COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

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

CASE NO. 2018-00261

FILING REQUIREMENTS

VOLUME 1

Duke Energy Kentucky, Inc.
Case No. 2018-00261
Forecasted Test Period Filing Requirements
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1	6	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.	Amy B. Spiller
1	7	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.	Amy B. Spiller
1	8	807 KAR 5:001 Section 16 (1)(b)(1)	Reason adjustment is required.	Amy B. Spiller William Don Wathen, Jr.
1	9	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.	Amy B. Spiller
1	10	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	11	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	12	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.	Amy B. Spiller
1	13	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.	Amy B. Spiller
1	14	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.	Amy B. Spiller
1	15	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. "Beau" Pratt
1	16	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. "Beau" Pratt
1	17	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	18	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. "Beau" Pratt

1	19	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. "Beau" Pratt
1	20	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	21	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	22	807 KAR 5:001 Section 16(7)(b)	Most recent capital construction budget containing at minimum 3 year forecast of construction expenditures.	Robert H. "Beau" Pratt Gary J. Hebbeler
1	23	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. "Beau" Pratt
1	24	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. "Beau" Pratt
1	25	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.	Amy B. Spiller
1	26	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. "Beau" Pratt Gary J. Hebbeler
1	27	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. "Beau" Pratt Gary J. Hebbeler

1	28	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. "Beau" Pratt Gary J. Hebbeler Benjamin Passty
1	29	807 KAR 5:001 Section 16(7)(i)	Most recent FERC or FCC audit reports.	Michael Covington
1	30	807 KAR 5:001 Section 16(7)(j)	Prospectuses of most recent stock or bond offerings.	Robert H. "Beau" Pratt
1	31	807 KAR 5:001 Section 16(7)(k)	Most recent FERC Form 1 (electric), FERC Form 2 (gas), or PSC Form T (telephone).	Michael Covington
2	32	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.	Robert H. "Beau" Pratt
3	33	807 KAR 5:001 Section 16(7)(m)	Current chart of accounts if more detailed than Uniform System of Accounts charts.	Michael Covington
3	34	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.	Michael Covington
3	35	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.	Michael Covington Robert H. "Beau" Pratt
3-11	36	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.	Michael Covington
11	37	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.	Michael Covington
11	38	807 KAR 5:001 Section 16(7)(r)	Quarterly reports to the stockholders for the most recent 5 quarters.	Robert H. "Beau" Pratt

11	39	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
11	40	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
11	41	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
11	42	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	43	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	44	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	45	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. "Beau" Pratt John R. Panizza James E. Ziolkowski Michael Covington
11	46	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	.47	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. "Beau" Pratt James E. Ziolkowski
11	48	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.	John R. Panizza
11	49	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	50	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 Renee H. Metzler
11	51	807 KAR 5:001 Section 16(8)(h)	Computation of gross revenue conversion factor for forecasted period.	Sarah E. Lawler
11	52	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.	Michael Covington Robert H. "Beau" Pratt
11	53	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.	Robert H. "Beau" Pratt
11	54	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. "Beau" Pratt Michael Covington
11	55	807 KAR 5:001 Section 16(8)(l)	Narrative description and explanation of all proposed tariff changes.	Bruce L. Sailers
11	56	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	57	807 KAR 5:001 Section 16(8)(n)	Typical bill comparison under present and proposed rates for all customer classes.	Bruce L. Sailers
11	58	807 KAR 5:001 Section 16(9)	The commission shall notify the applicant of any deficiencies in the application within thirty (30) days of the application's submission. An application shall not be accepted for filing until the utility has cured all noted deficiencies.	William Don Wathen, Jr.

11	59	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.	Amy B. Spiller
11	60	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.	Amy B. Spiller

11	61	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.	Amy B. Spiller

11	62	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	63	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 (n)	Schedule Book, including Work Papers (Schedules A-N)	Various
13	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 1 of 3)	Various
14	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 2 of 3)	Various
15	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 3 of 3)	Various
16-17	-	KRS 278.2205(6)	Cost Allocation Manual	Legal

DUKE ENERGY KENTUCKY
CASE NO. 2018-00261
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR KRS 278.180

KRS 278.180

Description of Filing Requirement:

Provide thirty (30) days' notice of rate change to Kentucky Public Service Commission.

Response:

See attached.

Sponsoring Witness: Amy B. Spiller

DUKE ENERGY.

Amy B. Spiller
President
Duke Energy Kentucky

139 E. 4th Street
Room 1409-M
Cincinnati, OH 45202

513.287.4359
amy.spiller@duke-energy.com

VIA HAND DELIVERY

RECEIVED

AUG 01 2018

PUBLIC SE[illegible]
COM[illegible]

August 1, 2018

Ms. Gwen R. Pinson
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602-0615

RE: Case No. 2018- 00261
Duke Energy Kentucky, Inc.'s Application for Authority to Adjust Natural Gas Rates, Approval of a Decoupling Mechanism, Approval of New Tariffs, and for All Other Required Approvals, Waivers, and Relief

Dear Ms. Pinson:

Duke Energy Kentucky, Inc. ("Duke Energy Kentucky" or the "Company") notifies the Commission that it will file a general natural gas rate case in thirty days or reasonably soon thereafter.[1] Duke Energy Kentucky will use a forward-looking test period for this case.

Additionally, as part of the new tariffs included in the Company's application, Duke Energy Kentucky seeks to establish a weather normalization adjustment mechanism.

Duke Energy Kentucky has contemporaneously filed a Notice of Election of use of Electronic Filing Procedures for this proceeding. Please assign this matter a case number and style and advise us of same so that it can be incorporated into the application and supporting testimony before filing with the Commission.

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[1] Duke Energy Kentucky provides this notice pursuant to Commission regulation 807 KAR 5:001 Section 16(2).

Duke Energy Kentucky is providing a copy of this notice to the Attorney General's Utility Intervention and Rate Division. We will work diligently with the Commission and our other stakeholders to seek a constructive resolution. Thank you for your consideration.

Sincerely,

Amy B. Spiller

cc: Chairman Michael Schmitt (via overnight mail)
Vice Chairman Robert Cicero (via overnight mail)
Commissioner Dr. Talina Mathews (via overnight mail)
Hon. Andrew Beshear (via overnight mail)
Hon. Rebecca Goodman (via overnight mail)

DUKE ENERGY KENTUCKY
CASE NO. 2018-00261
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 7(1)

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807 KAR 5:001, SECTION 7(1)

Description of Filing Requirement:

Unless the Commission orders otherwise or the electronic filing procedures established in Section 8 of this administrative regulation are used, if a paper is filed with the commission, an original unbound and ten (10) additional copies in paper medium shall be filed.

Response:

Duke Energy Kentucky elected, and was approved for, the use of electronic filing procedures in this matter. As such, in accordance with 807 KAR 5:001, Section 8(3), the Company will file one (1) copy of the paper Application no later than the second business day following the successful electronic submission.

Witness Responsible: Amy B. Spiller

DUKE ENERGY KENTUCKY
CASE NO. 2018-00261
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 12(2)(a) through (i)

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807 KAR 5:001, SECTIONS 12(2)(a) through 12(2)(i)

Description of Filing Requirements:

Section 12(2)(a)

- Amount and kinds of stock authorized.

Section 12(2)(b)

- Amount and kinds of stock issued and outstanding.

Section 12(2)(c)

- Terms of preference of preferred stock, cumulative or participating, or on dividends or assets or otherwise.

Section 12(2)(d)

- A brief description of each mortgage on property of applicant, giving date of execution, name of mortgagor, name of mortgagee or trustee, amount of indebtedness authorized to be secured, and the amount of indebtedness actually secured, together with sinking fund provisions, if applicable.

Section 12(2)(e)

- The amount of bonds authorized and amount issued, giving the name of the public utility that issued the same, describing each class separately and giving the date of issue, face value, rate of interest, date of maturity, and how secured, together with amount of interest paid during the last fiscal year.

Section 12(2)(f)

- Each note outstanding, giving date of issue, amount, date of maturity, rate of interest, in whose favor, together with amount of interest paid during the last fiscal year.

Section 12(2)(g)

- Other indebtedness, giving same by classes and describing security, if any, with a brief statement of the devolution or assumption of a portion of the indebtedness upon or by person or corporation if the original liability has been transferred, together with amount of interest paid during the last fiscal year.

Section 12(2)(h)

- The rate and amount of dividends paid during the five (5) previous fiscal years, and the amount of capital stock on which dividends were paid each year.

Section 12(2)(i)

- A detailed Income Statement and Balance Sheet

Response:

See attached.

Sponsoring Witness:

Robert H. "Beau" Pratt – Sections 12(2)(a)-(h)
Michael Covington – Section 12(2)(i)

FINANCIAL EXHIBIT

(1) Section 12(2)(a) Amount and kinds of stock authorized.

1,000,000 shares of Capital Stock $15 par value amounting to $15,000,000 par value.

(2) Section 12(2)(b) Amount and kinds of stock issued and outstanding.

585,333 shares of Capital Stock $15 par value amounting to $8,779,995 total par value. Total Capital Stock and Additional Paid-in Capital as of June 30, 2018:

Capital Stock and Additional Paid-in Capital
As of June 30, 2018
($ per 1,000)

Capital Stock	$8,780
Premiums thereon	18,839
Total Capital Contributions from Parent (since 2006)	58,594
Contribution from Parent Company for Purchase of Generation Assets	140,061
Total Capital Stock and Additional Paid-in-Capital	$226,274

(3) Section 12(2)(c) Terms of preference or preferred stock, cumulative or participating, or on dividends or assets or otherwise.

There is no preferred stock authorized, issued or outstanding.

(4) Section 12(2)(d) Brief description of each mortgage on property of applicant, giving date of execution, name of mortgagor, name or mortgagee, or trustee, amount of indebtedness authorized to be secured, and the amount of indebtedness actually secured, together with any sinking fund provision.

Duke Energy Kentucky does not have any liabilities secured by a mortgage.

(5) Section 12(2)(e) Amount of bonds authorized, and amount issued, giving the name of the public utility which issued the same, describing each class separately, and giving the date of issue, face value, rate of interest, date of maturity and how secured, together with the amount of interest paid thereon during the last fiscal year.

The Company has seven outstanding issues of unsecured senior debentures issued under an Indenture dated December 1, 2004, between itself and Deutsche Bank Trust Company Americas, as Trustee, as supplemented by four Supplemental Indentures. The Indenture allows the Company to issue debt securities in an unlimited amount from time to time. The Debentures issued and outstanding under the Indenture are the following:

Supplemental Indenture	Date of Issue	Principal Amount Authorized and Issued	Principal Amount Outstanding	Rate of Interest	Date of Maturity	Interest Paid Year 2017
1st Supplemental	3/7/2006	65,000,000	65,000,000	6.200%	3/10/2036	4,030,000
2nd Supplemental	9/22/2009	100,000,000	100,000,000	4.650%	10/1/2019	4,650,000
3rd Supplemental	1/5/2016	45,000,000	45,000,000	3.420%	1/15/2026	1,539,000
3rd Supplemental	1/5/2016	50,000,000	50,000,000	4.450%	1/15/2046	2,225,000
4th Supplemental	9/7/2017	30,000,000	30,000,000	3.350%	9/15/2029	0
4th Supplemental	9/7/2017	30,000,000	30,000,000	4.110%	9/15/2047	0
4th Supplemental	9/7/2017	30,000,000	30,000,000	4.260%	9/15/2057	0
			350,000,000			12,444,000

(6) Section 12(2)(f) Each note outstanding, giving date of issue, amount, date of maturity, rate of interest, in whose favor, together with amount of interest paid thereon during the last fiscal year.

Not applicable.

(7) Section 12(2)(g) Other indebtedness, giving same by classes and describing security, if any, with a brief statement of the devolution or assumption of any portion of such indebtedness upon or by person or corporation if the original liability has been transferred, together with amount of interest paid thereon during the last fiscal year.

The Company has two series of Pollution Control Revenue Refunding Bonds issued under a Trust Indenture dated as of August 1, 2006 and a Trust Indenture dated as of December 1, 2008, between the County of Boone, Kentucky and Deutsche Bank National Trust Company as Trustee. The Company's obligation to make payments equal to debt service on the Bonds is evidenced by a Loan Agreement dated as of August 1, 2006 and December 1, 2008 between the County of Boone, Kentucky and Duke Energy Kentucky. The Bonds issued under the Indentures are as follows:

Indenture	Date of Issue	Principal Amount Authorized and Issued	Principal Amount Outstanding	Rate of Interest	Date of Maturity	Interest Paid Year 2017
Series 2010	11/24/2010	26,720,000	26,720,000	3.86%[(1)]	8/1/2027	212,753
Series 2008A	12/01/2011	50,000,000	50,000,000	1.50% [(2)]	8/1/2027	748,652
			76,720,000			961,405

[(1)] The bonds were issued at a variable-rate and were swapped to a fixed rate of 3.86% for the life of the debt. The average floating-rate of interest on the bonds for 2017 was 0.80%.
[(2)] The interest rate represents the average floating-rate of interest on the bonds for 2017. The interest rate on the bonds resets on the first day of every month based on 75% of the sum of one month and spread of 1.25%.

The Company has issued and has outstanding as of June 30, 2018 the following capital leases:

Series	Date of Issue	Principal Amount Authorized and Issued	Principal Amount Outstanding	Rate of Interest	Date of Maturity
Erlanger	12/30/2006	2,100,000	518,255	8.634	09/30/2020
2010	06/18/2010	955,061	221,302	3.330	06/18/2019
		3,055,061	739,557		

The Company also has $99,892,000 of money pool borrowings outstanding as of June 30, 2018, $25,000,000 of which is classified as Long-Term Debt payable to affiliated companies. This obligation, which is short-term by nature, is classified as long-term due to Duke Energy Kentucky's intent and ability to utilize such borrowings as long-term financing.

(8) Section 12(2)(h) Rate and amount of dividends paid during the last five (5) previous fiscal years, and the amount of capital stock on which dividends were paid each year.

DIVIDENDS PER SHARE

Year Ending	Per Share	Total	No. of Shares	Par Value of Stock
December 31, 2013	68.34	40,001,000	585,333	8,779,995
December 31, 2014	0.00	0	585,333	8,779,995
December 31, 2015	93.96	55,000,000	585,333	8,779,995
December 31, 2016	17.08	10,000,000	585,333	8,779,995
December 31, 2017	0.00	0	585,333	8,779,995

(9) Section 12(2)(i) A detailed Income Statement and Balance Sheet.

DUKE ENERGY KENTUCKY, INC.
Condensed Statements of Operations
(Unaudited)

(in thousands)	12 Months Ended June 30, 2018
Operating Revenues	
Electric	$ 354,190
Natural gas	100,451
Total operating revenues	454,641
Operating Expenses	
Fuel used in electric generation and purchased power	134,968
Cost of natural gas	39,434
Operation, maintenance and other	145,927
Depreciation and amortization	54,047
Property and other taxes	14,892
Total operating expenses	389,268
Loss on Sales of Assets, net	(163)
Operating Income	65,210
Other Income and Expenses, net	8,164
Interest Expense	15,729
Income Before Income Taxes	57,644
Income Tax Expense (Benefit)	(7,600)
Net Income	$ 65,245

DUKE ENERGY KENTUCKY, INC.
Condensed Balance Sheets
(Unaudited)

(in thousands, except share amounts)	June 30, 2018	December 31, 2017
ASSETS		
Current Assets		
Cash and cash equivalents	$ 1,270	$ 1,687
Receivables (net of allowance for doubtful accounts of $222 at June 30, 2018 and $234 at December 31, 2017)	6,163	3,537
Receivables from affiliated companies	14,921	22,286
Notes receivable from affiliated companies	—	14,671
Inventory	39,745	43,793
Regulatory assets	11,887	4,356
Collateral assets	6,609	1,975
Other	10,192	2,913
Total current assets	90,787	95,218
Property, Plant and Equipment		
Cost	2,402,750	2,292,085
Accumulated depreciation and amortization	(965,119)	(977,244)
Net property, plant and equipment	1,437,631	1,314,841
Other Noncurrent Assets		
Regulatory Assets	117,354	118,738
Other	11,593	2,175
Total other noncurrent assets	128,947	120,913
Total Assets	$ 1,657,365	$ 1,530,972
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$ 38,030	$ 48,797
Accounts payable to affiliated companies	12,626	15,774
Notes payable to affiliated companies	74,892	—
Taxes accrued	10,110	17,602
Interest accrued	5,419	5,387
Current maturities of long-term debt	439	885
Asset retirement obligations	5,006	3,378
Regulatory liabilities	9,888	6,892
Other	21,683	17,335
Total current liabilities	178,093	116,050
Long-Term Debt	425,079	425,295
Long-Term Debt Payable to Affiliated Companies	25,000	25,000
Other Noncurrent Liabilities		
Deferred income taxes	191,899	186,437
Asset retirement obligations	54,704	51,204
Regulatory liabilities	162,275	171,617
Accrued pension and other post-retirement benefit costs	24,576	17,418
Other	25,332	26,537
Total other noncurrent liabilities	458,786	453,213
Commitments and Contingencies		
Equity		
Common Stock, $15.00 par value, 1,000,000 shares authorized and 585,333 shares outstanding	8,780	8,780
Additional paid-in-capital	217,494	182,494
Retained earnings	344,133	320,140
Total equity	570,407	511,414
Total Liabilities and Equity	$ 1,657,365	$ 1,530,972

DUKE ENERGY KENTUCKY
CASE NO. 2018-00261
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 14(1)

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807 KAR 5:001, SECTION 14(1)

Description of Filing Requirement:

Each application shall state the full name, mailing address, and electronic mail address of the applicant, and shall contain fully the facts on 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 for the information.

Response:

See application submitted in this proceeding.

Sponsoring Witness: Amy B. Spiller

DUKE ENERGY KENTUCKY
CASE NO. 2018-00261
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 14(2)

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807 KAR 5:001, SECTION 14(2)

Description of Filing Requirement:

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.

Response:

See attached.

Sponsoring Witness: Amy B. Spiller

Commonwealth of Kentucky
Alison Lundergan Grimes, Secretary of State

Alison Lundergan Grimes
Secretary of State
P. O. Box 718
Frankfort, KY 40602-0718
(502) 564-3490
http://www.sos.ky.gov

Certificate of Existence

Authentication number: 205536
Visit https://app.sos.ky.gov/ftshow/certvalidate.aspx to authenticate this certificate.

I, Alison Lundergan Grimes, Secretary of State of the Commonwealth of Kentucky, do hereby certify that according to the records in the Office of the Secretary of State,

DUKE ENERGY KENTUCKY, INC.

is a corporation duly incorporated and existing under KRS Chapter 14A and KRS Chapter 271B, whose date of incorporation is March 20, 1901 and whose period of duration is perpetual.

I further certify that all fees and penalties owed to the Secretary of State have been paid; that Articles of Dissolution have not been filed; and that the most recent annual report required by KRS 14A.6-010 has been delivered to the Secretary of State.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my Official Seal at Frankfort, Kentucky, this 7th day of August, 2018, in the 227th year of the Commonwealth.

Alison Lundergan Grimes
Secretary of State
Commonwealth of Kentucky
205536/0052929

DUKE ENERGY KENTUCKY
CASE NO. 2018-00261
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 14(3)

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807 KAR 5:001, SECTION 14(3)

Description of Filing Requirement:

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.

Response:

Duke Energy Kentucky is a corporation; therefore, this requirement does not apply.

Sponsoring Witness: Amy B. Spiller

DUKE ENERGY KENTUCKY
CASE NO. 2018-00261
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 14(4)

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807 KAR 5:001, SECTION 14(4)

Description of Filing Requirement:

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.

Response:

Duke Energy Kentucky is a corporation; therefore, this requirement does not apply.

Sponsoring Witness: Amy B. Spiller

807 KAR 5:001, SECTION 16(1)(b)(1)

Description of Filing Requirement:

Statement of the reason the adjustment is required.

Response:

1) Duke Energy Kentucky's current base rates reflect its cost of service as prepared in 2009. At current rates, the Company's calculated rate of return on rate base for the test period is 4.66% which is not sufficient to enable the Company to furnish safe, efficient and reliable service and to have the opportunity to earn a fair rate of return on its investments.
2) Duke Energy Kentucky needs to adjust its current costs of service to reflect its capital investments and operations and maintenance of its gas operations that have changed since its 2009 case.
   a. The thirteen-month average of gross plant in this forecasted test period for this case is $589 million, as compared to approximately $389 million included in the 2009 rate case. The depreciation, property taxes, and return on this increased investment are the primary drivers of the need for new rates.
3) Other drivers include:
   a. Near stagnant load growth;
   b. Need to commence recovery of authorized deferrals (*e.g.*, integrity management);

c. The completion of the Company's Accelerated Service Replacement Program (ASRP);

d. Implementation of a new weather normalization adjustment mechanism; and

e. Updated Tax Expense as a result of the Tax Cuts and Jobs Act (TCJA).

Please refer to the direct testimony of Duke Energy Kentucky witnesses Amy B. Spiller and William Don Wathen, Jr.

Sponsoring Witness:

Amy B. Spiller
William Don Wathen, Jr.

DUKE ENERGY KENTUCKY
CASE NO. 2018-00261
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(1)(b)(2)

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807 KAR 5:001, SECTION 16(1)(b)(2)

Description of Filing Requirement:

A certified copy of a certificate of assumed name as required by KRS 365.015 or a statement that a certificate is not necessary.

Response:

Duke Energy Kentucky transacts business using the following assumed name: Duke Energy.

A certified copy of the Company's certificate of assumed name is attached.

Sponsoring Witness: Amy B. Spiller

COMMONWEALTH OF KENTUCKY

Alison Lundergan Grimes
Secretary of State

Certificate

I, Alison Lundergan Grimes, Secretary of State for the Commonwealth of Kentucky, do hereby certify that the foregoing writing has been carefully compared by me with the original thereof, now in my official custody as Secretary of State and remaining on file in my office, and found to be a true and correct copy of

RENEWAL CERTIFICATE OF

ASSUMED NAME OF DUKE ENERGY FILED FEBRUARY 24, 2016.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my Official Seal at Frankfort, Kentucky, this 8th day of August, 2018.

Alison Lundergan Grimes
Secretary of State
Commonwealth of Kentucky
RPacheco/0052929 - Certificate ID: 205559

C227
0052929.04
Alison Lundergan Grimes
KY Secretary of State
Received and Filed
2/24/2016 11:47:22 AM
Fee receipt: $20.00

Commonwealth of Kentucky
Alison Lundergan Grimes, Secretary o

Alison Lundergan Grimes Secretary of State P. O. Box 718 Frankfort, KY 40602-0718 (502) 564-3490 http://www.sos.ky.gov	**Renewal Certificate of Assumed Name**	**REN**

This certifies that the assumed name of

DUKE ENERGY

is hereby renewed by

DUKE ENERGY KENTUCKY, INC.

a business entity organized and existing in the state of Kentucky.

Signatures

Signature	Nancy M. Wright
Title	Assistant Corporate Secretary
Date	2/24/2016 11:47:22 AM

DUKE ENERGY KENTUCKY
CASE NO. 2018-00261
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(1)(b)(3)

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807 KAR 5:001, SECTION 16(1)(b)(3)

Description of Filing Requirement:

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.

Response:

The proposed tariffs are at Schedule L-1.

Sponsoring Witness: Bruce L. Sailers

DUKE ENERGY KENTUCKY
CASE NO. 2018-00261
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(1)(b)(4)

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807 KAR 5:001, SECTION 16(1)(b)(4)

Description of Filing Requirement:

New or revised tariff sheets, if applicable, identified in compliance with 807 KAR 5:011, shown either by providing:

a. The present and proposed tariffs in comparative form on the same sheet side by side or on facing sheets side by side; or

b. A copy of the present tariff indicating proposed additions by italicized inserts or underscoring and striking over proposed deletions.

Response:

See Schedules L-2.1 and L-2.2.

Sponsoring Witness: Bruce L. Sailers

DUKE ENERGY KENTUCKY
CASE NO. 2018-00261
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(1)(b)(5)

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807 KAR 5:001, SECTION 16(1)(b)(5)

Description of Filing Requirement:

A statement that notice has been given in compliance with Section 17 of this administrative regulation with a copy of the notice.

Response:

See attached.

Sponsoring Witness: Amy B. Spiller

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 Natural Gas Rates; 2) Approval of a Decoupling Mechanism; 3) Approval of New Tariffs; and 4) All Other Required Approvals, Waivers, and Relief.	)))))))	Case No. 2018-000261

CERTIFICATE OF NOTICE

Pursuant to the Kentucky Public Service Commission's Regulation 807 KAR 5:001, Section 16(1)(b)(5), I hereby certify that I am Amy B. Spiller, President of Duke Energy Kentucky, Inc. (Duke Energy Kentucky or Company), a utility furnishing retail electric and gas service within the Commonwealth of Kentucky, which, on the 31st day of August 2018, filed an application with the Kentucky Public Service Commission for the approval of an adjustment of the natural gas rates, terms, conditions, and tariffs of Duke Energy Kentucky and that notice to the public of the issuing of the same is being given in all respects as required by 807 KAR 5:001, Section 17 and 807 KAR 5:001, Sections 8(2)(c) and 9(2), as follows:

On the 31st day of August 2018, the notice to the public was delivered for exhibition and public inspection at 4580 Olympic Boulevard, Erlanger, Kentucky 41018 and the same will be kept open to public inspection at said office in conformity with the requirements of 807 KAR 5:001, Section 17(1)(a) and 807 KAR 5:011, Section 8(1)(a).

I further certify that more than twenty (20) customers will be affected by said change by way of an increase in their rates or charges and that on the 21st day of August 2018, there was delivered to the Kentucky Press Association, an agency that acts on behalf of newspapers of general circulation throughout the Commonwealth of Kentucky in which customers affected reside, for publication therein once a week for three consecutive weeks beginning on August 28, 2018, a notice of the filing of Duke Energy Kentucky's application, including its proposed rates, a copy of said notice being attached hereto as Exhibit A, and a list of newspapers of general circulation throughout the Commonwealth of Kentucky in which customers affected reside, a copy of said list being attached hereto as Exhibit B. A certificate of publication of said notice will be furnished to the Kentucky Public Service Commission upon completion of same pursuant to 807 KAR 5:001, Section 17(3)(b).

Also beginning on August 31, 2018, Duke Energy Kentucky posted on its website a complete copy of the Company's notice and a hyperlink to the location on the Kentucky Public Service Commission's website where the case documents and tariff filings are available.

Given under my hand this 31st day of August, 2018.

Amy B. Spiller

Amy B. Spiller
President, Duke Energy Kentucky, Inc.
139 E. 4th Street
Cincinnati, Ohio 45202

Subscribed and sworn to before me, a Notary Public, in and before said County and State, this 31st day of August, 2018.

E. Minna Rolfes-Adkins

Notary Public

My Commission expires: July 8, 2022

NOTARY PUBLIC ★ STATE OF OHIO ★

E. MINNA ROLFES-ADKINS
Notary Public, State of Ohio
My Commission Expires
July 8, 2022

NOTICE

Duke Energy Kentucky, Inc. (Duke Energy Kentucky) hereby gives notice that it will file an application on or about August 31, 2018 seeking approval by the Kentucky Public Service Commission of an adjustment of natural gas rates to become effective on and after October 1, 2018. The Commission has docketed this proceeding as Case No. 2018-00261.

The proposed natural gas rates are applicable to the following communities:

Alexandria	Elsmere	Ludlow
Bellevue	Erlanger	Melbourne
Boone County	Fairview	Newport
Bracken County	Falmouth	Park Hills
Bromley	Florence	Pendleton County
Butler	Fort Mitchell	Ryland Heights
Campbell County	Fort Thomas	Silver Grove
Cold Spring	Fort Wright	Southgate
Covington	Gallatin County	Taylor Mill
Crescent Park	Glencoe	Union
Crescent Springs	Grant County	Villa Hills
Crestview	Highland Heights	Visalia
Crestview Hills	Independence	Walton
Crittenden	Kenton County	Warsaw
Dayton	Kenton Vale	Wilder
Dry Ridge	Lakeside Park	Woodlawn
Edgewood	Latonia Lakes	Williamstown

DUKE ENERGY KENTUCKY PRESENT AND PROPOSED RATES

The present and proposed rates charged in all territories served by Duke Energy Kentucky are as follows. The current GCA Rate in effect as of August 1, 2018 is $0.4170 per CCF.

Residential Service - Rate RS

	Present Rates	Proposed Rates
Monthly Customer Charge:	$16.00	$17.50
Base Rate for all Ccf	$0.37213	$0.48677
GCA for all Ccf	$0.41700	$0.41700
Total Rate (Base Rate + GCA) for all Ccf	$0.78913	$0.90377

General Service - Rate GS

	Present Rates	Proposed Rates
Monthly Customer Charge:	$47.50	$50.00
Base Rate – All Ccf	$0.20530	$0.28077
GCA – All Ccf	$0.41700	$0.41700
Total Rate (Base Rate + GCA) for all Ccf	$0.62230	$0.69777

Interruptible Transportation Service - Rate IT

	Present Rates	Proposed Rates
Monthly Customer Charge:	$430.00	$430.00
Base Rate – All Ccf	$0.09493	$0.10369

Firm Transportation Service-Large - Rate FT-L

	Present Rates	Proposed Rates
Monthly Customer Charge:	$430.00	$430.00
Base Rate – All Ccf	$0.17369	$0.23319

Interruptible Monthly Balancing Service - Rate IMBS

Present Rate

Transportation customers who avail themselves of the service under this rate schedule must, with the agreement of their supplier, select a monthly imbalance carry over tolerance level from the following options:

	Allowed Monthly Under-Run %	Allowed Seasonal Monthly Over-Run May Through November %	December Through April %	Charge on All Throughput
Option 1	0	5	7	$0.015 per Mcf
Option 2	0	6	8	$0.020 per Mcf
Option 3	0	8	10	$0.025 per Mcf

Proposed Rate

Transportation customers who avail themselves of the service under this rate schedule must conform to the monthly imbalance carry over tolerance level shown below.

	Allowed Monthly Under-Run %	Allowed Seasonal Monthly Over-Run May Through November %	December Through April %	Charge on All Throughput
All Pools	0	8	10	$0.1097 per Mcf

Weather Normalization Adjustment Rider – Rider WNA

Present Rate

This is a new tariff schedule.

Proposed Rate

APPLICABILITY

Applicable to all customers receiving service under Rate RS, Residential Service, and Rate GS, General Service.

DETERMINATION OF WNA

The distribution charge per Ccf for gas service as set forth in Rates RS and GS shall be adjusted by an amount herein under described as the Weather Normalization Adjustment (WNA).

The WNA shall apply to all Rate RS and Rate GS bills during the November through April billing periods. The WNA shall increase or decrease accordingly by month. The WNA will not be billed during the billing periods of May through October. Customer base loads and heating sensitivity factors will be determined by rate class and adopted from the most recent order of the Kentucky Public Service Commission (KYPSC) approving such factors to be used in the application of this Rider.

The WNA shall be computed by rate class using the following formula:

$$WNA_i = R_i * \frac{(HSF_i * (\mathrm{NDD} - \mathrm{ADD}))}{(BL_i + (HSF_i * \mathrm{ADD})}$$

Where:

i	=	A rate schedule or billing classification within a rate schedule
WNA_i	=	Weather Normalization Adjustment Factor for the ith rate schedule or classification expressed as a rate per Ccf.
R_i	=	Weighted average rate (distribution charge) of temperature sensitive sales for the ith schedule or classification.
HSF_i	=	Heat sensitivity factor for ith rate schedule or classification.
NDD	=	Normal billing cycle heating degree days (based upon Company's 30-year normal period adopted from the most recent order of the KYPSC approving such normal for use in the application of this Rider.
ADD	=	Actual billing cycle heating degree days.
BL_i	=	Base load for the ith rate schedule or classification.

Charge for Reconnection of Service

Present Rate

The Company may charge and collect in advance the following:

A. The reconnection charge for service which has been disconnected due to enforcement of Rule 3 shall be twenty-five dollars ($25.00).
B. The reconnection charge for service which has been disconnected within the preceding twelve months at the request of the customer shall be twenty-five dollars ($25.00).
C. If service is discontinued because of fraudulent use thereof, the Company may charge and collect in addition to the reconnection charge of twenty-five dollars ($25.00) the expense incurred by the Company by reason of such fraudulent use, plus an estimated bill for gas used, prior to the reconnection of service.
D. If both the gas and electric service are reconnected at one time, the total charge shall not exceed thirty-eight dollars ($38.00).

Proposed Rate

The Company may charge and collect in advance the following:

A. The reconnection charge for service which has been disconnected due to enforcement of Rule 3 shall be seventy-five dollars ($75.00).
B. The reconnection charge for service which has been disconnected within the preceding twelve months at the request of the customer shall be seventy-five dollars ($75.00).
C. If service is discontinued because of fraudulent use thereof, the Company may charge and collect in addition to the reconnection charge of seventy-five dollars ($75.00) the expense incurred by the Company by reason of such fraudulent use, plus an estimated bill for gas used, prior to the reconnection of service.
D. If both the gas and electric service are reconnected at the premise at one time, the total charge is available on Company's Electric Tariff Sheet No. 91, Charge for Reconnection of Service.

Meter Pulse Service - Rate MPS

Present Rates

Rate MPS is an optional service available to customers that request the Company to install gas meter pulse equipment, a meter-related service not otherwise provided by the Company. The gas meter pulse equipment provides an electronic pulse output representing a pre-determined natural gas volume. The volume will vary at different meter installations, and will thus be communicated to the customer at the time of installation. Pressure and temperature correcting factors may need to be applied by the customer. The customer is responsible for providing power and communication links to the meter pulse equipment per the Company's specifications. Customer must provide either a regulated 24 volts DC, or 120 volts AC electric supply, to an area 2' x 2', approximately 20' away from any gas pipeline flanges or gas pressure relief devices.

Installation of meter pulse equipment:	$500.00
If replacement of Meter Index is necessary, additional charge of:	$155.00

Proposed Rates

Rate MPS is an optional service available to customers that request the Company to install gas meter pulse equipment, a meter-related service not otherwise provided by the Company. The gas meter pulse equipment provides an electronic pulse output representing a pre-determined natural gas volume. The volume will vary at different meter installations, and will thus be communicated to the customer at the time of installation. Pressure and temperature correcting factors may need to be applied by the customer. The customer is responsible for providing power and communication links to the meter pulse equipment per the Company's specifications. Customer must provide either a regulated 24 volts DC, or 120 volts AC electric supply, to an area 2' x 2', approximately 20' away from any gas pipeline flanges or gas pressure relief devices.

Installation of meter pulse equipment:	$550.00
If replacement of Meter Index is necessary, additional charge of:	$560.00

In addition, Duke Energy Kentucky proposes to change the text as noted for the following tariffs:

Service Regulations Section II – Supplying and Taking of Service

Present Rate
6. USE OF SERVICE:
Service is supplied directly to Customer through Company's own meter and is to be used by Customer only for the purposes specified in and in accordance with the provisions of the Service Agreement and applicable Rate Schedule. Service is for Customer's use only and under no circumstances may Customer or Customer's agent or any other individual, association or corporation install meters for the purpose of reselling or otherwise disposing of service supplied Customer.

Proposed Rate
6. USE OF SERVICE:
Service is supplied directly to Customer through Company's own meter and is to be used by Customer only for the purposes specified in and in accordance with the provisions of the Service Agreement and applicable Rate Schedule. Service is for Customer's use only and under no circumstances may Customer or Customer's agent or any other individual, association or corporation install meters for the purpose of reselling service supplied Customer to any other individual, association, or corporation on Customer's premises or for use on any other premises. This does not preclude Customer from allocating Company's billing to Customer to any other individual, association, or corporation provided the sum of such allocations does not exceed Company's billing.

Service Regulations Section V – Metering

Present Rate
Each month the Company will monitor the usage of each customer according to the following procedure:
1. The customer's monthly usage is monitored through a "hi-lo" review process. An estimating factor is utilized to provide an expected level of usage. The estimating factor considers the customer's past usage and current variables, such as weather.
2. The actual usage is compared to an estimate based on the previous month's usage, an estimate based on the usage from the same month, one year previous, and an estimate based on the usage from the same month, two years previous.

Proposed Rate
Each month the Company will monitor the usage of each customer according to the following procedure:
1. The customer's monthly usage is monitored through a "hi-lo" review process that will incorporate customer past usage and other related information to provide an expected level of usage.

Service Regulations Section VI – Billing and Payment

Present Rate
The following text is removed from the tariff sheet, "If bills are rendered electronically then a charge not to exceed $0.25 per usage may be assessed."

Proposed Rate
The following description of the budget bill plan is added to the tariff sheet.
<u>Budget Billing Plan Description:</u>
Annual Plan:
- The Annual Plan provides 11 months of equal payments by using 12 months of customer's usage, dividing the usage by 11, and using the result to calculate the bill.
- Month 12 is a settle-up month between the billed amounts and customer bills based on actual usage.
- A bill message is sent after 6 months with a suggested new bill amount if the budget bill amounts compared to the actual bill amounts exceeds a Company set threshold; however, Customer must contact Company to change the amount.
- The budget bill amount is changed as needed after the 12 month review.

Quarterly Plan:
- The Quarterly Plan provides 3 months of equal payments starting by using 12 months of customer's usage, dividing the usage by 12, and using the result to calculate the bill.
- However, to prevent a settle-up month, reviews occur after 3, 6, 9, and 12 months on the plan and continue every 3 months thereafter.

- The budget bill amount is changed as needed after each review. The change is automatic and the customer does not need to contact Company.
- A bill message is sent after each review with a new bill amount if the budget bill amounts compared to the actual bill amounts exceeds a Company set threshold.

Full Requirements Aggregation Service - Rate FRAS

Present Rate

UPSTREAM CAPACITY REQUIREMENTS

Suppliers participating in the Company's firm transportation program must secure their own upstream pipeline capacity required to meet Supplier's Rate FT-L pool peak day requirements. Due to the physical configuration of the Company's system, and certain upstream interstate pipeline facilities, and to enable the Company to comply with lawful interstate pipeline tariffs and/or to maintain the Company's system integrity, during the months of December, January, and February, the Company reserves the right to direct Supplier to proportionally deliver, with respect to the Systems' (the Duke Energy Ohio and Duke Energy Kentucky, Inc. integrated operating system) northern and southern interstate pipeline interconnects, the Supplier's daily pool requirements. In those instances where the pool operator delivers gas into the Duke Energy Ohio pipeline system and Duke Energy Ohio then delivers said gas to Duke Energy Kentucky, Inc. for delivery to the pool operator's customers located in Kentucky, the pool operator shall pay Duke Energy Kentucky, Inc. for charges from Duke Energy Ohio for delivery of said gas, at the FERC approved rate.

