COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE ADJUSTMENT
OF ELECTRIC RATES OF DUKE ENERGY KENTUCKY, INC.

CASE NO. 2017-00321

FILING REQUIREMENTS

VOLUME 15

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Vol. #	Tab #	Filing Requirement	Description	Sponsoring Witness
1	6	807 KAR 5:001 Section 14(2)	If a corporation, the applicant shall identify in the application the state in which it is incorporated and the date of its incorporation, attest that it is currently in good standing in the state in which it is incorporated, and, if it is not a Kentucky corporation, state if it is authorized to transact business in Kentucky.	James P. Henning
1	7	807 KAR 5:001 Section 14(3)	If a limited liability company, the applicant shall identify in the application the state in which it is organized and the date on which it was organized, attest that it is in good standing in the state in which it is organized, and, if it is not a Kentucky limited liability company, state if it is authorized to transact business in Kentucky.	James P. Henning
1	8	807 KAR 5:001 Section 14(4)	If the applicant is a limited partnership, a certified copy of its limited partnership agreement and all amendments, if any, shall be annexed to the application, or a written statement attesting that its partnership agreement and all amendments have been filed with the commission in a prior proceeding and referencing the case number of the prior proceeding.	James P. Henning
1	9	807 KAR 5:001 Section 16 (1)(b)(1)	Reason adjustment is required.	James P. Henning William Don Wathen, Jr.
1	10	807 KAR 5:001 Section 16 (1)(b)(2)	Certified copy of certificate of assumed name required by KRS 365.015 or statement that certificate not necessary.	James P. Henning
1	11	807 KAR 5:001 Section 16 (1)(b)(3)	New or revised tariff sheets, if applicable in a format that complies with 807 KAR 5:011 with an effective date not less than thirty (30) days from the date the application is filed	Bruce L. Sailers
1	12	807 KAR 5:001 Section 16 (1)(b)(4)	Proposed tariff changes shown by present and proposed tariffs in comparative form or by indicating additions in italics or by underscoring and striking over deletions in current tariff.	Bruce L. Sailers
1	13	807 KAR 5:001 Section 16 (1)(b)(5)	A statement that notice has been given in compliance with Section 17 of this administrative regulation with a copy of the notice.	James P. Henning
1	14	807 KAR 5:001 Section 16(2)	If gross annual revenues exceed $5,000,000, written notice of intent filed at least 30 days, but not more than 60 days prior to application. Notice shall state whether application will be supported by historical or fully forecasted test period.	James P. Henning
1	15	807 KAR 5:001 Section 16(3)	Notice given pursuant to Section 17 of this administrative regulation shall satisfy the requirements of 807 KAR 5:051, Section 2.	James P. Henning

1	16	807 KAR 5:001 Section 16(6)(a)	The financial data for the forecasted period shall be presented in the form of pro forma adjustments to the base period.	Robert H. Pratt
1	17	807 KAR 5:001 Section 16(6)(b)	Forecasted adjustments shall be limited to the twelve (12) months immediately following the suspension period.	Sarah E. Lawler Cynthia S. Lee Robert H. Pratt
1	18	807 KAR 5:001 Section 16(6)(c)	Capitalization and net investment rate base shall be based on a thirteen (13) month average for the forecasted period.	Sarah E. Lawler
1	19	807 KAR 5:001 Section 16(6)(d)	After an application based on a forecasted test period is filed, there shall be no revisions to the forecast, except for the correction of mathematical errors, unless the revisions reflect statutory or regulatory enactments that could not, with reasonable diligence, have been included in the forecast on the date it was filed. There shall be no revisions filed within thirty (30) days of a scheduled hearing on the rate application.	Robert H. Pratt
1	20	807 KAR 5:001 Section 16(6)(e)	The commission may require the utility to prepare an alternative forecast based on a reasonable number of changes in the variables, assumptions, and other factors used as the basis for the utility's forecast.	Robert H. Pratt
1	21	807 KAR 5:001 Section 16(6)(f)	The utility shall provide a reconciliation of the rate base and capital used to determine its revenue requirements.	Sarah E. Lawler
1	22	807 KAR 5:001 Section 16(7)(a)	Prepared testimony of each witness supporting its application including testimony from chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program.	All Witnesses
1	23	807 KAR 5:001 Section 16(7)(b)	Most recent capital construction budget containing at minimum 3 year forecast of construction expenditures.	Robert H. Pratt Joseph A. Miller Anthony J. Platz
1	24	807 KAR 5:001 Section 16(7)(c)	Complete description, which may be in prefiled testimony form, of all factors used to prepare forecast period. All econometric models, variables, assumptions, escalation factors, contingency provisions, and changes in activity levels shall be quantified, explained, and properly supported.	Robert H. Pratt
1	25	807 KAR 5:001 Section 16(7)(d)	Annual and monthly budget for the 12 months preceding filing date, base period and forecasted period.	Robert H. Pratt
1	26	807 KAR 5:001 Section 16(7)(e)	Attestation signed by utility's chief officer in charge of Kentucky operations providing: 1. That forecast is reasonable, reliable, made in good faith and that all basic assumptions used have been identified and justified; and 2. That forecast contains same assumptions and methodologies used in forecast prepared for use by management, or an identification and explanation for any differences; and 3. That productivity and efficiency gains are included in the forecast.	James P. Henning

1	27	807 KAR 5:001 Section 16(7)(f)	For each major construction project constituting 5% or more of annual construction budget within 3 year forecast, following information shall be filed: 1. Date project began or estimated starting date; 2. Estimated completion date; 3. Total estimated cost of construction by year exclusive and inclusive of Allowance for Funds Used During construction ("AFUDC") or Interest During construction Credit; and 4. Most recent available total costs incurred exclusive and inclusive of AFUDC or Interest During Construction Credit.	Robert H. Pratt Joseph A. Miller Anthony J. Platz
1	28	807 KAR 5:001 Section 16(7)(g)	For all construction projects constituting less than 5% of annual construction budget within 3 year forecast, file aggregate of information requested in paragraph (f) 3 and 4 of this subsection.	Robert H. Pratt Joseph A. Miller Anthony J. Platz
1	29	807 KAR 5:001 Section 16(7)(h)	Financial forecast for each of 3 forecasted years included in capital construction budget supported by underlying assumptions made in projecting results of operations and including the following information: 1. Operating income statement (exclusive of dividends per share or earnings per share); 2. Balance sheet; 3. Statement of cash flows; 4. Revenue requirements necessary to support the forecasted rate of return; 5. Load forecast including energy and demand (electric); 6. Access line forecast (telephone); 7. Mix of generation (electric); 8. Mix of gas supply (gas); 9. Employee level; 10.Labor cost changes; 11.Capital structure requirements; 12.Rate base; 13.Gallons of water projected to be sold (water); 14.Customer forecast (gas, water); 15.MCF sales forecasts (gas); 16.Toll and access forecast of number of calls and number of minutes (telephone); and 17.A detailed explanation of any other information provided.	Robert H. Pratt John Verderame John L. Sullivan, III Benjamin Passty
1	30	807 KAR 5:001 Section 16(7)(i)	Most recent FERC or FCC audit reports.	David L. Doss
2	31	807 KAR 5:001 Section 16(7)(j)	Prospectuses of most recent stock or bond offerings.	John L. Sullivan, III
2	32	807 KAR 5:001 Section 16(7)(k)	Most recent FERC Form 1 (electric), FERC Form 2 (gas), or PSC Form T (telephone).	David L. Doss
3-4	33	807 KAR 5:001 Section 16(7)(l)	Annual report to shareholders or members and statistical supplements for the most recent 2 years prior to application filing date.	John L. Sullivan, III
5	34	807 KAR 5:001 Section 16(7)(m)	Current chart of accounts if more detailed than Uniform System of Accounts charts.	David L. Doss
5	35	807 KAR 5:001 Section 16(7)(n)	Latest 12 months of the monthly managerial reports providing financial results of operations in comparison to forecast.	David L. Doss

5	36	807 KAR 5:001 Section 16(7)(o)	Complete monthly budget variance reports, with narrative explanations, for the 12 months prior to base period, each month of base period, and subsequent months, as available.	David L. Doss Robert H. Pratt
6-8	37	807 KAR 5:001 Section 16(7)(p)	SEC's annual report for most recent 2 years, Form 10-Ks and any Form 8-Ks issued during prior 2 years and any Form 10-Qs issued during past 6 quarters.	David L. Doss
9	38	807 KAR 5:001 Section 16(7)(q)	Independent auditor's annual opinion report, with any written communication which indicates the existence of a material weakness in internal controls.	David L. Doss
9	39	807 KAR 5:001 Section 16(7)(r)	Quarterly reports to the stockholders for the most recent 5 quarters.	John L. Sullivan
9	40	807 KAR 5:001 Section 16(7)(s)	Summary of latest depreciation study with schedules itemized by major plant accounts, except that telecommunications utilities adopting PSC's average depreciation rates shall identify current and base period depreciation rates used by major plant accounts. If information has been filed in another PSC case, refer to that case's number and style.	John J. Spanos
9	41	807 KAR 5:001 Section 16(7)(t)	List all commercial or in-house computer software, programs, and models used to develop schedules and work papers associated with application. Include each software, program, or model; its use; identify the supplier of each; briefly describe software, program, or model; specifications for computer hardware and operating system required to run program	Sarah E. Lawler
9	42	807 KAR 5:001 Section 16(7)(u)	If utility had any amounts charged or allocated to it by affiliate or general or home office or paid any monies to affiliate or general or home office during the base period or during previous 3 calendar years, file: 1. Detailed description of method of calculation and amounts allocated or charged to utility by affiliate or general or home office for each allocation or payment; 2. method and amounts allocated during base period and method and estimated amounts to be allocated during forecasted test period; 3. Explain how allocator for both base and forecasted test period was determined; and 4. All facts relied upon, including other regulatory approval, to demonstrate that each amount charged, allocated or paid during base period is reasonable.	Jeffrey R. Setser
10	43	807 KAR 5:001 Section 16(7)(v)	If gas, electric or water utility with annual gross revenues greater than $5,000,000, cost of service study based on methodology generally accepted in industry and based on current and reliable data from single time period.	James E. Ziolkowski

11	44	807 KAR 5:001 Section 16(7)(w)	Local exchange carriers with fewer than 50,000 access lines need not file cost of service studies, except as specifically directed by PSC. Local exchange carriers with more than 50,000 access lines shall file: 1. Jurisdictional separations study consistent with Part 36 of the FCC's rules and regulations; and 2. Service specific cost studies supporting pricing of services generating annual revenue greater than $1,000,000 except local exchange access: a. Based on current and reliable data from single time period; and b. Using generally recognized fully allocated, embedded, or incremental cost principles.	N/A
11	45	807 KAR 5:001 Section 16(8)(a)	Jurisdictional financial summary for both base and forecasted periods detailing how utility derived amount of requested revenue increase.	Sarah E. Lawler
11	46	807 KAR 5:001 Section 16(8)(b)	Jurisdictional rate base summary for both base and forecasted periods with supporting schedules which include detailed analyses of each component of the rate base.	Sarah E. Lawler Cynthia S. Lee Robert H. Pratt Lisa M. Belluci James E. Ziolkowski David L. Doss
11	47	807 KAR 5:001 Section 16(8)(c)	Jurisdictional operating income summary for both base and forecasted periods with supporting schedules which provide breakdowns by major account group and by individual account.	Sarah E. Lawler
11	48	807 KAR 5:001 Section 16(8)(d)	Summary of jurisdictional adjustments to operating income by major account with supporting schedules for individual adjustments and jurisdictional factors.	Sarah E. Lawler Cynthia S. Lee Robert H. Pratt James E. Ziolkowski
11	49	807 KAR 5:001 Section 16(8)(e)	Jurisdictional federal and state income tax summary for both base and forecasted periods with all supporting schedules of the various components of jurisdictional income taxes.	Lisa M. Bellucci
11	50	807 KAR 5:001 Section 16(8)(f)	Summary schedules for both base and forecasted periods (utility may also provide summary segregating items it proposes to recover in rates) of organization membership dues; initiation fees; expenditures for country club; charitable contributions; marketing, sales, and advertising; professional services; civic and political activities; employee parties and outings; employee gifts; and rate cases.	Sarah E. Lawler
11	51	807 KAR 5:001 Section 16(8)(g)	Analyses of payroll costs including schedules for wages and salaries, employee benefits, payroll taxes, straight time and overtime hours, and executive compensation by title.	Sarah E. Lawler Tom Silinski
11	52	807 KAR 5:001 Section 16(8)(h)	Computation of gross revenue conversion factor for forecasted period.	Sarah E. Lawler
11	53	807 KAR 5:001 Section 16(8)(i)	Comparative income statements (exclusive of dividends per share or earnings per share), revenue statistics and sales statistics for 5 calendar years prior to application filing date, base period, forecasted period, and 2 calendar years beyond forecast period.	David L. Doss Robert H. Pratt

11	54	807 KAR 5:001 Section 16(8)(j)	Cost of capital summary for both base and forecasted periods with supporting schedules providing details on each component of the capital structure.	John L. Sullivan, III
11	55	807 KAR 5:001 Section 16(8)(k)	Comparative financial data and earnings measures for the 10 most recent calendar years, base period, and forecast period.	Cynthia S. Lee Robert H. Pratt John L. Sullivan David L. Doss
11	56	807 KAR 5:001 Section 16(8)(l)	Narrative description and explanation of all proposed tariff changes.	Bruce L. Sailers
11	57	807 KAR 5:001 Section 16(8)(m)	Revenue summary for both base and forecasted periods with supporting schedules which provide detailed billing analyses for all customer classes.	Bruce L. Sailers
11	58	807 KAR 5:001 Section 16(8)(n)	Typical bill comparison under present and proposed rates for all customer classes.	Bruce L. Sailers
11	59	807 KAR 5:001 Section 16(10)	Request for waivers from the requirements of this section shall include the specific reasons for the request. The commission shall grant the request upon good cause shown by the utility.	Legal
11	60	807 KAR 5:001 Section (17)(1)	(1) Public postings. (a) A utility shall post at its place of business a copy of the notice no later than the date the application is submitted to the commission. (b) A utility that maintains a Web site shall, within five (5) business days of the date the application is submitted to the commission, post on its Web sites: 1. A copy of the public notice; and 2. A hyperlink to the location on the commission's Web site where the case documents are available. (c) The information required in paragraphs (a) and (b) of this subsection shall not be removed until the commission issues a final decision on the application.	James P. Henning

11	61	807 KAR 5:001 Section 17(2)	(2) Customer Notice. (a) If a utility has twenty (20) or fewer customers, the utility shall mail a written notice to each customer no later than the date on which the application is submitted to the commission. (b) If a utility has more than twenty (20) customers, it shall provide notice by: 1. Including notice with customer bills mailed no later than the date the application is submitted to the commission; 2. Mailing a written notice to each customer no later than the date the application is submitted to the commission; 3. Publishing notice once a week for three (3) consecutive weeks in a prominent manner in a newspaper of general circulation in the utility's service area, the first publication to be made no later than the date the application is submitted to the commission; or 4. Publishing notice in a trade publication or newsletter delivered to all customers no later than the date the application is submitted to the commission. (c) A utility that provides service in more than one (1) county may use a combination of the notice methods listed in paragraph (b) of this subsection.	James P. Henning
11	62	807 KAR 5:001 Section 17(3)	(3) Proof of Notice. A utility shall file with the commission no later than forty-five (45) days from the date the application was initially submitted to the commission: (a) If notice is mailed to its customers, an affidavit from an authorized representative of the utility verifying the contents of the notice, that notice was mailed to all customers, and the date of the mailing; (b) If notice is published in a newspaper of general circulation in the utility's service area, an affidavit from the publisher verifying the contents of the notice, that the notice was published, and the dates of the notice's publication; or (c) If notice is published in a trade publication or newsletter delivered to all customers, an affidavit from an authorized representative of the utility verifying the contents of the notice, the mailing of the trade publication or newsletter, that notice was included in the publication or newsletter, and the date of mailing.	James P. Henning

11	63	807 KAR 5:001 Section 17(4)	(4) Notice Content. Each notice issued in accordance with this section shall contain: (a) The proposed effective date and the date the proposed rates are expected to be filed with the commission; (b) The present rates and proposed rates for each customer classification to which the proposed rates will apply; (c) The amount of the change requested in both dollar amounts and percentage change for each customer classification to which the proposed rates will apply; (d) The amount of the average usage and the effect upon the average bill for each customer classification to which the proposed rates will apply, except for local exchange companies, which shall include the effect upon the average bill for each customer classification for the proposed rate change in basic local service; (e) A statement that a person may examine this application at the offices of (utility name) located at (utility address); (f) A statement that a person may examine this application at the commission's offices located at 211 Sower Boulevard, Frankfort, Kentucky, Monday through Friday, 8:00 a.m. to 4:30 p.m., or through the commission's Web site at http://psc.ky.gov; (g) A statement that comments regarding the application may be submitted to the Public Service Commission through its Web site or by mail to Public Service Commission, Post Office Box 615, Frankfort, Kentucky 40602; (h) A statement that the rates contained in this notice are the rates proposed by (utility name) but that the Public Service Commission may order rates to be charged that differ from the proposed rates contained in this notice; (i) A statement that a person may submit a timely written request for intervention to the Public Service Commission, Post Office Box 615, Frankfort, Kentucky 40602, establishing the grounds for the request including the status and interest of the party; and (j) A statement that if the commission does not receive a written request for intervention within thirty (30) days of initial publication or mailing of the notice, the commission may take final action on the application.	Bruce L. Sailers
11	64	807 KAR 5:001 Section 17(5)	(5) Abbreviated form of notice. Upon written request, the commission may grant a utility permission to use an abbreviated form of published notice of the proposed rates, provided the notice includes a coupon that may be used to obtain all the required information.	N/A
12	-	807 KAR 5:001 Section 16(8)(a) through (k)	Schedule Book (Schedules A-K)	Various
13	-	807 KAR 5:001 Section 16(8)(l) through (n)	Schedule Book (Schedules L-N)	Bruce L. Sailers

14	-	-	Work papers	Various
15	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 1 of 6)	Various
16	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 2 of 6)	Various
17	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 3 of 6)	Various
18	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 4 of 6)	Various
19	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 5 of 6)	Various
20	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 6 of 6)	Various
20	-	KRS 278.2205(6)	Cost Allocation Manual	Legal

Direct Testimony of
James P. Henning

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; 3) Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All Other Required Approvals and Relief.	)))))))))	Case No. 2017-00321

DIRECT TESTIMONY OF

JAMES P. HENNING

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

September 1, 2017

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James P. Henning, and my business address is 139 East Fourth Street, Cincinnati, Ohio 45202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services LLC (DEBS), as State President of Duke Energy Kentucky, Inc., (Duke Energy Kentucky or the Company) and its parent, Duke Energy Ohio, Inc. (Duke Energy Ohio). DEBS provides various administrative and other services to Duke Energy Kentucky and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science in Financial Services from Wright State University in 1988 and a Master of Business Administration from the University of South Florida in 1990.

I have worked in the energy industry for over twenty-five years. From 1990 through 1996, I was employed at The Dayton Power & Light Company (DP&L) as a Natural Gas Analyst in the Natural Gas Supply Planning Department. In 1996, I joined Cinergy Corp.'s non-regulated natural gas sales company, Cinergy Resources, Inc., as the Manager of Energy Sales and Services and worked in this capacity until 2000. From 2000 through 2001, I worked for various departments within Cinergy, including Environmental Services, Labor Relations, and Natural Gas Operations. Beginning October 2001, I led the commercial activities of Duke Energy's regulated natural gas business in Ohio and Kentucky as General Manager, Natural Gas Commercial Operations. In September 2010, I became Vice President of Government and Regulatory Affairs for Duke Energy Kentucky and Duke Energy Ohio. I assumed the role of State President, Duke Energy Kentucky and Duke Energy Ohio, in December 2012.

Q. PLEASE DESCRIBE YOUR DUTIES AS STATE PRESIDENT, DUKE ENERGY KENTUCKY.

A. As State President, Duke Energy Kentucky, I am responsible for ensuring that our customers continue to have access to safe, reliable, and reasonably priced electric and natural gas service and that these services are provided in accordance with applicable federal and state laws and regulations. I am also involved in external efforts relating to governmental and regulatory affairs, interacting with state and community leaders and regulators on matters relevant to Duke Energy Kentucky's business and presence in the Commonwealth of Kentucky. I am responsible for the Company's community relations and economic development efforts, as well as Duke Energy's charitable contributions in the Northern Kentucky and Greater Cincinnati region.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. Yes. I have previously testified before the Kentucky Public Service Commission (Commission). Most recently, I provided testimony supporting the Company's Advanced Metering Infrastructure deployment in Case No. 2016-00152.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THESE PROCEEDINGS?

A. My testimony provides an overview of Duke Energy Kentucky's electric business operations and community involvement in its Northern Kentucky service territory. I next discuss the major developments since the Company's last electric base rate case in 2006, including the Company's integration into the PJM Interconnection, LLC, (PJM) in 2012, its becoming the sole owner of the East Bend Generating Station (East Bend) in 2015, and the retirement of Duke Energy Kentucky's Miami Fort Unit 6 generating station (MF6) May of 2015.

I next provide an overview of Duke Energy Kentucky's need for an increase in electric rates, the reasonableness of the Company's request, and discuss how the timely and constructive regulatory treatment the Company is seeking in this proceeding will enable us to continue our strong levels of customer satisfaction by providing our customers with the reasonably priced, reliable service they have come to expect from us.

I describe the Company's proposals to implement three new cost recovery mechanisms for environmental expenditures, incremental distribution capital related to reliability and integrity performance improvement programs, and certain incremental costs associated with tariffs approved by the Federal Energy Regulatory Commission (FERC).

I provide an overview of the new customer-oriented optional billing offers to provide customers greater control and transparency over their electric bills.

I sponsor the following Filing Requirements (FR) required under 807 KAR 5:001: FR 14(1) through FR 14(4), FR 16(1)(b)(1), FR 16(1)(b)(2), FR 16(1)(b)(5), FR 16(2), FR 16(3). Additionally, I discuss the existing programs to achieve improvements in efficiency and productivity and the purpose of each program, as required by FR 16(7)(a). I provide the management statement of attestation, required by FR 16(7)(e), concerning the forecasted financial data. I sponsor the affidavit in support of the notice requirements under FR 17(1) through (3). Finally, I introduce the other witnesses who testify on the Company's behalf, and provide an overview of their testimony.

II. OVERVIEW OF KENTUCKY OPERATIONS

A. COMPANY OVERVIEW

Q. PLEASE DESCRIBE DUKE ENERGY KENTUCKY'S UTILITY OPERATIONS IN NORTHERN KENTUCKY.

A. Duke Energy Kentucky provides electric service to approximately 140,600 customers and natural gas service to approximately 98,200 customers in Boone, Campbell, Gallatin, Grant, Kenton, and Pendleton counties in northern Kentucky.

From our Cincinnati headquarters, Duke Energy Kentucky directs the planning, construction, operation, and maintenance of our electric transmission and distribution systems. The Company's electric customers are served via approximately 107 circuit-miles of transmission lines and approximately 2,900 circuit-miles of distribution lines throughout our territory. Most customers continue to be served via overhead transmission and distribution lines; however, the Company is increasingly serving customers with underground facilities.

The Company's local operations are as follows:

- Cincinnati, Ohio – the headquarters for Duke Energy Kentucky;
- Rabbit Hash, Kentucky – the East Bend Generating Station;
- Trenton, Ohio – the Woodsdale Generating Station;
- Erlanger, Kentucky – Duke Energy Kentucky's construction and maintenance facility; and
- Covington, Kentucky – Duke Energy Kentucky's meter reading.

From these locations, Duke Energy Kentucky generates electricity; provides for the construction, operation and maintenance of its electric delivery system; and conducts its business operations.

Q. PLEASE PROVIDE AN OVERVIEW OF THE DUKE ENERGY CORPORATE AND BUSINESS STRUCTURE.

A. Duke Energy is one of the largest utility companies in the United States. Through a series of mergers and acquisitions, including the 2006 merger with Cinergy Corp., the 2012 merger with Progress Energy, and the more recent merger with Piedmont Natural Gas Company, Duke Energy now serves approximately 7.4 million electric customers and over 1.5 million natural gas customers, representing a population of over 24 million in seven states, comprising Kentucky, Ohio, Indiana, Florida, North Carolina, South Carolina, and Tennessee.

Duke Energy Kentucky is a wholly owned subsidiary of Duke Energy Ohio. Duke Energy Ohio is a wholly owned subsidiary of Cinergy Corporation, which is wholly owned by Duke Energy.

Q. PLEASE DESCRIBE HOW BEING A PART OF THE DUKE ENERGY FAMILY OF COMPANIES ASSISTS DUKE ENERGY KENTUCKY IN PROVIDING SAFE, RELIABLE, ADEQUATE, AND REASONABLY-PRICED ELECTRIC SERVICE TO ITS KENTUCKY CUSTOMERS.

A. Duke Energy Kentucky is the regulated utility operating company that provides retail electric and natural gas services in six counties in northern Kentucky. The services that Duke Energy Kentucky's electric customers receive from Duke Energy Kentucky, however, may be performed by Duke Energy Kentucky employees, by shared service employees, by employees of another affiliated company in accordance with approved service agreements, or by third-party contractor employees.

Duke Energy has one service company, DEBS that provides various administrative and operational services for Duke Energy Kentucky. Duke Energy Kentucky also receives services from expertise contained in several of its affiliated utility operating companies, including its parent, Duke Energy Ohio, as well as sister companies, Duke Energy Indiana LLC, Duke Energy Carolinas, LLC, Duke Energy Progress LLC, and Piedmont.

Our customers benefit from services provided by other Duke Energy affiliates that have entered into services agreements with Duke Energy Kentucky. The benefit of these affiliated relationships to customers is that Duke Energy Kentucky has ready access to personnel and expertise in the industry without having to absorb all of the costs of having its own dedicated resources for these shared functions. Such costs are shared between and among all of the Duke

Energy family of companies according to the terms and conditions of the various service agreements.

The Commission approved these services agreements in Case No. 2005-00228, involving the Duke Energy/Cinergy merger, again in Case No. 2011-00124 involving the merger between Duke Energy and Progress Energy, and most recently in Case No. 2016-00312 to incorporate the recently acquired Piedmont Natural Gas Company (Piedmont) as an affiliate party to these agreements.

Q. HOW DO DUKE ENERGY KENTUCKY'S CUSTOMERS KNOW WHICH LEGAL ENTITY IS PROVIDING SERVICE?

A. Our customers in Kentucky receive all of their utility services from Duke Energy Kentucky. The legal entity structure and relationships that I have described (and that Duke Energy Kentucky witness Mr. Jeffrey Setser describes in more detail in his testimony) are essentially invisible and seamless to our retail electric customers in Kentucky. In other words, our Kentucky customers receive reliable, adequate, and reasonably priced electric service from Duke Energy Kentucky without regard to how the Company is structured or organized to provide those services.

B. COMMUNITY ENGAGEMENT

Q. PLEASE GIVE AN OVERVIEW OF DUKE ENERGY KENTUCKY'S ECONOMIC DEVELOPMENT ACTIVITIES.

A. Duke Energy embraces its responsibility to promote economic development in the communities in which it does business. Access to affordable, reliable power is a critical factor in a company's decision about where to locate its facilities.

With some of the most competitive electric rates in the state, Duke Energy Kentucky is well positioned to meet companies' energy needs and attract job-creating industry and capital investment in our service territory. But business clients need more than reliable power. They also need readily available building sites, access to state and local incentives, flexible workforce training programs, and proximity to a community of customers and business partners. Duke Energy Kentucky assists in meeting these needs through our partnerships with our local communities and with the Commonwealth of Kentucky.

In 2016, Site Selection magazine named Duke Energy to its Top 10 Utilities in Site Selection for North America for the eighteenth consecutive year. Whether a company is looking for a new site for manufacturing, logistics, distribution, or headquarters, our economic development team is there to help local and regional economic development professionals. Cited by Site Selection magazine as a best practice, the Duke Energy "Site Readiness" program seeks to identify a plan to improve large tracts of industrial land in the service territory, moving them closer to being "fully marketable." In collaboration with local economic development organizations, Duke Energy offered funding to local communities that have taken advantage of the program and spent dollars improving participant sites.

Duke Energy Kentucky's strategic partnerships and board memberships with local and regional economic development efforts such as the Regional Economic Development Initiative (REDI) Cincinnati and Northern Kentucky Tri-

ED, combined with Duke Energy Kentucky's low electric rates, have resulted in a number of economic development successes in northern Kentucky.

We estimate that our cooperative efforts, along with those of state and local economic development officials, have contributed to the creation of nearly 20,000 Northern Kentucky jobs and more than $2 billion of capital investment in northern Kentucky since 2006.

Duke Energy Kentucky's employees have actively served on several boards and committees of organizations in the community that promote economic development in the region. Some of these organizations include:

- Northern Kentucky Tri-ED;
- Northern Kentucky Chamber of Commerce;
- Kentucky Association of Economic Development;
- REDI;
- Cintrifuse;
- Cincinnati USA Regional Chamber of Commerce;
- Cincinnati Business Committee, Economic Development;
- Cincinnati Center City Development Corporation;
- Greater Cincinnati Chinese Chamber of Commerce;
- European American Chamber of Commerce; and
- Kentucky Chamber of Commerce.

Q. DESCRIBE DUKE ENERGY KENTUCKY'S CHARITABLE GIVING PHILOSOPHY.

A. Duke Energy Kentucky has made good corporate citizenship a priority by giving back to the communities we serve. Since 2009, Duke Energy Kentucky and the Duke Energy Foundation, formerly the Cinergy Foundation, have contributed approximately $4 million in shareholder dollars to Kentucky charitable organizations. We strongly encourage a spirit of volunteerism among our employees, who contribute countless hours of volunteer time each year to support the many communities in which they live and work. This passion for giving back is part of our legacy and who we are as a company. Whenever our employees act on this passion by volunteering or making charitable contributions, we are part of what is known as Duke Energy In Action. During 2016, Duke Energy In Action had fifteen volunteer events in Kentucky where employees, their families, and retirees volunteered over 700 hours of their time. Corporate stewardship is important to Duke Energy Kentucky. We participate in local giving campaigns that support United Way and ArtsWave. These campaigns support numerous non-profit organizations in Northern Kentucky making our communities more vibrant.

Q. DESCRIBE THE METHODS EMPLOYED BY DUKE ENERGY KENTUCKY TO INTERACT WITH CUSTOMERS.

A. Duke Energy Corporation and Duke Energy Kentucky place a significant emphasis on customer satisfaction. Providing customers with a variety of convenient methods for interacting with its electric service provider is an important means of enhancing customer satisfaction. Customers can remotely interact with the Company through a variety of customer service channels, including:

- Contact Centers;
- Business Service Center;
- Pay Agents;
- Automated Phone Service;
- Enhanced Web Functionality for Online Services; and
- Focus groups for small/medium businesses.

Q. DO CUSTOMERS HAVE OPTIONS FOR HOW THEY ARE ABLE TO PAY THEIR BILLS?

A. Duke Energy Kentucky has a number of programs designed to allow customers to conveniently manage their bills:

- Budget Billing;
- Adjusted Due Date;
- Extended Payment Agreements; and
- Home Energy Assistance.

The Company also offers a number of convenient bill payment options in addition to the traditional option of payment via the United States Postal Service. Such options include:

- Speedpay;
- e-bill; and
- Payment Advantage.

C. CUSTOMER SATISFACTION

Q. HOW DOES DUKE ENERGY KENTUCKY MEASURE PERFORMANCE FOR PROVIDING HIGH QUALITY CUSTOMER SERVICE?

A. Duke Energy Kentucky strives to consistently provide high quality customer service. We measure customer satisfaction performance through two primary tools: the annual J.D. Power Electric Utility Residential Customer Satisfaction Study (J.D. Power), and Duke Energy's proprietary transaction survey – Fastrack – in which we survey residential customers who have recently interacted with Duke Energy Kentucky.

Q. PLEASE DESCRIBE THE J.D. POWER STUDIES AND DUKE ENERGY KENTUCKY'S PERFORMANCE.

A. J.D. Power is well known for setting the standard for measurement of consumer opinion and customer satisfaction in many key industries. J.D. Power annually surveys electric utilities' residential customers regarding their satisfaction with their utility overall, plus key areas of their relationship. Duke Energy Midwest (Ohio, Kentucky, and Indiana) participates in these annual studies.

The J.D. Power Electric Utility Residential (EUR) Customer Satisfaction Study, established in 1999, calculates overall customer satisfaction based on six performance areas: (1) power quality and reliability; (2) billing and payment; (3) price and value; (4) corporate citizenship; (5) communications; and (6) customer service. J.D. Power published the results of its 2017 EUR Customer Satisfaction Study on July 12, 2017. Attachment JPH-1 is an excerpt from the 2017 J.D. Power EUR Customer Satisfaction Study. This study measured residential customer satisfaction for the country's 138 largest electric utilities, serving over 97 million customers. In this study, Duke Energy Midwest's overall satisfaction scores outperformed both the Midwest Region average scores and the large utility industry average, finishing in the second quartile among large utilities nationally. The results indicate that Duke Energy consistently provides high quality customer satisfaction.

Q. PLEASE DESCRIBE THE DUKE ENERGY KENTUCKY – SPECIFIC CUSTOMER SURVEYS AND THE COMPANY'S PERFORMANCE.

A. In addition to the independent J.D. Power studies, our internal customer satisfaction measurements continue to reflect strong performance in meeting the needs of Duke Energy Kentucky customers. Through Fastrack, Duke Energy's proprietary transaction study, we regularly survey residential customers who have had a recent service interaction with Duke Energy Kentucky.

Fastrack is administered to a random sample of customers roughly 24-48 hours after these customers have a service interaction/experience with the Company. Customers respond to this live phone interview and provide ratings on their overall satisfaction, as well as ratings on each part of their end-to-end experience to enable Duke Energy Kentucky to identify what parts of the customer journey are working well and what parts need to be enhanced to better the customer experience. These surveys are conducted daily (except Sundays and major holidays) throughout the year by an independent research firm – Bellomy Research. Since 2014, we have accumulated over 2,500 Duke Energy Kentucky survey responses. These responses represent the "voice" of our Duke Energy

Kentucky customers and enable us to continue to improve customer satisfaction in each of the key processes included in the survey.

Current results are available for Duke Energy Midwest, as well as its geographic breakouts in Indiana and Ohio/Kentucky through June 2017. The results are expressed on the basis of the percentage of respondents who are highly satisfied and the percentage who are least satisfied. Using a ranking system of zero to ten, customers who rated the Company an eight or higher are considered to be highly satisfied and those who rated the Company on a four or below are considered to be least satisfied. Attachment JPH-2 and JPH-3 are copies of the Q-1 Duke Energy Midwest Fastrack Quarterly Report and the Duke Energy Midwest Fastrack June 2017 Update.

Four key processes are measured by these surveys, reflecting the majority of interactions customers have with Duke Energy Kentucky: (1) service initiation requests (requests to turn on or transfer service); (2) outage and restoration experiences; (3) billing issues (billing inquiries/requests/complaints, *etc.*); and (4) outdoor lighting repair requests.

Duke Energy Kentucky's customer satisfaction scores indicate that overall customer satisfaction is relatively high and either steady or improving. Through the first six months of 2017, customers provided the following ratings:

- **Service Initiation:** 90% of Duke Energy Kentucky residential customers were highly satisfied with their overall Service Initiation experience;

- **Outage/Restoration:** 74% of Duke Energy Kentucky residential customers were highly satisfied with their overall Outage/Restoration experience;
- **Billing Questions/Requests/Complaints:** 85% of Duke Energy Kentucky residential customers were highly satisfied with their overall Billing experience; and
- **Outdoor Lighting Repair:** 97% of Duke Energy Kentucky residential customers were highly satisfied with their overall Outdoor Lighting Repair experience.

These surveys also indicate that our customers want more timely restoration and outage information communication to keep them informed. Duke Energy Kentucky witness Mr. Anthony Platz discusses the results of the Fastrack studies as it relates to expectations of Power Quality and Reliability in greater detail in his testimony. Duke Energy Kentucky is focused on meeting these desires through new and emerging initiatives and system investments like its recently approved Advanced Metering Infrastructure (AMI) deployment and our proposal for a distribution reliability and integrity performance improvement plan with timely cost recovery that is being proposed in this case.

D. DEVELOPMENTS SINCE THE COMPANY'S LAST ELECTRIC RATE CASE

Q. HAS DUKE ENERGY KENTUCKY SUCCESSFULLY MANAGED ITS COSTS OF PROVIDING SERVICE TO ITS CUSTOMERS SINCE ITS LAST BASE ELECTRIC RATE CASE?

A. Yes. Duke Energy Kentucky has proven itself successful and capable of implementing initiatives to manage its costs to serve. Since the Company's last base electric rate case in 2006, Duke Energy Kentucky has been part of two significant utility mergers that have enabled the Company to implement best practices and to find opportunities to operate more efficiently. The Company's electric rates compare very favorably to its peers in the Commonwealth. In fact, the Company's non-production O&M expense has trended well below the consumer price index rate of inflation and has remained relatively flat since the Company's last base electric rate case. The Company has also been successful in managing its capital investments, including various environmental compliance investments, without having previously implemented an environmental surcharge mechanism or seeking base rate increases. This includes acquiring approximately 186 MWs of coal-fired capacity for only $12.4 million, to replace approximately 163 MWs that were retired, and construction of the first cell of a new landfill at East Bend. Through these efforts, the Company has been successful in providing its customers with very stable and low-cost electric rates for many years.

Despite these best efforts, the Company can no longer continue to operate at this level without seeking an increase in its base electric rates. The Company is entering into a period where due to its aging system, and changes in laws, the Company must make additional investments in its electric system to continue to provide reasonable and adequate service and to have the opportunity to earn a fair and reasonable return.

Q. PLEASE SUMMARIZE THE SIGNIFICANT OPERATIONAL DEVELOPMENTS THAT HAVE OCCURRED SINCE DUKE ENERGY KENTUCKY'S LAST ELECTRIC RATE CASE IN 2006.

A. With the Company's 2006 electric rate case, Duke Energy Kentucky completed its acquisition of three generating stations, East Bend, Woodsdale, and MF6, dedicated to customers and reflected in base rates. Prior to that, Duke Energy Kentucky did not own any generating assets and served its Kentucky electric load through a long-term purchase power agreement.

In July of 2012, Duke Energy completed its merger with Progress Energy. This combination has expanded Duke Energy Kentucky's access to, and the availabity of, resources and expertise in the electric utility industry, as well as the implementation of best practices. Duke Energy Kentucky files reports with the Commission on implementation of these best practices, as well as, on other merger-related commitments annually.

In 2012, with Commission authorization, Duke Energy Kentucky, became a member of the PJM, leaving the Midcontinent Independent System Operator (ISO) (MISO), f/k/a Midwest ISO. This integration into PJM provides additional reliability and revenue opportunities for Duke Energy Kentucky's customers through PJM's energy, capacity and ancillary services wholesale markets. As explained by Duke Energy Kentucky witnesses Messrs. Wathen, Swez and Verderame, Duke Energy Kentucky shares net off-system sales in the PJM markets with its customers through its Profit Sharing Mechanism, Rider PSM.

Looking forward, Duke Energy Kentucky will be updating its existing Customer Information System (CIS) to a new state of the art system. This software investment will be occurring over time and will be fully in service by 2022 as part of a consolidated Duke Energy effort to modernize its customer experience in all jurisdictions and provide greater flexibility and efficiency in meeting ever evolving customer expectations. Duke Energy Kentucky's current CIS's primary function, as designed, was to use the aggregated usage data for simple billing purposes per each individual meter. The utility industry, however, is not now limited to such simplistic transactions. For example, complex billing capability is necessary for supporting net metering. Today, Duke Energy Kentucky must manually calculate net metering bills because the current CIS is not capable of handling that complexity.

Advanced electric meters and associated components have the capability of recording more granular usage data. This data, in turn, can create personalized opportunities for customers according to their preferences, whether in the form of rate options or other usage-related services. Duke Energy Kentucky intends to continue transforming its electric utility service in order to position our customers to have more control, convenience, and information. A more robust and capable CIS system is necessary to evolve the Company to meet customer expectations.

Q. PLEASE SUMMARIZE THE SIGNIFICANT GENERATION INVESTMENTS THAT HAVE OCCURRED SINCE DUKE ENERGY KENTUCKY'S LAST ELECTRIC RATE CASE IN 2006.

A. Duke Energy Kentucky continues to make prudent operational decisions and investments in its generating stations to ensure they continue to provide safe, reliable, adequate and reasonably priced electric service

In 2014, Duke Energy Kentucky increased its commitment to Kentucky sited coal-burning resources by becoming the sole owner of East Bend, when it purchased DP&L's 31 percent interest in the station. The need for this acquisition stemmed from, in primary part, a need to retire Duke Energy Kentucky's MF6 station. MF6 was an unscrubbed unit whose retirement became necessary due to an inability to cost-effectively comply with the Mercury Air Toxics Standard (MATS). Duke Energy Kentucky was able to replace these lost MWs through a very reliable and inexpensive acquisition, resulting in additional MWs for customers.

In 2015, Duke Energy Kentucky commenced its construction of a new onsite landfill at East Bend to replace its 30-year old landfill that reached capacity. The availability of an onsite landfill enables the Company to continue to cost-effectively operate East Bend by providing an onsite waste disposal system and avoiding the need to truck generator waste materials to an offsite third-party owned landfill.

Earlier this year, the Company received Commission authorization to convert East Bend's wet ash handling system to a dry ash disposal system to comply with the recently enacted Coal Combustion Residuals Final Rule (CCR Final Rule). The Company also received Commission authorization to close its current ash pond, repurpose it and construct new process water systems to comply with both the CCR Final Rule and the Steam Electric Effluent Limitation Guidelines (ELG) final rule.

Finally, Duke Energy Kentucky is commencing construction of three small solar installation facilities that have an aggregate capacity of approximately 7 MWs in its Kentucky service territory. The Company is intending to use these facilities to serve its Kentucky customers, generate renewable energy certificates for sale in the market, and to gain experience with utility-owned and operated renewable generating resources. The Company is planning for these facilities to go into service later this year. Duke Energy Kentucky witness Mr. Joseph Miller Jr. describes the Company's generating fleet and its operation more fully in his testimony.

Q. PLEASE BRIEFLY DISCUSS THE CONTINUING INVESTMENTS THE COMPANY HAS MADE IN ITS DISTRIBUTION SYSTEM.

A. Duke Energy Kentucky has regularly made prudent investments in its distribution system, as needed for its continued safe, reliable, and efficient operation. And, over the years, the system has evolved, consistent with applicable standards, changes in technology, and, importantly, changes in our customers' expectations. Our investments and the manner in which they are made have thus also evolved. The Company continues to explore strategies to improve the performance of its electric delivery system and examines new technologies for opportunities to make prudent investments. Most recently, the Company received approval and commenced deployment of an AMI system. This deployment will provide the platform for the Company to provide better communication with our customers regarding their usage.

The Company continues to invest in its distribution grid to enhance its integrity and overall reliability. Mr. Platz discusses these investments in his direct testimony.

III. OVERVIEW OF DUKE ENERGY KENTUCKY'S RATE CASE

Q. PLEASE EXPLAIN WHY DUKE ENERGY KENTUCKY PROPOSES TO INCREASE ITS RETAIL ELECTRIC RATES.

A. The Company proposes new rates because our present base rates reflect our cost of service from 2007, which are no longer sufficient to enable the Company to furnish adequate, efficient and reasonable service or have the opportunity to earn a fair rate of return on investments. Duke Energy Kentucky also needs to reflect the costs of service related to its capital investments and operations and maintenance of its electric generation, transmission and distribution systems that have occurred since 2007. And, although the Company has added customers over that time, energy efficiency and customer behavior has kept overall sales relatively flat; consequently, load growth has not significantly offset increases in costs. These factors compel the Company to propose new rates in this proceeding.

Q. PLEASE GENERALLY DESCRIBE DUKE ENERGY KENTUCKY'S PROPOSED RATE INCREASE.

A. Duke Energy Kentucky proposes to increase its non-fuel electric base rates so as to increase its annual base electric rate revenues for its electric business by approximately $48.6 million. The Company is also proposing to implement three new discrete cost recovery mechanisms to enable the Company to timely recover its costs for providing safe, reliable, adequate and reasonable service going forward and in response to evolving environmental compliance requirements, changes in FERC-jurisdictional costs, and to enable continual distribution system reliability and integrity enhancements. The Company is also proposing changes to its existing profit sharing mechanism, Rider PSM, to adapt, simplify, and streamline the process of sharing revenues (and costs) from the Company's owned and Kentucky-dedicated stations and to address changes in the wholesale markets and opportunities in the renewable markets. Additionally, the Company is proposing to begin offering new optional billing programs and products and services to customers to provide greater control, transparency and flexibility in how they use and pay for electricity.

The approximate $48.6 million increase to the current electric base rate revenue requirement represents an increase to total electric revenues of approximately 14.96 percent. This rate increase is necessary in order to allow Duke Energy Kentucky to recover its costs for providing reliable electric service, plus have the opportunity to earn a fair return on its shareholders' investment in electric generation, local transmission and distribution facilities.

Q. PLEASE DESCRIBE THE COMPANY'S TEST PERIOD IN THIS CASE.

A. Duke Energy Kentucky is using a forecasted test period with projected information starting with the Company's 2017 budget with certain adjustments as a basis for the forecasted test period ending March 31, 2019, as discussed by Duke Energy Kentucky witness, Mr. Robert "Beau" Pratt.

Q. PLEASE FURTHER DESCRIBE THE COMPANY'S PROPOSAL TO IMPLEMENT AN ENVIRONMENTAL SURCHARGE MECHANISM.

A. Duke Energy Kentucky is proposing to implement an environmental surcharge mechanism (ESM) under KRS 278.183 as part of this case. Anecdotally, Duke Energy Kentucky does not currently have an ESM because it only acquired ownership of generating assets in 2006. As part of the settlement of the Company's last electric rate case, Duke Energy Kentucky agreed to a "stay-out" that prevented it from filing to implement an ESM before January 1, 2009. Because East Bend was well suited for environmental compliance with regulations that existed at the time of our last rate case, the Company did not have any significant incremental environmental project investments.

Through this application, the Company is now establishing a new base level of environmental costs to be included in base electric rates so that the ESM will be capable of tracking incremental environmental investments at East Bend going forward, and that are approved as an environmental compliance plan. Duke Energy Kentucky witnesses Mr. Bruce Sailers, Ms. Tammy Jett, Ms. Sarah Lawler, Mr. William Don Wathen Jr., and Mr. Miller further explain the Company's ESM proposal and the projects and costs to be included in its environmental compliance plan in greater detail.

Q. PLEASE FURTHER DESCRIBE THE COMPANY'S PROPOSAL TO IMPLEMENT A DISTRIBUTION RELIABILITY AND INTEGRITY PERFORMANCE IMPROVEMENT PLAN WITH CAPITAL RECOVERY MECHANISM.

A. Duke Energy Kentucky is proposing to implement a Distribution Capital Investment Rider (Rider DCI), to recover the incremental capital costs, above what is to be included in base rates, for specific Commission-approved programs that are designed to enhance the Company's distribution system's performance in terms of integrity and/or reliability. The intent is to provide the Company flexibility to implement new reliability programs, accelerate investments designed to improve performance of the electric delivery system in terms of reliability or system integrity, and to receive timely recovery of capital costs, for implementing these programs between rate cases. The Company has modeled this program after similar programs this Commission has previously approved for the Company's natural gas operations, as well as similar mechanisms approved by regulatory commissions for electric utilities in Ohio and Indiana. Much like Duke Energy Kentucky's Commission-approved accelerated service line replacement program (ASRP) and its predecessor, accelerated main replacement program (AMRP), the Rider DCI will recover incremental costs for defined programs that will enhance reliability or the distribution system's integrity. The Company will file an annual application to set and true-up its Rider DCI, for the duration of any Commission-approved program. The Company is proposing one program in this case, Targeted Underground, to be included in the initial Rider DCI process. Going forward, as system challenges, opportunities for improvement and solutions are identified, the Company will apply to the Commission for consideration of new programs and recovery under the Rider DCI. Mr. Platz, Mr. Wathen, Ms. Lawler, and Mr.

Sailers, provide greater detail regarding the Targeted Underground program, the operation of the mechanism, and tariff, in their direct testimonies, respectively.

Q. PLEASE DESCRIBE DUKE ENERGY KENTUCKY'S PROPOSAL TO IMPLEMENT A FERC TRANSMISSION COST RECONCILIATION RIDER.

A. Duke Energy Kentucky is proposing to implement a tracking mechanism for the incremental cost recovery of FERC-approved tariffed costs that the Company incurs for network transmission (firm point-to-point and non-firm point-to-point) services as well as for any incremental PJM regional transmission expansion plan costs (RTEP). Duke Energy Kentucky is proposing to include a base amount in its base electric rates. The FERC Transmission Cost Reconciliation Rider (Rider FTR) is simply to recover the actual costs the Company incurs to serve customers that are incremental to what is established in base rates in this proceeding. These transmission-related costs are material and are outside of Duke Energy Kentucky's control and are not constant. Duke Energy Kentucky is a transmission-dependent utility. Duke Energy Kentucky effectively has no control over these costs and they represent a continuously changing, and thus volatile expense to the Company. These transmission costs (such as network integrated transmission service and RTEP) are FERC jurisdictional and are incurred by Duke Energy Kentucky as part of FERC-approved tariffed rates. Because Duke Energy Kentucky incurs these costs as a necessary expense to provide service to its customers, it is appropriate for the Company to receive cost recovery as they are incurred. Duke Energy Kentucky witness Mr. John Swez and Messrs. Wathen and Sailers support Rider FTR in their direct testimonies.

Q. PLEASE FURTHER DESCRIBE THE COMPANY'S PROPOSED CHANGES TO ITS RIDER PSM.

A. Duke Energy Kentucky is proposing enhancements to its Rider PSM to expand the number of categories of net proceeds that can be flowed through the mechanism related to the ownership and dedication of the Company's generation assets to Kentucky customers and to streamline and simplify its calculation. The expansion will include all non-native sales, and revenues, net of costs, in the wholesale electric markets (*e.g.,* PJM's energy market, PJM's capacity performance market, PJM's ancillary services market, and any future PJM revenues/costs), as well as for sales of renewable energy credits (RECs). The Company will also use the Rider PSM to recover costs for any short-term capacity purchases necessary to meet the Company's FRR plan (native load) obligations until a physical asset is either built or contracted as well as any capacity purchases to qualified resources in accordance with the Public Utility Regulatory Policy Act (PURPA). The Company is proposing to simplify the calculation of the Rider PSM to a pure sharing mechanism by eliminating the current threshold of $1 million before the sharing mechanism activates. As part of the simplification, the Company is proposing to increase the sharing of the net proceeds under the Rider PSM from a 75/25 percent customer/Company split, to a 90/10 percent customer/Company split for all categories of recoverable. Messrs. Wathen, Swez, Verderame, Sailers, and Ms. Lawler support this proposal and the Rider PSM tariff changes in their direct testimonies.

Q. PLEASE DESCRIBE THE ACCOUNTING TREATMENT THAT THE COMPANY IS REQUESTING BE ESTABLISHED IN THIS CASE.

A. As part of this proceeding, Duke Energy Kentucky is seeking Commission authorization to create two deferrals for incremental costs, under or over the amount established in base rates in this proceeding, for planned maintenance outages at the Company's generating stations, as well as for, incremental purchased power expense related to forced outages not otherwise recovered through the Company's FAC. Each year the incremental amount over or under what is established in base rates will be added or subtracted from the total balance deferred. Duke Energy Kentucky further proposes that any regulatory asset or liability created be reviewed for recovery through amortization as part of the Company's next base electric rate case. Duke Energy Kentucky witness Mr. David Doss discusses these deferrals in his testimony.

Q. PLEASE FURTHER DESCRIBE THE COMPANY'S OPTIONAL BILLING AND PRODUCTS AND SERVICES BEING PROPOSED IN THIS CASE.

A. Duke Energy Kentucky witness Dr. Sasha Weintraub further discusses these new services in his direct testimony. In summary, Duke Energy Kentucky is continually exploring opportunities to offer programs that will allow customers to have greater convenience, transparency, and control over their energy usage and the utility bills they receive. The Company has been developing a suite of programs and services to provide to customers. These products include: (1) Pick Your Own Due Date; (2) Fixed Bill; (3) Usage Alerts; and (4) Outage Alerts with AMI.

Q. HOW DO DUKE ENERGY KENTUCKY'S RETAIL ELECTRIC RATES COMPARE TO THE RATES FOR OTHER ELECTRIC UTILITIES?

A. Duke Energy Kentucky's average electric rates are currently the lowest among all of Kentucky's investor-owned utilities. According to the Typical Bills and Average Rates Report for Winter 2017 published by the Edison Electric Institute, the national average rate for residential electric customers was 46% higher than Duke Energy Kentucky's current residential electric rates. For commercial and industrial customers, the national average rates were approximately 38% and 3% higher than Duke Energy Kentucky's, respectively. Duke Energy Kentucky's rates are significantly lower than other Kentucky investor-owned utilities for residential and commercial customers and very competitive with the other utilities for industrial customers based on information that predates the implementation of new rates for the other utilities.

Avg Retail Rate for IOUs (cents/kWh)[1]				
	Total	Residential	Commercial	Industrial
Duke Energy Kentucky	7.91	8.86	7.70	6.61
Total USA	10.61	12.93	10.61	6.80
All of Kentucky	8.74	10.24	9.60	6.38
Kentucky Power	9.76	11.92	11.89	6.65
LG&E	9.11	10.41	9.46	6.69
KU	8.34	9.87	9.71	6.13

[1] Source: EEI Typical Bills and Average Rates Report, Winter 2017.

Q. HOW HAVE DUKE ENERGY KENTUCKY'S COSTS INCREASED AS COMPARED TO THE AMOUNTS CURRENTLY REFLECTED IN RATES?

A. Since its last general electric rate case, Duke Energy has made significant capital investments in its generating, transmission, and distribution facilities. Comparing the thirteen-month average gross plant from the forecasted test period used in Case No. 2006-00172 to the thirteen-month average gross plant in the forecasted test year in this case, the Company's has invested in over $600 million in new utility plant over that time frame. Mr. Wathen discusses in greater detail the drivers for the Company's proposed rates.

IV. INTRODUCTION OF WITNESSES

Q. PLEASE INTRODUCE THE OTHER WITNESSES IN THESE PROCEEDINGS.

A. I identify below the other individuals who will present testimony on behalf of Duke Energy Kentucky, as well as the subject matters of their respective testimony:

- Lisa M. Bellucci, Director, Tax Operations, addresses the Company's tax expense in the test year revenue requirement;
- David L. Doss, Jr., Director, Electric Utilities and Infrastructure, offers testimony regarding the Company's accounting policies and the accounting treatment requested in this case;

- Tammy Jett, Principal Environmental Specialist, discusses the environmental regulations driving the Company's investments in controls at East Bend;
- Jeffrey Koop, Manager, Business Consulting Department, Burns & McDonnell Engineering Company, Inc., supports the Company's decommissioning study;
- Sarah E. Lawler, Utility Strategy Director, provides testimony supporting Duke Energy Kentucky's overall revenue requirement for the test year and certain adjustments to the test year financial data;
- Cynthia S. Lee, Director, Asset Accounting, offers testimony on Duke Energy Kentucky's capital accounting processes and sponsors certain accounting information used for the test year financial data and the handling of our ash pond closure asset retirement obligation;
- Joseph A. Miller, Jr., Vice President, Central Services, provides testimony describing the Company's investments in its generating assets and performance. Mr. Miller also supports the Company's proposal to implement an ESM and the supporting Environmental Compliance Plan;
- Roger A. Morin, PhD, Principal, Utility Research International, offers testimony on Duke Energy Kentucky's requested rate of return;
- Benjamin Walter Bohdan Passty Ph.D., Lead Load Forecasting Analyst, Mr. Passty performed and supports the Company's electric load forecast;
- Anthony J. Platz, Director, Power Quality, Reliability and Integrity (PQR&I) Engineering, will present testimony regarding Duke Energy

Kentucky's electric distribution and transmission systems, safety and reliability programs and supports the Company's Rider DCI;

- Robert ("Beau") H. Pratt, Director, Regional Financial Forecasting, presents testimony on Duke Energy Kentucky's budgeting and forecasting processes;
- Bruce L. Sailers, Rates and Regulatory Strategy Manager, Pricing and Rates Options, offers testimony as to rate design and tariff language;
- Jeffrey R. Setser, Director of Allocations and Reporting, supports the Company's various service agreements and associated allocations;
- Thomas Silinski, Vice President Total Rewards, and Human Resource Operations, supports the Company's compensation and benefits programs;
- John J. Spanos, Gannet Fleming Valuation and Rate Consultants, LLC, provides testimony on Duke Energy Kentucky's latest depreciation study;
- John L. Sullivan, III, Director – Corporate Finance and Assistant Treasurer, offers testimony regarding Duke Energy Kentucky's credit ratings, financial objectives, cash requirements, and capital structure;
- John D. Swez, Director - Generator Dispatch and Operations, discusses the Company's operations in PJM's energy and ancillary services markets. Mr. Swez also discusses the Company's proposals for cost recovery of the various PJM billing line items;
- John A. Verderame, Managing Director Power Trading and Dispatch, provides support for the Company's generating assets operation and dispatch in PJM, it's the Company's proposal to streamline and expand the

categories of sharing of net costs and credits in the wholesale power markets with customers;

- William Don Wathen Jr., Director, Rates and Regulatory Strategy, Ohio and Kentucky, provides a more detailed overview of the filing including support for the Company's proposed ESM, Rider DCI, Rider FTR, and changes to its PSM;
- Alexander "Sasha" J. Weintraub, PhD, Senior Vice-President, Customer Solutions, provides testimony regarding the products and service available as a result of AMI deployment and optional products and services to be offered; and
- James E. Ziolkowski, Director, Rates and Regulatory Planning, provides testimony regarding Duke Energy Kentucky's cost of service study.

V. ATTACHMENTS SPONSORED BY WITNESS

Q. PLEASE DESCRIBE FR 14(1) THROUGH FR 14(4).

A. These filing requirements provide for the Company to seek proposed new rates through a written application addressing various matters, including the full name, address and electronic mail address of the Company and set forth the facts upon which the application is based, with a request for the order, authorization, permission, or certificate desired and a reference to the particular law requiring or providing the same. FR 14(2) applies to Duke Energy Kentucky because it is a corporation, registered to do business, and is in good standing in the Commonwealth of Kentucky. The Application submitted in this proceeding includes this information and was prepared at my direction. FR 14(3) and FR

14(4) are not applicable to Duke Energy Kentucky because it is neither a limited liability company nor a limited partnership.

Q. PLEASE DESCRIBE FR 16(1)(b)(1).

A. FR 16(1)(b)(1) is a statement for the reason for the adjustment. As I explained above and as further explained by Mr. Wathen, the Company is proposing new electric base rates because its present rates reflect the cost of service from 2007, which is no longer sufficient to enable the Company to furnish adequate, efficient and reasonable service. Duke Energy Kentucky also needs to reflect the costs of service related to its capital investments and operations and maintenance of its electric generation, transmission and distribution systems that have occurred since 2007. The load growth on Duke Energy Kentucky's system has been relatively slow, and has not significantly offset these increased costs.

Q. PLEASE DESCRIBE FR 16(1)(b)(2).

A. FR 16(1)(b)(2) is the certificate of assumed name. Duke Energy Kentucky's actual legal name is "Duke Energy Kentucky, Inc." The Company has filed for the assumed name of "Duke Energy." The certificate of assumed name is provided with our filing.

Q. PLEASE DESCRIBE FR 16(1)(b)(5).

A. FR 16(1)(b)(5) is a statement that customer notice has been given in accordance with the Commission's rules. The Company is publishing notice in accordance with the Commission's regulations.

