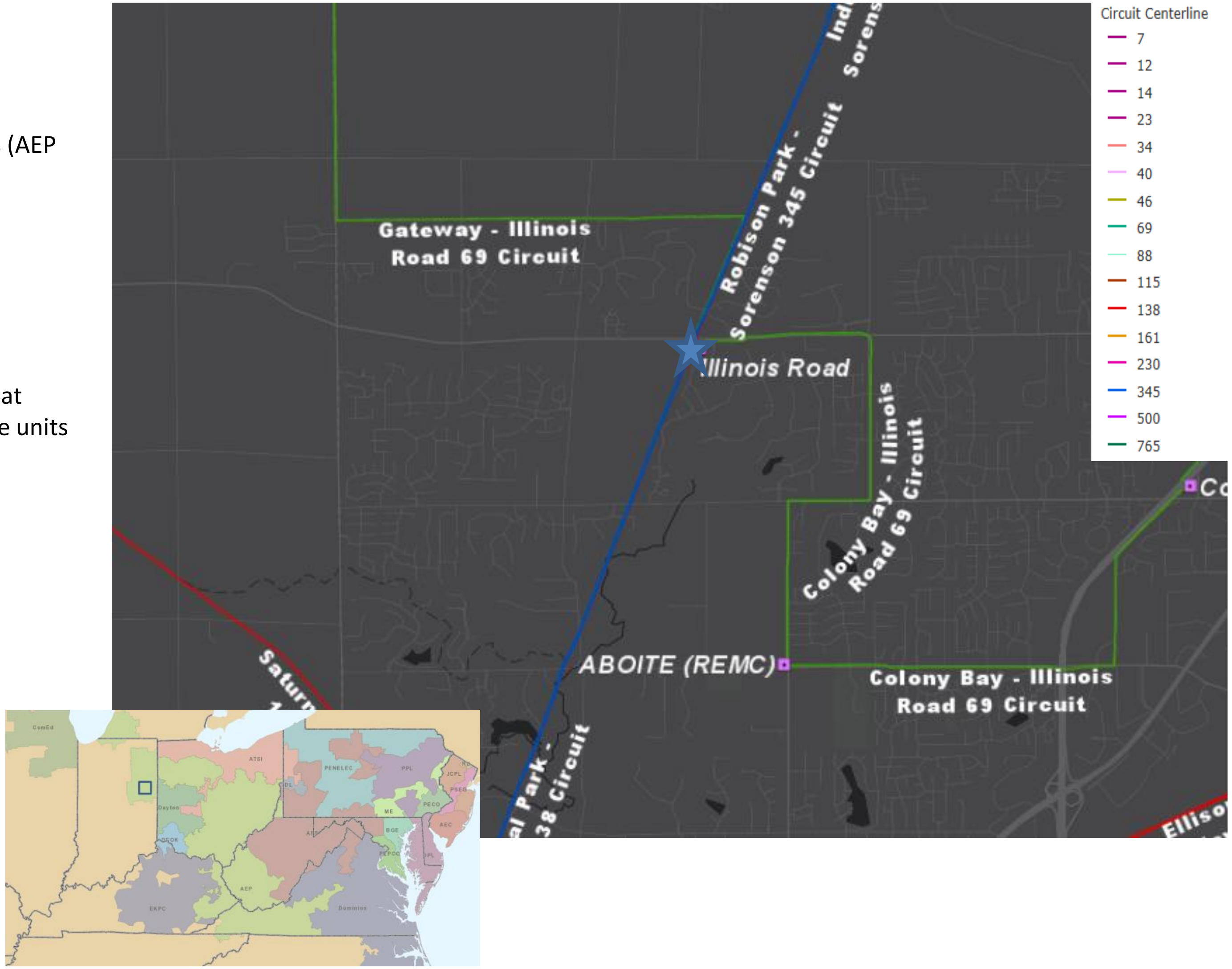




AEP Transmission Zone: Supplemental
Illinois Road Station Improvements

Need Number: AEP-2019-IM012
Process Stage: Solution Meeting 02/21/2020
Previously Submitted: Needs Meeting 04/23/2019
Supplemental Project Driver: Equipment Material/Condition/Performance/Risk
Specific Assumptions Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)
Problem Statement:

Illinois Road 138kV station
- Breakers A & B 69kV
  - 1969 and 1970 vintage Oil breakers
  - Fault Operations: A(23) & B(67) – Recommended(10)
  - Oil filled breakers have much more maintenance required due to oil handling that their modern, vacuum counterparts do not require. Finding spare parts for these units is difficult or impossible, and these models are no longer vendor supported



AEP Transmission Zone: Supplemental
Illinois Road Station Improvements

Need Numbers: AEP-2019-IM012
Process Stage: Solutions Meeting 02/21/2020

Proposed Solution:

Illinois Road 138/69kV station:
Replace 69kV CB's A and B and add a low side 69kV CB. Add 2 138kV CB's on the line exits.
Estimated Cost: $5.9M

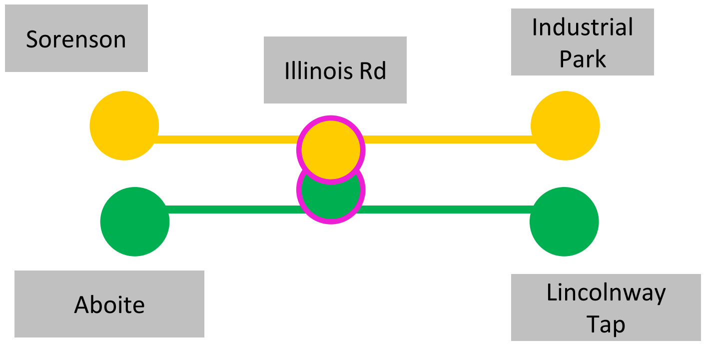
Alternatives Considered:
Alternative 1:
Rebuild the high and low side as ring busses. The station still has significant equipment that's in good condition including the transformer, transformer high side protection and busing. For this reason, it was decided to just replace the aging equipment and add the required protection.

Estimated Cost: $7M.

Ancillary benefits:
Since the outage on the 138/69kV XFR was required, AEP decided to take the time to install the low side 69kV CB and high side 138kV CB's in order to bring the station up to the current protection standard.