OPERATIONAL FLOW ORDERS:

Over-deliveries

(1) Over-deliveries by Supplier will be confiscated by the Company and used for its general supply requirements, without compensation to Supplier,

Proposed Rate

DEFINITIONS:

"Under-Deliveries" or "Negative Imbalance Volume" is the amount by which the sum of all volumes actually delivered to the Pool customers during the period exceeds the sum of the volumes made available by supplier for redelivery by the Company to the Pool during the same period.

UPSTREAM CAPACITY REQUIREMENTS

Suppliers participating in the Company's firm transportation program must secure their own upstream pipeline capacity required to meet Supplier's Rate FT-L pool peak day requirements. Due to the physical configuration of the Company's system, and certain upstream interstate pipeline facilities, and to enable the Company to comply with lawful interstate pipeline tariffs and/or to maintain the Company's system integrity, the Company reserves the right to direct Supplier to proportionally deliver, with respect to the Systems' (the Duke Energy Ohio and Duke Energy Kentucky, Inc. integrated operating system) northern and southern interstate pipeline interconnects, the Supplier's daily pool requirements. In those instances where the pool operator delivers gas into the Duke Energy Ohio system and Duke Energy Ohio then delivers said gas to Duke Energy Kentucky, Inc. for delivery to the pool operator's customers located in Kentucky, the pool operator shall pay Duke Energy Kentucky, Inc. for charges from Duke Energy Ohio for delivery of said gas, at the FERC approved rate.

OPERATIONAL FLOW ORDERS:

Over-deliveries

(1) Over-deliveries will be cashed out to the Supplier at the lowest cost of gas available to Company on the date of non-compliance, plus transportation and fuel charges to the Company's city gate; and

Spark Spread Interruptible Transportation Rate - Rate SSIT

Proposed Rate

This tariff is hereby cancelled and withdrawn. Any references on individual tariffs were deleted.

Pooling Service for Interruptible Gas Transportation - Rate AS

Proposed Rate

The name of this rate is proposed as Rate AS - Aggregation Service for Interruptible Gas Transportation.

Gas Trading Service - Rate GTS

Present Rate
Daily imbalance trades or transfers must be made within four (4) business days from the date that the trade or transfer applies. Monthly imbalance trades or transfers must be completed within four (4) business days following the end of the month.

Proposed Rate
Daily imbalance trades or transfers must be completed within two (2) business days from the date that the trade or transfer applies. Monthly imbalance trades or transfers must be completed within two (2) business days following the end of the month.

Accelerated Service Replacement Program Rider - Rider ASRP

Present Rate
The charges for the respective gas service schedules for the revenue month beginning January 2018 are:

Rate RS, Residential Service	$1.80/month
Rate GS, General Service	$1.78/month
Rate DGS, Distributed Generation Service	$0.00045/CCF
Rate FT-L, Firm Transportation Service – Large	$0.00045/CCF
Rate IT, Interruptible Transportation Service	$0.00039/CCF
Rate SSIT, Spark Spread Interruptible Transportation Rate	$0.00039/CCF

Proposed Rate
This tariff is proposed to be incorporated into base rates listed above. This tariff is hereby cancelled and withdrawn.

Curtailment Plan for Management of Available Gas Supplies

Present Rate
Available in entire territory to which tariff Ky.P.S.C. Gas No. 1 applies.

Proposed Rate
Available in entire territory to which tariff Ky.P.S.C. Gas No. 2 applies.

IMPACT OF PROPOSED RATES

The foregoing proposed rates designed to recover Duke Energy Kentucky's revenue deficiency reflect an increase in gas revenues of approximately $10.5 million or 11.1% to Duke Energy Kentucky. The estimated amount of this increase per customer class is as follows:

Customer Class	Revenue Increase Proposed	%
Rate RS – Residential Service	$ 6,448,449	9.8%
Rate GS – Commercial Service	$ 2,041,693	10.3%
Rate GS – Industrial Service	$ 131,405	11.3%
Rate GS – Other Public Authority Service	$ 251,299	11.3%
Rate FT-L – Firm Transportation Service	$ 1,545,442	30.6%
Rate IT – Interruptible Transportation Service	$ 123,931	8.1%
Rate GTS – Gas Trading Service*	$0	0.0%
Rate IMBS – Interruptible Monthly Balancing Service*	$0	0.0%
Rider WNA – Weather Normalization Adjustment*	$0	0.0%
Charge for Reconnection of Service*	$0	0.0%
Rate MPS – Meter Pulse Service*	$0	0.0%

*The revenue deficiency is not allocated to these items.

The average monthly bill for each customer class to which the proposed rates will apply will increase approximately as follows:

Customer Class	Average Monthly CCF	Average Monthly Bill Increase Proposed	% Increase
Rate RS – Residential Service	53	$ 5.78	10.2%
Rate GS – Commercial Service	336	$ 26.08	10.3%
Rate GS – Industrial Service	683	$ 52.27	11.3%
Rate GS – Other Public Authority Service	733	$ 56.04	11.3%
Rate FT-L – Firm Transportation Service	23,202	$ 1,370.07	30.6%
Rate IT – Interruptible Transportation Service	56,060	$ 469.22	8.1%
Rate GTS – Gas Trading Service**	NA	$0	0.0%
Rate IMBS – Interruptible Monthly Balancing Service**	NA	$0	0.0%
Rider WNA – Weather Normalization Adjustment	NA	$0	0.0%
Charge for Reconnection of Service**	NA	$0	0.0%
Rate MPS – Meter Pulse Service**	NA	$0	0.0%

**These items are optional services not necessarily applicable to customer's average monthly bill.

The rates contained in this notice are the rates proposed by Duke Energy Kentucky; however, the Kentucky Public Service Commission may order rates to be charged that differ from the proposed rates contained in this notice. Such action may result in rates for consumers other than the rates in this notice.

A person may submit a timely written request for leave to intervene to the Public Service Commission, P.O. Box 615, Frankfort, Kentucky 40602, establishing the grounds for the request including the status and interest of the party. If the Commission does not receive a written request for intervention within thirty (30) days of the initial publication of the notice, the Commission may take final action on the application. Comments regarding the application can be submitted to the Public Service Commission through its website http://psc.ky.gov or by mailing a copy to the Public Service Commission, P.O. Box 615, Frankfort, Kentucky 40602.

Customers may obtain copies of the application and other filings made by the Company by emailing DEKInquiries@duke-energy.com or by telephone at (513) 287-4356. A copy of the application and other filings made by the Company is available for public inspection through the Commission's website at http://psc.ky.gov, at the Commission's office at 211 Sower Boulevard, Frankfort, Kentucky, Monday through Friday, 8:00 am. to 4:30 p.m., and at the following Duke Energy Kentucky offices: 4580 Olympic Boulevard, Erlanger, Kentucky 41018. Comments regarding the application may be submitted to the Public Service Commission through its website, or by mail at the following Commission address.

For further information contact:

PUBLIC SERVICE COMMISSION
COMMONWEALTH OF KENTUCKY
P. O. BOX 615
211 SOWER BOULEVARD
FRANKFORT, KENTUCKY 40602-0615
(502) 564-3940

DUKE ENERGY KENTUCKY
4580 OLYMPIC BOULEVARD
ERLANGER, KENTUCKY 41018
(513) 287-4356

List of Newspapers in Duke Energy Kentucky Territory

Campbell County Recorder
Covington Kentucky Enquirer
Falmouth Outlook
Kenton County Recorder
Warsaw Gallatin County News
Williamstown Grant County News

DUKE ENERGY KENTUCKY
CASE NO. 2018-00261
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(2)

---

807 KAR 5:001, SECTION 16(2)

Description of Filing Requirement:

Notice of intent. A utility with gross annual revenues greater than $5,000,000 shall notify the commission in writing of its intent to file a rate application at least thirty (30) days, but not more than sixty (60) days, prior to filing its application.

(a) The notice of intent shall state if the rate application will be supported by a historical test period or a fully forecasted test period.

(b) Upon filing the notice of intent, an application may be made to the commission for permission to use an abbreviated form of newspaper notice of proposed rate increases provided the notice includes a coupon that may be used to obtain a copy from the applicant of the full schedule of increases or rate changes.

(c) Upon filing the notice of intent with the commission, the applicant shall mail to the Attorney General's Office of Rate Intervention a copy of the notice of intent or send by electronic mail in a portable document format, to rateintervention@ag.ky.gov.

Response:

See Duke Energy Kentucky's response to Filing Requirement KRS 278.180 [Tab 1].

Sponsoring Witness: Amy B. Spiller

DUKE ENERGY KENTUCKY
CASE NO. 2018-00261
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(3)

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807 KAR 5:001, SECTION 16(3)

Description of Filing Requirement:

Notice given pursuant to Section 17 of this administrative regulation shall satisfy the requirements of 807 KAR 5:051, Section 2.

Response:

Notice given pursuant to 807 KAR 5:001, Section 17 satisfies the requirements of 807 KAR 5:051, Section 2. A copy of the customer notice is attached in response to Filing Requirement, 807 KAR 5:001, Section 16(1)(b)(5) [Tab 12].

Sponsoring Witness: Amy B. Spiller

DUKE ENERGY KENTUCKY
CASE NO. 2018-00261
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(6)(a)

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807 KAR 5:001, SECTION 16(6)(a)

Description of Filing Requirement:

The financial data for the forecasted period shall be presented in the form of pro forma adjustments to the base period.

Response:

See Schedules D-2.1 through D-2.14 located in Schedule Book.

Witness Responsible: Robert H. "Beau" Pratt

DUKE ENERGY KENTUCKY
CASE NO. 2018-00261
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(6)(b)

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807 KAR 5:001, SECTION 16(6)(b)

Description of Filing Requirement:

Forecasted adjustments shall be limited to the twelve (12) months immediately following the suspension period.

Response:

See Schedules D-2.15 through D-2.26 for adjustments to the forecasted period located in Schedule Book. These adjustments are limited to the twelve (12) months immediately following the suspension period.

Witness Responsible:

Sarah E. Lawler – Schedules D-2.15 thru D-2.22, D-2.24, D-2.26
Cynthia S. Lee – Schedule D-2.23
Robert H. "Beau" Pratt – Schedule D-2.25

DUKE ENERGY KENTUCKY
CASE NO. 2018-00261
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(6)(c)

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807 KAR 5:001, SECTION 16(6)(c)

Description of Filing Requirement:

Capitalization and net investment rate base shall be based on a thirteen (13) month average for the forecasted period.

Response:

Capitalization and Net Investment Rate Base for the Forecasted Period are based on a thirteen-month average.

Witness Responsible: Sarah E. Lawler

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807 KAR 5:001, SECTION 16(6)(d)

Description of Filing Requirement:

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.

Response:

The Company will comply with this requirement.

Witness Responsible: Robert H. "Beau" Pratt

DUKE ENERGY KENTUCKY
CASE NO. 2018-00261
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(6)(e)

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807 KAR 5:001, SECTION 16(6)(e)

Description of Filing Requirement:

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.

Response:

The Company will prepare an alternative forecast if requested by the Commission.

Witness Responsible: Robert H. "Beau" Pratt

DUKE ENERGY KENTUCKY
CASE NO. 2018-00261
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(6)(f)

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807 KAR 5:001, SECTION 16(6)(f)

Description of Filing Requirement:

The utility shall provide a reconciliation of the rate base and capital use to determine its revenue requirements.

Response:

See attached.

Witness Responsible: Sarah E. Lawler

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2018-00261
RECONCILIATION OF CAPITALIZATION AND RATE BASE
THIRTEEN MONTH AVERAGE BALANCE ENDING MARCH 31, 2020

DATA: BASE PERIOD "X" FORECASTED PERIOD
TYPE OF FILING: "X" ORIGINAL UPDATED REVISED
WORK PAPER REFERENCE NO(S).:

FR 16(6)(f)
PAGE 1 OF 3
WITNESS RESPONSIBLE:
S. E. LAWLER

Line No.	Description	Source	Amount
1	Capitalization Allocated to Gas Operations	Page 2 of 3	336,264,336
2	Adjustments to Plant in Service	Sch. B-2.2 & B-3.1	(4,381,521)
3	Assets per Books not included in Rate Base:		
4	Other Property and Investments		(405,919)
5	CWIP	Schedule B-4	(30,499,809)
6	Cash		(4,831,811)
7	Other Current Assets		(6,757,557)
8	Other Regulatory Assets		(17,733,247)
9	Other Deferred Debits		(12,103,762)
10	Subtotal		(72,332,105)
11	Liabilities per Books not included in Rate Base:		
12	Other Current liabilities		19,805,959
13	Other Non-current liabilities		18,492,160
14	Deferred Credits		12,811,912
15	Subtotal		51,110,031
16	Items included in Rate Base:		
17	Cash Working Capital Formula		3,021,735
18	Depreciation adjustment not included in capitalization		(1,084,440)
19	Capitalization / Rate Base Differences		1,077,202
20	Subtotal		3,014,497
21	Total Variance		(22,589,097)
22	Gas Rate Base	Schedule B-1	313,675,239

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2018-00261
RECONCILIATION OF CAPITALIZATION AND RATE BASE
THIRTEEN MONTH AVERAGE BALANCE ENDING MARCH 31, 2020

DATA: BASE PERIOD "X" FORECASTED PERIOD
TYPE OF FILING: "X" ORIGINAL UPDATED REVISED
WORK PAPER REFERENCE NO(S).:

FR 16(6)(f)

WITNESS RESPONSIBLE:
S. E. LAWLER

Line No.	Description		Capitalization Total	Capitalization Gas
1	Total Forecasted Period Capitalization	(1)	1,223,750,252	
2				
3	Less: Gas Non-jurisdictional Rate Base	(2)	5,305,479	
4	Electric Non-jurisdictional Rate Base	(2)	(2,483,226)	
5	Non-jurisdictional Rate Base	(2)	(25,213,748)	
6				
7	Jurisdictional Capitalization		1,246,141,747	
8				
9	Gas Jurisdictional Rate Base Allocation %	(2)	26.948%	335,810,278
10				
11	Plus: Jurisdictional Gas ITC	(3)		454,058
12				
13	Total Allocated Capitalization			336,264,336

To Page 1 of 1

Notes:
(1) Schedule J-1, page 1.
(2) Page 3 of 3
(3) Schedule B-6, page 1.

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2018-00261
RECONCILIATION OF CAPITALIZATION AND RATE BASE
THIRTEEN MONTH AVERAGE BALANCE ENDING MARCH 31, 2020

DATA: BASE PERIOD "X" FORECASTED PERIOD
TYPE OF FILING: "X" ORIGINAL UPDATED REVISED
WORK PAPER REFERENCE NO(S).:

FR 16(6)(f)

WITNESS RESPONSIBLE:
S. E. LAWLER

Line No.	Description	Schedule Reference	Total Company	Gas Excl. of Facil Dev. to Other Than DE-Ky Custs.		Gas Non-Juris.		Electric Jurisdictional		Electric Non-Juris.	Non-Jurisdictional
1	Total Utility Plant in Service (Accts 101 & 106) (B)	Sch B-2	2,464,838,661	588,627,191	(E)	12,331,190	(E)	1,863,880,280		0	0
2											
3	Additions:										
4	Construction Work in Progress (Account 107)	(D)	0	0		0		0		0	0
5											
6	Fuel Inventory	WPB-5.1i	18,664,613	0		0		18,664,613		0	0
7											
8	Materials & Supplies -										
9	Propane Inventory (Account 151) (B)	WPB-5.1b	3,586,912	1,284,114		2,302,798		0		0	0
10	Other Material and Supplies (Accts. 154 & 163)	WPB-5.1c	18,481,347	1,143,072		0		17,338,275		0	0
11	Total Materials & Supplies		22,068,259	2,427,186		2,302,798		17,338,275		0	0
12											
13	Gas Stored Underground (Account 164) (B)	WPB-5.1g	2,958,880	2,958,880		0		0		0	0
14											
15	Prepayments (Account 165) (B)	WPB-5.1e	2,148,487	37,742		14,056		1,325,422		771,267	0
16											
17	Emission Allowances (Account 158)	WPB-5.1j	0	0		0		0			
18											
19	Cash Working Capital Allowance	WPB-5.1a	17,915,083	3,021,735		0		14,893,348		0	0
20											
21	Other Rate Base Items	Sch B-6	0	0		0		0		0	0
22	Total Additions		63,755,322	8,445,543		2,316,854		52,221,658		771,267	0
23											
24	Deductions:										
25	Reserve for Accumulated Depreciation (Acct 108) (B)	Sch B-3.2	1,060,126,703	188,626,133	(E)	7,949,669	(E)	863,550,901	(A)	0	0
26											
27	Accum. Deferred Income Taxes (Accts 190, 282, & 283) (B)	Sch B-6, WPB-6a	232,299,813	62,665,883	(B)	596,887	(C)	143,823,296		0	25,213,748
28											
29	Customer Advances for Construction (Account 252)	Sch B-6	1,579,329	1,579,329		0		0		0	0
30											
31	Total Regulatory Liability - Excess Deferred Taxes (Acct 254)	Sch B-6	92,201,753	31,320,215		341,951		60,539,587		0	0
32											
33	Investment Tax Credits	WPB-6	3,708,551	0		454,058		0		3,254,493	0
34	Total Deductions		1,389,916,149	284,191,560		9,342,565		1,067,913,784		3,254,493	25,213,748
35											
36	Net Original Cost Rate Base		1,138,677,833	312,881,174		5,305,479		848,188,154		(2,483,226)	(25,213,748)
37											
38	Jurisdictional Rate Base Ratio		100.000%	27.478%		0.466%		74.489%		-0.218%	-2.214%
39											
40	Jurisdictional Rate Base Ratio - Excluding Non-Jurisdictional		100.000%	26.948%				73.052%			

Notes:
(A) Does not include depreciation annualization adjustment per Commission precedent.
(B) Adjusted for non-jurisdictional gas plant.
(C) WPB-6d. Liberalized Depreciation of $576,859.
(D) The Company is not requesting to include recovery of CWIP in base rates.
(E) Company records.

DUKE ENERGY KENTUCKY
CASE NO. 2018-00261
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(7)(a)

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807 KAR 5:001, SECTION 16(7)(a)

Description of Filing Requirement:

The written testimony of each witness the utility proposes to use to support its application, which shall include testimony from 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 the program.

Response:

All testimony is provided under separate cover. Also, please see the Direct Testimony of Amy B. Spiller, Duke Energy Kentucky's chief officer in charge of operations, for an overview discussion of efficiency and productivity improvements.

Sponsoring Witness: All Witnesses

DUKE ENERGY KENTUCKY
CASE NO. 2018-00261
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(7)(b)

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807 KAR 5:001, SECTION 16(7)(b)

Description of Filing Requirement:

The utility's most recent capital construction budget containing at minimum a three (3) year forecast of construction expenditures.

Response:

See attached.

Sponsoring Witnesses:

Robert H. "Beau" Pratt
Gary J. Hebbeler

Duke Energy Kentucky, Inc.
Case No. 2018-00261
Capital Expenditure Budget
Years 2018 - 2020

Line No.	Project ID/Description	CWIP Balance @ 12/31/17	Projected Expenditures 2018	2019	2020
1	NORMAL RECURRING CONSTRUCTION	21,353,977	26,960,591	14,944,764	14,405,361
2					
3	G7UL02PH1 / UL02 Bypass Loop Phase 1	0	0	3,608,045	18,778,421
4	Line AM00B	0	0	247,409	3,350,655
5	#G73MILES - Three Mile Station Replacement	846,521	2,114,004	2,244,523	0
6	#G7ASRP - ASRP	886,397	15,000,000	10,000,000	0
7	#SGKAMIF - DEK Gas AMI	1,820,993	6,502,959	89,713	0
8	TOTAL	24,907,888	50,577,555	31,134,454	36,534,437

DUKE ENERGY KENTUCKY
CASE NO. 2018-00261
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(7)(c)

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807 KAR 5:001, SECTION 16(7)(c)

Description of Filing Requirement:

A complete description, which may be filed in written testimony form, of all factors used in preparing the utility's forecast period. All econometric models, variables, assumptions, escalation factors, contingency provisions, and changes in activity levels shall be quantified, explained, and properly supported.

Response:

Attached are a copy of the Budget Guidelines for 2018 and a summary of the assumptions that were used in developing the projected data in the base and forecasted test periods. Descriptions of the factors used in preparing the forecasted test period are also incorporated in each witness' pre-filed testimony.

Sponsoring Witness: Robert H. "Beau" Pratt

2018-2019

BUDGET GUIDELINES AND ASSUMPTIONS

Duke Energy - Corporate Version No: 1.0 - Last Update: 7/31/2017

Business Confidential & Proprietary

Table of Contents

1.0 GENERAL GUIDELINES FOR THE 2018-2019 BUDGET

All guidance contained in this document is based on the best available information as of the published date. The contents and guidance are subject to change as business circumstances require.

1.1 Key Changes for 2018-2019 Budgeting

- Piedmont budgeting – O & M and CapEx
  - O&M budget will be input via Hyperion Planning using appropriate RCs and OUs.
  - Capex budget will be input via Piedmont's versions of Powerplan and will be transferred to Hyperion Planning.
  - Piedmont costs to achieve (CTA) budgets should use information from: CTA Instructions Piedmont
- The budget calendar has been updated - see section **2.0 Budget Timeline**
  - Staggered deadlines for corporate/shared services groups, Capex, and O&M
- Inflation and Loading rates have been updated
  - Section 3.2 Labor Inflation Rates and Labor Loading Rates
  - Section 4.3 Non-Labor Loading Rates (Stores/Freight/Handling)

1.2 Reference Material

A Budget link is available on the Finance Portal for various reference materials.
From the Portal, navigate to ***Work Related Sites → Finance.***
Locate the ***Share Point Sites*** section, then select the ***Enterprise Budget Development***
Link: Work Related Sites > Finance > SharePoint Sites > Enterprise Budget Development

1.3 Budget Requirements- Year One and Year Two

- O&M and Capital budgets for two years, will be completed during the budget cycle (2018 and 2019).
- Targets have been issued for each year
- Year two budget details should be at the same level of detail as year one to support multi-year business/financial plans and certain regulatory filings.
- There are two ways to enter Year 2 data:
  - Directly in the Budgets Cube
  - Ad hoc SmartView
  - Feed from Copperleaf Horizons or PowerPlan LRP

- There is a separate Send to Validation form for year two
- Budget allocations steps/stats for year one will be applied to year two. Results of allocations will be available in the HUB on a one day lag.

The table below shows which scenarios are open for editing in each budget year:

Scenario	Year 1	Year 2
User Input	Open	Open
Labor Input**	Closed	Open
LRP Input*	Closed	Closed
Horizons Input*	Closed	Closed
Service Provider Input	Open	Open
Unit Cost Input**	Closed	Open
Unit Qty Input**	Closed	Open

** Year 1 and Year 2 are from external feeders (e.g., Copperleaf)*
*** Year 1 is developed in separate Hyperion Planning Cubes (e.g., Worker Cost / Labor)*

1.4 Budget Development

Budgets should be prepared on an accrual basis. This should include a focus on accurate monthly timing of budgeted costs. The goal is to reduce actual versus budget timing variances for 2018 reporting by placing budget dollars in the months the costs are expected to be spent, assuming accruals recorded based on completed work.

Costs should be directly charged to the legal entity (Duke Energy Carolinas, Duke Energy Progress, Duke Energy Ohio, etc.) benefiting from the services to the extent it is feasible.

Care should be taken to identify where affiliate transactions are occurring to ensure that Service Agreements are put in place.

1.5 Budget Systems

All 2018 and 2019 budgets (excluding PeopleSoft allocations) make their way to the Hyperion Planning Budget Tool, by direct entry or by an interface from Fossil Hydro and Nuclear long range planning tools to Hyperion Planning (i.e., PowerPlan LRP and Copperleaf Horizons, respectively).

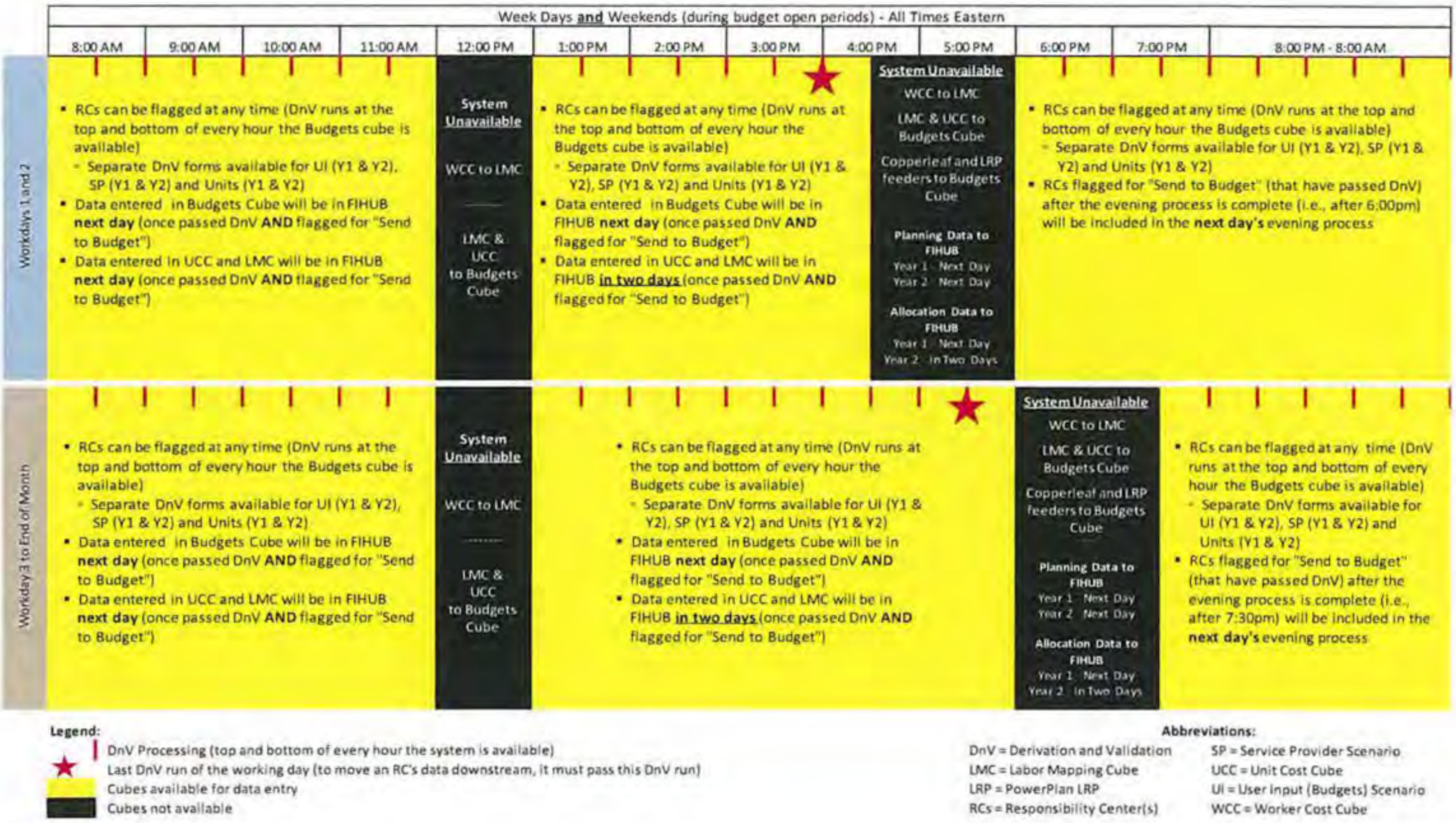
- Fossil Hydro will plan all capital projects and outage projects using PowerPlan LRP; users cannot modify these budgets in Hyperion Planning.
- Nuclear will plan all capital projects and non-routine O&M projects using Copperleaf Horizons; users cannot modify these budgets in Hyperion Planning.
- Piedmont will plan all Capex in PowerPlan and we will transfer to Hyperion Planning.
- All other budgets will be entered (directly or via spreadsheet upload) to Hyperion Planning.

Monday-Sunday nights, Hyperion Planning budget data is sent to PeopleSoft for allocations / loadings, then sent to the FIHUB for reporting of "fully-loaded" budgets.
The Hyperion Planning user guide can be accessed via link : FIN2631 Budgeting and Projections Using Hyperion Planning - User Guide or can be found on the portal. From the home portal site, navigate to Work Related Sites > Finance > Finance Systems Page > Budgeting and Forecasting Folder

1.6 Budgeting Tool Availability and Data Flow

- Hyperion Planning Budget Tool daily processing times will occur based on the following schedule. During the first 2 days of close, the nightly processing cut-off will be 4:30 p.m. All other days, processing begins at 6:00 p.m.
- LRP (Fossil Hydro) and Horizons (Nuclear) will feed budget information to the Hyperion Planning Budget Tool according to those systems' operating/processing schedules.
- Budget data sent to PeopleSoft/FIHUB (Monday-Sunday) via the Hyperion Planning Budget Tool will be available in the FIHUB the next morning. PeopleSoft allocations and labor loadings are running Monday - Sunday. Year 1 (2018) data with allocations and labor loadings will be available the next day. Year 2 (2019) data with allocations and labor loadings will be available in two days.

The following timeline details system availability along with the budget data that is processed throughout the workday:



2.0 BUDGET TIMELINE

Below is a summary of the key dates for the 2018 and 2019 budgeting process. *Please note that the deadlines indicated are for final signoffs. All internal department reviews must be completed prior to these final signoff dates.*

These dates reflect the calendar as planned, dates and events are subject to change as business circumstances may require.

Dates	Activity
March 27	Refresh Worker Cost Data
April 3	Hyperion Planning Budget Tool opens
End of April	Financial Guidance issued
May 1	Refresh Worker Cost Data
August 11	Corporate and Shared Services @ Target and locked
August 17	Capital Budgets @ Target and locked
August 23	Capital templates due
August 23	O&M Budgets @ Target and locked
August 28	Forecasting loads O&M into UI for 8x4v1
August 29	O&M special items templates for 2020 - 2022 due
September 5	Budget reopens for Cash Flow changes
October 3	2016 8x4v1 complete
October 3	Corporate, Shared Services & Capital @ Target and locked
October 6	O&M Budget @ Target and locked
October 9 - 12	Fringe Benefit Loading Rates updated
October 16	Forecasting loads O&M into UI for 8x4v2
October 25 - November 17	Update Service Company, Commercial, and OH/KY allocations
November 10	2016 8x4v2 complete
December 13 - 14	Board Meeting
December 14 - 17	Run monthly allocations
December 19	Forecasting loads O&M/Capital into UI for 12x0
January 25	2016 12x0 complete
January 29 - Feb 14	Forecasting loads rest of Income Statement to budget tools (HP complete Feb 8, HFM complete Feb 14)
February 9 - 10	Budget scenario marked 'Final' for AvB reporting

Notes:

Budget entry and deadlines includes 2018 and 2019 inputs

3.0 Workforce Budgeting

3.1 Labor Inflation Rates

The table below contains the preliminary wage increases that will be used to begin the 2018 budgeting process. Labor increases will be automatically applied to Worker Cost in Hyperion Planning after HR employee data is loaded. If labor budgets are loaded using the Labor Mapping cube, labor will feed in with increases layered in to the appropriate months. If labor is loaded using the Budgets Cube, be sure to budget the effects of labor increases in the appropriate months. TBD – "To Be Determined" guidance will be provided as information becomes available.

Category	Union	Date of Increase	2017 Wage Increase[1]	2018 Wage Increase Est.[1]	2019 Wage Increase Est.[1]
Non-Union	n/a	March 1	3.5% *(Total compensation including merit, promotion, etc.)*	3.5% *(Total compensation including merit, promotion, etc.)*	3.5% *(Total compensation including merit, promotion, etc.)*
Non-Union	Non-represented Craft	October 1	3.0% est. TBD – Early Summer 2017	TBD – Early Summer 2018	TBD – Early Summer 2019
Union	UWUA, IUU Local 600 (Technical)[2]	April 1	2.0%	2.0%	TBD
Union	UWUA, IUU Local 600 (Clerical/Manual)[2]	April 1	2.0%	2.0%	TBD
Union	IBEW 1347[2]	April 1	2.5%	2.5%	2.5%
Union	IBEW 1347-Matl Spec C, Meter Repair, Manual Techs[2]	April 1	1.0%	TBD	TBD
Union	IBEW 1393[2]	May 1	2.5%	3.0%	3.0%
Union	USW 12049[2]	May 15	2.25% (2017)	2.25%	2.5%
Union	USW 5541	May 15	TBD – May/June 2017	2.25%	2.25%
Union	USW 7202	October 1	3.0% est. TBD – Fall 2017	TBD – Fall 2018	TBD – Fall 2019
Union	IBEW 962	October 1	3.0% est. TBD – Fall 2017	TBD – Fall 2018	TBD – Fall 2019
Union	IBEW 962T	December 1	3.0% est. TBD – Fall 2017	TBD – Fall 2018	TBD – Fall 2019
Union	IBEW SCU-8 Florida (Main IBEW Florida)	December	3.0% – (12/5/16 – 12/3/17)	3.0% – Fall 2017 (12/4/17 –12/3/19)	TBD – Fall 2018
Union	IBEW SCU-8 Florida (Hines Energy Complex)	March	3.00% – Fall 2016 (3/28/16 – 3-27/17)	3.0% – Fall 2017 (3/27/17 – 3/25/18)	3.0% - Fall 2019 (3/26/18 – 3/24/19)

Notes:

1) Estimates have been included where negotiations are pending. ***Estimates used are for budget purposes only*** *and may not be representative of management's offer during future negotiations.*

2) Employees in the IBEW 1347, IBEW 1393, UWUA, and USW 12049 unions receive one week of prepaid sick time in the month of January. This week of prepaid sick time is calculated by the Worker Cost Cube process in Hyperion Planning.

3.2 Labor Loading Rates

The table below contains the preliminary labor loading rates used to begin the 2017 and 2018 budgeting process. These rates will be applied using PeopleSoft allocation processing and will be held static throughout the budgeting process. At the end of the budget cycle the rates will be updated to reflect the anticipated impact as determined by the actuarial analysis.

Labor inflation rates will be calculated using an effective escalation rate.

Category	2018 & 2019 Rate	Comments
Fringe Benefits		
DE Carolinas	22.33%	
DE Progress	26.09%	*The fringe benefits rate includes health and insurance (medical, dental, life, disability), retirement (pension, 401k), service awards, EAP costs, tuition reimbursement, and the administrative fees that go along with those costs*
DE Florida	26.38%	
DE Indiana	22.09%	
DE Kentucky	21.05%	
DE Ohio	12.53%	
DE Commercial Power	6.96%	
DE Business Services	23.71%	
Payroll Tax	7.65%	*Only applicable to Capital*
Incentive		
DEBS	11.5%	
Other Non-Union	10.5%	
Union	3.0%	

3.3 Incentives

STPP and discretionary pool plans will be budgeted through incentive loading rates calculated at target performance. Executive stock based incentives, including EIP and the equity portion of CEIP, will be budgeted in a Human Resources responsibility center (RC 8937) and allocated to operating units as appropriate. Any incentives outside the aforementioned plans should be budgeted at the responsibility center level.

3.4 Payroll Cycle for Exempt and Non-Exempt Employees

All exempt employees should be budgeted assuming a semi-monthly pay cycle (two payrolls per month). Non-exempt employees will continue on a bi-weekly payroll cycle.

- In 2018, there will be two payrolls for all months except <u>**March**</u> and <u>**August**</u>, which will have <u>**three pay periods**</u>.
- In 2019, there will be two payrolls for all months except <u>**March**</u> and <u>**August**</u>, which will have <u>**three pay periods**</u>.

Accounting will budget payroll accruals quarterly to ensure the financial statements reflect the appropriate amount of payroll in each quarter. Below are the number of days to be accrued each quarter.

Month	2018	2019
March	6	7
June	13	14
September	7	8
December	15	16

3.5 Recruiting & Relocation Expenses

Items budgeted by HR:
- Recruiting
- Job Postings
- Testing Fees

Items budgeted by hiring organization:
- Candidate Travel Expenses
- Agency Fees
- Staff Augmentation
- Relocation Expenses

If you have questions on Relocation & Recruiting Fees, please contact Lindsay Franklin Walles at (704) 382-5256.

3.6 Military Leave Pay

All responsibility centers with employees incurring military pay should budget for those employees based on the updated Military Leave of Absence Policy which can be found through the pathway:
Portal Home > Our Company > Policies > Human Resources

Employees are eligible to receive 100% pay for up to 80 hours for non-deployment related training. In addition, the Company will pay the difference between the employee's military pay and the Company's regular base pay for up to five years per leave for each deployment, including pre-deployment training.

3.7 Education Reimbursement (Tuition Refund) Expenses

All education reimbursement will be budgeted within the employee benefit rates. No tuition refund expenses should be budgeted within the business unit budgets unless the business unit plans to exceed established limits on graduate education reimbursement.

3.8 Dependent Care and Short Term Disability Accruals

Labor for employees on short-term disability should be budgeted by the business unit.

Accruals are established at the enterprise level as appropriate and provided to the business units to the extent they are required, per Accounting Research Group guidance.

3.9 Service and Retirement Awards

All service and retirement award gifts will be budgeted by HR and included in the employee fringe benefits load rate. The department is responsible for expenditures for any informal recognition events.

4.0 NON-LABOR BUDGETING

4.1 Inter-company Transactions

In certain instances (e.g., sale of Accounts Receivables and Bison Insurance), O&M budget lines must identify the inter-company account such that eliminations can be determined. To specify the offsetting business unit, the Supporting Detail feature within the Budgets application in Hyperion Planning can be used in conjunction with intercompany accounts.