Q. PLEASE DESCRIBE FR 16(2).

A. FR 16(2) is the notice of intent submitted to the Commission at least thirty, but no more than sixty days prior to filing the application. The notice was filed on August 2, 2017, at my direction.

Q. PLEASE DESCRIBE FR 16(3).

A. FR 16(3) states that notice given in accordance with 807 KAR 5:001 Section 7 will satisfy notice requirements of 807 KAR 5:051, Section 2. The Company provided notice to customers in accordance with 807 KAR 5:001 Section 7.

Q. PLEASE DESCRIBE FR 16(7)(a)

A. FR 16(7)(a) is a statement of attestation from me, the utility's chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of each program. These programs are described below

- Duke/Progress merger: In July 2012, Duke Energy and Progress Energy closed their merger. Duke Energy Kentucky has benefitted from the implementation of best practices and through the access too additional resources and expertise from its sister electric utilities in five other jurisdictions. The Company has benefitted from the economies of scale that naturally arise from being a part of a combined corporation with a market capitalization of more than $52.1 billion, and more than 7.4 million total retail electric customers.
- Service outage management systems: we manage electric outages using the following systems designed to enhance efficiency and

productivity: Supervisory Control and Data Acquisition (SCADA), the Distribution Outage Management System (DOMS), and the Distribution Management System (DMS). Mr. Platz describes our outage management process and systems in more detail.

- Electric distribution system maintenance programs: our major programs to achieve efficiency and productivity in maintaining our distribution system are the substation inspection program, the line inspection program, the vegetation management program, the underground replacement program, the capacitor installation maintenance program, infrared scanning of equipment and dissolved gas analysis. These programs are all designed to keep our distribution systems in good working order through efficient use of our resources. These programs are part of our distribution maintenance practices, which Mr. Platz discusses.
- AMI technology: Duke Energy Kentucky began deploying AMI technology, as I discussed earlier in my testimony. We expect this to ultimately improve customer service and reduce our costs related to meter reading, customer service calls and call center operations. The cost savings related to the AMI initiative are reflected in the forecasted test period.

- Plant maintenance and pollution control improvements: Mr. Miller discusses various maintenance programs and capital improvement programs to install pollution control equipment, which are designed to enhance the efficiency and productivity of the Plants.

The cost savings impacts of these programs are reflected in the forecasted test period.

Q. PLEASE DESCRIBE FR 16(7)(e).

A. FR 16(7)(e) is a statement of attestation signed by me, the utility's chief officer in charge of Kentucky operations that the forecast is reasonable, reliable, made in good faith and that all basic assumptions used in the forecast have been identified and justified, and that the forecast contains the same assumptions and methodologies as used in the forecast for use by management and an explanation for differences that exist, if applicable, and that productivity and efficiency gains are included.

Q. PLEASE DESCRIBE FR 17(1)

A. FR 17(1) relates to public postings. Duke Energy Kentucky will post a copy of the notice and application at its place of business and will also make available on the Company's website a copy of the public notice and a hyperlink to the Kentucky Public Service Commission's website where the case documents will be available.

Q. PLEASE DESCRIBE FR 17(2).

A. FR 17(2) is the customer notice.

Q. PLEASE DESCRIBE FR 17(3).

A. FR 17(3) includes the method of notice. Duke Energy Kentucky has published notice in newspapers of general circulation. Mr. Sailers supports FR 17(4), which describes required content of the notice. Duke Energy Kentucky has included all content listed in FR 17(4) in its notice.

VI. CONCLUSION

Q. WERE FR 14(1), FR 14(2), 14(3), 14(4), FR 16(1)(b)(1), FR 16(1)(b)(2), FR 16(1)(b)(5), FR 16(2), FR 16(3), FR 16(7)(a), FR 16(7)(e), FR 17(1), FR 17(2), AND FR 17(3) PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

VERIFICATION

STATE OF OHIO)
) **SS:**
COUNTY OF HAMILTON)

The undersigned, James P. Henning, State President of Duke Energy Kentucky, Inc. and its parent, Duke Energy Ohio, Inc., being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of his knowledge, information and belief.

James P. Henning, Affiant

Subscribed and sworn to before me by James P. Henning, on this 24th day of August, 2017.

Adele M. Frisch
NOTARY PUBLIC

ADELE M. FRISCH
Notary Public, State of Ohio
My Commission Expires 01-05-2019

My Commission Expires: 1/5/2019

J.D. POWER

2017 Electric Utility Residential Customer Satisfaction Study℠

Final Results – An Excerpt

July 11, 2017

J.D. Power 2017 Electric Utility Residential Customer Satisfaction Study

Key Factors

28% Power Quality and Reliability

19% Billing and Payment

16% Corporate Citizenship

19% Price

14% Communications

5% Customer Service

138 Total Brands

99,000+ Total Responses

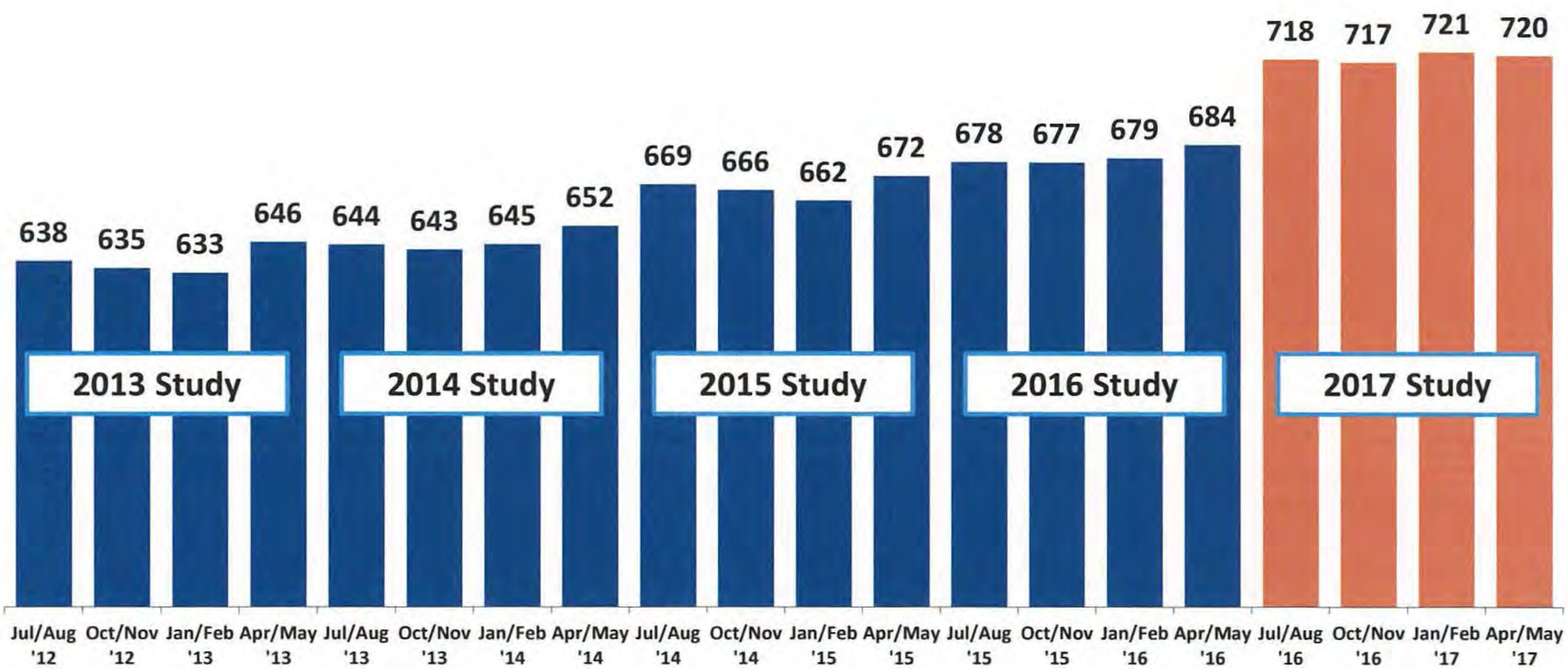
19th Year of the Study

2017 Key Study Findings – Industry

- Industry Satisfaction scores are up nationally (+39) but still a significant gap between the top and bottom.
- Overall Satisfaction gap between the top and bottom brand is 142 points.
- 28 Brands with Overall Satisfaction below 700.
- Brands impacted by Hurricane Matthew did an excellent job and saw an increase in overall satisfaction
- More customers are getting outage information
- Communications recall is flat but satisfaction higher due to a shift away from bill inserts to electronic channels

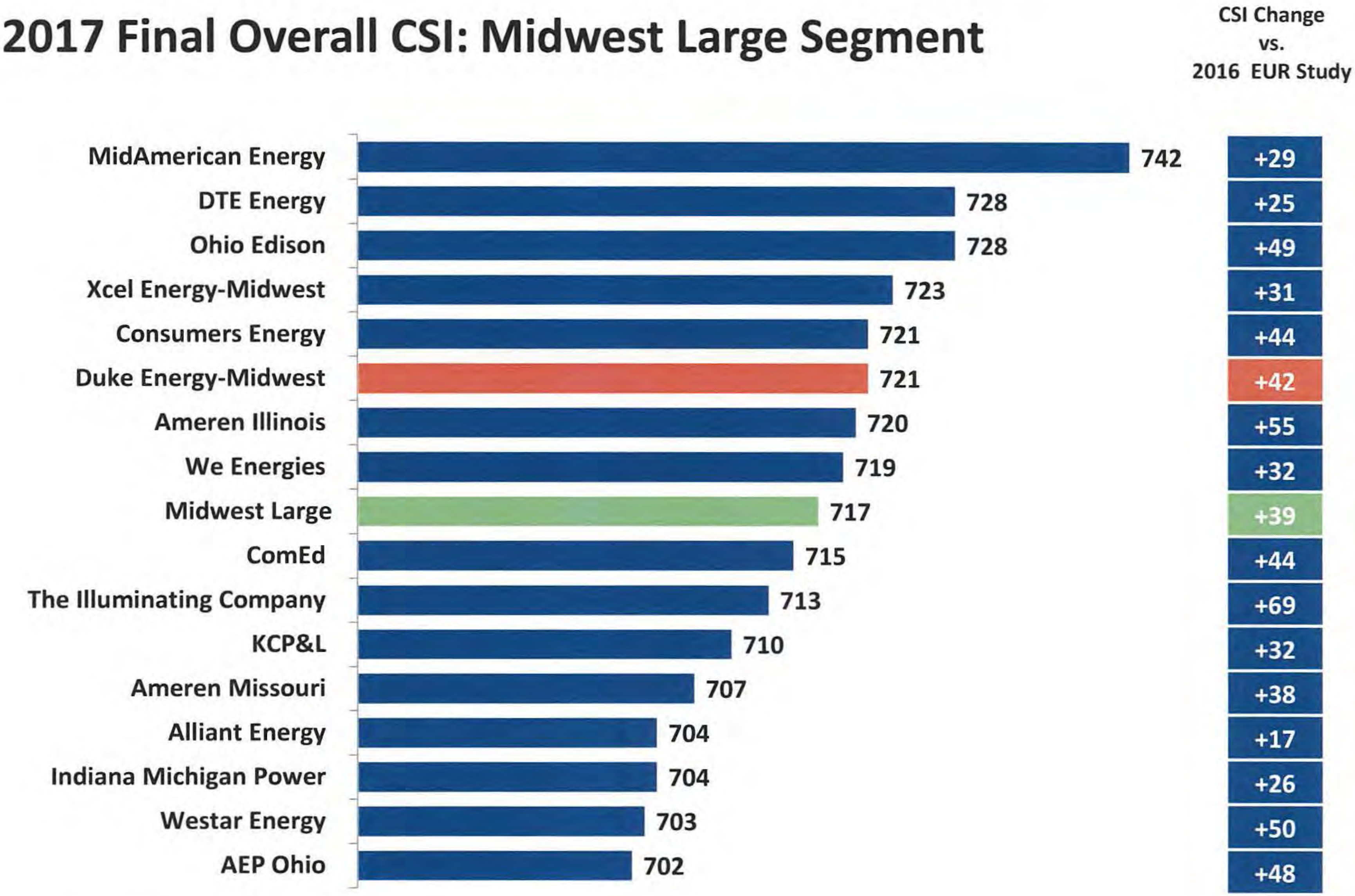
Overall Customer Satisfaction Index (CSI) is Up vs. 2016, but Relatively Flat for the 2017 Waves

Overall CSI Performance – Large Utility Average



2017 Electric Utility Residential Customer Satisfaction Study℠

2017 Final Overall CSI: Midwest Large Segment



J.D. POWER

28%

Power Quality & Reliability Performance

"Perfect Power": No Brief and No Lengthy Outages

Highest Brands	
Lincoln Electric System	63%
United Illuminating	63%
Connexus Energy	59%
Clark Public Utilities	57%
APS	55%
San Diego Gas & Electric	55%
Con Edison	54%
Madison Gas & Electric	53%
Wisconsin Public Service	53%
Avista	52%
We Energies	52%
Colorado Springs Utilities	51%
SRP	51%

Lowest Brands	
Appalachian Power	26%
Entergy Mississippi	26%
Lee County Electric Cooperative	26%
Public Service Co. of Oklahoma	26%
Entergy New Orleans	25%
Mon Power	25%
Duke Energy-Progress	24%
Tampa Electric	23%
Withlacoochee River Electric Cooperative	23%
Clay Electric Cooperative	15%

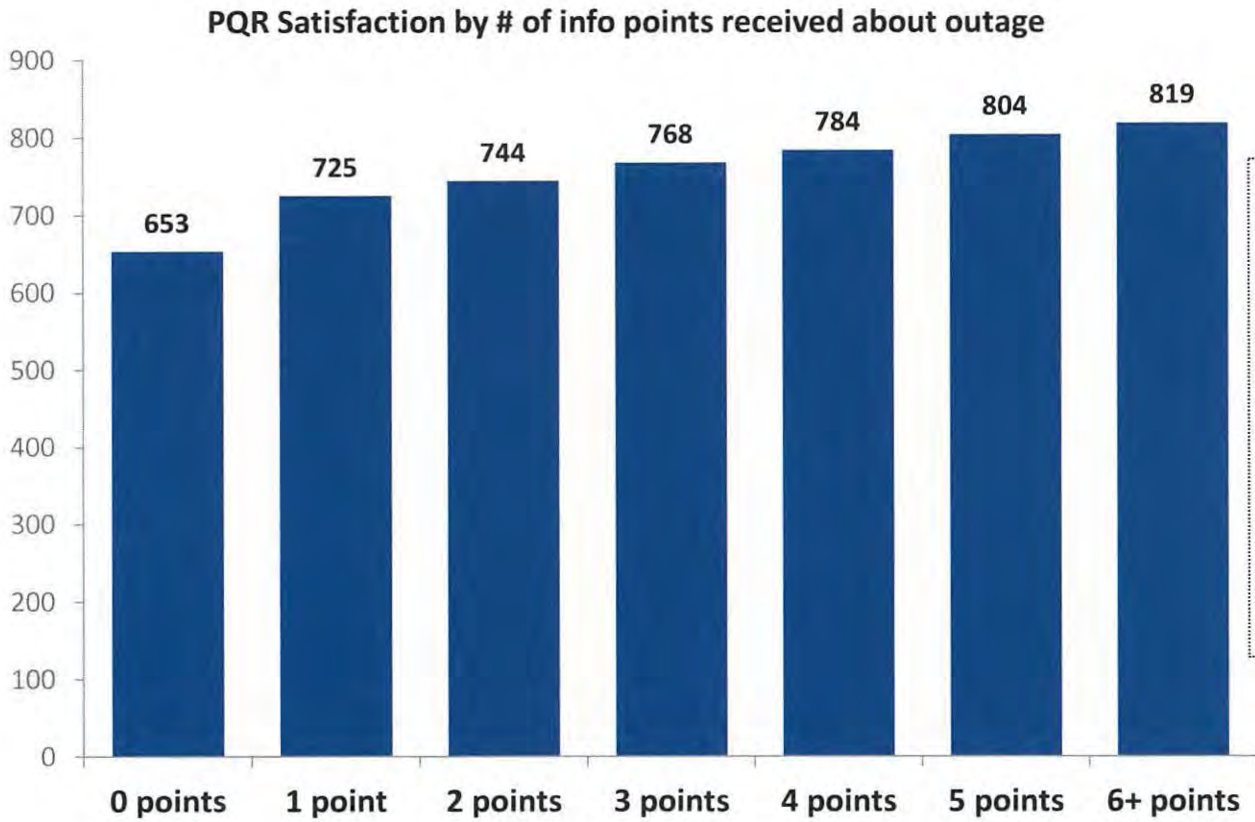
Award Winners

Overall Industry

4th Quartile Industry

J.D. POWER

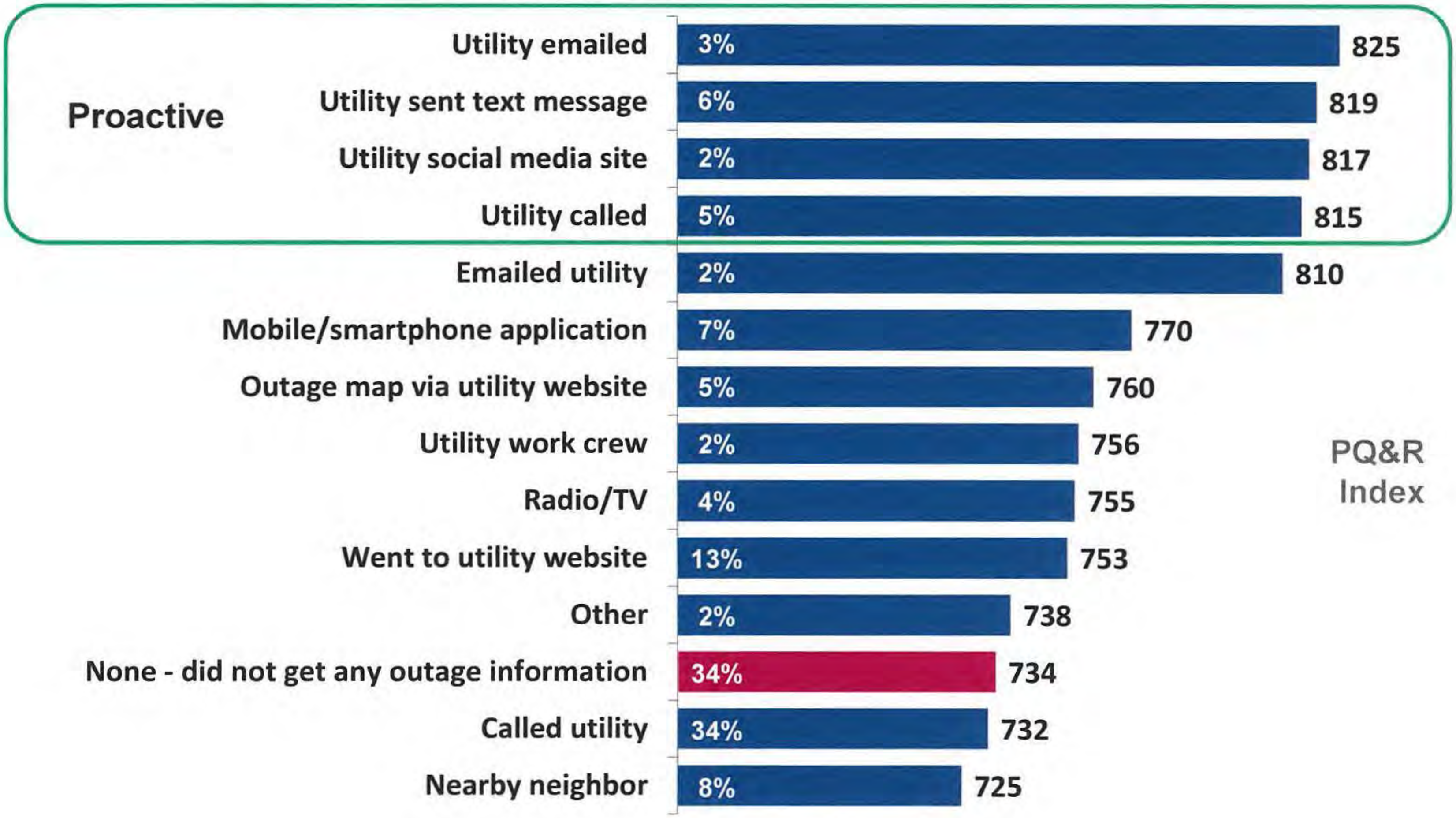
Outages Are Going To Happen… Customers Want Information



Outage Information Points:

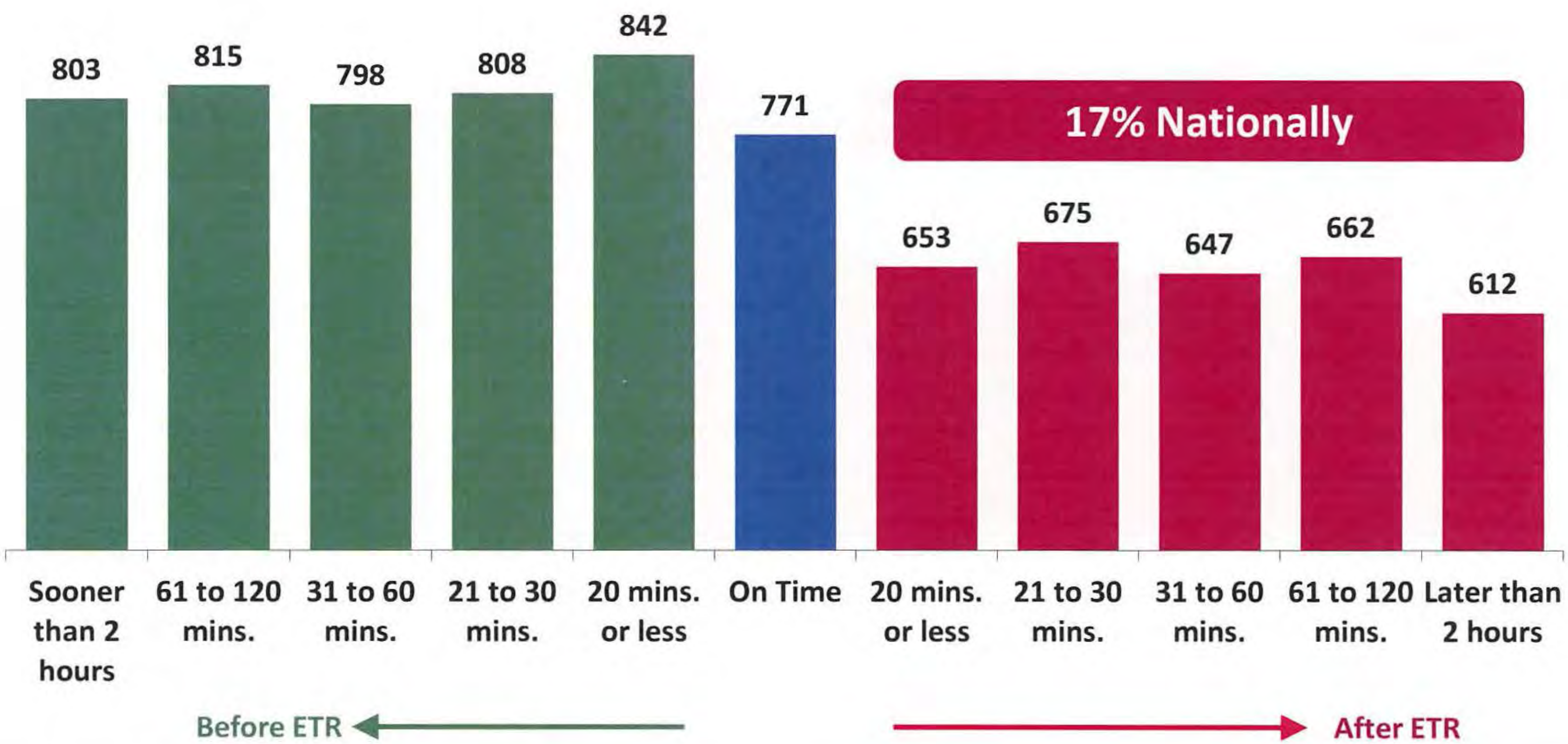
- Utility Aware of Outage
- Time outage began
- Number of customers impacted/area affected
- ETR
- Cause of outage
- Work crews dispatched to local area
- Time Outage Restored

Customers Want Their Outage Info Delivered Proactively… But the majority still call their utility or never receive any

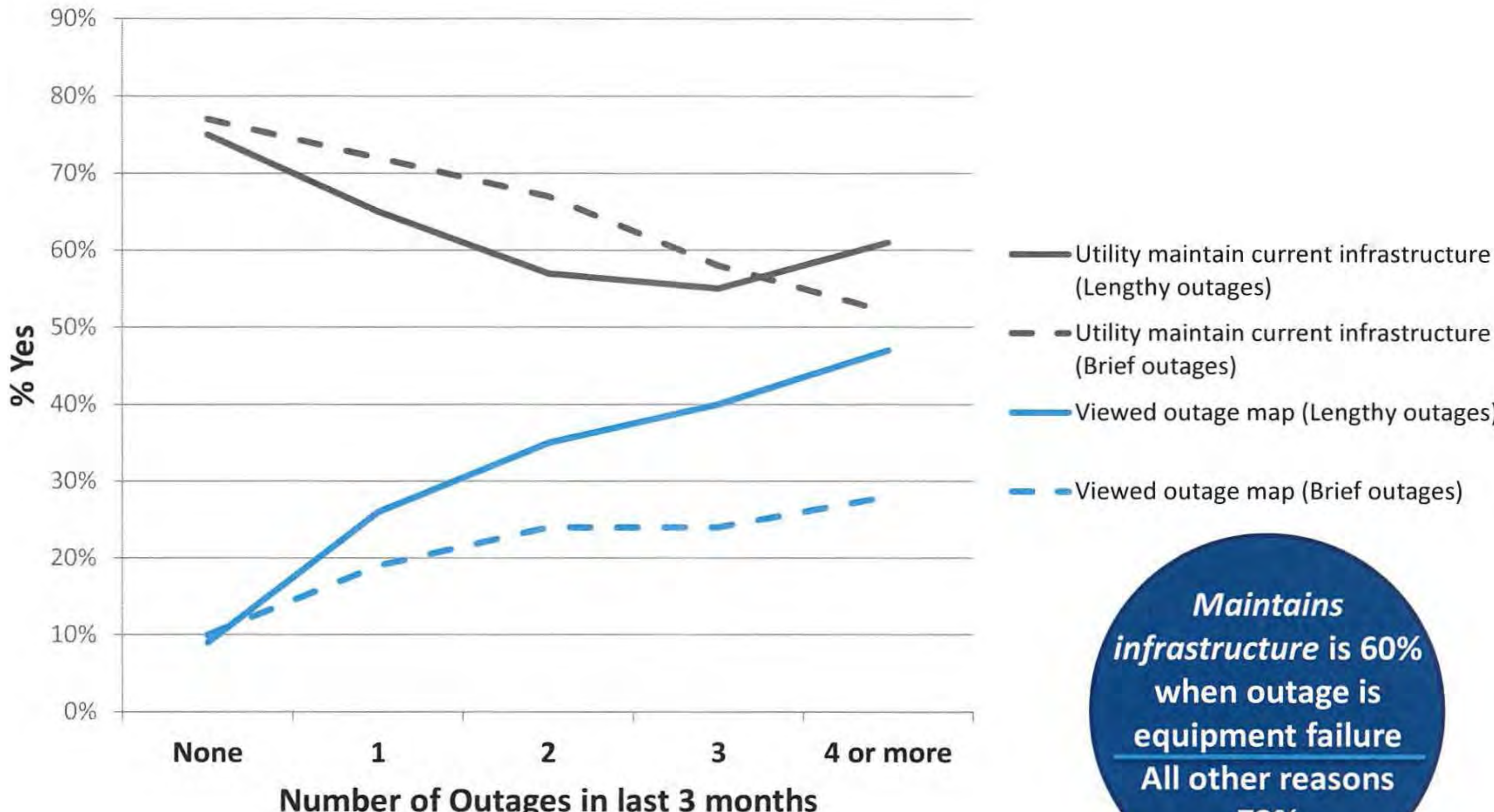


Customers Expect Timely & Accurate Restoration Times

PQ&R Index by Restoration Time



Multiple Brief Outages Drive Down Opinion of Infrastructure



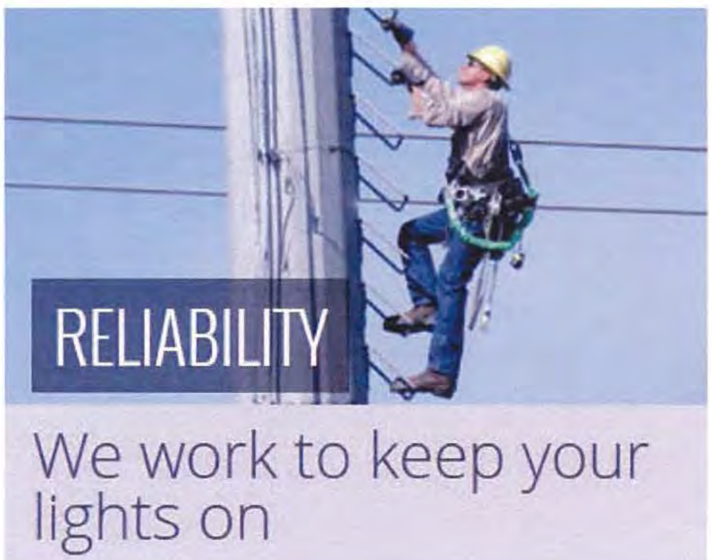
***Maintains infrastructure* is 60% when outage is equipment failure**

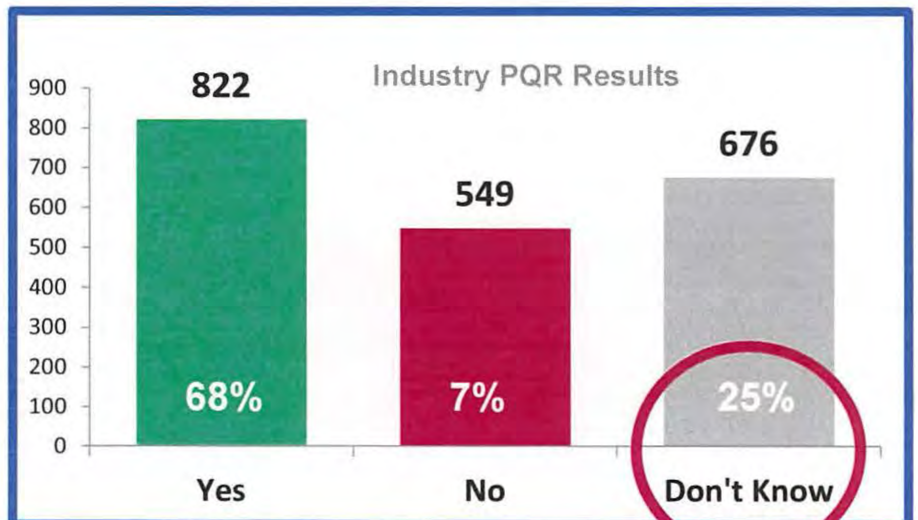
All other reasons 72%

Top Brands Continuously Tell Customers About Their Efforts to Improve Reliability

Does your utility maintain current infrastructure?

Top Large Utilities Nationally	
SRP	76%
Central Maine Power	76%
PPL Electric Utilities	75%
Entergy Arkansas	74%
Entergy Louisiana	74%
MidAmerican Energy	73%
Florida Power & Light	73%
Rocky Mountain Power	73%

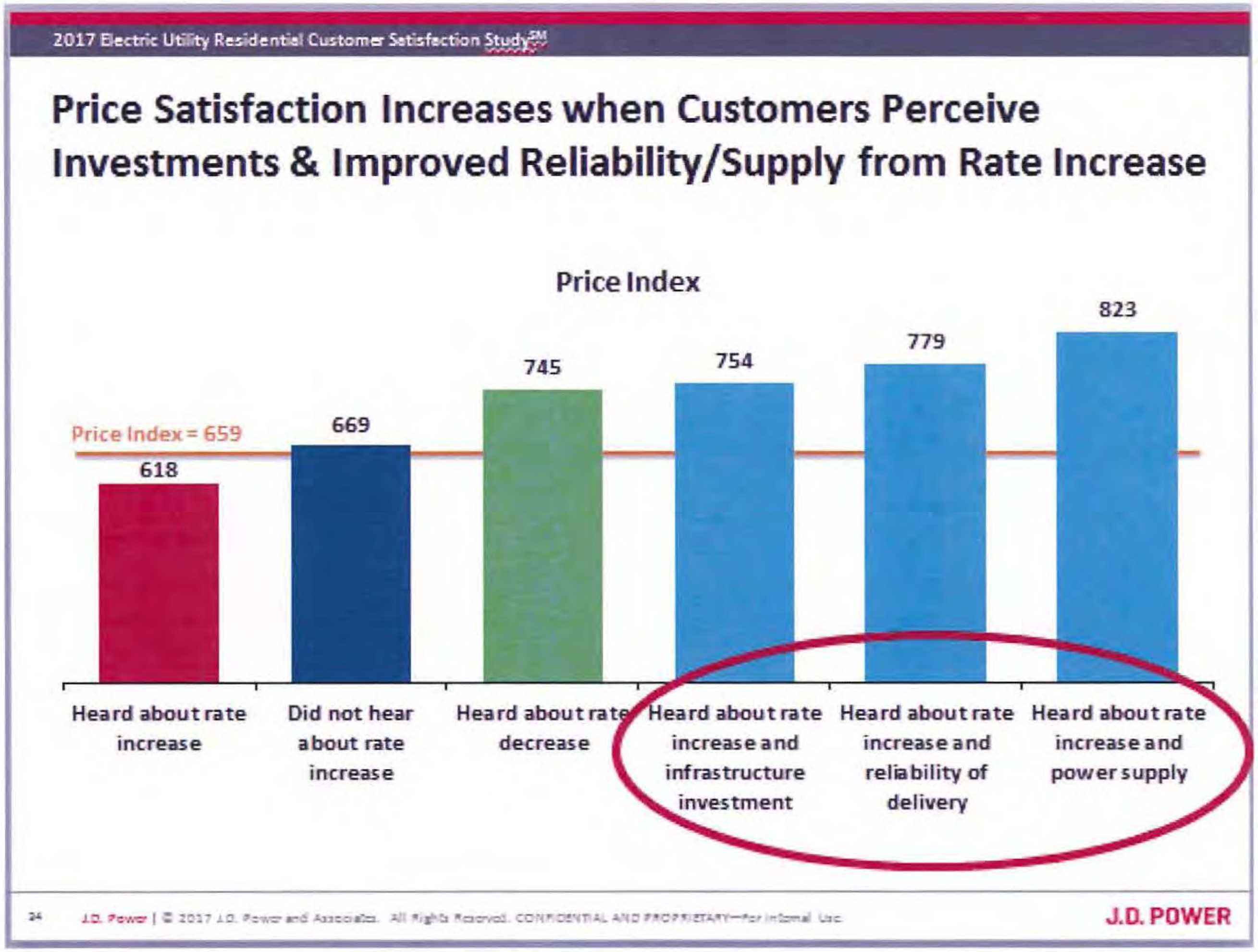




19%

Price Performance

Utilities need to over-communicate, particularly in rate cases



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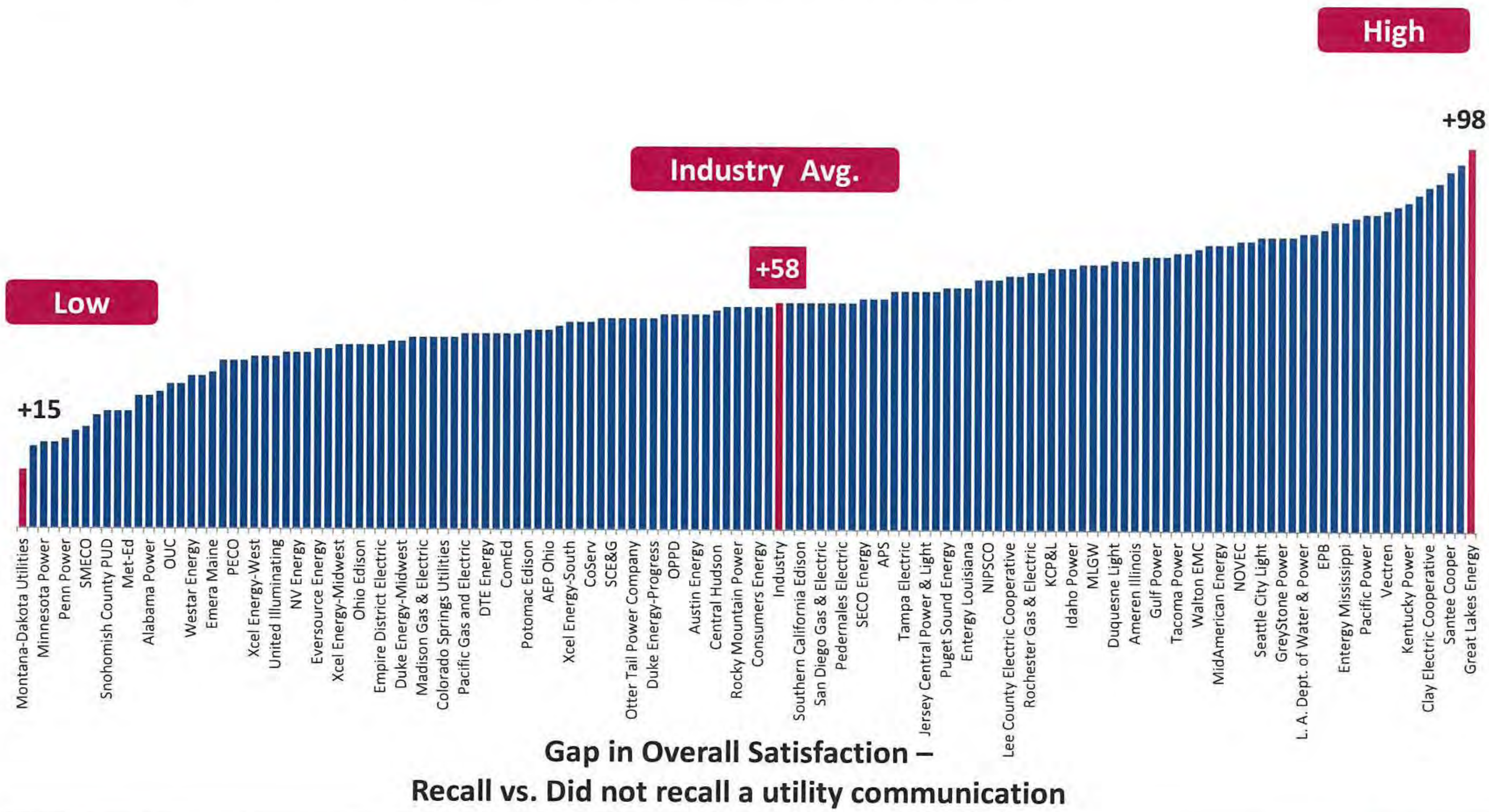
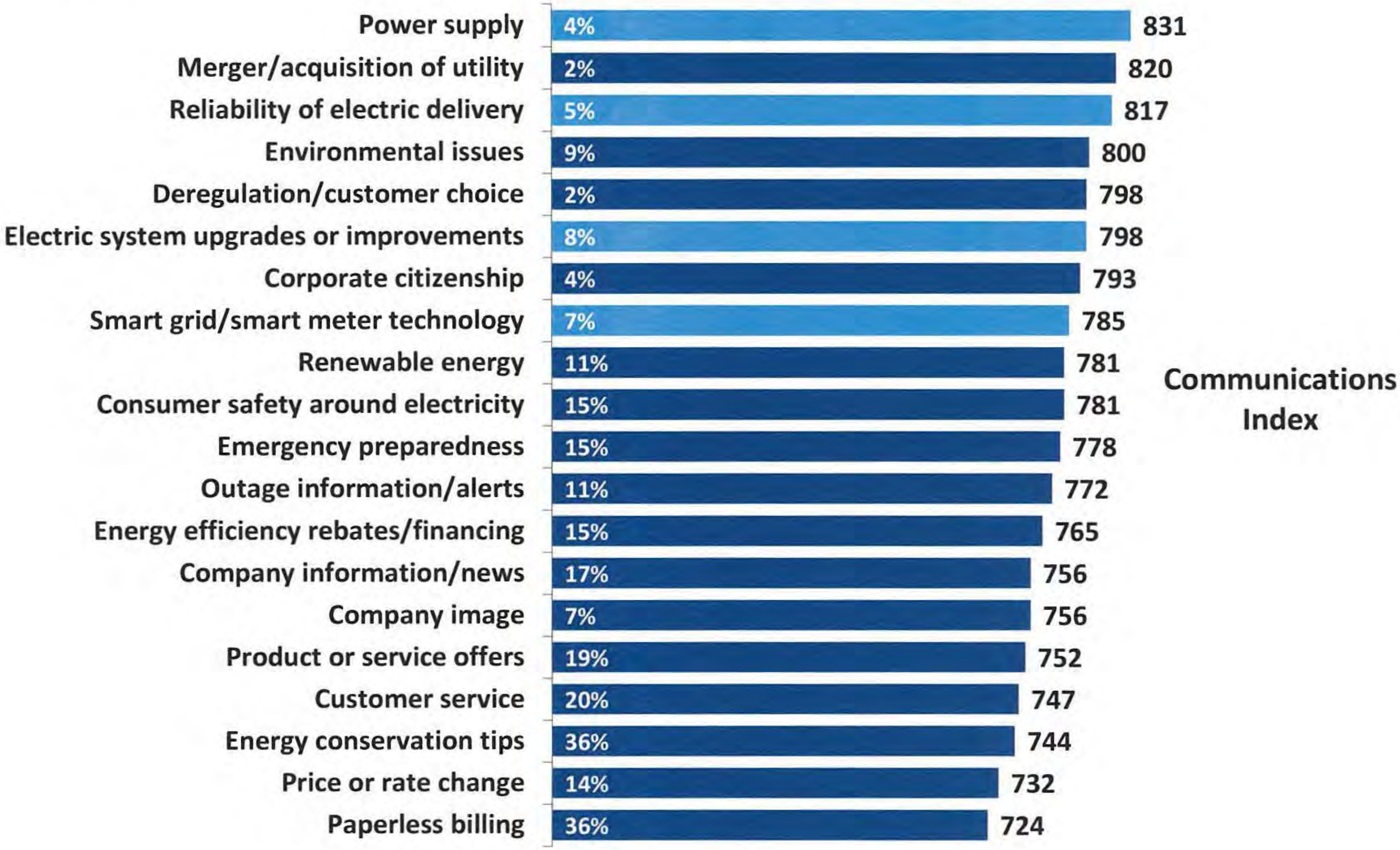
14% Communication Performance

Customers that Recall Utility Communications have Higher Overall Satisfaction vs. those that Don't Recall



  J.D. POWER

System Investment Topics Continue to Drive Highest CSAT



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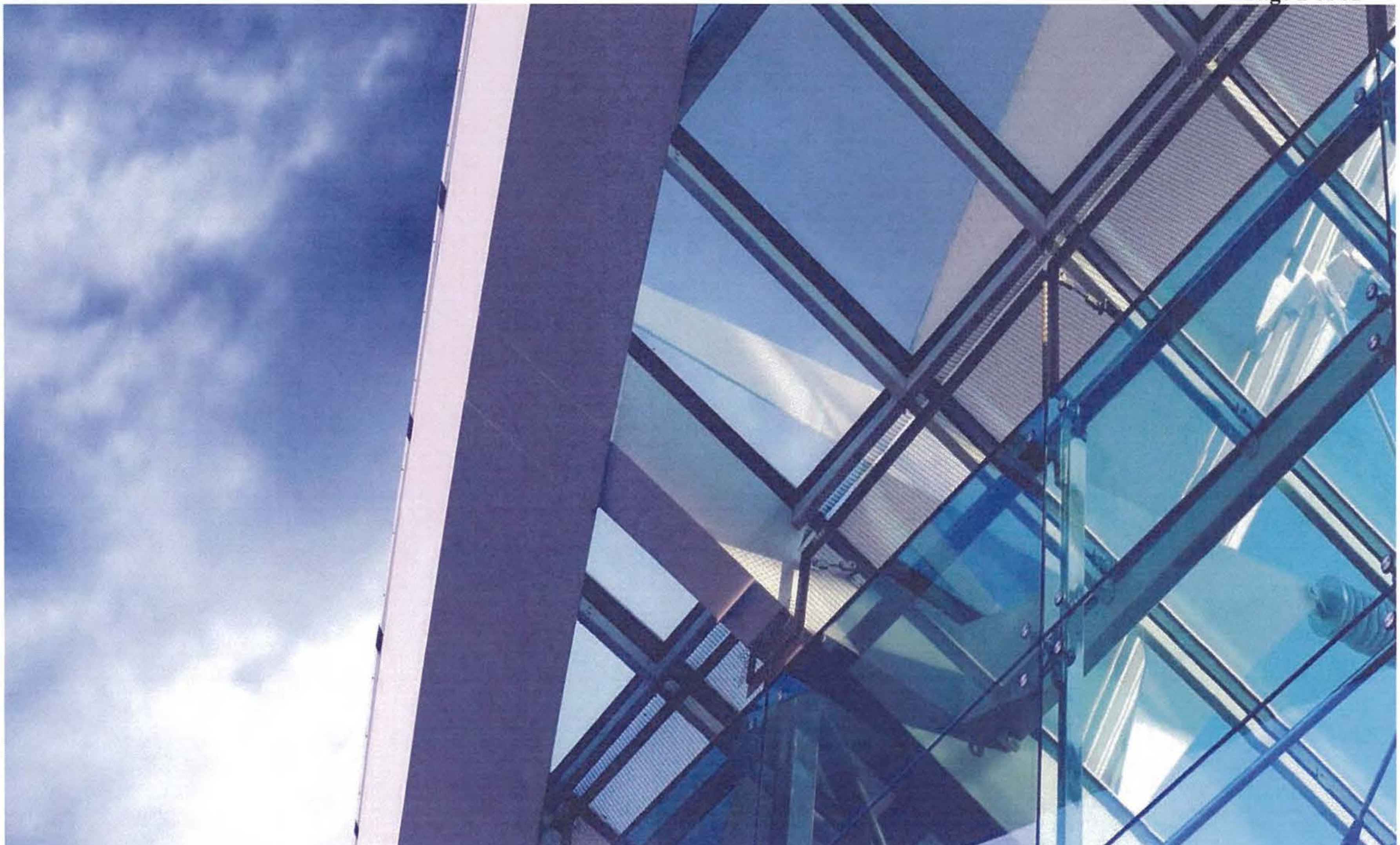

Q1-2017 DEMW Fastrack Quarterly Report

May 9th, 2017

DUKE ENERGY.

Midwest Fastrack
Goal Update – March 2017

	March Score	2017 YTD	2017 Goal	Goal Status
Midwest Fastrack	**83**	**82**	**79**	
Service Initiation	91	**91**	86	
Outage	72	**77**	76	
Outdoor Lighting	86	**77**	74	
Indiana Fastrack	**86**	**85**	**80**	
Service Initiation	89	**90**	86	
Outage	87	**85**	79	
Outdoor Lighting	83	**79**	74	
Ohio/Kentucky Fastrack	**80**	**79**	**78**	
Service Initiation	92	**92**	86	
Outage	58	**70**	73	
Outdoor Lighting	88	**76**	74	

Scores = Avg. of 'Service Initiation,' Outage,' and 'Outdoor Lighting' module scores
Scores = % Customers rating their overall satisfaction an '8, 9 or 10' on a '0-10' scale

DUKE ENERGY.

Midwest Fastrack

Total Goal Module Performance by Zone – March 2017

	March Score	2017 YTD	2017 Goal	Goal Status
Duke Energy Midwest	**83**	**82**	**79**	
Indiana North	87	**86**	80	
Indiana Southeast	88	**85**	80	
Indiana Southwest	84	**82**	80	
Ohio/Kentucky	80	**79**	78	

Scores *= Avg. of 'Service Initiation,' Outage,' and 'Outdoor Lighting' module scores*
Scores *= % Customers rating their overall satisfaction an '8, 9 or 10' on a '0-10' scale*
Zones *ranked by 2017 YTD performance*

Midwest Fastrack

'Service Initiation' Performance by Zone – March 2017

	March Score	2017 YTD	2017 Goal	Goal Status
Duke Energy Midwest	**91**	**91**	**86**	
Indiana Southeast	92	**93**	86	
Indiana North	88	**92**	86	
Ohio/Kentucky	92	**92**	86	
Indiana Southwest	88	**83**	86	

***Scores** = % Customers rating their overall satisfaction an '8, 9 or 10' on a '0-10' scale*
***Zones** ranked by 2017 YTD performance*

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Midwest Fastrack

'Outage' Performance by Zone – March 2017

	March Score	2017 YTD	2017 Goal	Goal Status
Duke Energy Midwest	**72**	**77**	**76**	
Indiana Southeast	88	**88**	79	
Indiana Southwest	83	**84**	79	
Indiana North	88	**83**	79	
Ohio/Kentucky	58	**70**	73	

Scores *= % Customers rating their overall satisfaction an '8, 9 or 10' on a '0-10' scale*
Zones *ranked by 2017 YTD performance*

DUKE ENERGY.

Midwest Fastrack

'Outdoor Lighting' Performance by Zone – March 2017

	March Score	2017 YTD	2017 Goal	Goal Status
Duke Energy Midwest	**86**	**77**	**74**	
Indiana North	85	**82**	74	
Indiana Southwest	79	**81**	74	
Ohio/Kentucky	88	**76**	74	
Indiana Southeast	84	**73**	74	

Scores *= % Customers rating their overall satisfaction an '8, 9 or 10' on a '0-10' scale*
Zones *ranked by 2017 YTD performance*

DUKE ENERGY.

Midwest Fastrack

Outage Module

Q1-17

DEMW Fastrack

Q1-17 Key Improvement Opportunities

The areas listed performed lower (less than 90% of customers rated an 8, 9, or 10) AND have above average impact on overall satisfaction.

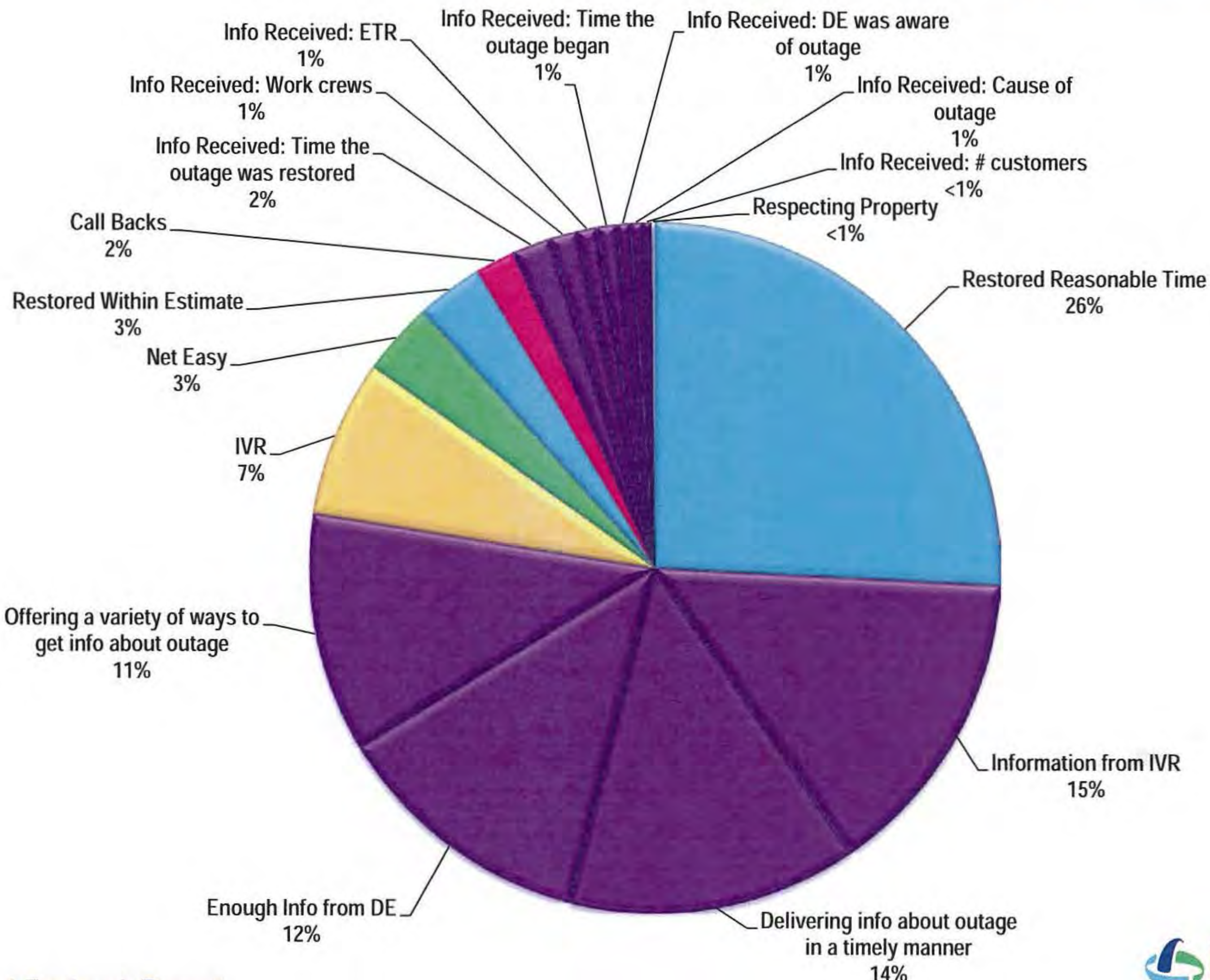
Service Initiation
Deposit Required
-
Deposit Not Required
Kept informed of status

Outdoor Lighting
Reported by Phone
Resolution/Timeliness
Net Easy
One call resolution
Reported Online
Resolution/Timeliness

Outage
IVR Only Transactions
Overall satisfaction with IVR
IVR providing outage info needed
Offering a variety of ways to get outage info
Providing enough info about outage
Delivering outage info in a timely manner
Restored within reasonable amount of time
IVR & Customer Care Specialist Transactions
IVR providing outage info needed
Offering a variety of ways to get outage info
Providing enough info about outage
Restored within reasonable amount of time
Restored within estimated time
Net Easy

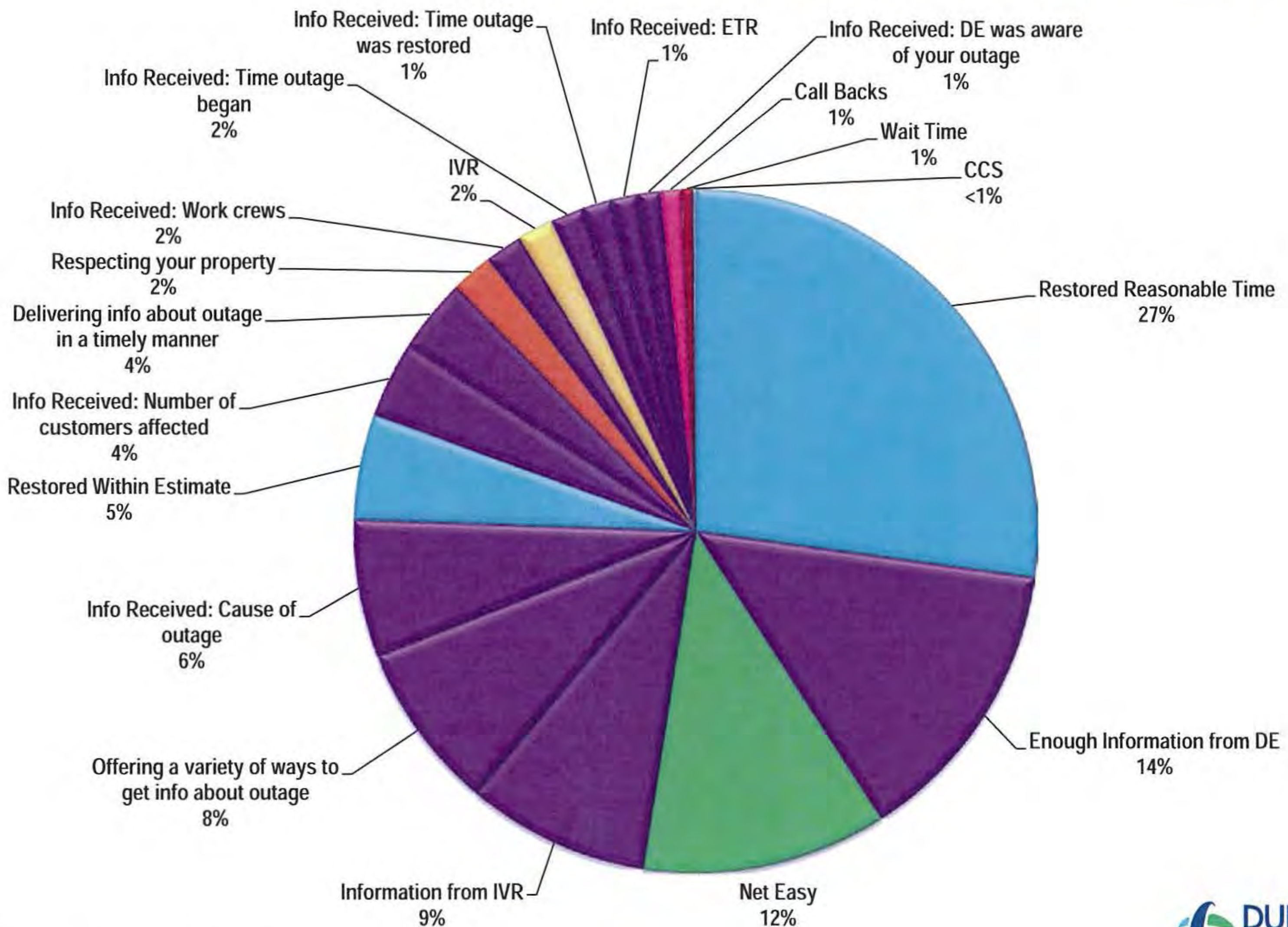
Billing
Internal - IVR Only
Resolution/Timeliness
Internal - IVR & CCS
Resolution/Timeliness
Net Easy
Overall satisfaction with CCS
Outsource - IVR & CCS
Resolution/Timeliness
Net Easy
Overall satisfaction with CCS

Outage (IVR Only)
DEMW Q1-17 Improvement Opportunity Score



Outage (IVR & CCS)

DEMW Q1-17 Improvement Opportunity Score



Outage
Impact on Overall Satisfaction

	YTD-16	Q1-17	Q2-17	Q3-17	Q4-17	YTD-17
Overall Satisfaction with Duke Energy's overall performance as your electric supplier	86	87				87
	2	2				2
Would you say that this recent service experience has had a positive, negative, or no effect on this overall satisfaction with Duke Energy?						
Net Effect[1]	32	32				32
A positive effect	*44*	*44*				*44*
A negative effect	*12*	*11*				*11*
No effect	*44*	*45*				*45*

[1] Net Effect = A positive effect – A negative effect

DUKE ENERGY.

Impact on Overall Satisfaction
DE-MW Fastrack Modules

	YTD-16	Q1-17	Q2-17	Q3-17	Q4-17	YTD-17
Would you say that this recent service experience has had a positive, negative, or no effect on your overall satisfaction with Duke Energy?						
Net Effect[1]						
Service Initiation	63	65				65
Service Initiation (Gas)	57	58				58
Outdoor Lighting	43	51				51
Billing (Internal)	38	36				36
Billing (Outsource)	44	35				35
Outage	32	32				32

[1] *Net Effect = A positive effect – A negative effect.*

IVR Only

IVR & CCS

Outage
Call Center Metrics

	YTD-16	Q1-17	Q2-17	Q3-17	Q4-17	YTD-17
Overall Satisfaction with IVR (IVR Only)		77				77
		8				8
Overall Satisfaction with IVR (IVR & CCS)		68				68
		8				8
Amount of time you waited to be transferred to CCS	83	89				89
	6	1				1
Overall Satisfaction with Customer Care Specialist	90	94				94
	3	0				0

Rating Scale (0 - 10):

% (8-10)
% (0-4)

DUKE ENERGY.