Total Estimated Transmission Cost: $5.9M

Projected In-Service: 11/10/2021
Project Status: Scoping



Legend	
500 kV	
345 kV	
138 kV	
69 kV	
34.5 kV	
23 kV	
New	

Need Number: AEP-2019-IM019
Process Stage: Solution Meeting 02/21/2020
Previously Presented: Needs Meeting 06/17/2019
Supplemental Project Driver: Equipment Material/Condition/Risk/Performance/
Specific Assumptions Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

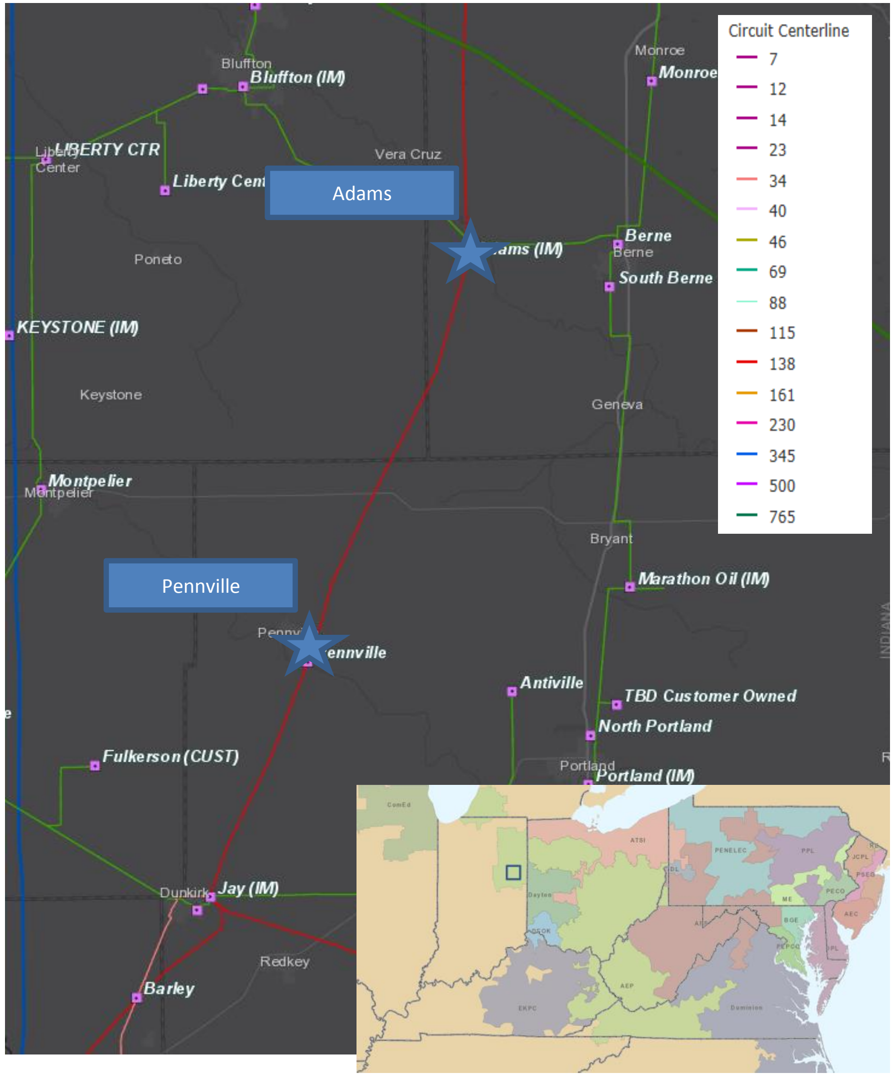
Problem Statement:

Adams 138/69kV station

- The 138/69kV XFR currently is protected by a high side ground switching MOAB.
- Currently there are 3 dissimilar zones of protection at this station with a 138kV line, 138kV bus and a 138/69kV transformer

Pennville 138kV station

- This station's through path is composed of wood support structures and cap and pin bus insulators, both have been identified as safety concerns.
- The Cap and Pin support insulators have a documented history of failing due to degradation in the glue that holds them together. It is currently AEP policy to remove these support style insulators as we have opportunity.
- The support structures for the station's through path reside mostly outside of the station footprint. These bus support structures straddle the station fence which leaves most of the main bus, switches, insulators and support structures outside the station's footprint where there is no ground grid. This has been identified as a safety hazard and will be addressed.