4.2 Rate Case Support

Duke Energy utilizes the budget to file rate cases for Ohio, Kentucky, and Florida. To help provide details needed to support rate requests, please consider the following:
Budget to Accounts where actual charges will occur.
Budget to the appropriate Gas vs. Electric business units where actual charges will occur.
Budget social club dues, professional dues, charitable contributions, advertising, professional services and civic/political expenses to the accounts provided below:

Expense Type	Account
Social Club Dues	0926430
Professional Dues	0930210
Charitable Contributions	0426100
Advertising	Link: On the Enterprise Budget Development SharePoint site
Professional Services	0923000
Civic/Political Expenses	0426400

4.3 Non-Labor Loading Rates

The table below contains the non-labor loading rates that will be used to begin the 2018/2019 budgeting process.

Stores, Freight & Handling	DE Carolinas	DE Indiana	DE Ohio	DE Kentucky	DE Progress	DE Florida
Fossil Hydro Operations	16.58%	6.84%		9.80%	18.99%	8.77%
Transmission Distribution & Gas	11.5%	11.5%	11.0%	11.0%	10.0%	10.0%
Nuclear – Catawba	16.0%					
Nuclear – McGuire	16.0%					
Nuclear – Oconee	16.0%					
Nuclear - Brunswick					16.0%	
Nuclear – Harris					16.0%	
Nuclear - Robinson					16.0%	
Nuclear - Crystal River						16.0%

4.4 Print Services Costs

In 2018 & 2019, Print Services will charge business units (i.e. General Counsel, Commercial Business, etc.) based on actual or allocated usage for copier use based on negotiated price per impression. The budgeted charges include impressions only. Supplies and maintenance are included in the price per impression. Administrative Services Finance will budget on behalf of the business – using the business' responsibility centers.

Departments should continue to budget for paper in 2018 & 2019.

Copy Center Services (prints, binding, etc.):
Any copy/print job created at an in house Copy Center should be budgeted by the respective Business Unit. All accounting should be provided at time of order within the myChoice Print Request tool.

Wide Format Fleet Devices –(non-Imaging Center)
Based on actual usage for wide format use based on negotiated cost per square foot of paper used. The budgeted charges include impressions only. Equipment, supplies, paper, and maintenance are included in the cost per square foot. Administrative Services Finance will budget on behalf of the business – using the business' responsibility centers. Business units no longer needs to budget for the capital cost of the equipment.

Imaging Center devices and services (prints, scans, etc.)
Any large format prints and scans created at Imaging Production Centers should be budgeted by the respective Business Unit.
If you have questions about the 2018 & 2019 Print Services budget contact Ricky Bollinger (704-382-5885)

4.5 Facility Costs

Corporate Offices
Budgeting responsibility for renovations to corporate office space in 2018 & 2019 will be handled by Real Estate, including office consolidations in 526 S Church St, the Duke Energy Center, 400 South Tryon, any regional headquarter locations in Cincinnati, Plainfield, Raleigh, St. Petersburg and North Point.

Facility Maintenance / Additions / Changes
Real Estate will budget all building maintenance costs (i.e., janitorial services, cleaning supplies, lease payments, parking, utilities, grounds maintenance) for the corporate offices and electric/gas distribution facilities (excludes operational costs such as tools, equipment used by customer, etc.). Real Estate will budget for facility infrastructure replacements (i.e. roof, air conditioning, paving, carpet). For Real Estate questions contact:

- Fred Trammel – Midwest (513) 678-3550
- Keith Stenzler – Carolinas West (336) 917-2719
- Kim Bunnell – Carolinas East (919) 546-5723
- Sam Johnson – Charlotte (704) 382-4687
- Eric Rathburn – Florida (727)-820-5094

Additions or changes to facilities and grounds will be budgeted by Real Estate. A multi-year capital planning effort will address the needs from the Business Units as well as those of the Corporate areas. So that these needs are addressed during the budget process, they should be discussed with the BPRM contacts noted below. They are also available for additional pricing estimates and budget additions.

- Chris Gilb – Midwest
- Martha B Brown/ Cathy Smedelay-Martin – Carolinas West
- Joe Rycroft – Carolinas East
- Misty Lanham/Cathy Smedelay-Martin– Charlotte Metro
- April Harley – Florida

Personnel Moves
Personnel moves that involve the movement of boxes and computers will be budgeted by the business unit unless associated with a Real Estate project. Typical rates for moves range from $75-150 for moves that occur within the same buildings, $100-175 for moves from bldg. to bldg. less than 25 miles, and $150-250 for moves greater than 25 miles. Customers requesting moves that involve reconfiguration of furniture, cubicles, keyboard trays, etc. should be budgeted within the department's budget. Note: this is a change from 2016 as these costs were budgeted by the Real Estate Group.

Substation control house and Telecommunication building facility maintenance (i.e. plumbing, roof, air conditioning) will be budgeted by Real Estate for all locations except substations locations in Ohio/Kentucky.

Lease Administration
Real Estate is responsible for the budgeting and administration of all facility and land leases. This includes both Payable and Receivable leases. Leases are budgeted and paid internally by Real Estate using Real Estates' Responsibility Center and charged to the Operating Unit and other accounting provided by the Business Unit where the facility resides.
Contact Eric Rouse (980) 373-2436 for Lease or lease administration questions.

4.6 Transportation – (Fleet Services) Costs

A direct charging process is used for costs associated with all assigned vehicles and mobile (off-road) equipment. This enables Fleet Services' customers to (1) see actual costs associated with owning their vehicle and to more appropriately show the costs associated with how a particular vehicle or piece of equipment is used in their daily work, (2) create awareness of the total costs to the company for owning and operating vehicles and equipment, and (3) provide an effective management tool to use in the decision making process regarding vehicle and equipment purchases.

The direct charging process breaks down costs by ownership, repair labor, parts, fuel, commercial repair, and other miscellaneous costs. Customers can view these breakdowns by accessing the Fleet Services' Maximo customer report "Vehicle Chargeback by Level 4." You will need to get the proper security clearance to access Fleet Services customer reports in Maximo prior to viewing this report. Contact the Help Desk and press the button for Maximo Support. Ask them to open a ticket to the Fleet Services Maximo Support Team requesting access to the Fleet Services Customer Reports. If you need further assistance in getting this access or if you have questions regarding the report, please contact Linda Price (704-382-1968).

<u>All vehicle and mobile (off-road) equipment purchases are to be coordinated through Fleet Services</u>. Certain mobile equipment purchases may be eligible to be funded using the customer's departmental capital accounting. Please contact Mike Allison (704-382-4750) for details and how this may affect Fleet Services chargebacks to the customer.

For 2018 budgeting purposes, all assigned vehicles and mobile equipment should be budgeted to Resource Type 50000 in the appropriate business unit budgets. This can be at a departmental level or as low as each individual responsibility center. The following guidelines may be used in determining what to budget for in the upcoming year:

(1) Take the current YTD costs in RT 50000 (and RT 50002 for Distribution) on your financial reports and annualize them. Then go to #3 below. OR
(2) Run the Fleet Services' Maximo customer report " Vehicle Chargeback by Level 4" for the last 12 months. Take into consideration if units were added or reduced from the group or department and compare the result with (1) above. Then go to #3 below.
(3) If units are anticipated to be added in 2018 & 2019, plan on adding monies for those units. Contact the Fleet Services Customer Representative for your region to assist with determining how much to budget for these additional units (see names and contact information below).
(4) If we are in a year where fuel costs are rising <u>significantly</u> each month, plan on adding a slight inflation factor to your costs in order to account for this increase in fuel costs. If unsure, please contact Fleet Services for guidance on this issue.

It is essential that adequate dollars are budgeted for the vehicles and equipment assigned to your group/department as Fleet Services does not budget these dollars for you. If you need assistance with how to calculate the Fleet Services' costs for your group/department, please contact any of the following Fleet Services representatives:

Region	Contact	Phone	Email
Carolinas	Greg Sites	704-382-2320	Gregory.Sites@duke-energy.com
Florida	Jerry Shelley	407-942-9470	Jerry.Shelley@duke-energy.com
Midwest	Cory Zimmerman	317-838-2226	Cory.Zimmerman@duke-energy.com
All Regions	Linda Price	704-382-1968	Linda.Price@duke-energy.com

If you need further assistance in getting this access or if you have questions regarding the reports, please contact Linda Price (704-382-1968).

4.7 Parking Costs for Company Owned Vehicles

Each Business Unit is responsible for budgeting monthly parking costs for their company owned vehicles. The accounting below should be used to process parking costs for company owned vehicles that are parked at company owned parking facilities (Mint Street, Ohio Regional Headquarters, Florida Regional Headquarters, etc:)

Code block Element	What to charge
Responsibility Center	Business Unit Responsibility Center
Operating Unit	Business Unit Operating Unit
Process	PARK
Resource Type	69500
Account	0417007

Please contact your financial support contact for the appropriate parking accounting for non-company owned parking facilities.

4.8 Postage, Courier Services and Freight Logistics

The Administrative Services - Distribution Services group budgets for postage for routine mailings from the Corporate Mail Centers. Please use the following guidelines for specific situations:

Type of Mailing Expense	Budgeted by
Customer billing and customer bill-related mailings	User organization
Marketing related mailings	User organization
Bulk or large mailings	User organization
Employee paychecks, pension checks, incentive checks	Administrative Services - Distribution Services
Daily routing business mailings processed by Distribution Services	Administrative Services - Distribution Services
All other postage, courier, and freight-related costs – Florida	User organization
All other postage, courier, and freight-related costs – other jurisdictions	Administrative Services - Distribution Services

4.9 Research Sources, Subscriptions and Book

Records Management:

- Business Units should budget for the purchase of bankers boxes that are intended for corporate records storage. These boxes can be purchased through Faison/Staples via the Portal.
- Business Units should budget for records storage deliveries if they anticipate expedited box requests such as deliveries via UPS 2nd Day Air. The Enterprise Record Center does not bill for routine, day-to-day operational costs associated with deliveries.

Corporate Library services:

- Budgeted by Administrative Services - Research Services, contact Chris Hamrick (704-382-6413)
- For Specialized Subscriptions/Memberships which are unique to a specific organization, the Business Unit will budget for this. Chris Hamrick (704-382-6413) can be contacted for information or a cost estimate.

4.10 Personal Mobile Device

The Personal Mobile Device (PMD) program is managed out of IT Customer Services. The AirWatch Technology licenses are purchased by IT. The monthly reimbursement for approved PMD program participants is provided via the expense system, meaning these costs come out of individual manager's expense budgets. $50 per month should be budgeted for each employee approved for reimbursement.

5.0 CAPITAL BUDGETING

5.1 Capitalization Guidelines

If you have questions regarding the capitalization policies, please contact the following:

- Linda Miller for Land, Software, General Inquiries - (704) 373-2407
- Mike Mc Gee for Power Production, Renewables, Non-utility - (704) 382-8625
- Karen Brown for Power Delivery (T/D/Gas/Grid) and General Plant (704) 382-5817

To access the current Duke Energy capitalization guidelines or the Unit of Property Catalogues navigate to the following site on the Portal or click the link: Portal Home > Our Company > Policies > Internal Controls & Finance > Property, Plant & Equipment

5.2 Capital Class Types / Classifications & Definitions

Capital Class Type/ Classifications' Definitions:

Capital Class Type / Classification:	Capital Class Type/ Classifications' Definitions:
Recoverable	Defined as items that are recovered outside of normal base rates that: (1) have a specific clause/rider/tracker/special tariff with immediate recovery or (2) are deemed probable for future regulatory treatment that would result in a clause/rider/tracker. Examples: DCI-DEO Rider ECRC & ECCR Clause Recovery in Florida Indiana Environmental Trackers Edwardsport Tracker No or limited regulatory lag
Expansion	**New Generation:** Expenditures on projects for assets expanding generation capabilities. **New Connects:** Capital expenditures to provide lighting and metered services to new customers including dollars to achieve connection and long-term capacity increases (includes new lighting installations). **Transmission Line Expansion/major modification**: to accommodate new generating facilities. **Renewables**: Would include projects adding MW, revenue producing projects, and acquisitions.
Major Projects	Includes large projects greater than $25M that are garnering AFUDC that are not in 'Recoverable' or 'Expansion', also includes strategic projects. Examples: Wholesale large replacement or retrofitting a plant. Strategic Projects (Grid)
Maintenance	Defined as capital expenditures not included in the above capital class types (Non-Recoverable, Non-Expansion, Non-Major Projects/Investments) Maintenance would generally include minimal to no AFUDC and carries regulatory lag implications.

For 2018, **For Corporate Reporting**, the ROCR will continue to report on the following capital class types :

Recoverable
Expansion
Major Projects
Maintenance

If you have questions regarding the Capital Class definitions, please contact Kathy Dimoff at (704) 382-4795.

5.3 Capital Contingency

Project Management Center of Excellence standards require project teams to evaluate risks and establish, monitor, and report project contingency.

In order to increase the transparency around budgeted contingency across the Company, all business units and corporate areas are requested to separately identify contingency by budgeting those amounts using Resource Type 94008 – Contingency.

Ideally, contingency should be cash-flowed based on the timing of the identified risks and estimates with which it is associated. If the Project is early in the development stages, and the risks have not yet been defined, it is recommended that contingency be budgeted in December or in the final month of the Project if closing prior to year end. This also applies to large O&M projects subject to PMCoE standards.

6.0 Service Company Guidelines

6.1 Charging Guidance

Costs should be directly charged to the legal entity (Duke Energy Carolinas, Duke Energy Progress, Duke Energy Ohio, etc.) benefiting from the services to the extent it is feasible. Otherwise, the service company allocations should be utilized.

There are three types of service company allocation pools:

Governance – Corporate departments with accountability for the management of the overall function and respective issues within Duke Energy; responsible for the governance, compliance, oversight, control, audit, and strategic program design of corporate-wide activities. These costs are charged to a governance identified business unit.

Enterprise – Support departments providing day-to-day services to all lines of business (e.g., IT, Corporate Facilities, Accounts Payable, HR Services); the execution of the governance process which benefits all business units. These costs are driven by and support the business, but for simplification, are allocated by the service company. These costs are charged to segment business units.

Utility – Support departments providing day-to-day services to regulated utilities only. The execution of the governance process which only benefits the regulated utilities. These costs are driven by and support the utility businesses, but for simplification, are allocated by the service company. These costs are charged to regulated utility business units.

7.0 BUDGET FINANCE SUPPORT BUSINESS CONTACTS

For detailed listings of the Finance Support of Business Unit Contacts, please reference:
https://portal.duke-energy.com/WorkSites/Finance/Quick%20Links/Contacts/Business%20Support%20Representatives.xlsx

DUKE ENERGY KENTUCKY
CASE NO. 2018-00261
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(7)(d)

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807 KAR 5:001, SECTION 16(7)(d)

Description of Filing Requirement:

The utility's annual and monthly budget for the twelve (12) months preceding the Filing Date, the Base Period, and Forecasted Period.

Response:

See the attached for the Company's official 2017 and 2018 operating budgets which include the 12 months preceding the Filing Date (September 2017 - August 2018) and the Base Period (December 2017 - November 2018). The requested annual budget for the 12 months of the Forecasted Test Period is provided in Schedule C-1. The monthly revenue and monthly O&M amounts are shown in Work Papers WPC-2d and WPC-2.1a, respectively. This data is comprised of Duke Energy Kentucky's 2019 annual budget and extended through March 2020 as described in the testimony of Mr. Pratt.

Sponsoring Witness: Robert H. "Beau" Pratt

Duke Energy Segment Reporting

DE Kentucky Gas
Dynamic Income Statement for Budget
Periodic

	Jan 2017 Budget Periodic	Feb 2017 Budget Periodic	Mar 2017 Budget Periodic	Apr 2017 Budget Periodic	May 2017 Budget Periodic	Jun 2017 Budget Periodic	Jul 2017 Budget Periodic	Aug 2017 Budget Periodic	Sep 2017 Budget Periodic	Oct 2017 Budget Periodic	Nov 2017 Budget Periodic	Dec 2017 Budget Periodic	Dec 2017 Budget YTD
Operating Revenue													
Regulated Natural Gas	23,142,475	15,159,387	10,691,285	3,947,720	3,682,746	3,889,748	3,957,226	4,047,764	4,139,485	6,487,290	10,353,469	15,299,686	104,798,279
Total Operating Revenues	**23,142,475**	**15,159,387**	**10,691,285**	**3,947,720**	**3,682,746**	**3,889,748**	**3,957,226**	**4,047,764**	**4,139,485**	**6,487,290**	**10,353,469**	**15,299,686**	**104,798,279**
Operating Expenses													
Cost of Natural Gas and Coal Sold	11,379,775	6,823,308	4,178,339	242,910	787,244	1,060,911	1,163,392	1,259,057	1,329,379	2,861,270	5,061,738	7,516,628	43,663,951
Operations, Maintenance and Other	2,784,470	2,362,284	1,724,431	2,046,086	2,126,683	1,814,925	1,925,909	1,983,175	1,664,108	1,747,508	2,099,966	2,938,004	25,217,549
Depreciation and Amortization	1,050,594	1,052,510	1,054,171	1,079,606	1,082,243	1,080,301	1,097,720	1,087,387	1,083,858	1,103,418	1,108,016	1,111,381	12,991,205
Property and Other Taxes	292,687	290,490	288,047	291,888	292,623	284,353	287,207	284,567	283,914	283,214	291,944	325,179	3,496,115
Total Operating Expenses	**15,507,526**	**10,528,593**	**7,244,989**	**3,660,491**	**4,288,794**	**4,240,490**	**4,474,228**	**4,614,186**	**4,361,259**	**5,995,410**	**8,561,663**	**11,891,191**	**85,368,820**
Operating Income	**7,634,949**	**4,630,794**	**3,446,296**	**287,229**	**(606,048)**	**(350,742)**	**(517,002)**	**(566,423)**	**(221,774)**	**491,880**	**1,791,806**	**3,408,495**	**19,429,459**
Other Income and Expenses													
7311_AFUDC_OTH_DF_RT - AFUDC and Other Deferred	14,184	22,759	8,063	(8,077)	(3,523)	(6,900)	(11,192)	(6,241)	(6,200)	(6,752)	394	(22)	(3,508)
7310_INT_DIV - Interest and Dividends	24	-	-	-	-	-	-	-	-	-	-	-	24
7330_INTERCO_INT - Intercompany Interest Income	60	178	263	340	12,392	19,997	13,216	8,950	4,875	4,562	4,663	1,885	71,380
Other Income and Expenses	**14,267**	**22,937**	**8,326**	**(7,738)**	**8,869**	**13,097**	**2,024**	**2,709**	**(1,325)**	**(2,190)**	**5,057**	**1,863**	**67,896**
Earnings Before Interest Expense and Taxes	7,649,215	4,653,731	3,454,622	279,491	(597,179)	(337,646)	(514,978)	(563,714)	(223,099)	489,690	1,796,862	3,410,358	19,497,355
Interest Expense	381,656	376,088	388,642	392,993	419,095	480,425	477,212	461,684	481,842	475,610	459,145	478,360	5,272,752
Earnings From Continuing Operations Before Income Taxes	7,267,559	4,277,643	3,065,980	(113,502)	(1,016,274)	(818,071)	(992,190)	(1,025,397)	(704,941)	14,080	1,337,717	2,931,998	14,224,602
Income Tax Expense (Benefit) From Continuing Operations	2,789,549	1,635,898	1,175,325	(41,751)	(390,839)	(313,283)	(378,623)	(393,304)	(270,026)	6,825	513,337	1,126,887	5,459,996
Income From Continuing Operations Attributable to Duke E	**4,478,010**	**2,641,745**	**1,890,655**	**(71,751)**	**(625,435)**	**(504,788)**	**(613,567)**	**(632,094)**	**(434,915)**	**7,255**	**824,380**	**1,805,111**	**8,764,606**
Income (Loss) From Continuing Operations	**4,478,010**	**2,641,745**	**1,890,655**	**(71,751)**	**(625,435)**	**(504,788)**	**(613,567)**	**(632,094)**	**(434,915)**	**7,255**	**824,380**	**1,805,111**	**8,764,606**
Net Inc Bfr Ext and Chg in Acct. Prin.	**4,478,010**	**2,641,745**	**1,890,655**	**(71,751)**	**(625,435)**	**(504,788)**	**(613,567)**	**(632,094)**	**(434,915)**	**7,255**	**824,380**	**1,805,111**	**8,764,606**
Consolidated Net Income	4,478,010	2,641,745	1,890,655	(71,751)	(625,435)	(504,788)	(613,567)	(632,094)	(434,915)	7,255	824,380	1,805,111	8,764,606

Duke Energy Segment Reporting

DE Kentucky Gas
Dynamic Income Statement for Budget
Periodic

	Jan 2017 Budget Periodic	Feb 2017 Budget Periodic	Mar 2017 Budget Periodic	Apr 2017 Budget Periodic	May 2017 Budget Periodic	Jun 2017 Budget Periodic	Jul 2017 Budget Periodic	Aug 2017 Budget Periodic	Sep 2017 Budget Periodic	Oct 2017 Budget Periodic	Nov 2017 Budget Periodic	Dec 2017 Budget Periodic	Dec 2017 Budget YTD
Less: Net Income (Loss) attributable to non controlling interes	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Income Attributable to Controlling Interests	4,478,010	2,641,745	1,890,655	(71,751)	(625,435)	(504,788)	(613,567)	(632,094)	(434,915)	7,255	824,380	1,805,111	8,764,606

Duke Energy Segment Reporting

DE Kentucky Gas
Dynamic Income Statement for Budget
Periodic

	Jan 2018 Budget Periodic	Feb 2018 Budget Periodic	Mar 2018 Budget Periodic	Apr 2018 Budget Periodic	May 2018 Budget Periodic	Jun 2018 Budget Periodic	Jul 2018 Budget Periodic	Aug 2018 Budget Periodic	Sep 2018 Budget Periodic	Oct 2018 Budget Periodic	Nov 2018 Budget Periodic	Dec 2018 Budget Periodic	Dec 2018 Budget YTD
Operating Revenue													
Regulated Natural Gas	17,805,723	14,768,582	10,287,594	4,604,623	4,250,914	4,157,116	4,667,136	3,533,246	4,395,880	5,375,923	10,303,215	13,406,026	97,555,981
Total Operating Revenues	**17,805,723**	**14,768,582**	**10,287,594**	**4,604,623**	**4,250,914**	**4,157,116**	**4,667,136**	**3,533,246**	**4,395,880**	**5,375,923**	**10,303,215**	**13,406,026**	**97,555,981**
Operating Expenses													
Cost of Natural Gas and Coal Sold	8,477,207	6,702,955	3,940,633	699,348	1,206,293	1,263,363	1,955,892	839,286	1,740,208	1,973,149	5,145,487	5,734,647	39,678,470
Operations, Maintenance and Other	2,589,969	1,978,998	1,958,447	1,869,329	1,905,773	2,083,019	1,908,225	1,864,518	1,861,931	1,898,997	1,794,230	2,237,377	23,950,811
Depreciation and Amortization	1,147,250	1,165,743	1,172,695	1,207,527	1,210,527	1,214,277	1,238,452	1,239,951	1,240,651	1,271,963	1,271,619	1,271,973	14,652,628
Property and Other Taxes	309,132	304,477	311,219	310,938	304,708	304,086	299,629	305,341	307,715	300,889	300,933	305,326	3,664,394
Total Operating Expenses	**12,523,558**	**10,152,173**	**7,382,993**	**4,087,142**	**4,627,302**	**4,864,745**	**5,402,197**	**4,249,097**	**5,150,505**	**5,444,998**	**8,512,269**	**9,549,324**	**81,946,303**
Operating Income	**5,282,165**	**4,616,409**	**2,904,601**	**517,482**	**(376,387)**	**(707,629)**	**(735,061)**	**(715,850)**	**(754,625)**	**(69,075)**	**1,790,946**	**3,856,702**	**15,609,678**
Other Income and Expenses													
71XX_OTHER_INCOME - Other Income	4,862	4,862	4,862	4,862	4,862	4,862	4,862	4,862	4,862	4,862	4,862	4,862	58,346
7311_AFUDC_OTH_DF_RT - AFUDC and Other Deferred	94,784	100,223	77,133	56,779	64,031	60,048	60,203	72,122	62,863	63,805	74,770	70,271	857,032
7310_INT_DIV - Interest and Dividends	251	-	-	-	-	-	-	-	-	-	-	-	251
7330_INTERCO_INT - Intercompany Interest Income	12,782	20,180	19,395	17,800	17,655	11,831	4,047	168	27,995	51,527	45,364	43,572	272,316
Other Income and Expenses	**112,680**	**125,266**	**101,391**	**79,441**	**86,548**	**76,741**	**69,112**	**77,152**	**95,720**	**120,194**	**124,995**	**118,705**	**1,187,946**
Earnings Before Interest Expense and Taxes	5,394,845	4,741,675	3,005,992	596,923	(289,840)	(630,888)	(665,949)	(638,698)	(658,904)	51,119	1,915,942	3,975,408	16,797,623
Interest Expense	442,225	438,005	453,722	459,539	443,181	458,530	462,154	449,206	553,289	569,381	551,923	571,457	5,852,610
Earnings From Continuing Operations Before Income Taxes	4,952,620	4,303,670	2,552,269	137,383	(733,020)	(1,089,418)	(1,128,103)	(1,087,903)	(1,212,193)	(518,262)	1,364,019	3,403,951	10,945,013
Income Tax Expense (Benefit) From Continuing Operations	1,236,667	1,070,317	630,244	20,451	(203,007)	(292,749)	(302,620)	(295,427)	(324,658)	(148,236)	328,196	848,636	2,567,813
Income From Continuing Operations Attributable to Duke E	**3,715,953**	**3,233,353**	**1,922,025**	**116,932**	**(530,013)**	**(796,669)**	**(825,483)**	**(792,477)**	**(887,535)**	**(370,025)**	**1,035,823**	**2,555,315**	**8,377,200**
Income (Loss) From Continuing Operations	**3,715,953**	**3,233,353**	**1,922,025**	**116,932**	**(530,013)**	**(796,669)**	**(825,483)**	**(792,477)**	**(887,535)**	**(370,025)**	**1,035,823**	**2,555,315**	**8,377,200**
Net Inc Bfr Ext and Chg in Acct. Prin.	**3,715,953**	**3,233,353**	**1,922,025**	**116,932**	**(530,013)**	**(796,669)**	**(825,483)**	**(792,477)**	**(887,535)**	**(370,025)**	**1,035,823**	**2,555,315**	**8,377,200**

Report: TREND_IS_BUDGET
Run By: GSCarpe
Run Date: August 07, 2018 9:26:59 AM

imclthfmsvcp01
Reporting

Duke Energy Segment Reporting

DE Kentucky Gas
Dynamic Income Statement for Budget
Periodic

	Jan 2018 Budget Periodic	Feb 2018 Budget Periodic	Mar 2018 Budget Periodic	Apr 2018 Budget Periodic	May 2018 Budget Periodic	Jun 2018 Budget Periodic	Jul 2018 Budget Periodic	Aug 2018 Budget Periodic	Sep 2018 Budget Periodic	Oct 2018 Budget Periodic	Nov 2018 Budget Periodic	Dec 2018 Budget Periodic	Dec 2018 Budget YTD
Consolidated Net Income	3,715,953	3,233,353	1,922,025	116,932	(530,013)	(796,669)	(825,483)	(792,477)	(887,535)	(370,025)	1,035,823	2,555,315	8,377,200
Less: Net Income (Loss) attributable to non controlling interes	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Income Attributable to Controlling Interests	3,715,953	3,233,353	1,922,025	116,932	(530,013)	(796,669)	(825,483)	(792,477)	(887,535)	(370,025)	1,035,823	2,555,315	8,377,200

DUKE ENERGY KENTUCKY
CASE NO. 2018-00261
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(7)(e)

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807 KAR 5:001, SECTION 16(7)(e)

Description of Filing Requirement:

A statement of attestation signed by the utility's chief officer in charge of Kentucky operations which shall provide:

(1) that the forecast is reasonable, reliable, made in good faith and that all basic assumptions used in the forecast have been identified and justified;

(2) that the forecast contains the same assumptions and methodologies as used in the forecast prepared for use by management, or an identification and explanation for any differences that exist; and

(3) that productivity and efficiency gains are included in the forecast.

Response:

See attached.

Sponsoring Witness: Amy B. Spiller

AFFIDAVIT OF AMY B. SPILLER

STATE OF OHIO)
)
COUNTY OF HAMILTON)

Now comes Amy B. Spiller, President of Duke Energy Kentucky, Inc., and as required by 807 KAR 5:001, Section 16(7)(e), hereby attests as follows:

1. The forecast used in this rate application is reasonable, reliable, made in good faith, and that all basic assumptions used in the forecast have been identified and justified;
2. The forecast contains the same assumptions and methodologies as used in the forecast prepared for use by management, or an identification and explanation for any differences that exist; and
3. Productivity and efficiency gains are included in the forecast.

Further affiant sayeth naught.

Amy B. Spiller

Amy B. Spiller, Affiant

Sworn and subscribed before me by Amy B. Spiller on this 31st day of August 2018.

E. Minna Rolfes-Adkins

Notary Public

My Commission Expires: July 8, 2022

E. MINNA ROLFES-ADKINS
Notary Public, State of Ohio
My Commission Expires
July 8, 2022

DUKE ENERGY KENTUCKY
CASE NO. 2018-00261
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(7)(f)(1) through (4)

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807 KAR 5:001, SECTION 16(7)(f)(1) through (4)

Description of Filing Requirement:

For each major construction project which constitutes five (5) percent or more of the annual construction budget within the three (3) year forecast the following information shall be filed:

(1) The date the project was started or estimated starting date;

(2) The estimated completion date;

(3) The 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) The most recent available total costs incurred exclusive and inclusive of AFUDC or interest during construction credit.

Response:

See attached.

Sponsoring Witness:

Robert H. "Beau" Pratt
Gary J. Hebbeler

Duke Energy Kentucky, Inc.
Case No. 2018-00261
Major Construction Projects
Constituting 5% or More of Annual Budget

Line No.	Project ID/Description	Actual or Projected Start Date	Projected Completion Date	Estimated Costs Including AFUDC 2018	Estimated Costs Including AFUDC 2019	Estimated Costs Including AFUDC 2020	Estimated Costs Excluding AFUDC 2018	Estimated Costs Excluding AFUDC 2019	Estimated Costs Excluding AFUDC 2020	Actual Costs To Date incl AFUDC	Actual Costs To Date excl AFUDC
1	G7UL02PH1 / UL02 Bypass Loop Phase 1	1/1/2019	2/28/2021	0	3,608,045	18,778,421	0	3,500,000	18,000,000	-	-
2	Line AM00B	10/1/2019	3/30/2021	0	247,409	3,350,655	0	240,000	3,235,500	-	-
3	#G73MILES - Three Mile Station Replacement	3/1/2017	12/31/2019	2,114,004	2,244,523	0	2,000,000	2,000,000	0	846,521	806,272
4	#G7ASRP - ASRP	1/1/2013	12/31/2019	15,000,000	10,000,000	0	15,000,000	10,000,000	0	886,397	886,397
5	#SGKAMIF - DEK Gas AMI	2/1/2017	2/28/2019	6,502,959	89,713	0	6,502,959	89,713	0	1,820,993	1,820,993

DUKE ENERGY KENTUCKY
CASE NO. 2018-00261
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(7)(g)

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807 KAR 5:001, SECTION 16(7)(g)

Description of Filing Requirement:

For all construction projects which constitute less than five (5) percent of the annual construction budget within the three (3) year forecast, the utility shall file an aggregate of the information requested in paragraph (f) 3 and 4 of this subsection.

Response:

See attached.

Sponsoring Witness:

Robert H. "Beau" Pratt
Gary J. Hebbeler

Duke Energy Kentucky, Inc.
Case No. 2018-00261
Major Construction Projects
Constituting Less than 5% of Annual Budget

Line No.	Project ID/Description	Actual or Projected Start Date	Projected Completion Date	Estimated Costs Including AFUDC 2018	Estimated Costs Including AFUDC 2019	Estimated Costs Including AFUDC 2020	Estimated Costs Excluding AFUDC 2018	Estimated Costs Excluding AFUDC 2019	Estimated Costs Excluding AFUDC 2020	Actual Costs To Date incl AFUDC	Actual Costs To Date excl AFUDC
1	Sum of all projects not included on 7(f)	Various	Various	26,960,591	14,944,764	14,405,361	25,939,284	14,022,020	13,299,100	21,353,977	20,685,983

DUKE ENERGY KENTUCKY
CASE NO. 2018-00261
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(7)(h)

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807 KAR 5:001, SECTION 16(7)(h)

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include 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, if applicable.

Response:

Items 6, 13, 16, and 17 are not applicable. For all other items, see attached.

Sponsoring Witnesses:

Robert H. "Beau" Pratt – Items 1, 2, 3, 4, 7, 9, 10, 11, 12
Gary J. Hebbeler – Item 8
Benjamin Passty – Items 5, 14, 15

FR 16(7)(h)(1)

Duke Energy Kentucky, Inc.
Case No. 2018-00261
Projected Income Statement 2018-2020

Line No.	Description	2018	2019	2020
1	Operating Revenue			
2	Electric Revenue	$359,678,621	$372,165,279	$379,925,064
3	Gas Revenue	100,181,365	94,271,956	95,495,712
4	Other Revenue	220,000	220,000	220,000
5	Total Operating Revenue	$460,079,986	$466,657,235	$475,640,776
6	Operating Expenses			
7	Fuel & Purchased Power	$115,979,791	$108,524,625	$110,659,218
8	Gas Purchased	39,678,470	36,513,025	37,129,021
9	Operation & Maintenance	155,811,485	142,232,490	151,488,227
10	Depreciation & Amortization	68,323,985	79,563,297	81,219,516
11	Taxes Other Than Income	15,299,535	17,980,830	19,047,964
12	Operating Expenses before Income Tax	$395,093,266	$384,814,267	$399,543,946
13	Pre-Tax Operating Income	$64,986,720	$81,842,968	$76,096,830
14	Other Income	$4,939,110	$4,805,155	$5,667,199
15	Interest Expense	$20,604,267	$24,861,832	$25,646,131
16	State Income Taxes	$2,365,230	$3,018,749	$2,701,341
17	Federal Income Taxes	6,167,317	6,958,202	5,585,452
18	Total Income Taxes	$8,532,547	$9,976,951	$8,286,793
19	Income Available for Common Dividends	$40,789,016	$51,809,340	$47,831,105
20	Average Common Equity	$549,304,622	$603,103,914	$630,424,136
21	Earned Return	7.43%	8.59%	7.59%

FR 16(7)(h)(2)

Duke Energy Kentucky, Inc.
Case No. 2018-00261
Projected Balance Sheet 2018-2020

Line No.	Description	2018	2019	2020
1	**Assets**			
2	Utility plant in service	$ 2,444,765,191	$ 2,568,760,349	$ 2,693,224,469
3	Construction work in progress	78,079,681	73,153,947	75,283,905
4	Total Utility Plant	$ 2,522,844,872	$ 2,641,914,296	$ 2,768,508,374
5	Non-regulated property, plant, and equipment	$ 2,206	$ 2,206	$ 2,206
6	Accumulated depreciation	1,021,169,162	1,071,047,709	1,121,906,794
7	Net Property, Plant, and Equipment	$ 1,501,677,916	$ 1,570,868,793	$ 1,646,603,786
8	Current Assets	$ 87,107,249	$ 86,440,809	$ 84,032,904
9	Other Assets	120,483,504	114,917,575	104,954,842
10	Total Assets	$ 1,709,268,669	$ 1,772,227,177	$ 1,835,591,532
	Liabilities			
11	Total Current Liabilities	$ 224,726,527	$ 121,423,758	$ 129,761,116
12	Long-term debt	425,096,552	560,071,450	595,198,687
13	ADIT / EDIT	323,590,701	325,770,464	326,726,937
14	Unamortized investment tax credits	3,836,961	3,836,961	3,836,961
15	Other	144,818,684	142,115,961	138,228,143
16	Total Non-Current Liabilities	$897,342,898	$1,031,794,836	1,063,990,728
17	Total Common Stock Equity	$ 587,199,244	$ 619,008,583	$ 641,839,688
18	Total Liabilities	$1,709,268,669	$1,772,227,177	1,835,591,532

FR 16(7)(h)(3)

Duke Energy Kentucky, Inc.
Case No. 2018-00261
Projected Cash Flow Statement 2018-2020

Line No.	Description	2018	2019	2020
1	Net Income	$40,789,016	$51,809,340	$47,831,105
2	Other Operating Activities	46,887,858	73,414,370	69,601,714
3	Cash from Operating Activities	87,676,874	125,223,710	117,432,819
4	Financing Activities			
5	Change in contributed capital	$35,000,000	$0	$0
6	Change in short-term debt	3,599,742	(3,599,742)	7,890,037
7	Issuance of long-term debt	100,000,000	135,000,000	35,000,000
8	Change in non-current capital leases	-	-	-
9	Redemption of long-term debt	(885,340)	(100,396,222)	(184,010)
10	Dividends on common stock	-	(20,000,000)	(25,000,000)
11	Cash from Financing Actitivies	137,714,402	11,004,036	17,706,027
12	Investing Activities			
13	Construction Expenditures (net of AFUDC)	($241,167,743)	($131,290,134)	($138,185,875)
14	Acquisitions and other investments	418,321	(878,011)	(1,012,570)
15	Cash from Investing Actitivies	(240,749,422)	(132,168,145)	(139,198,445)
16	Net Increase/(Decrease) in Cash	(15,358,146)	4,059,601	(4,059,599)

FR 16(7)(h)(4)

Duke Energy Kentucky, Inc.
Case No. 2018-00261
Revenue Requirements 2018-2020

Line No.	Description	2018	2019	2020
1	Rate Base	316,617,935	327,918,258	348,953,653
2	Operating Income	14,890,663	12,007,903	12,199,406
3	Earned Rate of Return (Line 2 / Line 1)	4.700%	3.700%	3.500%
4	Rate of Return	7.113%	7.181%	7.181%
5	Required Operating Income (Line 1 x Line 4)	22,521,034	23,547,810	25,058,362
6	Operating Income Deficiency (Line 5 - Line 2)	7,630,371	11,539,907	12,858,956
7	Gross Revenue Conversion Factor	1.334673	1.334673	1.334673
8	Revenue Deficiency (Line 6 x Line 7)	10,184,051	15,402,002	17,162,501

FR 16(7)(h)(5)

Duke Energy Kentucky, Inc.
Case No. 2018-00261
Load Forecast 2018-2020

Line No.	Description	2018	2019	2020
1	KW Demand - Coincident Peak			
2				
3	January	746,943	745,664	746,219
4	February	705,177	703,329	703,950
5	March	633,144	631,646	634,065
6	April	571,354	570,214	572,944
7	May	695,147	691,822	693,555
8	June	770,389	766,792	768,329
9	July	813,176	811,064	813,867
10	August	803,122	800,866	803,175
11	September	779,880	781,786	779,261
12	October	596,118	600,119	600,623
13	November	585,222	587,986	586,976
14	December	669,991	672,837	671,205
15				
16	KWH Sales			
17				
18	January	361,038,527	363,065,984	363,102,560
19	February	328,869,584	330,484,099	331,033,440
20	March	312,834,391	313,871,154	313,641,990
21	April	292,616,836	293,462,072	293,269,231
22	May	309,908,992	310,189,155	310,871,267
23	June	355,685,674	356,228,273	357,181,624
24	July	393,052,453	393,561,666	394,867,933
25	August	377,556,176	377,794,101	379,164,316
26	September	340,296,838	341,890,773	341,712,572
27	October	303,394,070	304,731,029	304,431,737
28	November	304,721,552	305,811,723	306,353,684
29	December	354,028,012	354,920,632	355,718,445

FR 16(7)(h)(7)

Duke Energy Kentucky, Inc.
Case No. 2018-00261
Mix of Generation 2018-2020

Line No.	Description	2018	2019	2020
1	Coal	2,949,290	3,723,574	3,484,051
2	Natural Gas	14,349	7,946	9,208
3	Oil	0	0	0
4	Total Generation (MWH)	2,963,639	3,731,519	3,493,259

FR 16(7)(h)(8)

Duke Energy Kentucky, Inc.
Case No. 2018-00261
Mix of Gas Supply 2018-2020

Line No.	Description	2018	2019	2020
1	Columbia Gas Trans - No Notice	965,453	965,453	965,453
2	Undetermined	8,366,832	8,462,597	8,538,741
3	Propane - Air	42,000	42,000	42,000
4	Total Supply - MCF	9,374,285	9,470,050	9,546,194
5	Columbia Gas Trans - No Notice	$ 3,536,776	$ 3,077,408	$ 2,871,656
6	Undetermined	28,191,569	27,128,950	26,666,041
7	Propane - Air	528,150	528,150	528,150
8	Demand Costs	6,286,615	6,227,531	6,290,635
9	Total Cost	$ 38,543,110	$ 36,962,040	$ 36,356,481

FR 16(7)(h)(9)

Duke Energy Kentucky, Inc.
Case No. 2018-00261
Number of Employees 2018-2020

Line No.	Description	2018	2019	2020
1	Number of employees	203	203	203

This count includes only direct employees of Duke Energy Kentucky, Inc..