IVR Only IVR & CCS

Outage

Outage Info Provided by Duke Energy

	YTD-16	Q1-17	Q2-17	Q3-17	Q4-17	YTD-17
IVR providing you with the outage information you needed	75	79				79
	13	9				9
Offering a variety of ways to get information about your outage*		76				76
		11				11
Providing you with enough information about your outage	78	73				73
	7	12				12
Delivering information about your outage in a timely manner*		79				79
		12				12
Did Duke Energy Provide The Following Information?[1] (% Yes)						
The cause of the outage	*34*	*44*				*44*
The number of customers affected	*72*	*72*				*72*
Whether a crew was dispatched	*71*	*64*				*64*
The time the outage began	*60*	*62*				*62*
Duke Energy was aware of the outage	*71*	*75*				*75*
Estimated time of restoration	*77*	*82*				*82*
*The time the outage was restored**	*72*	*68*				*68*
No information provided	*7*	*3*				*3*

[1] Includes information provided in the initial call to Duke Energy, as well as any subsequent points of contact regarding the outage.

** Question added to survey in Q1-17.*

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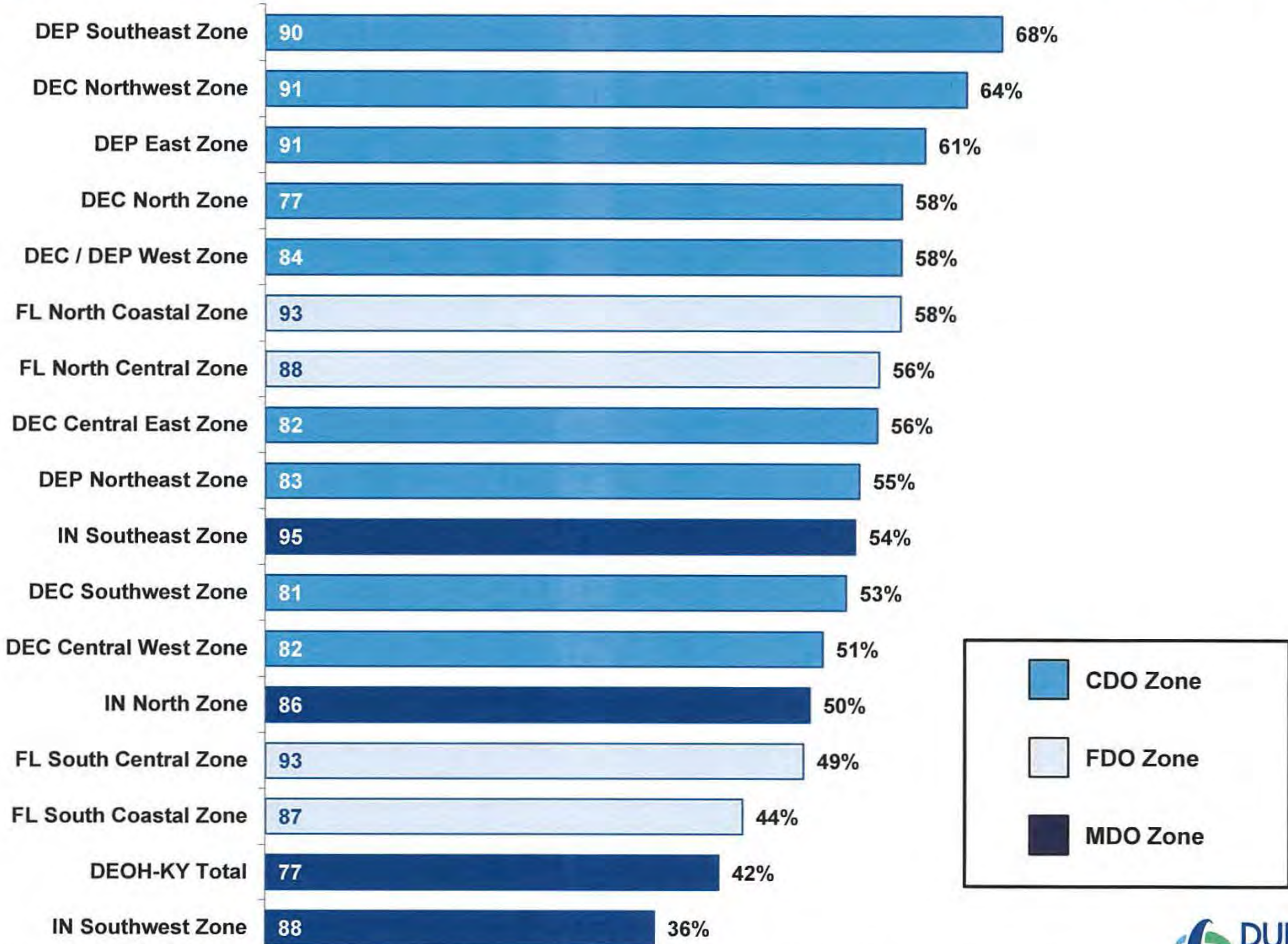
Duke Energy Total Fastrack

March 2017 YTD – % Received Cause of Outage*



Score inside bar represents % 8-10 OSAT score when Received Cause of Outage, score outside bar represents % of customers who Received Cause of Outage

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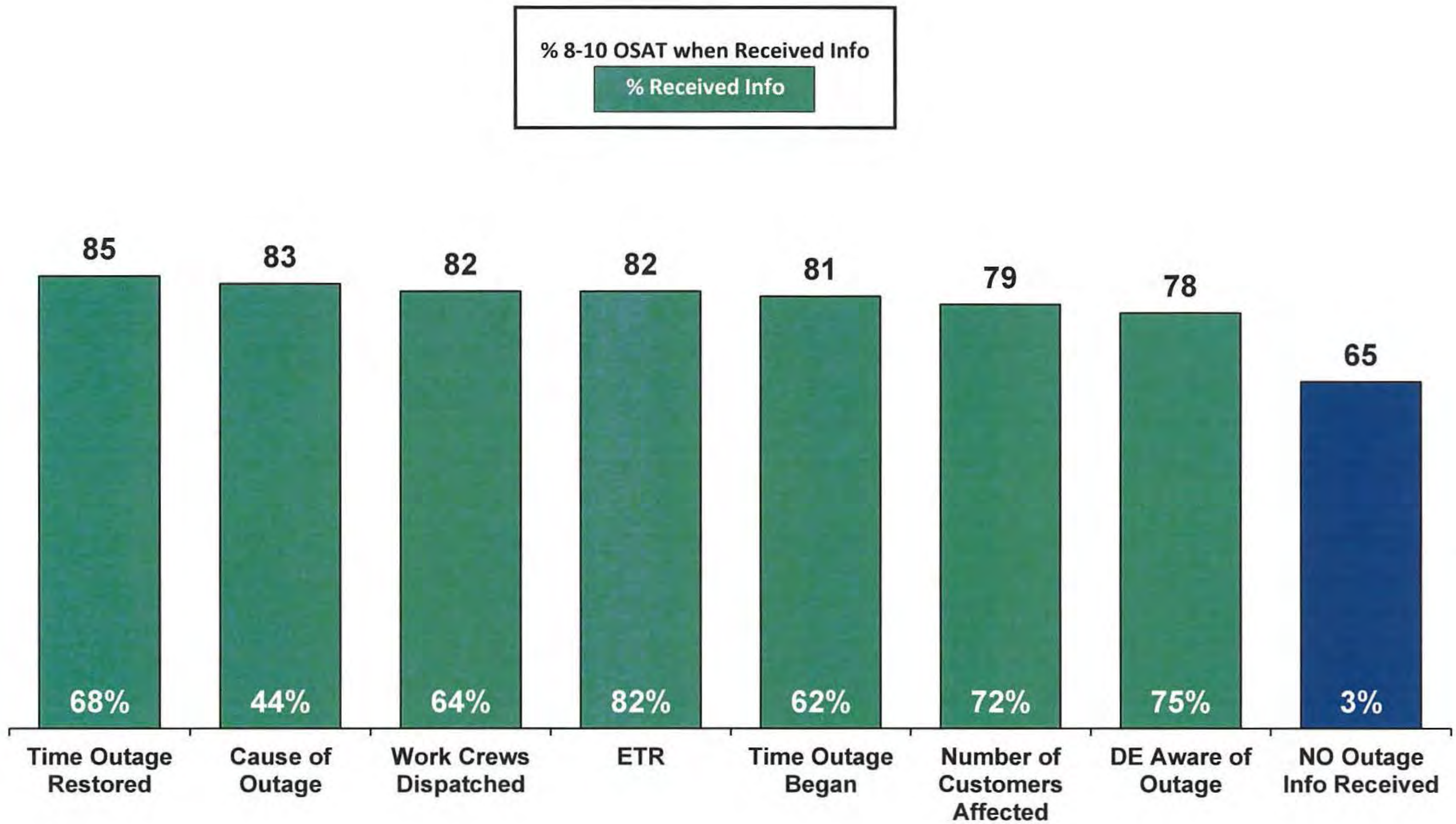
IVR Only IVR & CCS

Outage
Satisfaction by Outage Info Received – Q1-17



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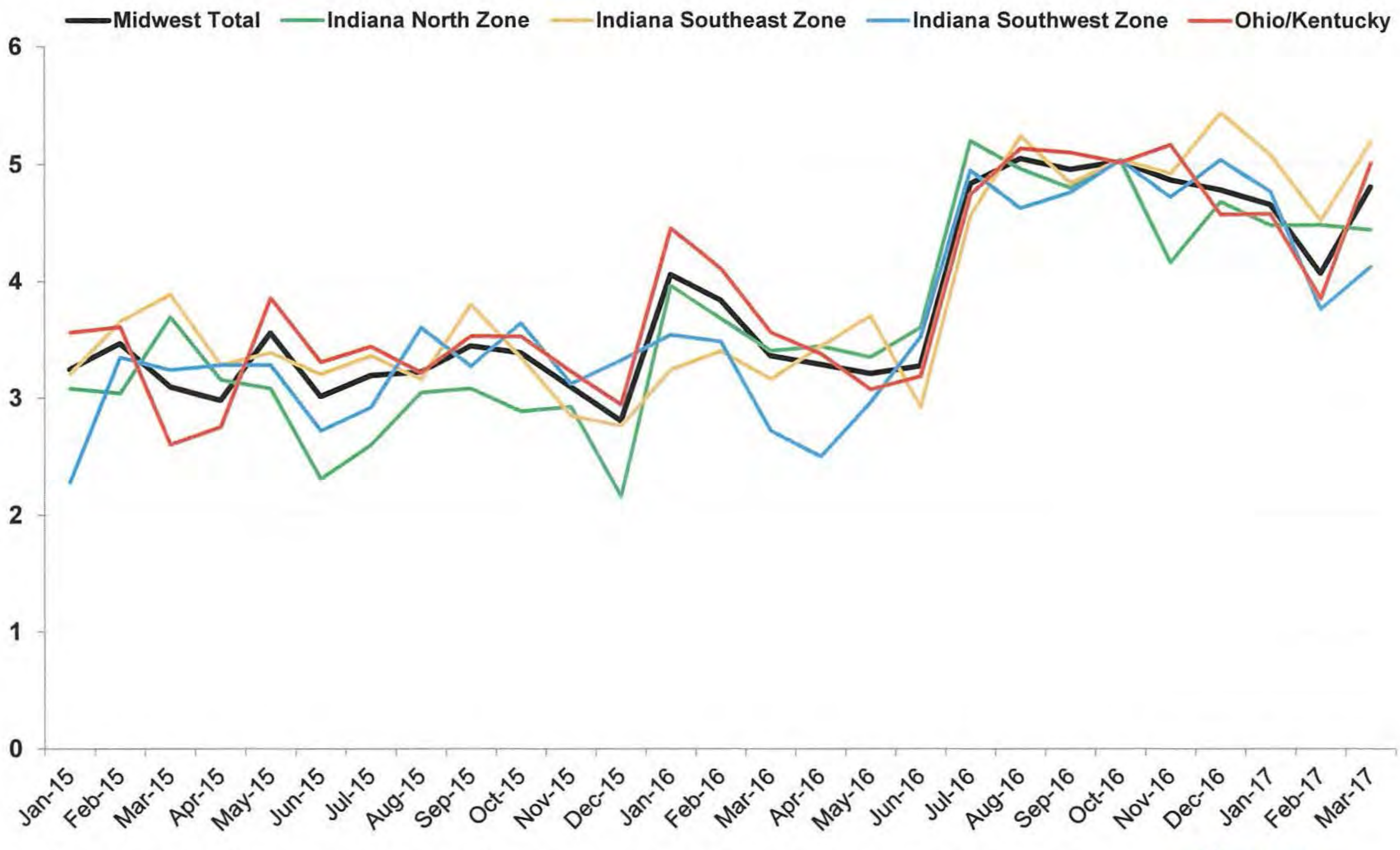
Midwest Fastrack

Zones – Monthly Avg. # Outage Information Points

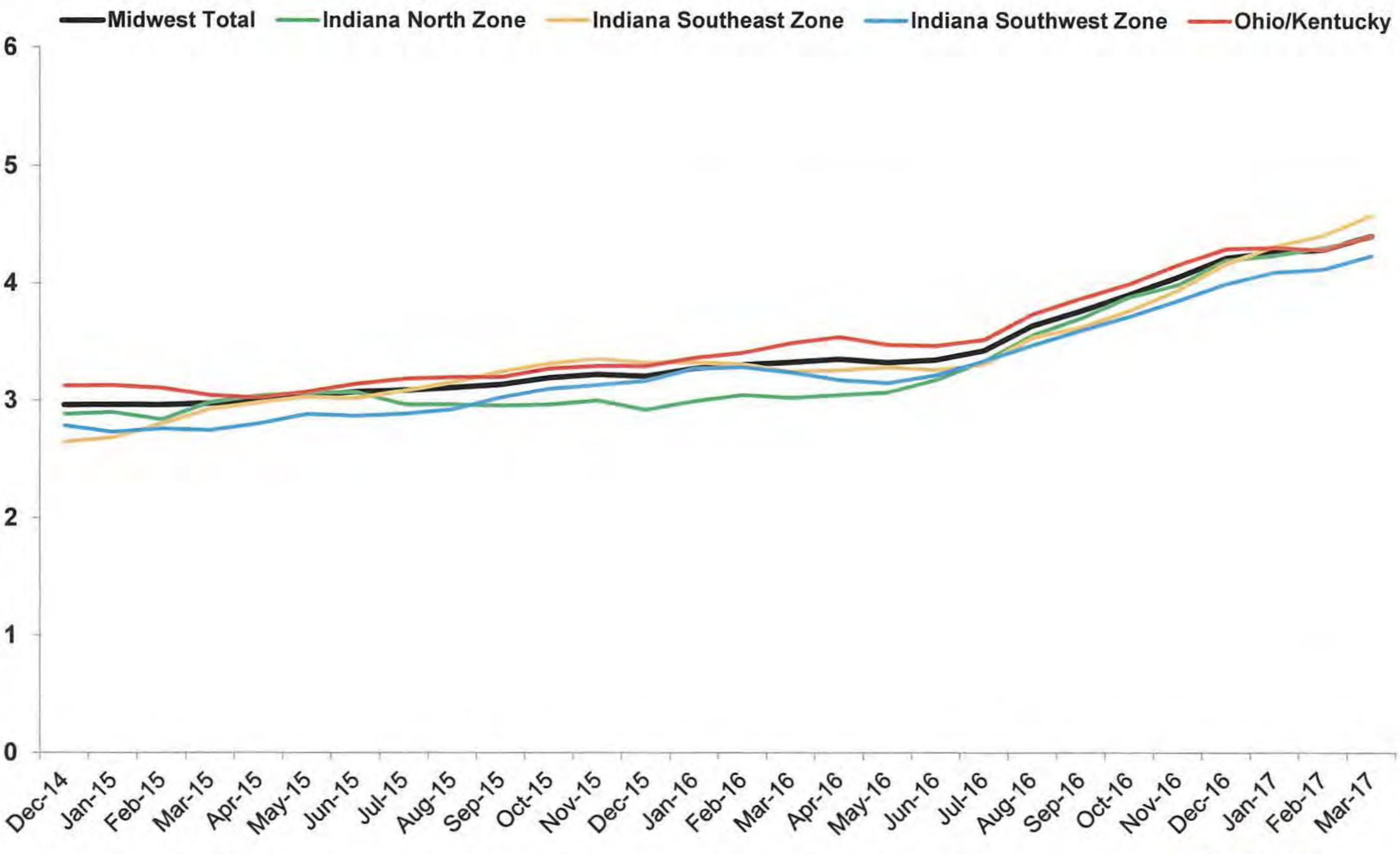


There were 6 possible information points Jan-14 through Jun-16, and 7 possible information points from Jul-16 forward

DUKE ENERGY.

Midwest Fastrack

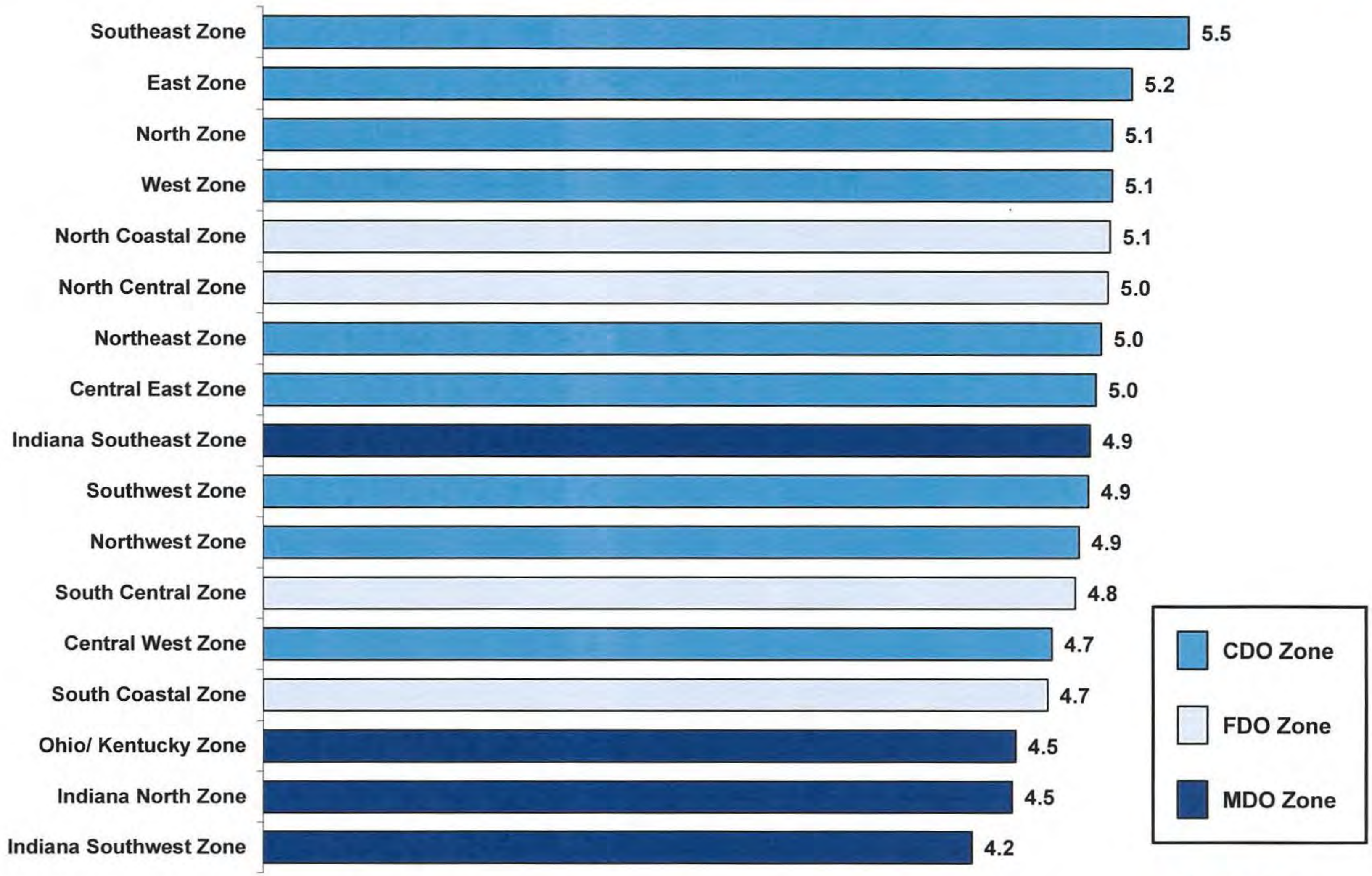
Zones – Rolling 12-Months Avg. # Outage Information Points



**There were 6 possible information points Jan-14 through Jun-16, and 7 possible information points from Jul-16 forward*

'Total Duke' Outage Performance by Zone

Average # of Outage Info Points Received* – 2017 YTD



** Out of 7 possible information points. Includes information received during initial call and any other subsequent points of contact.*


IVR Only


IVR & CCS

Outage
ETRs & Restoration

Midwest Total

		YTD-16	Q1-17	Q2-17	Q3-17	Q4-17	YTD-17
Estimated Time of Restoration							
Received estimated time of restoration (% Yes)	IVR Only	81	83				83
	IVR+CCS	70	79				79
Restored within estimated time (% Yes)	IVR Only	77	81				81
	IVR+CCS	76	89				89
Restored within a reasonable time (% 8-10)	IVR Only	78	77				77
	IVR+CCS	82	82				82

DUKE ENERGY.

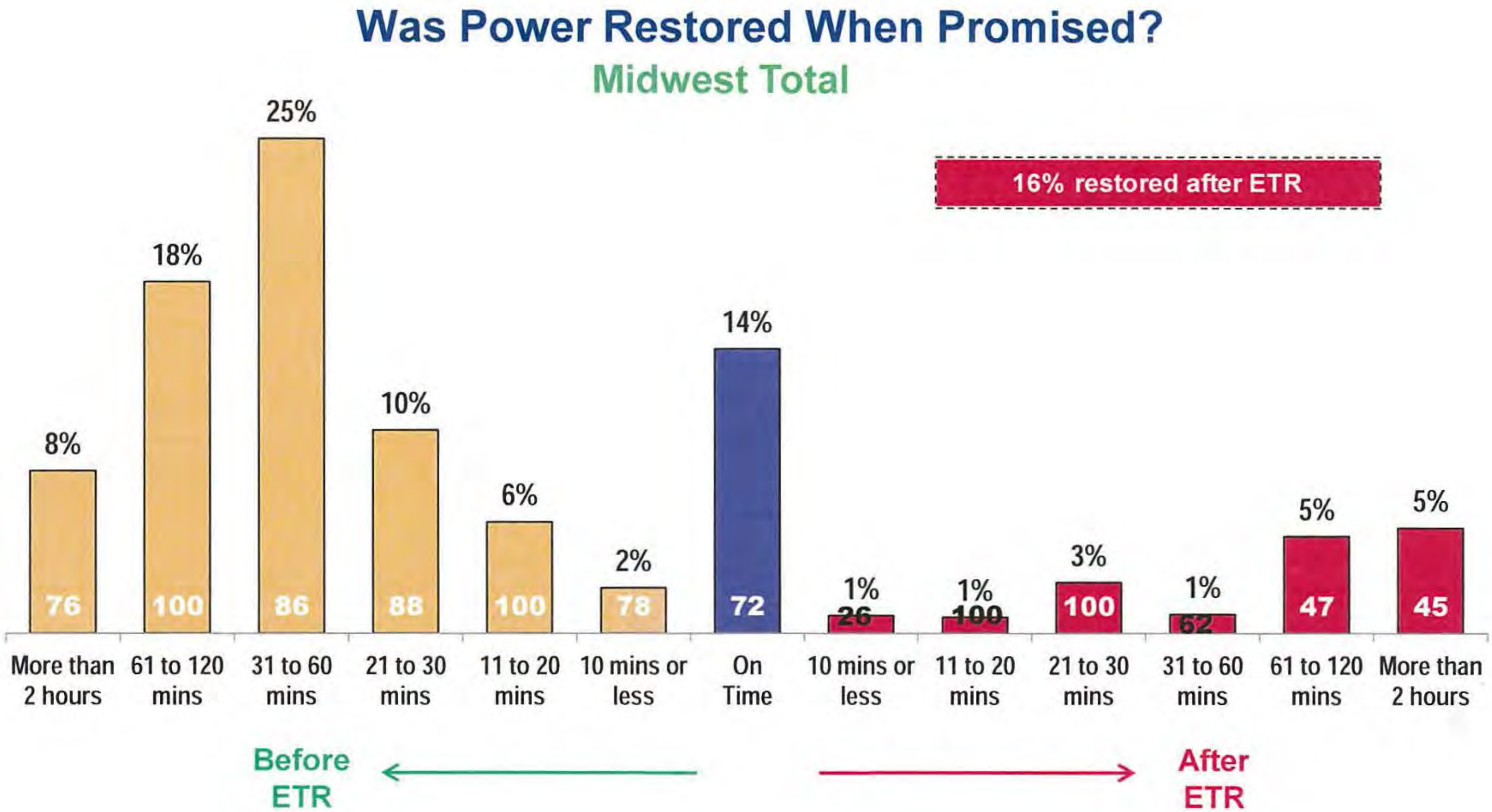
Outage
ETRs & Restoration

Ohio/Kentucky Zone

		YTD-16	Q1-17	Q2-17	Q3-17	Q4-17	YTD-17
Estimated Time of Restoration							
Received estimated time of restoration (% Yes)	IVR Only	82	76				76
	IVR+CCS	71	87				87
Restored within estimated time (% Yes)	IVR Only	78	80				80
	IVR+CCS	71	91				91
Restored within a reasonable time (% 8-10)	IVR Only	73	68				68
	IVR+CCS	79	75				75

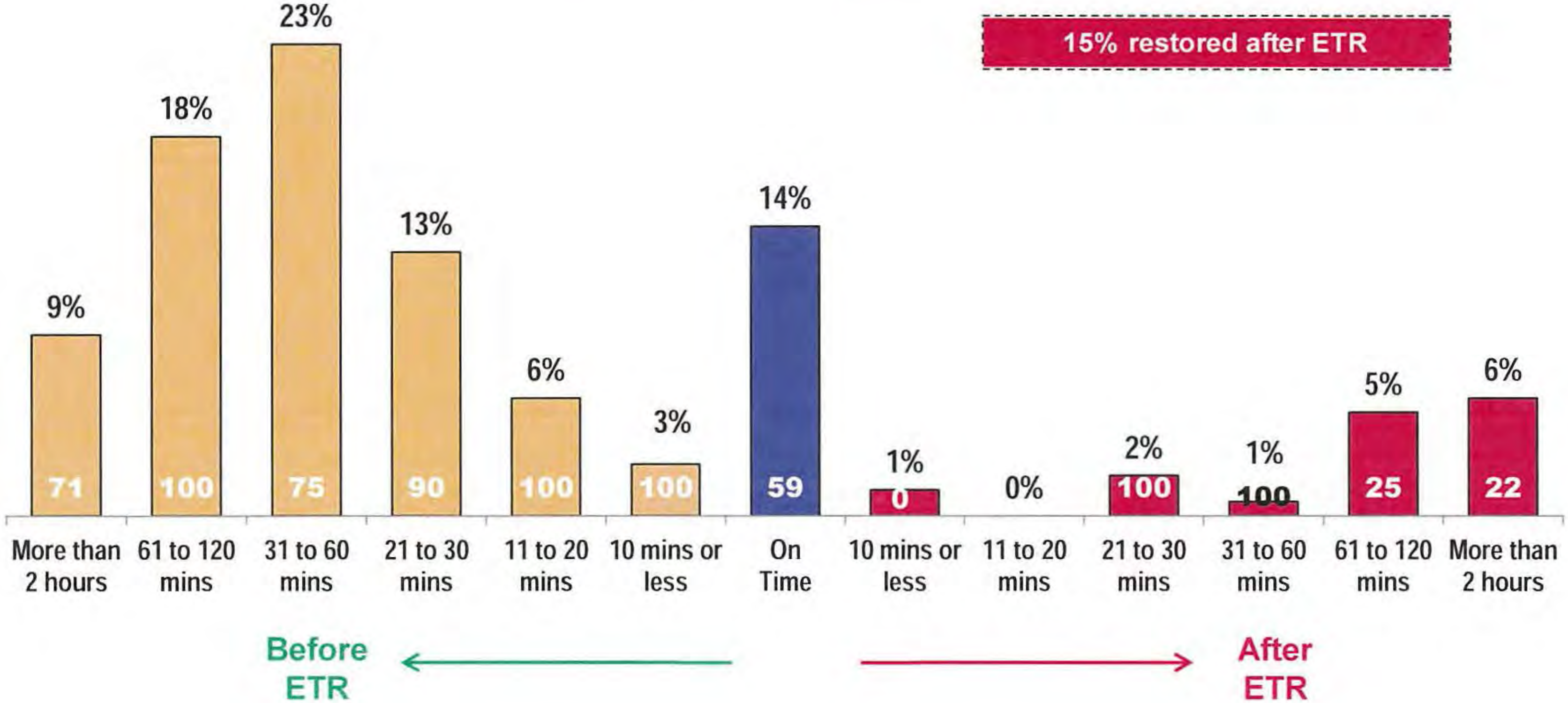
DUKE ENERGY.

Outage
Restoration Time vs. Estimate – Q1-17



Outage
Restoration Time vs. Estimate – Q1-17

Was Power Restored When Promised?
Ohio/Kentucky Zone



IVR Only

IVR & CCS

Outage
Quality of Field Service

	YTD-16	Q1-17	Q2-17	Q3-17	Q4-17	YTD-17
Respecting your property	94	92				92
	2	3				3
Talked with field service technician DURING visit (% Yes)	*13*	*12*				*12*
Overall Satisfaction with service provided by Field Service Technician at your property	89	85				85
	3	0				0

DUKE ENERGY.


IVR Only


IVR & CCS

Outage
ETR Call-backs

Did you request a call-back or text message to confirm power restoration or receive an updated estimate? (% Yes)	YTD-16	Q1-17	Q2-17	Q3-17	Q4-17	YTD-17
Requested call-back	27	32				32
Received call-back (Total)	81	75				75
Received call-back (IVR Only)		74				74
Received call-back (IVR & CCS)		73				73
Requested text message	36	36				36
Received text message (Total)	83	79				79
Received text message (IVR Only)		76				76
Received text message (IVR & CCS)		84				84
Requested email*		1				1
Received email* (Total)		100				100
Received email* (IVR Only)		100				100
Received email* (IVR & CCS)		100				100

* Question added to survey in Q1-17.

DUKE ENERGY.

Outage
Net Easy

	YTD-16	Q1-17	Q2-17	Q3-17	Q4-17	YTD-17
Net Easy*	73	72				72
Easy	85	84				84
Neither easy nor difficult	3	4				4
Difficult	12	12				12

*Net Easy = Easy – Difficult.

DUKE ENERGY.

Net Easy
DE-MW Fastrack Modules

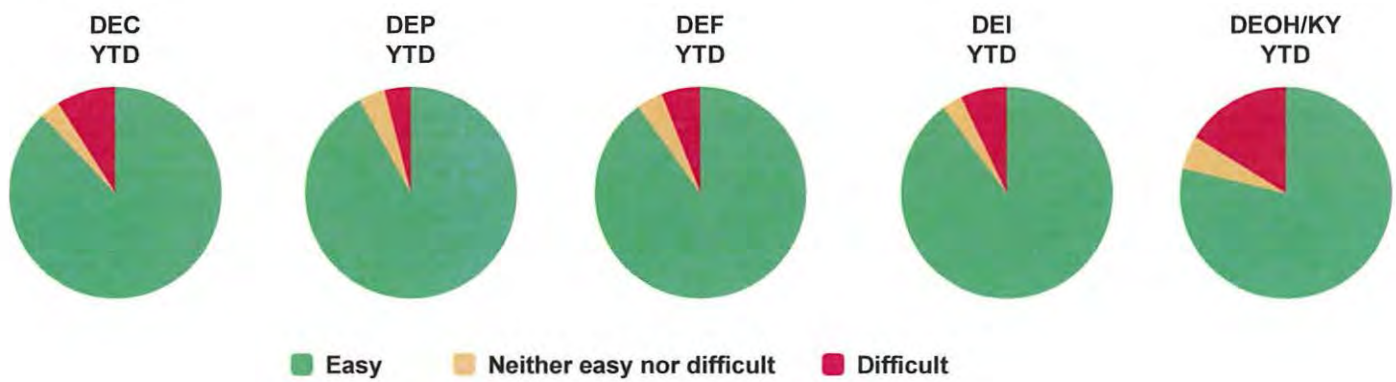
	YTD-16	Q1-17	Q2-17	Q3-17	Q4-17	YTD-17
All things considered, would you say it was easy - or difficult - for you to get your request resolved?						
Net Easy*						
Service Initiation	91	91				91
Service Initiation (Gas)	86	87				87
Billing (Internal)	79	80				80
Outage	73	72				72
Outdoor Lighting	58	68				68
Billing (Outsource)	71	64				64

*Net Easy = Easy – Difficult.

Net Easy
Outage – 2017

	DEC					DEP					DEF					DEI					DEOH/KY				
	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Net Easy*	79				**79**	88				**88**	85				**85**	82				**82**	62				**62**
Easy	88				88	92				92	91				91	89				89	78				78
Neither easy nor difficult	3				3	4				4	4				4	3				3	5				5
Difficult	9				9	4				4	6				6	7				7	16				16

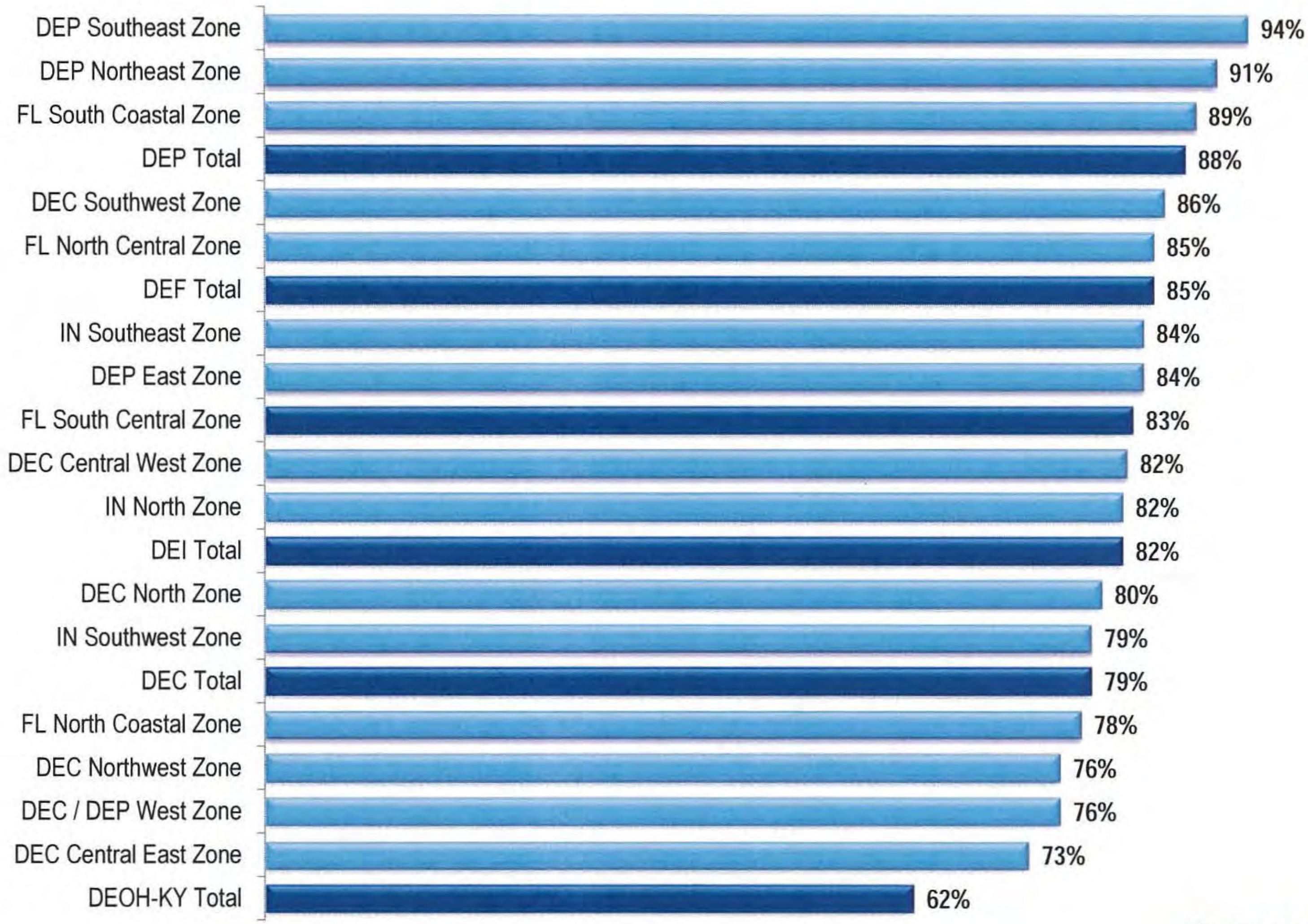
*Net Easy score = Easy - Difficult



All things considered, would you say it was easy – or difficult – for you to get your power restored?

DUKE ENERGY.

Net Easy
Outage By Zone – Q1-17



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Midwest Fastrack

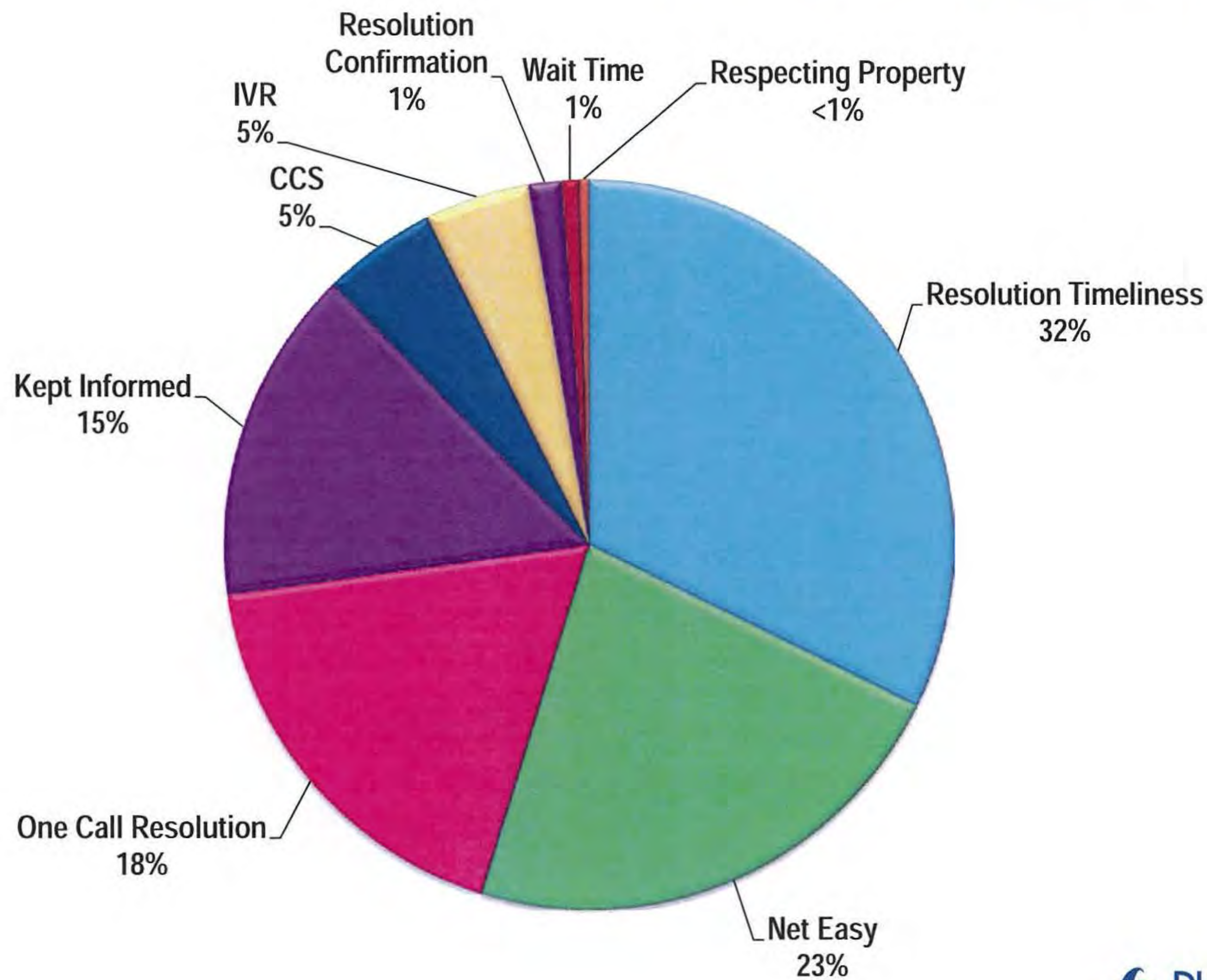
Outdoor Lighting Module

Q1-17

DUKE ENERGY®

Outdoor Lighting (Reported by Phone)

DEMW Q1-17 Opportunity Score



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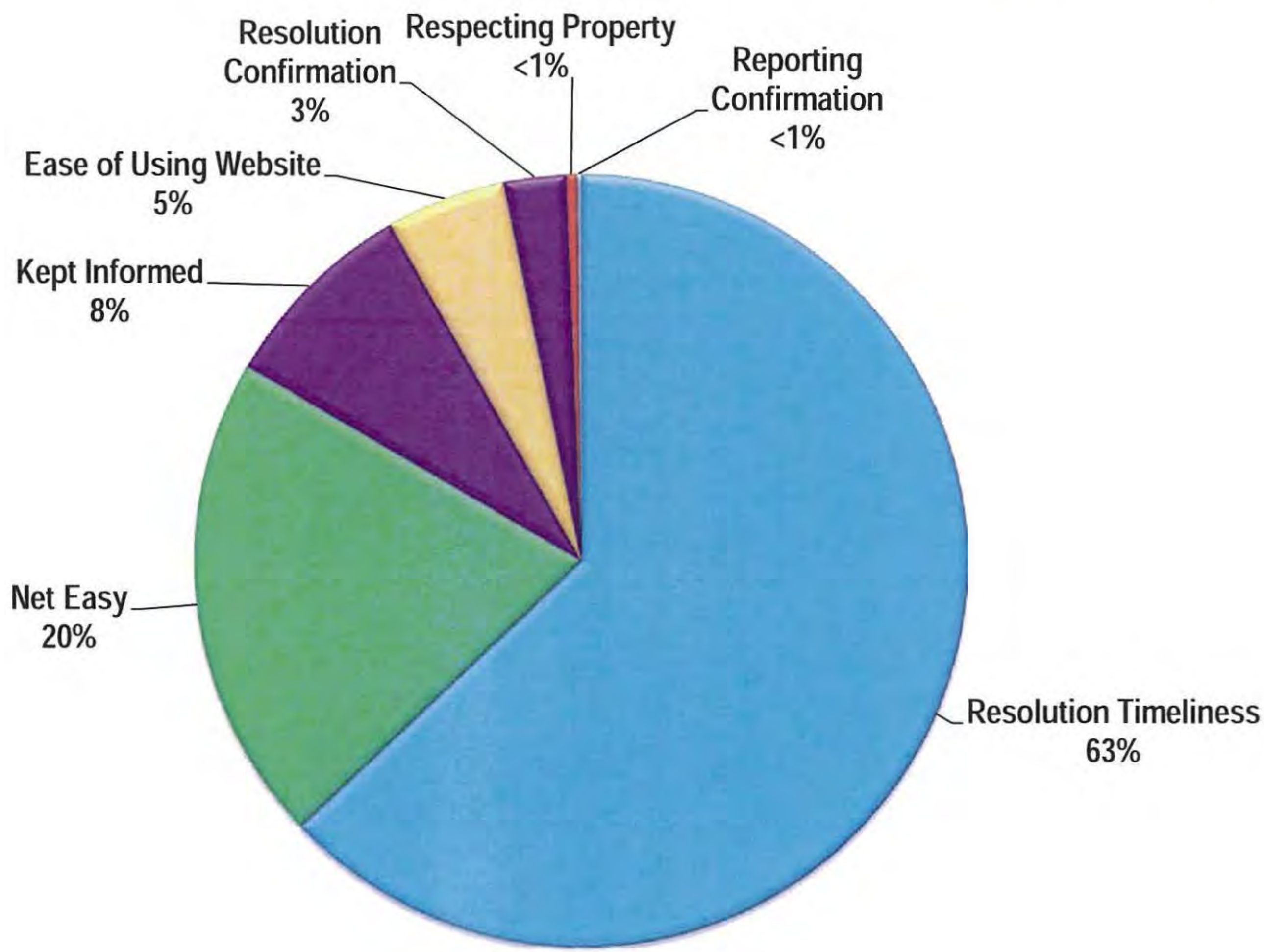
Outdoor Lighting (Reported Online)
DEMW Q1-17 Opportunity Score



Outdoor Lighting
Impact on Overall Satisfaction

	YTD-16	Q1-17	Q2-17	Q3-17	Q4-17	YTD-17
Overall Satisfaction with Duke Energy's overall performance as your electric supplier	89	85				85
	3	3				3
Would you say that this recent service experience has had a positive, negative, or no effect on this overall satisfaction with Duke Energy?						
Net Effect[1]	43	51				51
A positive effect	*57*	*60*				*60*
A negative effect	*14*	*8*				*8*
No effect	*28*	*32*				*32*

[1] Net Effect = A positive effect – A negative effect.

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Impact on Overall Satisfaction
DE-MW Fastrack Modules

	YTD-16	Q1-17	Q2-17	Q3-17	Q4-17	YTD-17
Would you say that this recent service experience has had a positive, negative, or no effect on your overall satisfaction with Duke Energy?						
Net Effect[1]						
Service Initiation	63	65				65
Service Initiation (Gas)	57	58				58
Outdoor Lighting	43	51				51
Billing (Internal)	38	36				36
Billing (Outsource)	44	35				35
Outage	32	32				32

[1] Net Effect = A positive effect – A negative effect.

DUKE ENERGY.

Phone Reported

Outdoor Lighting
IVR Ratings

	YTD-16	Q1-17	Q2-17	Q3-17	Q4-17	YTD-17
Overall Satisfaction with IVR	52	45				45
	26	18				18
Amount of time you waited to be transferred to CCS	67	73				73
	10	6				6
Overall Satisfaction with Customer Care Specialist	89	88				88
	4	5				5
One call resolution (% Yes)	*68*	*73*				*73*

Rating Scale (0 - 10):

% (8-10)
% (0-4)

DUKE ENERGY.

Online Reported

Outdoor Lighting
Website Ratings

	YTD-16	Q1-17	Q2-17	Q3-17	Q4-17	YTD-17
Website Evaluation						
Ease of using Duke Energy's website to make your outdoor lighting request	84	74				74
	2	8				8
Did you receive a confirmation email your outdoor lighting repair has been reported? (% Yes)	98	97				97

Rating Scale (0 - 10): % (8-10) / % (0-4)

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Phone Reported Online Reported

Outdoor Lighting
Request Resolution

	YTD-16	Q1-17	Q2-17	Q3-17	Q4-17	YTD-17
Request Resolution						
One call resolution (% Yes)	*68*	*73*				*73*
Timeliness of resolving outdoor lighting request	71	78				78
	15	12				12

Rating Scale (0 - 10): % (8-10) / % (0-4)

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Phone Reported Online Reported

Outdoor Lighting
Kept Informed

	YTD-16	Q1-17	Q2-17	Q3-17	Q4-17	YTD-17
Kept informed throughout the process of your request (% Yes)	69	66				66
Informed that your outdoor lighting request had been resolved (% Yes)	59	53				53

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Phone Reported Online Reported

Outdoor Lighting
Quality of Field Service

	YTD-16	Q1-17	Q2-17	Q3-17	Q4-17	YTD-17
Did you speak with the Field Service Technician who repaired your light? (% Yes)*		*20*				*20*
Overall Satisfaction with service provided by Field Service Technician at your property	86	89				89
	10	7				7
Was the outdoor light located on your property? (% Yes)	*45*	*43*				*43*
Respecting your property	98	92				92
	2	6				6

** Question added to survey in Q1-17.*

Rating Scale (0 - 10):

% (8-10)
% (0-4)

Phone Reported Online Reported

Outdoor Lighting
Net Easy

	YTD-16	Q1-17	Q2-17	Q3-17	Q4-17	YTD-17
Net Easy*	58	68				68
Easy	78	83				83
Neither easy nor difficult	3	2				2
Difficult	20	15				15

**Net Easy = Easy – Difficult.*

DUKE ENERGY.

Net Easy
DE-MW Fastrack Modules

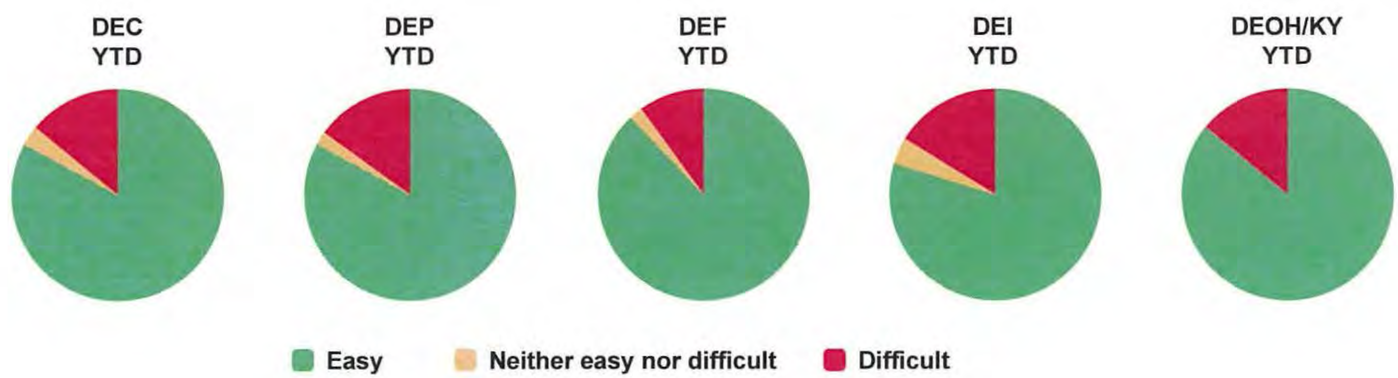
	YTD-16	Q1-17	Q2-17	Q3-17	Q4-17	YTD-17
All things considered, would you say it was easy - or difficult - for you to get your request resolved?						
Net Easy*						
Service Initiation	91	91				91
Service Initiation (Gas)	86	87				87
Billing (Internal)	79	80				80
Outage	73	72				72
Outdoor Lighting	58	68				68
Billing (Outsource)	71	64				64

**Net Easy = Easy – Difficult.*

Net Easy
Outdoor Lighting – 2017

	DEC					DEP					DEF					DEI					DEOH/KY				
	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Net Easy*	70				**70**	68				**68**	77				**77**	63				**63**	72				**72**
Easy	83				83	83				83	88				88	79				79	86				86
Neither easy nor difficult	3				3	2				2	2				2	4				4	0				0
Difficult	14				14	15				15	10				10	16				16	14				14

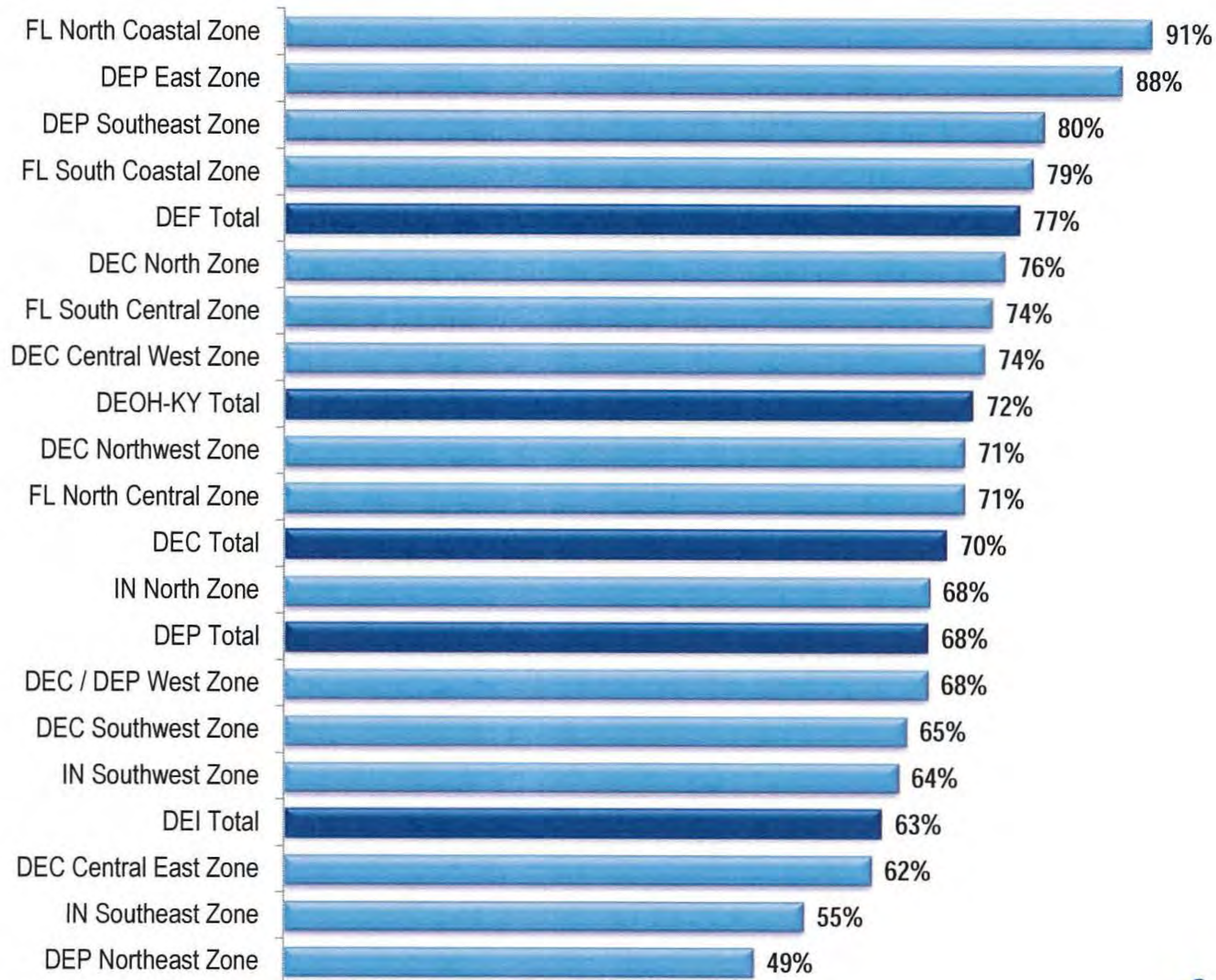
**Net Easy score = Easy - Difficult*



All things considered, would you say it was easy – or difficult – for you to get your request resolved?

DUKE ENERGY.

Net Easy
Outdoor Lighting By Zone – Q1-17



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Midwest Fastrack

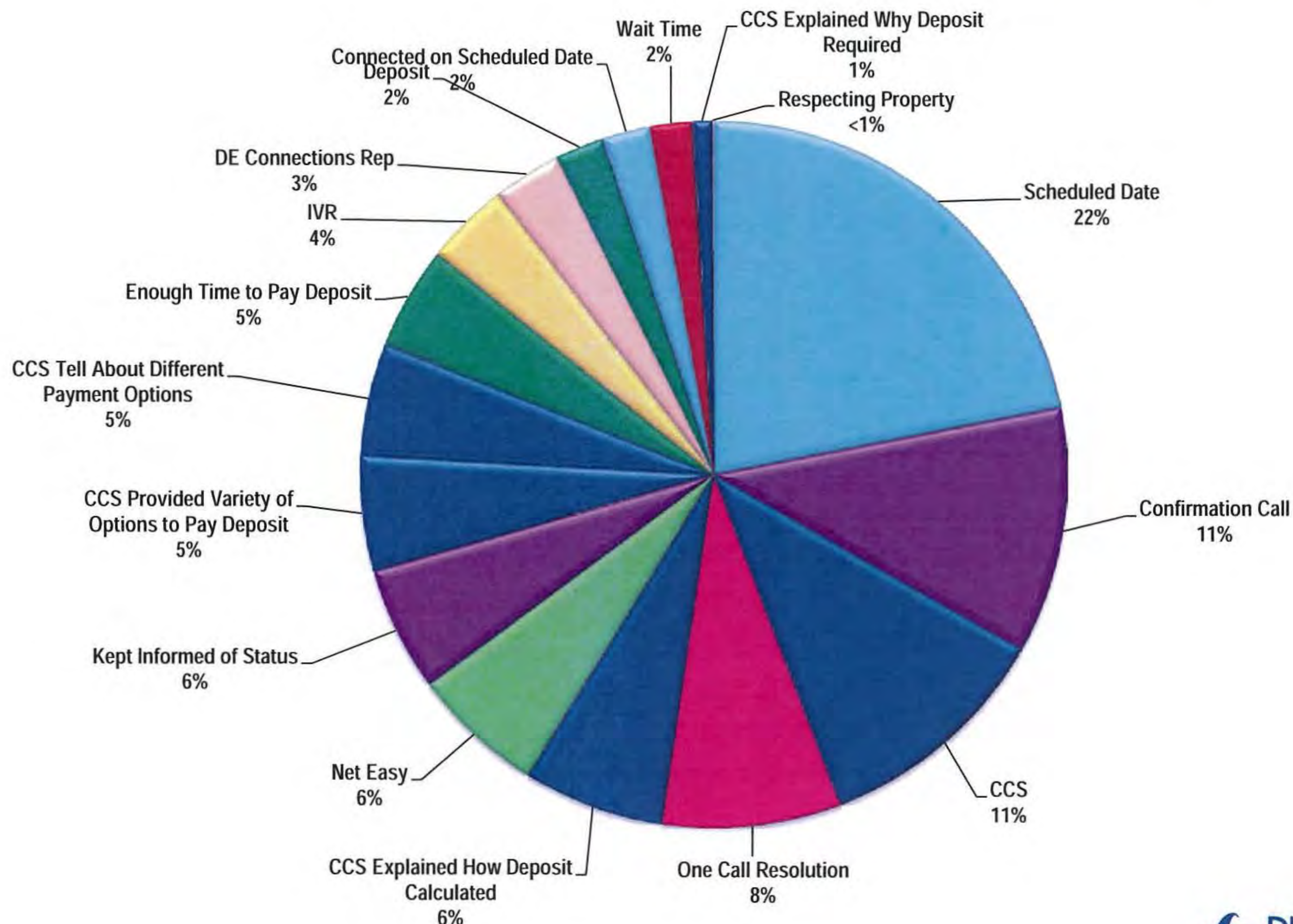
Service Initiation Module

Q1-17

DUKE ENERGY®

Service Initiation – Deposit Required

DEMW Q1-17 Opportunity Score



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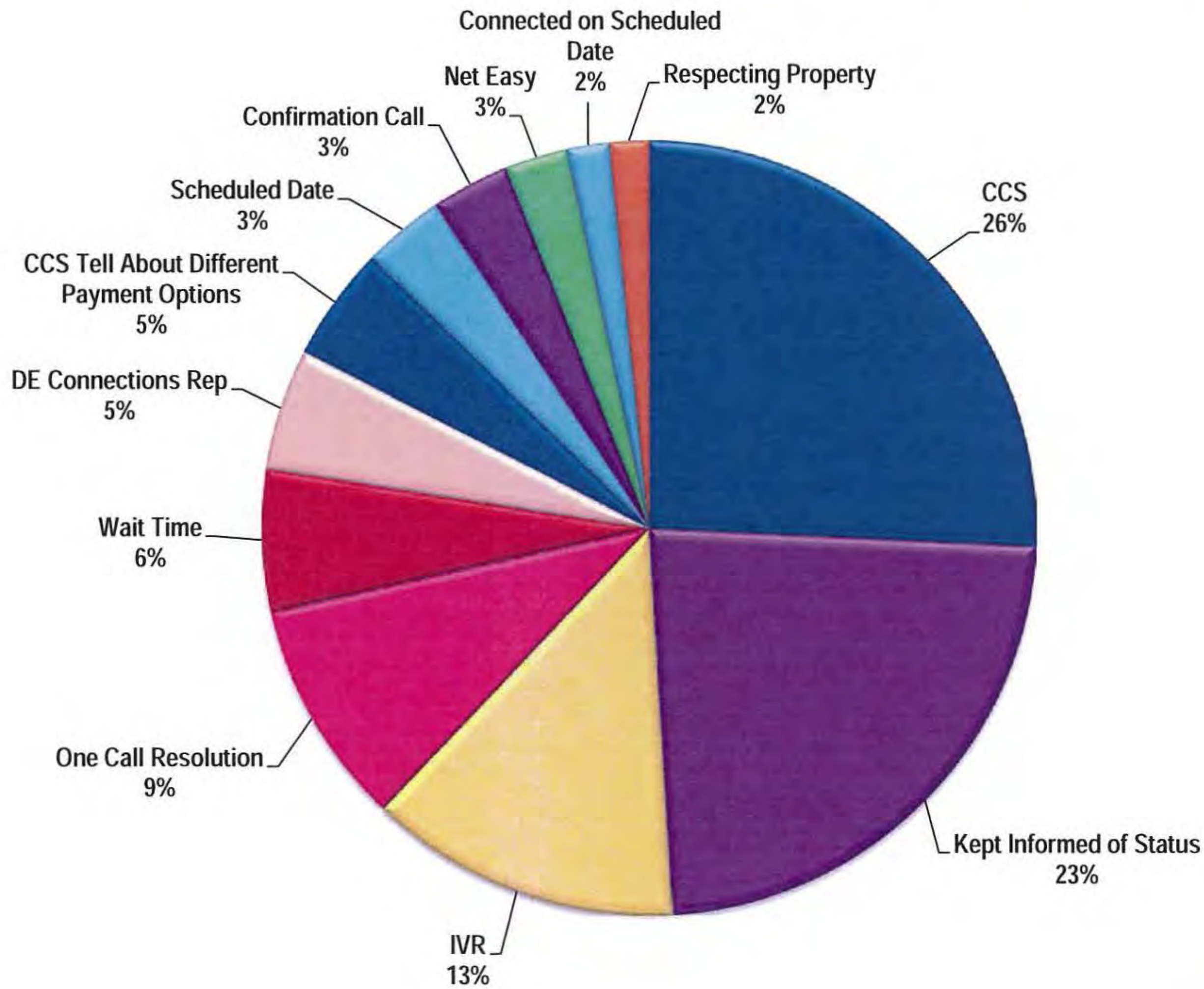
Service Initiation – Deposit NOT Required
DEMW Q1-17 Opportunity Score



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Service Initiation
Impact on Overall Satisfaction

	YTD-16	Q1-17	Q2-17	Q3-17	Q4-17	YTD-17
Overall Satisfaction with Duke Energy's overall performance as your electric supplier	91	91				91
	1	1				1
Would you say that this recent service experience has had a positive, negative, or no effect on your overall satisfaction with Duke Energy?						
Net Effect[1]	63	65				65
A positive effect	67	67				67
A negative effect	4	2				2
No effect	29	31				31

[1] *Net Effect = A positive effect – A negative effect*

DUKE ENERGY.