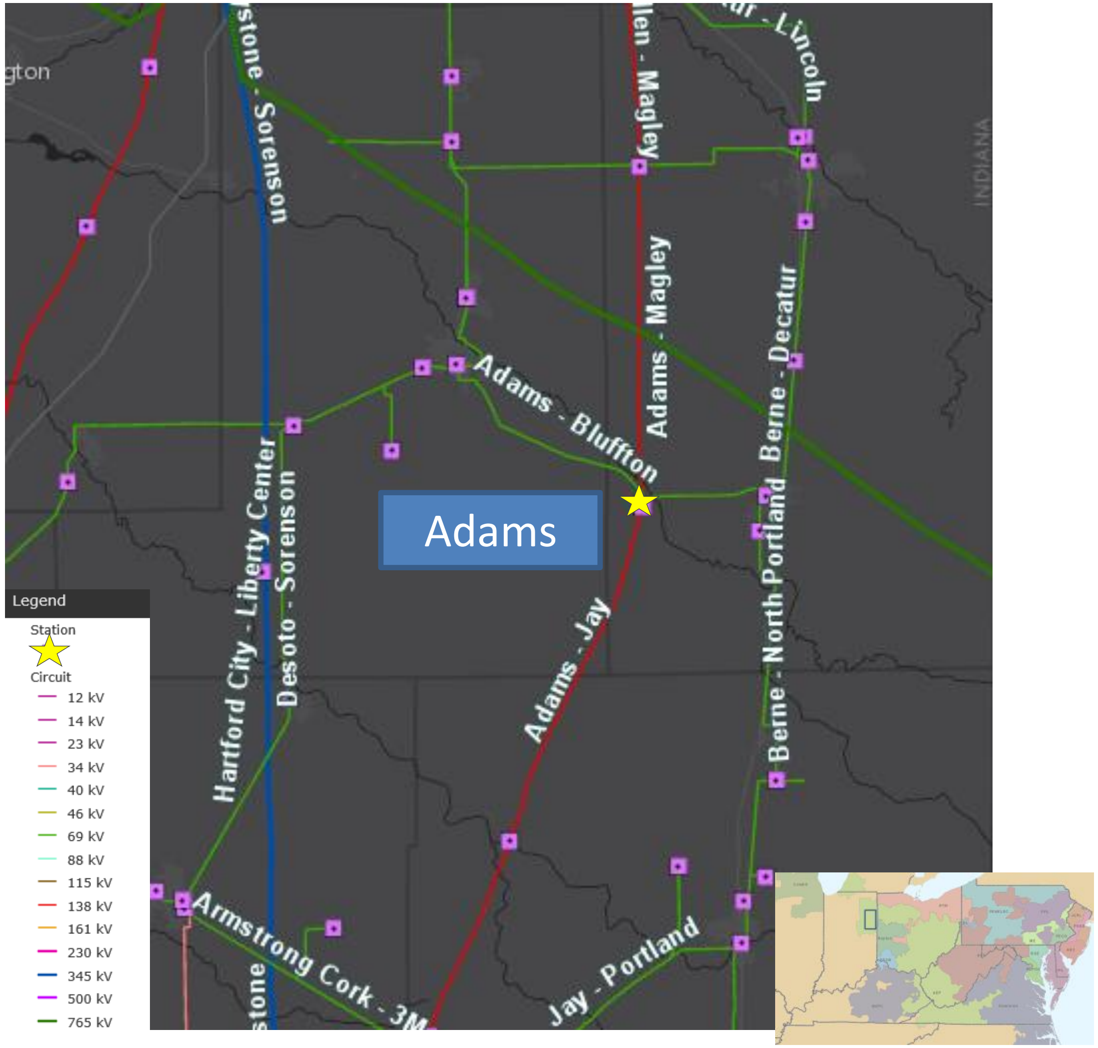


Need Number: AEP-2019-IM027
Process Stage: Solution Meeting 02/21/2020
Previously Presented: Needs Meeting 08/29/2019
Supplemental Project Driver: Equipment Condition/Performance/Risk
Specific Assumptions Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)
Problem Statement:

Adams 69kV Station:

69kV Circuit Breaker D

- Vintage 1966 Oil filled McGraw Edison CF type breaker
- Last oil breaker at Adams station
- Oil filled breakers have much more maintenance required due to oil handling that their modern, vacuum counterparts do not require
- Spare parts are not available and these models are no longer vendor supported
- Fault operations (10) – Manufacturers recommended maximum (10)



AEP Transmission Zone: Supplemental
Adams & Pennville Station Rehab

Need Number: AEP-2019-IM027 & AEP-2019-IM019
Process Stage: Solutions Meeting 02/21/2020

Potential Solution

Rebuild the high side of Adams 138/69kV station as a 3 breaker ring bus, re-using the existing breaker “C,” and replace 69kV Breaker “D”
Estimated Cost: $6.3M

Rebuild the through-path of Pennville 138kV station with 2 MOABS
Estimated Cost: $1.7M

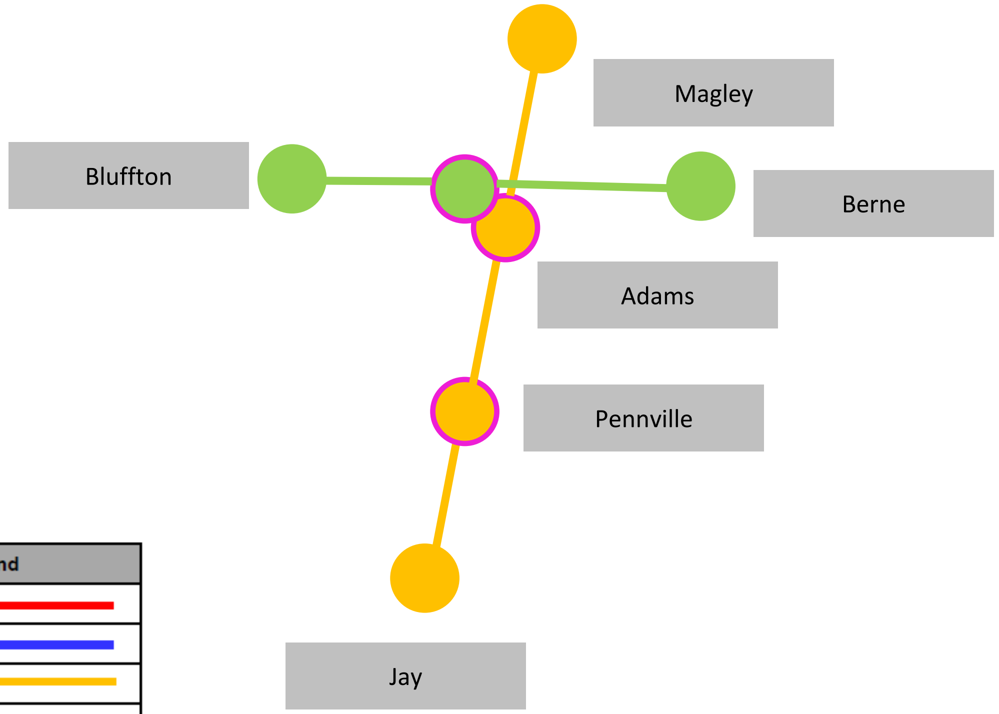
Total Estimated Transmission Cost: $8M

Alternates Considered
Rebuild the Pennville station through-path as is.
Due to the unrecoverable nature of the load at Pennville it is recommended that two Moabs be installed in lieu of the GOAB and circuit switcher.