FR 16(7)(h)(10)

Duke Energy Kentucky, Inc.
Case No. 2018-00261
Labor Cost Changes 2018-2020

Line No.	Description	2018	2019	2020
1	Total Labor Costs:			
2				
3	Gas O&M Expense	$ 12,195,660	$ 12,689,607	$ 12,816,503
4	Electric O&M Expense	38,603,070	38,409,414	38,793,508
5	Total O&M	50,798,730	51,099,021	51,610,011
6				
7	Gas Capital	12,229,280	8,541,973	8,627,393
8	Electric Capital	17,031,296	19,962,520	20,162,145
9	Non-jurisdictional Capital	0	0	0
10	Total Capital	29,260,576	28,504,493	28,789,538
11				
12	Total	$ 80,059,306	$ 79,603,514	$ 80,399,549

* Includes benefits & incentives (direct & allocated).

FR 16(7)(h)(11)

Duke Energy Kentucky, Inc.
Case No. 2018-00261
Capital Structure Requirements 2018-2020

Line No.	Description	2018		2019		2020	
		$	%	$	%	$	%
1	Common Equity	587,199,244	56.307%	619,008,583	51.173%	641,839,688	50.634%
2	Long-term Debt	425,096,552	40.763%	560,071,450	46.301%	595,198,687	46.955%
3	Short-term Debt	30,556,687	2.930%	30,556,687	2.526%	30,556,687	2.411%
4	Total Capital	1,042,852,483	100.00%	1,209,636,720	100.00%	1,267,595,062	100.00%

FR 16(7)(h)(12)

Duke Energy Kentucky, Inc.
Case No. 2018-00261
Rate Base 2018-2020

Line No.	Description	2018	2019	2020
1	Adjusted Jurisdictional Plant in Service	$ 572,101,198	$ 595,921,802	$ 629,107,465
2	Accumulated Depreciation and Amortization	(173,168,412)	(184,420,007)	(195,997,809)
3	Net Plant in Service (Line 1 + Line 2)	398,932,786	411,501,795	433,109,656
4	Construction Work in Progress	0	0	0
5	Cash Working Capital Allowance	3,029,353	3,090,987	3,096,138
6	Other Working Capital Allowances	5,423,808	5,423,808	5,423,808
7	Other Items:			
8	Customers' Advances for Construction	0	0	0
9	Investment Tax Credits	(570,830)	(570,830)	(570,830)
10	ADIT / EDIT	(90,197,182)	(91,527,502)	(92,105,119)
11	Other Rate Base Adjustments	0	0	0
12	Jurisdictional Rate Base (Line 3 through Line 11)	$ 316,617,935	$ 327,918,258	$ 348,953,653

FR 16(7)(h)(14)

Duke Energy Kentucky, Inc.
Case No. 2018-00261
Customer Forecast 2018-2020

Line No.	Description	2018	2019	2020
1	Residential	126,913	127,470	128,041
2	Commercial	13,879	13,981	14,035
3	Industrial	361	358	356
4	Other	1,420	1,431	1,441
5	Total Electric Retail	142,573	143,240	143,873
6	Residential	92,183	92,736	93,292
7	Commercial	7,156	7,199	7,242
8	Industrial	210	211	213
9	Other	375	377	379
10	Total Full Requirements	99,924	100,523	101,126
11				
12	Transportation			
13	Commercial	44	44	44
14	Industrial	37	37	37
15	Other	35	35	35
16	Total Transportation	116	116	116
17				
18	Total Gas Retail (Line 10 + Line 16)	100,040	100,639	101,242

FR 16(7)(h)(15)

Duke Energy Kentucky, Inc.
Case No. 2018-00261
MCF Sales Forecast 2018-2020

Line No.	Description	2018	2019	2020
1	Residential	5,737,781	5,805,628	5,882,107
2	Commercial	2,810,429	2,794,582	2,753,044
3	Industrial	194,346	178,597	155,803
4	Other	331,804	328,490	327,707
5	Interdepartmental	4,435	4,520	4,583
6	Total Retail	9,078,795	9,111,817	9,123,244
7	Transportation			
8	Commercial	628,671	669,564	731,907
9	Industrial	1,690,022	1,732,804	1,789,475
10	Other	1,669,676	1,672,585	1,677,499
11	Total Transportation	3,988,369	4,074,953	4,198,881
12	Total MCF Sales	13,067,164	13,186,770	13,322,125

DUKE ENERGY KENTUCKY
CASE NO. 2018-00261
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(7)(i)

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807 KAR 5:001, SECTION 16(7)(i)

Description of Filing Requirement:

The most recent Federal Energy Regulatory Commission or Federal Communication Commission audit reports.

Response:

See attached.

Witness Responsible: Michael Covington

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

In Reply Refer To:
Office of Enforcement
Docket No. PA14-2-000
April 1, 2016

Duke Energy Corporation
Attention: Mr. Brian D. Savoy
Senior Vice President, Chief Accounting
Officer and Controller
550 South Tryon St.
Charlotte, NC 28202

Dear Mr. Savoy:

1. The Division of Audits and Accounting (DAA) within the Office of Enforcement (OE) of the Federal Energy Regulatory Commission (Commission) has completed an audit of Duke Energy Corporation (Duke Energy) and its public utility subsidiaries. The audit covered the period from January 1, 2011 through January 31, 2016.

2. The audit evaluated Duke Energy's compliance with conditions and requirements established in Commission orders authorizing the merger of Duke Energy and Progress Energy, Inc. The audit also evaluated each Duke Energy public utility subsidiary's compliance with: (1) tariff requirements governing its transmission formula rate; (2) accounting regulations in 18 C.F.R. Part 101, Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act; and (3) financial reporting regulations in 18 C.F.R. Part 141, Statements and Reports. The enclosed audit report contains eight findings and 37 recommendations that require Duke Energy to take corrective action.

3. On March 30, 2016, you notified DAA that Duke Energy does not contest the audit report or any of its recommendations. A copy of your verbatim response is included as an appendix to this report. I hereby approve the audit report.

4. Duke Energy should submit its implementation plan to comply with the recommendations within 30 days of this letter order. Duke Energy should make quarterly submissions to DAA describing the progress made to comply with the recommendations, including the completion date for each corrective action. As directed by the audit report, these submissions should be made no later than 30 days after the end of each calendar quarter, beginning with the first quarter after this audit report is issued, and continuing until all the corrective actions are completed.

5. The Commission delegated authority to act on this matter to the Director of OE under 18 C.F.R. § 375.311 (2015). This letter order constitutes final agency action. Duke Energy may file a request for rehearing with the Commission within 30 days of the date of this order under 18 C.F.R. § 385.713 (2015).

6. This letter order is without prejudice to the Commission's right to require hereafter any adjustments it may consider proper from additional information that may come to its attention. In addition, any instance of noncompliance not addressed herein or that may occur in the future may also be subject to investigation and appropriate remedies.

7. I appreciate the courtesies extended to the auditors. If you have any questions, please contact Mr. Bryan K. Craig, Director and Chief Accountant, Division of Audits and Accounting at (202) 502-8741.

Sincerely,

Larry R. Parkinson
Director
Office of Enforcement

Enclosure

Federal Energy Regulatory Commission
Office of Enforcement
Division of Audits and Accounting

AUDIT REPORT

Audit of Duke Energy Corporation and its Public Utility Subsidiaries' Compliance with:

- Conditions in Commission Merger Authorization Orders;
- Transmission Formula Rate Tariff Requirements; and
- Accounting and Financial Reporting Regulations.

Docket No. PA14-2-000
March 29, 2016

Table of Contents

I. Executive Summary

A. Overview

The Division of Audits and Accounting (DAA) in the Office of Enforcement has completed an audit of Duke Energy Corporation (Duke Energy) and its public utility subsidiaries'[1] (collectively, Duke Companies) compliance with conditions and requirements established in Commission orders authorizing the merger of Duke Energy and Progress Energy, Inc. (Progress Energy).[2] The audit also evaluated each Duke Energy public utility subsidiary's compliance with: (1) tariff requirements governing its transmission formula rate; (2) accounting regulations in 18 C.F.R. Part 101, Uniform System of Accounts (USofA) Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act; and (3) financial reporting regulations in 18 C.F.R. Part 141, Statements and Reports. The audit covered the period January 1, 2011 through January 31, 2016.

B. Duke Energy Corporation

Duke Energy is a public utility holding company headquartered in Charlotte, NC. It is engaged in energy production, trade, transmission, and distribution through its six public utility subsidiaries that operate in the Southeast and Midwest regions of the United States. In 2014, Duke Energy was the largest electric utility in the nation. The company had 7.3 million retail electric and 500,000 natural gas customers, 32,400 miles of transmission lines, 57,500 MW of generating capacity, and total operating revenue of $23.9 billion. Its service area covered about 95,000 square miles and had an estimated population of 23 million. Regulated operations accounted for over 90 percent of the company's total revenue, and commercial power generation and international operations provided most of the remainder.

[1] The Duke Energy public utility subsidiaries are: Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP), Duke Energy Florida, LLC (DEF), Duke Energy Indiana, LLC (DEI), Duke Energy Ohio, Inc. (DEO), and Duke Energy Kentucky, Inc. (DEK).

[2] *Duke Energy Corp. and Progress Energy, Inc.*, 136 FERC ¶ 61,245 (2011) (Merger Order), *order on compliance*, 137 FERC ¶ 61,210 (2011), *order on compliance*, 139 FERC ¶ 61,194 (2012) (June 8 Compliance Order), *order on compliance*, 149 FERC ¶ 61,078 (2014) (October 29 Compliance Order).

C. Summary of Compliance Findings

Audit staff identified eight findings of noncompliance. Below is a summary of audit staff's compliance findings. Details are in section IV of this report.

- *Accounting for Merger Transaction Costs* – Duke Companies did not file merger transaction accounting entries with the Commission as required by the Merger Order, and the companies recorded merger transaction costs in operating accounts, contrary to the Commission's long-standing policy that such costs be recorded in nonoperating accounts. By not filing the accounting entries, Duke Companies prevented Commission review of the merger accounting and correction of any entries that were not in accordance with Commission accounting requirements.

- *Merger Transaction Internal Labor Costs* – Duke Companies improperly included approximately $31.4 million of merger transaction internal labor costs in wholesale power and transmission formula rate service cost determinations without first submitting a section 205 filing demonstrating that the costs were offset by quantified savings produced by the merger. As a result, the wholesale power and transmission customers' revenue requirements were inappropriately overstated by an estimated $17.5 million.

- *Merger Transaction Outside Services and Related Costs* – Duke Companies incorrectly included $1.5 million of merger transaction outside services and related costs in wholesale power and transmission formula rate service cost determinations without first submitting a section 205 filing demonstrating the costs were offset by quantified savings produced by the merger. In addition, the companies recorded the merger transaction costs in operating accounts, contrary to the Commission's long-standing policy that such costs be recorded in nonoperating accounts. As a result, the wholesale power and transmission customers' revenue requirements were inappropriately overstated by an estimated $745,000.

- *Use of the Consolidation Method of Accounting* – DEC and DEP accounted for investments in subsidiaries on a consolidated basis in their FERC Form No. 1, Annual Reports (Form No. 1), contrary to the Commission's long-standing accounting policy.

- *Accounting for Sales of Accounts Receivable* – DEC, DEP, and DEF misclassified an estimated $94.7 million of nonoperating expenses and receivables arising from transactions with their subsidiaries during the audit period. As a result, the wholesale power and transmission customers' revenue requirements were inappropriately overstated by an estimated $61 million.

- *Accounting for Lobbying Expenses:* Duke Companies recorded approximately $2.4 million of lobbying expenses in above-the-line operating accounts from 2011 through 2013. As a consequence, Duke Companies improperly included these costs in wholesale power and transmission formula rate service cost determinations.

- *Allocation of Lobbyist Labor Costs:* Duke Companies accounted for the labor costs of internal lobbyists and their support staff in operating accounts that lacked support for inclusion in the accounts. Improper accounting for the costs can lead to inappropriate recovery of the costs through rates charged and billed to customers.

- *Nonutility Expenses in Operating Accounts:* Duke Companies recorded approximately $490,000 of nonutility expenses in operating accounts in 2014. As a result, inappropriate costs were included in wholesale power and transmission formula rate service cost determinations and charged to customers.

D. Summary of Recommendations

Audit staff's recommendations to remedy the findings are summarized below with details in section IV of this report. Audit staff recommends that Duke Companies:

Accounting for Merger Transaction Costs

1. Revise accounting policies and procedures to appropriately account for merger transactions consistent with Commission accounting requirements.

2. Develop written policies and procedures to timely identify proposed accounting transactions that would trigger a notification to the Commission.

3. Develop written policies and procedures to submit accounting questions of doubtful interpretation to the Commission.

4. Provide training to employees on compliance with the merger cost accounting conditions and the revised policies, procedures, and controls for complying with the conditions. Also, develop a training program that supports the provision of periodic training in this area.

Merger Transaction Internal Labor Costs

5. Revise all policies and procedures for tracking, accounting, and excluding merger transaction costs from wholesale power and transmission formula rates, including amounts previously charged to utility plant, accumulated deferred income taxes, construction work in progress with the associated capitalized cost of funds used during construction (AFUDC), and maintenance and operating expense accounts, and future charges to such accounts for any transaction to which a FERC hold harmless obligation applies. The revised procedures should hold customers harmless from all merger transaction costs consistent with requirements of the Merger Order. Among other things, the revised policies and procedures should include an annual review of each subsidiary's merger transaction cost adjustments as well as periodic evaluations within the year, as needed and appropriate.

6. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the inclusion of merger transaction internal labor and related costs in wholesale power and transmission formula rates during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

7. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

8. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Merger Transaction Outside Services and Related Costs

9. Revise accounting policies and procedures to appropriately account for merger transaction costs consistent with Commission accounting requirements.

10. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the inclusion of merger transaction outside services and related costs in wholesale power and transmission formula rate charges during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

11. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

12. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Use of the Consolidation Method of Accounting

13. Review and, as needed, revise accounting policies, practices, and procedures to ensure that investments in subsidiaries are accounted for consistent with the Commission's equity method accounting requirements.

14. Evaluate the accounting applied to Duke Companies' existing subsidiaries and notify DAA of any areas of noncompliance with Commission accounting requirements.

15. Revise documented policies, procedures and processes to ensure timely notice is provided to relevant regulators regarding instances of noncompliance with regulations, rules, and orders.

16. Provide training to staff on procedures, practices, and available tools to transparently or anonymously report instances of noncompliance to senior management, the Board of Directors, and relevant regulators.

Accounting for Sales of Accounts Receivable

17. Revise procedures to ensure that all costs and account balances associated with the sale of accounts receivable are accounted for in accordance with Commission accounting regulations. Among other things, the corrected accounting should ensure that all losses associated with receivable sales are recorded in Account 426.5.

18. Provide the revised procedures to DAA for review within 60 days of receiving the final audit report.

19. Recalculate charges to wholesale power and transmission customers of DEC, DEP, and DEF and submit the recalculations in a refund analysis to DAA for review within 60 days of receiving the final audit report. The refund analysis should explain and detail the: (1) return of collection service billings charged in 2014; (2) return of losses on the sales included in rates; (3) determinative components of the refund; (4) refund method; (5) period(s) refunds will be

made; and (6) interest calculated in accordance with section 35.19 of Commission regulations.

20. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

21. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Accounting for Lobbying Expenses

22. Establish and implement written procedures governing the methods used to account for, track, report, and review lobbying costs incurred.

23. Provide training on Commission accounting requirements and the impact of accounting on cost-of-service rate determinations to employees involved in lobbying and lobbying-related work, and those with oversight responsibility for lobbying cost allocations. Also, develop a training program that supports the provision of periodic training in this area.

24. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the improper inclusion of lobbying cost in operating accounts during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

25. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

26. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Allocation of Lobbyist Labor Costs

27. Revise written policies and procedures to create a process to document and verify appropriate allocation of lobbying and lobbying-related costs, and maintain auditable support for the cost included in rate determinations.

28. Retain an independent third-party entity to conduct a representative labor time study to determine an appropriate allocation of internal lobbyist labor, support

staff, and associated costs that should be accounted for in operating and nonoperating accounts based on time spent by employees engaged in the activities. Provide the study results to audit staff within 180 days of the date of the final audit report.

29. Include the results of the labor time study in the determination of lobbying-related labor cost allocations as of January 1, 2016.

30. Implement policies and procedures to perform a labor time study biennially using an independent third-party or internal company resources that are able to attest to the results of the study. Revise the lobbying-related labor cost allocations based on the results of the study.

Nonutility Expenses in Operating Accounts

31. Develop and implement written policies, procedures, and controls to ensure proper accounting and reporting of nonutility expenses.

32. Provide training for employees involved in the invoicing process on Commission accounting requirements and the impact of the accounting on cost-of-service rate determinations.

33. Within 60 days of receiving the final audit report, provide documentation supporting the analysis performed of invoiced expenses recorded to administrative and general (A&G) accounts in 2014 that identified misclassified nonutility expenses included in A&G accounts. Develop an estimate of misclassified nonutility expenses accounted for in operating accounts in 2011 through 2013 and 2015.

34. Implement policies and procedures to provide periodic audits or reviews of A&G transactions by external or internal auditors.

35. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the improper inclusion of identified and estimated nonutility expenses in charges to wholesale power and transmission customers during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made. Include the results of the invoice analysis in the refund analysis.

36. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

37. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

E. Implementation of Recommendations

Audit staff further recommends that Duke Companies submit the following for audit staff's review:

- A plan for implementing the audit recommendations within 30 days after the final audit report is issued;

- Quarterly reports describing progress in completing each corrective action recommended in the final audit report. Quarterly nonpublic submissions should be made no later than 30 days after the end of each calendar quarter, beginning with the first quarter after the final audit report is issued, and continuing until all recommended corrective actions are completed; and

- Copies of any written policies and procedures developed in response to recommendations in the audit report. These documents should be submitted in the first quarterly filing after Duke Companies complete such policies and procedures.

II. Background

A. Merger of Duke Energy and Progress Energy

On January 10, 2011, Duke Energy and Progress Energy announced their intention to merge in a stock-for-stock transaction under which Progress Energy would become a wholly owned subsidiary of Duke Energy, and the shareholders of Progress Energy would become shareholders of Duke Energy. At the time, the transaction was valued at over $31 billion. The merger was poised to create the largest U.S. electric utility in history with over seven million electric customers and operations in six states.

Following the announcement, on April 4, 2011, Duke Energy, Progress Energy, and their public utility subsidiaries (collectively, Duke Companies) filed an application with the Commission seeking authorization for the merger transaction under section 203 of the Federal Power Act (FPA)[3] and Part 33 of Commission regulations.[4] To receive authorization for the transaction, the companies committed to hold transmission and wholesale requirements customers harmless from the costs of the transaction for five years. The companies also contended that the transaction would not adversely affect competition, and thus there were no market power concerns associated with the transaction.

On September 30, 2011, the Commission found that the transaction, as proposed in the application, would result in significant screen failures in the horizontal market power analysis and have an adverse effect on competition.[5] As such, the Commission authorized the transaction subject to conditions. Among other things, the transaction was conditioned on Duke Companies holding transmission and wholesale requirements customers harmless from the costs of the transaction, and submitting proposed market power mitigation measures that the Commission approves. The Commission advised Duke Companies that sufficient mitigation measures could include membership in a regional transmission organization, implementing an independent coordinator of transmission arrangement, actual or virtual divestiture of generation, and/or transmission upgrades to provide greater market access to third-party energy suppliers.

Further, the Commission stated that the hold harmless commitment included all merger transaction costs, not only costs related to consummating the transaction.[6] To recover merger transaction costs through wholesale requirement or transmission rates, the

[3] 16 U.S.C. § 824b (2012).

[4] 18 C.F.R. Part 33.

[5] Merger Order, 136 FERC ¶ 61,245 at PP 145-146.

[6] *Id.* P 169.

companies were required to submit a filing to the Commission that identified merger costs to be recovered and demonstrated that the costs were exceeded by savings produced by the transaction.[7] Duke Companies did not submit a filing to recover merger transaction costs during the audit period. However, as discussed in detail below, the companies recovered merger transaction costs through rates charged.

Consistent with the Commission's merger authorization condition that required Duke Companies to submit proposed market power mitigation measures for approval, the companies submitted an initial compliance filing on October 17, 2011, which proposed to mitigate market power through virtual divestiture of generation. The filing proposed a must-offer obligation under which Duke Companies would sell specified quantities of energy at cost-based rates to entities directly or indirectly serving load in the DEC and DEP Balancing Authority Areas (BAAs). The Commission rejected the filing on the grounds that the market power mitigation proposals did not remedy the market power concerns identified in the Merger Order.[8]

A revised compliance filing was submitted by Duke Companies on March 26, 2012 that proposed permanent and interim market power mitigation measures. To permanently mitigate market power, Duke Companies proposed to build seven transmission expansion projects (TEPs), expedite completion of an eighth project that was already planned, and set aside 25 MW of transfer capacity on their transmission systems for use by third parties (Stub Mitigation). During construction of the TEPs, as an interim measure to protect against potential market power concerns, Duke Companies proposed to enter into power sale agreements with three unaffiliated firms – Cargill Power Marketing, EDF Trading, and Morgan Stanley Capital Markets – to which the companies would sell power during all periods requiring mitigation. The companies also proposed to hire an independent monitor, Potomac Economics Ltd. (Potomac Economics), to verify compliance with the provisions of the power sale agreements.

The Commission accepted the revised compliance filing on June 8, 2012, subject to certain revisions and conditions, which included, among other things, requirements to hold customers harmless from the cost of the mitigation actions and to expand Potomac Economics' duties to verify that the TEPs were completed within the prescribed scope and timeline.[9] The merger was consummated on July 2, 2012.

On December 6, 2013, after the merger was consummated, Duke Companies submitted a motion to supplement its March 26, 2012 compliance filing, due to newly identified information that affected calculation of the impact of the market power

[7] *Id.* P 170.

[8] *Duke Energy Corp.*, 137 FERC ¶ 61,210 (2011).

[9] *See* June 8 Compliance Order, 139 FERC ¶ 61,194 at P 113.

mitigation measures. In the filing, Duke Companies offered to increase the Stub Mitigation by 104 MW (thereby raising the total amount of the transmission set-aside to 129 MW), repair out of service phase-shifting transformers at DEC's Rockingham substation and return them to service, and operate the transformers so as to create additional import capability on the transmission system. The Commission granted the motion and accepted the supplementary compliance filing subject to conditions on October 29, 2014.[10] Moreover, the Commission reiterated its requirement that transmission and wholesale requirements customers be held harmless from costs associated with repairing the transformers and returning them to service.

B. Duke Energy's Public Utility Subsidiaries

During the audit period, the Duke Companies provided electricity service in portions of North Carolina, South Carolina, Florida, Indiana, Ohio, and Kentucky. DEO and DEK also provided natural gas service in portions of Ohio and Kentucky. The following describes the services provided by each company, its open access transmission tariff (OATT), membership in an independent system operator (ISO) or regional transmission organization (RTO), transmission formula rate, and market-based rate authority.

Duke Energy Carolinas, LLC

DEC is a vertically integrated public utility that generates, transmits, distributes, and sells electricity to 2.5 million customers in a 24,000 square mile service area in North and South Carolina. DEC owns 8,302 miles of transmission lines and 19,600 MW of generating capacity.

DEC provided open access transmission service under a Commission-approved OATT at cost-based stated rates from 1995 through 2011.[11] In 2011, DEC began recovery of its transmission service cost pursuant to a formula rate that became effective June 1, 2011.[12] However, on March 26, 2012, in connection with the merger transaction, DEC, DEP, and DEF filed for approval of a Joint OATT under section 205 of the FPA and Part 35 of the Commission's regulations. The filing was conditionally accepted by the Commission on June 8, 2012.[13]

[10] October 29 Compliance Order, 149 FERC ¶ 61,078 (2014).

[11] *Duke Power Co.*, 73 FERC ¶ 61,309 (1995) (Duke Power Order).

[12] *Duke Energy Carolinas, LLC*, 137 FERC ¶ 61,058 (2011).

[13] *Duke Energy Corp.*, 139 FERC ¶ 61,193 (2012).

The Joint OATT provided for transmission service at non pancaked rates for transactions involving the combined transmission systems of the companies. DEC's transmission formula rate is incorporated as Schedule 10-B of the Joint OATT. DEC's formula rate implementation protocols are incorporated as Exhibit A of the Joint OATT, and the formula rate template and formula rate principles are contained in Exhibit B. DEC does not belong to an ISO or RTO.

DEC has wholesale power sale agreements with cost-based rates determined under a formula, and it has Commission authorization to make wholesale sales at market-based rates outside its and DEP's BAAs and Peninsular Florida.

Duke Energy Progress, LLC

DEP is a vertically integrated public utility that generates, transmits, distributes, and sells electricity to 1.5 million customers in a 32,000 square mile service area in North and South Carolina. DEP owns 6,981 miles of transmission lines and 12,200 MW of generating capacity.

DEP provided open access transmission service under a Commission-approved OATT at cost-based stated rates from 1996 through 2008. In 2008, DEP began recovery of its transmission service cost pursuant to a formula rate that became effective July 1, 2008.[14] Since the merger, DEP has provided transmission service under the Joint OATT with DEC and DEF. DEP's transmission formula rate is incorporated in Attachment H of the Joint OATT. The formula rate template is incorporated as Attachment H-1 of the Joint OATT, and the implementation protocols as Attachment H-2. DEP does not belong to an ISO or RTO.

DEP has wholesale power sale agreements with cost-based rates determined under a formula, and it has Commission authorization to sell energy and capacity at market-based rates outside its and DEC's BAAs and Peninsular Florida.

Duke Energy Florida, LLC

DEF is a vertically integrated public utility that generates, transmits, and delivers electricity to 1.7 million customers in a 13,000 square mile area in central and southern Florida. DEF owns 4,424 miles of transmission lines and 1,200 MW of generating capacity.

[14] *Carolina Power and Light Co.*, Docket No. ER08-889-000 (June 27, 2008) (delegated letter order).

DEF provided open access transmission service under a Commission-approved OATT at cost-based stated rates from 1996 through 2008. In 2008, DEF began recovery of its transmission service cost pursuant to a formula rate that became effective January 1, 2008.[15] Since the merger, DEF has provided transmission service under the Joint OATT with DEC and DEP. DEF's transmission formula rate is incorporated as Schedule 10-A of the Joint OATT. The implementation protocols are designated as Schedule 10-A.1 of the Joint OATT, and the formula rate template as Schedule 10-A.2. DEF does not belong to an ISO or RTO. Additionally, DEF has Commission authorization to sell energy and capacity outside the DEC and DEP BAAs and Peninsular Florida.

Duke Energy Indiana, LLC

DEI is a vertically integrated utility that generates, transmits, distributes, and sells electricity to 810,000 customers within a 23,000 square mile service territory in central, north central, and southern Indiana. DEI owns 7,500 MW of generating capacity and 4,815 miles of transmission lines.

DEI became a member of the Midcontinent Independent System Operator, Inc., (MISO) in 1997 and recovered its cost of transmission service pursuant to cost-based stated rates. In 1998, DEI began to recover its transmission service cost pursuant to a transmission formula rate. DEI's transmission formula rate template is included at Attachment O of the MISO Open Access Transmission, Energy, and Operating Reserve Markets Tariff. Additionally, DEI has Commission authorization to sell power at market-based rates outside the DEC and DEP BAAs and Peninsular Florida.

Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.

DEO is the direct parent of DEK. The companies are combination electric and gas utilities that transmit, distribute, and sell electricity at retail and wholesale, and distribute and sell natural gas at retail in southwestern Ohio and northern Kentucky, respectively. DEO owns 1,879 miles of transmission lines. The company divested its generating assets pursuant to Ohio's electric restructuring program and received Commission authorization for the divestiture.[16] DEK owns 102 miles of transmission lines and about 1,200 MW of generating capacity.

[15] *Florida Power Corp.,* Docket No. ER08-105-000 (Dec. 17, 2007) (delegated letter order).

[16] *See Dynegy Resource I, LLC,* 150 FERC ¶ 61,232 (2015).

DEO and DEK were members of MISO until January 1, 2012, when they withdrew their membership and joined PJM Interconnection, L.L.C. (PJM).[17] The companies recover transmission service costs pursuant to a transmission formula rate under the PJM OATT. DEO and DEK's transmission formula rate is incorporated as Attachment H-22 of the PJM OATT. The formula rate template is incorporated as Attachment H-22A of the OATT, and the implementation protocols as Attachment H-22B. Additionally, DEO and DEK have Commission authorization to sell power at market-based rates outside the DEC and DEP BAAs and Peninsular Florida.

[17] The Commission conditionally authorized the move in an order issued October 21, 2010. *See Duke Energy Ohio, Inc.*, 133 FERC ¶ 61,058 (2010).

III. Introduction

A. Objectives

The audit evaluated Duke Companies' compliance with conditions established in the Merger Order and associated orders on compliance, requirements of each company's transmission formula rate tariff, and accounting and financial reporting regulations. The audit covered the period January 1, 2011 through January 31, 2016.

B. Scope and Methodology

Audit staff performed specific actions to facilitate the audit and evaluate compliance with the audit objectives. Audit staff also reviewed the effectiveness of Duke Companies' compliance program in relation to the audit objectives and other key factors. To address overall audit objectives, audit staff:

- Conducted an extensive review of publicly available materials to understand the companies' corporate structure and organization, operations, financial accounting and reporting activities, and other key regulatory and business activities, both before and after the merger. Examples of materials and documentation reviewed include Commission rules, regulations, and orders, Form No. 1 reports, FERC Form No. 65, Notification of Holding Company Status, formula rate filings, the Commission's enforcement hotline calls and company self-reports, company-related web sites, and relevant media sources. This also included a review of filings with other government agencies, such as the Securities and Exchange Commission Forms 10-K and 10-Q, Annual and Quarterly Reports;

- Evaluated the companies' internal policies and procedures relevant to the audit objectives;

- Conferred with other Commission staff on various compliance issues to ensure audit findings were consistent with Commission precedent and policy. For example, audit staff communicated with staff from other divisions within the Office of Enforcement and staff from the Office of Energy Market Regulation and Office of General Counsel;

- Conducted two site visits to Duke Energy's headquarters in Charlotte, NC. The visits enabled audit staff to further understand the company's corporate structure, functions, operations, accounting systems and practices, transmission planning and cost-estimating procedures, formula rate, internal audit function, and regulatory and corporate compliance programs. While on site, audit staff interviewed employees and managers responsible for performing tasks within the audit scope, sampled and tested documents to verify compliance with Commission orders related to merger conditions, accounting regulations, financial reporting, transmission formula rates, and related matters. Additionally, audit staff also interviewed compliance program staff, senior officials, internal auditors, and employees who fulfill day-to-day compliance activities for the purposes of carrying out regulatory oversight responsibilities;

- Conducted teleconferences to discuss audit objectives and scope, data requests and responses, technical and administrative matters, compliance concerns, and held a closing conference to discuss the completion of audit fieldwork and results; and

- Issued data requests to gather information not available through public means. This information related to internal policies and procedures, business practices, reporting activities, corporate compliance, internal and external audit reports, merger order conditions and compliance, transaction and operational data, and other pertinent information. Audit staff used this information as underlying support for testing and evaluating compliance with Commission requirements relevant to the audit scope and objectives.

Further, audit staff performed these specific actions to facilitate the testing and evaluation of compliance with relevant requirements for the audit scope areas. A summary of these actions follows.

Compliance with Merger Conditions

To evaluate compliance with the hold harmless and market power mitigation conditions established in the Merger Order and associated compliance orders, audit staff performed audit fieldwork applicable to the merger. Audit staff performed the following steps:

- Reviewed the merger application, supporting testimony and exhibits to understand the context, terms, and conditions of the merger proposal and commitment to hold transmission and wholesale requirements customers harmless from costs of the transaction. Reviewed intervenor comments and protests, and responses to the comments and protests, and also reviewed Duke Companies' compliance filings, intervenor responses, and answers to the responses;

- Evaluated Duke Companies' responses to Commission staff's delegated data requests that sought information regarding the merger application and compliance filings;

- Examined the companies' policies and procedures associated with tracking and accounting for merger transaction costs incurred prior to and following consummation of the merger;

- Performed a comparative analysis of Duke Energy and Progress Energy's accounting for costs of the merger prior to and after its consummation and the companies' policies associated with the accounting;

- Reviewed actions taken by the companies to maintain compliance with merger conditions;

- Analyzed the companies' procedures to ensure compliance with hold harmless conditions and to account for merger transaction costs;

- Conducted sample-based tests of internal costs and external contracted costs incurred by the companies to assess the accounting for the costs and the impact on wholesale rate determinations;

- Obtained information on staff involved in merger activities, including employee names, positions, salaries, work performed on merger activities, and time spent on merger-related activities;

- Reviewed documentation and supporting evidence of merger transaction costs and performed substantive tests of sample data;

- Inspected reports submitted by Potomac Economics regarding the Rockingham phase shifters and other relevant Commission filings;

- Evaluated expenses incurred to repair the Rockingham phase shifters to assess the accounting for the costs and impacts on wholesale rate determinations; and

- Examined costs incurred to operate the TEPs – including the Rockingham phase shifters – from 2012 through Q1 2015 to evaluate the accounting used to record cost of activity and the resulting impact on wholesale rate determinations.

Furthermore, audit staff conducted the following additional steps to evaluate Duke Companies' compliance with the market power mitigation conditions:

- Reviewed the companies' contract with Potomac Economics to ascertain whether the independent monitor had sufficient oversight authority and timely access to data needed to monitor compliance with interim and permanent market power mitigation measures;

- Examined the quarterly independent monitoring reports prepared by Potomac Economics detailing Duke Companies' compliance with interim and permanent market power mitigation conditions;

- Interviewed personnel responsible for reporting the status of TEP construction to Potomac Economics, and reviewed a sample of email communications between the parties;

- Interviewed personnel involved with TEP planning, engineering and design, purchasing and contracting, construction, and project management to verify that the projects were completed as required and to ascertain the amount of labor time employees spent on the projects;

- Identified scope changes made to the TEP plans and assessed the impact of changes on project cost and expected performance of the transmission system;

- Examined a sample of information that Potomac Economics relied on to conclude that the TEPs were placed into service. This information included data from the supervisory control and data acquisition (SCADA) system on the operation of the constructed projects and associated work orders;

- Analyzed photographs of TEP equipment nameplates for asset identification and facility ratings for a sample of major equipment installed, and compared nameplate information to construction work orders and internal company correspondence related to the TEPs;

- Reviewed Duke Companies' written procedures that governed implementation of the power sales agreements required by the Commission's interim market power mitigation measures. Also, interviewed personnel responsible for developing and implementing the agreements, and reviewed Potomac Economics' seasonal and event-based reports to the Commission on the company's performance under the agreements;

- Analyzed a sample of transaction data on power sales DEC and DEP made under the power sale agreements and reviewed transmission schedules on the Open Access Same-time Information System (OASIS) to verify the energy was scheduled and delivered;

- Interviewed power marketing personnel to gain information on operating procedures and processes used to comply with the requirement to set aside firm transmission capacity on the DEC-DEP interface (i.e., Stub Mitigation requirement);

- Reviewed Potomac Economics' reports on the Stub Mitigation requirement and analyzed a sample of data from OASIS regarding transmission offerings and requests for firm transmission service on the DEC-DEP interface;

- Evaluated the DEC-DEP Joint Dispatch Agreement (JDA) and associated operating procedures to understand the methods used to forecast load and determine the mix of generating resources needed to meet load demand on daily and weekly bases;

- Interviewed power marketing employees responsible for scheduling power between the DEC and DEP BAAs, and examined a sample of transactions that involved dispatch of generating resources, reserving and scheduling transmission service consistent with the JDA, and operating the respective BAAs separately. Also, tested a sample of OASIS transmission reservations and schedules to evaluate DEC and DEP's reservations of point-to-point and network transmission service to transmit energy and capacity between the two BAAs; and

- Identified instances in which DEC and DEP used network transmission to deliver power to their respective BAAs, and evaluated these transactions to assess compliance with conditions that restricted certain transactions in the BAAs.