Impact on Overall Satisfaction
DE-MW Fastrack Modules

	YTD-16	Q1-17	Q2-17	Q3-17	Q4-17	YTD-17
Would you say that this recent service experience has had a positive, negative, or no effect on your overall satisfaction with Duke Energy?						
Net Effect[1]						
Service Initiation	63	65				65
Service Initiation (Gas)	57	58				58
Outdoor Lighting	43	51				51
Billing (Internal)	38	36				36
Billing (Outsource)	44	35				35
Outage	32	32				32

[1] Net Effect = A positive effect – A negative effect

DUKE ENERGY.

Deposit

Service Initiation

Call Center Metrics – Deposit Required

	YTD-16	Q1-17	Q2-17	Q3-17	Q4-17	YTD-17
Overall Satisfaction with IVR		82				82
		6				6
Amount of time you waited to be transferred to CCS		88				88
		2				2
Overall Satisfaction with Customer Care Specialist		95				95
		3				3
Payment options explained (% Yes)		*70*				*70*
One call resolution (% Yes)		*83*				*83*
Overall Satisfaction with Duke Energy Connections Representative		85				85
		8				8

Rating Scale (0 - 10):

% (8-10)
% (0-4)

DUKE ENERGY.

Deposit

Service Initiation
Deposit

	YTD-16	Q1-17	Q2-17	Q3-17	Q4-17	YTD-17
Required to Pay Deposit (% Yes)	36	33				33
Deposit affected overall satisfaction	59	48				48
SOME effect on overall satisfaction	41	26				26
BIG effect on overall satisfaction	7	8				8
BIGGER impact on overall satisfaction than anything else	12	13				13
CCS explained why the deposit was required (% Yes)*		61				61
CCS explained how the deposit was calculated (% Yes)*		44				44
CCS provided a variety of options to pay or satisfy the deposit (% Yes)*		75				75
Overall satisfaction with providing enough time to pay the deposit*		77 8				77 8

** Question added to survey in Q1-17*

No Deposit

Service Initiation

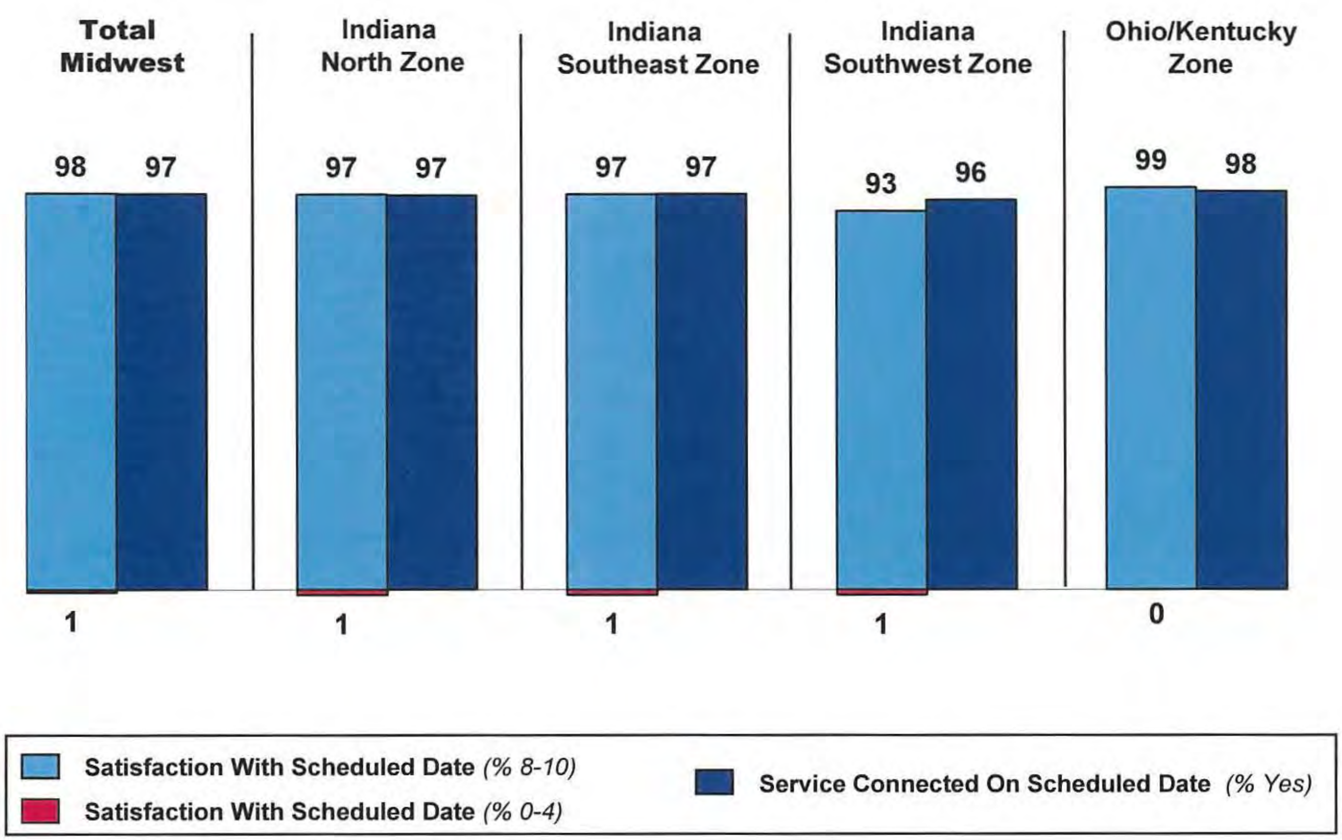
Call Center Metrics – Deposit NOT Required

	YTD-16	Q1-17	Q2-17	Q3-17	Q4-17	YTD-17
Overall Satisfaction with IVR		69				69
		10				10
Amount of time you waited to be transferred to CCS		90				90
		2				2
Overall Satisfaction with Customer Care Specialist		93				93
		1				1
Payment options explained (% Yes)		*68*				*68*
One call resolution (% Yes)		*90*				*90*
Overall Satisfaction with Duke Energy Connections Representative		87				87
		6				6

Rating Scale (0 - 10):

% (8-10)
% (0-4)

Service Initiation
Scheduled Date & Performance – Q1-17



Deposit No Deposit

Service Initiation
Scheduled Date & Performance

	YTD-16	Q1-17	Q2-17	Q3-17	Q4-17	YTD-17
Scheduled Date & Performance						
Satisfaction with scheduled connection date	96 2	98 1				98 1
Service connected on scheduled date (%Yes)	97	97				97
Received confirmation call or phone message (% Yes)	57	59				59
Kept Informed About Status of Request (% Yes)	85	87				87

Rating Scale (0 - 10): % (8-10) / % (0-4)

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Deposit No Deposit

Service Initiation
Field Service Technician

Midwest Total

	YTD-16	Q1-17	Q2-17	Q3-17	Q4-17	YTD-17
Respecting your property	99	97				97
	1	1				1
Talked with field service technician DURING visit (% Yes)	*8*	*5*				*5*
Overall Satisfaction with service provided by Field Service Technician at your property	95	96				96
	1	0				0

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Service Initiation
Field Service Technician

Ohio/Kentucky Zone

	YTD-16	Q1-17	Q2-17	Q3-17	Q4-17	YTD-17
Respecting your property	99	96				96
	1	1				1
Talked with field service technician DURING visit (% Yes)	*9*	*4*				*4*
Overall Satisfaction with service provided by Field Service Technician at your property	95	100				100
	2	0				0

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Deposit No Deposit

Service Initiation
Net Easy – Connected on Scheduled Date

	YTD-16	Q1-17	Q2-17	Q3-17	Q4-17	YTD-17
Net Easy*	91	91				91
Easy	95	95				95
Neither easy nor difficult	1	2				2
Difficult	4	3				3
% Indicating Connected on Scheduled Date	97	97				97
Easy	97	96				96
Neither easy nor difficult	<1	1				1
Difficult	3	3				3
% Indicating NOT Connected on Scheduled Date	3	3				3
Easy	59	69				69
Neither easy nor difficult	3	20				20
Difficult	37	11				11

*Net Easy = Easy – Difficult.

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Deposit


No Deposit

Service Initiation
Net Easy – Deposit Required

	YTD-16	Q1-17	Q2-17	Q3-17	Q4-17	YTD-17
Net Easy*	91	91				91
Easy	95	95				95
Neither easy nor difficult	1	2				2
Difficult	4	3				3
% Indicating Required to Pay Deposit	36	33				33
Easy		94				94
Neither easy nor difficult		2				2
Difficult		4				4
% Indicating NOT Required to Pay Deposit	64	67				67
Easy		94				94
Neither easy nor difficult		3				3
Difficult		3				3

**Net Easy = Easy – Difficult.*

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Net Easy
DE-MW Fastrack Modules

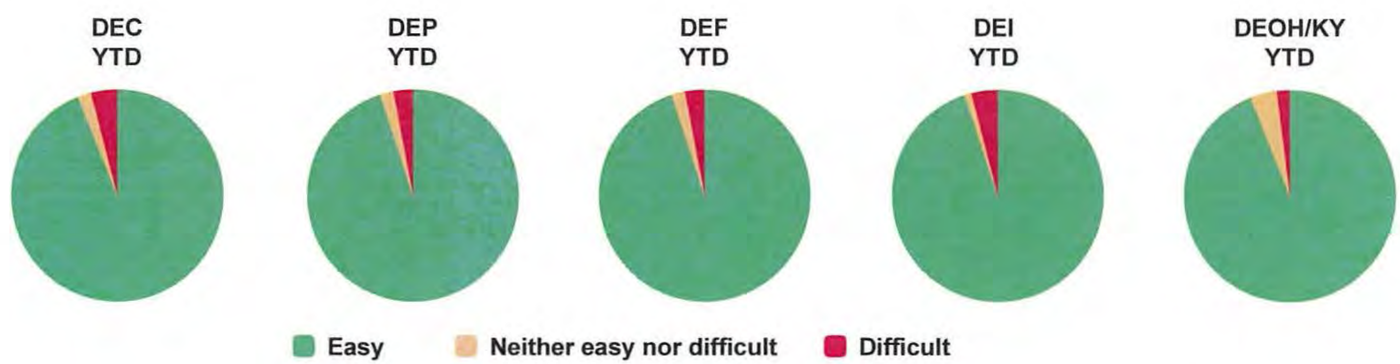
	YTD-16	Q1-17	Q2-17	Q3-17	Q4-17	YTD-17
All things considered, would you say it was easy - or difficult - for you to get your request resolved?						
Net Easy*						
Service Initiation	91	91				91
Service Initiation (Gas)	86	87				87
Billing (Internal)	79	80				80
Outage	73	72				72
Outdoor Lighting	58	68				68
Billing (Outsource)	71	64				64

*Net Easy = Easy – Difficult.

Net Easy
Service Initiation – 2017

	DEC					DEP					DEF					DEI					DEOH/KY				
	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Net Easy*	89				**89**	93				**93**	92				**92**	91				**91**	92				**92**
Easy	93				94	96				96	95				95	95				95	94				94
Neither easy nor difficult	2				2	2				2	2				2	1				1	4				4
Difficult	5				4	3				3	3				3	4				4	2				2

*Net Easy score = Easy - Difficult



All things considered, would you say it was easy – or difficult – for you to get your service connected?

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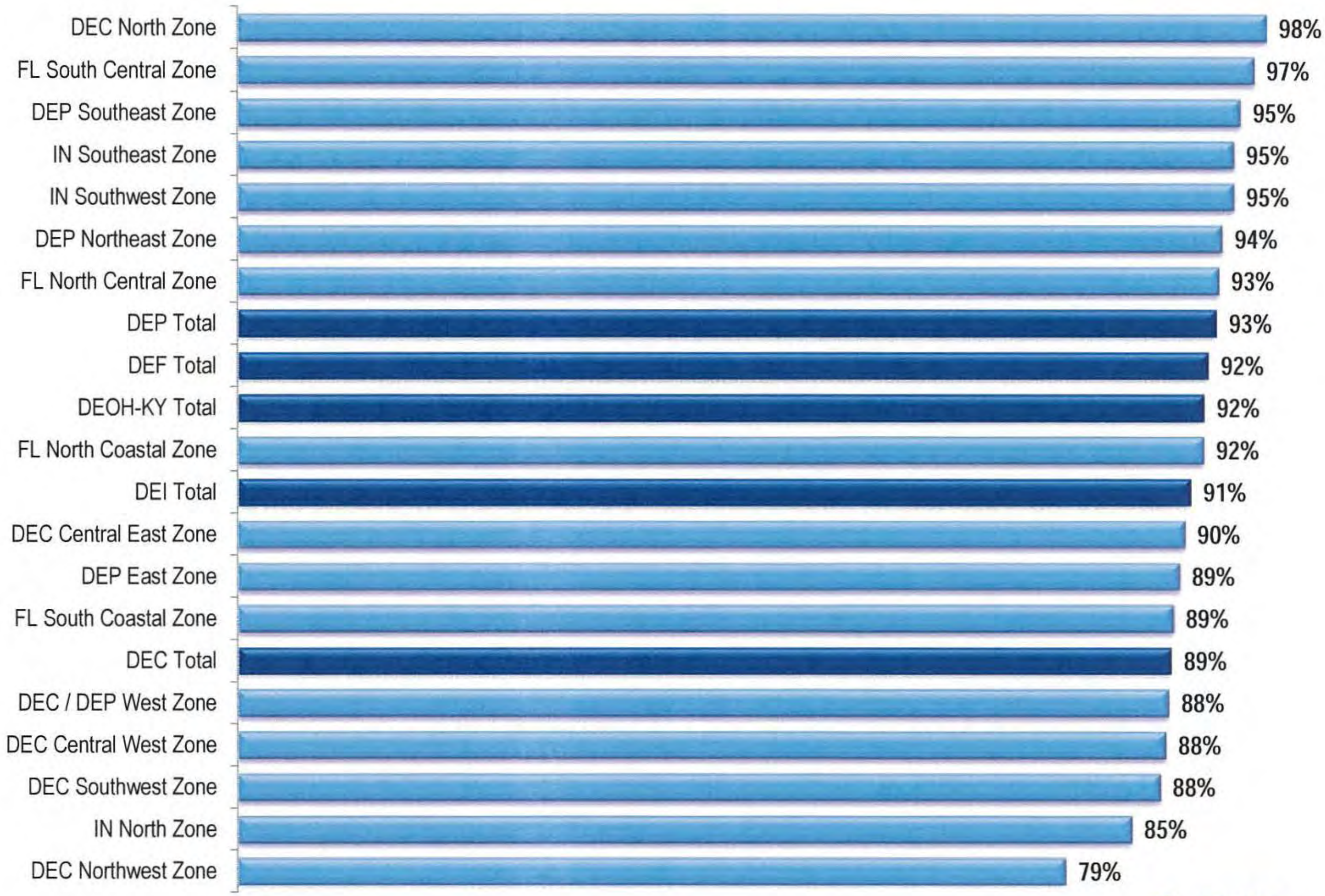
Net Easy
Service Initiation By Zone – Q1-17



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Duke Energy Midwest
Fastrack

June 2017 Update

bellomy research

Midwest Fastrack
Summary – June 2017

Midwest Fastrack Score

- Fastrack is the company's transaction study, through which we measure customer satisfaction with their recent service experience with us
- **Fastrack Score** = % of customers rating their 'Overall Satisfaction' an '8, 9 or 10' on a '0-10' scale
- Note: 3 modules comprise the Fastrack score for 2017:
  - 'Service Initiation' Module
  - 'Outage' Module
  - 'Outdoor Lighting' Module
- June 2017 score is 86

Overall Midwest Fastrack Results – June 2017 YTD

- **MDO June 2017 YTD (83):** 4 points above the goal of 79
  - Service Initiation YTD (91): 5 points above the goal of 86
  - Outage YTD (81): 5 points above the goal of 76
  - Outdoor Lighting YTD (79): 5 points above the goal of 74
- **DEI June 2017 YTD (84):** 4 points above the goal of 80
  - Service Initiation YTD (91): 5 points above the goal of 86
  - Outage YTD (85): 6 points above the goal of 79
  - Outdoor Lighting YTD (77): 3 points above the goal of 74
- **DEOH/KY June 2017 YTD (83):** 5 points above the goal of 78
  - Service Initiation YTD (90): 4 points above the goal of 86
  - Outage YTD (77): 4 points above the goal of 73
  - Outdoor Lighting YTD (81): 7 points above the goal of 74

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Midwest Fastrack
Goal Update – June 2017

	June Score	2017 YTD	2017 Goal	Goal Status
Midwest Fastrack	86	83	79	
Service Initiation	93	**91**	86	
Outage	80	**81**	76	
Outdoor Lighting	84	**79**	74	
Indiana Fastrack	82	84	80	
Service Initiation	93	**91**	86	
Outage	84	**85**	79	
Outdoor Lighting	67	**77**	74	
Ohio/Kentucky Fastrack	89	83	78	
Service Initiation	92	**90**	86	
Outage	76	**77**	73	
Outdoor Lighting	100	**81**	74	

***Scores** = Avg. of 'Service Initiation,' Outage,' and 'Outdoor Lighting' module scores*
***Scores** = % Customers rating their overall satisfaction an '8, 9 or 10' on a '0-10' scale*

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Midwest Fastrack

Total Goal Module Performance by Zone – June 2017

	June Score	2017 YTD	2017 Goal	Goal Status
Duke Energy Midwest	86	83	79	●
Indiana North	83	**86**	80	●
Indiana Southeast	82	**84**	80	●
Ohio/Kentucky	89	**83**	78	●
Indiana Southwest	80	**82**	80	●

***Scores** = Avg. of 'Service Initiation,' Outage,' and 'Outdoor Lighting' module scores*
***Scores** = % Customers rating their overall satisfaction an '8, 9 or 10' on a '0-10' scale*
***Zones** ranked by 2017 YTD performance*

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Midwest Fastrack

'Service Initiation' Performance by Zone – June 2017

	June Score	2017 YTD	2017 Goal	Goal Status
Duke Energy Midwest	93	91	86	●
Indiana North	100	**93**	86	●
Indiana Southeast	88	**91**	86	●
Ohio/Kentucky	92	**90**	86	●
Indiana Southwest	88	**87**	86	●

***Scores** = % Customers rating their overall satisfaction an '8, 9 or 10' on a '0-10' scale*
***Zones** ranked by 2017 YTD performance*

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Midwest Fastrack

'Outage' Performance by Zone – June 2017

	June Score	2017 YTD	2017 Goal	Goal Status
Duke Energy Midwest	80	81	76	●
Indiana Southeast	89	**90**	79	●
Indiana North	84	**83**	79	●
Indiana Southwest	80	**82**	79	●
Ohio/Kentucky	76	**77**	73	●

***Scores** = % Customers rating their overall satisfaction an '8, 9 or 10' on a '0-10' scale*
***Zones** ranked by 2017 YTD performance*

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Midwest Fastrack

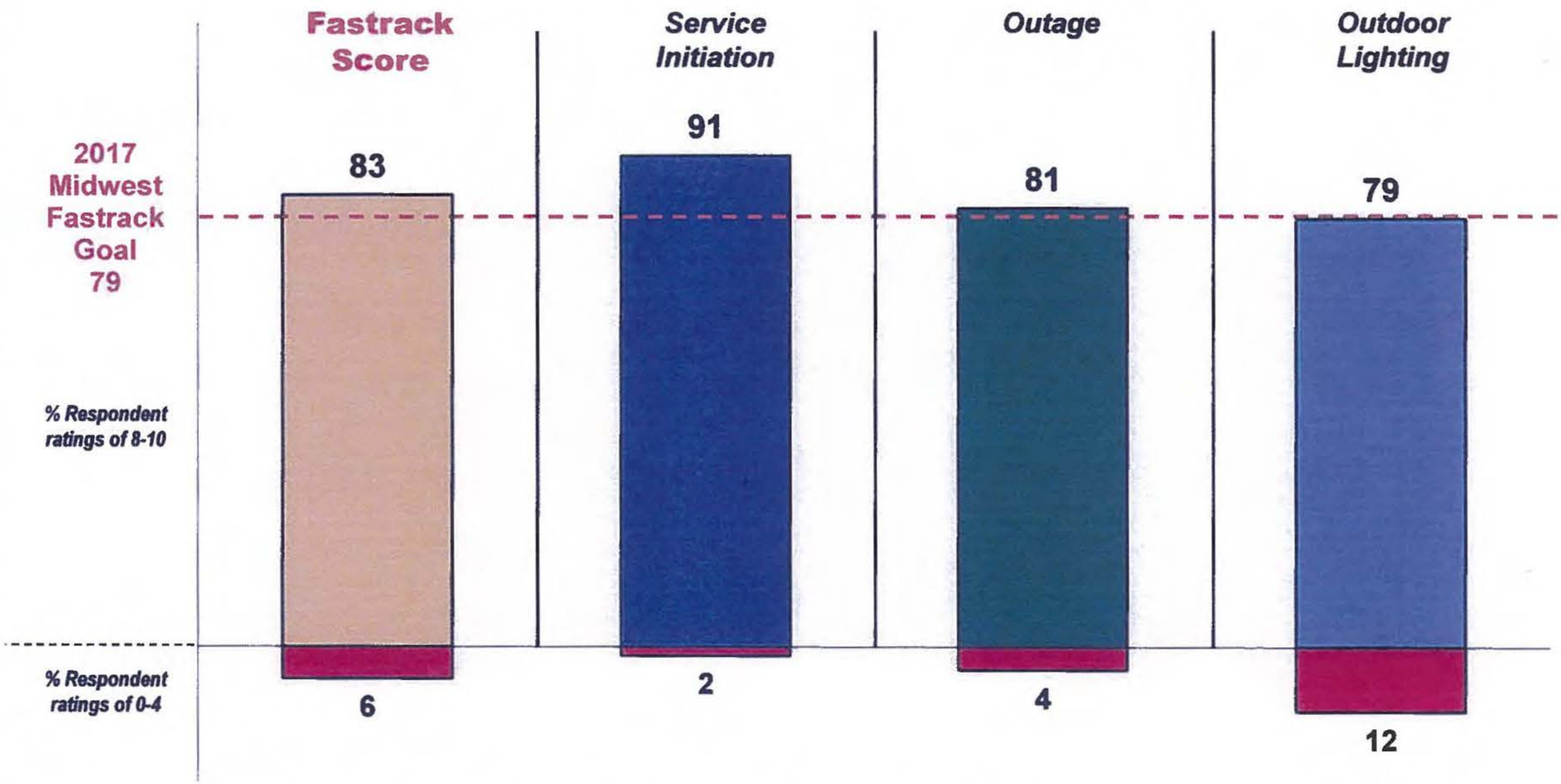
'Outdoor Lighting' Performance by Zone – June 2017

	June Score	2017 YTD	2017 Goal	Goal Status
Duke Energy Midwest	84	79	74	
Ohio/Kentucky	100	**81**	74	
Indiana North	64	**80**	74	
Indiana Southwest	72	**77**	74	
Indiana Southeast	68	**71**	74	

Scores *= % Customers rating their overall satisfaction an '8, 9 or 10' on a '0-10' scale*
Zones *ranked by 2017 YTD performance*

Midwest Fastrack

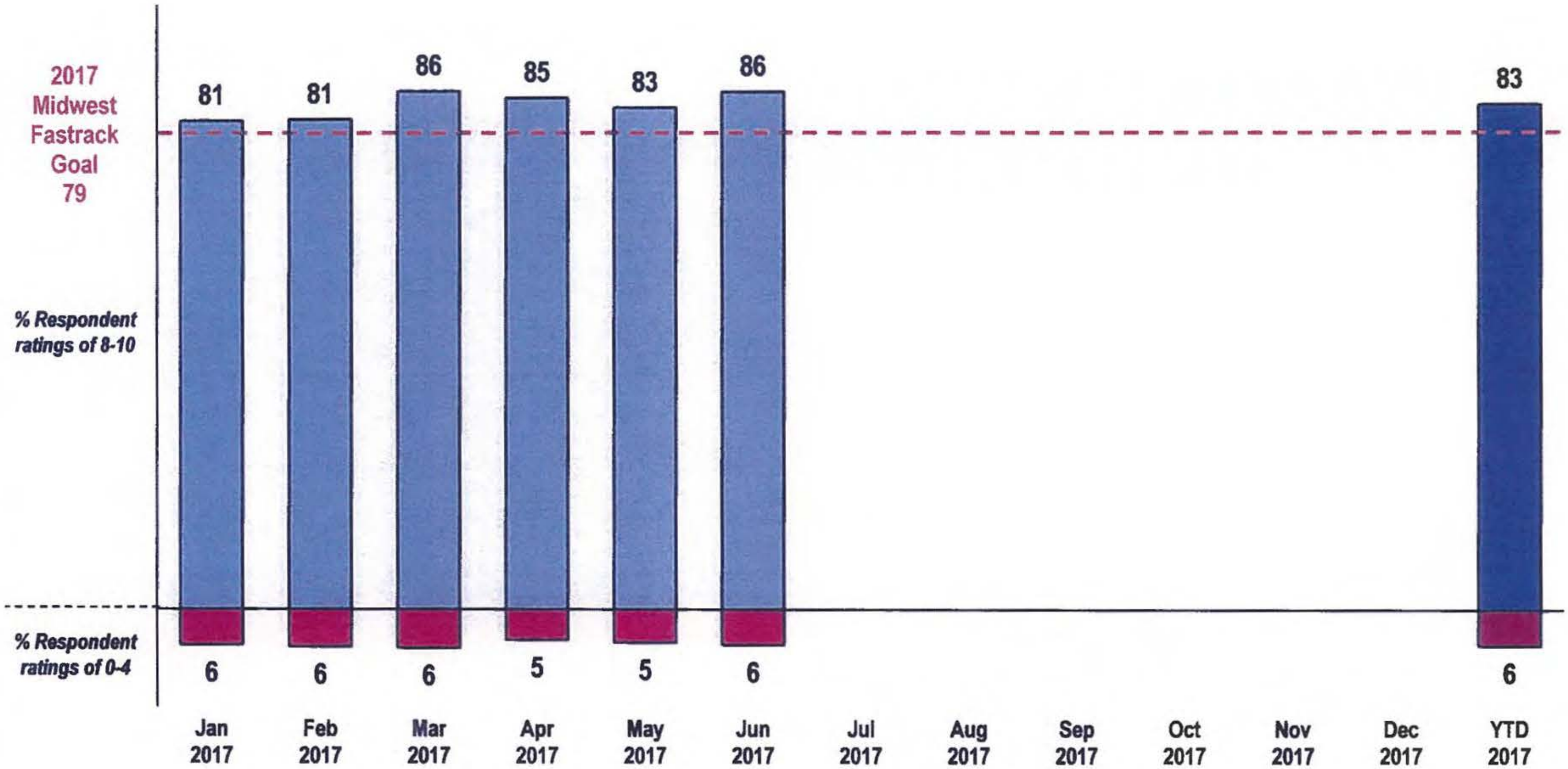
Fastrack Scores – June 2017 YTD



***Fastrack score** is the average of three modules ('Service Initiation', 'Outage', and 'Outdoor Lighting')*

Midwest Fastrack

Monthly Fastrack Score Trend



***Fastrack score** is the average of <u>three</u> modules ('Service Initiation', 'Outage', and 'Outdoor Lighting')*

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Midwest Fastrack

Monthly Fastrack Scores by Module

	2017												
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**YTD**
Goal Modules	**81**	**81**	**86**	**85**	**83**	**86**							**83**
Service Initiation	91	91	91	90	88	93							91
Outage	80	80	80	80	84	80							81
Outdoor Lighting	72	72	86	84	77	84							79
Non-Goal Modules													
Gas Service Initiation	85	87	92	89	85	88							88
Total Billing	76	72	85	77	81	85							79
New Construction		74											74

***Fastrack score** is the average of three modules ('Service Initiation', 'Outage', and 'Outdoor Lighting')*
'New Construction' Fastrack Module is reported on a quarterly basis.

2017 Midwest Fastrack Goal = 79

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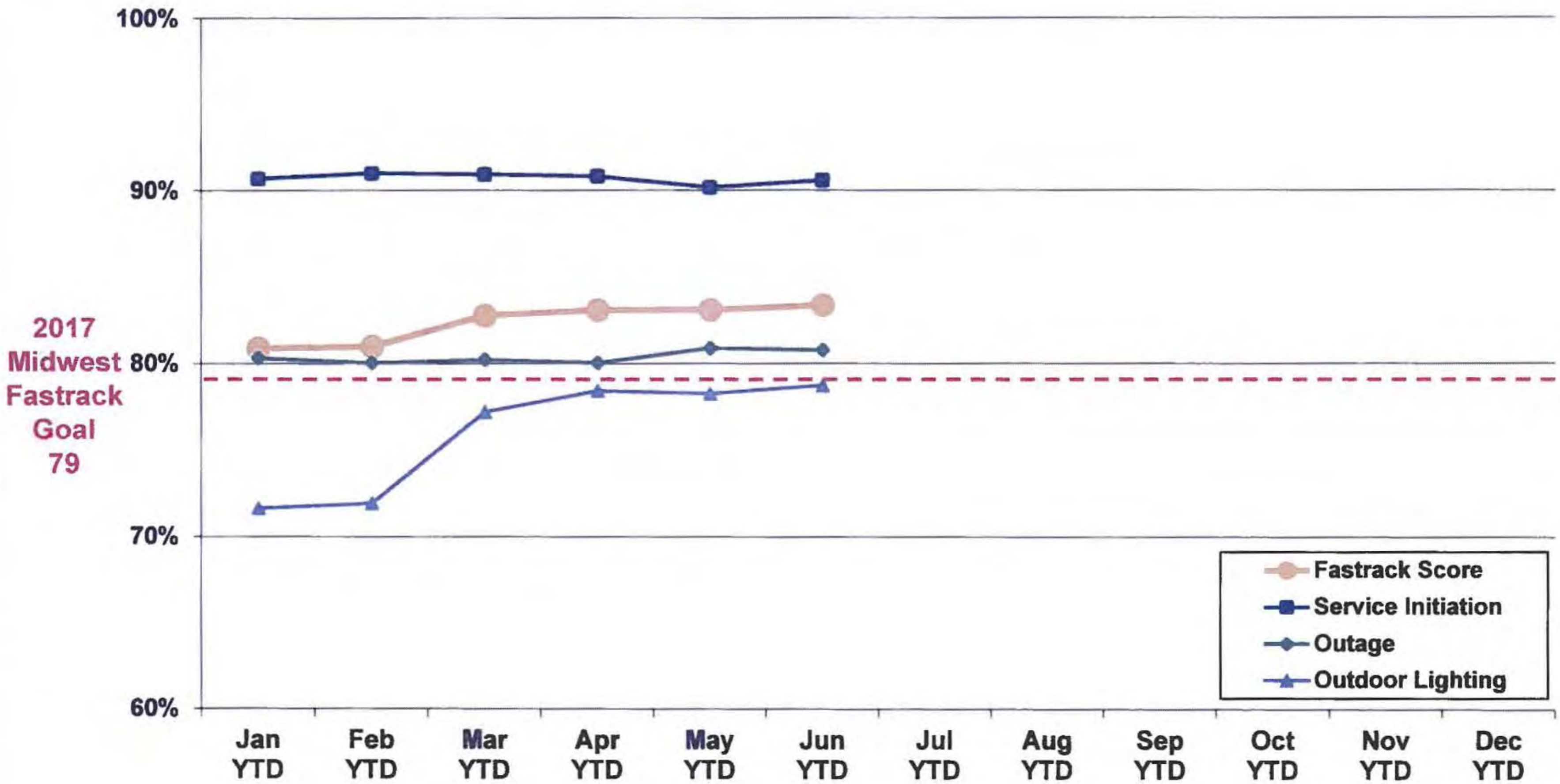
Midwest Fastrack

2017 YTD Fastrack Scores



Fastrack score is the average of three modules ('Service Initiation', 'Outage', and 'Outdoor Lighting')

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Midwest Fastrack

DEOH/KY Reporting

June 2017

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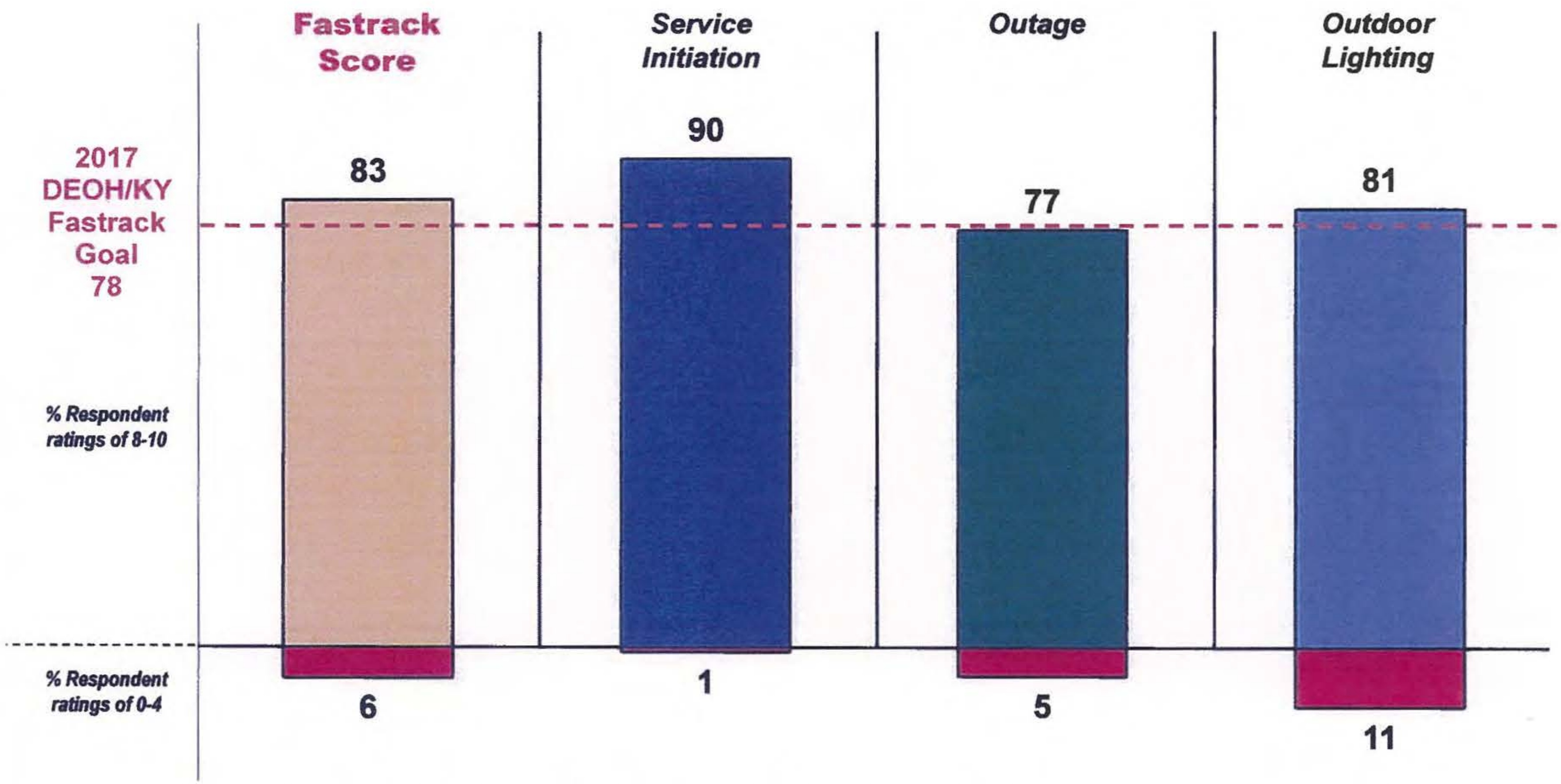
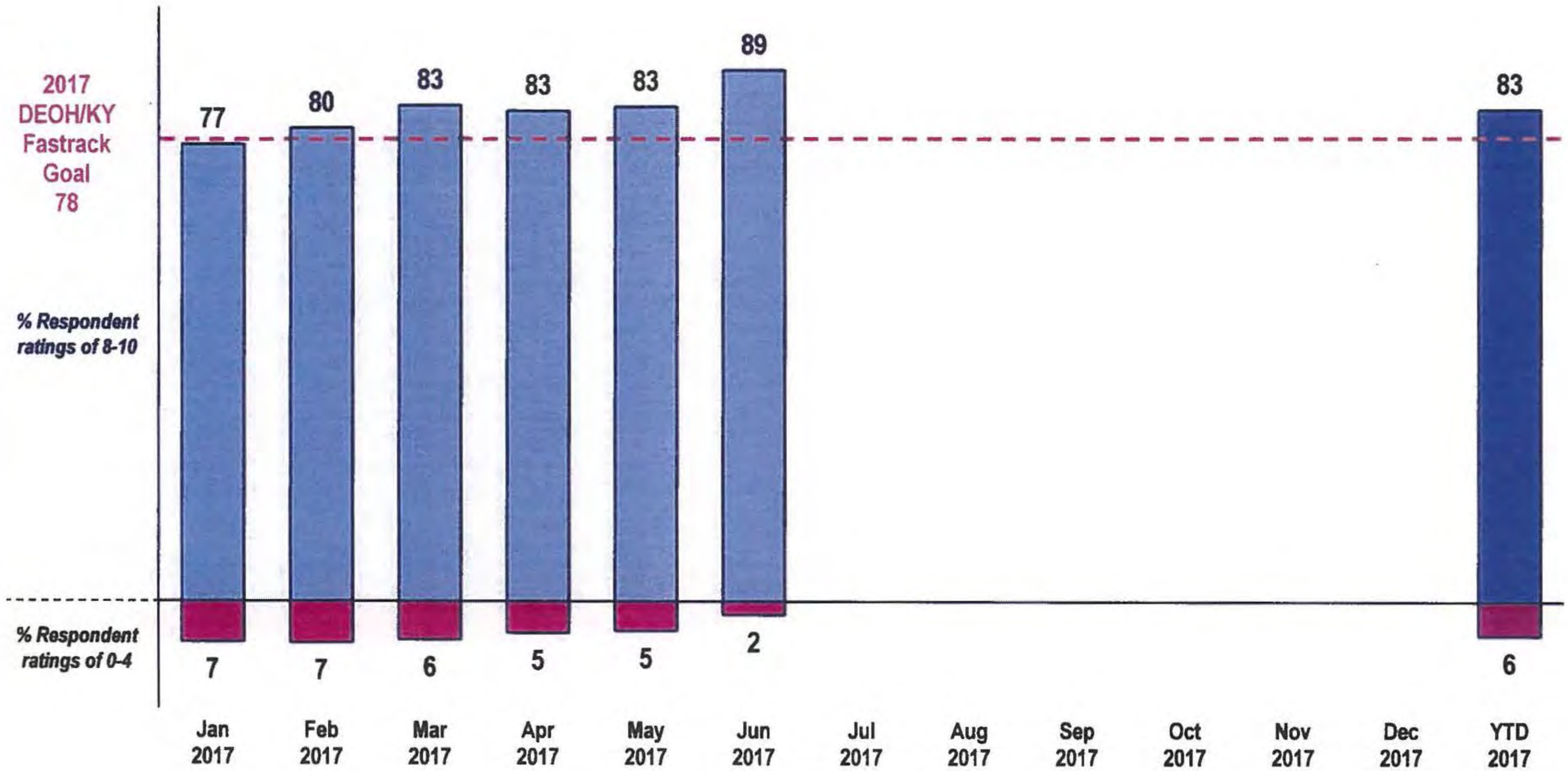
DEOH/KY Fastrack

Fastrack Scores – June 2017 YTD



***Fastrack score** is the average of <u>three</u> modules ('Service Initiation', 'Outage', and 'Outdoor Lighting')*

DEOH/KY Fastrack
Monthly Score Trend



Fastrack score *is the average of <u>three</u> modules ('Service Initiation', 'Outage', and 'Outdoor Lighting')*

DEOH/KY Fastrack

Monthly Fastrack Scores by Module

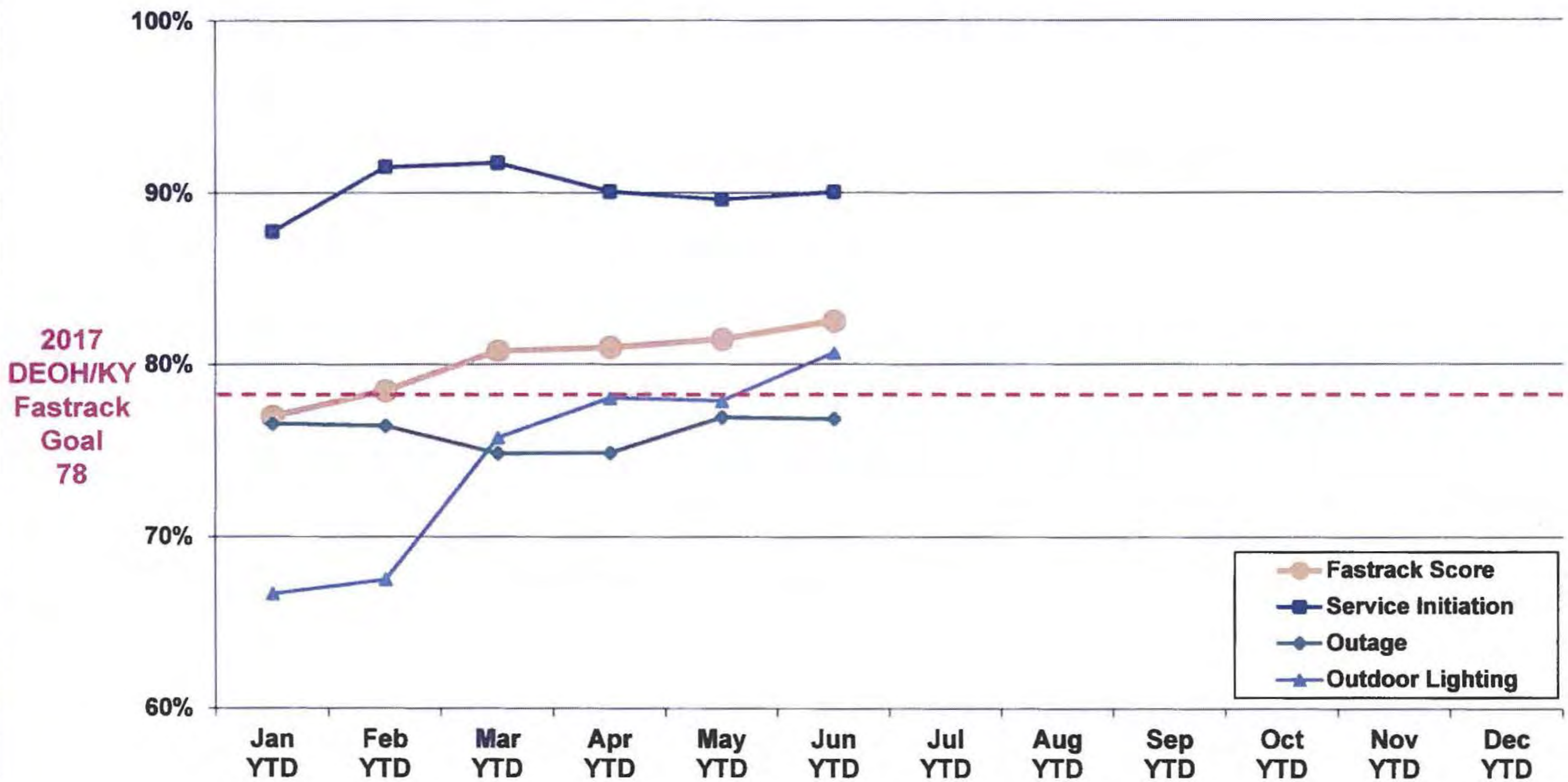
	2017												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
Goal Modules	**77**	**80**	**83**	**83**	**83**	**89**							**83**
Service Initiation	88	95	92	85	88	92							90
Outage	77	76	70	75	85	76							77
Outdoor Lighting	67	68	88	88	77	100							81
Non-Goal Modules													
Total Billing	76	75	87	74	80	79							79
Gas Service Initiation	85	87	92	89	85	88							88
New Construction		46											46

***Fastrack score** is the average of three modules ('Service Initiation', 'Outage', and 'Outdoor Lighting')*
'New Construction' Fastrack Module is reported on a quarterly basis.

2017 DEOH/KY Fastrack Goal = 78

DUKE ENERGY.

DEOH/KY Fastrack
2017 YTD Fastrack Scores



***Fastrack score** is the average of <u>three</u> modules ('Service Initiation', 'Outage', and 'Outdoor Lighting')*

DUKE ENERGY.

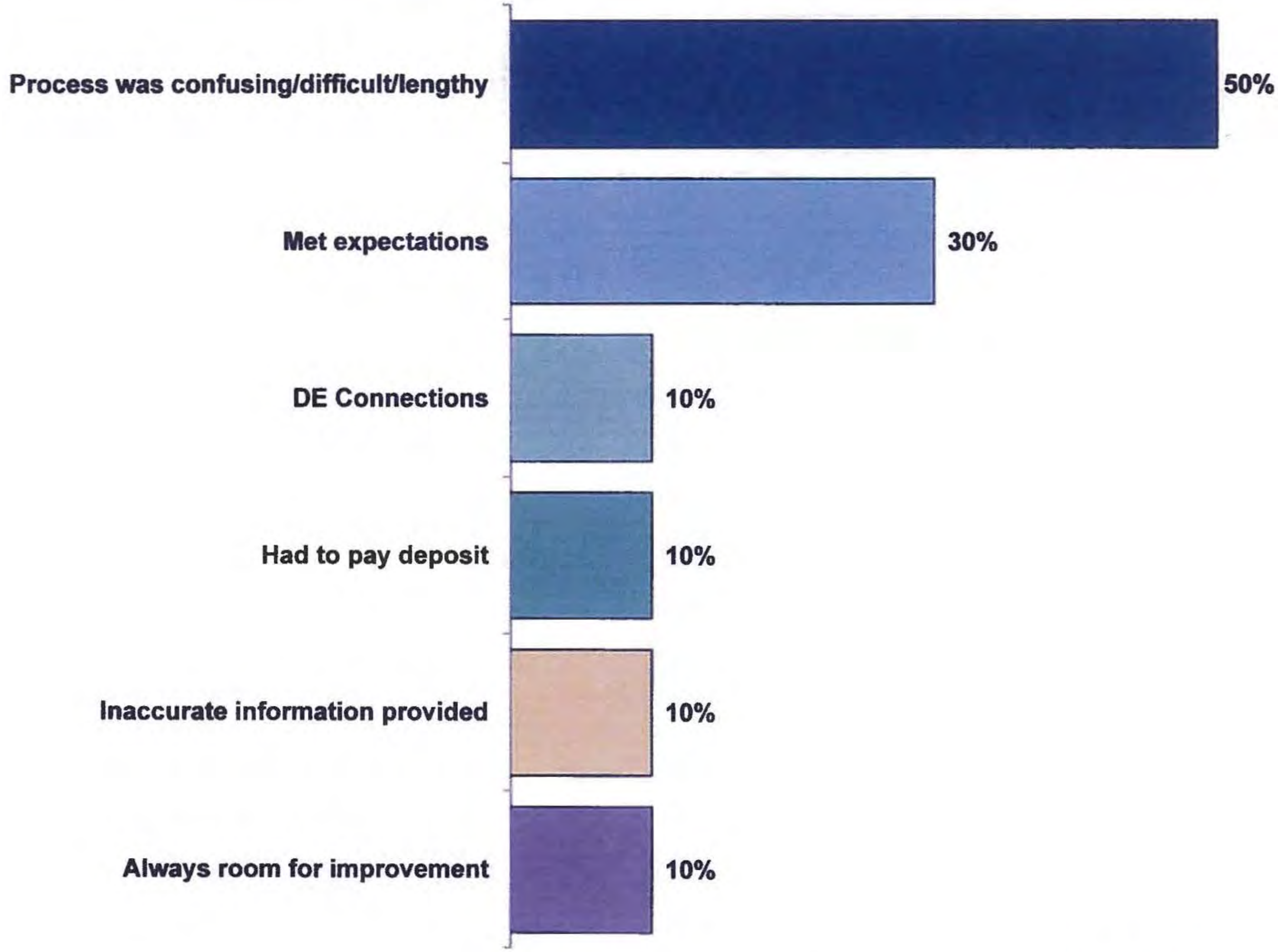
Midwest
Fastrack

Reasons for 0-7 OSAT Ratings

June 2017

DEMW Service Initiation

Reason for 0-7 OSAT Rating – June 2017

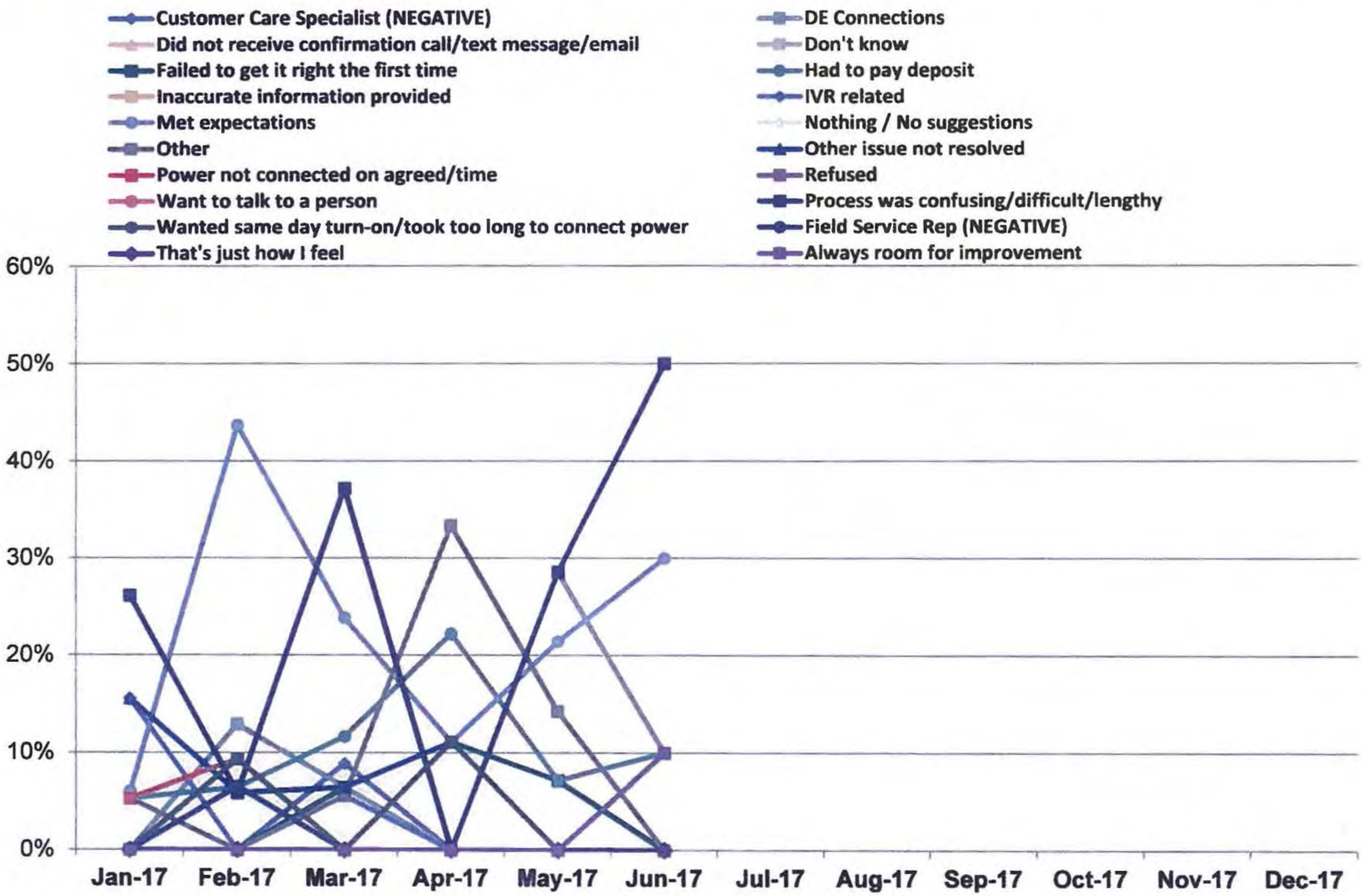


Note: may sum to greater than 100% due to multiple responses per respondent.

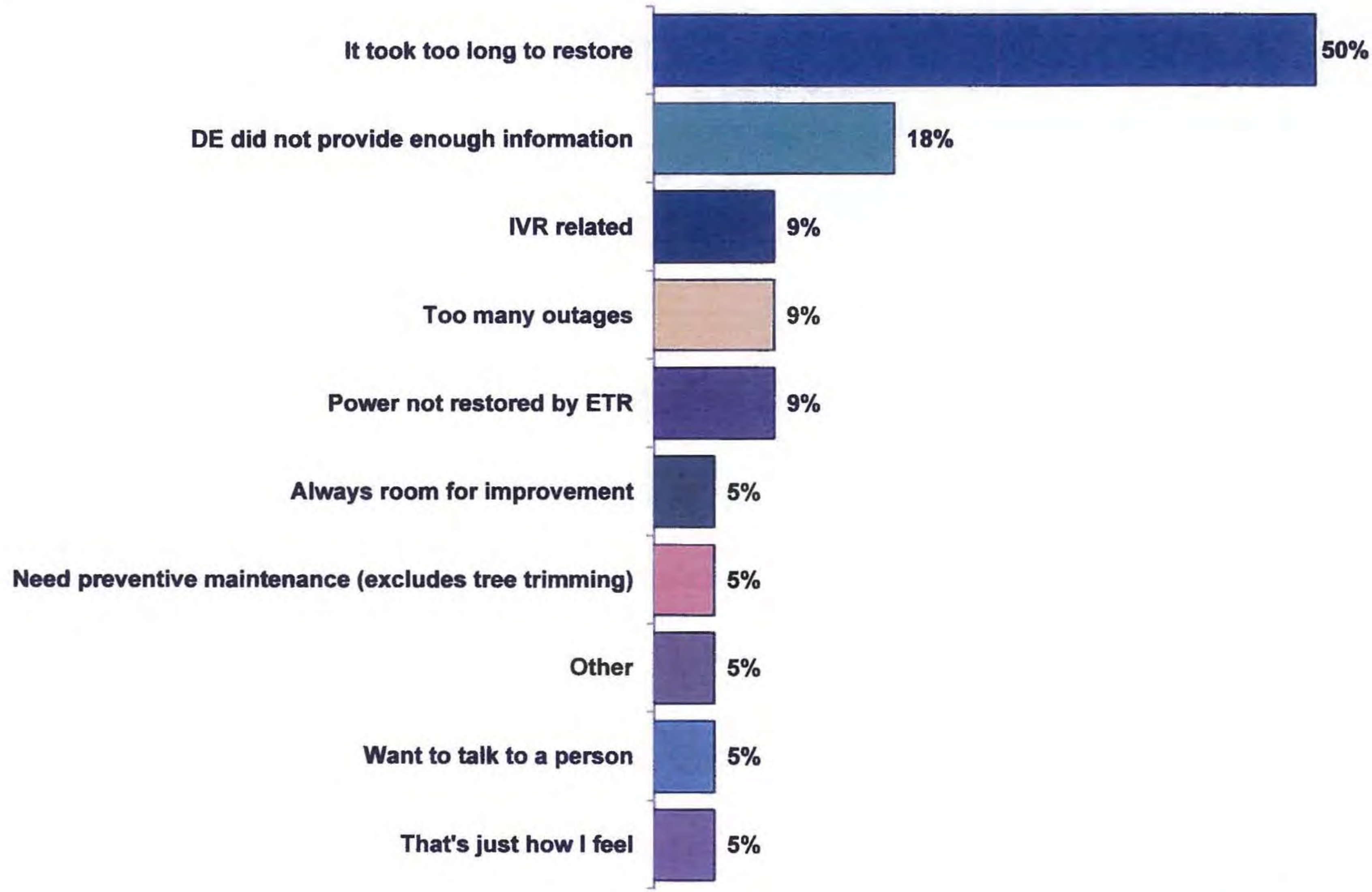
DUKE ENERGY.