*This project will be worked in conjunction with outages for project S2021.3

Projected IS Date: 1/2/2026

Project Status: Scoping

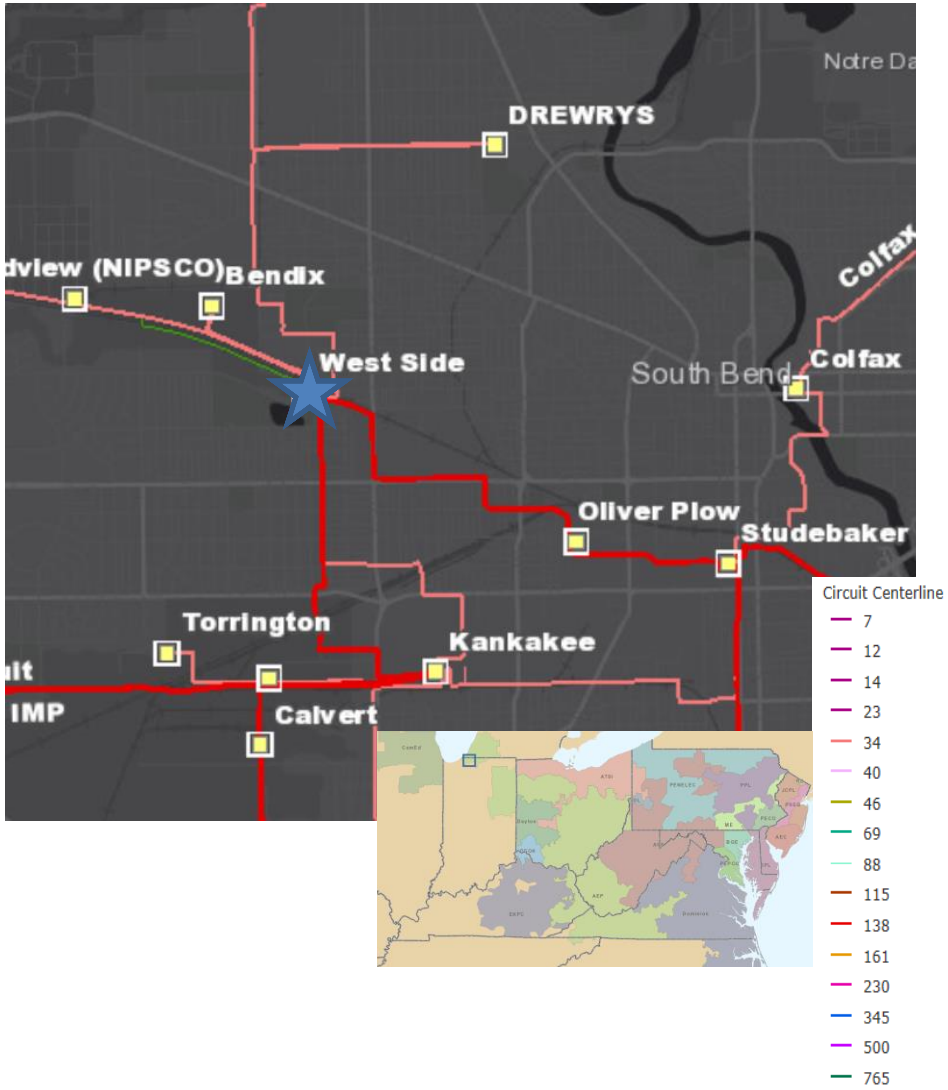


Legend	
500 kV	
345 kV	
138 kV	
69 kV	
34.5 kV	
23 kV	
New	

Need Number: AEP-2019-IM034
Process Stage: Solutions Meeting 02/21/2020
Supplemental Project Driver: Equipment Condition/Performance/Risk
Specific Assumptions Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)
Problem Statement:

West Side 138kV Station
- Three terminal line
    - Three-terminal lines are very challenging to protect/coordinate and mis-operation or switching error become much more significant.

- Bus Tie Switch between the distribution transformers
    - Bus Tie Switch when operated without de-energizing the whole bus jeopardizes the Bus Differential Protection.
    - With no Bus Differential Protection the correct interrupting device wouldn't operate during fault scenarios, this can be dangerous for people working in the station.



AEP Transmission Zone M-3 Process
West Side Station Improvements

Need Number: AEP-2019-IM034
Process Stage: Solutions Meeting 02/21/2020

Proposed Solution

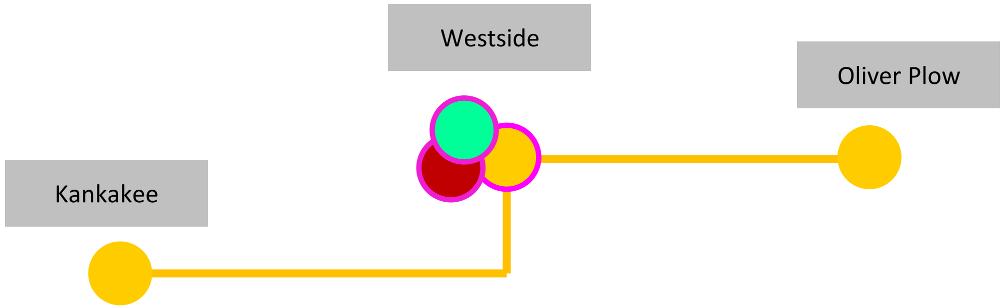
Westside Station
Install 2 138kV line breakers at West Side station to break up the three-terminal line. Install 1 138kV bus tie breaker. Install one 69kV low-side breaker at Westside Station. **Estimated Cost: $3.5M**

Ancillary Benefits:
While at the station, AEP will take advantage of the outage and also install a 69kV low side Transformer Circuit Breaker. This way the bus can remain in-service when the transformer goes out as the 69kV has more than one exit and the bus is a single bus single breaker.

Alternatives Considered:
Only adding one line breaker to mitigate the three terminal line.

- Using two line breakers helps mitigate three zones of protection for a line fault. Adding a line breaker to the Oliver Plow –West Side 138kV line helps mitigate the loss of the transmission transformer, the line, and the 138kV bus for a fault.
- Adding a line breaker to the West Side – Kankakee 138kV line protects the distribution load from being dropped for a line fault. During peak conditions this load is not transferable between the two distribution banks so the load will not be recoverable for an outage on the line.

Total Estimated Transmission Cost: $3.5M
Project In-Service date: 01/15/2021



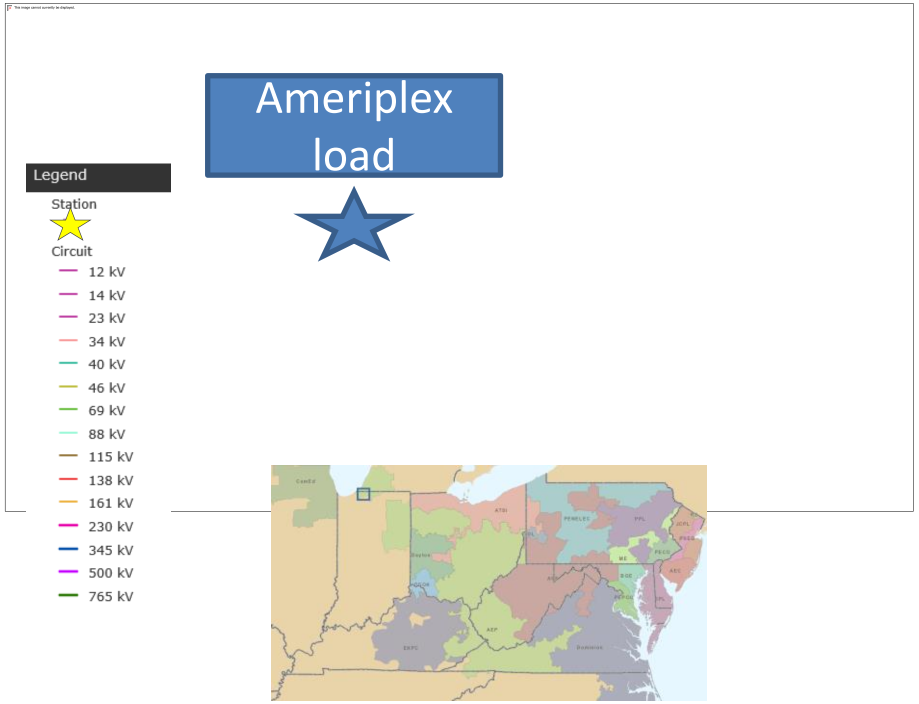
Legend	
345kV	
138kV	
69kV	
34.5kV	
New	
Retired	