Transmission Formula Rates

To evaluate compliance with the requirements of each company's transmission formula rate tariff, audit staff:

- Reviewed the initial applications filed seeking approval of each company's transmission formula rate tariff, intervenor responses to the filings, any associated settlement agreements with wholesale customers and interested parties, and the Commission orders that approved the transmission formula rate tariffs;

- Examined the transmission formula rate templates and all appendices and attachments used to compute key inputs to the annual transmission revenue requirement and associated formula rate protocols;

- Interviewed employees responsible for populating each public utility's transmission formula rate template, verifying data and calculations, and reviewing and obtaining management approval of the calculated transmission service rates;

- Assessed the adequacy of management oversight and verification controls that support performance of key activities;

- Evaluated data responses and conducted conference calls to understand the accounting for major items affecting the formula rate, including miscellaneous deferred debits, income taxes, and others. Also, reviewed these items to determine compliance with relevant accounting regulations, instructions, and definitions;

- Reviewed annual informational and true-up filings submitted after the initial rate years and during the audit period. Reconciled the Form No. 1 data with formula rate calculations and evaluated discrepancies. Conducted a detailed analysis of supporting worksheets and attachments to evaluate the calculation of transmission formula rate inputs;

- Analyzed footnotes included in each company's Form No. 1 to determine whether information disclosed provided for a reconciliation of publicly available data to balances used to calculate the transmission service rates;

- Performed procedures to verify that transmission formula rate inputs were supported by data reported in each company's Form No. 1;

- Evaluated the companies' accounting for merger transaction costs by assessing documented policies, operating processes, and procedures, and tested a sample of invoices and work orders that included merger activities and associated costs. Analyzed the accounting for the costs and the impact on transmission rate determinations;

- Checked plant balances used to calculate transmission revenue requirements, sampled work order charges included in construction work in progress and plant balances, and performed tests on amortized pre-commercial costs;

- Tested a sample of depreciation accruals on utility plant to assess the depreciation rates applied to the plant; and

- Performed substantive tests on a sample of invoices and work orders that included nonutility expenses, and evaluated the impact of identified misclassified items on transmission rate determinations.

Accounting and Reporting

To evaluate compliance with the Commission's accounting and reporting regulations in the USofA under 18 C.F.R. Parts 101 and 141, audit staff performed the following with respect to the merger:

- Conducted interviews and teleconferences and met with company staff to discuss accounting policies, procedures, and practices. These interviews included discussions with employees involved in the operation of each public utility subsidiary's financial accounting systems to assess the adequacy of accounting and reporting oversight controls related to the merger, and employees in leadership positions responsible for day-to-day oversight of merger activities to understand how merger-related labor was reported on timesheets;

- Examined procedures for preparing, reviewing, and obtaining management approval of the Form No. 1 reports. Reviewed disclosures in the reports to understand major accounting policies;

- Reviewed and evaluated the processes, procedures, and controls the companies used before and after merger consummation to track and account for merger transaction costs;

- Evaluated the Form No. 1 and Securities and Exchange Commission 10-K notes and disclosures related to tracking, accounting, and reporting merger transaction costs;

- Analyzed the companies' accounting entries that recorded merger-related labor, goodwill, TEP project costs and impairments, and the income tax effects of the transaction;

- Reviewed third-party lobbying expenditure disclosures, press articles, meeting schedules, and agendas of internal lobbyists. Interviewed internal lobbyists and support staff to understand the nature and extent of the companies' lobbying activities;

- Tested a sample of work orders, invoices, and associated accounting detail records that support internal lobbyists' labor costs incurred;

- Assessed the impact on wholesale rates of merger and other costs incurred by the companies that were reported in the Form No. 1;

- Tested a sample of FERC accounts for compliance with the Merger Order as well as the companies' internal policies and procedures; and

- Evaluated certain income statement and balance sheet accounts and balances reported in the companies' Form No. 1 reports for 2012 through 2014.

IV. Findings and Recommendations

1. Accounting for Merger Transaction Costs

Duke Companies did not file merger transaction accounting entries with the Commission as required by the Merger Order, and the companies recorded merger transaction costs in operating accounts, contrary to the Commission's long-standing policy that such costs be recorded in nonoperating accounts. By not filing the accounting entries, Duke Companies prevented Commission review of the merger accounting and correction of any entries that were not in accordance with Commission accounting requirements.

Pertinent Guidance

The Commission's September 30, 2011 order conditionally authorizing the Proposed Transaction established the following requirement concerning the submission of accounting entries related to the merger:

> To the extent any applicant that is subject to the Commission's Uniform System of Accounts records any aspect of the Proposed Transaction in its accounts, it is directed to file its accounting entries with the Commission within six months of the consummation of the Proposed Transaction. Further, if the accounting entities are recorded six months after the consummation of the Proposed Transaction, the applicant must file those accounting entries with the Commission within 60 days from the date they were recorded. The accounting submission must provide all accounting entries related to the Proposed Transaction, including narrative explanations describing the basis, and the rate impact, of such entries.[18]

The Commission's long-standing precedent stipulates that transaction costs incurred by public utilities associated with a merger are nonoperating in nature and should be charged to Account 426.5, Other Deductions, to the extent the costs are not retained by the parent holding company. For example, in *Allegheny Energy, Inc.,* the Commission stated in part:

> The Commission has previously determined that merger transaction costs are considered non-operating in nature and should be recorded in

[18] Merger Order, 136 FERC ¶ 61,245 at P 190.

Account 426.5, Other Deductions.[19]

18 C.F.R. Part 101, Account 426.5, Other Deductions, states:

> This account shall include other miscellaneous expenses which are nonoperating in nature, but which are properly deductible before determining total income before interest charges.

18 C.F.R. Part 101, General Instruction No. 5, Submittal of Questions, states:

> To maintain uniformity of accounting, utilities shall submit questions of doubtful interpretation to the Commission for consideration and decision.

Background

In the Merger Order, the Commission authorized Duke Companies to merge, subject to conditions. With respect to accounting, the Merger Order stated that if any Duke Energy subsidiary subject to the USofA recorded any aspect of the merger on its books, the subsidiary must file the accounting entries with the Commission within 60 days of consummation of the transaction. The Commission noted that such accounting entries include entries related to transaction costs, merger premiums, acquisition adjustments, goodwill, or any cost related to the merger.[20]

Moreover, pursuant to long-standing Commission precedent, merger transaction costs are considered nonoperating in nature and are required to be recorded to Account 426.5, Other Deductions. The text of Account 426.5 states that the account shall include expenses that are nonoperating in nature. Audit staff evaluated Duke Companies' accounting for the merger and found that the companies recorded merger transaction costs on their books. Further, contrary to the requirements of the Merger Order and Commission accounting rules, Duke Companies neither filed accounting entries with the Commission that reflected the recording of the transaction costs on the companies' books nor accounted for nonoperating merger transaction costs in Account 426.5.

[19] *See Allegheny Energy, Inc.*, 133 FERC ¶ 61,222, at P 73 (2010). *See also Midwest Power Systems, Inc. and Iowa-Illinois Gas and Elec. Co.*, 71 FERC ¶ 61,386, at 62,509 (1995); *MidAmerican Energy Co. and MidAmerican Energy Holdings Co.*, 85 FERC ¶ 61,354, at 62,370 (1998); and *Wis. Elec. Power Co.,* 74 FERC ¶ 61,069, at 61,192 (1996).

[20] Merger Order, 136 FERC ¶ 61,245 at n. 414.

Duke Companies collectively incurred over $1 billion in merger costs and recorded the costs on their Form No. 1 reports from 2011 through October 30, 2015. The costs were accounted for in numerous operating plant and expense accounts, including: A&G expense; payroll tax; customer account expense; transmission, distribution, and production operating and maintenance expense; and other accounts.

Duke Energy explained that it interpreted the Merger Order to require submittal of accounting entries only if a subsidiary used the purchase method of accounting and increased the book value of assets for goodwill acquired in the transaction. However, the Merger Order did not require the companies to file accounting entries only if they used the purchase method of accounting or increased the book value of assets for goodwill. To the contrary, the Merger Order stated that if *any entity* subject to the USofA recorded *any aspect* of the merger on its books, it must file its accounting entries with the Commission. The Merger Order further clarified that such accounting entries included entries related to transaction costs, merger premiums, acquisition adjustments, goodwill, or any cost related to the merger.

All of Duke Energy's public utility subsidiaries were subject to the Commission's USofA, therefore the companies should have filed accounting entries. By not filing the accounting entries, Duke Companies prevented Commission review of the merger accounting and correction of any entries not in accordance with Commission accounting requirements.

Furthermore, Duke Companies should have recorded merger transaction costs incurred to effectuate the merger in Account 426.5 rather than in operating accounts consistent with the text of Account 426.5 and Commission precedent.[21] Audit staff found that prior to March 2012, both Duke Energy and Progress Energy recorded merger transaction costs in operating accounts. However, in March 2012, Progress Energy transferred its merger transaction costs to Account 426.5, due to its interpretation of a Commission merger order that required such accounting. Duke Energy did not implement a similar reclassification of its merger transaction costs. Duke Energy explained that it believed costs associated with the merger were appropriately recorded in operating accounts.

[21] Post-merger integration cost (i.e., cost incurred following consummation of a merger, in which the assets, personnel, and business activities of the entities participating in the merger are combined) are recordable to operating accounts; however, the cost would be subject to the Commission's hold harmless commitments and prohibited from recovery in jurisdictional rates.

In April 2012, Duke Energy's external auditors questioned its accounting of the merger transaction costs. The external auditors informed Duke Energy of the Commission's merger accounting policy, which the auditors interpreted as requiring merger transaction costs to be recorded below-the-line in Account 426.5. Duke Energy disagreed with the auditors' interpretation. Rather than adjusting its accounting, Duke Energy and its external auditors agreed that Duke Energy's management representation letter would be revised. The letter is a signed attestation by Duke Energy management of the accuracy of its financial statements. The letter was revised to include a statement that Duke Energy was aware of Commission orders that indicated merger transaction costs should be recorded in Account 426.5, but Duke Energy nonetheless believed that its classification of merger transaction costs in operating accounts was appropriate.

The Duke Companies were required to file the accounting entries with the Commission as directed in the Merger Order. The companies' improper accounting for merger transaction costs contributed to the inappropriate recovery of merger-related internal labor and outside service costs through charges to Commission-jurisdictional customers. To the extent Duke Companies was uncertain about the appropriate accounting for the transaction, the companies should have submitted accounting questions of doubtful interpretation to the Commission for consideration and decision. The Commission expects Duke Companies, and all entities that have a reporting requirement for transactions under FPA section 203, to fully comply with the orders approving such transactions. Duke Companies' lack of compliance with the Merger Order reporting requirement is a very serious matter.

Recommendations

We recommend Duke Companies:

1. Revise accounting policies and procedures to appropriately account for merger transactions consistent with Commission accounting requirements.

2. Develop written policies and procedures to timely identify proposed accounting transactions that would trigger a notification to the Commission.

3. Develop written policies and procedures to submit accounting questions of doubtful interpretation to the Commission.

4. Provide training to employees on compliance with the merger cost accounting conditions and the revised policies, procedures, and controls for complying with the conditions. Also, develop a training program that supports the provision of periodic training in this area.

2. Merger Transaction Internal Labor Costs

Duke Companies improperly included approximately $31.4 million of merger transaction internal labor costs in wholesale power and transmission formula rate service cost determinations without first submitting a section 205 filing demonstrating that the costs were offset by quantified savings produced by the merger. As a result, the wholesale power and transmission customers' revenue requirements were inappropriately overstated by an estimated $17.5 million.

Pertinent Guidance

The Commission's Merger Order states in part:

> We accept Applicants' commitment to hold transmission and wholesale requirements customers harmless for five years from costs related to the Proposed Transaction. We interpret Applicants' hold harmless commitment to include all transaction-related costs, not only costs related to consummating the transaction.
>
> If Applicants seek to recover transaction-related costs through their wholesale power or transmission rates within the next five years, they must submit a compliance filing that details how they are satisfying the hold harmless requirement. If Applicants seek to recover transaction-related costs in an existing formula rate that allows for such recovery within the next five years, then that compliance filing must be filed in the section 205 docket in which the formula rate was approved by the Commission, as well as in the instant section 203 docket. In such filings, Applicants must: (1) specifically identify the transaction-related costs they are seeking to recover; and (2) demonstrate that those costs are exceeded by quantified savings resulting from the transaction, in addition to any requirements associated with filings made under section 205.[22]

The Commission's June 8, 2012 order accepting Duke Companies' revised compliance filing states in part:

> [T]he Commission will require Applicants to hold transmission and wholesale requirements customers harmless from the costs of the Transmission Expansion Projects in accordance with the hold harmless commitment, as set forth in the Merger Order.[23]

[22] Merger Order, 136 FERC ¶ 61,245 at PP 169-170.

[23] June 8 Compliance Order, 139 FERC ¶ 61,194 at P 91.

The Commission's October 29, 2014 order denying rehearing and granting a motion to supplement compliance filing states in part:

> [T]he Commission requires Applicants to hold transmission and wholesale requirements customers harmless for five years from costs related to the Phase Shifters.[24]

Background

On April 4, 2011, Duke Energy, Progress Energy, and their public utility subsidiaries (collectively, Duke Companies) filed an application seeking Commission authorization of a proposal to merge under section 203 of the FPA and Part 33 of Commission regulations. In the application, Duke Companies committed to exclude costs related to the merger from transmission and wholesale requirements customers' rates, except to the extent the companies demonstrated in a section 205 rate filing that merger-related savings were equal to or in excess of merger costs included in the rate filing. On September 30, 2011, the Commission issued an order authorizing Duke Companies to merge subject to conditions. Among other things, the Commission conditioned authorization on Duke Companies maintaining its commitment to hold transmission and wholesale requirements customers harmless from costs related to the merger. Pursuant to this condition, "[a]ll transaction related costs, not only costs related to consummating the transaction," were required to be excluded from rates charged.[25] To determine if Duke Companies complied with the hold harmless requirement, audit staff examined the companies' procedures for tracking and accounting for merger costs, and excluding the costs from rates.

To track costs incurred due to the merger, the companies established special accounting processes and procedures. Audit staff found that Duke Energy and Progress Energy did not account for merger costs using the same accounting treatment prior to consummation of the merger. Prior to consummation of the merger, Duke Energy accounted for merger transaction costs in above-the-line operating accounts, whereas Progress Energy accounted for the costs below-the-line in Account 426.5, Other Deductions.[26] However, after consummation of the merger, Progress Energy adopted Duke Energy's internal accounting policy for merger transaction costs and thereafter began accounting for incurred merger transaction costs in operating accounts.

[24] October 29 Compliance Order, 149 FERC ¶ 61,078 at P 81.

[25] Merger Order, 136 FERC ¶ 61,245 at P 169.

[26] Account 426.5, Other Deductions, 18 C.F.R. Part 101 (2015), provides for the recording of expenses that are nonoperating in nature, but which are properly deductible before determining total income before interest charges.

Duke Energy devised and distributed instructions to its public utility subsidiaries regarding accounting for merger costs, which it characterized as Costs to Achieve (CTA) the merger. Duke Energy defined CTA as "costs that are incremental and nonrecurring that would otherwise not have been incurred but for the merger or integration planning efforts."[27] The CTA instructions identified the accounting codes to be used to account for and track merger costs. The codes included the business and operating unit that incurred the cost, process, task, project ID, and other details associated with activities that involved the incurrence of merger costs. The CTA instructions were communicated to managers and staff assigned to work on the merger, and employees were trained on use of the accounting codes. Duke Energy's shared services accounting group retrieved merger cost data from the general ledgers of the public utility subsidiaries, reviewed charges for reasonableness, and compared actual and budgeted costs as part of its monthly reporting process.

Duke Energy's shared services accounting group developed additional procedures to exclude certain merger costs from wholesale power and transmission formula rate determinations of the public utility subsidiaries. The procedures included preparation of monthly spreadsheets identifying merger costs included in each subsidiary's operating accounts as reported in the Form No. 1. The rate staff of each public utility subsidiary was instructed to subtract the merger costs from operating accounts in the Form No. 1 that were used to compute the company's transmission formula rate. The procedures were designed to prevent merger costs reported in operating accounts from being incorporated in wholesale power and transmission formula rate determinations.

As a result of these procedures under which merger-related internal labor costs were not treated as CTA, audit staff found that Duke Companies' wholesale power and transmission customers' revenue requirements were inappropriately overstated by an estimated $17.5 million due to the inclusion of merger transaction internal labor costs in wholesale power and transmission rate determinations without first making a section 205 filing with the Commission as the Merger Order required. The improper charges included an estimated $17.2 million through inclusion of internal labor costs incurred in merger transaction and integration activities, and over $300,000 through inclusion of

[27] This included costs incurred in developing, executing, and obtaining approvals for the merger as well as incremental integration costs, but did not include merger-related internal labor costs Duke Companies considered non-incremental. For example, the costs included severance payments, employee relocation and retention costs, bonuses paid to employees for their work on the merger, investment banking and advisory fees, state and Federal regulatory expenses, costs for integrating accounting and information technology systems, transmission systems, fuel and dispatch systems, as well as transition costs, mitigation/concession costs, depreciation expenses for merger projects, and fees paid to providers of transmission service between the regulated utilities.

internal labor costs incurred to construct and operate the transmission expansion projects (TEPs), and repair and operate the Rockingham phase shifters.

Merger Transaction Internal Labor

During fieldwork, audit staff determined that Duke Energy excluded merger transaction internal labor from its definition of CTA and its CTA coding procedures. Duke Energy acknowledged that employees spent substantial time on merger activities. However, the company contended that employees performed merger activities in addition to their regular responsibilities and, therefore, no incremental internal labor costs were incurred due to the merger. Based on a belief that the hold harmless obligation applied only to incremental merger costs, Duke Energy instructed employees not to use the special CTA codes to report time devoted to merger activities on their timesheets. Consequently, public utility subsidiaries did not track all merger transaction internal labor costs or exclude all such costs from wholesale power and transmission formula rate cost computations. As a result, the subsidiaries improperly included some merger transaction internal labor costs in wholesale power and transmission formula rate determinations and inappropriately charged the costs to customers.

Contrary to Duke Energy's interpretation, the Merger Order required Duke Companies to hold customers harmless from "*all* merger transaction costs," and did not limit this requirement only to costs Duke Energy considered incremental. Duke Energy's assertion that its hold harmless obligation extended only to incremental costs must be made within a section 205 proceeding where it and other interested parties will have an opportunity to assess all evidence that supports or contradicts such a position. By excluding internal labor from its CTA tracking and reporting procedures, Duke Energy did not have the ability to determine the proportion of employee labor costs devoted to merger-related tasks, as opposed to utility-related tasks, the cost of which are appropriately recovered in rates. Moreover, even in the absence of detailed time reporting and accounting data, the companies were nonetheless prohibited from including these merger transaction costs in rate determinations without first receiving Commission authorization to do so in a section 205 proceeding in accordance with Merger Order requirements.

Since Duke Companies did not track all merger transaction internal labor costs, audit staff issued data requests and interviewed company employees during site visits and conference calls to develop its own estimate of the amount of merger transaction internal labor costs Duke Companies incurred and included in transmission formula rate charges. The information audit staff obtained confirmed that company employees spent substantial amounts of time working on the merger, as Duke Energy acknowledged. For example, Duke Energy reported in data responses that over 2,400 employees were engaged in merger activities from mid-2010 through present. The total included more than 2,300 employees who participated in over 300 merger integration projects performed to upgrade and integrate the companies' information technology, human resources, finance, and accounting systems and functions. About 140 employees were engaged in merger planning and evaluation, preparing and supporting merger applications and post-merger litigation, and developing and implementing measures to mitigate market power due to the merger. Audit staff found through assessment of data response information and interviews of company staff, that certain of these employees worked full time on the merger for the duration of their projects, while others devoted 50 percent or more of their time to assigned merger activities. Moreover, detailed analysis of integration projects with the largest budgets indicated that the assigned employees were heavily engaged in the projects for prolonged periods of time.

Audit staff used this information, interviews with employees engaged in merger activities, employees' salary information procured from data responses, and salary estimates found on publicly available sources to approximate the amount of internal labor costs incurred due to the merger. Audit staff estimated that the Duke Companies incurred between $55 million and $75 million of internal labor costs related to the merger, including salaries and benefits.

Audit staff then asked Duke Energy to provide its own estimate of the internal labor costs associated with each merger activity and a breakdown by FERC account. As the table below shows, Duke Energy estimated that $78.8 million in merger transaction internal labor costs were incurred to perform four primary merger tasks. Duke Energy's estimate exceeded audit staff's high-range estimate of internal labor costs.

		A	B
Row	**Merger Tasks**	**Duke Companies' Estimated Internal Labor Cost (Million $)**	**Estimated Internal Labor Included in the Revenue Requirements of Wholesale Power and Transmission Rates (Million $)**
1	Merger Planning, Evaluation, Due Diligence	2.3	0.1
2	Preparation and Support for Regulatory Applications and Post-Merger Litigation	3.9	0.2
3	Development and Implementation of Measures to Mitigate Market Power	0.6	0.03
4	Planning, Management, and Execution of Merger Integration Projects	72.0	16.9
	Total	**78.8**	**17.2**

Of the $78.8 million in merger transaction internal labor costs estimated by Duke Energy, about $1.6 million of the costs were recorded in distribution operating and maintenance expense accounts that were not included in Commission-jurisdictional rate determinations, and $31.4 million was recorded in production and transmission operating and maintenance expense accounts incorporated in wholesale power and transmission formula rates. Duke Energy estimated that wholesale power and transmission customers' revenue requirements were inappropriately overstated by an estimated $17.2 million.[28] The remaining $45.8 million in merger transaction internal labor costs were charged to capital work orders for integration projects that are under construction and not yet completed. Duke Energy represented that these costs have been classified as CTA, and will be excluded from wholesale power and transmission formula rates when the projects are completed.

By including these merger-related tasks in its definition of CTA, Duke Energy acknowledged that the merger activities employees performed would not have been required in the absence of the merger. Since the work was not related to utility service, employee time engaged on the merger should have been excluded from transmission formula rate determinations. In accordance with the hold harmless commitment, to recover merger costs in their wholesale power or transmission rates, the companies were required to submit a section 205 filing with the Commission detailing costs to be recovered and demonstrating that the costs were offset by quantified savings produced by the merger. Duke Companies did not submit a section 205 filing; therefore, the companies should not have recovered the costs in rates charged.

TEP Operating Expenses

Duke Energy's public utility subsidiaries included an estimated $300,000 of merger transaction internal labor costs in the transmission customers' formula rate revenue requirement for costs related to the TEP projects from 2012 through 2015. This amount was incurred to repair and operate the Rockingham phase shifters. The $300,000 was recorded as transmission maintenance expenses in Account 570, Maintenance of Station Equipment. In accordance with Duke Companies' internal accounting policy, the companies neither characterize the costs as merger-related CTA nor exclude the costs from transmission formula rate determinations. As a result, the $300,000 was included in transmission formula rates, and thus a portion of these costs was inappropriately charged to transmission customers.

In its June 8 and October 29 Compliance Orders, the Commission explicitly directed Duke Companies to hold customers harmless from all costs related to the TEPs

[28] During the audit, DEC and DEP had about 20 wholesale power customers under service contracts with cost-based rates determined under a formula to which merger transaction internal labor costs were incorporated. As a result, a portion of the merger transaction labor costs included in the formula was charged to wholesale power customers.

and the Rockingham phase shifters, consistent with the hold harmless commitment established in the Merger Order. Duke Companies should not have included these internal labor charges in transmission formula rate determinations without first submitting a section 205 filing to the Commission that demonstrated that the costs were offset by quantified savings produced by the merger.

Recommendations

We recommend Duke Companies:

5. Revise all policies and procedures for tracking, accounting, and excluding merger transaction costs from wholesale power and transmission formula rates, including amounts previously charged to utility plant, accumulated deferred income taxes, construction work in progress with the associated capitalized cost of funds used during construction (AFUDC), and maintenance and operating expense accounts, and future charges to such accounts for any transaction to which a FERC hold harmless obligation applies. The revised procedures should hold customers harmless from all merger transaction costs consistent with requirements of the Merger Order. Among other things, the revised policies and procedures should include an annual review of each subsidiary's merger transaction cost adjustments as well as periodic evaluations within the year, as needed and appropriate.

6. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the inclusion of merger transaction internal labor and related costs in wholesale power and transmission formula rates during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

7. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

8. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

3. Merger Transaction Outside Services and Related Costs

Duke Companies incorrectly included $1.5 million of merger transaction outside services and related costs in wholesale power and transmission formula rate service cost determinations without first submitting a section 205 application demonstrating the costs were offset by quantified savings produced by the merger. In addition, the companies recorded the merger transaction costs in operating accounts, contrary to the Commission's long-standing policy that such costs be recorded in nonoperating accounts. As a result, the wholesale power and transmission customers' revenue requirements were inappropriately overstated by an estimated $745,000.

Pertinent Guidance

The Commission's Merger Order states in part:

> We accept Applicants' commitment to hold transmission and wholesale requirements customers harmless for five years from costs related to the Proposed Transaction. We interpret Applicants' hold harmless commitment to include all transaction-related costs, not only costs related to consummating the transaction.
>
> If Applicants seek to recover transaction-related costs through their wholesale power or transmission rates within the next five years, they must submit a compliance filing that details how they are satisfying the hold harmless requirement. If Applicants seek to recover transaction-related costs in an existing formula rate that allows for such recovery within the next five years, then that compliance filing must be filed in the section 205 docket in which the formula rate was approved by the Commission, as well as in the instant section 203 docket. In such filings, Applicants must: (1) specifically identify the transaction-related costs they are seeking to recover; and (2) demonstrate that those costs are exceeded by quantified savings resulting from the transaction, in addition to any requirements associated with filings made under section 205.[29]

The Commission's long-standing precedent stipulates that transaction costs incurred by public utilities associated with a merger are nonoperating in nature and should be charged to Account 426.5, Other Deductions, to the extent the costs are not passed on to the parent holding company. For example, in *Allegheny Energy, Inc.,* the Commission stated in part:

[29] Merger Order, 136 FERC ¶ 61,245 at PP 169-170.

The Commission has previously determined that merger transaction costs are considered non-operating in nature and should be recorded in Account 426.5, Other Deductions.[30]

18 C.F.R. Part 101, Account 426.5, Other Deductions, states:

This account shall include other miscellaneous expenses which are nonoperating in nature, but which are properly deductible before determining total income before interest charges.

Background

In the process of evaluating Duke Companies' compliance with the hold harmless commitment, audit staff issued data requests and interviewed company employees regarding the accounting and formula rate impact of activities engaged prior to and after public announcement of the merger, such as outside service costs incurred to facilitate the merger and associated internal corporate costs. In reviewing materials received, audit staff found that Duke Energy's corporate development group incurred over $1.5 million in merger transaction costs in the second half of 2010 (i.e., prior to the merger announcement in January 2011) and allocated those costs to its then public utility subsidiaries – DEC, DEI, DEO, and DEK – prior to consummation of the merger.

The costs included $1.35 million paid to outside consultants, lawyers, and accountants for financial forecasting, analysis of market power issues and related services, and $150,000 of internal labor and other costs related to this work. The subsidiary companies improperly recorded the merger transaction outside service costs in Account 923, Outside Services Employed, and most of the associated internal labor and other costs in Account 920, Administrative and General Salaries. Account balances reported in each company's Form No. 1 were included in the determination of the company's wholesale power and transmission formula rate service charges.

DEC, DEI, DEO, and DEK reported these costs in their respective 2010 Form No. 1 reports. The companies neither characterized the costs as merger-related CTA following the merger announcement and issuance of the Merger Order, nor excluded the costs from wholesale power and transmission formula rate determinations in 2011 or subsequent years.

[30] *See Allegheny Energy, Inc.*, 133 FERC ¶ 61,222 at P 73 (2010). See also *Midwest Power Systems, Inc. and Iowa-Illinois Gas and Elec. Co.*, 71 FERC ¶ 61,386, at 62,509 (1995); *MidAmerican Energy Co. and MidAmerican Energy Holdings Co.*, 85 FERC ¶ 61,354, at 62,370 (1998); and *Wis. Elec. Power Co.,* 74 FERC ¶ 61,069, at 61,192 (1996).

Pursuant to the hold harmless commitment, the companies should not have included the $1.5 million in merger transaction costs in wholesale rate determinations without first submitting a section 205 filing to the Commission that demonstrated the costs were offset by quantified savings produced by the merger. Moreover, pursuant to long-standing Commission precedent, the merger transaction costs the companies recorded in Accounts 920 and 923 are considered nonoperating in nature and, as such, were required to be recorded to Account 426.5. The text of Account 426.5 states that the account shall include expenses that are nonoperating in nature. Duke Energy estimated that wholesale power and transmission customers' revenue requirements were inappropriately overstated $745,000.

Recommendations

We recommend Duke Companies:

9. Revise accounting policies and procedures to appropriately account for merger transaction costs consistent with Commission accounting requirements.

10. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the inclusion of merger transaction outside services and related costs in wholesale power and transmission formula rate charges during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

11. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

12. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

4. Use of the Consolidated Method of Accounting

DEC and DEP accounted for investments in subsidiaries on a consolidated basis in their Form No. 1 reports, contrary to the Commission's long-standing accounting policy.

Pertinent Guidance

Order No. 469 revised and amended sections of 18 C.F.R. Parts 101 and 201 to adopt the equity method of accounting for long-term investments in subsidiaries and add new balance sheet and income statement accounts, and definitions. Order No. 469 states in part:

> Under the equity method of accounting, the utility's investment account is increased or decreased to reflect the utility's proportionate share of a subsidiary's current earnings applicable to common stock regardless of whether the earnings are actually paid out as dividends to the utility. When dividends are received, the investment account is reduced by an equivalent amount.[31]

18 C.F.R. Part 101, Account No. 123.1, Investment in Subsidiary Companies, states:

> A. This account shall include the cost of investments in securities issued or assumed by subsidiary companies and investment advances to such companies, including interest accrued thereon when such interest is not subject to current settlement plus the equity in undistributed earnings or losses of such subsidiary companies since acquisition. This account shall be credited with any dividends declared by such subsidiaries.
>
> B. This account shall be maintained in such a manner as to show separately for each subsidiary: the cost of such investments in the securities of the subsidiary at the time of acquisition; the amount of equity in the subsidiary's undistributed net earnings or net losses since acquisition; advances or loans to such subsidiary; and full particulars regarding any such investments that are pledged.

[31] *Revisions in the Uniform System of Accounts, and Annual Report Forms No. 1 and No. 2 to Adopt the Equity Method of Accounting for Long-Term Investments in Subsidiaries*, Order No. 469, 49 FPC 326, *reh'g denied*, 49 FPC 1028 (1973).

18 C.F.R. Part 101, Account 216.1, Unappropriated Undistributed Subsidiary Earnings, states:

> This account shall include the balances, either debit or credit, of undistributed retained earnings of subsidiary companies since their acquisition. When dividends are received from subsidiary companies relating to amounts included in this account, this account shall be debited and account 216, Unappropriated Retained Earnings, credited.

18 C.F.R. Part 101, Account No. 418.1, Equity in Earnings of Subsidiary Companies, states:

> This account shall include the utility's equity in the earnings or losses of subsidiary companies for the year.

Background

DEC and DEP formed wholly owned special purpose subsidiaries, Duke Energy Receivables Finance Company, LLC (DERF) and Duke Energy Progress Receivables, LLC (DEPR), respectively, in 2003 and 2013. The companies accounted for their investments in the subsidiaries using the consolidated method of accounting. Specifically, DEC consolidated DERF in its Form No. 1 reports from 2003 through 2013; and DEP consolidated DEPR in its Form No. 1 in 2013. The accounting resulted in the recognition of property, expenses, revenue, debt, and equity of the subsidiaries in DEC and DEP's respective Form No. 1 reports. During the course of the audit, in 2014, the companies ceased accounting for their investments in the subsidiaries using the consolidation method of accounting and began using the equity method of accounting.

Prior to 2014, DEC and DEP's accounting for their investments in the subsidiaries was not consistent with the Commission's accounting requirements, which required the companies to account for the investments using the equity method of accounting. In accordance with the provisions of Order No. 469, the companies were required to account for the subsidiaries as investments in Account 123.1, Investments in Associated Companies, and record equity in earnings of the subsidiaries in Account 418.1, Equity in Earnings of Subsidiary Companies, and undistributed retained earnings of the subsidiaries in Account 216.1, Unappropriated Undistributed Subsidiary Earnings.[32]

[32] *Id.*

On August 19, 2015, during the course of the audit, Duke Energy submitted a request to the Commission on behalf of the companies for retroactive and prospective waivers of the equity method accounting requirement.[33] In the filing, among other things, DEC and DEP acknowledged that they had inappropriately accounted for investments in their subsidiaries using the consolidation method of accounting, and improperly included the results of the subsidiaries' operations in cost of service formula rate determinations. On December 18, 2015, the companies submitted a filing to the Commission under section 205 of the FPA seeking approval of proposed amendments to the formula rates in their Joint OATT and wholesale power agreements to provide for consolidation of the subsidiaries for cost of service rate determination purposes.[34]

Duke Energy did not notify audit staff of the inappropriate consolidation accounting, or of its request for waiver of the equity accounting requirements. The company should have disclosed the erroneous accounting to audit staff when it discovered the matter, which according to its representation occurred in late 2014. However, neither audit staff nor the Commission was notified of the improper accounting and the associated rate impacts until August 2015. Duke Energy's lack of timely disclosure of DEC and DEP's noncompliance with Commission regulations is problematic. The company should take necessary steps to ensure that its corporate compliance culture and program are strengthened to prevent situations like this on a going forward basis.

[33] Duke Energy Carolinas, LLC, et al., Request for Waiver, Docket No. AC15-174-000, (filed Aug. 19, 2015). The filing requested waivers of the equity accounting requirement on behalf of DEC, DEP, and DEF, which formed a wholly owned subsidiary Duke Energy Florida Receivables, LLC (DEFR) in 2014. The Chief Accountant issued a delegated letter order on February 12, 2016 that granted the requested waivers to the companies and directed specific accounting regarding sales of accounts receivable. Duke Companies filed a request for rehearing of the letter order on March 14, 2016.

[34] *Duke Energy Carolinas, LLC, et al.*, Docket Nos. ER16-577-000, ER16-578-000, and ER16-579-000. The Commission issued delegated letter orders on February 11, 2016, accepting for filing the amendments to the Joint OATT and rate schedules to provide for DEC, DEP, and DEF's use of the consolidated method of accounting for ratemaking purposes.

Recommendations

We recommend Duke Companies:

13. Review and, as needed, revise accounting policies, practices, and procedures to ensure that investments in subsidiaries are accounted for consistent with the Commission's equity method accounting requirements.

14. Evaluate the accounting applied to Duke Companies' existing subsidiaries and notify DAA of any areas of noncompliance with Commission accounting requirements.

15. Revise documented policies, procedures and processes to ensure timely notice is provided to relevant regulators regarding instances of noncompliance with regulations, rules, and orders.

16. Provide training to staff on procedures, practices, and available tools to transparently or anonymously report instances of noncompliance to senior management, the Board of Directors, and relevant regulators.

5. Accounting for Sales of Accounts Receivable

DEC, DEP, and DEF misclassified an estimated $94.7 million of nonoperating expenses and receivables arising from transactions with their subsidiaries during the audit period. As a result, the wholesale power and transmission customers' revenue requirements were inappropriately overstated by an estimated $61 million.

Pertinent Guidance

18 C.F.R. Part 101, Account 930.2, Miscellaneous General Expenses, states in part:

> This account shall include the cost of labor and expenses incurred in connection with the general management of the utility not provided for elsewhere.

18 C.F.R. Part 101, Account 426.5, Other Deductions, states in part:

> This account shall include other miscellaneous expenses which are nonoperating in nature, but which are properly deductible before determining total income before interest charges.

The Commission addressed the appropriate accounting for the sale of accounts receivable in Opinion No. 375, which stated in part:

> From an accounting standpoint, we find that the record supports the staff and intervenors' position – which the initial decision adopted – that the loss on the sale of accounts receivable was erroneously recorded by SERI [System Energy Resources, Inc.] in Account 930.2. . ..[35]

Background

During audit fieldwork, audit staff analyzed data regarding transactions between DEC, DEP, and DEF and the companies' respective nonutility subsidiaries, DERF, DEPR, and DEFR, and interviewed employees responsible for accounting for the transactions. The transactions involved the companies' sales of accounts receivable to their subsidiaries. The receivables arose from billings on sales of electricity and related services by the companies. The companies sold the receivables to their subsidiaries at a loss (or discount), and accounted for the loss as an expense by debiting Account 930.2, Miscellaneous General Expenses, an account included in wholesale power and transmission service cost formula rate determinations, for the amount of the loss. DEC,

[35] *System Energy Resources, Inc.*, 60 FERC ¶ 61,131 (1992).

DEP, and DEF recognized total losses of $149.6 million, $35.1 million, and $23.5 million, respectively, from 2011 through 2014.

Audit staff also discovered that there were similar transactions involving sales of accounts receivable by DEI, DEO, and DEK to Cinergy Receivables, a Duke Energy subsidiary. However, through discussions with audit staff, Duke Energy represented that instead of recording losses on sold receivables in Account 930.2, DEI, DEO, and DEK accounted for the losses in Account 904, Uncollectible Accounts, an account not included in wholesale power or transmission service cost formula rate determinations.

DEC, DEP, and DEF performed collection services on behalf of their subsidiaries associated with the sold receivables whereby the companies collected bill payments from customers and remitted funds received to the subsidiaries. The companies charged the subsidiaries a fee for performing the collection service, which effectively resulted in a reimbursement of the collection service cost incurred by the companies. Expenses incurred by the companies associated with performing the collection service were accounted for by debiting the costs to Account 903, Customer Records and Collection Expenses. These expenses were also accounted for as a debit in Account 930.2 that Duke Energy represented was the fee billed to the subsidiaries for performing the collection service. As a result of this accounting, DEC, DEP, and DEF double-counted expenses in their respective Form No. 1 reports associated with collection services performed. Furthermore, the companies accounted for the reimbursements of their incurred collection service expenses that resulted from their billed subsidiaries by crediting Account 421, Miscellaneous Non-Operating Income.