DEMW Service Initiation

Reason for 0-7 OSAT Rating



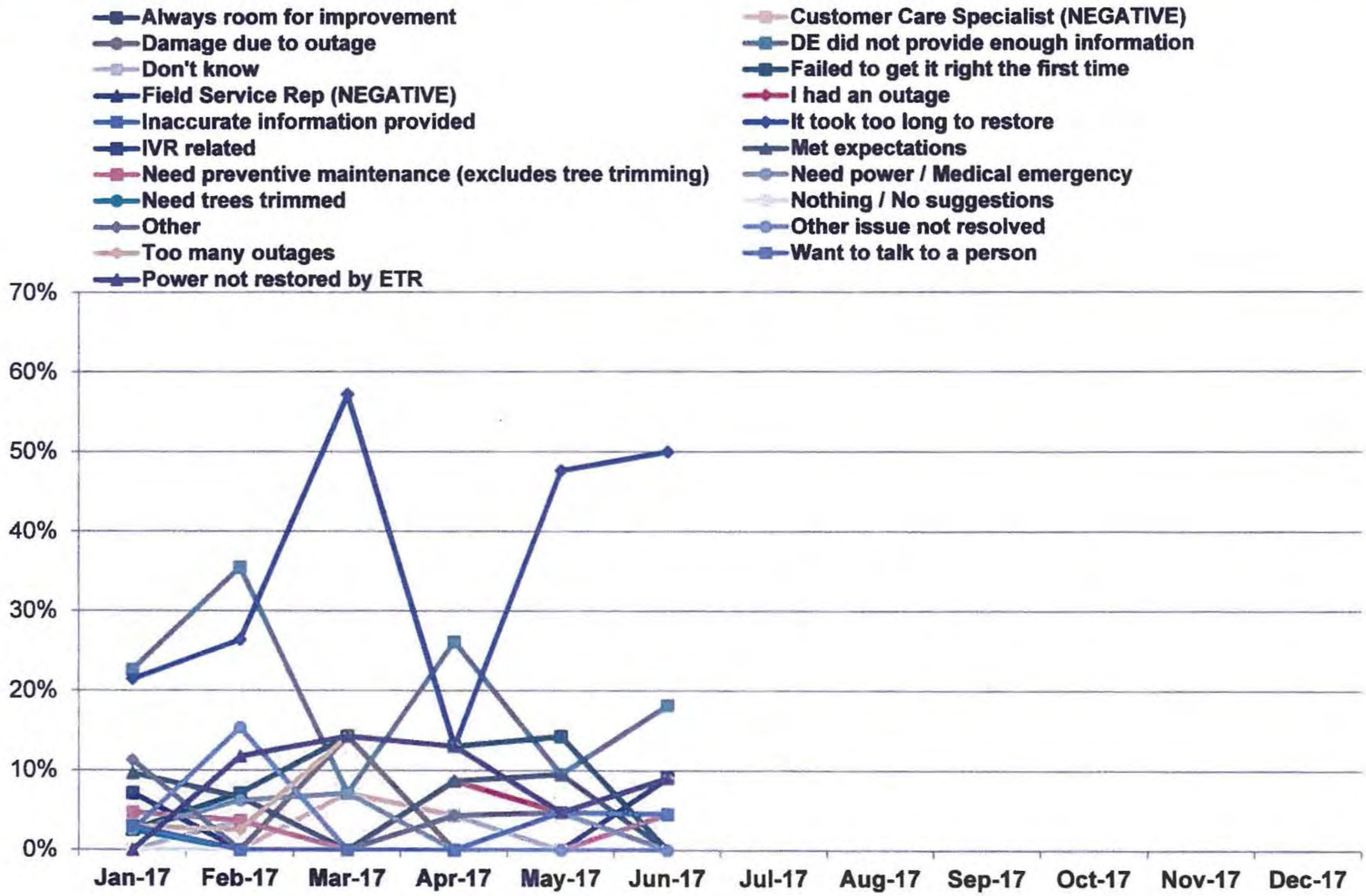
DEMW Outage
Reason for 0-7 OSAT Rating – June 2017



Note: may sum to greater than 100% due to multiple responses per respondent.

DUKE ENERGY.

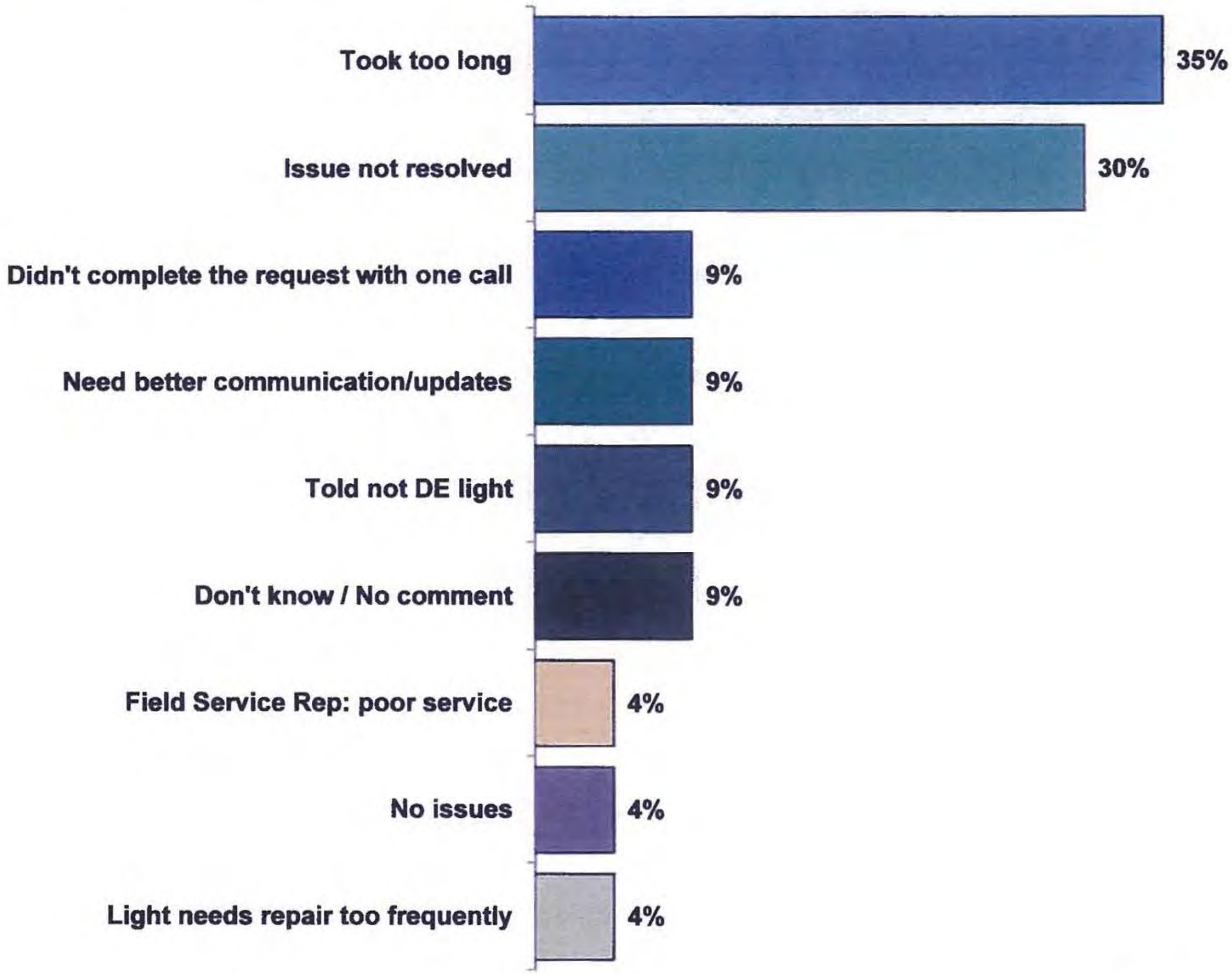
DEMW Outage
Reason for 0-7 OSAT Rating



DUKE ENERGY.

DEMW Outdoor Lighting

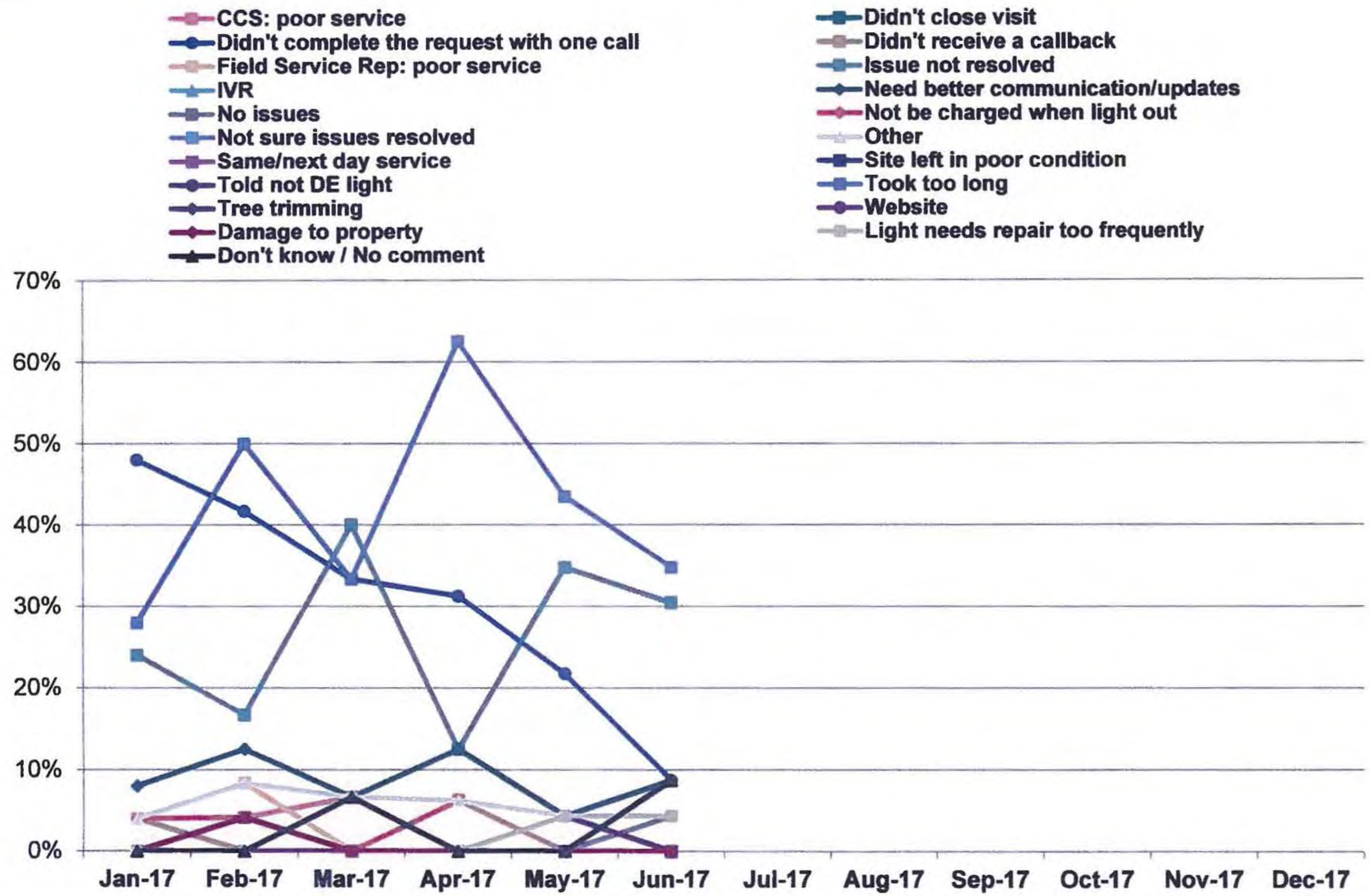
Reason for 0-7 OSAT Rating – June 2017



Note: may sum to greater than 100% due to multiple responses per respondent.

DUKE ENERGY.

DEMW Outdoor Lighting
Reason for 0-7 OSAT Rating



DUKE ENERGY.

DUKE
ENERGY®

Direct Testimony of
Lisa M. Bellucci

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; 3) Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All Other Required Approvals and Relief.	))))))))))	Case No. 2017-00321

DIRECT TESTIMONY OF

LISA M. BELLUCCI

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

September 1, 2017

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Lisa M. Bellucci, and my business address is 550 South Tryon Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services LLC (DEBS) as Director, Tax Operations. DEBS provides various administrative and other services to Duke Energy Kentucky, Inc., (Duke Energy Kentucky or Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor of Arts degree in Business Administration from the University of Rhode Island and a Master of Business Administration from Boston University. I am a Certified Public Accountant in the state of Rhode Island and I am a member of the Tax Executives Institute. My professional work experience began in 1984 as an auditor with Arthur Young and Company (now Ernst &Young or EY). From 1987 to 1998, I held a number of financial positions at two regulated utilities in Massachusetts (Yankee Atomic Electric Company and New England Electric System). In 1998, I joined Duke Energy and have held a number of financial positions of increasing responsibilities, including financial reporting and accounting, forecasting and investor relations. In February 2015, I joined the Corporate Tax Department as Director, Tax Operations.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AS DIRECTOR, TAX OPERATIONS.

A. As Director, Tax Operations, I have overall responsibility for corporate tax compliance, and accounting for Duke Energy. The Duke Energy Tax Operations Department prepares and files federal, state, and local income tax returns for Duke Energy. The department also files tax returns for various joint ventures if Duke Energy is the designated tax matters partner.

The Tax Department maintains and reconciles Duke Energy's tax accounts and is responsible for the reporting and disclosure of tax-related matters, to the extent required.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony addresses Duke Energy Kentucky's income tax expense presented in this filing and certain other tax matters. I sponsor Schedule B-6 and Schedule E-1 and E-2 in response to Filing Requirements FR 16(8)(b) and FR 16(8)(e) respectfully. I also provided certain additional tax information to other witnesses for their use in certain calculations for the base period and the forecasted period.

II. SCHEDULES SPONSORED BY WITNESS

Q. PLEASE DESCRIBE SCHEDULE B-6.

A. Schedule B-6 includes the Accumulated Deferred Investment Tax Credit and Accumulated Deferred Income Tax balance information.

Q. PLEASE DESCRIBE SCHEDULE E-1.

A. Schedule E-1 is the calculation of adjusted jurisdictional federal and state taxable income and federal and state income tax expense for the base period under current income tax rates and for the forecasted period at income tax rates in effect for that period.

Q. PLEASE DESCRIBE SCHEDULE E-2.

A. Schedule E-2 is for the calculation of jurisdictional federal and state taxable income and federal and state income tax expense. Since the utility taxes are 100% jurisdictional, this schedule is not applicable.

Q. WHAT TAX INFORMATION DID YOU PROVIDE TO OTHER WITNESSES?

A. I provided Duke Energy Kentucky witness Mr. Robert Beau Pratt with the property tax expense for the forecasted financial data. These expenses are based on projected property tax rates applied to the most recent valuations as approved by the Kentucky Department of Revenue (KDR), updated for projected additions, retirements, and additional depreciation.

I also provided Mr. Pratt with the income tax rates and the amortization of the investment tax credit for both the forecasted portion of the base period consisting of the six months ending November 30, 2017, and the forecasted test period ending March 31, 2019.

I reviewed Mr. Pratt's calculation of deferred income taxes for the base period and the forecasted period, I provided the amount of tax depreciation he used for this calculation, and I support the methodology he used for calculating deferred income taxes. I also provided Duke Energy Kentucky witness Mr. Jack Sullivan with the accumulated deferred investment tax credit balance for his use on Schedules J-1, J-1.1 and J-1.2.

III. INCOME TAX EXPENSE

Q. WHAT TAX RATE DID THE COMPANY USE TO CALCULATE ITS TEST PERIOD FEDERAL INCOME TAX EXPENSE?

A. The Company used the statutory Federal corporate income tax rate of 35% for both the base period and forecasted period.

Q. WHAT TAX RATE DID THE COMPANY USE TO CALCULATE ITS TEST PERIOD STATE INCOME TAX EXPENSE?

A. The Company used the composite Kentucky corporate income tax rate of 5.4% for both the base period and the forecast period.

Q. WHAT IS THE COMBINED FEDERAL AND STATE STATUTORY INCOME TAX RATE APPLICABLE DURING THE TEST PERIOD?

A. The combined statutory Federal and state statutory income tax rate for Duke Energy Kentucky, which is expected to be in effect during the base period and for the forecasted period is 38.47%. This rate includes the corporate statutory federal income tax rate of 35% and the composite statutory Kentucky corporate income tax rate of 5.34%. State income taxes are deductible in computing the federal tax liability and this deduction is considered in computing the overall effective tax liability. I provided this information to Ms. Lawler for her use in calculating the revenue requirement. I also provided her with the amount of income tax expense for the base period and the forecasted test period, based on these income tax rates.

Q. WHY DID YOU USE THE STATUTORY KENTUCKY INCOME TAX RATE INSTEAD OF THE EFFECTIVE KENTUCKY INCOME TAX RATE TO CALCULATE DUKE ENERGY KENTUCKY'S INCOME TAX EXPENSE?

A. In my opinion, Duke Energy Kentucky should use the income tax rate that most accurately reflects the actual state income tax for its business on a stand-alone basis, which is the composite statutory rate of 5.4%. These are the proper tax rates to apply to Duke Energy Kentucky's electric business operations and this treatment is consistent with the Kentucky income tax rate approved by the Commission for the Company's 2006 electric rate case and 2009 gas rate case.

IV. PROPERTY TAX EXPENSE

Q. HOW DID DUKE ENERGY KENTUCKY CALCULATE THE PROPERTY TAX EXPENSE FOR THE FORECASTED TEST PERIOD?

A. We calculated the property tax expense based on the assessed value of Duke Energy Kentucky's property located in Kentucky and Ohio with adjustments for anticipated property tax rate increases, additions including the power plant transfers, retirements and additional depreciation. As in past years, Duke Energy Kentucky will attempt to negotiate proper assessment values with the KDR. The

Company will notify the Commission of the result of its negotiations with the KDR for the 2017 tax year so the Commission can determine whether to adjust Duke Energy Kentucky's property tax expense for the forecasted test period. The Ohio real property is assessed on a triennial basis, with the next re-assessment expected to occur in 2017. The Ohio personal property assessment for the 2016 tax year will be available in the fall of 2017.

V. CONCLUSION

Q. WAS THE TAX INFORMATION YOU SUPPLIED FOR SCHEDULE B-6 AND SCHEDULES E-1 AND E-2, AND THE TAX INFORMATION YOU SUPPLIED TO OTHER WITNESSES, PREPARED UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

VERIFICATION

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF MECKLENBURG)

The undersigned, Lisa M. Bellucci, Director, Tax Operations, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of her knowledge, information and belief.

Lisa M Bellucci

Lisa M. Bellucci Affiant

Subscribed and sworn to before me by Lisa M. Bellucci on this 8th day of August, 2017.

Natalie W. Polk

NOTARY PUBLIC

My Commission Expires:

Direct Testimony of
David L. Doss, Jr.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; 3) Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All Other Required Approvals and Relief.	)	Case No. 2017-000321

DIRECT TESTIMONY OF

DAVID L. DOSS, JR.

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

September 1, 2017

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PAGE

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David L. Doss, Jr., and my business address is 550 South Tryon Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services LLC (DEBS), as Director, Electric Utilities & Infrastructure Accounting. DEBS provides various administrative and other services to Duke Energy Kentucky, Inc., (Duke Energy Kentucky or Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I graduated from the University of Texas at Austin with a Bachelor's of Business Administration degree and I am a certified public accountant in Texas. I have over 30 years of professional experience with Duke Energy, including over 20 years of management experience in various accounting and finance roles. I was named to my current role as Director, Electric Utilities and Infrastructure Accounting in December 2016.

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR, ELECTRIC UTILITIES AND INFRASTRUCTURE ACCOUNTING.

A. I am responsible for maintaining the books of account and reporting the financial position and the results of electric operations for Duke Energy's public utility operating companies in the Carolinas, Florida, Ohio, Indiana, and Kentucky.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. My testimony in this proceeding addresses the various capital and operating expenditures and accounting adjustments to Duke Energy Kentucky's books of account in support of Duke Energy Kentucky's application in this proceeding. I discuss the accounting treatment being requested in this proceeding for two categories of regulatory assets/liabilities that will effectively ensure that customers will not over or under pay for costs associated with two volatile types of costs the Company incurs to own and operate its generating fleet. I sponsor the historic data in Schedule B-8 provided in satisfaction of Filing Requirement FR 16(8)(b); and Filing Requirements FR 12(2)(i), FR 16(7)(i), FR 16(7)(k), FR 16(7)(m), FR 16(7)(n), FR 16(7)(o), FR 16(7)(p), and FR 16(7)(q). Finally, I also sponsor the historic data on Schedules I-1 through I-5 in response to FR 16(8)(i), and Schedule K in response to FR 16(8)(k) .

II. OVERVIEW OF DUKE ENERGY KENTUCKY'S ACCOUNTING RECORDS

Q. ARE YOU FAMILIAR WITH THE ACCOUNTING PROCEDURES AND BOOKS OF ACCOUNT OF DUKE ENERGY KENTUCKY?

A. Yes. The books of account for Duke Energy Kentucky's regulated business follow the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC).

Q. ARE THE BOOKS OF ACCOUNT FOR THE ELECTRIC BUSINESS OF DUKE ENERGY KENTUCKY PREPARED AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes.

Q. ARE THE CAPITAL AND OPERATING EXPENDITURES REPRESENTED ON DUKE ENERGY KENTUCKY'S BOOKS OF ACCOUNT ACCURATE AND REASONABLE?

A. Yes. Duke Energy Kentucky has various budgeting, planning, and review procedures in place to establish and monitor the capital and operating budgets, as well as actual expenditures. The system of internal accounting controls provides reasonable assurance that all transactions are executed in accordance with management's authorization and are recorded properly.

The system of internal accounting controls is annually reviewed, tested, and documented by Duke Energy Kentucky to provide reasonable assurance that amounts recorded on the books and records of the Company are accurate and proper. In addition, independent certified public accountants perform an annual audit to provide assurance that internal accounting controls are operating effectively and that Duke Energy Kentucky's financial statements are materially accurate.

III. ACCOUNTING TREATMENT

Q. PLEASE BRIEFLY DESCRIBE THE ACCOUNTING TREATMENT THE COMPANY IS REQUESTING IN THIS PROCEEDING.

A. As part of this proceeding, Duke Energy Kentucky is seeking Commission authorization to create two deferral mechanisms for the differences between the actual amounts incurred for certain costs and the amounts established in base rates for those costs in this proceeding. The first deferral mechanism proposed will allow the Company to defer the actual annual operation and maintenance (O&M) expense related to planned generation maintenance outages (excluding fuel, emission allowances, and environmental reagent costs,) above or below the amount being recovered in base rates.

The second deferral mechanism will allow the Company to defer the actual cost for replacement power expense related to forced outages, above or below the amounts being recovered through the Company's fuel adjustment clause or in base rates as established in this case.

In addition to the request for regulatory asset treatment for these items, Duke Energy Kentucky will continue recording deferrals, per normal regulatory accounting standards, for riders that are subject to being trued-up. Over- or under-recovery of costs are flowed through riders such as the fuel adjustment clause and the profit sharing mechanism and, therefore, the Company records the amounts to be trued-up in future periods as regulatory assets or regulatory liabilities.

Q. WHY IS IT APPROPRIATE TO CREATE THESE REGULATORY ASSETS/LIABILITIES?

A. The Commission has exercised its discretion to approve regulatory assets where a utility has incurred: (1) an extraordinary, nonrecurring expense which could not have reasonably been anticipated or included in the utility's planning; (2) an expense resulting from a statutory or administrative directive; (3) an expense in relation to an industry sponsored initiative; or (4) an extraordinary or nonrecurring expense that over time will result in a saving that fully offsets the costs.

The costs for which the Company is seeking to create the regulatory deferrals represent incremental costs or savings compared to normalized or expected levels, and as such they effectively constitute extraordinary non-recurring expenses (or savings) which could not have reasonably been anticipated or included in the utility's planning. The actual costs of these items are unable to be planned or anticipated.

The Company's forecasted test year budget for outage maintenance expense and replacement power costs for the Company's East Bend coal-fired Generating Station (East Bend), and Woodsdale Combustion Turbines (Woodsdale) have been adjusted to reflect a representative (*i.e.,* average) level of expense. Outage maintenance expense has been normalized based upon four years of actual maintenance expense and two years of projected maintenance expenses. Replacement power costs reflect the forecasted amounts from the GenTrader production cost model for the test period. Permitting the Company to defer for future recovery any incremental amount over or under what is established in base rates for these two expenses will ensure that customers are not over paying and the Company is not under recovering for actual costs incurred in serving customers.

Creating these two deferral mechanisms will insulate customers from rate shock that could happen if the Company were to file a base rate case with a test year reflecting actual costs of a significant planned maintenance outage or a year where replacement power expenses were substantial. The deferral mechanisms balance the need for protecting customers from over paying for these costs when the utility's actual costs incurred are below the levels used to establish base rates, and conversely mitigate the utility's risk to financial stability and performance during years where the Company's actual costs incurred are higher than those used to establish base rates.

Because Duke Energy Kentucky is relatively small, the swings from year to year in the costs of planned outages and replacement power for forced outages causes volatility in the Company's earnings. The proposed deferral mechanisms are designed so that, over time, the balance should approach $0, but will prevent these two volatile cost items from having a significant influence on the Company's earnings.

Q. HOW WILL THESE REGULATORY ASSETS/LIABILITIES WORK?

A. On an annual basis, the Company will track the actual costs for those two items against the base rate level established in this proceeding and will either debit a regulatory asset account (Account 182.3) or credit a regulatory liability account (Account 254), for the difference between the actual costs for these two items and the amounts in base rates. The balance of the regulatory asset or liability will accrue a carrying cost at the Company's long-term debt rate approved in this proceeding. The carrying costs will apply to any credit balance (*i.e.*, amounts owed to customers) or to any debit balance (*i.e.*, amounts owed to the Company) to maintain the symmetry and ensure that neither customer nor Company is deprived of the time value of money.

These regulatory accounts will continue to accumulate until the next rate case when the Company will seek to include the then existing balance for recovery or refund in new base rates. The intent with these deferrals is simply to provide assurance that the Company can recover its costs and customers pay no more or no less than the actual cost incurred to provide service with the generating assets.

Q. WHY IS THE INCLUSION OF CARRYING CHARGES BASED UPON THE COMPANY'S COST OF DEBT APPROPRIATE?

A. The use of carrying costs simply represents the time-value of money being deferred for future recovery/crediting to customers. The cost of debt is a reasonable rate and represents the Company's borrowing rate if it were to seek funds elsewhere. These carrying costs will work both ways in that they would accrue on both the regulatory asset as well as the liability.

Pursuant to KRS 278.220, the system of accounts established by the Commission for keeping by the Company shall conform as nearly as practicable to the system adopted by FERC. Relevant precedent from FERC reflects the fact that jurisdictional utilities are regularly authorized to accrue a carrying charge on a regulatory asset until the regulatory asset is included in rate base. Such an accrual is appropriate because the subject costs are necessarily incurred by the Company. Guidance from FERC and prudent accounting principles support the inclusion of carrying costs as part of the subject regulatory asset until the Commission determines whether the deferred costs are recoverable.

Q. PLEASE DESCRIBE THE ACCOUNTING/JOURNAL ENTRIES THAT WILL BE USED TO CREATE THESE DEFERRALS.

A. For the planned outage deferral, if the actual costs are higher than those in base rates, the Company would debit a regulatory asset and credit various O&M accounts, for example:

Debit Account 182.3

Credit Account 51X

Similar accounting treatment would apply to the replacement power deferral. If the actual costs are higher than those recovered in base rates or the fuel adjustment clause, the Company would debit a regulatory asset and credit O&M, for example:

Debit Account 182.3

Credit Account 555

For both of the deferrals above, if the actual costs are lower than those recovered in base rates or the fuel clause, the Company would debit revenue and credit a regulatory liability, for example:

Debit Account 4XX

Credit Account 254

IV. SCHEDULES AND FILING REQUIREMENTS SPONSORED BY WITNESS

Q. PLEASE DESCRIBE B-8.

A. Schedule B-8 contains the Comparative Balance Sheets for Duke Energy Kentucky for the most recent five calendar years, the base period and the forecasted period.

Q. PLEASE DESCRIBE FR 12(2)(i).

A. FR 12(2)(i) consists of Duke Energy Kentucky's detailed income statement and balance sheet for the period ended June 30, 2017.

Q. PLEASE DESCRIBE FR 16(7)(i).

A. FR 16(7)(i) consists of the Company's most recent Federal Energy Regulatory Commission (FERC) audit report, reporting the results of the Company's last FERC audit.

Q. PLEASE DESCRIBE FR 16(7)(k).

A. FR 16(7)(k) consists of Duke Energy Kentucky's most recent FERC Form 1 and FERC Form 2.

Q. PLEASE DESCRIBE FR 16(7)(m).

A. FR 16(7)(m) consists of Duke Energy Kentucky's current chart of accounts.

Q. PLEASE DESCRIBE FR 16(7)(n).

A. FR 16(7)(n) consists of the latest twelve months of the monthly management reports providing financial results of the Company's operations in comparison to the forecast.

Q. PLEASE DESCRIBE FR 16(7)(o).

A. FR 16(7)(o) consists of management's monthly budget variance reports for Duke Energy Kentucky electric operations.

Q. PLEASE DESCRIBE FR 16(7)(p).

A. FR 16(7)(p) consists of Duke Energy Kentucky's most recent Form 10-K and Form 8-K as well as those forms for the last two years. Additionally, the Company is submitting copies of its Form 10-Qs that were filed during the past six quarters.

Q. PLEASE DESCRIBE FR 16(7)(q).

A. FR 16(7)(q) consists of the independent auditor's annual opinion report for Duke Energy Kentucky. The auditor did not note any material weaknesses in internal controls.

Q. PLEASE DESCRIBE THE INFORMATION YOU SUPPORT IN RESPONSE TO FR 16(8)(i), SCHEDULES I-1 THROUGH I-5.

A. Schedule I-1 contains comparative income statements for the Company. Schedules I-2.1 through I-5 contains comparative revenue and sales statistical information as required by the Commission's filing requirements. I support the historic information contained on these schedules.

Q. PLEASE DESCRIBE THE INFORMATION YOU SUPPORT IN RESPONSE TO FR 16(8)(k), THE "K" SCHEDULES.

A. The information I support in response to FR 16(8)(k) consists of the Consolidated Condensed Income Statement for Duke Energy Kentucky. I provided this information to Mr. Pratt for his use in preparation of the forecast.

V. CONCLUSION

Q. WAS THE INFORMATION YOU SPONSORED IN SCHEDULES B-8, I-1, I-2.1, I-3, I-4, I-5 AND K AS WELL AS FR 12(2)(i), FR 16(7)(i), FR 16(7)(k), FR 16(7)(m), FR 16(7)(n), FR 16(7)(o), FR 16(7)(p), FR 16(7)(q), FR16(8)(i), AND FR 16(8)(k) PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes.

Q. IS THE INFORMATION YOU SPONSORED IN THOSE SCHEDULES AND FILING REQUIREMENTS ACCURATE TO THE BEST OF YOUR KNOWLEDGE AND BELIEF?

A. Yes.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

VERIFICATION

STATE OF NORTH CAROLINA	)	
	)	**SS:**
COUNTY OF MECKLENBURG	)	

The undersigned, David L. Doss, Jr., Director, Electric Utilities & Infrastructure, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of his knowledge, information and belief.

David L. Doss, Jr. Affiant

Subscribed and sworn to before me by David L. Doss, Jr. on this 9 day of August, 2017.

Kim V. Beal
NOTARY PUBLIC

KIM V BEAL
Notary Public
Catawba County
NORTH CAROLINA

My Commission Expires: Oct 24, 2019

Direct Testimony of
Tammy Jett

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; 3) Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All Other Required Approvals and Relief.	)	Case No. 2017-000321

DIRECT TESTIMONY OF

TAMMY JETT

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

September 1, 2017

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Tammy Jett. My business address is 139 East Fourth Street, Cincinnati, Ohio 45202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services LLC. (Duke Energy Business Services) as a Principal Environmental Specialist in the CCP (Coal Combustion Products) Environmental Programs Department.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUNDS.

A. I received a Master's Degree in Environmental Science from Miami University in 1989. I have also earned a Bachelor's Degree in Urban Ecology and an Associate's Degree in Psychology from Thomas More College in 1987. I began my career with The Cincinnati Gas & Electric Company in 1989 as an Intern as part of my graduate degree curriculum. I was hired as a Junior Licensing Specialist in 1989 after my internship was completed. I have held a number of environmental compliance related positions over the last twenty-eight years in the environmental organizations, within Duke Energy and predecessor companies. These positions involved increasing responsibility and include Regulatory Compliance Coordinator, Environmental Scientist III and Senior and Lead Environmental Specialist. In 2015, I was promoted to Principal Environmental Specialist, which is the highest technical (non-managerial) position currently available in the Duke Energy Environmental organization.

Q. PLEASE SUMMARIZE YOUR DUTIES AS PRINCIPAL ENVIRONMENTAL SPECIALIST.

A. As Principal Environmental Specialist, I am the subject matter expert for environmental coal ash compliance for Duke Energy Kentucky's East Bend, Generating Station (East Bend). I have responsibility for permitting and specializing in all facets of the coal ash program. I obtain permits for the Company's coal ash facilities, such as coal ash landfills, and then assist with monitoring, record keeping, reporting and other facets of our compliance program. I am also responsible for reviewing new Federal and State regulations which include the regulation of coal ash, such as the United States Environmental Protection Agency's (U.S. EPA) Coal Combustion Residual rule (CCR Final Rule) and the Kentucky Special Waste rules, among others, and determining their impact on our generating coal ash facilities. I am involved in strategic planning across all the Duke Energy service areas, including Ohio, Kentucky, Indiana, North Carolina, South Carolina and Florida, for federal coal ash compliance issues to provide a consistent strategy for implementing the CCR Final rule.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. Yes. I provided testimony in Case No. 2015-00089 supporting Duke Energy Kentucky's request for a Certificate of Public Convenience and Necessity for construction (CPCN) of its West Landfill at the East Bend Generating Station (East Bend). Most recently, I provided testimony in Case No. 2016-00268, Duke Energy Kentucky's application for a CPCN for constructing a dry bottom ash handling system at East Bend and in Case No. 2016-00398 involving the

Company's application for a CPCN for water redirects and basin closure and repurposing.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to discuss the environmental requirements applicable to Duke Energy Kentucky's operation of East Bend that specifically relate to the Company's requests for the implementation of an Environmental Compliance Plan to support the implementation of an environmental surcharge mechanism (ESM). In doing so, I provide an overview of the environmental controls that exist today at East Bend and the regulations that require such controls.

II. ENVIRONMENTAL REGULATIONS IMPACTING DUKE ENERGY KENTUCKY'S EAST BEND GENERATING STATION

Q. WHAT ARE THE MOST SIGNIFICANT ENVIRONMENTAL REGULATIONS CURRENTLY IMPACTING DUKE ENERGY KENTUCKY'S EAST BEND STATION?

A. There are several programs promulgated by the U.S. EPA under the Clean Air Act (CAA) that impact all of the Company's generating stations, and particularly East Bend. These regulations are the primary drivers of Duke Energy Kentucky's compliance strategies for its plants. They are as follows: the Mercury and Air Toxics Standard (MATS Rule) and the Cross State Air Pollution Rule (CSAPR) including the U.S. EPA's September 2016 final CSAPR Update Rule.

The CCR Final Rule and Steam Electric Effluent Limitation Guidelines (ELG Final Rule), in addition to other emerging regulations under the Clean

Water Act (CWA), are likely to impact the Company's generating stations. The regulations that most directly impact the Company's ash handling strategy as it pertains to East Bend are the CAA and the CCR Final Rule and ELG Final Rule.

Q. PLEASE BRIEFLY DESCRIBE THE CAA.

A. The CAA is the comprehensive federal law that regulates air emissions from stationary and mobile sources. Among other things, this law authorizes EPA to establish a number of programs to regulate air emissions so as to protect public health and public welfare. Many of these programs overlap and at times regulate the same pollutants.

Q. CAN YOU PROVIDE A BRIEF SUMMARY OF THE MATS RULE?

A. The MATS Rule regulates mercury and other toxic air pollutant emissions from new and existing coal- and oil-fired steam electric generating units (EGUs) that are greater than 25 MWs in capacity. It is a command and control program that imposes unit-by-unit restrictions on emissions of mercury, acid gases such as hydrogen chloride, and certain non-mercury metals, including arsenic, chromium, nickel and selenium. The MATS Rule allows EGUs, as one option, to demonstrate compliance by measuring mercury, hydrogen chloride, and non-mercury metal emissions directly. It also allows the EGUs the option of demonstrating compliance by measuring surrogates for acid gases and for non-mercury metals.

Q. DOES EAST BEND CURRENTLY COMPLY WITH THE MATS RULE?

A. Yes. East Bend began complying with MATS Rule in April 2015.

Q. PLEASE PROVIDE A SHORT DESCRIPTION OF THE HISTORY AND STATUS OF THE CLEAN AIR INTERSTATE RULE (CAIR) AND CSAPR.

A. On August 8, 2011, the EPA published the final CSAPR rule to replace the existing CAIR. CSAPR established new state-level annual SO_2 and NO_x budgets and ozone-season NO_x budgets. The rule was initially scheduled to take effect January 1, 2012; however, on December 30, 2011, the D.C. Circuit stayed the rule. On August 21, 2012, the D.C. Circuit then vacated CSAPR and directed that EPA continue administering CAIR pending completion of a new rulemaking to replace CSAPR. However, on April 26, 2014, the United States Supreme Court reversed the D.C. Circuit's decision and remanded the case back to the D.C. Circuit for further proceedings. Because of the litigation, the CSAPR deadlines were tolled by three years and CSPAR ultimately went into effect on January 1, 2015. On December 3, 2015, the U.S. EPA proposed to further update and reduce ozone season state NO_x allowance budget beginning in 2017. The U.S. EPA finalized this change with the Cross-State Air Pollution Rule Update (CSAPR Update) for the 2008 Ozone NAAQs published in the Federal Register on October 26, 2016. This change reduced the number of ozone season NO_x allowances for East Bend. It also maintains the restriction on trading contained in the original CSAPR by placing a penalty on excess emissions of NOx if statewide ozone season NOx emissions exceed the statewide budget by more than 21 percent (CSAPR Assurance provisions).

Q. HOW HAS CSAPR'S IMPLEMENTATION IMPACTED EAST BEND?

A. Because it has a well performing wet flue gas desulfurization (FGD) system and a selective catalytic reduction control (SCR), East Bend has, to date, been able to comply with CSAPR without the installation of additional controls. This is also the case with the U.S. EPA's CSAPR Update rule, which went into effect on May 1, 2017. Because of the restrictions on trading and the more limited state allowance budgets for ozone season NO_x, the allowance prices under the CSAPR Update rule are higher than they were under the original CSAPR. While the East Bend SCR design, coupled with the availability of allowances from the Company's retired Miami Fort Unit 6 station, is expected to be robust enough to comply with the CSAPR Update rule, if it is economically prudent, East Bend could also opt to buy allowances on the market.

Q. PLEASE DESCRIBE THE MAJOR EFFORTS TO REGULATE GREENHOUSE GASES THAT RELATE TO ELECTRIC GENERATING UNITS.

A. In 2007, the Supreme Court ruled in *Massachusetts v. EPA*[1] that greenhouse gases are a pollutant subject to regulation under the CAA. Subsequently, the U.S. EPA undertook a number of rulemakings targeting greenhouse gas emissions from EGUs. The first was the 2010 Tailoring Rule, which required major stationary sources of greenhouse gases to obtain preconstruction and operating permits. The U.S. Supreme Court eventually ruled that the U.S. EPA could only require a source to obtain a preconstruction permit for greenhouse gases if it also had to obtain a preconstruction permit for conventional pollutants such as sulfur dioxide.

[1] *Massachusetts v. Environmental Protection Agency*, 549 U.S. 497 (2007).

On April 13, 2012, the U.S. EPA proposed a rule to establish New Source Performance Standards for CO_2 emissions from new natural gas and coal-fired EGUs. Then on January 8, 2014, the U.S. EPA withdrew that proposal and proposed emission guidelines for states to follow in developing plans to address CO_2 emissions from existing fossil fuel-fired EGUs. On the same day, the U.S. EPA proposed a replacement establishing CO_2 emission limits for new, modified, and reconstructed fossil fuel-fired EGUs. On June 18, 2014, EPA proposed a rule, known as the Clean Power Plan (CPP) to regulate CO_2 emissions from existing fossil fuel-fired EGUs. The EPA finalized both rules on October 23, 2015.

Q. PLEASE DISCUSS THE STATUS OF THE EPA'S CPP RULE AND WHETHER THERE WILL BE ANY IMPACT TO EAST BEND.

A. The CPP established an emission performance rate of 1,305 pounds of CO_2 per net megawatt-hour of electricity produced for all existing coal-fired EGUs, including East Bend. The final rule also established state-level pounds of CO_2 per net megawatt-hour of electricity produced emission performance rates and state-level mass-based annual CO_2 tonnage limits for all states. The CPP required each state to develop and submit an implementation plan to EPA detailing how it would achieve the CO_2 emission limitations specified in the CPP. The CPP gave states the option of developing a rate-based or a mass-based implementation plan. The EPA in the CPP outlined three rate-based and three mass-based approaches states could select from when developing their implementation plans.

Numerous petitions for review were filed with the D.C. Circuit Court challenging the legal status of the CPP. On February 9, 2016, the U.S Supreme Court granted a stay of the CPP effective until its legal status is resolved. Oral argument before the full D.C. Circuit was held on September 27, 2016. The court has not issued a decision in the case.

The Supreme Court's stay of the CPP means that Kentucky is under no obligation at this time to develop and submit an implementation plan to EPA and would not be unless the CPP were ultimately upheld by the courts. If the CPP is ultimately overturned or otherwise repealed, there will be no obligation to reduce CO_2 emissions at East Bend. If the CPP were to be upheld by the courts, the September 6, 2018, date in the final CPP for states to submit final implementation plans to EPA for approval will need to be revised. The new date would depend on when the final legal status of the CPP is resolved.

On April 4, 2017, the U.S. EPA announced in the Federal Register that it is conducting a review of the CPP, in accordance with an Executive Order by the President issued on March 28, 2017. The EPA indicated that it "if appropriate, will as soon as practicable and consistent with law, initiate proceedings to suspend, revise or rescind this rule." On April 28, 2017, the D.C. Circuit issued an order temporarily suspending the litigation while it considers EPA's motion to stay the litigation while the Agency reviews the rule. On June 8, 2017, EPA sent a proposed rule to the Office of Management and Budget to repeal the CPP.

If the CPP were to survive legal challenge and regulatory review and were implemented as written, the regulatory requirements that would apply to East Bend will be established by the Commonwealth of Kentucky through its implementation plan. Therefore, Duke Energy Kentucky would not know the exact regulatory requirements that would apply to East Bend until the Commonwealth of Kentucky completes its implementation plan and it is approved by the U.S. EPA, which could occur as late as 2021. Duke Energy Kentucky cannot predict what GHG-related regulatory requirements might ultimately apply to East Bend.

III. GENERAL DESCRIPTION OF ENVIRONMENTAL CONTROLS AT DUKE ENERGY KENTUCKY'S EAST BEND GENERATION STATION

Q. PLEASE DESCRIBE THE ENVIRONMENTAL CONTROLS AT EAST BEND.

A. The major environmental and pollution control features at East Bend are: a mechanical draft cooling tower, a high-efficiency hot side electrostatic precipitator, a lime-based flue-gas desulfurization (FGD) system, low nitrogen oxide (NO_x) burners and a selective catalytic reduction (SCR) system. The SCR is designed to reduce NO_x emissions by approximately 85 percent. The FGD system was upgraded in 2005 to increase the sulfur dioxide (SO_2) emissions removal capability to about 97 percent. The station electrical output is directly connected to the Duke Energy Midwest (consisting of Kentucky and Ohio) 345 kilovolt (kV) transmission system.

Q. PLEASE DESCRIBE HOW ASH IS CURRENTLY HANDLED AT EAST BEND.

A. Duke Energy Kentucky currently operates one landfill at East Bend and is in the process of constructing another onsite landfill (collectively, the Landfills), which are being and will be used for the disposal of materials and ash resulting from the Company's FGD process and other CCR-producing processes.

The original or "East" Landfill is comprised of approximately 162 acres and has been in place since East Bend was constructed in 1981. The East

Landfill's original construction pre-dated the CCR rule's effective date. The East Landfill will eventually have to be closed in a manner that complies with the CCR rule.

The newer or "West" Landfill, once all phases are completed, will consist of approximately 200 acres of lined landfill that is designed to accept approximately 30 years of CCR waste from the East Bend Station and other permitted sources, as needed, to make fixated scrubber sludge. Duke Energy Kentucky received CPCN approval to begin construction of the first phase of the West Landfill in Case No. 2015-00089. As part of that approval, the Commission directed the Company to file a new CPCN request prior to commencing construction of each additional phase or cell. The West Landfill, when constructed, will comply with the CCR rule.

Together, these Landfills are permitted to receive various forms of CCR waste, including, but not limited to, FGD waste, fly ash and bottom ash (Generator Waste), from a number of generating sources, including those generating stations currently owned and/or operated by Duke Energy Kentucky and from generating stations owned by other Kentucky utilities and Ohio-based electric generators. The dry fly ash created at East Bend is combined into a mixture of FGD solids, fly ash, and lime, and forms a substance called Poz-O-Tec, that sets up much like concrete, and is placed in the East Landfill. Depending upon generation output, East Bend produces approximately 1.3 million tons of Poz-O-Tec, including approximately 156,000 tons of fly ash annually. The remaining 20 percent of CCR material is bottom ash. This bottom ash is currently treated in an ash pond (Pond) located on site at East Bend.

The other generating sources are permitted for disposal in the East Bend landfills primarily as fly ash sources to be used in the Poz-O-Tec process since East Bend does not produce enough fly ash needed for Poz-O-Tec production. The presence of the Landfills and Pond has permitted Duke Energy Kentucky to manage its costs of environmental compliance and provide safe and reliable electric service by eliminating the need to transport and pay for sending generator waste to commercial landfills.

Q. PLEASE BRIEFLY DESCRIBE THE ASH POND LOCATED AT EAST BEND.

A. The Pond was commissioned in 1981 and it has a volume of 1,844 acre feet. The Pond receives bottom ash from the bottom of the boiler that is sluiced to the Pond with water. While residing in the Pond, the bottom ash separates from the water used to convey the ash from the plant before the water is discharged to the Ohio River from the Pond in accordance with a National Pollutant Discharge Elimination System (NPDES) permit. The Pond is also used to treat other plant water streams, such as coal pile run-off and landfill leachate, before they are discharged under the NPDES permit.

Q. PLEASE DESCRIBE THE CURRENT STATUS OF, AND THE COMPANY'S MODELING ASSUMPTIONS FOR, THE CCR AND ELG FINAL RULES.

A. In April 2009, the EPA began assessing the integrity of ash dikes nationwide, and began developing regulations to manage CCRs. CCRs primarily include fly ash, bottom ash, and FGD byproducts (typically calcium sulfate (gypsum) or calcium sulfite) that are destined for disposal. In June 2010, the EPA proposed a rule containing two options for handling CCRs: 1) as a special waste listed under the Resource Conservation and Recovery Act (RCRA) Subtitle C Hazardous Waste Regulations; and 2) as a solid waste under RCRA Subtitle D Non-Hazardous Waste Regulations. Both options included dam safety requirements and had strict new requirements regarding the handling, disposal, and beneficial use of CCRs except when reused in encapsulated applications (such as ready mix concrete and the production of wallboard).

When the EPA published its proposed ELG revisions, it indicated that it was working to integrate the ELG rule with the CCR rule. In the CCR proposal, the EPA said that there could be strong support for a conclusion that regulation of CCR disposal under RCRA Subtitle D would be adequate because of 1) potentially lower CCR risk assessment results, 2) the ELG requirements that the EPA may promulgate, and 3) increased federal oversight such requirements could achieve. The CCR Final Rule and/or ELG Final Rule result in conversions to dry handling of fly ash and bottom ash; increased use of landfills; the closure of existing wet ash storage ponds; and the addition of alternative wastewater treatment systems. In its ELG proposal, the EPA indicated that the requirements of the two rules needed to be harmonized before either rule was released. The CCR Final rule was published as final as a Subtitle D, non-hazardous waste rule on April 17, 2015.

Q. PLEASE DESCRIBE THE IMPACT OF THE CCR AND ELG FINAL RULES ON EAST BEND'S OPERATIONS.

A. The ELG Final Rule was published on November 3, 2015. This rule sets new or additional requirements for wastewater streams from several processes and byproducts at steam electric generating plants. Some of these wastewater streams are generated at East Bend Station, including but not limited to fly ash and bottom ash wastewaters. This rule will require the Company to take action to achieve compliance that includes conversion of the existing wet ash system to a dry ash handling system. As part of converting to dry ash handling, new wastewater treatment systems must be installed. The existing Pond can no longer be used in its current form as an ash transport water treatment system. Additionally, due to East Bend site limitations (*e.g.*, proximity to the river, availability of other land, *etc.*) the existing Pond must be repurposed through clean closure to comply with the ELG Final Rule. Compliance with some aspects of the CCR Final Rule began within 6-12 months after publication, while other actions will require 5 years or more. Compliance with the ELG Final Rule was set to begin as early as November 1, 2018, but no later than December 31, 2023. On August 14, 2017, EPA filed a motion with the 5th Circuit to put portions of the 2015 ELR Final Rule litigation on hold while they reconsider certain ELG Final Rule limits. The EPA is requesting to sever and hold in abeyance the issues related to bottom ash transport water, FGD wastewater, and IGCC gasification wastewater. The EPA is also requesting to propose reconsideration of the effluent limits and pre-treatment standards for only bottom ash transport water and FGD wastewater. This action alone does not have a direct impact on any compliance needs or implementation schedules for East Bend projects because the drivers for the station's ash-related projects were not limited to the ELG Final Rule. However, the action does provide an indication that EPA will review and potentially change the ELG limits for the two waste streams listed above. Duke Energy expects EPA will move quickly to finalize this rule once the court rules on the recent motion for reconsideration. The reconsideration process could take between a year and 18 months to complete.

As expected, the combination of ELG Final Rule, CCR Final Rule, and Kentucky groundwater regulations implementation require East Bend's conversion to dry ash handling (bottom ash). The Commission approved the Company's CPCN request to convert East Bend to a dry ash handling system on February 23, 2017, in Case No. 2016-00268. Additionally, these rules require the initiation of closure of the active wet ash storage Pond; installation of balance-of-plant wastewater treatment systems, including Pond repurposing. The Commission approved the Company's CPCN request for the water redirection, and Pond closure and repurposing on June 6, 2017 in Case No 2016-00398.

Q. PLEASE EXPLAIN HOW THE CCR AND ELG REGULATIONS IMPACT DUKE ENERGY KENTUCKY'S ENVIRONMENTAL COMPLIANCE STRATEGY.

A. The CCR Final Rule and ELG Final Rule have implications to ash handling and impoundment basins across the industry, not just Duke Energy Kentucky. In Duke Energy Kentucky's situation, compliance strategies now must include provisions that necessitate the conversion to dry handling of ash and closure of its existing Pond and repurposing it in accordance with more stringent CCR and ELG Final Rule standards. Specifically, as it relates to East Bend, the CCR Final Rule required implementation of an altered groundwater monitoring program for the Landfills and the Pond.

Q. WILL THE POND CLOSURE AND REPURPOSING AND PROCESS WATER SYSTEMS CONSTRUCTION ALLOW THE COMPANY TO COMPLY THE WITH CCR FINAL RULE AND ELG FINAL RULE?

A. Yes. Duke Energy Kentucky must have a way to handle wastewater sources in compliance with the ELG Final Rule and Kentucky groundwater regulations. The Pond repurposing will provide a necessary wastewater treatment facility in response to both. While the driver of the Company's decision to close the Pond for repurposing is to meet ELG Final Rule requirements, the new groundwater monitoring requirements contained in the CCR Final Rule may force the closure of the Pond anyway. As such, the Pond closure and repurposing project is a proactive step in anticipation of the potential forced Pond closure likely to occur under the CCR Final Rule.

Q. WILL THE CURRENT WEST LANDFILL CELL 2 BE CONSTRUCTED TO COMPLY WITH CCR RULE?

A. Yes. The West Landfill cell 2 will be constructed to meet all applicable environmental requirements, including the US EPA's requirements for CCR Final Rule. Cell 1 was not required to meet the liner requirements because that phase's construction had commenced on site before October 2015.

IV. DUKE ENERGY KENTUCKY'S ENVIRONMENTAL COMPLIANCE PLAN

Q. PLEASE IDENTIFY THE PROJECTS THAT DUKE ENERGY KENTUCKY IS PROPOSING TO INCLUDE IN ITS ENVIRONMENTAL COMPLIANCE PLAN FOR PURPOSES OF ESTABLISHING ITS ESM.

A. There are four projects, as well as compliance inventories, that Duke Energy Kentucky is seeking authorization to include as its initial environmental compliance plan as follows:

a. Project EB020290 Lined Retention Basin West;
b. Project EB020745 Lined Retention Basin East;
c. Project EB020298 East Bend SW/PW Reroute;
d. ARO amortization for Pond Closure; and
e. Consumables inventories (Reagents and emission allowances).

The projects are interrelated and include the water redirection, pond closure, post closure maintenance, and repurposing in compliance with ELG Final Rule and CCR Final Rules previously authorized by this Commission. The Commission has already granted CPCN authorization for the Company to begin construction of these projects in Case No. 2016-00398.

The project component proposed for inclusion in the Company's environmental compliance plan is for the recovery of costs attributable to the coal ash asset retirement obligation (ARO) related to pond closure and post closure maintenance at East Bend in response to the CCR Final Rule. Together, the pond closure, repurposing and water redirection work is all necessitated by a need to comply with CCR, ELG as well as Kentucky groundwater regulations.

Finally, the Company is seeking authorization to include consumable inventories such as reagents and emission allowances that are necessary to comply with the CAIR.

The Company is requesting that these projects, necessary to comply with ELG Final Rule and CCR Final Rule be incorporated into the Company's Environmental Compliance Plan for purposes of establishing the ESM in this proceeding.

V. CONCLUSION

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

VERIFICATION

STATE OF OHIO	)	
	)	**SS:**
COUNTY OF HAMILTON	)	

The undersigned, Tammy Jett, Principal Environmental Specialist, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of her knowledge, information and belief.

Tammy Jett

Tammy Jett Affiant

Subscribed and sworn to before me by Tammy Jett on this 21st day of August, 2017.

Ruth M. Loccisano

NOTARY PUBLIC

My Commission Expires:
06-18-2022

NOTARIAL SEAL
STATE OF OHIO

RUTH M. LOCCISANO
Notary Public, State of Ohio
My Commission Expires 06-18-2022

Direct Testimony of
Jeffrey T. Kopp

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; 3) Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All Other Required Approvals and Relief.	))))))))))	Case No. 2017-00321

DIRECT TESTIMONY OF

JEFFREY T. KOPP

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC

September 1, 2017

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jeffrey (Jeff) T. Kopp, and my business address is 9400 Ward Parkway, Kansas City, Missouri 64114.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Burns & McDonnell Engineering Company, Inc. (BMcD) as a manager in the Business Consulting Department of the Business & Technology Services Division. BMcD has been in business since 1898, serving multiple industries, including the electric power industry. In 2016, BMcD was rated No. 14 overall of the Top 500 Design Firms by the Engineering News Record (ENR). BMcD was rated as the No. 1 engineering design firm in the United States serving the electric power industry by ENR in 2016.

BMcD has vast experience in both preparation of dismantlement studies and executing construction projects, including hundreds of construction projects totaling more than $1 billion dollars of construction last year alone. In order to execute over $1 billion dollars of construction projects on an annual basis, BMcD has to win this work through competitive bidding processes, which requires us to be able to accurately prepare cost estimates.

Our long history, large market presence, and top industry rankings demonstrate our ability to effectively and accurately estimate costs. In addition, we have worked with demolition contractors over the years to refine our estimating process for dismantlement studies to align our costs with theirs.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AS A MANAGER IN THE BUSINESS CONSULTING DEPARTMENT OF BMcD.

A. I am a professional engineer with 16 years of experience consulting to electric utilities. I have been involved in numerous decommissioning studies and served as project manager on the majority of them. I have helped prepare decommissioning studies on all types of power plants utilizing various technologies and fuels.

As a manager in the Business Consulting Department of BMcD, I oversee a team of 11 project managers who provide consulting services to clients primarily in the electric power generation and electric power transmission industries, but also to other industrial and commercial clients. The services provided by this group of project managers include decommissioning cost studies, independent engineering assessments of existing power generation assets, economic evaluations of capital expenditures, new power generation development and evaluation, electric and water rate analysis, electric transmission planning, generation resource planning, renewable power development, and other related engineering and economic assessments.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I have a Bachelor's Degree in Civil Engineering from the University of Missouri – Rolla (now the Missouri University of Science and Technology) and a Masters of Business Administration from the University of Kansas. In my role as a group manager, project manager, and project engineer, I have worked on and have overseen consulting activities for coal, natural gas, wind, solar, hydroelectric, and biomass power generation facilities.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe and support Duke Energy Kentucky, Inc.'s (Duke Energy Kentucky or the Company) Decommissioning Cost Estimate Study (Decommissioning Study) for its East Bend Generating Station (East Bend) Woodsdale Combustion Turbines (Woodsdale), and the Miami Fort Unit 6 Generating Station (MF6), (collectively the Plants).

II. DUKE ENERGY KENTUCKY'S DECOMMISSIONING STUDY

Q. PLEASE DESCRIBE THE DECOMMISSIONING STUDY PREPARED FOR THE COMPANY.

A. The Company retained BMcD to provide it with a recommendation regarding the total cost, in 2016 dollars, of decommissioning each Company-owned generation unit at the end of its useful life as well as the total cost of decommissioning the common facilities at these generating plants. The total decommissioning cost as determined by BMcD and reflected in the Decommissioning Study was net of salvage value for scrap materials at each plant.

Q. WHAT PLANTS DID BMcD EVALUATE IN THE 2016 DECOMMISSIONING COST STUDY?

A. For purposes of the Decommissioning Study, we evaluated three of the Company's electric generating plants, which includes East Bend, Woodsdale, and MF6.

Q. WHAT WAS THE EXTENT OF YOUR PERSONAL INVOLVEMENT IN THE PREPARATION OF THE DECOMMISSIONING STUDY?

A. I served as the BMcD project manager on the Decommissioning Study. I worked directly with all individuals and parties involved in the preparation of the decommissioning cost estimates in the Decommissioning Study. I was responsible for the overall project and was involved in the development of the decommissioning assumptions, decommissioning estimating methodology, preparation and review of the estimates, and preparation and review of the report.

Q. WHAT APPROACH WAS USED TO DEVELOP THE DECOMMISSIONING ESTIMATES IN THE DECOMMISSIONING STUDY?

A. The estimate of direct dismantlement costs was prepared with the intent of most accurately representing what BMcD would anticipate contractors bidding to dismantle the equipment, address environmental issues, and restore the site through a competitive bidding process, based on performing known dismantlement tasks under ideal conditions. In addition to these known tasks under ideal conditions, indirect costs are added to cover cost incurred by the

Company in executing the projects, and contingency is added to account for unknown, but reasonably expected to be incurred costs.