Need Number: AEP-2019-IM039
Process Stage: Solutions Meeting 02/21/2020
Previously Presented: Needs Meeting 10/25/2019
Supplemental Project Driver: Customer Service
Specific Assumptions Reference: AEP Interconnection Guidelines (AEP Assumptions Slide 7)

Problem Statement:
South Bend-Olive 138kV line-

- New 1.5MVA block load addition to the Ameriplex complex and new delivery point request from I&M distribution.
- Expected loading of 14MVA at Ameriplex distribution station. Future plans to double initial distribution configuration to allow for up to 25MVA load.

Model: 2024 RTEP



AEP Transmission Zone: M-3 Process
Ameriplex Station Solution

Need Number: AEP-2019-IM039
Process Stage: Solutions Meeting 02/21/2020

Proposed Solution

Cut into the existing South Bend-New Carlisle 138kV line and install tap structures for the Ameriplex extension.
Estimated Cost: $0.7M

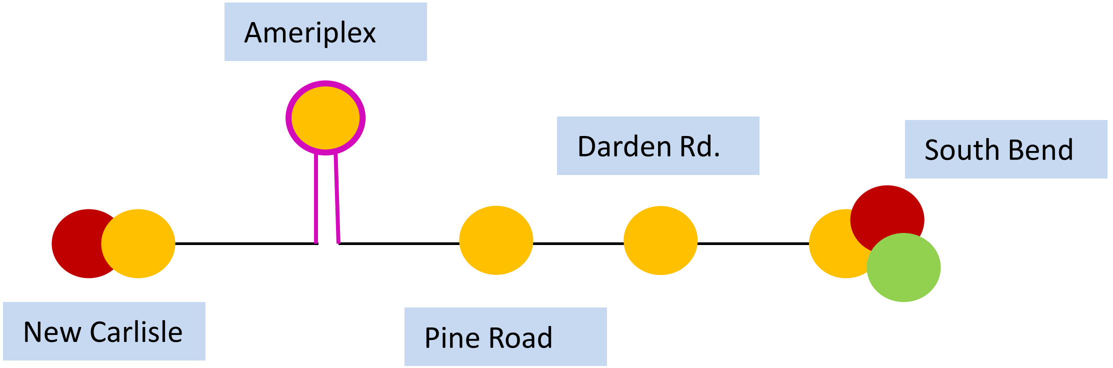
Install 1.75 miles of double circuit 138kV, 795 ACSR, off of the New Carlisle-South Bend 138kV line between New Carlisle and Pine road to serve new Ameriplex station.
Estimated Cost: $6.8M

Install new greenfield station Ameriplex on new greenfield Ameriplex 138kV tap off of the New Carlisle-South Bend 138kV line. The transmission through path consists of one 138kV breaker, one MOAB and one 138kV bus.
Estimated Cost: $2.1M

Total Estimated Transmission Cost: $9.6M

Alternatives Considered:
There were 2 greenfield locations closer to the 138kV line for the new station however these locations were not chosen due to the airport restrictions in the area.

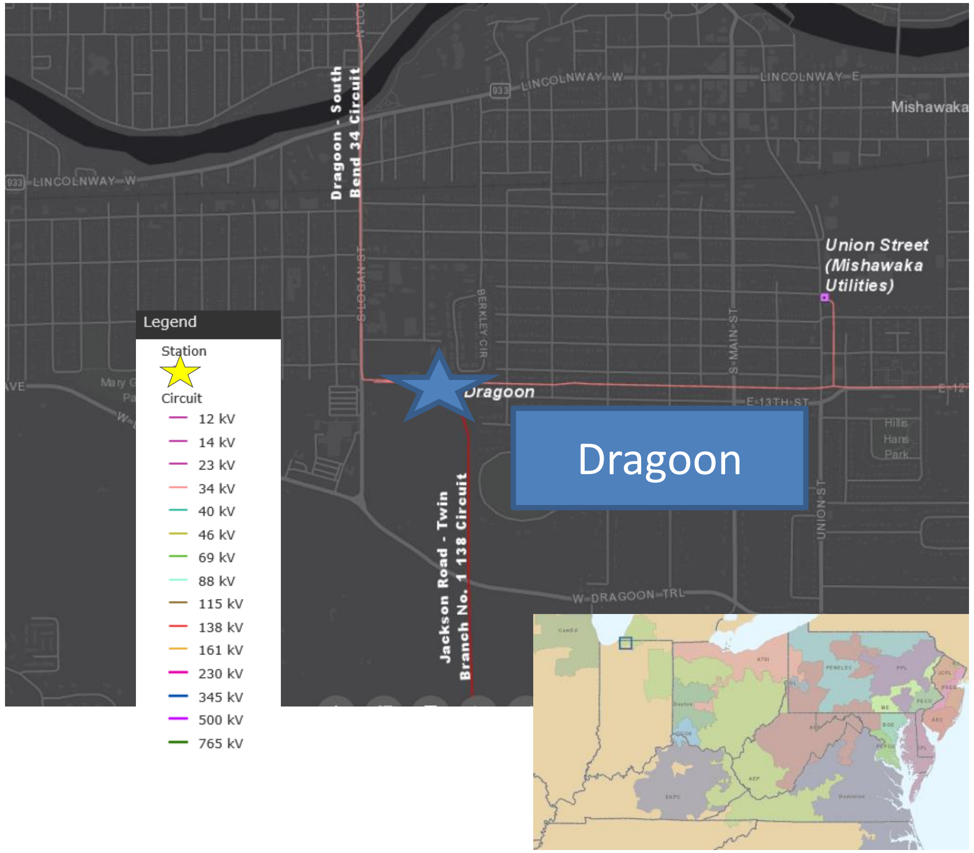
Projected In-Service: 06/01/2021
Project Status: Scoping