Duke Companies' accounting for the loss on the sale of the receivables was not consistent with the Commission's accounting requirements and precedent. Under the Uniform System of Accounts (USofA), sales of accounts receivable constitute the disposition of utility assets. The USofA contemplates that in transactions of this nature, a company should recognize a gain or loss, measured by the difference between the net book value of the asset at the date of the sale and the proceeds from the sale, less related fees and expenses of the sale. Further, the USofA requires a company to record any gains or losses from the disposition of assets in nonoperating expense accounts, except with respect to the sale of future use property.[36] The instructions to Account 426.5, Other Deductions, provide for the recording of nonoperating expenses of this nature. Additionally, the Commission has previously addressed the matter of the appropriate

[36] With respect to future use property recorded in Account 105, Electric Plant Held for Future Use, the USofA requires a company to include a gain on a sale in Account 411.6, Gains from Disposition of Utility Plant, and a loss in Account 411.7, Losses from Disposition of Utility Plant.

accounting for sales of receivables in its Opinion No. 375, wherein it was determined that the loss on the sale of receivables should be accounted for in Account 426.5.[37]

In addition, DEC, DEP, and DEF's accounting for reimbursements of incurred collection service expenses was not consistent with the Commission's accounting requirements. The USofA contemplates that such reimbursements of collection service expenses incurred by DEC, DEP, and DEF on behalf of their respective subsidiaries be recorded as a reduction of the expenses. Accordingly, the companies should have accounted for the reimbursements through a credit entry to the collection service expenses recorded in Account 903.

Duke Energy represented that prior to 2014, DEC and DEP's accounting for the losses on the sales of receivables and collection service fees billed to the subsidiaries that were recorded in Account 930.2 had no impact on service rates charged to wholesale power and transmission formula rate customers due to accounting entries the companies made associated with consolidation method accounting that offset the items and neutralized the rate impact. Duke Energy indicated that the companies made the offsetting entries from the respective dates their subsidiaries were established and transactions initiated through 2013.[38] However, in 2014, DEC and DEP ceased their practice of using the consolidation method of accounting.[39] Cessation of consolidation method accounting led the companies to end their practice of recording the offsetting entries. Moreover, DEF established its subsidiary, DEFR, in 2014, and did not record any accounting entries to offset its losses on the sales and collection service fees billed to its subsidiary. As a result, rates charged by DEC, DEP, and DEF based on amounts reported in the companies' respective 2014 Form No.1 reports included the nonoperating losses and collection service fees that were misclassified in Account 930.2 and not offset by other entries. This led to DEC, DEP, and DEF inappropriately including the losses and fees of $38.1 million, $33.1 million, and $23.5 million, respectively, in rate determinations.

The companies' accounting mistakes led to an estimated $94.7 million of costs being inappropriately included in wholesale power and transmission formula rate service cost determinations during the audit period. Duke Energy estimated that this resulted in wholesale power and transmission customers' revenue requirements being inappropriately overstated by an estimated $61 million.

[37] *System Energy Resources, Inc.*, 60 FERC ¶ 61,131 (1992).

[38] DEC's subsidiary, DERF, was established in 2003, and DEP's subsidiary, DEPR, was established in 2013.

[39] *See* Finding No. 4, Consolidation Method of Accounting.

On March 14, 2016, Duke Companies filed a request for rehearing of the Chief Accountant letter order in Docket No. AC15-174-000 challenging the order's decision regarding the appropriate accounting for losses on the sale of receivables, which is also addressed by this Audit Finding. In light of the current challenge to the Chief Accountant's order and uncertain outcome, as well as, the potential of a contested audit over the identical issue, in this instance the portions of this Audit Finding that relate to the losses issues, including Recommendations 17 and 18, shall be held in abeyance and shall be subject to the outcome of the rehearing request and any subsequent petitions for court review. Although the recommendations regarding the portion of this Audit Finding relating to the losses issues are held in abeyance and subject to the outcome of the rehearing request and any subsequent petitions for court review, the requirement to make refunds in accordance with Recommendation 21 below is not impacted by the rehearing request.

Recommendations

We recommend Duke Companies:

17. Revise procedures to ensure that all costs and account balances associated with the sale of accounts receivable are accounted for in accordance with Commission accounting regulations. Among other things, the corrected accounting should ensure that all losses associated with receivable sales are recorded in Account 426.5.

18. Provide the revised procedures to DAA for review within 60 days of receiving the final audit report.

19. Recalculate charges to wholesale power and transmission customers of DEC, DEP, and DEF and submit the recalculations in a refund analysis to DAA for review within 60 days of receiving the final audit report. The refund analysis should explain and detail the: (1) return of collection service billings charged in 2014; (2) return of losses on the sales included in rates; (3) determinative components of the refund; (4) refund method; (5) period(s) refunds will be made; and (6) interest calculated in accordance with section 35.19 of Commission regulations.

20. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

21. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

6. Accounting for Lobbying Expenses

Duke Companies recorded approximately $2.4 million of lobbying expenses in above-the-line operating accounts from 2011 to 2013. As a consequence, Duke Companies improperly included these costs in wholesale power and transmission formula rate service cost determinations.

Pertinent Guidance

18 C.F.R. Part 101, Account 426.4, Expenditures for Certain Civic, Political, and Related Activities, states in part:

> This account shall include expenditures for the purpose of influencing public opinion with respect to the election or appointment of public officials, referenda, legislation, or ordinances . . . or approval, modification, or revocation of franchises; or for the purpose of influencing the decisions of public officials. . . .

Background

Audit staff evaluated costs incurred by Duke Companies associated with civic, political, and related activities during the audit period. Audit staff reviewed third-party lobbying expenditure disclosures, press articles, internal lobbyist meeting schedules and agendas, and interviewed internal lobbyists and support staff to understand the nature and extent of the companies' lobbying activities. In addition, audit staff tested a sample of work orders, invoices, and associated accounting detail records that support internal lobbyists' labor costs incurred. Audit staff discovered that Duke Companies improperly recorded nearly $2.4 million in lobbying costs to above-the-line operating accounts rather than to Account 426.4, Expenditures for Certain Civic, Political, and Related Activities, as required.

Account 426.4 provides for reporting expenditures for the purpose of influencing public opinion, such as lobbying expenses. Audit staff found that Duke Companies recorded a portion of these costs associated with wages and salaries of internal lobbyist and support staff in Account 426.4 as required, but failed to properly charge other related costs to the account associated with the labor, such as payroll taxes, retirement, health, and other benefits. Audit staff also found that the companies incorrectly accounted for amounts paid to outside firms that lobby on behalf of the companies. Duke Companies improperly included these expenses in wholesale power and transmission formula rate determinations and recovered a portion of the costs through charges to customers.

Further, audit staff found that Duke Companies lacked formal procedures and oversight controls to help ensure that lobbying costs were accounted for appropriately.

The companies should implement procedures to reduce the risk that lobbying costs are inappropriately accounted for and included in jurisdictional rate determinations.

Recommendations

We recommend Duke Companies:

22. Establish and implement written procedures governing the methods used to account for, track, report, and review lobbying costs incurred.

23. Provide training on Commission accounting requirements and the impact of accounting on cost-of-service rate determinations to employees involved in lobbying and lobbying-related work, and those with oversight responsibility for lobbying cost allocations. Also, develop a training program that supports the provision of periodic training in this area.

24. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the improper inclusion of lobbying costs in operating accounts during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

25. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

26. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

7. Allocation of Lobbyist Labor Costs

Duke Companies accounted for the labor costs of internal lobbyists and their support staff in operating accounts that lacked support for inclusion in the accounts. Improper accounting for the costs can lead to inappropriate recovery of the costs through rates charged and billed to customers.

Pertinent Guidance

18 C.F.R. Part 101, General Instruction No. 9, Distribution of Pay and Expenses of Employees, states:

> The charges to electric plant, operating expense and other accounts for services and expenses of employees engaged in activities chargeable to various accounts, such as construction, maintenance, and operations, shall be based upon the actual time engaged in the respective classes of work, or in case that method is impracticable, upon the basis of a study of the time actually engaged during a representative period.

18 C.F.R. Part 101, General Instruction No. 10, Payroll Distribution, states:

> Underlying accounting data shall be maintained so that the distribution of the cost of labor charged direct to the various accounts will be readily available. Such underlying data shall permit a reasonably accurate distribution to be made of the cost of labor charged initially to clearing accounts so that the total labor cost may be classified among construction, cost of removal, electric operating functions (steam generation, nuclear generation, hydraulic generation, transmission, distribution, etc.) and nonutility operations.

18 C.F.R. Part 101, Account 426.4, Expenditures for Certain Civic, Political, and Related Activities, states in part:

> This account shall include expenditures for the purpose of influencing public opinion with respect to the election or appointment of public officials, referenda, legislation, or ordinances . . . or approval, modification, or revocation of franchises; or for the purpose of influencing the decisions of public officials . . . .

Background

In connection with the evaluation of Duke Companies' expenditures for lobbying activities, audit staff discovered that the companies' allocation of the labor costs of internal lobbyists and their support staff was based in part on the amount of time that state legislatures and Congress were in session. Duke Energy explained that these entities were in session on average 180 days a year, and that lobbying activities of its staff to influence legislation would typically be performed while the legislatures and Congress were in session. This resulted in the companies using a default allocator that charged 50 percent of lobbying costs above-the-line to operating accounts and 50 percent below-the-line to Account 426.4, Expenditures for Certain Civic, Political, and Related Activities.

Audit staff interviewed internal lobbyists and their support staff to understand their roles and job assignments, and reviewed lobbyists' schedules as documented in email, itineraries from industry conferences, and other materials. Duke Energy represented that the companies' internal lobbyist performed internal corporate functions such as (1) budgeting, (2) performance appraisals, (3) training, and (4) other activities. However, audit staff could not determine based on documentation provided, that the 50/50 labor allocation split between above- and below-the-line accounting for lobbying and related costs was accurate or reasonable. Moreover, audit staff discovered that the companies neither had a formal oversight review process to assess the accuracy of the labor allocations nor maintained documentation to support the allocations.

General Instructions No. 9, Distribution of Pay and Expenses of Employees, and No. 10, Payroll Distribution, require public utilities to charge lobbying-related labor to operations based on actual time engaged in utility operations or on a representative time study, and to maintain data supporting distribution of the labor to operating costs. Audit staff found that Duke Companies' charges of lobbying and support staff labor to operations were neither based on actual time engaged in utility operations nor derived from representative time studies, as required. The companies also did not maintain data supporting distribution of the costs to utility operations. Duke Companies' accounting for lobbying labor time charges was not consistent with Commission accounting requirements and could have resulted in the inclusion of inappropriate costs in operating accounts, and consequently, in charges to transmission service formula rate and wholesale requirements customers. This could have led to the overcharging of wholesale ratepayers.

Recommendations

We recommend Duke Companies:

27. Revise written policies and procedures to create a process to document and verify appropriate allocation of lobbying and lobbying-related costs, and maintain auditable support for the cost included in rate determinations.

28. Retain an independent third-party entity to conduct a representative labor time study to determine an appropriate allocation of internal lobbyist labor, support

staff, and associated costs that should be accounted for in operating and nonoperating accounts based on time spent by employees engaged in the activities. Provide the study results to audit staff within 180 days of receiving the final audit report.

29. Include the results of the labor time study in the determination of lobbying-related labor cost allocations as of January 1, 2016.

30. Implement policies and procedures to perform a labor time study at least biennially using an independent third-party or internal company resources that are able to attest to the results of the study. Revise the lobbying-related labor cost allocations based on the results of the study.

8. Nonutility Expenses in Operating Accounts

Duke Companies recorded approximately $490,000 of nonutility expenses in operating accounts in 2014. As a result, inappropriate costs were included in wholesale power and transmission formula rate service cost determinations and charged to customers.

Pertinent Guidance

Accounting Release 12, Discriminatory Employment Practices, states in part:

> Expenditures resulting from employment practices found to be discriminatory by a judicial or administrative decree or that were the result of a compromise settlement or consent decree are not just and reasonable cost of utility operations and as such must be charged to nonoperating expense accounts.

18 C.F.R Part 101, Account 426.1, Donations, states:

> This account shall include payments or donations for charitable, social, or community welfare purposes.

18 C.F.R. Part 101, Account 426.5, Other Deductions, states:

> This account shall include other miscellaneous expenses for which are non-operating in nature, but which are properly deductible before determining total income before interest charges.

Background

Audit staff reviewed a sample of expenses charged to administrative and general (A&G) accounts to determine whether the charges were accounted for in accordance with Commission accounting requirements. The sample included charges to Accounts 920, Administrative and General Salaries, 923, Outside Services Employed, and 926, Employee Pensions and Benefits, in 2012. Audit staff reviewed accounting records and documentation supporting amounts reported in the accounts, such as invoices, work orders, and billings. Audit staff also interviewed Duke Companies' employees with responsibility for documenting and accounting for costs reported in the accounts.

Audit staff's review found that Duke Companies accounted for $100,000 of expenditures resulting from employment practices found to be discriminatory as operating expenses. However, in accordance with the requirements of Accounting Release 12, Discriminatory Employment Practices, expenses of this nature should be accounted for as nonoperating expenses. Of the $100,000, audit staff found that $40,000 was improperly recorded to Account 923 and inappropriately included in transmission formula rate determinations. The remaining $60,000 was incorrectly accounted for in production and distribution operating accounts, including Accounts 519, Coolants and Water, 524, Miscellaneous Nuclear Power Expenses, and 583, Overhead Line Expenses. The costs should have been charged to Account 426.5, Other Deductions, consistent with the instructions of the account. Account 426.5 provides for recording expenses that are nonoperating in nature, and are properly deductible before determining total income before interest charges.

Further, audit staff also found that Duke Companies improperly charged about $39,000 in costs related to donations and charitable contributions to above-the-line operating accounts rather than Account 426.1, Donations, as required. Account 426.1 provides for reporting payments or donations for charitable, social, or community welfare purposes. The sampled invoices that audit staff reviewed included expenditures for charity-related activities that were improperly charged to operating accounts.

Because audit staff's review involved a select, small sample of transactions out of a larger population of transactions that involved expenses charged to Accounts 920, 923, and 926, audit staff believes that review of a larger number of transactions charged to these accounts may have revealed additional accounting errors that could have resulted in inappropriate charges to wholesale power and transmission formula rate customers. Duke Companies represented that they performed an analysis of all charges to the 900 series expense accounts for April 2014 through December 2014, and estimated that they incorrectly accounted for approximately $490,000 of costs in the accounts in 2014. These errors are the result of Duke Companies' lack of documented policies and insufficient training of employees on Commission requirements pertaining to accounting for nonoperating expenses. Employees with responsibility for recording expenses of this nature should have knowledge of the importance of appropriate accounting and the impact of improper accounting on rates charged through transmission formula rates.

Recommendations

We recommend Duke Companies:

31. Develop and implement written policies, procedures, and controls to ensure proper accounting and reporting of nonutility expenses.

32. Provide training for employees involved in the invoicing process on Commission accounting requirements and the impact of the accounting on cost-of-service rate determinations.

33. Within 60 days of receiving the final audit report, provide documentation supporting the analysis performed of invoiced expenses recorded to A&G accounts in 2014 that identified misclassified nonutility expenses included in A&G accounts. Develop an estimate of misclassified nonutility expenses accounted for in operating accounts in 2011 through 2013 and 2015.

34. Implement policies and procedures to provide periodic audits or reviews of A&G transactions by external or internal auditors.

35. Submit a refund analysis, within 60 days of receiving the final audit report, for review to DAA that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the improper inclusion of identified and estimated nonutility expenses in charges to wholesale power and transmission customers during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made. Include the results of the invoice analysis in the refund analysis.

36. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

37. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Appendix: Duke Energy's Comments on Audit Report

DUKE ENERGY.

Brian D. Savoy
Senior Vice President, Chief Accounting Officer and Controller

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March 30, 2016

Mr. Bryan K. Craig
Director and Chief Accountant
Division of Audits and Accounting
Office of Enforcement
Federal Energy Regulatory Commission
888 First Street NE, Room 5K-13
Washington, DC 20426

RE: Office of Enforcement
Docket No. PA14-2-000
Duke Energy Corporation

Dear Mr. Craig:

On February 19, 2016, the Division of Audits and Accounting ("DAA") within the Office of Enforcement of the Federal Energy Regulatory Commission (the "Commission") issued a draft audit report setting forth the DAA's findings and recommendations resulting from the audit of Duke Energy Corporation ("Duke Energy") and its public utility subsidiaries' compliance with (1) conditions in Commission merger authorization orders, (2) transmission formula rate tariff requirements, and (3) accounting and financial reporting regulations. After several constructive discussions between DAA staff and Duke Energy, the draft audit report was revised several times. DAA staff sent the latest revision to Duke Energy dated March 29, 2016. Duke Energy is responding to the March 29 revision.

SUMMARY

In the draft audit report as revised, the DAA made eight findings and 37 associated recommendations. In sum, Duke Energy accepts five of the eight findings and all associated recommendations. Duke Energy respectfully disagrees with, but will not contest, two of the eight findings (findings 2 and 3) and agrees to comply with all associated recommendations. Duke Energy disagrees with a portion of, but will not contest under 18 CFR Part 41, one of the eight findings (finding 5) and all recommendations as they apply to the portion with which it disagrees, and accepts in part finding 5 and all recommendations as they apply to the accepted portion.

RESPONSE TO FINDINGS

In accordance with the procedures set forth in 18 C.F.R. 41.1, Duke Energy responds to each of the findings as follows:

- **Finding 1.** *Accounting for Merger Transaction Costs* – Duke Companies did not file merger transaction accounting entries with the Commission as required by the Merger Order, and the companies recorded merger transaction costs in operating accounts, contrary to the Commission's long-standing policy that such costs be recorded in nonoperating accounts. By not filing the accounting entries, Duke Companies prevented Commission review of the merger accounting and correction of any entries that were not in accordance with Commission accounting requirements.

Response: Duke Energy accepts this finding.

- **Finding 2.** *Merger Transaction Internal Labor Costs* – Duke Companies improperly included approximately $31.4 million of merger transaction internal labor costs in wholesale power and transmission formula rate service cost determinations without first submitting a section 205 filing demonstrating that the costs were offset by quantified savings produced by the merger. As a result, the wholesale power and transmission customers' revenue requirements were inappropriately overstated an estimated $17.5 million.

Response: Duke Energy respectfully disagrees with this finding, but will not contest it. For the purpose of establishing a complete record, Duke Energy explains its position as follows.

Duke Energy acknowledges its obligation to hold transmission and wholesale power customers harmless for five years from costs related to the merger of Duke Energy and Progress Energy, Inc. (the "Merger").

Between the time of the Commission's Merger Order issued on September 30, 2011 and the closing of the Merger on July 2, 2012, Duke Energy determined that its hold harmless commitment is intended to apply to costs caused by the Merger ("Incremental Costs") and not to costs that would have been incurred even in the absence of the Merger ("Non-Incremental Costs"). No Commission orders squarely addressed this issue, and it seemed to be inherent in the nature of a *hold harmless* commitment that it would protect customers only from costs that they would not have incurred otherwise.

On the basis of this logic, Duke Energy did not treat as transaction-related costs any portion of the regular compensation that employees would have received in the absence of the Merger even if the employees spent some of their time working on transaction-related activities. The company would have paid those same salaries to the employees with or without the Merger. Thus the regular compensation of employees was viewed as Non-Incremental Costs. On the other hand, Duke Energy did treat as transaction-related costs any compensation paid to employees that would *not* have been incurred but for the Merger. For example, this included any bonuses paid to employees in recognition of the extended hours many employees worked to fulfill their regular duties and to work on merger activities. It also included temporary employees and contractors hired to backfill for work that could not be absorbed in this manner. These costs were viewed as Incremental Costs and accordingly were excluded from FERC-jurisdictional rates.

Treatment of internal labor costs in the context of a hold harmless obligation was certainly not a settled issue in early 2012 or even today. This uncertainty was reflected in the Commission's notice of proposed *Policy Statement on Hold Harmless Commitments* issued January 22, 2015 in Docket No. PL15-3. In this notice of proposed policy statement issued two and a half years after the closing of the Merger, the Commission states as follows:

> "...we propose to clarify those costs to which hold harmless commitments will apply. Although the Commission has provided broad guidance regarding the costs that should be covered under hold harmless commitments, it has never defined those costs with much specificity, leading to inconsistency with respect to this issue."[1]

The Commission proposed to clarify that internal labor costs should be treated as transaction-related costs and stated as follows:

> "If the duties of employees are not solely dedicated to activities related to a transaction, internal labor costs deemed merger-related should be determined in a manner that is proportionally equal to the amount of time spent on the merger compared to other activities of the utility and tracked accordingly."[2]

While this *proposal* is clear on this issue, it is worth repeating that it was issued two and a half years after the Merger closed. It is also important to note that it is just a proposal at this time because the final policy statement has not been issued. In addition, some commenters specifically disagreed with this point.[3] Finally, the Commission stated in the notice of proposed policy statement that it would have prospective effect only.[4]

Notwithstanding Duke Energy's belief that its failure to exclude from rates Non-Incremental internal labor costs was not a violation of any settled policy and in fact was based on the most reasonable interpretation of its hold harmless commitment, Duke Energy will not expend the resources necessary to contest this issue and will comply with all associated recommendations in the audit report. Duke Energy reserves all rights in the event that the Commission issues an order

[1] Paragraph 16 of the notice of proposed policy statement.
[2] Footnote 41 of the notice of proposed policy statement.
[3] See the comments of Edison Electric Institute filed on March 30, 2015 at p. 15-16.
[4] Paragraph 20 of the notice of proposed policy statement.

in the proposed policy statement proceeding or any other proceeding that is not consistent with Finding 2.
Duke Energy estimates that the total refunds that will be due to transmission and wholesale power customers arising from this finding will be approximately $1.2 million plus interest.

- **Finding 3**. *Merger Transaction Outside Services and Related Costs* – Duke Companies incorrectly included $1.5 million of merger transaction outside services and related costs in wholesale power and transmission formula rate service cost determinations without first submitting a section 205 filing demonstrating the costs were offset by quantified savings produced by the merger. In addition, the companies recorded the merger transaction costs in operating accounts, contrary to the Commission's long-standing policy that such costs be recorded in nonoperating accounts. As a result, the wholesale power and transmission customers' revenue requirements were inappropriately overstated an estimated $745,000.

Response: Duke Energy respectfully disagrees with this finding, but will not contest it. For the purpose of establishing a complete record, Duke Energy explains its position as follows.

The costs which are the subject of this finding are costs incurred in 2010 to investigate, agree to, and perform preliminary due diligence regarding, the Merger prior to the announcement of the Merger. Duke Energy made the determination that its hold harmless commitment was not intended to include such costs incurred during the formative stage of a potential transaction before it was clear that the company would even pursue the transaction. Like most utility holding companies, Duke Energy has a corporate development group that regularly investigates and reviews potential transactions as part of its routine operations. Only a very small percentage of potential transactions reviewed are ever consummated. In order to comply with a hold harmless commitment as interpreted in this Finding 3 for a transaction that is eventually consummated, the company would have to track all its costs for each and every potential transaction it reviews even though the vast majority will never be consummated. This would be unwieldy and wasteful. Because these potential transactions often will benefit customers, discouraging investigation of them is not in the best interests of customers.

Treatment of such investigation costs incurred prior to the announcement of a transaction in the context of a hold harmless obligation was certainly not a settled issue in early 2012 or even today. This uncertainty was reflected in the Commission's notice of proposed *Policy Statement on Hold Harmless Commitments* discussed in Duke Energy's response to Finding 2 above.

In the notice of proposed policy statement, the Commission proposed to clarify that such investigation costs would be subject to the hold harmless commitment.[5]

[5] Paragraph 22 of the notice of proposed policy statement.

As in Duke Energy's response to Finding 2 above, we will point out again that the notice of proposed policy statement was issued two and a half years after the Merger closed, and is just a proposal at this time because the final policy statement has not been issued. In addition, some commenters specifically disagreed with this point.[6]

Notwithstanding Duke Energy's belief that its failure to exclude pre-announcement costs that are the subject of Finding 3 was not a violation of any settled policy, Duke Energy will not expend the resources necessary to contest this issue and will comply with all associated recommendations in the audit report.

Duke Energy estimates that the total refunds that will be due to transmission and wholesale power customers arising from this finding will be approximately $60,000 plus interest.

- **Finding 4.** *Use of the Consolidation Method of Accounting* – DEC and DEP accounted for investments in subsidiaries on a consolidated basis in their FERC Form No. 1, Annual Reports (Form No. 1), contrary to the Commission's long-standing accounting policy.

Response: Duke Energy accepts this finding.

- **Finding 5.** *Accounting for Sales of Accounts Receivable* – DEC, DEP, and DEF misclassified an estimated $94.7 million of nonoperating expenses and receivables arising from transactions with their subsidiaries during the audit period. As a result, the wholesale power and transmission customers' revenue requirements were inappropriately overstated by an estimated $61 million.

Response: Duke Energy disagrees with the portion of this finding that concerns accounting for losses on the sale of receivables. However, Duke Energy will not contest this finding under 18 CFR Part 41 because the portion of this finding that relates to accounting for losses on the sale of receivables, including recommendations 17 and 18, will be held in abeyance and will be subject to the outcome of Duke Energy's request for rehearing in Docket No. AC15-174-001 pursuant to the draft audit report.

- **Finding 6.** *Accounting for Lobbying Expenses:* Duke Companies recorded approximately $2.4 million of lobbying expenses in above-the-line operating accounts from 2011 through 2013. As a consequence, Duke Companies improperly included these costs in wholesale power and transmission formula rate service cost determinations.

Response: Duke Energy accepts this finding.

[6] See the comments of Edison Electric Institute filed March 30, 2015 at p. 14-15.

- **Finding 7.** *Allocation of Lobbyist Labor Costs:* Duke Companies accounted for the labor costs of internal lobbyists and their support staff in operating accounts that lacked support for inclusion in the accounts. Improper accounting for the costs can lead to inappropriate recovery of the costs through rates charged and billed to customers.

Response: Duke Energy accepts this finding.

- **Finding 8.** *Nonutility Expenses in Operating Accounts:* Duke Companies recorded approximately $490,000 of nonutility expenses in operating accounts in 2014. As a result, inappropriate costs were included in wholesale power and transmission formula rate service cost determinations and charged to customers.

Response: Duke Energy accepts this finding.

RESPONSE TO RECOMMENDATIONS

Duke Energy will comply with all recommendations except as otherwise stated below. As requested, Duke Energy proposes target completion dates below for each recommendation wherever the recommendation does not specify the completion date.

Accounting for Merger Transaction Costs

1. Revise accounting policies and procedures to appropriately account for merger transactions consistent with Commission accounting requirements.

Target Completion Date: September 30, 2016

2. Develop written policies and procedures to timely identify proposed accounting transactions that would trigger a notification to the Commission.

Target Completion Date: September 30, 2016

3. Develop written policies and procedures to submit accounting questions of doubtful interpretation to the Commission.

Target Completion Date: September 30, 2016

4. Provide training to employees on compliance with the merger cost accounting conditions and the revised policies, procedures, and controls for complying with the conditions. Also, develop a training program that supports the provision of periodic training in this area.

Target Completion Date: December 31, 2016

Merger Transaction Internal Labor Costs

If the Commission issues a policy statement on hold harmless commitments and such policy statement is inconsistent with Finding 2 or Finding 3, then Duke Energy reserves the right to seek relief from compliance with any of recommendations 5 – 12 as appropriate.

5. Revise all policies and procedures for tracking, accounting, and excluding merger transaction costs from wholesale power and transmission formula rates, including amounts previously charged to utility plant, accumulated deferred income taxes, construction work in progress with the associated capitalized cost of funds used during construction (AFUDC), and maintenance and operating expense accounts, and future charges to such accounts for any transaction to which a FERC hold harmless obligation applies. The revised procedures should hold customers harmless from all merger transaction costs consistent with requirements of the Merger Order. Among other things, the revised policies and procedures should include an annual review of each subsidiary's merger transaction cost adjustments as well as periodic evaluations within the year, as needed and appropriate.

Target Completion Date: September 30, 2016

6. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the inclusion of merger transaction internal labor and related costs in wholesale power and transmission formula rates during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

7. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

Target Completion Date: 45 days after receiving DAA's assessment of the refund analysis

8. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Target Completion Date: 45 days after receiving DAA's assessment of the refund analysis

Merger Transaction Outside Services and Related Costs

9. Revise accounting policies and procedures to appropriately account for merger transaction costs consistent with Commission accounting requirements.

Target Completion Date: September 30, 2016

10. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the inclusion of merger transaction outside services and related costs in wholesale power and transmission formula rate charges during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

11. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

Target Completion Date: 45 days after receiving DAA's assessment of the refund analysis

12. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Target Completion Date: 45 days after receiving DAA's assessment of the refund analysis

Use of the Consolidation Method of Accounting

13. Review and, as needed, revise accounting policies, practices, and procedures to ensure that investments in subsidiaries are accounted for consistent with the Commission's equity method accounting requirements.

Response and Target Completion Date: Duke Energy will comply with this recommendation, but notes that the Commission has granted to DEC, DEP, and DEF a waiver from the requirement to use the equity method as discussed above. Target Completion date is 60 days after receiving the final audit report.

14. Evaluate the accounting applied to Duke Companies' existing subsidiaries and notify DAA of any areas of noncompliance with Commission accounting requirements.

Target Completion Date: 60 days after receiving the final audit report.

15. Revise documented policies, procedures and processes to ensure timely notice is provided to relevant regulators regarding instances of noncompliance with regulations, rules, and orders.

Target Completion Date: September 30, 2016

16. Provide training to staff on procedures, practices, and available tools to transparently or anonymously report instances of noncompliance to senior management, the Board of Directors, and relevant regulators.

Target Completion Date: December 31, 2016

Accounting for Sales of Accounts Receivable

17. Revise procedures to ensure that all costs, revenues, and account balances associated with the sale of accounts receivable are accounted for in accordance with Commission accounting regulations. Among other things, the corrected accounting should ensure that all discounts, fees, and revenues associated with receivable sales are recorded in Account 426.5, and that the cost of performing collection services on behalf of the subsidiaries, including employee labor, expenses, and an appropriate allocation of overhead and utility plant, are recorded in Account 426.5.

Response and Target Completion Date: In accordance with the draft audit report, the portions of this recommendation that relate to accounting for losses on the sale of receivables are held in abeyance and subject to the outcome of the rehearing request and any subsequent petitions for review proceedings. The target completion date for portions that do *not* relate to accounting for losses on the sale of receivables is 60 days after receiving the final audit report.

18. Provide the revised procedures to DAA for review within 60 days of receiving the final audit report.

Response and Target Completion Date: In accordance with the audit report, the portions of this recommendation that relate to accounting for losses on the sale of receivables are held in abeyance and subject to the outcome of the rehearing request and any subsequent petitions for review proceedings.

19. Recalculate charges to wholesale power and transmission customers of DEC, DEP, and DEF and submit the recalculations in a refund analysis to DAA for review within 60 days of receiving the final audit report. The refund analysis should explain and detail the: (1) return of collection service billings charged in 2014; (2) return of losses on the sales included in rates; (3) determinative components of the refund; (4) refund method; (5) period(s) refunds will be made; and (6) interest calculated in accordance with section 35.19 of Commission regulations.

20. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

Target Completion Date: 45 days after receiving DAA's assessment of the refund analysis

21. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Target Completion Date: 45 days after receiving DAA's assessment of the refund analysis

Accounting for Lobbying Expenses

22. Establish and implement written procedures governing the methods used to account for, track, report, and review lobbying costs incurred.

Response: Duke Energy has completed this action. Duke Energy will update its procedures upon completion of the labor time study referenced in recommendation 28.

23. Provide training on Commission accounting requirements and the impact of accounting on cost-of-service rate determinations to employees involved in lobbying and lobbying-related work, and those with oversight responsibility for lobbying cost allocations. Also, develop a training program that supports the provision of periodic training in this area.

Response: Duke Energy has completed this action. Duke Energy will update its procedures upon completion of the labor time study referenced in recommendation 28.

24. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the improper inclusion of lobbying cost in operating accounts during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

25. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

Target Completion Date: 45 days after receiving DAA's assessment of the refund analysis

26. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Target Completion Date: 45 days after receiving DAA's assessment of the refund analysis

Allocation of Lobbyist Labor Costs

27. Revise written policies and procedures to create a process to document and verify appropriate allocation of lobbying and lobbying-related costs, and maintain auditable support for the cost included in rate determinations.

Response: Duke Energy has completed this action. Duke Energy will update its procedures upon completion of the labor time study referenced in recommendation 28.

28. Retain an independent third-party entity to conduct a representative labor time study to determine an appropriate allocation of internal lobbyist labor, support staff, and associated costs that should be accounted for in operating and nonoperating accounts based on time spent by employees engaged in the activities. Provide the study results to audit staff within 180 days of the date of the final audit report.

29. Include the results of the labor time study in the determination of lobbying-related labor cost allocations as of January 1, 2016.

Target Completion Date: 180 days after the date of the final audit report

30. Implement policies and procedures to perform a labor time study biennially using an independent third-party or internal company resources that are able to attest to the results of the study. Revise the lobbying-related labor cost allocations based on the results of the study.

Target Completion Date: 180 days after the date of the final audit report

Nonutility Expenses in Operating Accounts

31. Develop and implement written policies, procedures, and controls to ensure proper accounting and reporting of nonutility expenses.

Response: Duke Energy has completed this action.

32. Provide training for employees involved in the invoicing process on Commission accounting requirements and the impact of the accounting on cost-of-service rate determinations.

Response: Duke Energy has completed this action.

33. Within 60 days of receiving the final audit report, provide documentation supporting the analysis performed of invoiced expenses recorded to administrative and general (A&G) accounts in 2014 that identified misclassified nonutility expenses included in A&G accounts. Develop an estimate of misclassified nonutility expenses accounted for in operating accounts in 2011 through 2013 and 2015.

34. Implement policies and procedures to provide periodic audits or reviews of A&G transactions by external or internal auditors.

Target Completion Date: 60 days after the date of the final audit report

35. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the improper inclusion of identified and estimated nonutility expenses in charges to wholesale power and transmission customers during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made. Include the results of the invoice analysis in the refund analysis.

36. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

Target Completion Date: 45 days after receiving DAA's assessment of the refund analysis

37. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Target Completion Date: 45 days after receiving DAA's assessment of the refund analysis

Duke Energy acknowledges and appreciates the professionalism and the courtesy with which DAA staff conducted this audit.

Sincerely,

Brian D Savoy by Paul King

Brian D. Savoy
Senior Vice President, Chief Accounting Officer and Controller

DUKE ENERGY KENTUCKY
CASE NO. 2018-00261
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(7)(j)

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807 KAR 5:001, SECTION 16(7)(j)

Description of Filing Requirement:

Prospectuses of the most recent stock or bond offerings.

Response:

See attached. The most recent Duke Energy Kentucky bond offering was a private placement and as a result did not have a prospectus. Private placements use a document similar to prospectus, called an executive summary.

Witness Responsible: Robert H. "Beau" Pratt

This Confidential Executive Summary (the "Executive Summary") must not be given to any person other than the offeree to whom it has been distributed and must not be reproduced in any manner whatsoever. No offeree is authorized to make any further distribution or reproduction of this Executive Summary or to disclose its contents. Any unauthorized distribution or reproduction of any part of this Executive Summary may result in a violation of the Securities Act of 1933, as amended (the "Securities Act").

$90,000,000
SENIOR UNSECURED DEBENTURES

DUKE ENERGY®

DUKE ENERGY KENTUCKY, INC.

JUNE 2017

CONFIDENTIAL EXECUTIVE SUMMARY

SOLE PLACEMENT AGENT

KeyBanc Capital Markets

The Securities described in this Executive Summary have not been registered under the Securities Act, or the securities laws of any jurisdiction. Duke Energy Kentucky, Inc. is offering the Securities in reliance on exemptions from the registration requirements of the Securities Act and other applicable laws. These exemptions apply to offers and sales of securities that do not involve a public offering. The Securities have not been approved or recommended by any federal, state or foreign securities authorities, nor have any of these authorities passed upon the merits of this offering or determined that this Executive Summary is accurate or complete. Any representation to the contrary is a criminal offense.

DISCLAIMER

NOTICE TO PROSPECTIVE PURCHASERS:

Duke Energy Kentucky, Inc. ("Duke Energy Kentucky" or the "Company") has requested that KeyBanc Capital Markets Inc. ("KeyBanc"), which is acting as sole placement agent (the "Placement Agent") on behalf of the Company, distribute this Executive Summary to prospective purchasers of the Company's Senior Unsecured Debentures (the "Securities").

This Executive Summary has been prepared solely for the benefit of a limited number of sophisticated institutions that are accredited investors within the meaning of Rule 501(a) under the Securities Act interested in the purchase of the Securities described herein to be issued by the Company. The information contained in this Executive Summary has been supplied by the Company, which is solely responsible for its contents. NONE OF KEYBANC'S EMPLOYEES OR AGENTS HAS VERIFIED SUCH INFORMATION AND KEYBANC DOES NOT MAKE ANY REPRESENTATION OR WARRANTY AS TO THE ACCURACY OR COMPLETENESS OF SUCH INFORMATION.

Your acceptance of this Executive Summary shall constitute an agreement by you and your representatives that to the extent that the Company discloses material, nonpublic information to you or your representatives, such disclosure is made with the understanding that you and your representatives agree to maintain such material, nonpublic information in confidence and that the Company does not, at this time, intend to disclose any such material nonpublic information publicly.

This Executive Summary is a confidential document. Prospective purchasers should read this Executive Summary before making a decision whether to purchase any Securities. Prospective purchasers must not (i) use this Executive Summary or any other information furnished by the Company for any other purpose; (ii) make copies of any part of this Executive Summary or give a copy of this Executive Summary or any other information furnished by the Company to any other person; (iii) disclose any information furnished by the Company, including the information in this Executive Summary, to any other person without the prior written approval of the Company; or (iv) trade in any securities of the Company (other than the Securities) while in possession of this Executive Summary or any information furnished by the Company in connection with the transaction contemplated hereby.