As outlined in the Dismantlement Study, we prepared these cost estimates by estimating quantities for equipment based on a visual inspection and interaction with the facilities' staff, review of engineering drawings, BMcD's in house database of plant equipment quantities, and BMcD's professional judgment. This resulted in an estimate of quantities for the tasks required to be performed for each decommissioning effort. Current market pricing for labor rates, equipment, scrap materials, and unit pricing were then developed for each task. These rates were applied to the quantities for the plants to determine the total cost of decommissioning for each site.

Q. WHAT LEVEL OF DECOMMISSIONING AND DEMOLITION WAS ASSUMED TO BE PERFORMED AT EACH OF THE SITES?

A. The basis of the estimates was that all sites will be restored to a condition suitable for industrial use. The MF6 facility includes costs for retiring the unit in place and then fully demolishing MF6 at a later date. The retire in place costs for MF6 would be incurred in the near term to reduce environmental liabilities and risks associated with a non-operating unit while the remaining units at the Miami Fort Station (Units 7 and 8) continue to operate. The full demolition costs for MF6 are in addition to the near-term retire in place costs and are assumed to take place after the retirement of all of the currently operating units 7 and 8 that are owned by Dynegy. Performing full demolition of MF6 while the adjacent units are operating would be cost prohibitive, and thus are potentially not feasible.

Q. WHAT DOES RESTORING THE SITE FOR INDUSTRIAL USE REQUIRE?

A. The sites will have all above grade buildings and equipment removed, foundations removed to two feet below grade, be rough graded, and seeded. Sites also will have small diameter underground pipes capped and abandoned in place. The sites can remain in this condition in perpetuity, until the site is specifically redeveloped for industrial use.

Q. DID YOU VISIT EACH OF THE SITES FOR WHICH THE SITE-SPECIFIC COST ESTIMATES WERE DEVELOPED?

A. Yes. I visited all sites for which site-specific decommissioning cost estimates were prepared, along with other individuals from BMcD, and representatives from the Company.

III. DESCRIPTION OF DECOMMISSIONING COSTS

Q. GENERALLY EXPLAIN THE TYPE OF COSTS REFLECTED IN THE DECOMMISSIONING STUDY.

A. The estimates reflected in the Decommissioning Study are inclusive of direct costs associated with decommissioning and demolishing the plant equipment and facilities and restoring the sites to an industrial condition. The direct costs include environmental remediation costs for asbestos removal and other hazardous material handling and disposal, as well as costs for removing and disposing of contaminated soil. The Decommissioning Study also includes estimates of indirect costs to be incurred by the Company during decommissioning and contingency costs.

Q. HOW WERE THE DIRECT COSTS DEVELOPED FOR PURPOSES OF THE DECOMMISSIONING STUDY?

A. As part of the Decommissioning Study, site-specific cost estimates were developed using a "bottom-up" cost estimating approach, where cost estimates are developed from scratch through the development of site-specific quantity estimates and the application of unit pricing to the quantity estimates.

BMcD estimated quantities based on a visual inspection of the facilities, review of engineering drawings, BMcD's in-house database of plant quantities, and BMcD's professional judgment. This resulted in an estimate of quantities for the tasks required to be performed for each decommissioning effort. Current market pricing for labor rates, equipment, and unit pricing were then developed for each task. These rates were applied to the quantities for the Plants to determine the total cost of decommissioning for each site. Additionally, unit pricing for scrap values was applied to the scrap quantities to determine anticipated salvage values, which were subtracted from the direct costs for demolition in order to arrive at a total net project cost in 2016 dollars.

Q. HOW WERE SCRAP VALUES CALCULATED?

A. Scrap metal prices used in the development of the scrap credit were based on a review of recent pricing trends for various types of materials published by American Metal Market, which is an industry standard publication and information subscription service (see http://www.amm.com) that reports the prices paid for scrap metals in transactions worldwide.

American Metal Market is the leading independent supplier of market intelligence and pricing to the North American metals industries and publisher of the widely-used reference prices for scrap. American Metal Market also has extensive experience in reporting scrap prices in a wide range of grades and locations. American Metal Market has been reporting on the U.S. scrap market for more than 100 years, providing benchmark prices to users in the scrap metal industry.

Q. WHAT IS INCLUDED IN THE PROJECT INDIRECT COSTS INCLUDED IN THE 2016 DECOMMISSIONING COST STUDY?

A. This category includes costs expected to be incurred by the Company during the decommissioning process, which would be in addition to the direct costs paid to a demolition contractor. This includes the costs for staff of the Company providing oversight during demolition activities, inspections, and testing to confirm that remediation has been completed, as well as Company overheads, general and administrative costs.

Q. HOW WERE THE INDIRECT COSTS DETERMINED?

A. Indirect costs were determined as a percentage of the direct costs, as is a typical approach when preparing these types of cost estimates. The percentage of direct costs that was applied to determine the indirect costs was developed by BMcD based on experience with recent decommissioning estimates.

Q. WHAT IS INCLUDED IN THE CONTINGENCY COSTS?

A. A contingency cost includes unspecified but reasonably expected additional costs to be incurred by the Company during the execution of decommissioning and demolition activities. For decommissioning projects, there is some uncertainty associated with work conditions, the scope of work and how the work will be performed. There also is some uncertainty associated with estimating the quantities for dismantlement of facilities. These uncertainties result from the age and limits on drawings available, as well as the absence of testing results for environmental contamination prior to preparation of these types of studies. Contingency costs account for these unspecified but expected costs and are in addition to the direct costs associated with the base decommissioning costs for known scope items.

Q. ARE CONTINGENCY COSTS STANDARD INDUSTRY PRACTICE?

A. Yes. The application of contingency is not only appropriate, but also standard industry practice. Even on a project where firm pricing has been agreed upon with a successful bidder, it is typical that a client carry some level of contingency to cover potential change orders. It is even more important to carry contingency on planning level cost estimates such as those presented in the Decommissioning Study.

IV. CONCLUSION

Q. DID YOU PROVIDE ANY INFORMATION TO OTHER WITNESSES FOR THEIR USE IN THIS PROCEEDING?

A. No.

Q. WAS THE DECOMMISSIONING STUDY ATTACHED TO YOUR TESTIMONY AS JK-1 PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. ARE THE ESTIMATED COSTS REFLECTED IN THE DECOMMISSIONING STUDY REASONABLY REFLECTIVE OF THE ACTUAL COSTS NECESSARY TO DISMANTLE THE COMPANY PLANTS?

A. Yes, they are.

Q. ARE THESE ESTIMATED COSTS APPROPRIATE FOR USE IN THE DEVELOPMENT OF DEPRECIATION RATES FOR THE COMPANY'S ELECTRIC GENERATING PLANTS?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

VERIFICATION

STATE OF Missouri)
) SS:
COUNTY OF Jackson)

The undersigned, Jeffrey (Jeff) T. Kopp, Manager in the Business Consulting Department of the Business & Technology Services Division, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of his knowledge, information and belief.

Jeffrey T Kopp

Jeffrey (Jeff) T. Kopp Affiant

Subscribed and sworn to before me by Jeffrey (Jeff) T. Kopp on this 11 day of August, 2017.

Amanda L G Dunn

NOTARY PUBLIC

My Commission Expires:

AMANDA L. G. DUNN
Notary Public - Notary Seal
STATE OF MISSOURI
Jackson County
My Commission Expires Sep. 15, 2020
Commission # 16012249

BURNS McDONNELL

Decommissioning Cost Estimate Study

DUKE ENERGY®

Duke Energy Kentucky

Decommissioning Cost Estimate Study
Project No. 95525

3/22/2017

Decommissioning Cost Estimate Study

prepared for

Duke Energy Kentucky
Decommissioning Cost Estimate Study
Union, Kentucky

Project No. 95525

3/22/2017

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
BOP	Balance of Plant Facilities
C&D	Construction and Demolition
CT	Combustion Turbine
DEK	Duke Energy Kentucky
OSHA	Occupational Safety and Health Administration
PCBs	Polychlorinated Biphenyls
Plants	Power Generation Assets
RS Means	Construction Cost Estimating Data
STG	Steam Turbine Generator
Study	Decommissioning Cost Study

1.0 EXECUTIVE SUMMARY

1.1 Introduction

Burns & McDonnell Engineering Company, Inc. ("Burns & McDonnell") of Kansas City, Missouri, was retained by Duke Energy Kentucky ("DEK") to conduct a Decommissioning Cost Study ("Study") for power generation assets ("Plants") in Kentucky and Ohio. The assets include natural gas and coal-fired generating facilities. The purpose of the Study was to review the facilities and to make a recommendation to DEK regarding the total cost to decommission the facilities at the end of their useful lives. The decommissioning costs were developed by Burns & McDonnell using information provided by DEK and in-house data available to Burns & McDonnell.

1.2 Results

Burns & McDonnell has prepared cost estimates in 2016 dollars for the decommissioning of the Plants. These cost estimates are summarized in Table 1-1. When DEK determines that the Plants should be retired, the above grade equipment and steel structures are assumed to have sufficient scrap value to a scrap contractor to offset a portion of the decommissioning costs. DEK will incur costs in the demolition and restoration of the sites less the scrap value of equipment and bulk steel.

Table 1-1: Decommissioning Cost Estimate Summary (2016$)

Plant	Decommissioning Costs	Credits	Net Project Cost
Woodsdale Station	$ 10,067,000	$ (3,800,000)	$ 6,267,000
Miami Fort Station Unit 6 – Retire in Place [1]	$ 13,046,000	$ (257,000)	$ 12,789,000
Miami Fort Station Unit 6– Full Demolition [2]	$ 5,754,000	$ (1,903,000)	$ 3,851,000
East Bend Station	$ 42,321,000	$ (7,987,000)	$ 34,334,000

Notes:
[1]: Retire in Place costs are assumed to be incurred in the near term to reduce environmental liabilities and risks associated with a non-operating unit.
[2]: The Full Demotion costs are in addition to the Retire in Place costs and are assumed to take place after the retirement of all of the currently operating units owned by Dynegy.

The total net project costs presented above include the costs to return the sites to an industrial condition suitable for reuse for development of an industrial facility. Included are the costs to dismantle the power generating equipment owned by DEK as well as the costs to dismantle the DEK-owned balance of plant facilities ("BOP") and environmental site restoration activities.

DEK does not own all assets at Miami Fort Station and only those assets associated with Unit 6 are considered in this Study.

1.3 Statement of Limitations

In preparation of this decommissioning study, Burns & McDonnell has relied upon information provided by DEK. Burns & McDonnell acknowledges that it has requested the information from DEK that it deemed necessary to complete this study. While Burns & McDonnell has no reason to believe that the information provided, and upon which Burns & McDonnell has relied, is inaccurate or incomplete in any material respect, Burns & McDonnell has not independently verified such information and cannot guarantee its accuracy or completeness.

Burns & McDonnell's estimates and projections of decommissioning costs are based on Burns & McDonnell's experience, qualifications and judgment. Since Burns & McDonnell has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractors' procedures and methods, and other factors, Burns & McDonnell does not guarantee the accuracy of its estimates and projections.

Burns & McDonnell's estimates do not include allowances for unforeseen environmental liabilities associated with unexpected environmental contamination due to events not considered part of normal operations, such as fuel tank ruptures, oil spills, etc. Estimates also do not include allowances for environmental remediation associated with changes in classification of hazardous materials.

2.0 INTRODUCTION

2.1 Background

Burns & McDonnell was retained by DEK to conduct a study for Plants in Kentucky and Ohio to estimate the decommissioning costs. The assets include natural gas and coal-fired generating facilities. Individuals from Burns & McDonnell visited each of the Plants covered by the Study in January of 2017. The purpose of the Study was to review the facilities and to make a recommendation to DEK regarding the total cost to decommission the facilities at the end of their useful lives.

Burns & McDonnell has prepared decommissioning studies for over 100 facilities on various types of fossil fuel and renewables power plants using a proven approach to developing these estimates. In addition to preparing decommissioning estimates, Burns & McDonnell has supported demolition projects as the owner's engineer, to evaluate demolition bids and oversee demolition activities. This has provided Burns & McDonnell with insight into the range of competitive demolition bids, which also assists in confirming the reasonableness of the decommissioning estimates developed by Burns & McDonnell.

2.2 Study Methodology

The site decommissioning costs were developed using information provided by DEK and in-house data Burns & McDonnell has collected from previous project experience. Burns & McDonnell estimated quantities for equipment based on a visual inspection of the facilities, review of engineering drawings, Burns & McDonnell's in-house database of plant equipment quantities, and Burns & McDonnell's professional judgment. This resulted in an estimate of quantities for the tasks required to be performed for each decommissioning effort. Current market pricing for labor rates, equipment, and unit pricing were then developed for each task. The unit pricing was developed for each site based on the labor rates, equipment costs, and disposal costs specific to the area in which the work is to be performed. These rates were applied to the quantities for the Plants to determine the total cost of decommissioning for each site.

The decommissioning costs include the cost to return the site to an industrial condition, suitable for reuse for development of an industrial facility, commonly referred to as a brownfield site. Included are the costs to decommission all of the assets owned by DEK at the site, including power generating equipment and BOP facilities.

2.3 Site Visits

Representatives from Burns & McDonnell and DEK visited the sites. The site visits consisted of a tour of each facility with plant personnel to review the equipment installed at each site. Tours were conducted by plant personnel.

Mr. John Edelen, from Duke Energy Kentucky, served as the DEK representative throughout the site visits, along with plant personnel at each of the sites.

The following Burns & McDonnell representatives comprised the site visit team:

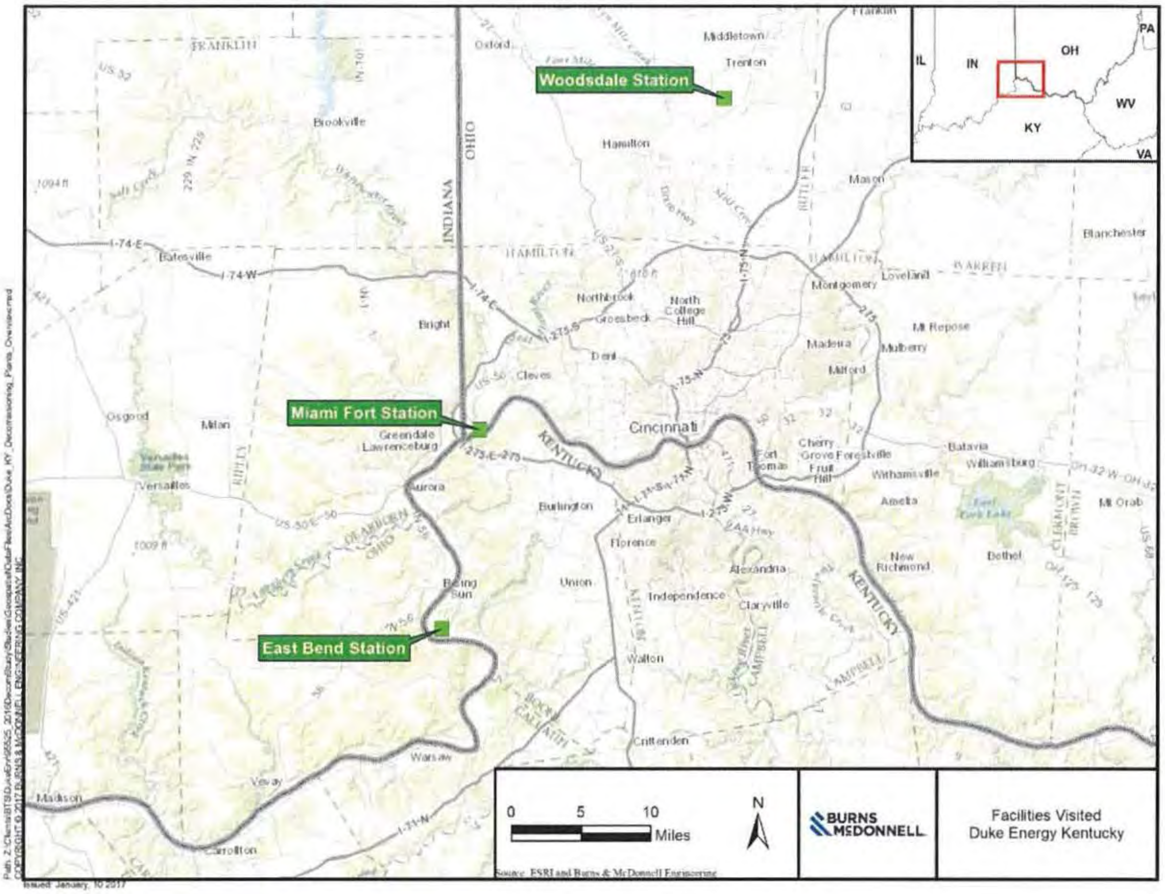
- Mr. Jeff Kopp, Project Manager
- Mr. Thom Bristow, Project Engineer
- Ms. Sara Ruckman, Lead Consultant

The site visits were performed on the following dates.

Table 2-1: Site Visit Dates

Plant	Site Visit Date
Woodsdale	December 12, 2016
Miami Fort	December 13, 2016
East Bend	December 13, 2016

Figure 2-1: DEK Facilities Visited



3.0 PLANT DESCRIPTIONS

The following sections provide site descriptions for each of the power plants included in this Study.

3.1 Simple Cycle / Combustion Turbines

3.1.1 Woodsdale

Woodsdale plant is located in Trenton, Ohio. The facility consists of six identical natural gas-fired combustion turbines operating in simple cycle mode. Operation began in 1992 with Unit 2 through Unit 6, followed by the operation of Unit 1 in 1993. The plant has a total capacity of 564.0 MW, with each unit's nameplate capacity equating to 95.3 MW.

3.2 Coal Generation

3.2.1 Miami Fort

Miami Fort plant consists of four units located in North Bend, Ohio, adjacent to the Ohio River. Commercial operation began in 1925. Units 1 & 2 retired in 1971 and were replaced by Unit 8. Units 3 & 4 retired in 1981, and Unit 5 retired on December 31, 2007. Only two units remain in operation (Units 7 & 8). Units 6, owned by DEK, has a nameplate capacity of 163 MW.

Unit 5 and Unit 6 share many of the same assets and are housed in the same facilities. Unit 6 is owned by DEK, and Unit 5 is owned by Dynegy. Assets owned by Dynegy are not included in the scope of this project.

3.2.2 East Bend

East Bend is located in Union, Kentucky, adjunct to the Ohio River. Originally, it was planned for two or more units to be built, but after the construction and beginning operation of Unit 2 in 1981, no additional units were built to completion. Unit 2 is a coal-fired boiler with a nameplate capacity of 772.0 MW. A steam turbine and the concrete for a control center building were built for Unit 1. These assets were left on site and have not been removed.

4.0 DECOMMISSIONING COSTS

Burns & McDonnell has prepared decommissioning cost estimates for the Plants. When DEK determines that each site should be retired, the above grade equipment and steel structures are assumed to have sufficient scrap value to a scrap contractor to offset a portion of the site decommissioning costs. However, DEK will incur costs of decommissioning of the Plants and restoration of the site to the extent that those costs exceed the scrap value of equipment and bulk steel.

The decommissioning costs include the cost to return the site to an industrial condition, suitable for reuse for development of an industrial facility. Included are the costs to dismantle all of the assets owned by DEK at the sites, including power generating equipment and BOP facilities, as well as environmental site restoration activities.

For purposes of this Study, Burns & McDonnell has assumed that each site will be decommissioned as a single project allowing the most cost effective demolition methods to be utilized. However, due to the current operation of Unit 7 and Unit 8 owned by Dynegy at Miami Fort, two (2) decommissioning cost estimates have been developed for that facility. The first summary provides cost estimates to retire in place the equipment and facilities for Unit 6. This includes performing tasks to reduce environmental and safety risks until full demolition occurs in the future. The retire in place cost summary also includes the removal of both Unit 6 precipitators to mitigate safety risks and to eliminate the need for maintenance of the retired assets in the future. The second cost estimate summary for Miami Fort included the costs associated with decommissioning and demolishing the entire plant as a single project. In this cost estimate, DEK is only responsible for costs associated with the Unit 6 assets that they own. Duke will be responsible for both the retire in place costs and full demolition of Unit 6, but the costs will be incurred at different times.

A summary of several of the means and methods that could be employed is summarized in the following paragraphs; however, means and methods will not be dictated to the contractor by Burns & McDonnell. It will be the contractor's responsibility to determine means and methods that result in safely decommissioning the Plants at the lowest possible cost.

Asbestos remediation, as required, would take place prior to commencement of any other demolition activities. Abatement would need to be performed in compliance with all state and federal regulations, including, but not limited to, requirements for sealing off work areas and maintaining negative pressure throughout the removal process. Final clearances and approvals would need to be achieved prior to performing further demolition activities.

High grade assets would then be removed from the site, to the extent possible. This would include items such as transformers, transformer coils, circuit breakers, electrical wire, condenser plates and tubes, and heater tubes. High grade assets include precious alloys such as copper, aluminum-brass tubes, stainless steel tubes, and other high value metals occurring in plant systems. High grade asset removal would occur up-front in the schedule, to reduce the potential for vandalism, to increase cash flow, and for separation of recyclable materials, in order to increase scrap recovery. Methods of removal vary with the location and nature of the asset. Small transformers, small equipment, and wire would likely be removed and shipped as-is for processing at a scrap yard. Large transformers, combustion turbines ("CT"), steam turbine generators ("STG"), and condensers would likely require some on-site disassembly prior to being shipped to a scrap yard.

Construction and Demolition ("C&D") waste includes items such as non-asbestos insulation, roofing, wood, drywall, plastics, and other non-metallic materials. C&D waste would typically be segregated from scrap and concrete to avoid cross-contaminating of waste streams or recycle streams. C&D demolition crews could remove these materials with equipment such as excavators equipped with material handling attachments, skid steers, etc. This material would be consolidated and loaded into bulk containers for disposal.

In general, boilers could be felled and cut into manageable sized pieces on the ground. First the structures around the boilers would need to be removed using excavators equipped with shears and grapples. Stairs, grating, elevators, and other high structures would be removed using an "ultra-high reach" excavator, equipped with shears. Following removal of these structures, the boilers would be felled, using explosive blasts. The boilers would then be dismantled using equipment such as excavators equipped with shears and grapples, and the scrap metal loaded onto trailers for recycling.

After the surrounding structures and ductwork have been removed, the stacks would be imploded, using controlled blasts. Following implosion the stack liners and concrete would be reduced in size to allow for handling and removal.

BOP structures and foundations would likely be demolished using excavators equipped with hydraulic shears, hydraulic grapples, and impact breakers, along with workers utilizing open flame cutting torches. Steel components would be separated, reduced in size, and loaded onto trailers for recycling. Concrete would be broken into manageable sized pieces and stockpiled for crushing on-site. Concrete pieces would ultimately be loaded in a hopper and fed through a crusher to be sized for on-site disposal.

For the retire in place estimate, the Miami Fort Unit 6 precipitators would likely be demolished utilizing a crane for removal from the top of the building, then cutting them into manageable sized pieces on the ground, since it cannot be felled, due to the continued operation of the remaining units.

4.1 General Assumptions for All Sites

The following assumptions were made as the basis of all of the cost estimates.

1. All cost estimates are in current 2016 dollars.
2. All estimates are budgetary in nature and do not reflect guaranteed costs. Budgetary refers to the nature of the itemized cost estimate being for planning purposes only and not a guarantee.
3. All estimates are based on labor rates from RS means values for a demolition crew B-8 with adjusted rates based on the local site cost index for the Plants.
4. All work will take place in a safe and cost efficient method.
5. Labor costs are based on a regular 40-hour workweek without overtime.
6. The estimates are inclusive of all costs necessary to properly dismantle and decommission all sites to a marketable or usable condition. For purposes of this Study and the included cost estimates, the sites will be restored to a condition suitable for industrial use. Such sites that are restored for reuse in industrial settings are referred to as brownfield sites.
7. Abatement of asbestos will precede any other work. After final air quality clearances have been reached, demolition can proceed.
8. All facilities will be decommissioned to zero generating output. Existing utilities will remain in place for use by the contractor for the duration of the demolition activities.
9. It is assumed that all of the power stations will be dismantled after all units at a single site are taken out of service, allowing dismantlement of entire sites at once with the exception of the retire in place cost estimate.
10. Soil testing and any other on-site testing has not been conducted for this study.
11. Transmission switchyards and substations outside the boundaries of the plant are not part of the demolition scope.
12. The costs for relocation of transmission lines, or other transmission assets, are specifically excluded from the decommissioning cost estimates.
13. Any costs necessary to support on-going operations of adjacent or newly proposed units will be allocated to the operating costs of the units not being decommissioned.
14. All demolition and abatement activities, including removal of asbestos, will be done in accordance with any and all applicable Federal, State and Local laws, rules and regulations.
15. Any residual oil or sludge in tanks and pipes will be cleaned up by DEK prior to demolition.

16. The scrap value of the equipment is based on the equipment being at the end of its useful life at the time of demolition; therefore, the equipment will not have a value on the grey market for reinstallation. Equipment will have value as scrap only at the time of site demolition.
17. All scrap materials include a deduction for transportation and are based on pricing at the Cincinnati hub and, with the exception of stainless steel, which is based on the Cleveland hub.
18. All scrap will be transported by truck rather than by train due to the high costs associated with shipping by train for this short of a distance.
19. It is assumed that sufficient area to receive, assemble and temporarily store equipment and materials is available.
20. Step-up transformers, auxiliary transformers, and spare transformers are included for demolition and scrap in all estimates.
21. Demolition will include the removal of all structures, equipment, tanks, conveyer systems, ancillary buildings, and any other associated equipment to two (2) feet below grade.
22. To the extent possible, concrete will be crushed and disposed of on-site. During crushing of the concrete, a large magnet is utilized to remove all rebar. All other non-hazardous material with no scrap value will be disposed of off-site at the nearest landfill.
23. All above grade plant structures and materials such as fire walls, masonry, doors, windows, building finishes, plumbing, HVAC ductwork, lighting fixtures, cable trays, etc., will be disposed of off-site at the nearest landfill.
24. Foundations and ground floor slabs will be removed to two (2) feet below grade. The surface will be graded for drainage using onsite soil and seeding.
25. All pipe supports, and pipe racks will be demolished and scrapped.
26. Three feet of soil beneath the fuel oil tanks is to be removed and replaced with clean fill.
27. Hazardous material abatement is included for all sites as necessary, including asbestos, mercury, and polychlorinated biphenyls ("PCBs"). Lead paint coated materials will be handled by certified personnel compliant with OSHA Standards as necessary, but will not be removed prior to demolition. Scrap steel can be taken to scrap brokers with lead paint still intact, and it will not impact the scrap value.
28. All portable tanks will be removed from the site and scrapped, including any propane tanks, oil storage tanks, and waste oil tanks.
29. All production wells will be closed as per state regulations. Production wells will be filled with grout to approximately five feet below surface grade. The top five feet will be overdrilled and filled with soil backfill to grade on top of the grout. Monitoring wells will remain intact.

30. All chemicals will be consumed or disposed of by the Plant prior to shut down, including process chemicals in equipment, stored chemicals, and laboratory chemicals.
31. Any observable surface spill will be cleaned up.
32. All trash, debris, and miscellaneous waste will be removed and disposed of properly.
33. The substation equipment owned by the Plant including breakers, air break disconnect switch, busbars, grounding cable and transformers up to the interconnection point will be removed.
34. Underground piping will be capped and abandoned in place. Circulating water tunnels will be filled with flowable fill.
35. No environmental costs have been included to address cleanup of contaminated soils, hazardous materials, or other conditions present on-site having a negative environmental impact, other than those specifically listed in these assumptions. No allowances are included for unforeseen environmental remediation activities.
36. Handling and disposal of hazardous material will be performed in compliance with the approved methods of DEK's Environmental Services Department.
37. Ash ponds and landfills are excluded from the scope of this Study.
38. Storm water ponds will be drained and the area graded out to allow for natural drainage.
39. Site areas will be graded to achieve suitable site drainage to natural drainage patterns, but grading will be minimized to the extent possible.
40. Existing basements will be used to bury non-hazardous debris. Concrete in trenches and basements will be perforated to create drainage. Non-hazardous debris, such as concrete will be crushed and used as clean fill on-site once the capacity of all existing basements has been exceeded. All inert debris will be disposed of on-site. Costs for offsite disposal are included for materials not classified as inert debris.
41. Major equipment, structural steel, CTs, generators, inlet filters, exhaust stacks, transformers, electrical equipment, cabling, wiring, pump skids, above ground piping, and equipment enclosures for the above equipment will be sold for scrap and removed from the Plant site by the demolition contractor. All other demolished materials are considered debris.
42. Valuation and sale of land and all replacement generation costs are excluded from this scope.
43. Spare parts inventories were not provided to Burns & McDonnell for review. Burns & McDonnell assumes that to the extent possible spare parts will be sold prior to decommissioning and remaining spare parts will be scrapped by the demolition contractor.
44. Rolling stock, including rail cars, dozers, plant vehicles, etc. is assumed to be removed by DEK prior to decommissioning.

45. The scope of the costs included in the Study is limited to the decommissioning activities that will occur at the end of useful life of the facilities. Additional on-going costs may be required. These costs are excluded from the cost estimates provided in this Study.
46. A 20 percent contingency was included on the direct costs in the estimates prepared as part of this Study to cover unknowns.
47. Indirect costs are included in the cost estimate to cover owner expenses such as management trailers, utilities, etc. which may impact the cost of decommissioning each site. An indirect cost of 5 percent was included in the estimates to cover such costs.
48. Market conditions may result in cost variations at the time of contract execution.

4.2 Site Specific Decommissioning Assumptions

The following assumptions were made specific to each plant cost estimate.

4.2.1 Woodsdale

1. The Madison Plant northwest of the Woodsdale Plant is not included in the scope of this Study.
2. No further work is necessary to restore the area where Unit 7 through Unit 12 were planned.
3. Due to the vintage of the plant, it is assumed no asbestos or lead paint is present.
4. Scrap values, net of transportation costs, used in the Study are as follows:
    a. Steel $174.62/ton
    b. Copper $1.74/lb
    c. Aluminum $0.42/lb
    d. Brass $1.31/lb

4.2.2 Miami Fort – Retirement in Place

5. Due to continued operation of Unit 7, and Unit 8 owned by Dynegy, and for purposes of maintaining structural integrity of plant facilities, assets owned by DEK will not be removed from the plant under the retirement in place scenario unless they pose a safety risk.
6. Both precipitators, old and new, and induced draft fans associated with Unit 6 will be removed. The old precipitator is currently seen as a safety hazard if it were to be retired in place, due to its vintage, and the new precipitator would require routine maintenance if retired in place and, therefore, it is assumed that they both will be removed.
7. Asbestos abatement of all DEK owned assets will precede any other work.
8. Materials from the demolition of Unit 6 precipitators will be scrapped and moved off-site.
9. Oil-filled transformers will be drained and the oil disposed of properly.
10. The chimney will be capped.

11. Fuel oil tanks in underground vault will be cleaned, flushed, and abandoned in place.

4.2.3 Miami Fort – Full Demolition

1. A full demo of the Miami Fort power plant is assumed to take place after the retirement of all of the currently operating units owned by Dynegy. The full demolition costs are in addition to the Retire in Place costs that will be incurred.
2. The full demolition costs include only the assets owned by DEK. These assets include Unit 6 boiler and steam turbine, three conveyors (#11, #12, and conveyer G), Unit 5 coal crusher, Unit 5 vacuum pump, and the exhaust stack. The building housing the four steam turbines is assumed to be 25 percent owned by DEK and, therefore, 25 percent of the demolition costs will be paid for by DEK.
3. The chimney is assumed to be imploded upon the retirement of all of the currently operating units owned by Dynegy due to the cost to remove the stacks mechanically with adjacent units in operation being approximately ten times that of implosion.
4. It is assumed that no material was removed from the site during construction; therefore, borrow material is available on-site to be used to backfill the basement.
5. Due to the vintage of the plant, lead based paint is assumed to be present.
6. Mooring cells and barge unloading facilities are not included in the scope of this Study.
7. Scrap values, net of transportation costs, used in the Study are as follows:
   a. Steel $180.68/ton
   b. Copper $1.74/lb
   c. Aluminum $0.42/lb
   d. Brass $1.34/lb
   e. Stainless steel $0.66/lb

4.2.4 East Bend

1. Due to the vintage of the plant it is assumed no asbestos or lead paint is present.
2. The coal pile area will be excavated to a depth of one foot, graded, capped, and covered with imported topsoil.
3. The landfill is not included in the scope of this Study.
4. Mooring cells and unloading facilities are included in the Study.
5. It is assumed that no material was removed from the site during construction; therefore, borrow material is available on-site to be used to backfill the basement.
6. Scrap values, net of transportation costs, used in the Study are as follows:
   a. Steel $176.3/ton

b. Copper $1.74/lb
c. Aluminum $0.42/lb
d. Brass $1.33/lb
e. Stainless steel $0.65/lb

4.3 Results

Table 4-1 presents a summary of the decommissioning cost for each Plant. This summary provides a breakout of the major decommissioning activities and the scrap value for the Plant.

Table 4-1: Decommissioning Cost Estimate Summary (2016$)

Plant	Decommissioning Costs	Credits	Net Project Cost
Woodsdale Station	$ 10,067,000	$ (3,800,000)	$ 6,267,000
Miami Fort Station Unit 6 – Retire in Place [1]	$ 13,046,000	$ (257,000)	$ 12,789,000
Miami Fort Station Unit 6– Full Demolition [2]	$ 5,754,000	$ (1,903,000)	$ 3,851,000
East Bend Station	$ 42,321,000	$ (7,987,000)	$ 34,334,000

Notes:
[1]: Retire in Place costs are assumed to be incurred in the near term to reduce environmental liabilities and risks associated with a non-operating unit.
[2]: The Full Demotion costs are in addition to the Retire in Place costs and are assumed to take place after the retirement of all of the currently operating units owned by Dynegy.

APPENDIX A - PLANT AERIALS

Figure 1: Woodsdale Station

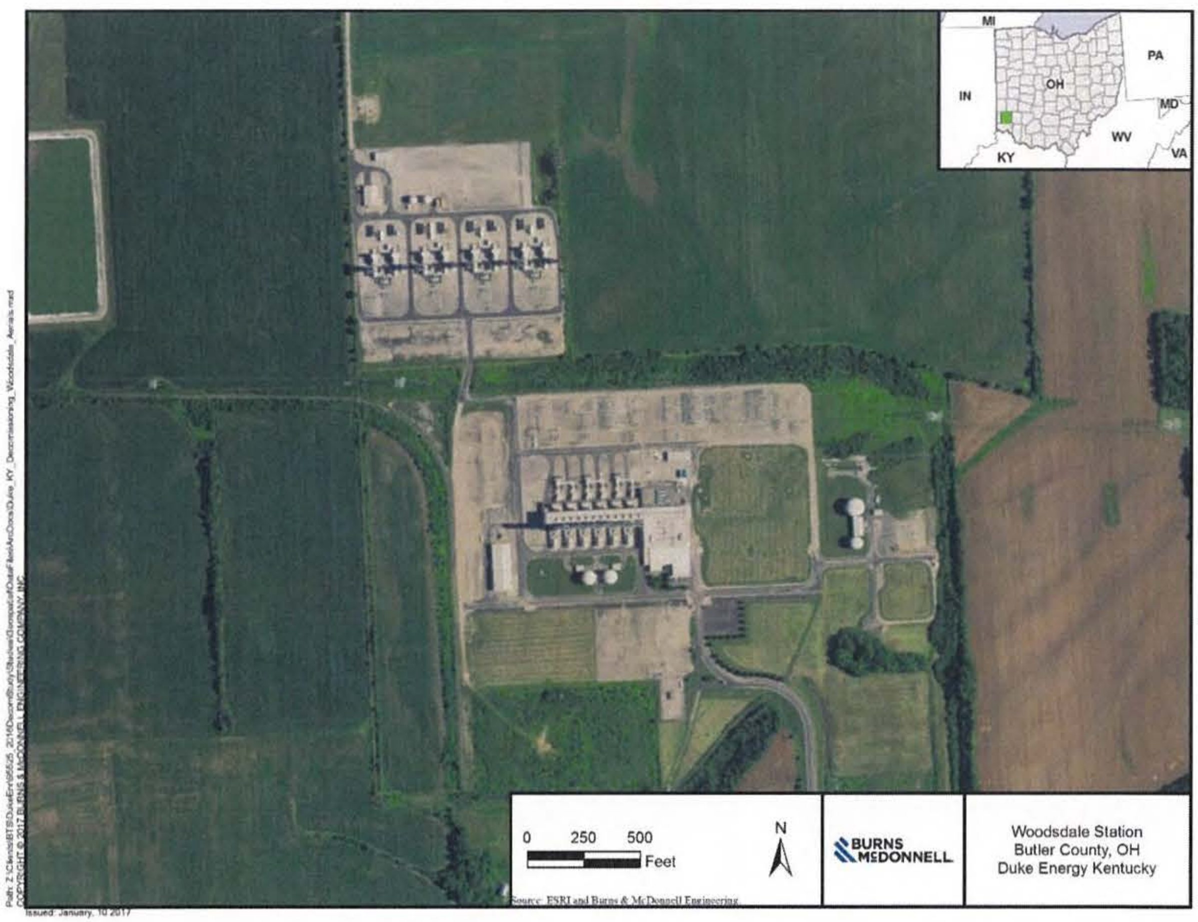


Figure 2: Miami Fort Station

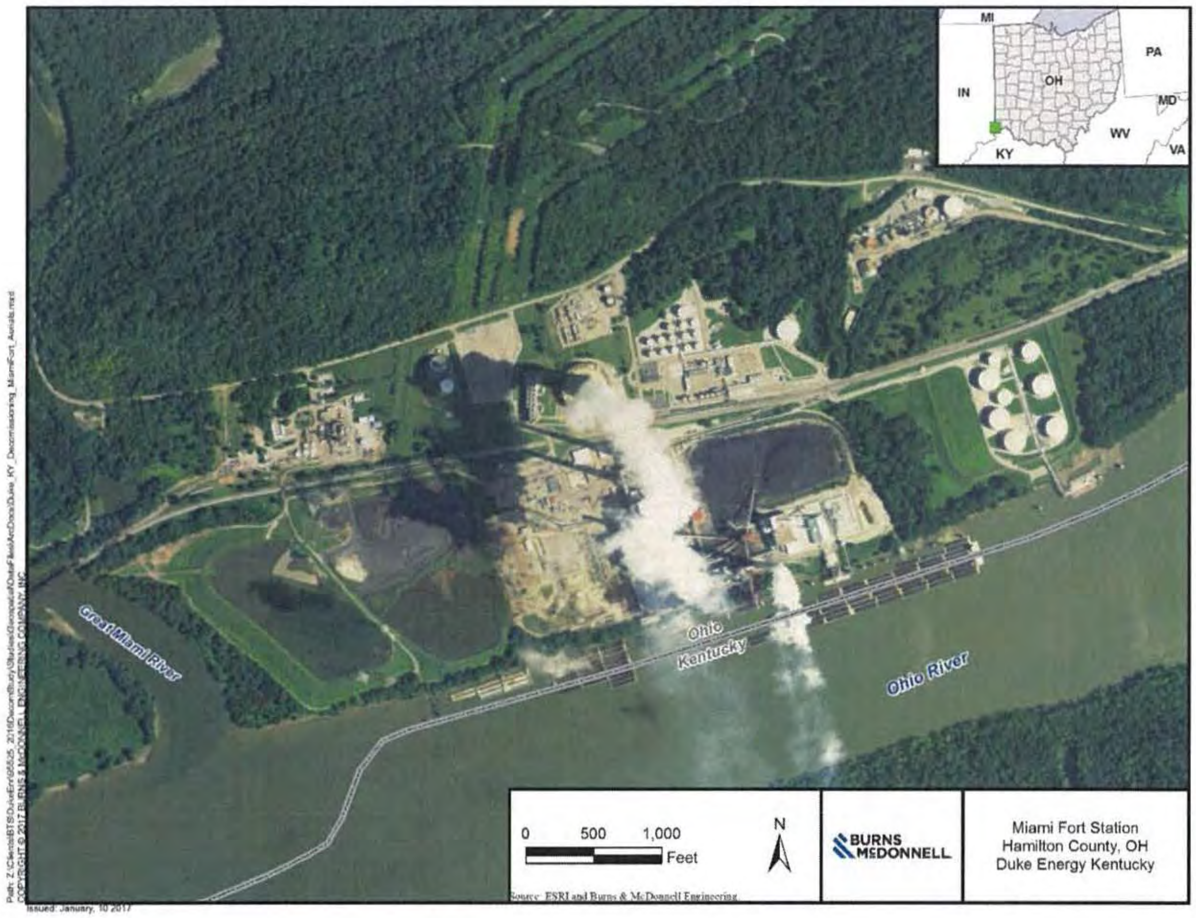
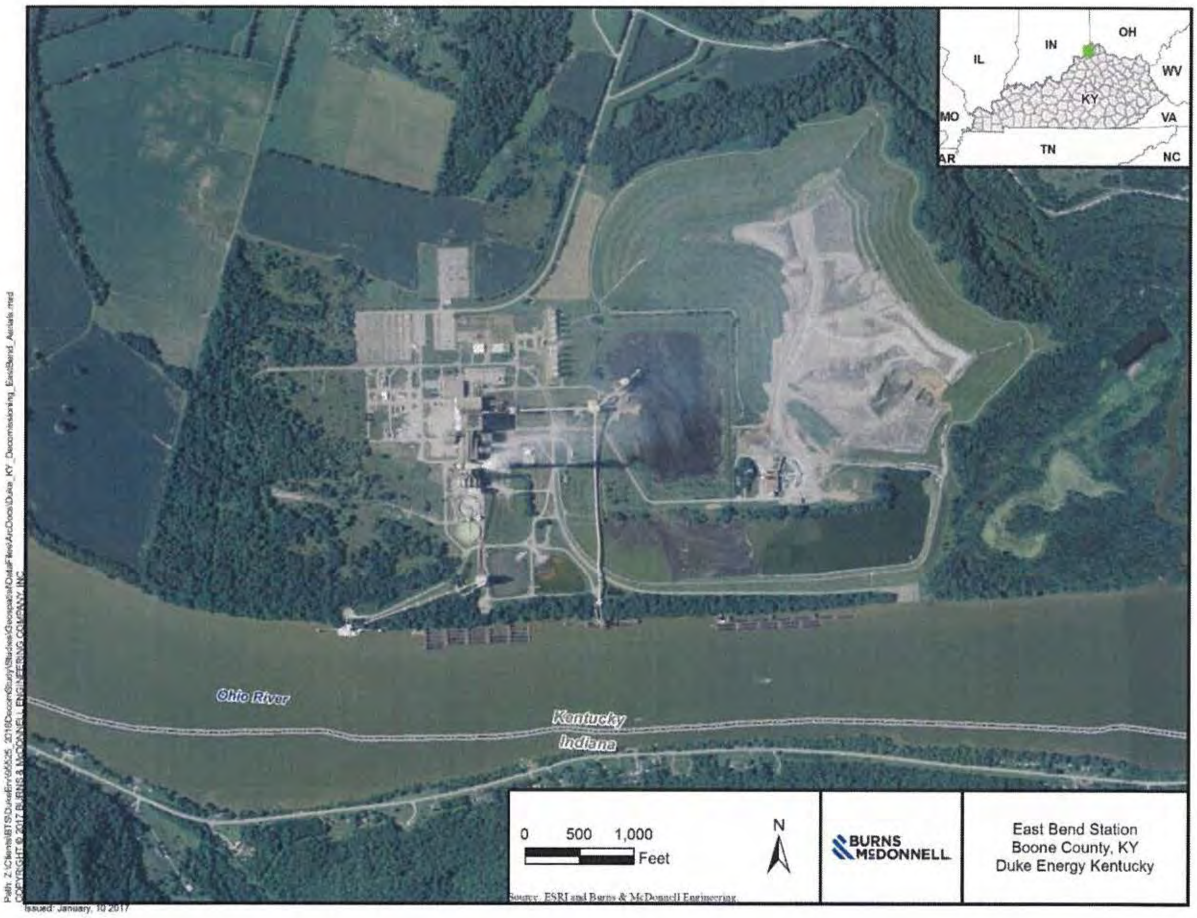


Figure 3: East Bend Station



APPENDIX B - COST ESTIMATE SUMMARIES

Table B-1
Woodsdale
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Scrap Value
Woodsdale						
Unit 1 - 6						
CTs	$ 1,752,000	$ 2,038,000	$ -	$ -	$ 3,790,000	$ -
Stack (Metal)	$ 34,000	$ 40,000	$ -	$ -	$ 74,000	$ -
GSUs, Electical, & Foundation	$ 124,000	$ 145,000	$ -	$ -	$ 269,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 33,000	$ -	$ 33,000	$ -
Debris	$ -	$ -	$ 1,000	$ -	$ 1,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (3,502,000)
Subtotal	**$ 1,910,000**	**$ 2,223,000**	**$ 34,000**	**$ -**	**$ 4,167,000**	**$ (3,502,000)**
Common						
Water Treatment Equipment and Piping	$ 351,000	$ 408,000	$ -	$ -	$ 758,000	$ -
Roads	$ 409,000	$ 476,000	$ -	$ -	$ 886,000	$ -
All BOP Buildings	$ 377,000	$ 439,000	$ -	$ -	$ 817,000	$ -
All Other Tanks	$ 191,000	$ 222,000	$ -	$ -	$ 413,000	$ -
Propane Boiler	$ 113,000	$ 131,000	$ -	$ -	$ 244,000	$ -
Switchgear & Electrical	$ 5,000	$ 6,000	$ -	$ -	$ 11,000	$ -
Transformer Oil Cleanup	$ -	$ -	$ -	$ 161,000	$ 161,000	$ -
Transformer Ped end Soil Removal	$ -	$ -	$ -	$ 85,000	$ 85,000	$ -
Plant Wash Down and Cleanup	$ -	$ -	$ -	$ 69,000	$ 69,000	$ -
Mercury and Universel Waste Cleanup	$ -	$ -	$ -	$ 11,000	$ 11,000	$ -
Battery Removal	$ -	$ -	$ -	$ 10,000	$ 10,000	$ -
Concrete Removal, Crushing, & Disposal	$ -	$ -	$ 76,000	$ -	$ 76,000	$ -
Grading & Seeding	$ -	$ -	$ -	$ 340,000	$ 340,000	$ -
Debris	$ -	$ -	$ 5,000	$ -	$ 5,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (298,000)
Subtotal	**$ 1,446,000**	**$ 1,682,000**	**$ 81,000**	**$ 676,000**	**$ 3,886,000**	**$ (298,000)**
Woodsdale Subtotal	**$ 3,356,000**	**$ 3,905,000**	**$ 115,000**	**$ 676,000**	**$ 8,053,000**	**$ (3,800,000)**
TOTAL DECOM COST (CREDIT)					**$ 8,053,000**	**$ (3,800,000)**
PROJECT INDIRECTS (5%)					**$ 403,000**	
CONTINGENCY (20%)					**$ 1,611,000**	
TOTAL PROJECT COST (CREDIT)					**$ 10,067,000**	**$ (3,800,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 6,267,000**	

Table B-2
Miami Fort
Decommissioning Cost Summary - Retire in Place

Description		One Time Costs		Scrap Value
Miami Fort				
Unit 6				
Asbestos Abatement	$	6,253,000	$	-
Shutdown Plant Equipment & Structures	$	48,000	$	-
Site Cleanup	$	12,000	$	-
Precipitator Removal	$	4,124,000	$	(257,000)
Retirement in Place Subtotal	**$**	**10,437,000**	**$**	**(257,000)**
TOTAL RETIRE IN PLACE COST (CREDIT)	**$**	**10,437,000**	**$**	**(257,000)**
PROJECT INDIRECTS (5%)	**$**	**522,000**		
CONTINGENCY (20%)	**$**	**2,087,000**		
TOTAL PROJECT COST (CREDIT)	**$**	**13,046,000**	**$**	**(257,000)**
TOTAL NET PROJECT COST (CREDIT)	**$**	**12,789,000**		

*Note: Due to future degradation, the cost to mechanically demolish the chimney prior to shut-down of Units 7 & 8 would cost up to approximately $3.9 million based on recent demolition contractor bids.

Table B-3
Miami Fort
Decommissioning Cost Summary - Full Demolition

Miami Fort	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Scrap Value
Unit 6						
Boiler	$ 997,000	$ 1,159,000	$ -	$ -	$ 2,156,000	$ -
Steam Turbine & Building	$ 449,000	$ 523,000	$ -	$ -	$ 972,000	$ -
Cooling Water Intakes and Circulating Water Pumps	$ 18,000	$ 21,000	$ -	$ -	$ 39,000	$ -
NSCR	$ 94,000	$ 110,000	$ -	$ -	$ 204,000	$ -
Switchgear & Electrical	$ 10,000	$ 12,000	$ -	$ -	$ 21,000	$ -
Stacks	$ 159,000	$ 185,000	$ -	$ -	$ 343,000	$ -
GSU & Foundation	$ 37,000	$ 43,000	$ -	$ 2,000	$ 82,000	$ -
Hazardous Materials Disposal	$ -	$ -	$ 10,000	$ -	$ 10,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 131,000	$ -	$ 131,000	$ -
Debris	$ -	$ -	$ 38,000	$ -	$ 38,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (1,873,000)
Subtotal	**$ 1,764,000**	**$ 2,053,000**	**$ 179,000**	**$ 2,000**	**$ 3,996,000**	**$ (1,873,000)**
Handling						
Coal Handling Demolition	$ 37,000	$ 43,000	$ -	$ -	$ 80,000	$ -
On-site Concrete Crushing & Disposal	$ 3,000	$ 4,000	$ -	$ -	$ 7,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (30,000)
Subtotal	**$ 40,000**	**$ 47,000**	**$ -**	**$ -**	**$ 87,000**	**$ (30,000)**
Common						
Transformers Transformer Oil Cleanup	$ -	$ -	$ -	$ 3,000	$ 3,000	$ -
Transformers Pad and Soil Removal	$ -	$ -	$ -	$ 8,000	$ 8,000	$ -
Refractory Cleanup	$ -	$ -	$ -	$ 33,000	$ 33,000	$ -
Plant Wash Down and Cleanup	$ -	$ -	$ -	$ 32,000	$ 32,000	$ -
Mercury and Universal Waste Cleanup	$ -	$ -	$ -	$ 11,000	$ 11,000	$ -
Nuclear Device Cleanup	$ -	$ -	$ -	$ 6,000	$ 6,000	$ -
Battery Removal	$ -	$ -	$ -	$ 10,000	$ 10,000	$ -
Grading & Seeding	$ -	$ -	$ -	$ 417,000	$ 417,000	$ -
Subtotal	**$ -**	**$ -**	**$ -**	**$ 520,000**	**$ 520,000**	**$ -**
Miami Fort Subtotal	**$ 1,804,000**	**$ 2,100,000**	**$ 179,000**	**$ 522,000**	**$ 4,603,000**	**$ (1,903,000)**
TOTAL DECOM COST (CREDIT)					**$ 4,603,000**	**$ (1,903,000)**
PROJECT INDIRECTS (5%)					**$ 230,000**	
CONTINGENCY (20%)					**$ 921,000**	
TOTAL PROJECT COST (CREDIT)					**$ 5,754,000**	**$ (1,903,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 3,851,000**	

Table B-4
East Bend
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Scrap Value
East Bend						
Unit 2						
Boiler	$ 3,491,000	$ 4,061,000	$ -	$ -	$ 7,552,000	$ -
Steam Turbine & Building	$ 1,439,000	$ 1,674,000	$ -	$ -	$ 3,113,000	$ -
Precipitator	$ 1,002,000	$ 1,165,000	$ -	$ -	$ 2,167,000	$ -
SCR	$ 606,000	$ 705,000	$ -	$ -	$ 1,311,000	$ -
Switchgear & Electrical	$ 10,000	$ 12,000	$ -	$ -	$ 22,000	$ -
Scrubber / FGD	$ 700,000	$ 815,000	$ -	$ -	$ 1,515,000	$ -
Stacks	$ 237,000	$ 275,000	$ -	$ -	$ 512,000	$ -
Cooling Towers & Basin	$ 714,000	$ 831,000	$ -	$ -	$ 1,545,000	$ -
GSU & Foundation	$ 65,000	$ 76,000	$ -	$ -	$ 141,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 378,000	$ -	$ 378,000	$ -
Debris	$ -	$ -	$ 61,000	$ -	$ 61,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (6,964,000)
Subtotal	**$ 8,264,000**	**$ 9,614,000**	**$ 439,000**	**$ -**	**$ 18,317,000**	**$ (6,964,000)**
Handling						
Coal Handling Demolition	$ 465,000	$ 541,000	$ -	$ -	$ 1,006,000	$ -
Grab Bucket and Coal Unloading Facilities	$ 720,000	$ 851,000	$ -	$ -	$ 1,571,000	$ -
Coal Storage Area Restoration	$ -	$ -	$ -	$ 4,828,000	$ 4,828,000	$ -
Limestone/Gypsum Handling Facilities	$ 189,000	$ 220,000	$ -	$ -	$ 409,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 30,000	$ -	$ 30,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (438,000)
Subtotal	**$ 1,374,000**	**$ 1,612,000**	**$ 30,000**	**$ 4,828,000**	**$ 7,844,000**	**$ (438,000)**
Common						
Cooling Water Intakes & Circ. Water Equip.	$ 59,000	$ 69,000	$ -	$ 845,000	$ 973,000	$ -
Roads	$ 631,000	$ 734,000	$ 741,000	$ -	$ 2,106,000	$ -
All BOP Buildings	$ 684,000	$ 795,000	$ -	$ -	$ 1,479,000	$ -
Fuel Oil Equipment	$ 22,000	$ 26,000	$ -	$ -	$ 48,000	$ -
All Other Tanks	$ 180,000	$ 209,000	$ -	$ -	$ 389,000	$ -
Transformers & Foundation	$ 84,000	$ 97,000	$ -	$ -	$ 181,000	$ -
Transformers Oil Cleanup	$ -	$ -	$ -	$ 153,000	$ 153,000	$ -
Transformers Pad and Soil Removal	$ -	$ -	$ -	$ 49,000	$ 49,000	$ -
Refractory Cleanup	$ -	$ -	$ -	$ 16,000	$ 16,000	$ -
Plant Wash Down and Cleanup	$ -	$ -	$ -	$ 32,000	$ 32,000	$ -
Mercury and Universal Waste	$ -	$ -	$ -	$ 11,000	$ 11,000	$ -
Fuel Oil Tank Soil Cleanup	$ -	$ -	$ -	$ 10,000	$ 10,000	$ -
Fuel Oil Tank Cleanup	$ -	$ -	$ -	$ 13,000	$ 13,000	$ -
Fuel Oil Line Flushing/Cleanup	$ -	$ -	$ -	$ 3,000	$ 3,000	$ -
Concrete Removal, Crushing, & Disposal	$ -	$ -	$ 60,000	$ -	$ 60,000	$ -
Grading & Seeding	$ -	$ -	$ -	$ 2,167,000	$ 2,167,000	$ -
Debris	$ -	$ -	$ 6,000	$ -	$ 6,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (585,000)
Subtotal	**$ 1,660,000**	**$ 1,930,000**	**$ 807,000**	**$ 3,299,000**	**$ 7,696,000**	**$ (585,000)**
East Bend Subtotal	**$ 11,298,000**	**$ 13,156,000**	**$ 1,276,000**	**$ 8,127,000**	**$ 33,857,000**	**$ (7,987,000)**
TOTAL DECOM COST (CREDIT)					**$ 33,857,000**	**$ (7,987,000)**
PROJECT INDIRECTS (5%)					**$ 1,693,000**	
CONTINGENCY (20%)					**$ 6,771,000**	
TOTAL PROJECT COST (CREDIT)					**$ 42,321,000**	**$ (7,987,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 34,334,000**	

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Direct Testimony of
Sarah E. Lawler

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; 3) Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All Other Required Approvals and Relief.	))))))))))	Case No. 2017-00321

DIRECT TESTIMONY OF

SARAH E. LAWLER

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

September 1, 2017

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Sarah E. Lawler, and my business address is 139 East Fourth Street, Cincinnati, Ohio 45202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services LLC (DEBS) as Utility Strategy Director, Midwest. DEBS provides various administrative and other services to Duke Energy Kentucky, Inc., (Duke Energy Kentucky or Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I earned a Bachelor of Science in Accountancy from Miami University, Oxford, Ohio in 1993. I am also a Certified Public Accountant.

I began my career in September 1993 with Coopers & Lybrand, L.L.P. as an audit associate and progressed to a senior audit associate. In August 1997, I moved to Kendle International Inc., where I held various positions in the accounting department, ultimately being promoted to Corporate Controller. In August 2003, I began working for Cinergy Corp., as External Reporting Manager, where I was responsible for the company's Securities & Exchange Commission (SEC) filings. In August 2005, I then moved into the role of Manager, Budgets & Forecasts. In June 2006, following the merger between Cinergy Corp. and Duke Energy, I became Manager, Financial Forecasting. In February 2015, I began in my current role as Utility Strategy Director, Midwest.

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS UTILITY STRATEGY DIRECTOR, MIDWEST.

A. As Utility Strategy Director, Midwest, I am responsible for the preparation of the Kentucky and Ohio Business Plans as well as other internal reporting and coordination of strategic initiatives. I am also responsible for the analysis of financial and accounting data used in certain Duke Energy Kentucky and Duke Energy Ohio, Inc., (Duke Energy Ohio) retail rate filings.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I support the revenue requirement proposed by Duke Energy Kentucky. Toward that end, I support various adjustments to the projected data for the forecasted test period provided by Duke Energy Kentucky witness, Robert "Beau" Pratt. I also sponsor Filing Requirements (FR) 16(6)(b), 16(6)(c), 16(6)(f) and 16(7)(t). I also sponsor the following schedules: Schedule A in satisfaction of FR 16(8)(a) and Schedule B-1, in response to FR 16(8)(b); Schedules C-1 through C-2.1 in compliance with FR 16(8)(c); Schedules D-1,D-2.17 through D-2.20, D-2.22, D-2.23, D-2.25 through D-2.27, D-2.29, and D-2.31 through D-2.33 in compliance with FR 16(8)(d); Schedules F-1 through F-7 in compliance with FR 16(8)(f); and Schedules G-1 and H in response to FR 16(8)(g) and FR16((8)(h), respectively. I sponsor Attachments SEL-1 through SEL-3 to my testimony. Attachment SEL-1 is the template for the Company's proposed changes to its profit sharing mechanism (Rider PSM). Attachment SEL-2 is the filing template for the Company's establishment of its Environmental Surcharge Mechanism (ESM). Attachment SEL-3 is the filing template for Duke Energy Kentucky's proposal to implement a new cost recovery mechanism to recover incremental capital costs for specific distribution system reliability and integrity performance enhancements (Rider DCI).

II. TEST PERIOD AND RATE BASE

Q. WHAT IS THE TEST PERIOD IN THIS PROCEEDING?

A. The Company has elected to use a forecasted test period in this proceeding. The forecasted test period reflects the twelve months ending March 31, 2019, adjusted for known and measurable changes, and a base period of twelve months ending November 30, 2017. The base period consists of six months of actual data, through May 31, 2017, and the remaining six months consist of forecasted data.

Q. HOW WERE THE RATE BASE AND CAPITALIZATION DETERMINED IN THIS PROCEEDING?

A. The Company determined rate base and capitalization using a thirteen-month average for the forecasted test period ending March 31, 2019. The base period rate base and capitalization represent end-of-period balances.

Q. DID THE COMPANY FOLLOW THE COMMISSION'S GUIDELINES IN DEVELOPING THE BASE AND FORECASTED TEST PERIOD DATA?

A. Yes. Per the Commission's rules, 807 KAR 5:001, Section 16(7)(e)(2), "the forecast contains the same assumptions and methodologies as used in the forecast period for use by management." As described by Mr. Pratt, the base and forecasted test periods were developed using the same methods applied in the Company's annual budgeting process. The first six months of the base period are actual results and are taken from the Company's books and records.