Legend	
500 kV	
345 kV	
138 kV	
69 kV	
34.5 kV	
23 kV	
New	

Need Number: AEP-2019-IM040
Process Stage: Solutions Meeting 02/21/2020
Previously Presented: Needs Meeting 10/25/2019
Supplemental Project Driver: Equipment Material/Condition/Performance/Risk
Specific Assumptions Reference: AEP Connection Requirements for the AEP Transmission System (AEP Assumptions Slide 7)

Problem Statement:
Dragoon Station:
- The 34.5 kV Circuit Breakers A, C and D at Dragoon Station are GE 'FK' oil-filled breaker manufactured in 1968
- 17, 51 and 9 fault operations (manufacturer recommendation of 10)
- Oil filled Breakers without oil containment
- The breakers have the following documented conditions:
    - Bushing problems
    - Unavailability of spare parts
    - Fault operations count
    - High moisture readings
- Oil spills are frequent with failures and routine maintenance which is also an environmental hazard



Need Number: AEP-2019-IM040
Process Stage: Solution Meeting 02/21/2020

Proposed Solution:
At Dragoon Station, replace 3-69kV breakers A, C & D.
Estimated Cost: $2M

Alternatives:
There are no viable alternatives.

Proposed IS Date: 11/01/2020

Legend	
500 kV	
345 kV	
138 kV	
69 kV	
34.5 kV	
23 kV	
New	

Appendix

High Level M-3 Meeting Schedule

Assumptions

Activity	Timing
Posting of TO Assumptions Meeting information	20 days before Assumptions Meeting
Stakeholder comments	10 days after Assumptions Meeting

Needs

Activity	Timing
TOs and Stakeholders Post Needs Meeting slides	10 days before Needs Meeting
Stakeholder comments	10 days after Needs Meeting

Solutions

Activity	Timing
TOs and Stakeholders Post Solutions Meeting slides	10 days before Solutions Meeting
Stakeholder comments	10 days after Solutions Meeting

Submission of Supplemental Projects & Local Plan

Activity	Timing
Do No Harm (DNH) analysis for selected solution	Prior to posting selected solution
Post selected solution(s)	Following completion of DNH analysis
Stakeholder comments	10 days prior to Local Plan Submission for integration into RTEP
Local Plan submitted to PJM for integration into RTEP	Following review and consideration of comments received after posting of selected solutions

Revision History

2/10/2020 – V1 – Original version posted to pjm.com

2/21/2020 – V2 – Slide #69, Add project status

– Slide #78, add KV level for the capacitor

3/6/2020 – V3 – Slide #39, Changes reflected in the slides

– Add Slide #43, Need AEP-2020-OH022

PSC Exhibit 16

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF AEP KENTUCKY TRANSMISSION COMPANY, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY PURSUANT TO KRS 278.020 TO PROVIDE WHOLESALE TRANSMISSION SERVICE IN THE COMMONWEALTH	)))))))	CASE NO. 2011-00042

ORDER

This matter comes before the Commission through the application of AEP Kentucky Transmission Company, Inc. ("KY Transco") for a Certificate of Public Convenience and Necessity ("CPCN"), pursuant to KRS 278.020(1), to authorize it to begin providing utility service that consists of wholesale electric transmission service in Kentucky. KY Transco is a third-tier subsidiary of American Electric Power Company, Inc. ("AEP"), is an affiliate of Kentucky Power Company ("Kentucky Power"), and is a member of PJM Interconnection, LLC ("PJM"). KY Transco states that its transmission service will be subject to the jurisdiction of both this Commission and the Federal Energy Regulatory Commission ("FERC"). Its application states that its operations will be subject to this Commission's jurisdiction "as a utility within the meaning of KRS 278.010(3) because it will own, control, operate, and manage facilities to be used for the transmission of electricity to the public for compensation."[1] KY Transco is one of seven wholesale transmission subsidiary companies established by AEP since 2009.

[1] Ky Transco Application at 2.

BACKGROUND

Parties intervening in this matter are the Attorney General of the Commonwealth of Kentucky and Kentucky Industrial Utility Customers, Inc. Neither party filed testimony or a post-hearing brief. The hearing in this matter was initially scheduled for June 21, 2011, but was cancelled and KY Transco was required to file supplemental testimony after it had filed press releases regarding AEP's plans for adding new transmission facilities in Kentucky and after the Commission became aware of the publication of statements by AEP officials concerning AEP's possible divesture of Kentucky Power. KY Transco and Kentucky Power addressed these issues in supplemental testimony and the case was heard on October 19, 2011.

KY Transco filed its post-hearing brief on November 18, 2011. By Order dated March 22, 2012, the Commission directed KY Transco to provide additional information and file testimony by a consultant whose report on investor perceptions of transmission-only companies ("transcos") was presented in support of its request for a CPCN.[2] KY Transco submitted the additional information and testimony of its consultant on May 16, 2012. The record is complete and this matter now stands submitted for a decision.

KY TRANSCO'S PROPOSAL

KY Transco asserts that various construction projects that Kentucky Power will be required to undertake in the next five to ten years will put a significant strain on Kentucky Power's financial condition due to its size, credit standing, and the expected

[2] Ms. Julie Cannell, a financial advisor, authored a report on investors' views of AEP's formation of transcos. She had not been presented as a witness, but her report had been filed as an exhibit to the testimony of one of the witnesses who appeared for KY Transco at the October 19, 2011 hearing.

magnitude of those projects.[3] Creating a transco, which would be responsible for a large part of the future transmission facilities to be built in Kentucky, would lessen this strain and result in a financially healthier Kentucky Power, according to KY Transco. It states that, with its stronger balance sheet, KY Transco would be able to attract capital at lower costs, which, in the long run, would produce lower costs for Kentucky Power's ratepayers.

KY Transco states that when financing is constrained, transmission projects that are not immediately needed may be deferred. Due to its expected ability to obtain financing more easily than Kentucky Power, KY Transco contends that it will be able to undertake projects that might otherwise be deferred, thereby increasing transmission reliability. KY Transco claims that it will free-up capital capacity for Kentucky Power, which will result in "[a]n indirect benefit on the reliability of Kentucky Power's generation and distribution systems."[4]

KY Transco also states that its operation is not expected to adversely affect the credit quality or risk levels of Kentucky Power or other AEP operating companies. In summary, KY Transco claims that it will:

1. Stand in the shoes of Kentucky Power by constructing only transmission projects that Kentucky Power would have constructed and not operate as a merchant transmission provider.
2. Finance future transmission projects only, and not acquire any existing Kentucky Power transmission assets absent specific Commission approval.