Notwithstanding anything in this Executive Summary to the contrary, the Company, the Placement Agent and each prospective purchaser of the Securities (and any employee, representative or other agent of them) may disclose to any and all persons, without limitation of any kind, the tax treatment and tax structure of the transactions contemplated by this Executive Summary and all materials of any kind (including opinions or other tax analyses) that are provided to it relating to such tax treatment or tax structure. However, any such information relating to the tax treatment or tax structure is required to be kept confidential to the extent necessary to comply with any applicable federal or state securities laws.

A prospective purchaser must promptly return all copies of this Executive Summary to the Placement Agent, if the offering is terminated or withdrawn, if a prospective purchaser decides not to purchase the Securities or if requested by the Company. Each prospective purchaser is responsible for making its own examination of the Company and its own assessment of the merits and risks of investing in the Securities. This Executive Summary does not purport to contain all of the information that a prospective purchaser may require in making an investment decision. This Executive Summary may also contain summaries of certain documents. These summaries are not necessarily complete and prospective purchasers should refer to the documents that have been summarized.

The Company will offer prospective purchasers the opportunity to ask questions of and receive answers from the Company about the Company, the terms and conditions of the Securities or any other relevant information. Prospective purchasers may contact the persons listed below, if they need any additional information, including copies of any documents summarized in this Executive Summary.

By purchasing any Securities, a prospective purchaser will be deemed to have acknowledged that (i) it is aware of the need to conduct its own thorough investigation of the Company and the Securities before making an investment in the Securities; (ii) it is an institutional accredited investor that is willing and able to conduct an independent investigation of the risks of ownership of the Securities; (iii) it has had an opportunity to request any additional information that it needs from the Company; and (iv) the Placement Agent is not responsible for, and is not making any representation concerning, the Company's future performance, the adequacy, accuracy or completeness of this Executive Summary, the advisability of purchasing the Securities, the execution, validity or enforceability of the Securities or any documents delivered in connection with the Securities.

In making their investment decision, prospective purchasers should rely only on the information contained in this Executive Summary and on any other information furnished by the Company, whether directly or through the Placement Agent. The Company and the Placement Agent have not authorized anyone to provide prospective purchasers with any other information. If any other information is received, a prospective purchaser should not rely on it.

Prospective purchasers should not assume that the information contained in this Executive Summary is accurate as of any date other than the date on the front cover of this Executive Summary or that there has been no change in the affairs of the Company since that date.

The Company and the Placement Agent are not providing prospective purchasers with any legal, business, tax or other advice in this Executive Summary. Prospective purchasers should consult with their own advisors as needed to assist them in making their investment decision and to advise them whether they are legally permitted to purchase the Securities.

Each prospective purchaser must comply with all laws that apply to it in any place in which it buys, offers or sells any Securities or possesses this Executive Summary. Each prospective purchaser must also obtain any consents or approvals that it needs in order to purchase any Securities. The Company and the Placement Agent are not responsible for a prospective purchaser's compliance with these legal requirements. The Company and the Placement Agent are offering to sell the Securities only in places where, and to persons to whom, offers and sales are permitted.

The Company has not taken any action that would permit a public offer or sale of the Securities. Accordingly, the Securities will be subject to restrictions on resale and transfer as provided in the debenture purchase agreement and the supplemental indenture relating to the Securities. The Securities will bear a legend referring to these restrictions. Because of these restrictions, no secondary trading market for the Securities is expected to develop and purchasers may be required to bear the financial risks of investing in the Securities for an indefinite period of time.

The Company and the Placement Agent reserve the right to reject any commitment to purchase Securities in whole or in part and to allot to any prospective purchaser less than the full amount of Securities sought by it.

This Executive Summary contains certain "forward-looking statements" with respect to the financial condition, results of operations and business and business strategy of the Company. All of these forward-looking statements are based on estimates, projections and assumptions made by the Company about circumstances and events that have not yet taken place which, although the Company believes them to be reasonable, are inherently uncertain. Therefore, undue reliance should not be placed upon these estimates and statements. No assurance can be given that any of these estimates or statements will be realized. It is likely that actual results will vary from those contemplated by these forward-looking statements and such variations may be material. Prospective purchasers should carefully review the Risk Factors beginning on page 18 of this Executive Summary for a discussion of certain factors that could cause the Company's results to vary from those contemplated by these forward-looking statements.

By accepting this Executive Summary, the recipient will be deemed to have acknowledged and agreed to all of the foregoing.

KeyBanc Capital Markets is the trade name for the capital markets and investment banking services of KeyCorp and its subsidiaries, including KeyBank National Association and KeyBanc Capital Markets Inc. (a U.S. broker-dealer registered with the U.S. Securities and Exchange Commission and a member of FINRA and SIPC).

For further information, please contact one of the following KeyBanc professionals:

KEYBANC CAPITAL MARKETS

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I. DUKE ENERGY KENTUCKY, INC.

The Company's future performance is subject to a variety of risks and uncertainties, many of which are described in the section entitled Risk Factors. If any of the risks or uncertainties materialize, the Company's business, financial condition and results of operations could be materially and adversely affected. Additional risks not presently known to the Company, or that the Company currently deems immaterial, may also impair the business, financial condition or results of operations.

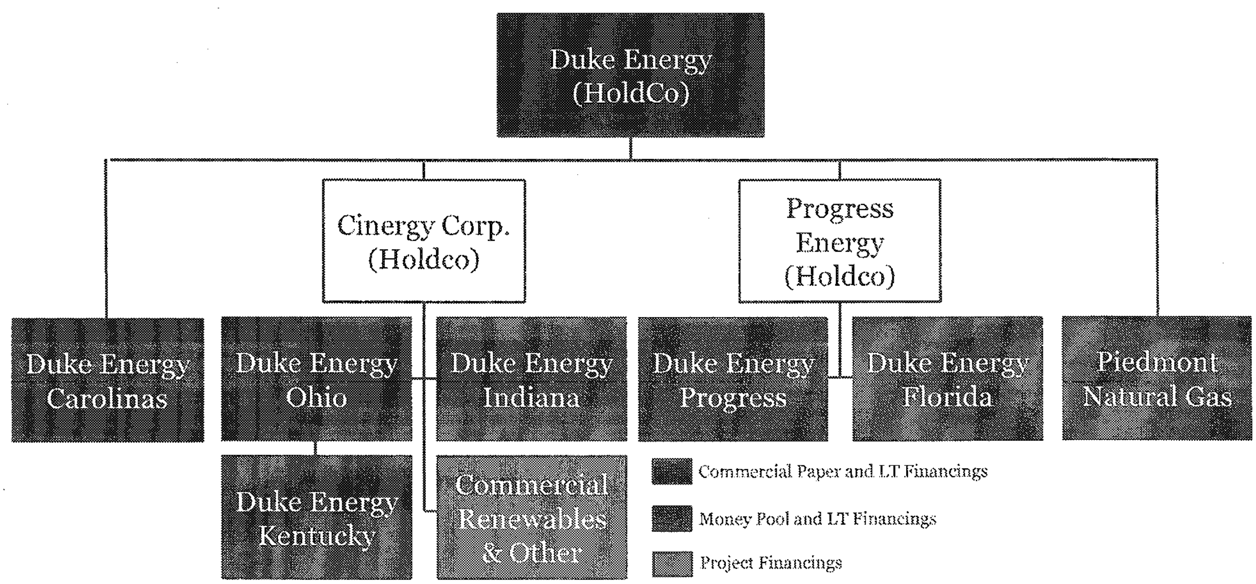
Prospective purchasers should read the information provided in the Executive Summary with respect to Duke Energy Kentucky, Inc. in conjunction with the more detailed information about Duke Energy Kentucky, Inc. in Duke Energy Corporation's SEC filings and Duke Energy Kentucky, Inc.'s quarterly and annual financial statements. In considering whether to purchase the Debentures, investors should carefully consider the risks and uncertainties.

1. COMPANY OVERVIEW

Duke Energy Kentucky, Inc. ("Duke Energy Kentucky" or the "Company") is a combination electric and gas public utility company that provides service in northern Kentucky. The Company's principal lines of business include generation, transmission and distribution of electricity as well as the sale of and/or transportation of natural gas. Duke Energy Kentucky's common stock is wholly owned by Duke Energy Ohio, Inc. (''Duke Energy Ohio''), an indirect wholly owned subsidiary of Duke Energy Corporation (collectively with its subsidiaries, "Duke Energy"), an energy company headquartered in Charlotte, North Carolina. Duke Energy operates in the U.S. primarily through its direct and indirect subsidiaries. Duke Energy's subsidiaries include Duke Energy Carolinas, LLC; Duke Energy Progress, LLC; Duke Energy Florida, LLC; Duke Energy Ohio, Inc.; Duke Energy Indiana, LLC; and Piedmont Natural Gas Company, Inc. The table below displays the simplified financing structure of Duke Energy:

Duke Energy Kentucky is the sole obligor on the Securities, and neither Duke Energy nor any of its affiliates are guaranteeing Duke Energy Kentucky's obligation on the Securities.

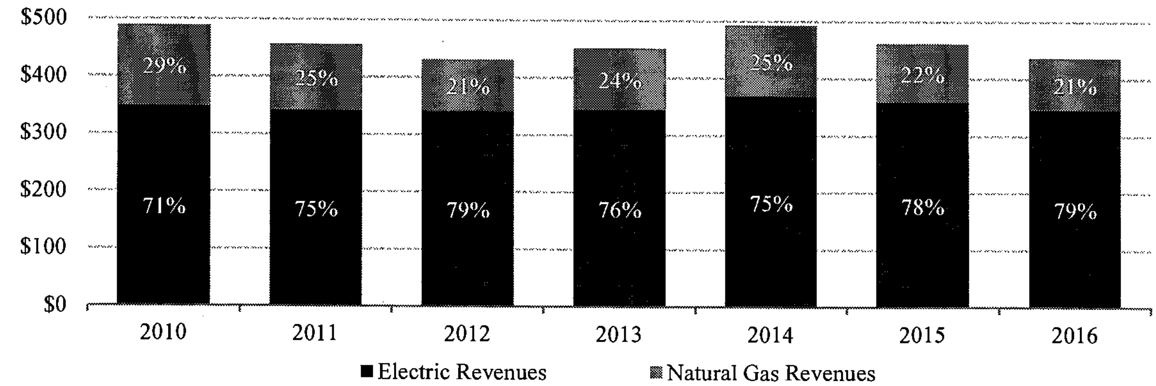
DUKE ENERGY SIMPLIFIED FINANCING STRUCTURE



Source: the Company

Below is the Company's yearly historical revenue breakdown since 2010:

DUKE ENERGY KENTUCKY HISTORICAL REVENUE BREAKDOWN



Source: the Company

2. *CUSTOMERS & SERVICE TERRITORY*

Duke Energy Kentucky provides electric and gas service in the northern Kentucky area. The approximately 300 square mile service territory includes the cities of Covington and Florence, Kentucky. The Company owns an electric transmission and distribution system in Kenton, Campbell, Boone, Grant, and Pendleton counties of northern Kentucky. The Company also owns a gas distribution system, which serves either all or parts of Kenton, Campbell, Boone, Grant, Gallatin, Bracken, and Pendleton counties of northern Kentucky.

At December 31, 2016, Duke Energy Kentucky had approximately 140,000 electric customers and 98,000 gas customers. For the year ended December 31, 2016, the Company sold 4,672,987 MWh of electricity and 8,659,778 Mcf of gas to retail customers. Electric sales to residential customers account for approximately 38% of electric revenue, with commercial customers at 33%, industrial at 16%, wholesale at 6% and other at 7%. Gas sales to residential and commercial customers account for approximately 67% and 23% of gas revenue, respectively, with other at 10%.

3. *ASSETS & GENERATION OVERVIEW*

At December 31, 2016, Duke Energy Kentucky owned approximately 105 conductor miles of 69 kilovolt electric transmission lines. The Company also owned approximately 4,500 conductor miles of electric distribution lines, 3,000 miles of overhead lines, and 1,500 miles of underground lines. Duke Energy Kentucky also has approximately 1,400 miles of gas transmission and distribution mains. The electric transmission and distribution systems have approximately 40 substations.

Duke Energy Kentucky owns and operates the East Bend Generating Station ("East Bend") coal-fired station, located in Rabbit Hash, Kentucky, with a net capacity of 600 megawatt ("MW") and one natural gas combustion turbine peaking station, Woodsdale, with a net capacity of 564 MW. Duke Energy Kentucky previously owned 69% of the East Bend generating station. It acquired the additional 31% stake in the facility in December 2014 for $12.4 million. The acquisition replaces generation lost as a result of the retirement of the 163 MW, 55 year old Miami Fort 6 plant. East Bend, in operation since 1981, ran at a 76.73% capacity factor in calendar year 2015, and 69.58% in 2016. East Bend is a fully scrubbed power plant and is equipped to reduce sulfur dioxide emissions by 97% and NOx emissions by 85%. It has an air permit that limits SO2 emissions to 1.2 lbs/MMBTU.

Following the retirement of the Miami Fort 6 plant in June 2015, 100% of the 600 MW of coal-fired capacity is equipped with scrubbers and Selective Catalytic Reduction equipment.

Additional information on Duke Energy Kentucky's assets is provided below:

Duke Energy Kentucky Power Plants

Plant	Year	State	Owner	Operator	Status	Prime Mover	Fuel Type	Capacity (MW)	Ownership
East Bend	1981	KY	Duke Kentucky	Duke Kentucky	Operating	Steam Turbine	Bituminous Coal	600.0	100.00%
Miami Fort	1949	OH	Duke Kentucky	Dynegy Inc.	Retired	Steam Turbine	Bituminous Coal	--	--
Woodsdale	1992	OH	Duke Kentucky	Duke Kentucky	Operating	Gas Turbine	Natural Gas	564.0	100.00%

Source: SNL

Duke Energy Kentucky Current Plant Capacity and Operations Summary as of Year End 2016

		Owned Operating Capacity (MW)						
	Avg. Age of Fleet (Yrs)	Operating Nameplate	Operating Summer	Operating Winter	Total	MWh Net Generation	Capacity Factor	Average Heat Rate (Btu/kWh)
Total Coal (Steam Turbine)	36	768.0	600.0	600.0	768.0	3,667,297	69.58%	10,889
Total Natural Gas (Gas Turbine)	25	572.0	462.0	564.0	572.0	31,659	0.65%	25,258
Total	31	1,340.0	1,062.0	1,164.0	1,340.0	3,698,956		

Source: SNL

4. *RATES & REGULATION*

The Company is regulated primarily by the Kentucky Public Service Commission ("KPSC"). Fuel costs are adjusted monthly. Although Duke Energy Kentucky currently recovers its environmental compliance costs through base rates, Kentucky law permits a Cost Recovery Mechanism for recovery of certain environmental costs related to coal combustion and a cash return on associated construction work in progress ("CWIP") outside base rate filings. Adjustment mechanisms also permit cost recovery, including an incentive, for energy efficiency programs. The effective dates of the Company's most recent base rate increases are December 2006 for electric and January 2010 for gas.

In 2009, the Company proposed to implement a new rate design for residential customers, which involves moving more of the fixed charges of providing gas service, such as capital investment in pipes and regulating equipment and billing and meter reading, from the volumetric charges to the fixed monthly charge. The settlement ultimately provided for a portion of the increase to be reflected in the customers' fixed monthly charge with the remainder of the increase to be reflected in the volumetric charge. Duke Energy Kentucky recovers the gas commodity portion in its costs via a gas cost adjustment ("GCA") rider.

Duke Energy Kentucky's electric rates are the lowest of any investor-owned utility in the state and its gas rates are competitive with peer companies. The Company's retail electric rates are segregated into residential, non-residential, and lighting, with the non-residential rates segregated based on the voltage level of delivery (i.e., transmission level, primary level, or distribution level). The significant existing electric riders are for recovery of fuel and purchased power costs, sharing of profits from off-system sales, and energy efficiency. The Company's gas rates are segregated between residential, general service (i.e., non-residential), and interruptible. The significant existing gas riders are for recovery of the commodity costs of gas and for energy efficiency.

Summaries of the most recent electric and natural gas rate cases are shown in the table below:

		Increase Requested					Increase Authorized			
Service	Date	Rate Increase	Return on Rate Base	ROE	Equity to Cap	Rate Base	Date	Rate Increase	ROE	Equity to Cap
Natural Gas	7/1/09	$17.5M	7.67%	11.00%	49.90%	$253.8M	12/29/09	$13.0M	10.38%	50.80%
Electric	5/31/06	$66.6M	8.26%	11.50%	51.00%	$591.1M	12/21/06	$49.0M	NA	NA

Source: SNL

As part of a recent stipulation with the Kentucky attorney general related to the acquisition of the remaining 31% interest in East Bend, the Company agreed to an electric base rate freeze to not file for an electric base rate increase earlier than January 1, 2016. Duke Energy Kentucky is a member of PJM Interconnection, LLC ("PJM"), a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia and operates an energy market and a capacity market. Duke Energy Kentucky participates in the PJM capacity market as a Fixed Resource Requirement ("FRR") entity. As an FRR entity, Duke Energy Kentucky is required to submit an FRR capacity plan that identifies specific generating resources that provide Duke Energy Kentucky with capacity to meet its reliability obligations and to satisfy its load and generation needs. The FRR plan is submitted annually for a period of three delivery years into the future. Duke Energy Kentucky currently uses primarily its owned generating resources to satisfy its FRR plan.

Regional Transmission Organization ("RTO") Realignment

Duke Energy Ohio, including Duke Energy Kentucky, transferred control of their transmission assets from Midcontinent Independent System Operator, Inc. ("MISO") to PJM, effective December 31, 2011. On December 22, 2010, the KPSC approved Duke Energy Kentucky's request to effect the RTO realignment, subject to a commitment not to seek double-recovery in a future rate case of the transmission expansion fees that may be charged by MISO and PJM in the same period or overlapping periods.

FERC Transmission Return on Equity and MISO Transmission Expansion Planning ("MTEP") Cost Settlement

On October 14, 2011, Duke Energy Ohio and Duke Energy Kentucky submitted with the FERC proposed modifications to the PJM Interconnection Open Access Transmission Tariff pertaining to recovery of the transmission revenue requirement as PJM transmission owners. The filing was made in connection with Duke Energy Ohio's and Duke Energy Kentucky's move from MISO to PJM effective January 1, 2012. On April 24, 2012, the FERC issued an order accepting the proposed filing effective January 1, 2012, except that the order denied a request to recover certain costs associated with the move from MISO to PJM without prejudice to the right to submit another filing seeking such recovery and including certain additional evidence, and set the rate of return on equity of 12.38 percent for settlement and hearing. On April 16, 2015, the FERC approved a settlement agreement between Duke Energy Ohio, Duke Energy Kentucky and six PJM transmission customers with load in the Duke Energy Ohio and Duke Energy Kentucky zone. The principal terms of the settlement agreement are that, effective upon the date of FERC approval, (i) the return on equity for wholesale transmission service is reduced to 11.38 percent, (ii) the settling parties agreed not to seek a change in the return on equity that would be effective prior to June 1, 2017, and (iii) Duke Energy Ohio and Duke Energy Kentucky will recover 30 percent of the wholesale portion of costs arising from their obligation to pay any portion of the costs of projects included in any MTEP that was approved prior to the date of Duke Energy Ohio's and Duke Energy Kentucky's integration into PJM.

East Bend Coal Ash Basin Filing

On December 2, 2016, Duke Energy Kentucky filed with the KPSC a request for a CPCN for construction projects necessary to close and repurpose an ash basin at the East Bend necessitated by current and proposed EPA regulations related to Coal Combustion Residuals ("CCR") and 2015 Amendments to the Steam Electric Effluent Limitation Guidelines ("ELG"). Duke Energy Kentucky is targeting a completion date in fourth quarter 2018 for these projects and estimates a total cost of approximately $93 million. Duke Energy Kentucky has requested an order to be issued by April 30, 2017. On April 25, the United States Environmental Protection Agency ("EPA") published its stay of applicability for the 2015 Amendments to the Steam Electric Effluent Limitation Guidelines. On May 18, 2017, the Company met with the Commission Staff to discuss the impact of this stay of applicability and the Company's need to continue to the projects to comply with CCR and other Kentucky groundwater related regulations. On May 23, 2017, Duke Energy Kentucky supplemented the record with additional information regarding the costs of the compliance initiatives initially evaluated. Duke Energy Kentucky cannot predict the outcome of this matter.

On June 10, 2015, Duke Energy Kentucky filed an application with the KPSC seeking approval to record ARO amounts and other compliance obligations related to the disposal of coal combustion residuals at the East Bend Station as regulatory assets and to defer costs incurred, including carrying costs. The application was approved in December 2015.

Dry Bottom Ash Conversion

On July 28, 2016, Duke Energy Kentucky filed with the KPSC a request for approval of a CPCN to convert to dry bottom ash at the East Bend station. The project is necessary to comply with various environmental law requirements. The project is estimated to cost approximately $25 million. On February 23, 2017, the KPSC granted a CPCN for the project.

Big Bone Pipeline Project

On May 11, 2016, Duke Energy Kentucky filed with the KPSC a request for approval of a CPCN to construct a new natural gas pipeline and related facilities. The project will provide for needed capacity on the Duke Energy Kentucky natural gas delivery system and will provide greater reliability of the overall delivery system. The project is estimated to be completed prior to the 2017 winter heating season at a total cost of approximately $14 million. On November 28, 2016, the KPSC granted a CPCN for the project.

Natural Gas Pipeline Testing Costs

On April 29, 2016, Duke Energy Kentucky filed an application with the KPSC requesting approval to defer approximately $2 million of unplanned operations and maintenance expense related to pressure testing of natural gas pipelines which will be completed in 2017. The testing is required to comply with regulations promulgated by the Pipeline and Hazardous Materials Safety Administration. The KPSC approved the application on July 22, 2016.

Advanced Metering Infrastructure

On April 25, 2016, Duke Energy Kentucky filed with the KPSC an application for approval of a CPCN for the construction of AMI. Duke Energy Kentucky anticipates that the estimated $49 million project, if approved, will take about two years to complete. Duke Energy Kentucky also requested approval to establish a regulatory asset of approximately $10 million for the remaining book value of existing meter equipment and inventory that will be replaced. On July 20, 2016, the Kentucky Attorney General, the only intervenor in the proceeding, moved to dismiss the application. Duke Energy Kentucky filed its opposition to the Kentucky Attorney General's motion to dismiss on July 27, 2016. On September 28, 2016, the KPSC denied the Kentucky Attorney General's motion to dismiss and granted Duke Energy Kentucky's motion to file rebuttal testimony. Duke Energy Kentucky and the Kentucky Attorney General entered into a stipulation resolving the matters raised in the application. An evidentiary hearing was held on December 8, 2016. On May 25, 2017 the Commission issued an Order approving the stipulation with three modifications impacting the depreciation, and timing and method of cost recovery for natural gas-related metering devices. Duke Energy Kentucky has agreed to accept these modifications.

Accelerated Natural Gas Service Line Replacement Rider

On July 6, 2015, Duke Energy Kentucky filed an application for approval of an accelerated natural gas service line replacement program ("ASRP"). Under the ASRP, Duke Energy Kentucky proposed to replace certain natural gas service lines on an accelerated basis over a 5-year period. Duke Energy Kentucky also proposed to complete preliminary survey and investigation work related to natural gas service lines that are customer owned and for which it does not have valid records and, further, to relocate interior natural gas meters to suitable exterior locations where such relocation can be accomplished. Duke Energy Kentucky's projected total capital and operations and maintenance expenditures under the ASRP were approximately $ 50 million. The filing also sought approval of Rider ASRP to recover related expenditures. Duke Energy Kentucky proposed to update Rider ASRP on an annual basis. On December 18, 2015 Duke Energy Kentucky entered into a settlement with the Attorney General of the Commonwealth of Kentucky to resolve all issues in the case. On February 2, 2016 the Commission approved the settlement. Duke Energy Kentucky filed its first annual true-up of the Rider ASRP on July 1, 2016. As part of that filing, the Company informed the Commission that the estimated total cost of the ASRP program has been reduced to approximately $34-38 million due to favorable vendor pricing and a lower than expected amount of service line replacements. The Commission approved the Company's application on December 16, 2016.

East Bend Station

On December 30, 2014, Duke Energy Kentucky acquired The Dayton Power and Light Company's 31 percent interest in the jointly owned East Bend Station for approximately $12.4 million. Duke Energy Kentucky owns 100 percent of the East Bend Station as a result of the acquisition. The KPSC approved the deferral of incremental operations and maintenance costs related to the additional ownership interest above amounts currently reflected in base rates. At December 31, 2016, Duke Energy Kentucky had approximately $23 million included in Regulatory assets related to incremental operations and maintenance costs for East Bend.

The purchase price, in accordance with FERC guidelines, was reflected with The Dayton Power & Light Company's historical original cost as an increase to property, plant and equipment and accumulated depreciation as of December 31, 2015. Based on FERC methodology, Duke Energy Kentucky is required to apply depreciation rates to the original historical plant cost, not the $12.4 million purchase price. As a result, the purchase price will be fully depreciated over a four-year period, not the remaining useful life of the assets of 27 years. On August 20, 2015, the KPSC approved Duke Energy Kentucky's application to use the purchase price as the value of the newly acquired interest in the East Bend Station for depreciation and ratemaking purposes and to create a regulatory asset for the excess FERC-mandated depreciation to be recovered over the remaining useful life of the assets. At December 31, 2016, Duke Energy Kentucky had approximately $9 million included in Regulatory assets related to excess depreciation.

5. *SELECTED HISTORICAL FINANCIALS*

SUMMARY HISTORICAL FINANCIALS

($ in thousands)	Fiscal Year End December 31, 2012	2013	2014	2015	2016
Income statement					
Operating Revenues					
Electric	$ 340,632	$ 344,471	$ 368,894	$ 359,196	$ 346,124
Natural Gas	90,353	107,005	124,403	102,354	90,216
Total operating revenues	430,985	451,476	493,297	461,550	436,340
Operating Income	60,602	85,793	70,869	87,334	72,198
EBITDA	106,625	131,931	117,061	132,222	118,187
Interest expense and other financing costs	17,520	15,989	16,345	14,172	14,888
Net Income	28,221	45,070	35,302	46,176	42,584
Balance Sheet					
Cash and cash equivalents	$ 10,693	$ 13,038	$ 11,307	$ 9,141	$ 6,534
Total asset value	1,173,031	1,165,746	1,214,158	1,340,478	1,370,148
Total debt	340,840	339,053	360,026	374,770	381,702
Total net debt	330,147	326,015	348,719	365,629	375,168
Total shareholders' equity	372,885	377,954	413,256	404,432	437,015
Total capitalization	713,725	717,007	773,282	779,202	818,717
Cash flow statement					
Cash flow from operations	$ 84,521	$ 75,745	$ 42,811	$ 109,932	$ 108,596
Capital expenditures	74,179	42,095	56,001	69,234	100,899
Depreciation and amortization	45,242	45,277	44,904	44,497	44,683
Ratios					
Total debt / EBITDA	3.2x	2.6x	3.1x	2.8x	3.2x
Total net debt / EBITDA	3.1x	2.5x	3.0x	2.8x	3.2x
EBITDA / Interest expense	6.1x	8.3x	7.2x	9.3x	7.9x
Total debt / Total capitalization	47.8%	47.3%	46.6%	48.1%	46.6%

Source: the Company

6. *OTHER*

MVP

MISO approved 17 Multi-Value Project ("MVP") proposals prior to Duke Energy Kentucky's exit from MISO on December 31, 2011. Construction of these projects is expected to continue through 2020. Costs of these projects, including operating and maintenance costs, property and income taxes, depreciation and an allowed return, are allocated and billed to MISO transmission owners.

On December 29, 2011, MISO filed a tariff with the FERC providing for the allocation of MVP costs to a withdrawing owner based on monthly energy usage. The FERC set for hearing (i) whether MISO's proposed cost allocation methodology to transmission owners who withdrew from MISO prior to January 1, 2012 is consistent with the tariff at the time of their withdrawal from MISO, and, (ii) if not, the amount of and methodology for calculating any MVP cost responsibility. In 2012, MISO estimated Duke Energy Kentucky's MVP obligation over the period from 2012 to 2071 at $450 million, on an undiscounted basis. On July 16, 2013, a FERC Administrative Law Judge (ALJ) issued an initial decision. Under this initial decision, Duke Energy Kentucky would be liable for MVP costs. Duke Energy Kentucky filed exceptions to the initial decision, requesting the FERC overturn the ALJ's decision.

On October 29, 2015, the FERC issued an order reversing the ALJ's decision. The FERC ruled the cost allocation methodology is not consistent with the MISO tariff and that Duke Energy Kentucky has no liability for MVP costs after its withdrawal from MISO. On May 19, 2016, the FERC denied the request for rehearing filed by MISO and the MISO Transmission Owners. On July 15, 2016, the MISO Transmission Owners filed a petition for review with the U.S. Court of Appeals for the Sixth Circuit. Oral arguments in this matter are scheduled to occur in June 2017. Duke Energy Kentucky cannot predict the outcome of this matter.

PJM Capacity Performance Proposal

On June 9, 2015, the FERC ruled in favor of PJM on a revised Tariff and Reliability Assurance Agreement including implementation of a Capacity Performance (CP) proposal and to amend sections of the Operating Agreement related to generation non-performance. The CP proposal includes performance-based penalties for non-compliance. Duke Energy Kentucky is a Fixed Resource Requirement (FRR) entity, and therefore is subject to the compliance standards through its FRR plans. A partial CP obligation will apply to Duke Energy Kentucky in the delivery year beginning June 1, 2019, with full compliance beginning June 1, 2020. Duke Energy Kentucky has developed strategies for compliance and required investments, including a dual fuel system at its Woodsdale Generating station. The execution of these strategies and investments may require approval from the KPSC. Duke Energy Kentucky has recently filed an application for a certificate of public convenience and necessity to construct the new dual fuel system. The Company cannot predict the outcome of this proceeding.

Remediation Activities

In addition to the AROs discussed in the Coal Combustion Residuals section below, Duke Energy Kentucky is responsible for environmental remediation at various sites. These include some properties that are part of ongoing operations and sites formerly owned or used by Duke Energy Kentucky. These sites are in various stages of investigation, remediation and monitoring. Managed in conjunction with relevant federal, state and local agencies, remediation activities vary based upon site condition and location, remediation requirements, complexity and sharing of responsibility. If remediation activities involve joint and several liability provisions, strict liability, or cost recovery or contribution actions, Duke Energy Kentucky could potentially be held responsible for environmental impacts caused by other potentially responsible parties, and may also benefit from insurance policies or contractual indemnities that cover some or all cleanup costs. Liabilities are recorded when losses become probable and are reasonably estimable. The total costs that may be incurred cannot be estimated because the extent of environmental impact, allocation among potentially responsible parties, remediation alternatives, and/or regulatory decisions have not yet been determined. Additional costs associated with remediation activities are likely to be incurred in the future and could be significant. Costs are typically expensed as Operation, maintenance and other in the Statements of Operations unless regulatory recovery of the costs is deemed probable.

Duke Energy Kentucky has accrued approximately $670 thousand and $515 thousand of probable and estimable costs related to its various environmental sites in Other within Deferred Credits and Other Liabilities on the Condensed Balance Sheets as of December 31, 2016 and 2015, respectively. Additional losses in excess of recorded reserves are expected to be immaterial for the stages of investigation, remediation and monitoring for the environmental sites that have been evaluated. The maximum amount of the range for all stages of Duke Energy Kentucky's environmental sites cannot be determined at this time.

Coal Combustion Residuals

In April 2015, the EPA published a rule to regulate the disposal of CCR from electric utilities as solid waste. The federal regulation classifies CCR as nonhazardous waste and allows for beneficial use of CCR with some restrictions. The regulation applies to all new and existing landfills, new and existing surface impoundments receiving CCR and existing surface impoundments that are no longer receiving CCR but contain liquid located at stations currently generating electricity (regardless of fuel source). The rule establishes requirements regarding landfill design, structural integrity design and assessment criteria for surface impoundments, groundwater monitoring and protection procedures and other operational and reporting procedures to ensure the safe disposal and management of CCR. As a result of the EPA rule, Duke Energy Kentucky recorded additional ARO amounts during 2015 for estimated ash basin closure costs at the East Bend Station. In addition to the requirements of the federal CCR regulation, CCR landfills and surface impoundments are also independently regulated by the Commonwealth of Kentucky.

The ARO amount recorded on the Balance Sheets is based upon estimated closure costs for impacted ash impoundments. The amount recorded represents the discounted cash flows for estimated closure costs based upon either specific closure plans or the probability weightings of the potential closure methods as evaluated on a site-by-site basis. Actual costs to be incurred will be dependent upon factors that vary from site to site. The most significant factors are the method and time frame of closure at the individual sites. Closure methods considered include removing the water from the basins, consolidating material as necessary and capping the ash with a synthetic barrier, excavating and relocating the ash to a lined structural fill or lined landfill, or recycling the ash for concrete or some other beneficial use. The ultimate method and timetable for closure will be in compliance with standards set by federal and state regulations.

During 2016, Duke Energy Kentucky updated its coal ash ARO liability estimate based on additional site-specific information about the related costs, methods and timing of work to be performed. The ARO amount will be adjusted as additional information is gained through the closure and post-closure process, including acceptance and approval of compliance approaches which may change management assumptions, and may result in a material change to the balance.

Clean Power Plan

On October 23, 2015, the EPA published in the Federal Register the CPP rule for regulating carbon dioxide (CO2) emissions from existing fossil fuel-fired electric generating units. The CPP establishes CO2 emission rates and mass cap goals that apply to fossil fuel-fired generation. Petitions challenging the CPP have been filed by several groups and on February 9, 2016, the Supreme Court issued a stay of the final CPP rule, halting implementation of the CPP until legal challenges are resolved. Kentucky has suspended work on the CPP in response to the stay. Oral arguments before 10 of the 11 judges on the D.C. Circuit Court were heard on September 27, 2016. The court has not issued its opinion in the case.

On March 28, 2017, President Trump signed an Executive Order directing EPA to review the CPP and determine whether to suspend, revise or rescind the rule. On the same day the DOJ filed a motion with the D.C. Circuit Court requesting that the court stay the litigation of the rule while it is reviewed by EPA. On April 28, 2017, the court issued an order to suspend the litigation for 60 days and directing parties to file supplemental briefs by May 15, 2017, addressing whether the rule should be remanded to the EPA rather than be suspended. Neither the Executive Order nor the court's order changes the current status of the CPP, which is under a legal hold by the U.S. Supreme Court. The EPA has not announced a schedule for completing its review. Duke Energy Kentucky cannot predict the outcome of these matters.

Compliance with CPP could cause the industry to replace coal-fired generation with natural gas and renewables. Costs to operate coal-fired generation plants continue to grow due to increasing environmental compliance requirements, including ash management costs unrelated to CPP, which may result in the retirement of coal-fired generation plants earlier than the current useful lives. If the CPP is ultimately upheld by the courts and implementation goes forward, Duke Energy Kentucky could incur increased fuel, purchased power, operation and maintenance and other costs for replacement generation as a result of this rule. Due to the uncertainties related to the implementation of the CPP, Duke Energy Kentucky cannot predict the outcome of these matters. Duke Energy Kentucky continues to evaluate the need to retire generating facilities and plans to seek regulatory recovery, where appropriate, for amounts that have not been recovered upon asset retirements. However, recovery is subject to future regulatory approval, including the recovery of carrying costs on remaining book values, and therefore cannot be assured.

Litigation

Duke Energy Kentucky is involved in other legal, tax and regulatory proceedings arising in the ordinary course of business, some of which involve significant amounts. Duke Energy Kentucky believes the final disposition of these proceedings will not have a material effect on its results of operations, cash flows or financial position. Duke Energy Kentucky expenses legal costs related to the defense of loss contingencies as incurred.

II. PROPOSED OFFERING

1. *SUMMARY OF PROPOSED OFFERING*

Duke Energy Kentucky proposes to issue $90 million of Senior Unsecured Debentures (the "Securities"). The Company reserves the right to increase or decrease the size of the issue. The Securities contemplated will be issued with final bullet maturities between 12 and 30 years. The Company reserves the right to consider additional maturities and structures. Interest on the Debentures will be payable semi-annually in arrears.

The Company will use the proceeds from the sale of the Securities for capital expenditures, to refinance short-term debt (consisting of money pool borrowings), and for general corporate purposes.

The Securities have not been pre-rated by the SVO of the NAIC and will not be rated prior to closing.

The Company proposes to issue the Securities pursuant to the terms and conditions outlined in the Summary Term Sheet included in Section V. The Summary Term Sheet provides an outline of relevant terms and conditions contained in a debenture purchase agreement to be entered into between the Company and the purchasers therein (the "Debenture Purchase Agreement"). To the extent a difference exists between the Summary Term Sheet and the Debenture Purchase Agreement, the Debenture Purchase Agreement will govern. Prospective noteholders' counsel will be Ed Pelican at Chapman & Cutler LLP (epelican@chapman.com; 312-845-3861).

The Placement Agent and its affiliates provide various investment banking, commercial banking and financial advisory services to the Company and its affiliates. An affiliate of the Placement Agent is a lender under the Duke Energy Master Credit Facility (as defined herein).

Transaction Timetable

The transaction will fund on September 7, 2017.