III. FILING REQUIREMENTS SPONSORED BY WITNESS

Q. PLEASE DESCRIBE FR 16(6)(b).

A. FR 16(6)(b) requires that the forecasted adjustments are limited to the twelve months immediately following the suspension period.

Q. PLEASE DESCRIBE FR 16(6)(c).

A. FR 16(6)(c) requires that capitalization and net investment rate base are based on a thirteen-month average for the forecasted test period, in this case, the twelve months ending March 31, 2019.

Q. PLEASE DESCRIBE FR 16(6)(f)

A. FR 16(6)(f) contains a reconciliation of the rate base and capital used to determine the revenue requirement in this case.

Q. PLEASE DESCRIBE FR 16(7)(t)

A. FR 16(7)(t) contains a list of all commercially available or in-house developed computer software, programs, and models used in the development of the schedules and workpapers associated with the filing of the utility's application.

Q. PLEASE DESCRIBE SCHEDULE A.

A. Schedule A is the overall financial summary for both the base period and the forecasted period at present rates. Based on the filing in this proceeding, as adjusted, the Company's electric operations are projected to earn a return on capitalization of 2.850 percent for the forecasted test period, which is considerably less than the 7.083

percent return requested in this proceeding. In order to achieve the appropriate return on capitalization, Duke Energy Kentucky's base electric revenues must increase $48,646,222, as shown in Schedule A.

Q. WHY IS THE COMPANY USING CAPITALIZATION AS THE BASIS FOR COMPUTING ITS REVENUE REQUIREMENT?

A. Although KRS 278.290 allows the Commission to use other bases for this computation, precedent suggests that capitalization is the Commission's favored method.

Q. HOW WAS TOTAL CAPITALIZATION FROM SCHEDULE J ALLOCATED TO ELECTRIC OPERATIONS ON SCHEDULE A?

A. The Company's capitalization supports both its electric business and its gas business. Some capitalization is also attributable to items not recoverable in rates or non-jurisdictional business. In order to determine the amount of the Company's total capitalization allocable to electric operations, Duke Energy Kentucky used the methodology approved by the Commission in prior rate proceedings. This methodology involves applying an electric rate base ratio, as determined on WPA-1d, to total company capitalization, as shown on Schedule J-1, page 2, adjusted for non-jurisdictional rate base. The total capitalization allocated to electric operations for the forecasted period as contained in Schedule A is $705,051,140.

Q. PLEASE DESCRIBE SCHEDULE B-1.

A. Schedule B-1 is the jurisdictional rate base summary for both the base and forecasted periods and is supported by various schedules in Section B of the Company's filing. The plant in service, and reserve for accumulated depreciation and amortization for the base and forecasted periods were summarized from Schedules B-2, B-3, and B-3.2 as supported by Company witnesses Ms. Cynthia S. Lee and Mr. Pratt. The working capital component was summarized from Schedule B-5, as supported by Mr. Pratt, and other items of rate base were obtained from Schedule B-6, as supported by Ms. Lisa M. Bellucci. The jurisdictional electric rate base for the forecast period as contained in Schedule B-1 is $700,204,561.

Q. PLEASE DESCRIBE SCHEDULE C-1.

A. Schedule C-1 is a jurisdictional operating income summary for the forecasted period ended March 31, 2019. This schedule includes the operating income summary at both current and proposed rates. It assumes that the Commission allows the total amount of the requested electric revenue increase of $48,646,213. The adjusted operating results at current rates were summarized from Schedule C-2 and the proposed increase was obtained from Schedule M. The revenue at proposed rates was developed by adding the revenue increase to the operating revenues at current rates. The related expenses and taxes on the proposed increase were added to the current adjusted operating results to determine the jurisdictional *pro forma* amounts and the corresponding rate of return. The rate base as shown on this schedule is calculated on Schedule B-1. The capitalization allocated to electric operations is calculated on workpaper WPA-1c.

Q. PLEASE DESCRIBE SCHEDULE C-2.

A. Schedule C-2 is a jurisdictional operating income statement to be used for ratemaking purposes. In order to develop the forecasted test year that is appropriate for ratemaking, a two-step process was required. First, as required by 807 KAR 5:001, Section 16(6)(a), it was necessary to show the adjustments necessary to transform the financial data for the base period into the forecasted period. Second, it was necessary to adjust the forecasted period data to reflect any fixed, known and measurable adjustments required to ensure that the revenues and expenses to be recovered in rates are representative of the expected costs to serve Duke Energy Kentucky electric customers on an ongoing basis.

Schedule C-2 starts with the unadjusted base period and shows the adjustments required to extend the Company's income statement from the base period to the forecasted period. The next column on the schedule summarizes the adjustments to the unadjusted forecasted test year. These adjustments are described below. Generally, they relate to costs that were not reflected in the Company's forecasted data, or were reflected in the forecasted data but not allocable to Duke Energy Kentucky's customers, or were made to reflect traditional ratemaking methodology. The unadjusted operating results are summarized from Schedule C-2.1. The adjusted amounts include the effects of the adjustments summarized on Schedule D-1.

Q. PLEASE DESCRIBE SCHEDULE C-2.1.

A. Schedule C-2.1 sets forth the detail of total Company operating results for both the base and forecasted periods. The operating results as shown in this Schedule C-2.1 are listed by account and are summarized on Schedule C-2.

Q. PLEASE DESCRIBE SCHEDULE D-1.

A. Schedule D-1 is a summary of the detailed adjustments to test period operating revenues and operating expenses as set forth in Schedules D-2.1 through D-2.35. These *pro forma* adjustments to the base period data are necessary to derive the forecasted test period level which includes the fixed, known, and measurable adjustments required to ensure that revenue and expenses to be recovered in rates are set at the level required to cover the cost of providing service to Duke Energy Kentucky's electric customers.

Q. WHY ARE ADJUSTMENTS TO THE BASE AND FORECASTED PERIOD INFORMATION NECESSARY?

A. The adjustments shown in Schedules D-2.1 through D-2.15 reflect the normal budgetary changes that are expected to occur from the base period through the forecasted period. Schedules D-2.1 through D-2.15, are sponsored by Mr. Pratt. The remaining adjustments, shown in Schedules D-2.16 through D-2.35, present adjustments to the forecasted period data needed to ensure that the correct level of revenue and expense is included in rates at the proper ongoing level. Some costs, although reflected in the normal forecasting process, are not recoverable from Duke Energy Kentucky's customers. Other adjustments were made to reflect traditional ratemaking methodology (*e.g.*, amortizing a regulatory asset to reflect the Commission's prior orders). The reflection of a proper cost level is necessary in order to give the Company a reasonable opportunity to earn its authorized return and to ensure that customers are not paying for more than the cost of providing service. Ignoring appropriate adjustments to the test year used for setting rates puts the Company at risk for potentially under-recovering its ongoing costs and also puts customers at risk for overpaying for service. Schedules D-2.16, D-2.21, and D-2.24

are sponsored by Ms. Lee. Schedules D-2.28, D-2.30, D-2.34, and D-2.35 are sponsored by Mr. Pratt. Schedules D-2.17 through D-2.20, D-2.22, D-2.23, D-2.25 through D-2.27, D-2.29, and D-2.31 through D-2.33 are discussed in my testimony below.

Q. HOW ARE THE TAX EFFECTS OF THESE ADJUSTMENTS SHOWN ON YOUR SCHEDULES?

A. All adjustments to taxes, including taxes other than income taxes and state and federal income taxes resulting from the adjustments, described below, are shown for each individual adjustment on Schedule D-1.

Q. PLEASE DESCRIBE SCHEDULE D-2.17.

A. The adjustment in Schedule D-2.17 is to amortize the projected cost of presenting the instant case. Duke Energy Kentucky proposes to amortize these costs over five years, which increases pre-tax operating expenses by $120,538.

Q. PLEASE DESCRIBE SCHEDULE D-2.18.

A. Schedule D-2.18 is an adjustment required to eliminate environmental reagent and emission allowance (EA) expenses to be included in the Environmental Surcharge Mechanism. The effect of the adjustment on electric operations is a decrease in pre-tax operating expenses of $12,398,573.

Q. PLEASE DESCRIBE SCHEDULE D-2.19.

A. Interest synchronization is used to ensure that the revenue requirements reflect the appropriate income tax effects for interest expense determined in the weighted-average cost of capital. Schedule D-2.19 presents the calculation of the state and federal income taxes on the interest cost included in the cost of capital. The adjustment is calculated by first determining the debt portion of total electric capitalization (as shown in WPA-1c). The capitalization allocated to electric is multiplied by the long-term and short-term debt percentage of total capitalization.

The result is then multiplied by the average cost of long-term and short-term debt. The sum of these results represents the annualized electric interest cost deductible for income tax purposes. From this annualized total, we subtract the forecasted test period electric book interest to determine the electric interest expense adjustment for income tax purposes. The effect of this adjustment on electric operations is to decrease federal income taxes by $92,910 and to decrease state income taxes by $14,991.

Q. PLEASE DESCRIBE SCHEDULE D-2.20.

A. Revenue and expenses associated with off-system sales are included in the budget and, consequently, in the forecasted test period. As I will discuss later in my testimony, Duke Energy Kentucky is proposing to continue its existing Rider PSM, albeit with some modifications, for off-system sales, that credits customers with the majority share of net margins on off-system sales. Therefore, Schedule D-2.20 is intended to completely exclude all revenue and costs that will flow through the Rider PSM from the calculation of the base rate revenue requirement. Other Revenue is reduced by $11,439,184 for the revenue flowing through Rider PSM. Operating expenses are reduced by $9,615,548 for related expenses flowing through Rider PSM. Related expenses include fuel, purchased power, allocated emission allowance expenses, and other variable expenses.

Q. PLEASE DESCRIBE SCHEDULE D-2.22.

A. The adjustment in Schedule D-2.22 eliminates the impact of Demand Side Management (DSM) revenue of $9,203,902 and DSM expense of $8,978,524. The adjustment recognizes that revenue and expenses associated with the Company's energy efficiency programs are addressed in its existing Rider DSM.

Q. PLEASE DESCRIBE SCHEDULE D-2.23.

A. Schedule D-2.23 is an adjustment to eliminate miscellaneous expenses such as community relations, advertising, donations, employee recognition, governmental affairs, club dues and miscellaneous events expenses from the forecasted test period. These adjustments were made in order to comply with the Commission's orders in prior rate proceedings. The effect of the adjustment on electric operations is a decrease in pre-tax operating expenses of $539,892.

Q. PLEASE DESCRIBE SCHEDULE D-2.25.

A. Schedule D-2.25 is an adjustment to eliminate unbilled revenue from the forecasted test period. The adjustment increases revenue in the forecasted test period by $3,258,473.

Q. PLEASE DESCRIBE SCHEDULE D-2.26.

A. Schedule D-2.26 is an adjustment to reflect the levelization of benefits related to the implementation of the Company's advanced metering infrastructure (AMI) initiative as agreed upon and approved in the Commission's order in Case No. 2016-00152. This adjustment for the projected operational savings is in the form of a levelized net present value calculation using the 7.05% which was presented in Confidential Exhibit DLS-4 in Case No. 2016-0152. The operational savings were defined in part 4 of the Stipulation and Recommendation in that same case. The impact of this adjustment is to decrease customer accounts expense by $2,321,137.

Q. PLEASE DESCRIBE SCHEDULE D-2.27.

A. Schedule D-2.27 is an adjustment to eliminate cost to achieve merging savings (CTA) related to the Duke Energy / Piedmont Natural Gas merger. The effect of the adjustment on electric operations is a decrease in pre-tax operating expenses of $237,780.

Q. PLEASE DESCRIBE SCHEDULE D-2.29.

A. Schedule D-2.29 is an adjustment to reflect a fixed bill premium, or increase in revenue, expected as a result of the implementation of the Company's proposed fixed bill program. This adjustment offsets the Company's overall revenue requirement but is dependent on the acceptance of the program by the Commission. See the direct testimony of Company witness Alexander "Sasha" Weintraub, PhD for a description of the Company's proposal. The adjustment increases revenue in the forecasted period by $122,230.

Q. PLEASE DESCRIBE SCHEDULE D-2.31.

A. Schedule D-2.31 summarizes the Company's proposal for recovering certain regulatory assets. The first regulatory asset represents costs associated with the Hurricane Ike storm restoration expense, which was authorized by the Commission in Case No. 2008-00476. The Company is proposing to amortize this expense over five years. The effect of this adjustment on electric operations is an increase in the pre-tax operating expenses of $982,560.

The second regulatory asset was approved by the Commission in Case No. 2008-00308 allowing the Company to defer annual contributions towards research for the management of carbon and carbon dioxide associated with existing coal-fired electric generating facilities in Kentucky. This research was performed by the Carbon Management Research Group partnership through the University of Kentucky Center for Applied Energy. The Commission allowed the Company to defer its $200,000 annual payment for this program for up to ten years. The Company plans to discontinue making this payment after its ten-year commitment and is proposing to amortize the projected balance of this regulatory asset over five years. The effect of this adjustment on electric operations is an increase in the pre-tax operating expenses of $400,000.

The third regulatory asset is associated with the Company's acquisition of the 31 percent interest in the East Bend Generating Station (East Bend) as approved in Case No. 2014-00201. In that case, the Commission authorized the Company to defer the incremental operations and maintenance expenses above amounts that were currently reflected in base rates associated with the acquisition of the 31 percent interest in East Bend, the incremental retirement costs associated with the retirement of Miami Fort Unit 6 Generating Station (MF6), carrying costs on the unrecovered balance based upon the Company's actual cost of debt, and any other incremental costs related to the assumed liabilities or otherwise necessary to effectuate the purchase of East Bend. Duke Energy Kentucky is proposing to amortize these costs over ten years. The effect of this adjustment on electric operations is an increase in the pre-tax operating expenses of $4,812,457.

The fourth regulatory asset is related to the informational technology solution costs the Company projects to incur to implement its AMI Opt-Out program as agreed upon in Case No. 2016-00152. The Company is proposing to amortize these costs over five years. The effect of this adjustment on electric operations is an increase in the pre-tax operating expenses of $52,606.

Q. PLEASE DESCRIBE SCHEDULE D-2.32.

A. Schedule D-2.32 includes an adjustment for uncollectible expenses. The Company sells all of its accounts receivable to an affiliate, Cinergy Receivables, L.L.C. (Cinergy Receivables) at a discount. The discount is based on a formula that compensates the purchasing company for the time value of money and a discount rate based on Duke Energy Kentucky's uncollectible expense.

Since the short-term debt component of the Company's weighted-average cost of capital calculation in Schedule J-1 includes the average balance of receivables at the interest rate being paid to Cinergy Receivables, Schedule D-2.32 ensures that there is no double recovery of the time value of money in the uncollectible expense. Consequently, the time value of money component of the discount being charged to Uncollectible Expense (Account 904) is eliminated from the forecasted test year expenses. The adjustment reduces expenses by $1,418,703. Note that the calculation of the gross revenue conversion factor (GRCF) includes only the portion of the discount rate not associated with the time value of money.

Q. PLEASE DESCRIBE SCHEDULE D-2.33.

A. Schedule D-2.33 is an adjustment required to normalize the cost of planned outages in the forecasted test period to reflect an average of the costs based on a six-year average. The effect of the adjustment on electric operations is an increase in pre-tax operating expenses of $1,005,775. The Commission recently approved a similar methodology for levelizing outage costs in approving base rates for Kentucky Utilities and Louisville Gas & Electric Company in Cases No. 2016-370 and 2016-371, respectively.

Q. PLEASE DESCRIBE SCHEDULE F-1.

A. Schedule F-1 sets forth the detail, by account, of Social and Service Club Dues for both the base and unadjusted forecasted test periods. All amounts are either charged below the line or have been removed from operating expenses on Schedule D-2.23 and, thus, not included in the forecasted test period revenue requirement.

Q. PLEASE DESCRIBE SCHEDULE F-2.1.

A. Schedule F-2.1 sets forth the detail, by account, of Charitable Contributions for both the base period and unadjusted forecasted test periods. All amounts are charged below the line and, thus, not included in the forecasted test period revenue requirement.

Q. PLEASE DESCRIBE SCHEDULE F-2.2.

A. Schedule F-2.2 indicates that the Initiation Fees and Country Club expenses for the base and forecasted test periods are included on Schedule F-1.

Q. PLEASE DESCRIBE SCHEDULE F-2.3.

A. Schedule F-2.3 sets forth the detail, by account of Employee Party, Outing, & Gift

Expense for both the base and forecasted test periods.

Q. PLEASE DESCRIBE SCHEDULE F-3.

A. Schedule F-3 sets forth the detail, by account, of Customer Service and Informational Expense, Sales Expense and General Advertising Expense for both the base and unadjusted forecasted test periods. Advertising costs included in Account 913 have been removed from operating expenses on Schedule D-2.23 and, thus, not included in the forecasted test period revenue requirement.

Q. PLEASE DESCRIBE SCHEDULE F-4.

A. Schedule F-4 sets forth additional details supporting advertising costs for both the base and unadjusted forecasted test periods. As noted above, these costs are not included in the forecasted test period revenue requirement.

Q. PLEASE DESCRIBE SCHEDULE F-5.

A. Schedule F-5 sets forth the detail of Professional Services Expenses for both the base and forecasted test periods.

Q. PLEASE DESCRIBE SCHEDULE F-6.

A. Schedule F-6, entitled "Rate Case Expense," indicates the estimated expense of presenting this case. The top half of this schedule details the estimated expense of this proceeding. Also included is a comparison to the rate case expense in the Company's last two rate case proceedings. The bottom half of this schedule shows the amortization over a five-year period. This amount is included in expense through the adjustment contained in Schedule D-2.17.

Q. PLEASE DESCRIBE SCHEDULE F-7.

A. Schedule F-7 sets forth Civic, Political and Related Expense for both the base and unadjusted forecasted test periods. All amounts are charged below the line and, thus, not included in the forecasted test period revenue requirement.

Q. PLEASE DESCRIBE SCHEDULE G-1.

A. Schedule G-1 contains a summary of all payroll costs and related benefits and taxes included in electric O&M expense for both the base and forecasted test periods.

Q. PLEASE DESCRIBE SCHEDULE H.

A. Schedule H, entitled "Computation of Gross Revenue Conversion Factor," sets forth the calculation of the GRCF. This is the factor, or multiplier, used to gross-up the operating income deficiency to a revenue deficiency amount. It includes an uncollectible accounts factor which represents the portion of the average total discount rate that is related to charge-offs, collection costs and late payment charges. Also included in the GRCF are the Kentucky Public Service Commission assessment, and state and federal income taxes. The GRCF is included on Schedule A and is used to compute the calculated revenue deficiency.

IV. FUEL ADJUSTMENT CLAUSE AND PROFIT SHARING MECHANISM

Q. DESCRIBE HOW THE COMPANY RECOVERS ITS FUEL COSTS.

A. Projected recoverable fuel costs through the end of the forecasted test period are included in the forecasted test period revenue requirement. Duke Energy Kentucky makes monthly Fuel Adjustment Clause (FAC) filings. These monthly FAC filings measure Duke Energy Kentucky's actual recoverable fuel costs against the amount included in base rates. Duke Energy Kentucky refunds or recovers the difference using the FAC pursuant to Commission regulation 807 KAR 5:056.

Q. IS THE COMPANY PROPOSING CHANGES TO ITS FAC?

A. Yes. As explained by Company witness Mr. John Swez, Duke Energy Kentucky has examined the nature of all PJM billing line items, costs and credits, to identify those specific line items that are related to fuel and that are appropriate for recovery through the Company's FAC.

Q. HOW WILL THE FAC RELFECT THE CHANGES DUKE ENERGY KENTUCKY IS PROPOSING?

A. The line item entitled "PJM Balancing and Day Ahead Operating Reserve Credit" on FAC Schedule 2, Section A will be changed to "Net Fuel Related PJM Billing Line Items" to incorporate the changes proposed by Mr. Swez. The same change will be made on Schedule 4 and Schedule 6.

Q. WHAT ADJUSTMENTS WILL THE COMPANY HAVE TO MAKE TO ITS REVENUE REQUIREMENT IF THE COMMISSION DISALLOWS THE MOVEMENT OF CERTAIN COSTS TO THE FAC?

A. The Company has made adjustments to its forecasted test year revenue requirement to include as fuel those charges that it is proposing to be recovered in the FAC. If the Commission disallows this proposal, then the forecasted test period revenue requirement will increase by $5,644,199. This amount is comprised of native congestion and losses and fuel related ancillary services as projected in the test period.

Q. WILL THE PROPOSED CHANGES TO THE FAC AFFECT THE RIDER PSM?

A. Yes. The changes proposed by Mr. Swez for fuel-related PJM billing line items will also result in changes to the PSM. The non-native portion of these PJM billing line items will be included in the calculation of the off-system sales margin.

Q. IS THERE OTHER CHANGES BEING PROPOSED TO RIDER PSM?

A. Yes. Duke Energy Kentucky witness Mr. William Don Wathen Jr. discusses the proposed changes to other components of the PSM and proposed changes to the profit sharing formula. Mr. Swez and Company witnesses Mr. John Verderame provide more detail on the proposed additional components to be included in the PSM.

Q. HAS THE COMPANY PROVIDED A REVISED TEMPLATE FOR THE PROPOSED CHANGES TO RIDER PSM?

A. Yes. Attached to my testimony is Attachment SEL-1 which provides a revised template for the Company's Rider PSM incorporating the changes mentioned above.

V. ENVIRONMENTAL SURCHARGE MECHANISM

Q. IS THE COMPANY PROPOSING AN ENVIRONMENTAL SURCHARGE MECHANISM?

A. Yes. As discussed in the testimony of Company witnesses Mr. Joseph A. Miller, Jr., Ms. Tammy Jett and Mr. Wathen, the Company is seeking to establish an ESM in accordance with KRS 278.183.

Q. HAS THE COMPANY DEVELOPED A TEMPLATE FOR THE PROPOSED ESM?

A. Yes. Attached to my testimony is Attachment SEL-2, which provides a template for the proposed ESM. In accordance with KRS 278.183, the Company will make monthly filings to establish new rider rates. The revenue requirement for the rider will include a return on the eligible environmental compliance rate base (*i.e.*, gross plant plus CWIP less accumulated depreciation less accumulated deferred income taxes plus emission allowances inventory). The revenue requirement will also include recovery of environmental operating expenses, including property taxes and depreciation expense associated with the incremental investment as well as environmental reagent expenses and the native portion of emission allowance expenses. The rider will also credit back to customers any proceeds from emission allowance sales.

VI. DISTRIBUTION CAPITAL INVESTMENT RIDER

Q. IS THE COMPANY PROPOSING A DISTRIBUTION CAPITAL INVESTMENT TRACKING MECHANISM?

A. Yes. As discussed in the testimony of Company witnesses Mr. Anthony Platz and Mr. Wathen, the Company is proposing to implement a distribution capital investment rider (Rider DCI) to recover the incremental revenue requirement associated with certain programs to proactively improve the reliability of its electric distribution system.

Q. HAS THE COMPANY DEVELOPED A TEMPLATE FOR THE PROPOSED RIDER?

A. Yes. Attached to my testimony is Attachment SEL-3, which provides a template for the proposed Rider DCI. Once approved, the Company will make annual applications to establish new rider rates based on actual net rate base as of the end of each calendar year, as well as any new programs to be introduced. The revenue requirement for the rider will include a return on the incremental in-service rate base (*i.e.*, gross plant less accumulated depreciation less accumulated deferred income taxes) and recovery of property taxes and depreciation expense associated with the incremental investment. The rider will only include incremental revenue requirement associated with the capital investment and will not include recovery of incremental O&M expenses.

VII. CONCLUSION

Q. WERE FR 16(6)(b), FR 16(6)(c), FR 16(6)(f), AND FR 16(7)(t), SCHEDULES A, B-1, C-1 THROUGH C-2.1, D-1, D-2.17 THROUGH D2.20, D-2.22, D-2.23, D-2.25 THROUGH D-2.27, D.29, AND D-2.31 THROUGH D-2.33, F-1 THROUGH F-7, G-1, H AND ATTACHMENTS SEL-1 THROUGH SEL-3 PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

VERIFICATION

STATE OF OHIO	**)**	
	)	**SS:**
COUNTY OF HAMILTON	**)**	

The undersigned, Sarah E. Lawler, Utility Strategy Director, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of her knowledge, information and belief.

Sarah E. Lawler Affiant

Subscribed and sworn to before me by Sarah E. Lawler on this 3RD day of AUGUST, 2017.

NOTARY PUBLIC

My Commission Expires:

NOTARY PUBLIC STATE OF OHIO

ANITA M. SCHAFER
Notary Public, State of Ohio
My Commission Expires
November 4, 2019

Schedule 1

DUKE ENERGY KENTUCKY
CALCULATION OF RIDER PSM CREDIT FOR MARCH 20XX - MAY 20XX BILLING

Line No.	Description	Jan-XX	Feb-XX	Mar-XX	Apr-XX	May-XX	Jun-XX	Jul-XX	Aug-XX	Sep-XX	Oct-XX	Nov-XX	Dec-XX		Total
		Billing Month													
1	Off-System Sales Margin Allocated to Customers (Schedule 2, Line 16)													(+)	$ -
2	Non-Fuel Related RTO Costs and Credits (Schedule 3, Line 13)													(+)	-
3	Net Proceeds on Capacity Transactions (Schedule 4, Line 11)													(+)	-
4	Net Proceeds from the Sale of Renewable Energy Credits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	(+)	-
5	Total														$ -
6	Percentage Allocated to Customers (90% of net margin)														90.00%
7	Total Allocated to Customers (Line 5 x Line 6)													(+)	$ -
8	Remaining PSM Credit due to (from) Customers at 12/31/XX (Schedule 5, Line 10)													(+)	-
9	Total Amount of Credits due to (from) Customers													(+)	$ -
10	Actual Amount Credited to Customers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	(-)	$0
11	Net Refund due to (from) Customers														$ -
12	Sales (kWh) from FAC Filing for the current quarter (FAC Schedule 3, Line C)										0	0	0	÷	0
13	Profit Sharing Mechanism Credit Rate ($/kWh) [(a)]														0

Note:

(a) Rider PSM credits, reductions to bills, are shown as positive numbers without parentheses.
Rider PSM charges, increases to bills, are shown in parentheses.

Effective Date for Billing: ______________________

Submitted by: ______________________

Title: ______________________

Date Submitted: ______________________

Schedule 2

DUKE ENERGY KENTUCKY
OFF-SYSTEM SALES SCHEDULE
PERIOD: YEAR TO DATE - DECEMBER 31, 20XX

Line No.	Description		Jan-XX	Feb-XX	Mar-XX	Apr-XX	May-XX	Jun-XX	Jul-XX	Aug-XX	Sep-XX	Oct-XX	Nov-XX	Dec-XX	Total
1	**Off-System Sales Revenue**														
2	Asset Energy	(+)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Non-Asset Energy	(+)	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Bilateral Sales	(+)	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Hedges	(+)	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Sub-Total Revenues		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	**Variable Costs Allocable to Off-System Sales**														
8	Bilateral Purchases	(+)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Non-Native Fuel Cost [a]	(+)	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Variable O&M Cost	(+)	-	-	-	-	-	-	-	-	-	-	-	-	-
11	SO_2 Cost	(+)	-	-	-	-	-	-	-	-	-	-	-	-	-
12	NO_x Cost	(+)	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Fuel Related PJM Costs and Credits[a]	(+)	-	-	-	-	-	-	-	-	-	-	-	-	-
14	(Gain)/Loss on Sale of Fuel	(+)	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Sub-Total Expenses		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	Off-System Sales Margin (Line 6 - Line 15)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Note:
[a] Line 9 + Line 13, ties to Duke Energy Kentucky's FAC Filing, Schedule 2, Schedule 4 or Schedule 6, Line C.

Schedule 3

DUKE ENERGY KENTUCKY
NON-FUEL RELATED RTO CHARGES AND CREDITS
PERIOD: YEAR TO DATE - DECEMBER 31, 20XX

Line No.	Description	PJM BLI	Jan-XX	Feb-XX	Mar-XX	Apr-XX	May-XX	Jun-XX	Jul-XX	Aug-XX	Sep-XX	Oct-XX	Nov-XX	Dec-XX	Total
1	Day-Ahead Economic Load Response	1240 / 2240	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Real-Time Economic Load Response	1241 / 2241	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Day-Ahead Load Response Charge Alloc	1242	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Real-Time Load Response Charge Alloc	1243	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Pre-Emergency and Emergency Load Response	1245 / 2245	-	-	-	-	-	-	-	-	-	-	-	-	-
6	PJM Reactive Supply	1330 / 2330	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Non-Syncchronized Reserve	1362 / 2362 / 1472	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Day-Ahead Scheduling Reserve	1365 / 2365 / 1475	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Day-Ahead Operating Reserve for Load Response	1371 / 2371	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Balancing Operating Reserve for Load Response	1376 / 2376	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Blackstart	1380 / 2380	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Other		-	-	-	-	-	-	-	-	-	-	-	-	-
13	Total		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Schedule 4

DUKE ENERGY KENTUCKY
CAPACITY TRANSACTIONS
PERIOD: YEAR TO DATE - DECEMBER 31, 20XX

Line No.	Description	PJM BLI		Jan-XX	Feb-XX	Mar-XX	Apr-XX	May-XX	Jun-XX	Jul-XX	Aug-XX	Sep-XX	Oct-XX	Nov-XX	Dec-XX	Total
1	**Capacity Sales Revenues**															
2	Revenue Received for Capacity Sales	2600	(+)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Bilateral Sales		(+)	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Capacity Performance Credits		(+)	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Sub-Total Revenues			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	**Capacity Purchase Expenses**															
7	Cost of Replacement Capacity	1600	(+)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Bilateral Purchases		(+)	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Capacity Performance Assessments		(+)	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Sub-Total Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Net Capacity Revenue (Expense) (Line 5 - Line 10)			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Schedule 5

DUKE ENERGY KENTUCKY
RECONCILIATION OF PRIOR PERIOD
PERIOD: YEAR TO DATE - DECEMBER 31, 20XX

Line No.	Description		Total
1	Off-System Sales Margin Allocated to Customers	(+)	$ -
2	Non-Fuel Related PJM Costs and Credits	(+)	-
3	Net Margins on Capacity Transactions Allocated to Customers	(+)	-
4	Net Proceeds on the Sale of Solar RECs	(+)	-
5	Sub-Total		$ -
6	Percentage Allocated to Customers (90% of net margin)		90.00%
7	Total Allocated to Customers (Line 5 x Line 6)	(+)	$ -
8	Prior Period Over (Under) Recovery	(+)	-
9	Actual Amount Credited to Customers 20XX	(-)	-
10	Remaining PSM Credit Due to (From) Customer at 12/31/XX		$ -

ES FORM 1.00

DUKE ENERGY KENTUCKY, INC.
ENVIRONMENTAL SURCHARGE REPORT

Calculation of Monthly Environmental Surcharge Factor

For the Expense Month of April 2018

MESF = CESF - BESF

Where:

CESF = Current Period Environmental Surcharge Factor

BESF = Base Period Environmental Surcharge Factor

MESF = Monthly Environmental Surcharge Factor

Calculation of MESF:	**Source**		**Residential**	**Non-Residential**
CESF	ES Form 1.10	=	0.00%	0.00%
BESF	Case No. 2017-00321	=	0.00%	0.00%
MESF		=	0.00%	0.00%

Effective Date for Billing: ____________________

Submitted by: ____________________

Title: ____________________

Date Submitted: ____________________

ES FORM 1.10

DUKE ENERGY KENTUCKY, INC.
ENVIRONMENTAL SURCHARGE REPORT

Calculation of Current Month Environmental Surcharge Factors

Line No.	E(m) = RORB + OE - EAS + Prior Period Adjustment + (Over)/Under Recovery	Source		Environmental Compliance Plans
1	Environmental Compliance Rate Base (RB)	ES Form 2.00		$ -
2	RB ÷ 12 months	(1) ÷ 12		$ -
3	Pretax Rate of Return (ROR)	ES Form 1.20		10.23%
4	Return on the Environmental Compliance Rate Base (RORB)	(2) x (3)		$ -
5	Environmental Operating Expenses (OE)	ES Form 2.00	+	$ -
6	Less: Proceeds from Emission Allowance Sales (EAS)	ES Form 2.00	-	$ -
7	Sub-Total E(m)	(4) + (5) - (6)		$ -
8	Jurisdictional Allocation Ratio for Expense Month	(A)		100.00%
9	Jurisdictional E(m)	(7) x (8)		$ -
10	Prior Period Adjustment (if necessary)	(B)	+	$ -
11	Adjustment for (Over)/Under Recovery	ES Form 2.00	+	$ -
12	Total Jurisdictional E(m)	(9) + (10) + (11)		$ -

Calculation of Environmental Surcharge Billing Factors

			Residential	Non-Residential
13	Revenues as a Percentage of Total Revenues	ES Form 3.00	0.00%	0.00%
14	Jurisdictional E(m) - Allocated	(11) x (12)	$ -	$ -
15	R(m) = Average Monthly Revenue for the 12 Months Ending with the Current Expense Month	ES Form 3.00	$ -	$ -
16	CESF: Jurisdictional E(m) / R(m)	(13) ÷ (14)	0.00%	0.00%

Note: (A) Duke Energy Kentucky has no firm wholesale customers.
(B) Amounts determined by the Commission during six-month and two-year reviews.

DUKE ENERGY KENTUCKY, INC.
ENVIRONMENTAL SURCHARGE REPORT

Cost of Capital

Line No.	Capital Structure	Ratio	Cost	Weighted Cost (A)	Gross up for Tax Rate (B)	Pre-Tax Rate of Return (A)x(B)
1	Short-term Debt	10.428%	3.083%	0.321%		0.321%
2	Long-term Debt	40.679%	4.243%	1.726%		1.726%
3	Common Equity	48.893%	10.300%	5.036%	1.6253392	8.185%
4	Total	100.000%		7.083%		10.232%

Note: Capital structure and cost of debt as requested in this case per Schedule J-1 page 2.
Gross up for tax rate per Schedule H excluding uncollectible accounts expenses and KPSC maintenance tax factors.

ES FORM 2.00

DUKE ENERGY KENTUCKY, INC.
ENVIRONMENTAL SURCHARGE REPORT

Revenue Requirement of Environmental Compliance Costs

For the Expense Month of April 2018

Line No.	Determination of Environmental Compliance Rate Base (RB)	Source	Amount
1	Eligible Environmental Compliance Plant (Gross Plant)	ES Form 2.10	$ -
2	Eligible Environmental Compliance CWIP Excluding AFUDC	ES Form 2.10	$ -
3	Subtotal		$ -
4	Additions:		
5	Inventory - Emission Allowances	ES Form 2.30	$ -
6	Subtotal		$ -
7	Deductions:		
8	Accumulated Depreciation on Eligible Environmental Compliance Plant	ES Form 2.10	$ -
9	Accumulated Deferred Income Taxes on Eligible Environmental Compliance Plant	ES Form 2.10	$ -
10	Accumulated Deferred Investment Tax Credits (ITC) on Eligible Environmental Compliance Plant	ES Form 2.10	$ -
11	Subtotal		$ -
12	Environmental Compliance Rate Base		$ -
13	**Determination of Environmental Compliance Operating Expenses (OE)**		
14	Monthly Depreciation Expense	ES Form 2.10	$ -
15	Monthly Taxes Other Than Income Taxes	ES Form 2.10	$ -
16	Monthly Amortization Expense	ES Form 2.20	$ -
17	Monthly Emission Allowance Expense	ES Form 2.30	$ -
18	Monthly Enivronmental Reagent Expense	ES Form 2.50	$ -
19	Total Environmental Compliance Operating Expense		$ -
20	**Proceeds from Emission Allowance Sales (EAS)**		
21	SO_2 Allowance Sales		$ -
22	NOx Allowances Sales		$ -
23	Total Emission Allowance Sales		$ -
24	**(Over) / Under Recovery**		
25	Net Jurisdictional E(m) Authorized for Expense Month two Months Prior		
26	Jurisdictional E(m) Revenue Recovered in Current Expense Month		
27	(Over) / Under Recovery		$ -

Note: (Over) recovery will be deducted from Jurisdictional E(m)
Under recovery will be added to Jurisdictional E(m)

ES FORM 2.10

DUKE ENERGY KENTUCKY, INC.
ENVIRONMENTAL SURCHARGE REPORT

Plant, Accumulated Depreciation, CWIP, ITC, ADIT
Depreciation Expense, Taxes Other Than Income Taxes

For the Expense Month of April 2018

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Project No.	Description	Gross Plant in-Service as of April-18	Accumulated Depreciation as of April-18	Net Plant in-Service as of April-18	CWIP Excluding AFUDC as of April-18	Accumulated Deferred ITC as of April-18	Accumulated Deferred Tax Balance as of April-18	Monthly Depreciation Expense	Monthly Property Tax Expense
				(2)-(3)					
1	EB020290 Lined Retention Basin West	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	EB020745 Lined Retention Basin East	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	EB020298 East Bend SW/PW Reroute	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4				$ -					
5				$ -					
6				$ -					
7				$ -					
8				$ -					
9				$ -					
10				$ -					
11				$ -					
12				$ -					
13				$ -					
14				$ -					
15				$ -					
		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ES FORM 2.20

DUKE ENERGY KENTUCKY, INC.
ENVIRONMENTAL SURCHARGE REPORT

Amortization Calculation for Coal Ash ARO

Line No.	Period (1)		Cash Spend (2)	COR Credit (3)	Carrying Cost (4)	Recovery (5)	Ending Balance (6)
1	2015 Total	*Actual*					$0
2	2016 Total	*Actual*					-
3	Jan-17	*Actual*					-
4	Feb-17	*Actual*					-
5	Mar-17	*Actual*					-
6	Apr-17	*Actual*					-
7	May-17	*Actual*					-
8	Jun-17	*Actual*					-
9	Jul-17	*Projection*					-
10	Aug-17	*Projection*					-
11	Sep-17	*Projection*					-
12	Oct-17	*Projection*					-
13	Nov-17	*Projection*					-
14	Dec-17	*Projection*					-
15	Jan-18	*Projection*					-
16	Feb-18	*Projection*					-
17	Mar-18	*Projection*					-
18	Apr-18	*Projection*					-
19	May-18	*Projection*					-
20	Jun-18	*Projection*					-
21	Jul-18	*Projection*					-
22	Aug-18	*Projection*					-
23	Sep-18	*Projection*					-
24	Oct-18	*Projection*					-
25	Nov-18	*Projection*					-
26	Dec-18	*Projection*					-
27	Jan-19	*Projection*					-
28	Feb-19	*Projection*					-
29	Mar-19	*Projection*					-
30	Apr-19	*Projection*					-
31	May-19	*Projection*					-
32	Jun-19	*Projection*					-
33	Jul-19	*Projection*					-
34	Aug-19	*Projection*					-
35	Sep-19	*Projection*					-
36	Oct-19	*Projection*					-
37	Nov-19	*Projection*					-
38	Dec-19	*Projection*					-
39	Jan-20	*Projection*					-
40	Feb-20	*Projection*					-
41	Mar-20	*Projection*					-
42	Apr-20	*Projection*					-
43	May-20	*Projection*					-
44	Jun-20	*Projection*					-
45	Jul-20	*Projection*					-
46	Aug-20	*Projection*					-
47	Sep-20	*Projection*					-
48	Oct-20	*Projection*					-
49	Nov-20	*Projection*					-
50	Dec-20	*Projection*					-
51	Jan-21	*Projection*					-
52	Feb-21	*Projection*					-
53	Mar-21	*Projection*					-
54	Apr-21	*Projection*					-
55	May-21	*Projection*					-
56	Jun-21	*Projection*					-
57	Jul-21	*Projection*					-
58	Aug-21	*Projection*					-
59	Sep-21	*Projection*					-
60	Oct-21	*Projection*					-
61	Nov-21	*Projection*					-
62	Dec-21	*Projection*					-
63	Jan-22	*Projection*					-
64	Feb-22	*Projection*					-
65	Mar-22	*Projection*					-
66	Apr-22	*Projection*					-
67	May-22	*Projection*					-
68	Jun-22	*Projection*					-
69	Jul-22	*Projection*					-
70	Aug-22	*Projection*					-
71	Sep-22	*Projection*					-
72	Oct-22	*Projection*					-
73	Nov-22	*Projection*					-
74	Dec-22	*Projection*					-
75	Jan-23	*Projection*					-
76	Feb-23	*Projection*					-
77	Mar-23	*Projection*					-
78	Apr-23	*Projection*					-

ES FORM 2.20

DUKE ENERGY KENTUCKY, INC.
ENVIRONMENTAL SURCHARGE REPORT

Amortization Calculation for Coal Ash ARO

Line No.	Period (1)		Cash Spend (2)	COR Credit (3)	Carrying Cost (4)	Recovery (5)	Ending Balance (6)
79	May-23	*Projection*					-
80	Jun-23	*Projection*					-
81	Jul-23	*Projection*					-
82	Aug-23	*Projection*					-
83	Sep-23	*Projection*					-
84	Oct-23	*Projection*					-
85	Nov-23	*Projection*					-
86	Dec-23	*Projection*					-
87	Jan-24	*Projection*					-
88	Feb-24	*Projection*					-
89	Mar-24	*Projection*					-
90	Apr-24	*Projection*					-
91	May-24	*Projection*					-
92	Jun-24	*Projection*					-
93	Jul-24	*Projection*					-
94	Aug-24	*Projection*					-
95	Sep-24	*Projection*					-
96	Oct-24	*Projection*					-
97	Nov-24	*Projection*					-
98	Dec-24	*Projection*					-
99	Jan-25	*Projection*					-
100	Feb-25	*Projection*					-
101	Mar-25	*Projection*					-
102	Apr-25	*Projection*					-
103	May-25	*Projection*					-
104	Jun-25	*Projection*					-
105	Jul-25	*Projection*					-
106	Aug-25	*Projection*					-
107	Sep-25	*Projection*					-
108	Oct-25	*Projection*					-
109	Nov-25	*Projection*					-
110	Dec-25	*Projection*					-
111	Jan-26	*Projection*					-
112	Feb-26	*Projection*					-
113	Mar-26	*Projection*					-
114	Apr-26	*Projection*					-
115	May-26	*Projection*					-
116	Jun-26	*Projection*					-
117	Jul-26	*Projection*					-
118	Aug-26	*Projection*					-
119	Sep-26	*Projection*					-
120	Oct-26	*Projection*					-
121	Nov-26	*Projection*					-
122	Dec-26	*Projection*					-
123	Jan-27	*Projection*					-
124	Feb-27	*Projection*					-
125	Mar-27	*Projection*					-
126	Apr-27	*Projection*					-
127	May-27	*Projection*					-
128	Jun-27	*Projection*					-
129	Jul-27	*Projection*					-
130	Aug-27	*Projection*					-
131	Sep-27	*Projection*					-
132	Oct-27	*Projection*					-
133	Nov-27	*Projection*					-
134	Dec-27	*Projection*					-
135	Jan-28	*Projection*					-
136	Feb-28	*Projection*					-
137	Mar-28	*Projection*					-
138	Apr-28	*Projection*					-
139	May-28	*Projection*					-
			-	-	-	-	

Amortization Period (yrs)	10
Monthly Amortization Amount	-
Annualized Amortization Amount	-

ES FORM 2.30

DUKE ENERGY KENTUCKY, INC.
ENVIRONMENTAL SURCHARGE REPORT

Inventory and Expense of Emission Allowances

For the Expense Month Ending April 2018

Total SO_2 and NOx Emission Allowances					
	Beginning Inventory	Allocations / Purchases	Utilized	Sold	Ending Inventory
SO_2 Allowances					
Quantity	-	-	-	-	-
Dollars	$ -	$ -	$ -	$ -	$ -
$/Allowance	$ -	$ -	$ -	$ -	$ -
NOx Allowances					
Quantity	-	-	-	-	-
Dollars	$ -	$ -	$ -	$ -	$ -
$/Allowance	$ -	$ -	$ -	$ -	$ -
Total Emission Allowances					
Quantity	-	-	-	-	-
Dollars	$ -	$ -	$ -	$ -	$ -

ES FORM 2.50

DUKE ENERGY KENTUCKY, INC.
ENVIRONMENTAL SURCHARGE REPORT

Environmental Reagent Expenses

For the Expense Month of April 2018

Line No.	Expense Type	Account Number	East Bend Unit 2	Total
1	Ammonia	502020	$ -	$ -
2	Limestone	502040	$ -	$ -
3	Trona	502040	$ -	$ -
4	Total		$ -	$ -

ES FORM 3.00

DUKE ENERGY KENTUCKY, INC.
ENVIRONMENTAL SURCHARGE REPORT

Monthly Average Revenue Computation of R(m) for Residential and Non-Residential Customers

For the Expense Month of April 2018

Residential - Kentucky Jurisdictional Revenues							
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Month	Non-Fuel Base Rate Revenues	Base Rate Fuel Component	Fuel Clause Revenues	Other Rider Revenues	Environmental Surcharge Revenues	Total	Total Excluding Environmental Surcharge
						(2) thru (6)	(7) - (6)
May-17	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Jun-17	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Jul-17	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Aug-17	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sep-17	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oct-17	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Nov-17	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dec-17	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Jan-18	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Feb-18	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mar-18	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Apr-18	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Monthly Residential Revenues, Excluding Environmental Surcharge, for 12 Months Ending Current Expense Month							$ -
Average Total Kentucky Revenues, Excluding Environmental Surcharge, for 12 Months Ending Current Expense Month							$ -
Residential Revenues as a Percentage of Total Revenues for 12 Months Ending with the Current Expense Month							0.00%

Non-Residential - Kentucky Jurisdictional Revenues								
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Month	Non-Fuel Base Rate Revenues	Base Rate Fuel Component	Fuel Clause Revenues	Other Rider Revenues	Environmental Surcharge Revenues	Total	Total Excluding Environmental Surcharge	Total Non-Fuel Revenue
						(2) thru (6)	(7) - (6)	(8) - (3) - (4)
May-17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Jun-17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Jul-17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Aug-17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sep-17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oct-17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Nov-17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dec-17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Jan-18	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Feb-18	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mar-18	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Apr-18	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Monthly Non-Residential Revenues, Excluding Environmental Surcharge, for 12 Months Ending Current Expense Month							$ -	$ -
Average Total Kentucky Revenues, Excluding Environmental Surcharge, for 12 Months Ending Current Expense Month							$ -	
Non-Residential Revenues as a Percentage of Total Revenues for 12 Months Ending with the Current Expense Month							0.00%	

Summary

Duke Energy Kentucky
Annual Rider DCI Filing
Actual Year Ending December 31, 2018
Table of Contents

Schedule 1.0

Duke Energy Kentucky
Annual Adjustment to Distribution Capital Investment Plan (DCI)
DCI Rider by Rate Schedule

Line No.	Rate Schedule		Revenue Requirement	Billing Determinants # of Bills	Monthly DCI Rider	
1	RS, Residential Service	60.845%	-			Per kwh
2	DS, Service at Secondary Distribution Voltage	22.131%	-			Per kw
3	GS-FL, Optional General Service Rate for Small Fixed Loads	0.129%	-			Per kwh
4	EH, Optional Rate for Electric Space Heating	0.464%	-			Per kwh
5	SP, Seasonal Sports Service	0.008%	-			Per kwh
6	DT, Time-of-Day Rate for Servie at Distribution Voltage - Secondary	9.301%	-			Per kw
7	DT, Time-of-Day Rate for Servie at Distribution Voltage - Primary	6.365%	-			Per kw
8	DP, Service at Primary Distribution Voltage	0.216%	-			Per kw
9	Lighting (SL,TL,UOLS,NSU,SC,SE and LED)	0.535%	-			Per kwh
10	Other Water Pumping	0.006%	-			Per kwh
11	Total	100.000%	-	-		

Notes:
(1) Rate allocation is based on Factor K405 (Underground/Secondary) which is an allocation based on customer count

Duke Energy Kentucky
Annual Adjustment to Distribution Capital Investment Plan (DCI)
Revenue Requirement

Line No.		DCI Investment December 31, 2018	Reference	
	Return on Investment			
	Rate Base			
1	Net Investment - Property, Plant and Equipment	$ -	Schedule 2.0	
2	Cost of Removal	-	Schedule 2.0	
3	Accumulated Reserve for Depreciation	-	Schedule 2.0	
4	Net PP&E	-		
5	Accumulated Deferred Income Taxes	-	Schedule 2.1	
6	Net Rate Base	-	Line 4 + Line 5	
7	Authorized Rate of Return, Adjusted for Income Taxes	10.23%	Schedule 1.2	
8	Required Return on DCI Related Investment	-	Line 6 * Line 7	
	Operating Expenses			
9	Depreciation	-	Shedule 2.0	
10	Property Tax	-	Line 4 *	1.250%
11	PSC Assessment	-	(Sum Line 8 thru 10) * (.1996% / (1-.1996%))	
12	Total Operating Expenses	-	Sum Lines 9 thru 11	
13	**Total Annual Revenue Requirement**	-	Line 8 + Line 12	

Notes:
(1) Property taxes estimated using an effective rate of 1.25%
(2) based on most recent PSC Assessment of .1996%

Duke Energy Kentucky
Annual Adjustment to Distribution Capital Investment Plan (DCI)
Cost of Capital

Line No.	Capital Structure	Ratio	Cost	Weighted Cost (A)	Gross up for Tax Rate (B)	Pre-Tax Rate of Return (A)x(B)
1	Short-term Debt	10.428%	3.083%	0.321%		0.321%
2	Long-term Debt	40.679%	4.243%	1.726%		1.726%
3	Common Equity	48.893%	10.300%	5.036%	1.6253392	8.185%
4	Total	100.000%		7.083%		10.232%

Note: Capital structure and cost of debt as requested in this case per Schedule J-1 page 2.
Gross up for tax rate per Schedule H excluding uncollectible accounts expenses and KPSC maintenance tax factors.

Duke Energy Kentucky
Annual Adjustment to Distribution Capital Investment Plan (DCI)
Plant, Additions, Retirements, Cost of Removal and Depreciation

Line No.	Description (1)	Acct Number (2)	2018 Additions & Retirements (3)	Depr Rates (4)	Current Year Depr on Adds / (Ret.) (5) = (3) * (4)
1	**Beginning Plant In Service/Accumulated Depreciation**		0		0
	Additions				
2	Underground Lines	380	-		-
3	Total Additions		-		-
	Retirements				
4	Underground Lines	380	-		-
5	Total Retirements		-		-
6	**Total Plant In Service/Accumulated Depreciation**		-		-
	Cost of Removal				
7	Underground Lines	380	-		
8	Total Cost of removal		-		-

Notes:
(1) See Form 2.2 for detail of 2018 eligible additions.

Duke Energy Kentucky
Annual Adjustment to Distribution Capital Investment Plan (DCI)
Tax Depreciation

Line No.			Tax Year 2018 Vintage 2018
1	Total Plant Additions		
	Tax Base In-service subject to :		
2	Bonus Depreciation- 50%		0
3	MACRS		0
4	Tax Depreciation		
5	Bonus Depreciation- 50%		0
6	MACRS on Balance		0
7	Total Tax Depreciation		0
8	Book Depreciation		0
9	Tax Depreciation in Excess of Book Depreciation		0
10	Cost of Removal		0
11	Total Difference		0
10	Deferred Taxes @	38.47%	0

Duke Energy Kentucky
Annual Adjustment to Distribution Capital Investment Plan (DCI)
Additions and Retirements by Month

Calendar year 2018 Actual Capex in service

Line No.	Month	Capex-2018	Retirements	Cost of Removal
1	Jan-18			
2	Feb-18			
3	Mar-18			
4	Apr-18			
5	May-18			
6	Jun-18			
7	Jul-18			
8	Aug-18			
9	Sep-18			
10	Oct-18			
11	Nov-18			
12	Dec-18			
		-	-	-

Direct Testimony of
Cynthia S. Lee

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; 3) Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All Other Required Approvals and Relief.	))))))))))	Case No. 2017-0321

DIRECT TESTIMONY OF

CYNTHIA S. LEE

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC

September 1, 2017

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PAGE

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Cynthia S. Lee, and my business address is 550 South Tryon Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services LLC (DEBS), as Director, Asset Accounting. DEBS provides various administrative and other services to Duke Energy Kentucky, Inc., (Duke Energy Kentucky or Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I am a graduate of Rollins College, with a Bachelor of Arts degree in Economics, and a graduate of The Johns Hopkins University, with a Master of Business Administration. I am a Certified Public Accountant in the State of North Carolina. I am also a member of the Edison Electric Institute Property Accounting and Valuation Committee.

I began my employment with Duke Energy in 2002 in the Accounting Department for Progress Energy Service Company, predecessor to what is now DEBS. My responsibilities included oversight of financial reporting, general and regulatory accounting and asset accounting. I transitioned into my current position as the leader of the asset accounting group within Duke Energy's Regulated Utilities business segment in January 2015.

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR, ASSET ACCOUNTING.

A. As Director, Asset Accounting, I have responsibility for the accounting activities within Duke Energy's Electric and Gas Utilities and Infrastructure related to fixed assets, including electric plant in service, construction work in progress (CWIP), depreciation and asset retirement obligations, materials and supplies inventory, and fuel (including both inventory and payment of fuel invoices) and emission allowances.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I am responsible for actual net plant in service and construction work in progress contained in rate base and other actual plant-related items that Duke Energy Kentucky witness, Mr. Robert "Beau" Pratt uses in his testimony. In particular, I sponsor the following Schedules in satisfaction of Filing Requirements (FR) 16(8)(b): B-2, B-2.1, B-2.2, B-2.3, B-2.4, B-2.5, B-2.6, B-2.7, B-3, B-3.1, B-3.2, B-4. I sponsor the following Schedules in satisfaction of FR 16(6)(b) and FR 16(8)(d): D-2.16, D-2.21, and D-2.24, as well as the actual plant data on Schedule K page 1, and the composite depreciation rates on Schedule K, both being in response to FR 16(8)(k). The source and sponsor of the budgeted and projected data as shown on these schedules is Mr. Pratt. The source and sponsor of the proposed depreciation and amortization accrual rates used in these schedules, including the supporting depreciation study, is Company witness John J. Spanos. Finally, I discuss the Company's proposal to account for the asset retirement obligation (ARO) that was approved by the Commission related to the need to close the ash pond (*i.e.* ash basin) at the East Bend Generating Station (East Bend) as a direct result of the April 2015 publication of the coal combustion residual final rule (CCR Final Rule). I sponsor Attachment CSL-1, Recovery of Spend Related to Coal Ash Basin Closure.

II. SCHEDULES SPONSORED BY WITNESS

Q. PLEASE DESCRIBE THE INFORMATION CONTAINED IN THE SECTION B SCHEDULES.

A. The Section B schedules develop the Jurisdictional Net Plant In Service. The schedules are based on the Company's budget records as of the end of the base period (November 30, 2017) and the end of the forecast period (March 31, 2019).

Q. PLEASE DESCRIBE SCHEDULE B-2.

A. Schedule B-2 shows the plant in service including allocated common plant by major property grouping for the base period and the 13-month average as of the plant valuation date of March 31, 2019. The amount shown in the column labeled "Adjusted Jurisdiction" on page 1 of 2, and "13-Month Average Adjusted Jurisdiction" on page 2 of 2, represents plant in service that is deemed used and useful in providing electric service to our Kentucky jurisdictional customers.

Q. PLEASE DESCRIBE SCHEDULE B-2.1.

A. Schedule B-2.1 consists of a further breakdown of Schedule B-2 by the Federal

Energy Regulatory Commission (FERC) and Company Account for each major property grouping for the base period and the forecast period. The plant in service investment shown in the column labeled "Adjusted Jurisdiction" on pages 1 through 6, and "13-Month Average Adjusted Jurisdiction" on pages 7 through 12, represents electric plant in service including allocated common plant that is deemed used and useful in providing electric service to the Company's Kentucky jurisdictional customers.

Q. PLEASE DESCRIBE SCHEDULE B-2.2.

A. Schedule B-2.2 shows proposed adjustments to plant in service for the base period and the forecast period. The adjustments shown on this schedule are related to the Steam Production ARO Balances, street lighting balances, and meter balances. The adjustment for ARO is made to remove the ARO balances out of rate base for separate recovery under the Company's proposed environmental surcharge mechanism. The lighting adjustments remove customer lighting balances that are recovered through separate tariffs from rate base. Finally, the adjustment related to meters is for meters that will be replaced under the Advanced Metering Infrastructure (AMI) program. This adjustment reduces the amounts in rate base to only represent meters that will still be in-service after the completion of the Metering Upgrade Project. The remaining net book value of meters being replaced will be moved to a regulatory asset as authorized in the order from Case No. 2016-00152.

Q. PLEASE DESCRIBE SCHEDULE B-2.3.

A. Schedule B-2.3 shows gross additions, retirements and transfers by FERC and

Company Account for each major property grouping for the base period and the forecast period.

Q. PLEASE DESCRIBE SCHEDULE B-2.4.

A. Schedule B-2.4 is entitled "Property Merged or Acquired" for the base period and the forecast period. Duke Energy Kentucky projects that no property will be merged or acquired during the forecast period, so no items appear in this schedule.

Q. PLEASE DESCRIBE SCHEDULE B-2.5.

A. Schedule B-2.5 is entitled "Leased Property" and provides data for the base period and the forecast period. Duke Energy Kentucky began leasing new electric meters in 1999. Duke Energy Kentucky also entered into a lease for a building on Cox Road in Erlanger, Kentucky in 2005 to house its gas and electric construction and maintenance operations. Schedule B-2.5 contains the cost of electric meters and the cost associated with the building lease prior to allocation. The schedule also shows the monthly payment made for each of the leases.

Q. PLEASE DESCRIBE SCHEDULE B-2.6.

A. Schedule B-2.6 shows the property held for future use included in rate base for the base period and forecast period. The Company has not included any property held for future use in rate base.

Q. PLEASE DESCRIBE SCHEDULE B-2.7.

A. Schedule B-2.7 contains data on utility property excluded from rate base for the base period and forecast period. There are no exclusions of utility property from rate base.

Q. PLEASE DESCRIBE SCHEDULE B-3.

A. Schedule B-3 shows the total plant investment and Reserve for Accumulated Depreciation and Amortization by FERC and Company Account grouping for the base period and the forecast period. The amounts for the forecast period on pages 7 through 12 are 13-month averages. The adjusted jurisdictional reserve in the last column is applicable to the jurisdictional plant shown on Schedule B-2, "Adjusted Jurisdiction" and "13-Month Average Adjusted Jurisdiction."

Q. PLEASE DESCRIBE SCHEDULE B-3.1.

A. Schedule B-3.1 shows adjustments to Accumulated Depreciation and Amortization for the base period and the forecast period. The adjustments shown on this schedule are the related accumulated depreciation balances for the adjustments to Plant in Service shown on Schedule B-2.2, which are described above.

Q. PLEASE DESCRIBE SCHEDULE B-3.2.

A. Schedule B-3.2 lists the 13-month average jurisdictional plant investment and reserve balance as of March 31, 2019 for each FERC and Company Account within each major property grouping. It also shows the proposed depreciation and amortization accrual rate, calculated annual depreciation and amortization expense, percentage of net salvage value, average service life and curve form, as applicable for each account. The calculated annual depreciation and amortization was determined by multiplying the 13-month average adjusted jurisdictional plant investment for the forecast period by the proposed depreciation and amortization accrual rates.

With this filing, the Company filed with the Commission proposed depreciation and amortization accrual rates prepared in 2017 and sponsored by Mr. Spanos of Gannett Fleming, Inc., who prepared the depreciation study. The account numbers referred to in the depreciation study were those in effect in 2017 for Duke Energy Kentucky. The Company requests that the Commission approve these new depreciation and amortization accrual rates included in this filing and that the depreciation and amortization accrual rates be effective April 1, 2018, corresponding with the effective date of the electric rates established in this case.