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[3] According to the application, AEP is facing this issue in other states in which it operates. AEP transcos have been approved, or are operating, in Indiana, Michigan, Ohio, and Oklahoma and requests to form transcos are pending in other states.

[4] Direct testimony of Lisa M. Barton at 5.

3. Have a minimal effect on Kentucky Power, other than to improve its ability to maintain its current credit rating and to increase its opportunity for investment in facilities used to serve the public.
4. Be subject to substantial regulation by the Commission, if its request for a CPCN is granted.
5. Have the support of Kentucky Power's management.
6. Function as a "[f]inancing vehicle for transmission projects Kentucky Power otherwise would construct, assuming it had the financial ability to do so . . . ."[5]

ANALYSIS

KY Transco's application for a CPCN to provide utility service presents two major issues for adjudication by the Commission. The first is a legal issue of whether KY Transco will be providing utility service that is subject to the Commission's jurisdiction under KRS Chapter 278. The second is a factual issue of whether the public convenience and necessity require a new service provider in the form of a transco in response to the financial condition and capital needs of Kentucky Power. The Commission need only address the second issue, which relates to public convenience and necessity, if it finds that KY Transco will be providing utility service subject to our jurisdiction.

With regard to the first issue of whether KY Transco will be providing utility service that is subject to the Commission's jurisdiction, KY Transco states that it "will provide utility service in the form of the transmission of electricity to its wholesale customers."[6] KY Transco asserts that if its application is approved, KY Transco would

[5] KY Transco's post-hearing brief at 7.

[6] KY Transco's post-hearing brief at 13.

be subject to substantial regulation by the Commission.[7] That regulation would include jurisdiction over numerous aspects of its operations, such as the construction and siting of facilities, financing, and certain aspects of its service, but would not include jurisdiction over its rates or tariffs.[8] Further, KY Transco states that it "will provide the same wholesale transmission service currently being provided by Kentucky Power."[9]

The record clearly shows that KY Transco will be engaged exclusively in the transmission of electricity in interstate commerce and will provide wholesale only transmission service.[10] No retail transmission service will be provided directly to end-use customers in Kentucky.[11] Its transmission assets will be regulated exclusively by the Federal Energy Regulatory Commission ("FERC"). KY Transco's rates for transmission service will be set forth in a tariff to be on file with FERC, and no rates or tariffs will be on file with the Commission.

The Commission's jurisdiction is purely statutory. Kentucky courts have long recognized that "[t]he PSC is a creature of statute and has only such powers as have been granted to it by the General Assembly." *Boone County Water and Sewer v. Public Service Comm'n*, 949 S.W.2d 588, 591 (Ky. 1997). The Kentucky General Assembly has provided that, "The commission shall have exclusive jurisdiction over the regulation of rates and service of utilities . . . ." KRS 278.040(2). This statutory grant of jurisdiction

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[7] KY Transco's post-hearing brief at 10-11.
[8] KY Transco's post-hearing brief at 9-10.

[9] KY Transco's Response to Staff's Fourth Data Request, Item No. 16.

[10] KY Transco's Response to Staff's Fourth Data Request, Item No. 15, and KY Transco's Response to Staff's First Data Request, Item No. 2a.

[11] KY Transco's Response to September 13, 2011 Conference Request, Item No. 1.

to the Commission has also been held to be a limitation on the Commission's jurisdiction.

More than 70 years ago, in addressing the Commission's authority over the terms and conditions in a municipal franchise for utility service, Kentucky's then-highest Court declared that the Commission's "jurisdiction is exclusively confined 'to the regulation of rates and service.'"[12] The following year, the Court again addressed the Commission's jurisdiction under what is now KRS 278.040(2), holding that it "was expressly stated that the intention was to confer jurisdiction only over the matter of rates and service."[13]

In establishing a statutory scheme for the regulation of utilities, as now codified in KRS Chapter 278, the General Assembly directed that "[u]nder rules prescribed by the commission, each utility shall file with the commission, within such time and in such form as the commission designates, schedules showing all rates and conditions for service established by it and collected and enforced." KRS 278.160(1). Pursuant to this directive, the Commission promulgated 807 KAR 5:011, Section 1(9), which defines a "tariff" as "a utility's schedule of each of its rates, charges, tolls, maps, terms, and conditions of service over which the commission has jurisdiction," and Section 2(2), which requires that "[e]ach utility shall maintain a complete tariff with the commission." Thus, under Kentucky statutes and regulations, a utility must file with the Commission a

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[12] *People's Gas Co. of Kentucky v. City of Barbourville*, 291 Ky. 805, 165 S.W. 2d 567, 572 (Ky. 1942).

[13] *Benzinger v. Union Light, Heat & Power Co.*, 293 Ky. 747, 170 S.W. 2d 38, 41 (Ky. 1943). See also, *Simpson County Water District v. City of Franklin*, 872 S.W. 2d 460, 463 (Ky. 1994). ("*Benzinger* ... acknowledged the legislative intent of the act as to place the regulation of rates and service under the exclusive jurisdiction of the PSC.")

tariff setting forth all the rates and conditions of service that are subject to the Commission's jurisdiction.

KY Transco, however, has definitively stated that all of its transmission assets are regulated exclusively by FERC[14] and has specifically stated that "KY Transco would not be subject to any requirements of 807 KAR 5:011 that relate to KY Transco's rates or tariffs, including any requirement that such rates or tariffs be filed with the Public Service Commission of Kentucky, as KY Transco's rates and tariffs are within the exclusive jurisdiction of the Federal Energy Regulatory Commission."[15] While KY Transco asserts that aspects of its service will be subject to Commission jurisdiction,[16] in the absence of a tariff on file with the Commission, KY Transco will not be in compliance with Kentucky law.

The Commission further finds that the definitions set forth in KRS Chapter 278 include the term "regulated activity," which "means a service provided by a utility or other person, the rates and charges of which are regulated by the commission." KRS 278.010(23). Under this definition, the wholesale transmission service that KY Transco proposes to offer would not be a regulated activity, since the rates and charges for KY Transco's transmission service would not be regulated by the Commission. And since the only service that KY Transco is requesting authority to offer is wholesale transmission service, by law, KY Transco would not be providing a regulated service within the parameters of the Commission's jurisdiction under KRS Chapter 278.

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[14] KY Transco's post-hearing brief at 9.

[15] KY Transco's Response to Staff's Fourth Data Request, Item No. 19, at 4.