Q. PLEASE DESCRIBE SCHEDULE B-4.

A. Schedule B-4 is a list of construction work in progress by major property grouping. Construction Work in Progress (CWIP) is broken down by amounts subject to Allowance for Funds Used During Construction (AFUDC) and amounts not subject to AFUDC.

Q. PLEASE DESCRIBE SCHEDULE D-2.16

A. Per the order in Case No. 2016-00152 Duke Energy Kentucky was authorized to establish a regulatory asset for the actual costs of the balance of the undepreciated value of the existing metering infrastructure, including inventory, upon retirement of the meters as part of the AMI Metering Upgrade project. This schedule shows the amortization of this regulatory asset. For purposes of this schedule, Duke Energy Kentucky has estimated the amount of the regulatory asset to be $6,958,958, which yields an annual amortization expense of $463,931. The Metering Upgrade project is expected to be completed by the end of 2018. As such, to estimate the regulatory asset balance, Duke Energy Kentucky used the net book value as of May 31, 2017, and projected the net book value forward by assuming on average 10 months of depreciation. The values are estimated and will vary based on the pace of retirements experienced through the Metering Upgrade project. Meters that are in-service will continue to depreciate until they are replaced and once they have been replaced, the remaining net book value will be moved to the regulatory asset. The final balance of the regulatory asset will be trued-up at the completion of the Metering Upgrade project.

Q. PLEASE DESCRIBE SCHEDULE D-2.21

A. Per the order in Case No. 2015-00120, Duke Energy Kentucky was authorized to establish a regulatory asset for depreciation expense associated with the Company's acquisition of a 31% interest in East Bend from Dayton Power & Light Company. The regulatory asset is for the difference in annual depreciation expense resulting from application of FERC required depreciation calculations and the amounts originally intended by Duke Energy Kentucky to recover the interest purchased over the remaining life of East Bend. Per the order, Duke Energy Kentucky will begin amortizing the regulatory asset once the acquired interest is fully depreciated under the FERC-required depreciation methodology. The balance of the regulatory asset at March 31, 2018 will be $11,529,520. The estimated remaining life of East Bend is approximately 23.5 years, which results in annual amortization of $490,618.

Q. PLEASE DESCRIBE SCHEDULE D-2.24

A. Schedule D-2.24 reflects the adjustment to the forecasted period depreciation expense to reflect annualized depreciation expense as calculated on Schedule B-3.2.

Schedule B-3.2 shows annual depreciation on 13-month average plant balance at March 31, 2019, using the new proposed depreciation rates.

Q. PLEASE DESCRIBE THE INFORMATION YOU SPONSOR IN SCHEDULE K.

A. I sponsor the actual plant data submitted on page 1 of Schedule K. This information includes Plant in Service by major property grouping and Reserve for Accumulated Depreciation and Amortization by utility service for the 13-month average forecast period, for the base period and as of December 31 for each of the last ten years. Plant held for future use and construction work in progress have also been provided for the same periods. I also sponsor the composite depreciation rates shown on Schedule K.

Q. PLEASE PROVIDE A BACKGROUND OF THE CCR FINAL RULE AS IT RELATES TO EAST BEND ASH BASIN CLOSURE.

A. In June 2010, the United States Environmental Protection Agency (EPA) proposed national minimum criteria to regulate the disposal of Coal Combustion Residuals (CCRs) and the operation and closure of active CCR landfills and existing active and inactive CCR surface impoundments. Approximately five years later, EPA published the CCR Final Rule in the Federal Register in April 2015. The ash basin at East Bend must be closed under this program, and the Company has begun the closing process.

Although minor post-closure maintenance of the ash basin is estimated to continue through 2049, the majority of the costs related to the closure of the East Bend ash basin will be completed by the end of 2019. The total requested recovery amount proposed to be collected over a ten-year period (2018-2028) is $39.8 million (excluding post-closure maintenance), which includes $28.9 million in ash basin closure costs through the ten-year period and $12.0 million due to carrying costs on the unrecovered coal ash spend regulatory asset (as approved in Final Order - Case 2015-00187 on December 15, 2015) partially offset by a $1.1 million reduction due to the cost of removal (COR) credit. This COR credit is needed to adjust for the portion of current collection through depreciation rates associated with ash pond closure. This COR credit will not be included in depreciation rates upon adoption of the updated depreciation study filed by Mr. Spanos.

The actions necessary for Duke Energy Kentucky to comply with the requirements of the CCR Final Rule were included in the Certificate of Public Convenience and Necessity (CPCN) that was approved in the Final Order for Case No. 2016-00398 on June 6, 2017. This CPCN specifies the nature, timing, and expected amount of costs. Per this Order, Duke Energy Kentucky obtained approval to construct new water redirection and wastewater treatment processes and to close and repurpose its existing coal ash basin at East Bend. The proposed recovery addressed in this testimony specifically relates to the costs necessary to close the existing ash basin at East Bend, which is included in this approved CPCN.

The Company has recorded an ARO as a result of this legal obligation to close the East Bend ash basin in accordance with the CCR Final Rule. My testimony and exhibit support the reasonableness of the ARO associated with these required coal ash basin closure costs and the proposed recovery schedule.

Q. PLEASE DESCRIBE THE COAL ASH ARO

A. In accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification for Asset Retirement and Environmental Obligations (ASC 410-20) and FERC's Order No. 631, Duke Energy Kentucky records an ARO when it has a legal obligation to incur retirement costs associated with the retirement of a long-lived asset and the obligation can be reasonably estimated.

The ARO Duke Energy Kentucky has recorded resulting from this CCR Final Rule uses costs based on management's best estimates of required underlying activities and at fair value, as required under Generally Accepted Accounting Principles (GAAP) under ASC 410-20. Actual costs incurred through June 2017 total \$11.4 million and the remaining balance of \$17.6 million in the proposed recovery schedule represents projections, which are subject to change. The ARO is calculated based on the estimated cash outflows and is reduced as actual spend occurs related to expected ARO closure activities. These estimates support the request as identified in this filing for recovery of cash flows over the period June 2018 – May 2028. The calculation of the East Bend Coal Ash ARO is consistent with the calculation for other similar AROs and was last remeasured at December 31, 2016. The majority of the basin closure cost estimates were updated as of August 31, 2017 to support the recovery schedule filed with this testimony and are subject to change.

Q. PLEASE DESCRIBE ATTACHMENT CSL-1.

A. Attachment CSL-1 provides the proposed annual recovery amounts for the period June 2018 through May 2028 related to coal ash basin closure costs. The Company is proposing a levelized recovery of this amount that is amortized over a period of ten years so to minimize the rate impact to customers. This schedule begins with the actual costs incurred through June 2017, as well as projected costs for July 2017 through May 2028. These projected costs include the effect of inflation and are based on management's best estimates of required underlying activities. The costs total \$29.0 million (\$11.4 million of actual costs and \$17.6 million of projected costs, which are subject to change and exclude post-closure maintenance).

The costs are then adjusted by two items. First, there is a reduction due to the COR credit which totals \$1.1 million. This COR credit is needed to adjust for the portion of current collection through depreciation rates associated with ash pond closure and is only included on this recovery schedule through March 2018. This is because the COR credit will not be included in depreciation rates upon adoption of the updated depreciation study filed by Mr. Spanos. Second, there is an adjustment for carrying costs on the unrecovered coal ash spend regulatory asset (as approved in Final Order - Case 2015-00187 on December 15, 2015). The carrying costs are based on Duke Energy Kentucky's expected capitalized interest rates and are recorded monthly. The carrying costs included in this proposed recovery total \$12.0 million.

This recovery schedule is calculated by month with recovery starting in June 2018 and continuing through May 2028. Based on the amount of spend, adjusted for the COR credit and carrying costs, a straight line monthly amount of recovery was calculated to ensure a net zero position by May 2028. As discussed in the testimony of Company witness Wathen, and in accordance with KRS 278.183, the Company is implementing an environmental surcharge mechanism (ESM) and will include the costs associated with this ARO in that recovery mechanism. The June 1, 2018, start date for recovery coincides with the beginning of recovery under the ESM. A filing template for the ESM is included in the testimony of Duke Energy Kentucky witness, Ms. Sarah Lawler.

Q. PLEASE DESCRIBE ANY OTHER AROs WITH POTENTIAL SETTLEMENT IN THE FUTURE.

A. Duke Energy Kentucky has other AROs related to legal obligations to remove asbestos at Miami Fort 6 and East Bend, as well as closure of the non-CCR landfill at East Bend. Duke Energy Kentucky does not expect any spending to settle these AROs in the near term. The timing of the removal of asbestos of Miami Fort 6 will occur sometime after 2017, and is dependent upon other factors such as on-going partner operations at the site. The settlement of the East Bend asbestos ARO is anticipated to occur in 2041. The costs for asbestos removal are currently included in Duke Energy Kentucky's Fossil Dismantlement study performed by Burns and McDonnell and are already collected through rates. Therefore, they are not included in this recovery schedule. The timing of final closure of the non-CCR landfill is expected to occur in 2021 – 2022 to correspond with the anticipated end of life for the landfill. The final and permanent capping of the landfill occurs at the end of the landfill's life. Note that the total of these three AROs is $4.1 million at June 30, 2017, and is supported by underlying cash flows of $5.2 million ($3.3 million for asbestos and $1.9 million for the non-CCR landfill).

III. EAST BEND CASE NO. 2015-00120

Q. THE COMMISSION'S ORDER IN CASE NO. 2015-00120 STATED THAT "AT THE TIME OF ITS NEXT ELECTRIC BASE CASE, DUKE ENERGY KENTUCKY SHALL FILE AN UPDATED DEPRECIATION STUDY AND PROVIDE A DETAILED DESCRIPTION OF HOW IT PROPOSES TO RECOVER THE REGULATORY ASSET AND THE REMAINING BALANCE OF ITS INVESTMENT IN EAST BEND." PLEASE DESCRIBE.

A. Per the order in Case No. 2015-00120, Duke Energy Kentucky was authorized to establish a regulatory asset for deferred depreciation expense associated with the Company's acquisition of a 31% interest in East Bend. The order also stated that once Duke Energy Kentucky had fully depreciated the acquired interest in East Bend using the FERC-required depreciation methodology, Duke Energy Kentucky should begin to amortize the regulatory asset over the remaining service life of East Bend. Schedule D-2.21 shows the annual amortization expense related to the regulatory asset which has been included in total Pro Forma Forecasted Period Book Depreciation Expense. Additionally, in order to add this regulatory asset to rate base, the 13-month average balance of the regulatory asset has been added to the Forecasted Period balances shown within Schedule B-2.1 (See Line 6 on Page 7 of 12 for Schedule B-2.1).

All of the depreciation recorded under the FERC-required depreciation methodology as well as the negative acquisition adjustment resulting from the purchase of the additional ownership in East Bend was recorded in Account 108 –

Accumulated Depreciation, thus reducing the net book value of the assets used in the proposed depreciation study. The proposed depreciation study calculates a rate to recover the remaining net book value of East Bend over the expected life.

IV. INFORMATION PROVIDED TO OTHER WITNESSES

Q. DID YOU SUPPLY ANY INFORMATION TO OTHER WITNESSES FOR THEIR USE IN THIS PROCEEDING?

A. Yes, I provided Mr. Pratt with the actual net book value for the existing gas, electric and common plant for the period ending May 31, 2017, for his use in calculating the forecasted financial data.

V. CONCLUSION

Q. WERE SCHEDULES B-2, B-2.1, B-2.2, B-2.3, B-2.4, B-2.5, B-2.6, B-2.7, B-3, B-3.1, B-3.2, B-4, D-2.16, D-2.21, D-2.24, THE INFORMATION YOU PROVIDED ON SCHEDULE K, ATTACHMENT CSL-1 AND THE INFORMATION YOU PROVIDED TO MR. PRATT, (EXCLUDING THE BUDGET AND FORECAST NUMBERS PREPARED BY MR. PRATT AND THE PROPOSED DEPRECIATION AND AMORTIZATION ACCRUAL RATES AND SUPPORTING DEPRECIATION STUDY PREPARED BY MR. SPANOS) PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

VERIFICATION

STATE OF NORTH CAROLINA	)	
	)	**SS:**
COUNTY OF MECKLENBURG	)	

The undersigned, Cynthia S. Lee, Director, Asset Accounting, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of her knowledge, information and belief.

Cynthia S. Lee

Cynthia S. Lee Affiant

Subscribed and sworn to before me by Cynthia S. Lee on this 10 day of Aug, 2017.

Virginia M. Adams

NOTARY PUBLIC

VIRGINIA M. ADAMS
NOTARY
PUBLIC
Exp. 10/02/2021
MECKLENBURG COUNTY, NC

My Commission Expires:
Sept. 2, 2021

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2017-0321
RECOVERY OF SPEND RELATED TO COAL ASH BASIN CLOSURE
AS OF JUNE 30, 2017

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SCHEDULE CSL-1
PAGE 1 OF 4
WITNESS RESPONSIBLE:
C. S. Lee

Duke Energy Kentucky
Amortization Calculation for Coal Ash ARO

Period		Cash Spend	COR Credit	Carrying Cost	Recovery	Ending Balance
		See note A				
2015 Total	*Actual*	3,858,084	(856,412)	20,378	-	3,022,050
2016 Total	*Actual*	4,777,964	(107,051)	385,762	-	8,078,724
Jan-17	*Actual*	371,256	-	43,310	-	8,493,291
Feb-17	*Actual*	438,302	-	40,475	-	8,972,068
Mar-17	*Actual*	712,409	(26,763)	44,946	-	9,702,661
Apr-17	*Actual*	284,391	-	51,351	-	10,038,403
May-17	*Actual*	643,374	-	56,745	-	10,738,522
Jun-17	*Actual*	311,213	(26,763)	54,259	-	11,077,232
Jul-17	*Projection*	1,106,521	-	59,973	-	12,243,727
Aug-17	*Projection*	1,106,521	-	65,715	-	13,415,963
Sep-17	*Projection*	1,106,521	(26,763)	71,354	-	14,567,076
Oct-17	*Projection*	1,106,521	-	77,152	-	15,750,749
Nov-17	*Projection*	1,106,521	-	82,978	-	16,940,248
Dec-17	*Projection*	1,106,521	(26,763)	88,702	-	18,108,709
Jan-18	*Projection*	254,970	-	90,393	-	18,454,072
Feb-18	*Projection*	254,970	-	92,093	-	18,801,136
Mar-18	*Projection*	254,970	(26,763)	93,670	-	19,123,014
Apr-18	*Projection*	254,970	-	112,726	-	19,490,710
May-18	*Projection*	254,970	-	114,865	-	19,860,545
Jun-18	*Projection*	254,970	-	115,086	(331,697)	19,898,904
Jul-18	*Projection*	254,970	-	115,310	(331,697)	19,937,487
Aug-18	*Projection*	254,970	-	115,534	(331,697)	19,976,294
Sep-18	*Projection*	254,970	-	115,760	(331,697)	20,015,327
Oct-18	*Projection*	254,970	-	115,987	(331,697)	20,054,588
Nov-18	*Projection*	254,970	-	116,215	(331,697)	20,094,076
Dec-18	*Projection*	254,970	-	116,445	(331,697)	20,133,794
Jan-19	*Projection*	489,032	-	118,038	(331,697)	20,409,167
Feb-19	*Projection*	489,032	-	119,639	(331,697)	20,686,141
Mar-19	*Projection*	489,032	-	121,251	(331,697)	20,964,726
Apr-19	*Projection*	489,032	-	122,871	(331,697)	21,244,932
May-19	*Projection*	489,032	-	124,501	(331,697)	21,526,768
Jun-19	*Projection*	489,032	-	126,141	(331,697)	21,810,243
Jul-19	*Projection*	489,032	-	127,790	(331,697)	22,095,368
Aug-19	*Projection*	489,032	-	129,448	(331,697)	22,382,151
Sep-19	*Projection*	489,032	-	131,117	(331,697)	22,670,602
Oct-19	*Projection*	489,032	-	132,795	(331,697)	22,960,731
Nov-19	*Projection*	489,032	-	134,482	(331,697)	23,252,548
Dec-19	*Projection*	489,032	-	136,180	(331,697)	23,546,063

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SCHEDULE CSL-1
PAGE 2 OF 4
WITNESS RESPONSIBLE:
C. S. Lee

Duke Energy Kentucky
Amortization Calculation for Coal Ash ARO

Period		Cash Spend	COR Credit	Carrying Cost	Recovery	Ending Balance
		See note A				
Jan-20	*Projection*	113,207	-	135,701	(331,697)	23,463,274
Feb-20	*Projection*	113,207	-	135,220	(331,697)	23,380,004
Mar-20	*Projection*	113,207	-	134,735	(331,697)	23,296,250
Apr-20	*Projection*	113,207	-	134,248	(331,697)	23,212,008
May-20	*Projection*	113,207	-	133,758	(331,697)	23,127,276
Jun-20	*Projection*	113,207	-	133,265	(331,697)	23,042,052
Jul-20	*Projection*	113,207	-	132,769	(331,697)	22,956,331
Aug-20	*Projection*	113,207	-	132,271	(331,697)	22,870,112
Sep-20	*Projection*	113,207	-	131,769	(331,697)	22,783,392
Oct-20	*Projection*	113,207	-	131,265	(331,697)	22,696,167
Nov-20	*Projection*	113,207	-	130,757	(331,697)	22,608,434
Dec-20	*Projection*	113,207	-	130,247	(331,697)	22,520,191
Jan-21	*Projection*	52,127	-	129,378	(331,697)	22,369,999
Feb-21	*Projection*	52,127	-	128,504	(331,697)	22,218,934
Mar-21	*Projection*	52,127	-	127,626	(331,697)	22,066,989
Apr-21	*Projection*	52,127	-	126,742	(331,697)	21,914,161
May-21	*Projection*	52,127	-	125,853	(331,697)	21,760,443
Jun-21	*Projection*	52,127	-	124,959	(331,697)	21,605,832
Jul-21	*Projection*	52,127	-	124,059	(331,697)	21,450,321
Aug-21	*Projection*	52,127	-	123,154	(331,697)	21,293,905
Sep-21	*Projection*	52,127	-	122,245	(331,697)	21,136,579
Oct-21	*Projection*	52,127	-	121,329	(331,697)	20,978,339
Nov-21	*Projection*	52,127	-	120,409	(331,697)	20,819,177
Dec-21	*Projection*	52,127	-	119,483	(331,697)	20,659,090
Jan-22	*Projection*	-	-	118,249	(331,697)	20,445,642
Feb-22	*Projection*	-	-	117,007	(331,697)	20,230,951
Mar-22	*Projection*	-	-	115,758	(331,697)	20,015,012
Apr-22	*Projection*	-	-	114,502	(331,697)	19,797,817
May-22	*Projection*	-	-	113,238	(331,697)	19,579,358
Jun-22	*Projection*	-	-	111,967	(331,697)	19,359,629
Jul-22	*Projection*	-	-	110,689	(331,697)	19,138,621
Aug-22	*Projection*	-	-	109,404	(331,697)	18,916,327
Sep-22	*Projection*	-	-	108,111	(331,697)	18,692,741
Oct-22	*Projection*	-	-	106,810	(331,697)	18,467,854
Nov-22	*Projection*	-	-	105,502	(331,697)	18,241,658
Dec-22	*Projection*	-	-	104,186	(331,697)	18,014,147
Jan-23	*Projection*	-	-	102,862	(331,697)	17,785,312
Feb-23	*Projection*	-	-	101,531	(331,697)	17,555,146
Mar-23	*Projection*	-	-	100,192	(331,697)	17,323,642
Apr-23	*Projection*	-	-	98,846	(331,697)	17,090,790
May-23	*Projection*	-	-	97,491	(331,697)	16,856,584

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WITNESS RESPONSIBLE:
C. S. Lee

Duke Energy Kentucky
Amortization Calculation for Coal Ash ARO

Period		Cash Spend *See note A*	COR Credit	Carrying Cost	Recovery	Ending Balance
Jun-23	*Projection*	-	-	96,129	(331,697)	16,621,016
Jul-23	*Projection*	-	-	94,758	(331,697)	16,384,077
Aug-23	*Projection*	-	-	93,380	(331,697)	16,145,760
Sep-23	*Projection*	-	-	91,994	(331,697)	15,906,056
Oct-23	*Projection*	-	-	90,599	(331,697)	15,664,958
Nov-23	*Projection*	-	-	89,197	(331,697)	15,422,458
Dec-23	*Projection*	-	-	87,786	(331,697)	15,178,547
Jan-24	*Projection*	-	-	86,367	(331,697)	14,933,217
Feb-24	*Projection*	-	-	84,940	(331,697)	14,686,459
Mar-24	*Projection*	-	-	83,505	(331,697)	14,438,267
Apr-24	*Projection*	-	-	82,061	(331,697)	14,188,631
May-24	*Projection*	-	-	80,609	(331,697)	13,937,542
Jun-24	*Projection*	-	-	79,148	(331,697)	13,684,993
Jul-24	*Projection*	-	-	77,679	(331,697)	13,430,975
Aug-24	*Projection*	-	-	76,201	(331,697)	13,175,479
Sep-24	*Projection*	-	-	74,715	(331,697)	12,918,496
Oct-24	*Projection*	-	-	73,220	(331,697)	12,660,019
Nov-24	*Projection*	-	-	71,716	(331,697)	12,400,039
Dec-24	*Projection*	-	-	70,204	(331,697)	12,138,545
Jan-25	*Projection*	-	-	68,683	(331,697)	11,875,531
Feb-25	*Projection*	-	-	67,153	(331,697)	11,610,987
Mar-25	*Projection*	-	-	65,614	(331,697)	11,344,904
Apr-25	*Projection*	-	-	64,066	(331,697)	11,077,273
May-25	*Projection*	-	-	62,509	(331,697)	10,808,085
Jun-25	*Projection*	-	-	60,943	(331,697)	10,537,331
Jul-25	*Projection*	-	-	59,368	(331,697)	10,265,002
Aug-25	*Projection*	-	-	57,784	(331,697)	9,991,089
Sep-25	*Projection*	-	-	56,191	(331,697)	9,715,583
Oct-25	*Projection*	-	-	54,588	(331,697)	9,438,473
Nov-25	*Projection*	-	-	52,976	(331,697)	9,159,752
Dec-25	*Projection*	-	-	51,355	(331,697)	8,879,410
Jan-26	*Projection*	-	-	49,724	(331,697)	8,597,436
Feb-26	*Projection*	-	-	48,083	(331,697)	8,313,823
Mar-26	*Projection*	-	-	46,434	(331,697)	8,028,559
Apr-26	*Projection*	-	-	44,774	(331,697)	7,741,637
May-26	*Projection*	-	-	43,105	(331,697)	7,453,045
Jun-26	*Projection*	-	-	41,426	(331,697)	7,162,774
Jul-26	*Projection*	-	-	39,738	(331,697)	6,870,814
Aug-26	*Projection*	-	-	38,039	(331,697)	6,577,157
Sep-26	*Projection*	-	-	36,331	(331,697)	6,281,791
Oct-26	*Projection*	-	-	34,613	(331,697)	5,984,707
Nov-26	*Projection*	-	-	32,885	(331,697)	5,685,894

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WITNESS RESPONSIBLE:
C. S. Lee

Duke Energy Kentucky
Amortization Calculation for Coal Ash ARO

Period		Cash Spend	COR Credit	Carrying Cost	Recovery	Ending Balance
		See note A				
Dec-26	*Projection*	-	-	31,146	(331,697)	5,385,344
Jan-27	*Projection*	-	-	29,398	(331,697)	5,083,045
Feb-27	*Projection*	-	-	27,640	(331,697)	4,778,987
Mar-27	*Projection*	-	-	25,871	(331,697)	4,473,161
Apr-27	*Projection*	-	-	24,092	(331,697)	4,165,555
May-27	*Projection*	-	-	22,302	(331,697)	3,856,161
Jun-27	*Projection*	-	-	20,503	(331,697)	3,544,966
Jul-27	*Projection*	-	-	18,692	(331,697)	3,231,961
Aug-27	*Projection*	-	-	16,871	(331,697)	2,917,136
Sep-27	*Projection*	-	-	15,040	(331,697)	2,600,479
Oct-27	*Projection*	-	-	13,198	(331,697)	2,281,979
Nov-27	*Projection*	-	-	11,345	(331,697)	1,961,628
Dec-27	*Projection*	-	-	9,482	(331,697)	1,639,412
Jan-28	*Projection*	-	-	7,607	(331,697)	1,315,322
Feb-28	*Projection*	-	-	5,722	(331,697)	989,347
Mar-28	*Projection*	-	-	3,826	(331,697)	661,476
Apr-28	*Projection*	-	-	1,918	(331,697)	331,697
May-28	*Projection*	-	-	(0)	(331,697)	(0)
		28,948,159	(1,097,278)	11,952,767	(39,803,648)	

Note A: Actual costs included for May 2015 through June 2017 total $11.4 million. Projected costs included starting in July 2017 total $17.6 million.

Amortization Period (yrs)	10	(6/18 - 5/28)
Monthly Amortization Amount	331,697	
Annualized Amortization Amount	**3,980,365**	

Direct Testimony of
Joseph A. Miller, Jr.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; 3) Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All Other Required Approvals and Relief.	))))))))))	Case No. 2017-00321

DIRECT TESTIMONY OF

JOSEPH A. MILLER, JR.

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

September 1, 2017

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Joseph A. Miller Jr., and business address is 526 South Church Street, Charlotte, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Vice President of Central Services for Duke Energy Business Services, LLC (DEBS). DEBS is a service company subsidiary of Duke Energy Corporation (Duke Energy), which provides services to Duke Energy and its subsidiaries, including Duke Energy Kentucky, Inc. (Duke Energy Kentucky or the Company).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUNDS.

A. I graduated from Purdue University with a Bachelor of Science degree in Mechanical Engineering. I also completed twelve post-graduate level courses in Business Administration at Indiana State University. My career began with Duke Energy Indiana, Inc., (Duke Energy Indiana) f/k/a Public Service of Indiana, in 1991 as a staff engineer at Duke Energy Indiana's Cayuga Steam Station. Since that time, I have held various roles of increasing responsibility in the generation engineering, maintenance, and operations areas, including the role of station manager, first at Duke Energy Kentucky's East Bend Generating Station (East Bend), followed by Duke Energy Ohio's Zimmer Steam Station. I was named General Manager of Analytical and Investments Engineering in 2010 and became General Manager of Strategic Engineering in 2012 following the merger between

Duke Energy and Progress Energy, Inc. I became the Vice President of Central Services in 2014.

Q. PLEASE SUMMARIZE YOUR DUTIES AS VICE PRESIDENT OF CENTRAL SERVICES.

A. In this role, I am responsible for providing direction and oversight for engineering and business services, along with strategic and technical services including environmental compliance planning, for Duke Energy's fleet of fossil, hydroelectric, and solar (collectively, "fossil/hydro").

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. Yes. Most recently, I provided testimony in support of the Company's application to construct a new dry bottom ash handling system at East Bend in Case No. 2016-00268.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I describe the Company's three generating stations, East Bend, the Miami Fort Generating Station Unit No. 6 (Miami Fort 6) and Woodsdale Combustion Turbines (Woodsdale) (collectively the Plants). I explain how these stations are or were used to provide safe, affordable, reliable, and reasonable electric service to Duke Energy Kentucky's customers and the Company's continued investment in these stations. I support Duke Energy Kentucky's request to implement an environmental surcharge mechanism (ESM) and to institute an Environmental Compliance Plan. I discuss the retirement of Duke Energy Kentucky's Miami Fort

6 station and the potential strategies for eventual decommissioning. I discuss certain information of future plant maintenance outages that I provided to other witnesses for their testimony. Finally, I sponsor part of the information in the capital budget relating to the Plants contained in Filing Requirements (FR) 16(7)(b), FR 16(7)(f) and FR 16(7)(g), which I provided to Duke Energy Kentucky witness Mr. Robert "Beau" Pratt for the forecasted financial data.

II. GENERAL DESCRIPTION OF DUKE ENERGY KENTUCKY'S GENERATING STATIONS

A. EAST BEND

Q. PLEASE DESCRIBE EAST BEND.

A. East Bend is a 648 megawatt (MW) (nameplate rating) coal-fired base load unit located along the Ohio River in Boone County, Kentucky. East Bend was commissioned in 1981 and the Company now owns 100 percent of the station, having completed the purchase of the Dayton Power and Light Company's 31 percent interest in the station in 2014.

The nameplate ratings are the ratings provided by the manufacturer of the generating equipment and these ratings are actually engraved on a nameplate that is affixed to the equipment. The net ratings represent the net amount of power that we can dispatch from the plants after some portion of the gross power output is used to power the plant machinery. The net rating for East Bend is 600 MW. East Bend was originally planned for up to four coal-fired units but only one unit (Unit 2) was constructed. The station has river facilities to allow barge deliveries of coal and lime. East Bend is designed to burn eastern bituminous coal and achieved a net plant heat rate of 10,889 Btu/kWh for calendar year 2016. The major pollution control features are: a high-efficiency hot side electrostatic precipitator, a lime-based flue gas desulfurization (FGD) system, and a selective catalytic reduction control (SCR) system designed to reduce nitrogen oxide (NO_x) emissions by 85 percent. The FGD system was upgraded in 2005 to increase the sulfur dioxide (SO_2) emissions removal to an average of 97 percent. The station's electrical output is directly connected to the Duke Energy Midwest (consisting of Kentucky and Ohio) 345 kilovolt (kV) transmission system.

Q. PLEASE PROVIDE A SUMMARY OF THE HANDLING, STORAGE, AND DISPOSAL OF COAL COMBUSTION RESIDUALS (CCR) AT EAST BEND.

A. Duke Energy Kentucky provides reliable electric generation to its retail customers in Northern Kentucky from a portfolio of generating assets that generate electricity using coal and natural gas. For Duke Energy Kentucky, coal has been the historic "go-to" fuel choice for base-load, least-cost, and reliable service. The storage, treatment and disposal of coal combustion residuals (CCRs) at East Bend, primarily fly ash and bottom ash, historically have been handled through the onsite ash basin and landfills. The presence of the pond and landfills enabled Duke Energy Kentucky to manage its costs of providing safe and reliable electric service by eliminating the need to transport to and pay for disposal of the generator waste in commercial landfills.

Historically, approximately 80 percent of the ash produced at East Bend was dry fly ash. As part of the disposal process, that material is mixed with the spent scrubber slurry and lime to make a stable material called Poz-O-Tec. The Poz-O-Tec mixture sets up much like concrete and it is disposed of in the onsite landfill. The remaining 20 percent of ash is bottom ash that was treated and stored in the onsite ash pond. The East Bend ash pond has also historically supported East Bend's operation by providing dilution, settling and/or retention functions for other power plant process water flows, including, but not limited to, low volume wastewater, coal pile run-off, landfill leachate, and FGD wastewater. Duke Energy Kentucky utilizes a water sluice process to efficiently transport the bottom ash to its pond. Together the pond and landfill are used for the storage and disposal of waste products resulting from the Company's FGD system and other waste material.

As I explain later in my testimony, East Bend is currently being modified in response to environmental regulations, so to incorporate dry bottom ash handling and to close and repurpose its ash pond.

Q. PLEASE DESCRIBE THE LANDFILL STATUS AT EAST BEND.

A. There are two permitted landfills at East Bend, the East Landfill, which is nearing capacity, and its replacement, the West Landfill.

The East Landfill is comprised of approximately 162 acres and has been in place since East Bend was constructed in 1981. The East Landfill's original construction pre-dated Coal Combustion Residual Final Rule (CCR Final Rule) effective date but will eventually have to be closed in a manner that complies with the CCR Final Rule.

The East and West Landfills are permitted to receive various forms of waste, including, but not limited to, FGD waste, fly ash, and bottom ash (Generator Waste), from a number of generating sources, including those generating stations currently owned and/or operated by Duke Energy Kentucky and for generating stations for other Kentucky utilities and Ohio-based electric generators. The Landfills are permitted to receive Generator Waste from sources other than East Bend to ensure that Duke Energy Kentucky has sufficient dry fly ash material available to make the Poz-O-Tec byproduct necessary to operate the station's FGD handling process. This permitting for multiple stations is a significant benefit to the Company as Duke Energy Kentucky, at times, does not produce sufficient quantities of ash to make the Poz-O-Tec. The West Landfill design and estimated life contemplated the likely need to convert East Bend to a 100 percent dry ash disposal system eventually.

Q. WHY IS THE WEST LANDFILL NECESSARY?

A. The West Landfill will eventually replace East Bend's East Landfill once it is completely closed due to reaching capacity. The West Landfill construction allows East Bend to have a dedicated resource for generator waste disposal for many years to come and continue to store waste material from East Bend on site, rather than incurring costs to transport to and dispose of the waste material at third-party-owned landfills.

In terms of overall footprint, the West Landfill will cover approximately 200 acres of land on the East Bend campus with a total of eight cells. This 200 acre footprint is comprised of the first five cells and the eighth and final cell. Cells six and seven will be constructed directly on top of cells one through five.

The first cell is estimated to comprise approximately 38 acres of land. Cells two and three are estimated to comprise approximately 37 acres of land. Cells four and five are estimated at approximately 31 acres of land. Cell number six is estimated at approximately 41 acres of land and cell seven is approximately 36 acres. Cell eight is estimated at 28 acres.

The Company received approval to commence construction of the first cell of the West Landfill in Case No. 2015-00089. As part of that approval, the Commission directed the Company to seek a new CPCN for each subsequent phase or cell of the West Landfill before commencing construction. Duke Energy Kentucky anticipates a need to commence construction of West Landfill Cell 2 in 2018 or 2019 to allow sufficient lead time so to ensure there is sufficient West Landfill capacity available before Cell 1 reaches its capacity. Duke Energy Kentucky anticipates a need to have the Cell 2 ready to receive waste by mid-2019. As such, the Company needs to either complete construction of Cell 2 or arrange to transport its waste to another landfill operated by a third party prior to that date. The Company anticipates seeking CPCN authorization for Cell 2 sometime in late 2017 or early 2018.

Q. PLEASE DESCRIBE THE ASH POND AT EAST BEND.

A. The Pond was also commissioned in 1981 and it has a volume of 1,844 acre feet. It is used to separate bottom ash from the water used to convey the ash from the plant before the water is discharged to the Ohio River from the pond under the National Pollutant Discharge Elimination System (NPDES) permit. The Pond is also used to treat other plant water streams, such as coal pile run-off and landfill leachate, before they are discharged under the NPDES permit. Currently, boiler bottom ash is collected in a wet bottom ash hopper at the base of the boiler and then sluiced to East Bend's Pond for storage.

The Company received authorization to close the East Bend pond in Case No. 2016-00398 in order to comply with the CCR Final Rule and other applicable environmental regulations. The Company also is in the process of constructing dry ash handling system to eliminate the need for bottom ash storage and treatment. Once the dry ash handling conversion is completed, all station ash will be disposed of in the onsite West Landfill.

Q. PLEASE DESCRIBE WHAT ACTIONS THE COMPANY IS CURRENTLY DOING TO MAINTAIN RELIABILITY AT EAST BEND.

A. Duke Energy Kentucky follows a regular maintenance schedule for all of its plants, including East Bend. Generally speaking, the stations have annual maintenance activities scheduled during off-peak seasons in the spring or fall. The regular maintenance is typically one to two weeks of planned outage in duration. Every other year, a longer term outage is scheduled for more significant projects. In the spring of 2018, the Company has scheduled an approximate 12 week outage at East Bend to perform some significant, albeit routine, refurbishing of the station's boiler and precipitator. This work is typical for a station of the approximate age of East Bend in order to continue to maintain its reliability and long-term operation.

The major scope of work associated with the East Bend 2018 Outage include replacement of the Secondary Superheat Headers, Secondary Superheat

Intermediate Pendants, Economizer, Outer Loop of the Condenser, HP Turbine rotor and nozzle block, Circulating Water Piping lining, Induced Draft Fan Power Cells, Absorber Module Mist Eliminators, Secondary Air Heater Collar Seals, rebuilding of both Precipitators, and conversion of the station's Bottom Ash system from wet to dry. With the exception of the Dry Bottom Ash conversion, these projects are all being done to maintain the reliability of the station. The Dry Bottom Ash project is being completed to ensure compliance with current CCR regulations.

Q. PLEASE BRIEFLY DESCRIBE DUKE ENERGY KENTUCKY'S RECENT CAPITAL INVESTMENTS IN EAST BEND THAT ARE DRIVEN BY ENVIRONMENTAL COMPLIANCE STRATEGY.

A. Duke Energy Kentucky has continuous capital investments at all of its Plants as part of normal operations. In the last three years, the Company has made significant compliance investments at East Bend driven by recent changes in Federal Environmental Regulations enacted by the U.S. Environmental Protection Agency (EPA) including the CCR Final Rule and Electric Effluent Liquid Guidelines (ELG) Final Rule. Duke Energy Kentucky witness, Ms. Tammy Jett discusses these and other environmental regulations impacting the Company's Plants in her direct testimony.

The two recent rules, CCR Final Rule and ELG Final Rule, have been the catalyst for the Company's most recent CPCN applications for a new Dry Bottom

Ash Handling System in Case No. 2016-00268,[1] Water Redirection, Pond Closure and Repurposing in Case No. 2016-00398,[2] and other ash accounting and handling costs and liabilities as discussed in Case No. 2015-00187.[3]

Q. PLEASE SUMMARIZE THE COMPANY'S DRY BOTTOM ASH CONVERSION AND THE STATUS OF THIS PROJECT.

A. Duke Energy Kentucky received Commission approval for this project by Order dated February 23, 2017, in Case No. 2016-00268. East Bend was initially designed such that boiler bottom ash is collected in a wet bottom ash hopper at the base of the boiler and then it sluiced to the ash pond. The CCR Final Rule and ELG Final Rule prohibit future sluicing of bottom ash to a pond necessitating that bottom ash begin to be collected in a dry state and be disposed of in a landfill. The conversion of the existing wet bottom ash sluicing system includes construction of a Submerged Flight Conveyor (SFC) bottom ash removal system. The construction requires demolition of the existing bottom ash sluicing system and installation of the new under-boiler SFC for dewatering bottom ash, economizer ash, and mill rejects. The Company is constructing a dewatered bottom ash storage area and truck load out area for trucking to the existing Landfills for final disposal.

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[1] *In the Matter of the Electronic Application of Duke Energy Kentucky, Inc., for a Certificate of Public Convenience and Necessity for Dry Bottom Ash Conversion of the East Bend Generating Station*, Case No. 2016-00268, Ky.P.S.C. February 23, 2017.

[2] *In the Matter of the Electronic Application of Duke Energy Kentucky, Inc., for a Certificate of Public Convenience and Necessity Authorizing the Company to Close the East Bend Generating Station Coal Ash Impoundment and for All Other Required Approvals and Relief*, Case No. 2016-00398 Ky.P.S.C. June 6, 2017.

[3] *In the Matter of the Application of Duke Energy Kentucky, Inc., for an Order Approving the Establishment of a Regulatory Asset for the Liabilities Associated with Ash Pond Asset Retirement Obligations*, Case No. 2015-00187 Ky.P.S.C. December 15, 2015.

The Company has commenced construction activities and is beginning to acquire the long-lead-time equipment and materials to begin actual construction later this year. The Company is on schedule for completion of the project as part of the station's 2018 planned spring outage with an estimated in-service date of early second quarter 2018.

Q. PLEASE SUMMARIZE THE STATUS OF THE COMPANY'S WATER REDIRECTION, POND CLOSURE AND REPURPOSING PROJECT.

A. Duke Energy Kentucky filed its CPCN application for this project in December 2016, Case No. 2016-00398. The Commission approved the Company's CPCN request on June 6, 2017, and the Company has since commenced construction activity. The Company is in the process of cleaning out the ash pond so that closure and repurposing work can commence in a timely manner to comply with the CCR Final Rule and ELG Final Rule, as well as other groundwater regulations.

Q. IS EAST BEND USED AND USEFUL FOR SERVING DUKE ENERGY KENTUCKY'S NATIVE LOAD CUSTOMERS?

A. Yes. East Bend, as described above, has performed well and is a high quality generating asset relative to the age and condition of comparable generating plants. One useful measure of the quality of a coal-fired generating station is the equivalent availability factor, which measures the percentage of time that the station is available for operations after planned and unplanned outages and derates (which result from operational conditions) are taken into account. The equivalent availability factor for East Bend for time period 2011 through 2015 was 77.0 percent. East Bend's 2016 EAF was 79.51 percent.

East Bend has been well maintained and is in good working order. Coal supplies are readily available and there are no transmission constraints.

B. WOODSDALE

Q. PLEASE DESCRIBE WOODSDALE.

A. Woodsdale is a six-unit, single cycle, combustion turbine (CT) station located in Butler County, Ohio, just north of Cincinnati, with a collective net winter rating of 564 MW and a net summer rating of 462 MW. Woodsdale was designed to provide peaking service and to have black start and dual fuel capability. Black start capability means that the station has the ability to initiate a recovery of a substantial portion of load without relying on energy from outside sources if the regional grid experiences a blackout. The black start capability is initiated by an Allison 501-KB gas turbine that serves as a back-up power source and allows the station to start generating energy without power from the electric grid. The dual fuel capability was provided through the ability to burn both natural gas and propane. The propane dual fuel service was provided through direct pipeline access to the nearby Todhunter propane Storage Cavern (Todhunter) that was owned and operated by, Enterprise TE Products Pipeline Company LLC. In 2013, Todhunter was closed due to structural issues with no strategy to re-open, leaving Woodsdale without a sustainable secondary fuel source. The station has limited onsite storage capability for sufficient propane reserves to run Woodsdale for more than a couple of hours.

Woodsdale is connected to the Texas Eastern Transmission Company (TETCO) interstate pipeline that transports the natural gas to supply the station. The design of Woodsdale as a peaking unit with low capacity factors does not support acquiring firm natural gas transportation through the available natural gas interstate pipelines.

Q. PLEASE EXPLAIN WHY WOODSDALE BEING DESIGNED FOR PEAKING CAPABILITY IS SIGNIFICANT.

A. By design, peaking units run infrequently for short periods to meet peak demand. As a result peaking units have a much lower capacity factor than baseload units or intermediate load units. Woodsdale, like most natural gas CTs are generally dispatched in response to market price signals. These units have great flexibility in terms of operation and can start, ramp up and down very quickly in response to changes in the energy markets and reliability. Consequently, their higher production cost versus a base load coal station like East Bend or an intermediate combined cycle generating station makes Woodsdale (and all peaking units) fall higher on the list in terms of resource dispatch stacking. Even with the lower market prices of natural gas that have been experienced in recent years, Woodsdale is not dispatched frequently enough to justify firm natural gas contracts.

Q. PLEASE DESCRIBE WHAT ACTIONS THE COMPANY IS CURRENTLY DOING TO MAINTAIN OR ENHANCE RELIABILITY AT WOODSDALE.

A. In addition to the regular maintenance cycles for Duke Energy Kentucky's generating fleet that I mentioned above, the Company is currently seeking approval to construct new ultra-low sulfur diesel (ULSD) Fuel System as the secondary fuel to natural gas for Woodsdale in Case No. 2017-00186. The need for a ULSD Fuel System is a result of a change in PJM's rules for capacity performance that occurred in 2015 and 2016 as a result of the 2014 Polar Vortex. As a natural-gas fired CT, Woodsdale does not presently have a multiple-day reliable and available fuel source on site like a coal-fired generator such as East Bend. Although Woodsdale is connected to one interstate natural gas pipeline and is in close proximity to two others, firm transportation to the station having an onsite and readily available fuel source is the most economical solution in the long term to solving the fuel certainty needs for meeting PJM capacity performance requirements and ensuring the availability of Woodsdale's capacity to continue to serve our Kentucky customer load. The Company has identified and is planning project investments that will increase the starting reliability of the Woodsdale units, with particular focus on the static frequency convertors.

C. <u>MIAMI FORT 6</u>

Q. PLEASE DESCRIBE MIAMI FORT 6.

A. Miami Fort 6 is a 168 MW (nameplate rating) coal-fired base/intermediate load unit located at Miami Fort Station along the Ohio River in Hamilton County, Ohio, that was commissioned in 1960. The net rating was 163 MW. Miami Fort 6 was retired effective June 1, 2015, consistent with the Commission's Order in

Case No. 2014-00201 as a result of the enactment of the USEPA's Mercury Air Toxics Standard (MATS) Rule.

At the time of its retirement, Unit 6 was one of three operating coal-fired units at the Miami Fort Generating Station. While Duke Energy Kentucky wholly owns Miami Fort Unit 6, Miami Fort Units 7 and 8 are now jointly owned by Dynegy Inc., (Dynegy) (64 percent) and DP&L (36 percent). Duke Energy Ohio sold its interests in the Miami Fort Generating Station to Dynegy in 2016. As the now majority station owner, Dynegy operated Miami Fort Unit 6 on behalf of Duke Energy Kentucky until the unit's retirement, and today still provides basic maintenance and upkeep services at the station until its eventual decommissioning or disposal. Dynegy provides these services in accordance with an operating agreement that was approved by the Commission in Case No. 2014-00287. Duke Energy Kentucky is also responsible for ongoing costs associated with certain shared station facilities and equipment pursuant to leases approved by the Commission in Case No. 2003-00202, wherein Duke Energy Kentucky acquired the Plants from Duke Energy Ohio (f/k/a The Cincinnati Gas & Electric Company).

Q. PLEASE DESCRIBE DUKE ENERGY KENTUCKY'S STRATEGIES FOR MIAMI FORT 6 RETIREMENT DECOMMISSIONING IN THIS CASE.

A. Miami Fort 6 officially retired from commercial operation on June 1, 2015. The issue of the retirement of the unit due to MATs compliance was brought before the Commission in Case No. 2014-00201 regarding the Company's purchase of the remaining 31 percent interest in East Bend. As part of the Commission's approval of the East Bend interest acquisition in that proceeding, the Commission approved the retirement of Miami Fort 6 as a normal retirement for rate making purposes. Duke Energy Kentucky witness Mr. John R. Spanos discusses the Company's treatment of the retirement of this asset in this case.

As part of the retirement of this asset, Duke Energy Kentucky must now take action to make sure that the Miami Fort 6 facilities are decommissioned in a safe and reasonable manner. This includes removing necessary equipment and facilities to ensure that no safety or environmental hazards exist. Because of the close proximity of Miami Fort 6 and shared facilities with other station generating units that are still in operation, the Company cannot immediately perform all necessary decommissioning and demolishing work. Rather, that work must occur methodically over time so as not to interfere with operation of the other station units or personnel working at the station. In order to assist in determining the appropriate decommissioning activities for this site, near term and long term, as well as all of Duke Energy Kentucky's generating stations, the Company retained Burns & McDonnell to conduct a decommissioning study to determine whether the Company has appropriately accounted for all necessary decommissioning work and costs in its rates. Duke Energy Kentucky witness, Mr. Jeffrey Kopp from Burns & McDonnell sponsors the Company's Decommissioning Study submitted in this proceeding.

Q. IS THE DECOMMISSIONING OF MIAMI FORT UNIT 6 DUKE ENERGY KENTUCKY'S ONLY ALTERNATIVE FOR DISPOSAL OF THIS ASSET?

A. For purposes of this rate case, the Company is assuming that continued ownership and eventual decommissioning by the Company will be required. However, that said, the Company is exploring alternatives. At this point in time, however, any alternatives are speculative and conceptual in nature. If the Company is able to come to a reasonable alternative that the Company believes is at a reasonable cost in comparison to the costs of continued ownership and decommissioning and risks for future changes in environmental law, then Duke Energy Kentucky may pursue such an arrangement. The Company would bring such a proposal, along with any cost-benefit analysis supporting such a transaction to the Commission for its consideration, along with requests for accounting and regulatory treatment of any costs associated with such a transfer, as well as, what if any changes it causes to the base assumptions in this case. However, at this point in time, decommissioning is considered the most likely strategy and such work is anticipated to commence as outlined in the decommissioning study.

III. DUKE ENERGY KENTUCKY'S PROPOSAL TO IMPLEMENT AN ENVIRONMENTAL SURCHARGE MECHANISM

Q. PLEASE SUMMARIZE DUKE ENERGY KENTUCKY'S PROPOSAL TO ESTABLISH AN ESM IN THIS PROCEEDING?

A. Duke Energy Kentucky is seeking Commission authorization to establish an ESM in accordance with KRS 278.183, as described in Duke Energy Kentucky witness, William Don Wathen, Jr. testimony. To date, Duke Energy Kentucky has not sought to implement an ESM. The Company only acquired its generating assets effective January 2006. Prior to that time, the Company satisfied all of its load obligations through a long-term purchase power agreement.

At the time Duke Energy Kentucky acquired its generating fleet, East Bend was well suited for compliance with the existing and known environmental regulations at the time. Although Miami Fort 6 was not scrubbed, that station has since been retired. As such, the need for new and significant investment in terms of environmental compliance is relatively recent and is driven by regulations that have come to fruition since the Company's last base rate case.

The Company is now taking this opportunity in this case to firmly define what environmental costs are included in base rates so to establish a baseline for measuring incremental costs that would then be eligible for recovery through an ESM as part of the Company's new Environmental Compliance Plan.

Q. PLEASE IDENTIFY THE PROJECTS DUKE ENERGY KENTUCKY IS PROPOSING TO INCLUDE IN ITS ENVIRONMENTAL COMPLIANCE PLAN AND FOR RECOVERY THROUGH AN ESM?

A. Attachment JAM-1 is a summary of the Company's proposed Environmental Compliance Plan. For its initial Environmental Compliance Plan, Duke Energy Kentucky is seeking to include discrete capital projects and the recovery of incrementive expenses associated with environmental reagents and all emission allowances (purchases and sales). The four discrete projects pertain to the amortization of the Company's East Bend ash pond closure/retirement obligation

(ARO) accounting treatment as was previously approved in Case No. 2015-00187[4] and its process water system and redirection and pond repurposing strategy recently approved in Case No. 2016-00398.[5] The Company's initial Environmental Compliance Plan projects are as follows:

a. Project EB020290 Lined Retention Basin West;
b. Project EB020745 Lined Retention Basin East;
c. Project EB020298 East Bend SW/PW Reroute;
d. ARO amortization for Pond Closure; and
e. Consumables inventories (Reagents and emission allowances).

Projects EB020290, EB0202745, and EB020298 (collectively the Ash Pond Projects) are interrelated and are for the closure and repurposing of the ash pond at East Bend and the associated water redirection necessary in response to the CCR Final Rule and the ELG Final Rule as well as various Kentucky groundwater regulations. Duke Energy Kentucky witness Ms. Tammy Jett describes the environmental regulations driving these investments in her direct testimony. It should be noted that the need for these projects has already been established, as they were all recently approved by the Commission in Case No. 2016-00398.[6]

[4] *In the Matter of the Application of Duke Energy Kentucky, Inc., for an Order Approving the Establishment of a Regulatory Asset for the Liabilities Associated with Ash Pond Asset Retirement Obligations*, Case No 2015-00187 Ky.P.S.C. December 15, 2015.

[5] *In the Matter of the Electronic Application of Duke Energy Kentucky, Inc., for a Certificate of Public Convenience and Necessity Authorizing the Company to Close the East Bend Generating Station Coal Ash Impoundment and for All Other Required Approvals and Relief*, Case No. 2016-00398 Ky.P.S.C. June 6, 2017.

[6] *In the Matter of the Electronic Application of Duke Energy Kentucky, Inc., for a Certificate of Public Convenience and Necessity Authorizing the Company to Close the East Bend Generating Station Coal Ash Impoundment and for All Other Required Approvals and Relief*, Case No. 2016-00398 Ky.P.S.C. June 6, 2017.

Similarly, the accounting treatment for the ARO was previously approved in Case No. 2015-00187.[7]

The estimated costs of the fully loaded total estimated cost of Pond closure (bottom ash removal and dewatering) is approximately $29,000,000. The estimated fully loaded cost of construction (internal and external labor included) for Pond repurposing to a lined retention pond for ELG compliance is approximately $42,000,000. The total estimated fully loaded cost of construction for water redirection (internal and external labor included) is approximately $22,000,000.[8]

The Company has made test year assumptions related to recovery through amortization of the ARO deferrals and the capital costs of placing of the project components in service and is proposing to recover those projects through the ESM. The pond repurposing and water redirection projects will not be fully completed until outside the timeframe of the forecasted test year used in this proceeding. As a result, it is appropriate to recover these costs separately through the ESM. The Company is proposing that all capital, O&M, depreciation, taxes, etc., related to the East Bend Pond closure, repurposing and water redirection will be included in the ESM adjustments upon occurrence of costs upon approval.

[7] *In the Matter of the Application of Duke Energy Kentucky, Inc. for an Order Approving the Establishment of a Regulatory Asset for the Liabilities Associated with Ash Pond Asset Retirement Obligations,* Case No 2015-00187, Ky.P.S.C. December 15, 2015.
[8] *Application* at 12, Case No. 2016-00398.

Duke Energy Kentucky witness Ms. Cynthia S. Lee explains the accounting issues for the ARO and the Company's request for recovery in her direct testimony.

Finally, the Company is proposing to include the costs for emission allowances (purchases and sales) inventory in the ESM recovery as well as incremental reagent expenses. These are also costs necessary to operate the Company's environmental compliance equipment and meet regulations under the Clean Air Act. Including these costs in the ESM is a more transparent and practical method for cost recovery and ensures that customers are paying no more than the actual cost to comply.

Q. ARE THESE PROJECTS INCREMENTAL TO WHAT THE COMPANY HAS OR IS PROPOSING TO INCLUDE IN ITS BASE RATES AS PART OF THIS PROCEEDING?

A. All of the projects I have mentioned are incremental to base rates and are not included as part of the rate case test year. Mr. Pratt supports the Company's forecast in this proceeding, including the budgeted capital projects used in determining the forecast that was used by Ms. Lawler to determine the Company's revenue requirements.

Q. ARE THE PROJECTS THAT THE COMPANY IS SEEKING TO INCLUDE IN ITS COMPLAINCE PLAN FOR THE CURRENT RECOVERY OF COSTS OF COMPLYING WITH THE FEDERAL CLEAN AIR ACT, AND THOSE FEDERAL STATE, OR LOCAL ENVIRONMENTAL REGULATIONS WHICH APPLY TO COAL COMBUSTION WASTES AND BY-PRODUCTS FROM FACILITIES UTILIZED FOR THE PRODUCTION OF ENEGRY?

A. Yes, they are. Ms. Jett further explains this in her testimony.

Q. WHAT RETURN ON EQUITY IS THE COMPANY PROPOSING TO USE FOR CAPITAL RELATED PROJECTS TO BE INCLUDED IN THE ESM PROPOSED IN THIS CASE?

A. As Mr. Wathen explains in his testimony, the Company is proposing to use the 10.3 percent rate of return proposed and supported by Duke Energy Kentucky witness Dr. Roger A. Morin in his direct testimony.

IV. <u>FILING REQUIREMENTS SPONSORED BY WITNESS</u>

Q. PLEASE DESCRIBE THE INFORMATION YOU SPONSOR IN FR 16(7)(b).

A. FR 16(7)(b) consists of the most recent capital construction budget containing the forecasted construction expenditures for a minimum of three years. I provided the forecasted capital construction budget for the Plants contained in FR 16(7)(b) and for Mr. Pratt's use for the forecasted financial data.

Q. PLEASE DESCRIBE THE INFORMATION YOU SPONSOR IN FR 16(7)(f).

A. FR 16(7)(f) includes the following information for major projects constituting five percent or more of the annual construction budget during the three-year capital expenditure forecast: the starting date and completion date for each project and construction cost per year. I provided this information for the Plants contained in FR 16(7)(f).

Q. PLEASE DESCRIBE THE INFORMATION YOU SPONSOR IN FR 16(7)(g).

A. FR 16(7)(g) includes the following information for projects constituting less than five percent of the annual construction budget during the three-year capital expenditure forecast: the starting date and completion date for each project and construction cost per year. I provided this information for the Plants contained in FR 16(7)(g).

V. CONCLUSION

Q. IS THE INFORMATION ON PLANT CONSTRUCTION PROJECTS AND OUTAGES YOU PROVIDED TO OTHER WITNESSES ACCURATE, TO THE BEST OF YOUR KNOWLEDGE AND BELIEF?

A. Yes.

Q. WAS ATTACHMENT JAM-1, AND THE INFORMATION YOU SPONSOR IN FR 16(7)(b), FR 16(7)(f) AND FR 16(7)(g), PREPARED BY YOU OR AT YOUR DIRECTION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

VERIFICATION

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF MECKLENBURG)

The undersigned, Joseph A. Miller, Vice President of Central Services for Duke Energy Business Services, LLC, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of his knowledge, information and belief.

J. A. Miller

Joseph A. Miller Affiant

Subscribed and sworn to before me by Joseph A. Miller on this 24th day of August, 2017.

EVELYN G ROSEMAN NOTARY PUBLIC MECKLENBURG COUNTY, NC

Evelyn G. Roseman

NOTARY PUBLIC

My Commission Expires: Aug 18, 2019

Duke Energy Kentucky, Inc.

Environmental Compliance Plan

Project #	Project Description	Air Pollutant or Waste/Byproduct to be controlled	Control Facility	Generating Station	Environmental Regulation	Environmental Permits[1]	Scheduled Completion	Actual (A) or Est. (E) Projected Capital Cost ($Million)
1.	EB020290 Lined Retention Basin West;	Bottom Ash	CCR/ELG	East Bend	EPA CCR and ELG Final Rules	Division of Surface Water, KPDES Permit #0040444 Dam Safety Permit from Division of Surface Water listed (Stream Construction Permit), Permit No. **26395P**	November 2018	$24(E)
2.	EB020745 Lined Retention Basin East;	Bottom Ash	CCR/ELG	East Bend	EPA CCR and ELG Final Rules	Division of Surface Water, KPDES Permit #0040444 Dam Safety Permit from Division of Surface Water listed (Stream Construction Permit), Permit No. **26395P**	2021	$18(E)
3.	EB020298 East Bend SW/PW Reroute; and	Bottom Ash, misc., CCR runoff	CCR/ELG KY groundwater regulations	East Bend	EPA CCR and ELG Final Rules, KPDES	KDWM, Permit number SW00800006, KDEP Division of Surface Water, KPDES Permit #0040444	2020	$22 (E)
4.	ARO for Pond Closure;	Bottom Ash	CCR/ELG, KY Ground water regulations	East Bend	EPA CCR and ELG Final Rules and KPDES	KDEP Division of Waste Management concurrence for clean closure.	2021	$29 (E)
5.	Consumables (EAs Reagents, etc.)	SO_2, NOx, CO_2	CAIR	East Bend	CAIR		Ongoing	N/A

[1] Permits filed with Commission in Case No. 2016-00398

Duke Energy Kentucky, Inc.

Environmental Compliance Plan

Project #	Project Description	Air Pollutant or Waste/Byproduct to be controlled	Control Facility	Generating Station	Estimated Annual O&M			
					2018	2019	2020	2021
1.	EB020290 Lined Retention Basin West	Bottom Ash	CCR/ELG	East Bend	\$0 (E)	\$0 (E)	\$0 (E)	\$0 (E)
2.	EB020745 Lined Retention Basin East	Bottom Ash	CCR/ELG	East Bend	\$0 (E)	\$0 (E)	\$0 (E)	\$0 (E)
3.	EB020298 East Bend SW/PW Reroute	Bottom Ash, misc., CCR runoff	CCR/ELG KY groundwater regulations	East Bend	\$0 (E)	\$0 (E)	\$0 (E)	\$0 (E)
4.	ARO for Pond Closure	Bottom Ash	CCR/ELG, KY Ground water regulations	East Bend	\$0 (E)	\$0 (E)	\$0 (E)	\$0.1 (E)*
5.	Consumables (Emission Allowances, Reagents, etc)	SO_2, NOx, CO_2	CAIR	East Bend	\$13 (E)	\$15 (E)	\$13 (E)	\$16 (E)

*O&M estimates represent post-closure maintenance costs related to all four bottom ash projects listed above: EB020290, EB020745, EB020298 and the ARO for Pond Closure.