[16] *Id.*

Therefore, the Commission finds that the service that KY Transco proposes to provide in Kentucky cannot be classified as "utility service," as that term is used in the CPCN statute, KRS 278.020(1), since KY Transco's service would not be a Commission regulated activity. Consequently, KY Transco does not legally qualify for the issuance of a CPCN to provide only wholesale transmission service which would not be a Commission regulated activity and which would be provided under rates and tariffs that are not filed here as required by KRS 278.160(1) for regulated activities.

The fact that KY Transco intends to provide the same wholesale transmission service that Kentucky Power now provides does not convert that FERC regulated activity into one that is a Commission regulated activity under KRS Chapter 278. Kentucky Power provides its retail customers with a bundled service consisting of electric generation, transmission, and distribution. Kentucky Power has on file with the Commission tariffs setting forth its rates and terms and conditions for service, all of which are regulated by the Commission. If the only service provided by Kentucky Power were wholesale transmission, and if it had no tariffs on file with the Commission, that wholesale transmission service would similarly not be a regulated activity as defined in KRS 278.010(23). As noted in the Dissenting Opinion, should KY Transco propose to construction transmission facilities capable of operating at 69 kV or above, those facilities will be subject to siting review by the Kentucky State Board on Electric Generation and Transmission Siting, pursuant to KRS 278.700(5) and 278.714.[17] To the extent that the review of an unregulated transmission line may seem to be less

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[17] *See e.g.*, Case No. 2010-00223, *Application of Southern Indiana Gas & Electric Co. D/B/A Vectrin Energy Delivery of Indiana, Inc. for a Certificate to Construct an Electric Transmission Line from Its A.B. Brown Plant to the Big Rivers Reid EHV Station* (Ky. PSC Sep. 26, 2012).

stringent than the review of a regulated transmission line under KRS 278.020(2), that reflects a policy decision by the General Assembly. It is the General Assembly that establishes the legal bounds of our jurisdiction and we simply cannot expand our jurisdiction to include unregulated wholesale transmission service based on policy reasons.

Having concluded in the negative on the first issue, i.e., that KY Transco will not be providing utility service subject to our jurisdiction, we need not address whether the public convenience and necessity require a new service provider.

IT IS THEREFORE ORDERED that KY Transco's application for a CPCN to provide wholesale electric transmission service in Kentucky is denied.

By the Commission

Vice Chairman Gardner is dissenting.

ENTERED
JUN 10 2013
KENTUCKY PUBLIC
SERVICE COMMISSION

ATTEST:

Executive Director

Case No. 2011-00042

Dissenting Opinion of
Vice Chairman James W. Gardner

The case before us presents this Commission with two very important policy issues facing the regulatory community today: What is the best way to build transmission lines; and what is the relationship between federal and state authorities on this issue? Because the policy consequences of the majority decision on these issues are wrong for Kentucky, and because its legal reasoning is unconvincing, I respectfully dissent.

First, the legal reasoning of the majority opinion is novel and confusing. This opinion relies on FERC's having exclusive jurisdiction over rates and two 70-year old Kentucky cases. It is not disputed that FERC will have the exclusive jurisdiction over the transmission rates of the AEP Kentucky Transmission Company. Additionally, those cases merely hold that the PSC's jurisdiction is limited to rates and services.

The opinion, however, then jumps to the conclusion that if we can't regulate all rates and services, then we won't regulate any of the rates and services, because it is not a utility. This conclusion, however, is not expressed at all in those cases, nor in the statutes relied upon by the majority.

The majority also relies on our own regulation, 807 KAR 5:011, to buttress its conclusion. That regulation merely requires a tariff to be filed and maintained with the commission and defines tariffs as rates, tolls, charges, etc., over which we have jurisdiction. In fact, this regulation actually supports the opposite conclusion! The regulation doesn't say that if a utility's rate is not on file with the commission, it is not a jurisdictional utility. In a tautologous manner, it merely says that those rates which we regulate must be on file with us so we can regulate them. It says nothing else.

It is noteworthy to point out that Kentucky Power Company does not even currently file its transmission rates with the Commission, because FERC currently sets these rates. Thus, there would be no change at all. The transmission tariff would be set by FERC, as it is now, and not filed with us.

Second, with respect to the policy, as noted above, the majority decision seems to say, "Because we can't regulate all aspects of this proposed transmission company, we won't regulate any of it." The majority in my opinion is gambling that after we deny the applicant the ability to be a utility, AEP will build future transmission lines in Kentucky as it always has, i.e. by Kentucky Power Company itself. However, I believe that it is far more likely that the transmission will be built by the applicant, AEP Kentucky Transmission Company, Inc., as an unregulated merchant company. If that occurs we relinquish all regulation.[1]

Prior to this decision the Commission has consistently refused or has been reluctant to relinquish authority to federal utility regulators (i.e. FERC or FCC), to the market itself, or to regional transmission organizations. But I believe this decision does just that. We have let the perfect be the enemy of the possible. I do not believe we should further limit our ability to have a seat at the transmission planning table, but this decision, in fact, does that. The applicant acknowledges that there are many areas where we would still be able to regulate if we were to allow AEP Kentucky Transmission

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[1] As Commissioners, the three of us would, of course, sit on the seven-member siting board to review a transmission application; however, that review is similar to that of a local planning and zoning board, where we basically are limited to considering only aesthetics.

Company, Inc. to be a utility.[2] I would not risk losing the ability to regulate those important matters.

A lot has happened in utility regulation in the last 70 years. The federal government has assumed more and more authority from the states. The price of natural gas has been deregulated. The price of transporting gas on interstate pipelines is set by FERC, yet we still regulate the distribution of natural gas, even though the commodity cost of natural gas and interstate pipeline rates are not set by us. Likewise, we do not set the rates for telephone service. The FCC does, even though we still regulate some aspects, such as customer service. Likewise, just because we don't regulate <u>all</u> electric transmission functions, doesn't mean we shouldn't regulate <u>any</u> of them.

Finally, having concluded that the applicant is a utility, I also believe the evidence is sufficient that there is a public need and necessity for such service.

For these reasons, I respectfully dissent and would grant the applicant a certificate.

James W. Gardner, Vice Chairman

ENTERED
JUN 10 2013
KENTUCKY PUBLIC SERVICE COMMISSION

ATTEST:

[2] Those matters include transfer of control, construction and siting of transmission lines under KRS 278.020, service, transfer of assets, all financings, transactions with affiliates, requirement to obtain a CPCN before bidding on a franchise, production and examination of books and records, and revenues would be subject to levy of assessment.

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