May 2017					June 2017					September 2017				
M	T	W	Th	F	M	T	W	Th	F	M	T	W	Th	F
1	2	**3**	4	5				**1**	**2**					1
8	9	10	11	12	5	6	7	**8**	9	4	5	6	7	8
15	16	17	18	19	12	13	**14**	15	16	11	12	13	14	15
22	23	24	25	26	19	20	21	22	23	18	19	**20**	21	22
29	30	31			26	27	28	29	30	25	26	27	28	29

Eco Event   Launch Transaction   Circle & Price   Close & Fund

2. *PRO FORMA CAPITALIZATION*

Below is the Company's pro forma capitalization as of March 31, 2017:

PRO FORMA CAPITALIZATION

($ in Millions)		As of March 31, 2017		Senior Notes Adjustments		Pro Forma March 31, 2017
Cash and Cash Equivalents	$	8.2	$	80.8	$	89.0
Usecured Debt				-		-
4.650% Senior Notes due 2019		100.0		-		100.0
3.420% Senior Notes due 2026		45.0		-		45.0
6.200% Senior Notes due 2036		65.0		-		65.0
4.450% Senior Notes due 2046		50.0		-		50.0
Capital leases due 2018 - 2020		2.0		-		2.0
Tax-exempt bonds due 2027		76.7		-		76.7
Money pool borrowings		34.2		(9.2)		25.0
Commercial Paper		-		-		-
Unamortized debt discount and premium, net		(0.3)		-		(0.3)
Unamortized debt issuance costs		(1.4)		-		(1.4)
New Private Placement Senior Notes		-		90.0		90.0
Total Debt		*371.2*		80.8		*452.0*
Total Common Stock Equity		449.4		-		449.4
Total Book Capitalization		*820.6*		*80.8*		*901.4*
Credit Statistics						
Total Debt / Total Book Capitalization		45.2%				50.1%

Source: the Company

3. *LIQUIDITY*

In March 2017, Duke Energy amended its credit agreement to increase its capacity from $7.5 billion to $8 billion, and to extend the termination date of the facility from January 30, 2020, to March 16, 2022 (the "Master Credit Facility"). Duke Energy Kentucky has borrowing capacity under the Master Credit Facility up to a specified sublimit. Duke Energy has the unilateral ability at any time to increase or decrease Duke Energy Kentucky's borrowing sublimit, subject to a maximum sublimit. The amount available to Duke Energy Kentucky under the Master Credit Facility may be reduced to backstop issuances of commercial paper, certain letters of credit and variable-rate demand tax-exempt bonds that may be put to Duke Energy Kentucky at the option of the holder. At March 31, 2017, Duke Energy Kentucky had a borrowing sublimit of $150 million and available capacity of $120 million under the Master Credit Facility. The Master Credit Facility contains a covenant requiring Duke Energy Kentucky's debt-to-total capitalization ratio to not exceed 65 percent. Duke Energy Kentucky also maintains access to funding from Duke Energy's commercial paper program through an intercompany money pool arrangement.

Duke Energy Kentucky is a borrower under a bilateral letter of credit agreement expiring February 2019. Duke Energy Kentucky may request the issuance of letters of credit up to $27 million, on its behalf to support various series of tax-exempt bonds. This credit facility may not be used for any purpose other than to support certain tax-exempt bonds.

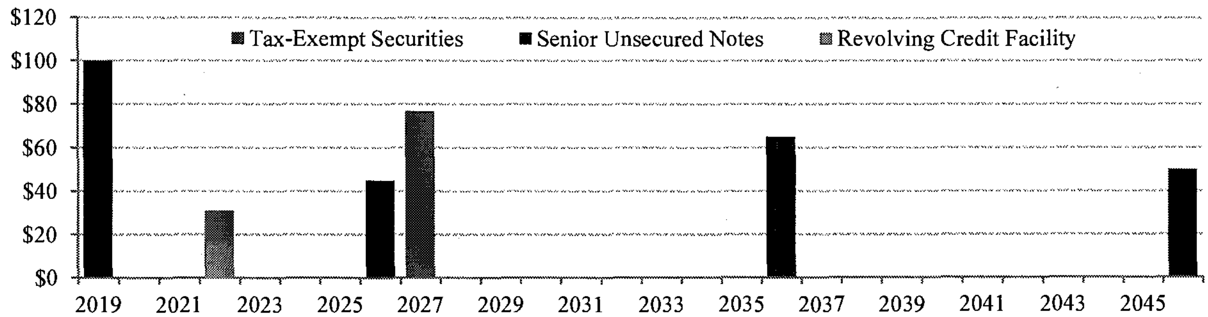
In January 2016, Duke Energy Kentucky issued $95 million of unsecured debentures, of which $45 million carry a fixed interest rate of 3.42 percent and mature January 15, 2026, and $50 million carry a fixed interest rate of 4.45 percent and mature January 15, 2046. Proceeds were used to refinance existing debt (including money pool borrowings), for capital expenditures, and for general corporate purposes.

Duke Energy Kentucky also has regulatory restriction requiring it to maintain an equity-to-total capitalization ratio of at least 35 percent, and limiting any dividend payments to the amount of Duke Energy Kentucky's retained earnings.

4. *LONG-TERM DEBT MATURITY SCHEDULE*

Below is the Company's long-term debt maturity schedule as of March 31, 2017:

DUKE ENERGY KENTUCKY LONG-TERM DEBT MATURITY SCHEDULE



Source: the Company

Note: $ in millions; table excludes capital leases

Duke Energy Kentucky has the ability under the terms of certain debt obligations to call and repay the obligation prior to its scheduled maturity; therefore, the actual timing of future cash prepayments could be materially different than as presented above.

Additionally, $50 million of the pollution control bonds maturing in 2027 are subject to mandatory tender for purchase on November 1, 2021, at which time it is anticipated such bonds will be remarketed to subsequent purchasers pursuant to their terms.

III. INVESTMENT CONSIDERATIONS

1. *LOW BUSINESS RISK*

Duke Energy Kentucky operates a relatively low-risk electric and natural gas business within a constructive regulatory environment in Kentucky. Regulatory policies allow for monthly fuel adjustments and permit recovery of certain environmental costs and a cash return on associated CWIP. Duke Energy Kentucky is also permitted to recover the costs of energy-efficiency programs.

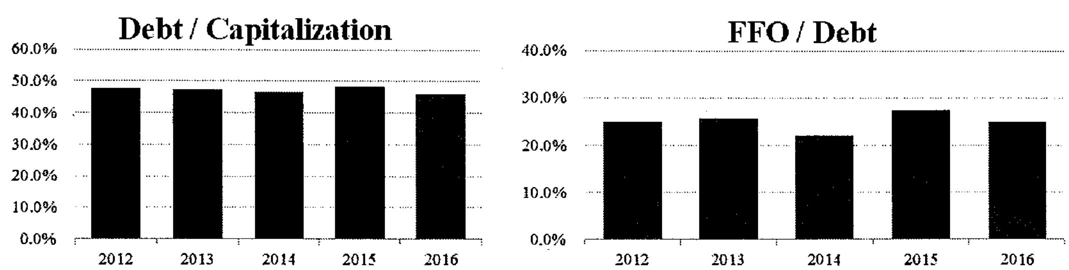
2. *SUPPORTIVE REGULATORY ENVIRONMENT*

Kentucky regulation is relatively constructive from an investor perspective according to the Regulatory Research Associates ("RRA"), which rates Kentucky as "Average 1". Rate cases have historically been resolved via settlements, and authorized equity returns tend to approximate prevailing nationwide industry averages at the time established. KPSC has approved the use of incentive mechanisms for several utilities that provide the companies an opportunity to retain a portion of commodity cost savings versus a benchmark and/or a portion of the margins associated with off-system sales and capacity release activities.

3. *STRONG FINANCIAL METRICS*

The following charts illustrate Duke Energy Kentucky's Debt / Capitalization and FFO / Debt over the past five years.

DUKE ENERGY KENTUCKY CREDIT METRICS



Source: Company information

Note: Debt/Capitalization calculated as total debt / total capitalization and FFO / Debt calculated as cash from operations, less changes in working capital, less asset retirement obligation costs (after-tax amount calculated using a 38% tax rate as a simplifying assumption) / total debt.

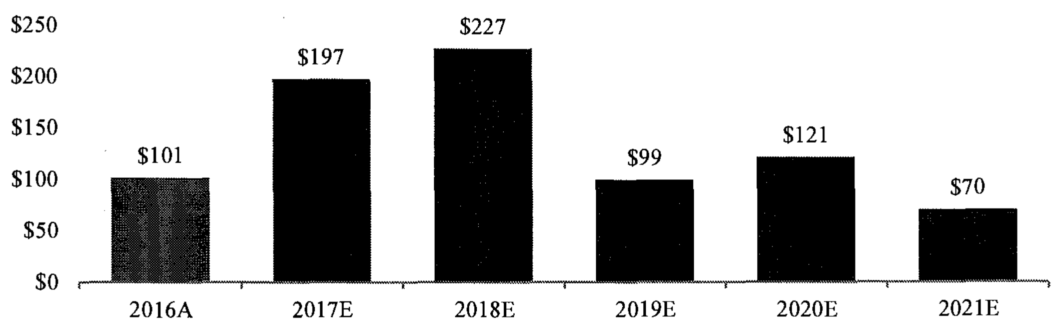
4. *EXPERIENCED UTILITY MANAGEMENT AND KEY MEMBER OF VERTICALLY INTEGRATED UTILITY SYSTEM*

Duke Energy, the ultimate parent of Duke Energy Kentucky, is one of the largest utility holding companies in the United States. The Duke Energy system operates as an integrated utility system whereby member companies have contractual, financial and other business relationships with other member companies, subject to regulatory oversight. As a subsidiary, Duke Energy Kentucky can leverage Duke Energy's utility management team. The Company is led by a solid group of senior executives with an average of 21 years of experience at Duke Energy.

5. *MODERATE CAPITAL EXPENDITURES*

Projected capital requirements average approximately $140 million over the next five years and are expected to be funded largely with internally generated cash. No capex for new generation is anticipated through 2021, other than an approximate $15 million solar investment.

DUKE ENERGY KENTUCKY HISTORICAL AND PROJECTED CAPITAL EXPENDITURES



Source: the Company
Note: $ in Thousands

IV. RISK FACTORS

You should carefully consider the risks described below, as well as other information contained in this Executive Summary, before buying any Securities. The risks described in this section are those that we consider to be the most significant to your decision whether to invest in the Securities. If any of the events described below occurs, our business, financial condition or results of operations could be materially harmed. In addition, we may not be able to make payments on the Securities, and this could result in your losing all or part of your investment. Furthermore, additional risks that we do not know about or that we currently view as immaterial may also impact our business or adversely affect our ability to make payments on the Securities.

Regulatory, Legislative and Legal Risks

Our regulated electric and gas revenues, earnings and results are dependent on state legislation and regulation that affect electric generation, transmission, distribution and related activities and gas sales and transportation, which may limit our ability to recover costs.

Our regulated utility businesses are regulated on a cost-of-service/rate-of-return basis subject to the statutes of Kentucky and the rules and procedures of the Kentucky Public Service Commission ("KPSC"). If our regulated utility earnings exceed the returns established by the KPSC, our retail rates may be subject to review and possible reduction by the KPSC, which may decrease our future earnings. Additionally, if regulatory bodies do not allow recovery of costs incurred in providing service on a timely basis, our future earnings could be negatively impacted.

If legislative and regulatory structures were to evolve in such a way that our exclusive rights to serve our regulated customers were eroded, our future earnings could be negatively impacted.

Deregulation or restructuring in the electric industry may result in increased competition and unrecovered costs that could adversely affect our financial position, results of operations or cash flows and our utility businesses.

Increased competition resulting from deregulation or restructuring legislation could have a significant adverse impact on our results of operations, financial position, or cash flows. Retail competition and the unbundling of regulated electric service could have a significant adverse financial impact on us due to an impairment of assets, a loss of retail customers, lower profit margins or increased costs of capital. We cannot predict the extent and timing of entry by additional competitors into the electric markets. We cannot predict if or when we will be subject to changes in legislation or regulation, nor can we predict the impact of these changes on our financial position, results of operations or cash flows.

Our businesses are subject to extensive federal regulation that will affect our operations and costs.

We are subject to regulation by the Federal Energy Regulatory Commission ("FERC"), the U.S. Environmental Protection Agency ("EPA") and various other federal agencies as well as the North American Electric Reliability Corporation. Regulation affects almost every aspect of our businesses, including, among other things, our ability to: take fundamental business management actions; determine the terms and rates of transmission and distribution services; make acquisitions; issue equity or debt securities; engage in transactions with other subsidiaries and affiliates; and pay dividends upstream to the our ultimate parent, Duke Energy. Changes to federal regulations are continuous and ongoing. We cannot predict the future course of regulatory changes or the ultimate effect those changes will have on our businesses. However, changes in regulation can cause delays in or affect business planning and transactions and can substantially increase our costs.

We are subject to numerous environmental laws and regulations requiring significant capital expenditures that can increase the cost of operations, and which may impact or limit business plans, or cause exposure to environmental liabilities.

We are subject to numerous environmental laws and regulations affecting many aspects of our present and future operations, including coal combustion residuals ("CCRs"), air emissions, water quality, wastewater discharges, solid waste and hazardous waste. These laws and regulations can result in increased capital, operating and other costs. These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Compliance with environmental laws and regulations can require significant expenditures, including expenditures for cleanup costs and damages arising from contaminated properties. Failure to comply with environmental regulations may result in the imposition of fines, penalties and injunctive measures affecting operating assets. The steps we could be required to take to ensure our facilities are in compliance could be prohibitively expensive. As a result, we may be required to shut down or alter the operation of our facilities, which may cause us to incur losses. Further, we may not be successful in recovering capital and operating costs incurred to comply with new environmental regulations through existing regulatory rate structures and our contracts with customers. Also, we may not be able to obtain or maintain from time to time all required environmental regulatory approvals for our operating assets or development projects. Delays in obtaining any required environmental regulatory approvals, failure to obtain and comply with them or changes in environmental laws or regulations to more stringent compliance levels could result in additional costs of operation for existing facilities or development of new facilities being prevented, delayed or subject to additional costs. Although it is not expected that the costs to comply with current environmental regulations will have a material adverse effect on our financial position, results of operations or cash flows due to regulatory cost recovery, we are at risk that the costs of complying with environmental regulations in the future will have such an effect.

The EPA has recently enacted or proposed new federal regulations governing the management of cooling water intake structures, wastewater and carbon dioxide (CO_2) emissions. These regulations may require us to make additional capital expenditures and increase operating and maintenance costs.

Operational Risks

Our results of operations may be negatively affected by overall market, economic and other conditions that are beyond our control.

Sustained downturns or sluggishness in the economy generally affect the markets in which we operate and negatively influence our operations. Declines in demand for electricity and gas as a result of economic downturns in our regulated service territories will reduce overall sales and lessen cash flows, especially as industrial customers reduce production and, therefore, consumption of electricity and gas. Although our regulated electric and gas businesses are subject to regulated allowable rates of return and recovery of certain costs, such as fuel and gas, under periodic adjustment clauses, overall declines in electricity and gas sold as a result of economic downturn or recession could reduce revenues and cash flows, thereby diminishing results of operations. Additionally, prolonged economic downturns that negatively impact our results of operations and cash flows could result in future material impairment charges to write-down the carrying value of certain assets to their respective fair values.

Factors that could impact sales volumes, generation of electricity and market prices at which we are able to sell electricity are as follows:

- weather conditions, including abnormally mild winter or summer weather that cause lower energy usage for heating or cooling purposes, respectively, and periods of low rainfall that decrease the ability to operate facilities in an economical manner;
- supply of and demand for energy commodities;
- availability of competitively priced alternative energy sources, which are preferred by some customers over electricity produced from coal, nuclear or gas plants, and customer usage of energy efficient equipment that reduces energy demand;
- natural gas prices;
- ability to procure satisfactory levels of inventory, such as coal and gas; and
- capacity and transmission service into, or out of, our markets.

Natural disasters or operational accidents may adversely affect our operating results.

Natural disasters (such as electromagnetic events or the 2011 earthquake and tsunami in Japan) or other operational accidents within the company or industry (such as the San Bruno, California natural gas transmission pipeline failure) could have direct significant impacts on us as well as on key contractors and suppliers. Such events could indirectly impact us through changes to policies, laws and regulations whose compliance costs have a significant impact on our financial position, results of operations and cash flows.

Coal ash storage and management strategies to comply with CCR regulations could impact on our reputation and financial condition.

As a result of electricity produced at our coal-fired power plant, we manage large amounts of CCRs, typically combined with water in ash basins. The potential exists for a coal ash pond failure or coal ash related incident that could impact the environment or raise general public health concerns. Such an incident could have a material adverse impact to our reputation and financial condition.

Recent regulations for the disposal of CCRs from power plants by the EPA became effective in 2015. These regulations classify CCR as nonhazardous waste under the RCRA and apply to all new and existing landfills, new and existing surface impoundments, structural fills and CCR piles and establish requirements regarding landfill design, structural integrity and assessment criteria for surface impoundments, groundwater monitoring and protection procedures and other operational and reporting procedures to ensure the safe disposal and management of CCR. Duke Energy Kentucky recorded an asset retirement obligation in the second quarter of 2015 as a result of such CCR regulations. In addition to federal CCR regulations, CCR landfills and surface impoundments will continue to be independently regulated by most states and additional regulations by states may be imposed in the future. These regulations may require additional capital expenditures, increased operating and maintenance costs, or closure of certain facilities which could affect our financial position, results of operations and cash flows. Although we intend to seek cost recovery for future expenditures through the normal ratemaking process with the KPSC, which permits recovery of necessary and prudently incurred costs associated with our regulated operations, there is no guarantee that recovery of such costs will be granted.

Our financial position, results of operations and cash flows may be negatively affected by a lack of growth or slower growth in the number of customers, or decline in customer demand or number of customers.

Growth in customer accounts and growth of customer usage each directly influence demand for electricity and the need for additional power generation and delivery facilities. Customer growth and customer usage are affected by a number of factors outside our control, such as mandated energy efficiency measures, demand-side management goals, distributed generation resources and economic and demographic conditions, such as population changes, job and income growth, housing starts, new business formation and the overall level of economic activity.

Certain regulatory and legislative bodies have introduced or are considering requirements and/or incentives to reduce energy consumption by certain dates. Additionally, technological advances driven by federal laws mandating new levels of energy efficiency in end-use electric devices or other improvements in or applications of technology could lead to declines in per capita energy consumption.

Advances in distributed generation technologies that produce power, including fuel cells, micro-turbines, wind turbines and solar cells, may reduce the cost of alternative methods of producing power to a level competitive with central power station electric production utilized by us.

Some or all of these factors, could result in a lack of growth or decline in customer demand for electricity or number of customers, and may cause the failure of us to fully realize anticipated benefits from significant capital investments and expenditures which could have a material adverse effect on our financial position, results of operations and cash flows.

Furthermore, we currently have energy efficiency riders in place to recover the cost of energy efficiency programs in Kentucky. Should we be required to invest in conservation measures that result in reduced sales from effective conservation, regulatory lag in adjusting rates for the impact of these measures could have a negative financial impact.

Our operating results may fluctuate on a seasonal and quarterly basis and can be negatively affected by changes in weather conditions and severe weather.

Electric power generation and the sale and transportation of natural gas are generally seasonal businesses. In most parts of the U.S. and in markets in which we operate, demand for power peaks during the warmer summer months and demand for natural gas peaks during the cold winter months, with market prices typically peaking during the warmer summer months for electricity and during the cold winter months for natural gas. Further, extreme weather conditions such as heat waves or winter storms could cause these seasonal fluctuations to be more pronounced. As a result, in the future, the overall operating results of our businesses may fluctuate substantially on a seasonal and quarterly basis and thus make period-to-period comparison less relevant.

Sustained severe drought conditions could impact generation by our fossil fuel plants, as these facilities use water for cooling purposes and for the operation of environmental compliance equipment. Furthermore, destruction caused by severe weather events, such as hurricanes, tornadoes, severe thunderstorms, snow and ice storms, can result in lost operating revenues due to outages; property damage, including downed transmission and distribution lines; and additional and unexpected expenses to mitigate storm damage. The cost of storm restoration efforts may not be fully recoverable through the regulatory process.

Our sales may decrease if we are unable to gain adequate, reliable and affordable access to transmission assets.

We depend on transmission and distribution facilities owned and operated by utilities and other energy companies to deliver electricity sold to the wholesale market. FERC's power transmission regulations require wholesale electric transmission services to be offered on an open-access, non-discriminatory basis. If transmission is disrupted, or if transmission capacity is inadequate, our ability to sell and deliver products may be hindered.

The different regional power markets have changing regulatory structures, which could affect growth and performance in these regions. In addition, the independent system operators who oversee the transmission systems in regional power markets have imposed in the past, and may impose in the future, price limitations and other mechanisms to address volatility in the power markets. These types of price limitations and other mechanisms may adversely impact the profitability of our wholesale power marketing business.

Fluctuations in commodity prices or availability may adversely affect various aspects of our operations as well as our financial condition, results of operations and cash flows.

We are exposed to the effects of market fluctuations in the price of natural gas, coal, electricity and other energy-related commodities as a result of our ownership of energy-related assets. Fuel and gas costs are recovered primarily through cost-recovery clauses, subject to the approval of the KPSC. In the event of a forced outage, recovery of replacement power costs in Kentucky is limited to the cost of the unit for which a forced outage occurred. Therefore, Duke Energy Kentucky could have unrecoverable replacement power costs in the event of a forced outage.

Additionally, we are exposed to risk that counterparties will not be able to fulfill our obligations. Disruption in the delivery of fuel, including disruptions as a result of, among other things, transportation delays, weather, labor relations, force majeure events, or environmental regulations affecting any of these fuel suppliers, could limit the operation of our facilities. Should counterparties fail to perform, we might be forced to replace the underlying commitment at prevailing market prices possibly resulting in unrecoverable losses in addition to the amounts, if any, already paid to the counterparties.

Certain of our hedge agreements may result in the receipt of, or posting of, derivative collateral with counterparties, depending on the daily derivative position. Fluctuations in commodity prices that lead to the return of collateral received and/or the posting of collateral with counterparties negatively impact liquidity. Downgrades in our credit ratings could lead to additional collateral posting requirements. We continually monitor derivative positions in relation to market price activity.

Potential terrorist activities or military or other actions could adversely affect our businesses.

The continued threat of terrorism and the impact of retaliatory military and other action by the U.S. and its allies may lead to increased political, economic and financial market instability and volatility in prices for natural gas and oil, which may have material adverse effects in ways we cannot predict at this time. In addition, future acts of terrorism and possible reprisals as a consequence of action by the U.S. and its allies could be directed against companies operating in the U.S. or our international affiliates. Information technology systems, transmission and distribution and generation facilities such as nuclear plants could be potential targets of terrorist activities or harmful activities by individuals or groups. The potential for terrorism has subjected our operations to increased risks and could have a material adverse effect on our businesses. In particular, we may experience increased capital and operating costs to implement increased security for our information technology systems, transmission and distribution and generation facilities. These increased costs could include additional physical plant security and security personnel or additional capability following a terrorist incident.

Cyberattacks and data security breaches could adversely affect our businesses.

Information security risks have generally increased in recent years as a result of the proliferation of new technologies and the increased sophistication and frequency of cyberattacks and data security breaches. The utility industry requires the continued operation of sophisticated information technology systems and network infrastructure, which are part of an interconnected regional grid. Additionally, connectivity to the Internet continues to increase through smart grid and other initiatives. Because of the critical nature of the infrastructure, increased connectivity to the

Internet and technology systems' inherent vulnerability to disability or failures due to hacking, viruses, acts of war or terrorism or other types of data security breaches, we face a heightened risk of cyberattack. In the event of such an attack, we could (i) have business operations disrupted, property damaged, customer information stolen and other private information accessed (ii) experience substantial loss of revenues, repair and restoration costs, implementation costs for additional security measures to avert future cyberattacks and other financial loss, and (iii) be subject to increased regulation, litigation and reputational damage.

Failure to attract and retain an appropriately qualified workforce could unfavorably impact our results of operations.

Certain events, such as an aging workforce, mismatch of skill set or complement to future needs, or unavailability of contract resources may lead to operating challenges and increased costs. The challenges include lack of resources, loss of knowledge base and the lengthy time required for skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, may rise. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to new employees, or future availability and cost of contract labor may adversely affect the ability to manage and operate the business, especially considering the workforce needs associated with nuclear generation facilities. If we are unable to successfully attract and retain an appropriately qualified workforce, our financial position or results of operations could be negatively affected.

Our membership in a Regional Transmission Organization (an "RTO") presents risks that could have a material adverse effect on our results of operations, financial condition and cash flows.

The rules governing the various regional power markets may change, which could affect our costs and/or revenues. To the degree we incur significant additional fees and increased costs to participate in an RTO, our results of operations may be impacted. We may be allocated a portion of the cost of transmission facilities built by others due to changes in RTO transmission rate design. We may be required to expand our transmission system according to decisions made by an RTO rather than our own internal planning process. While RTO transmission rates were initially designed to be revenue neutral, various proposals and proceedings currently taking place by the FERC may cause transmission rates to change from time to time. In addition, RTOs have been developing rules associated with the allocation and methodology of assigning costs associated with improved transmission reliability, reduced transmission congestion and firm transmission rights that may have a financial impact on us.

As a member of an RTO, we are subject to certain additional risks, including those associated with the allocation among RTO members, of losses caused by unreimbursed defaults of other participants in the RTO markets and those associated with complaint cases filed against an RTO that may seek refunds of revenues previously earned by RTO members.

Capital expenditure costs could materially differ from those projected

Construction risks associated with the completion of the Company's capital investment projects in existing generation facilities, including risks related to obtaining and complying with terms of permits, meeting construction budgets and schedules, and satisfying operating and environmental performance standards could cause costs to differ materially from those projected.

Liquidity and Capital Requirements Risks

We rely on access to short-term borrowings and longer-term capital markets to finance our capital requirements and support our liquidity needs. Access to those markets can be adversely affected by a number of conditions, many of which are beyond our control.

Our businesses are financed to a large degree through debt. The maturity and repayment profile of debt used to finance investments often does not correlate to cash flows from our assets. Accordingly, as a source of liquidity for capital requirements not satisfied by the cash flow from our operations and to fund investments originally financed through debt instruments with disparate maturities, we rely on access to short-term money markets as well as longer-term capital markets. We also rely on access to short-term intercompany borrowings. If we are not able to access capital at competitive rates or at all, the ability to finance our operations and implement our strategy and business plan as scheduled could be adversely affected. An inability to access capital may limit our ability to pursue improvements or acquisitions that we may otherwise rely on for future growth.

Market disruptions may increase the cost of borrowing or adversely affect the ability to access one or more financial markets. Such disruptions could include: economic downturns, the bankruptcy of an unrelated energy company, capital market conditions generally, market prices for electricity and gas, actual or threatened terrorist attacks, or the overall health of the energy industry. The availability of credit under Duke Energy's Master Credit Facility depends upon the ability of the banks providing commitments under the facility to provide funds when our obligations to do so arise. Systematic risk of the banking system and the financial markets could prevent a bank from meeting its obligations under the facility agreement.

Duke Energy maintains a revolving credit facility to provide backup for its commercial paper program and letters of credit to support variable rate demand tax-exempt bonds that may be put to its affiliate issuers (including Duke Energy Kentucky) at the option of the holder. The facility includes a borrowing sublimit for Duke Energy Kentucky, and financial covenants that limit the amount of debt that can be outstanding as a percentage of the total capital for the specific entity. Failure to maintain these covenants could preclude us from having letters of credit issued on our behalf or from making borrowings under the Master Credit Facility.

We must meet credit quality standards and there is no assurance we will maintain investment grade credit ratings.

Our senior long-term debt is currently rated investment grade by various rating agencies. We cannot ensure our senior long-term debt will be rated investment grade in the future.

If the rating agencies were to rate us below investment grade, borrowing costs would increase, perhaps significantly. In addition, the potential pool of investors and funding sources would likely decrease. Any downgrade or other event negatively affecting our credit ratings could also increase Duke Energy's need to provide liquidity in the form of capital contributions or loans, thus reducing the liquidity and borrowing availability of the Duke Energy consolidated group. These events would likely reduce our liquidity and profitability and could have a material effect on our financial position, results of operations or cash flows.

Non-compliance with debt covenants or conditions could adversely affect our ability to execute future borrowings.

Our debt and credit agreements contain various financial and other covenants. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements.

Poor investment performance of the Duke Energy pension plan holdings and other factors impacting pension plan costs could unfavorably impact our liquidity and results of operations.

The costs of providing non-contributory defined benefit pension plans are dependent upon a number of factors, such as the rates of return on plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plans, future government regulation and required or voluntary contributions made to the plans. Duke Energy Kentucky is allocated a proportionate share of the cost and obligations related to these plans. Without sustained growth in the pension investments over time to increase the value of plan assets and, depending upon the other factors impacting costs as listed above, Duke Energy could be required to fund its plans with significant amounts of cash. Such cash funding obligations, and our proportionate share of such cash funding obligations, could have a material impact on our financial position, results of operations or cash flows.

Risk Factors Relating to the Securities

Our ability to satisfy our obligations with respect to the Securities will depend or our future operating performance, results of operations, cash flows and financial position.

Our future operating performance, results of operations, cash flows and financial position are subject, in part, to factors beyond our control, including interest rates, commodity prices, general economic conditions and financial and business conditions. If we are unable to generate sufficient operating cash flows to service our debt, including the Securities, we may be required to obtain additional financing or take other actions to generate sufficient funds, which could have a material adverse effect on our financial position, results of operations or cash flows.

The Securities could be impacted by various transactions.

The indenture under which the Securities will be issued does not prohibit us from entering into various transactions, including acquisitions, change of control transactions, refinancings, recapitalizations or other highly leveraged transactions that could increase the amount of our outstanding indebtedness, or adversely affect our capital structure or credit ratings, or otherwise adversely affect holders of the Securities. As a result, we may enter into a transaction even though the transaction could increase the total amount of outstanding indebtedness, adversely affect our capital structure or credit ratings or otherwise adversely affect the holders of the Securities.

Sales or other transfers of the Securities are regulated by federal securities law.

The Securities are being offered and sold pursuant to an exemption from registration under federal and applicable state securities laws. Therefore, you may transfer or resell the Securities in the United States only in a transaction registered under, or exempt from the registration requirements of, federal and applicable state securities laws.

V. SUMMARY OF PROPOSED TERMS & CONDITIONS

Duke Energy Kentucky, Inc. will issue Senior Unsecured Debentures, Series [X] (the "Securities"). The Securities will be issued under a supplemental indenture to The Union Light, Heat and Power Company (now known as Duke Energy Kentucky, Inc.) Indenture dated as of December 1, 2004 (as amended and supplemented, the "Indenture").

The forms of the Debenture Purchase Agreement and Supplemental Indenture and a copy of the Indenture will be included with the Executive Summary. In the event of any inconsistency between the Summary of Proposed Terms and the aforementioned Debenture Purchase Agreement, Supplemental Indenture or Indenture, such Debenture Purchase Agreement, Supplemental Indenture or Indenture will govern, as the case may be. Investors submitting "circles" for the transaction contemplated hereby will be deemed to have reviewed and accepted such Debenture Purchase Agreement, Supplemental Indenture and Indenture (including in-house counsel review). Capitalized terms not defined herein shall bear the meaning set forth in the aforementioned Debenture Purchase Agreement, Supplemental Indenture or Indenture, as the case may be. Questions in respect of such documents should be referred to Ed Pelican (312) 845-3861, epelican@chapman.com, at Chapman and Cutler LLP who is requested to serve as special investor's counsel for the debenture issuance.

Issuer:	Duke Energy Kentucky, Inc. (the *"Company"*).
Issue:	Senior Unsecured Debentures (the *"Securities"*)
Amount:	$90,000,000
Final Maturity:	12 and 30 year bullet maturities ("12 year Securities" and "30 year Securities", respectively).
Ranking/Priority:	The Securities will be senior unsecured debt and will rank *pari passu* with all other senior unsecured debt of the Company.
Investor:	One or more institutional investors (the "Investors").
Plan of Distribution:	The Securities will be offered as a private placement to Investors and will not be registered under the Securities Act of 1933.
Use of Proceeds:	The Company will use the proceeds from the sale of the Securities for capital expenditures, to refinance short-term debt (consisting of money pool borrowings), and for general corporate purposes.
Coupon:	The 12 year Securities will bear interest at a fixed rate per annum equal to the yield on the on-the-run UST for a 12-year maturity (the 2.375% UST due May 2027) and the 30 year Securities will bear interest at a fixed rate per annum equal to the yield on the old long bond for a 30-year maturity (the 3.000% UST due February 2047) plus a number of basis points to be determined on the pricing date.
Interest Payments:	Interest will be payable semi-annually in arrears and calculated on the basis of a 360-day year of twelve 30-day months.

Optional Redemption	The 12 year Securities are redeemable in whole or in part at any time three months prior to the maturity date and the 30 year Securities are redeemable in whole or in part at any time six months prior to the maturity date. In the event of redemption, the Company will pay accrued interest to the date set for redemption plus the greater of: i) par, or ii) the present value of all remaining interest and principal payments due on the Securities being redeemed, discounted at the then current yield on the U.S. Treasury Security of a comparable maturity to the remaining weighted average life of the Securities plus fifty (50) basis points. The Company may elect to redeem (i) the 12 year Securities three months prior to the maturity date and (ii) the 30 year Securities six months prior to the maturity date, and will do so at a redemption price equal to one hundred percent of the principal amount of the series being redeemed, plus accrued and unpaid interest without make whole.
Representations and Warranties:	Standard for this market as set forth in the Debenture Purchase Agreement but to include and not be limited to: Organization, Power and Authority; Authorization; Disclosure; Organization; Financial Statements; Compliance with Law; Governmental Authorizations; Litigation; Taxes; Title to Property; Licenses; Compliance with ERISA; Private Offering; Use of Proceeds; Existing Indebtedness; Foreign Assets; Status under certain Statutes; and Pari Passu status.
Information as to Company	As set forth in the Supplemental Indenture, the Company will provide unaudited quarterly consolidated financial statements and annual audited consolidated financial statements. Each financial statement will be accompanied by a certificate from a senior financial officer.
Affirmative Covenants	As set forth in the Indenture to include but not limited to: Payment of Principal; Maintenance of Office; Maintenance of Properties; Payment of Taxes. Standard for this market as set forth in the Supplemental Indenture but to include and not be limited to: Compliance with Laws; Insurance; Existence; Books and Records; Subsidiary Guarantors.
Negative Covenants:	As set forth in the Supplemental Indenture and the Indenture: Line of Business; Terrorism Sanctions Regulations and Negative Pledge.
Negative Pledge:	The Company will not incur or permit to exist any mortgage, lien, pledge, security interest or other encumbrance not otherwise excepted under the Indenture without equally and ratably securing the Securities, if immediately after that creation or assumption, the principal amount of the

Indebtedness for borrowed money of the Company that all such other mortgages, liens, pledges, security interests and other encumbrances secure does not exceed an amount equal to 10% of the Company's total assets as shown on its balance sheet for the accounting period occurring immediately before the creation or assumption of that mortgage, lien, pledge, security interest or other encumbrance.

Events of Default / Remedies:

As set forth in the Indenture including, without limitation: the Company fails to pay interest when due, subject to a 30 day grace period; failure to pay any principal or premium, when due; defaults in the performance or compliance with the covenants as outlined in the Indenture subject to a 90 day grace period after notice; bankruptcy

As well as set forth in the Supplemental Indenture including, without limitation

(a) the Company defaults in the performance or compliance with the negative covenants as outlined in the Supplemental Indenture;

(b) the Company makes any written representation or warranty in connection with the issuance of any series of Securities that proves to have been false or incorrect in any material respect on the date as of which made;

(c) (i) the Company or any Subsidiary is in default in the payment of any principal, premium, or interest of any Indebtedness in the aggregate amount of at least $50,000,000 as and when due and payable and the continuation of such default beyond the period of grace, if any, allowed with respect thereto, or (ii) the Company or any Subsidiary is in default in the performance or compliance with any Indebtedness exceeding the principal amount, in aggregate, equal to at least $50,000,000 and as a consequence of such default or condition such Indebtedness has become, or has been declared, due and payable before its stated maturity;

(d) the Company or any Subsidiary has rendered against it final judgments or orders for payment of money in aggregate exceeding $50,000,000, including without limitation, any such final order enforcing a binding arbitration decision and which judgments are not, within 60 days after entry thereof, bonded, discharged or stayed pending appeal, or are not discharged within 60 days after the expiration of such stay; provided, however, that in the case of any liability or obligation arising from the proceedings described in Note 2 of the Company's financial statements for the year ended December 31, 2016, under the heading "MVP," such judgments or orders shall not result in an Event of Default under this subsection so long as payment obligations in excess of $50,000,000 in a given year arising from such proceedings are bonded, vacated, satisfied, discharged or stayed pending appeal or similar proceedings within 60 days of the date upon which such payments are due;

(e) if any retirement plan shall fail to satisfy minimum funding requirements of ERISA, a notice of intent to terminate a retirement plan shall have been received by the Company, or the aggregate "amount of unfunded benefit liabilities" shall exceed an amount that could reasonably be expected to have a Material Adverse Effect;

(f) any Subsidiary Guaranty ceases to be in full force and effect.

Sole Placement Agent:	KeyBanc Capital Markets Inc.
Governing Law	New York
Expenses:	The Issuer will pay reasonable legal fees of investors' counsel, whether or not the transaction closes.

VI. HISTORICAL FINANCIAL STATEMENTS

1. *HISTORICAL INCOME STATEMENTS*

($ in Thousands)	Fiscal Year Ended December 31,				
	2012	**2013**	**2014**	**2015**	**2016**
Operating Revenues					
Electric	$ 340,632	$ 344,471	$ 368,894	$ 359,196	$ 346,124
Natural gas	90,353	107,005	124,403	102,354	90,216
Total operating revenues	430,985	451,476	493,297	461,550	436,340
Operating Expenses					
Fuel used in electric generation and purchased power	137,674	142,501	171,705	142,546	132,681
Cost of natural gas	37,548	45,916	59,826	41,610	32,611
Operation, maintenance and other	136,087	122,921	133,085	133,403	140,573
Depreciation and amortization	44,533	44,601	44,296	43,813	43,668
Property and other taxes	14,988	13,183	13,516	13,089	14,637
Impairment charges	-	-	-	-	-
Total operating expenses	370,830	369,122	422,428	374,461	364,170
Gains on Sales of Other Assets and Other, net	447	3,439	-	245	28
Operating Income	60,602	85,793	70,869	87,334	72,198
Other Income and Expenses, net	1,490	1,537	1,896	1,075	2,321
Interest Expense	17,520	15,989	16,345	14,172	14,888
Income Before Income Taxes	44,572	71,341	56,420	74,237	59,631
Income Tax Expense	16,351	26,271	21,118	28,061	17,047
Net Income	$ 28,221	$ 45,070	$ 35,302	$ 46,176	$ 42,584
Key Metrics:					
Operating Margin	6.5%	10.0%	7.2%	10.0%	9.8%
EBITDA	$ 106,625	$ 131,931	$ 117,061	$ 132,222	$ 118,187
EBITDA Margin	24.7%	29.2%	23.7%	28.6%	27.1%

2. *HISTORICAL BALANCE SHEETS*

($ in Thousands, except share amounts)

	As of December 31,				
	2012	2013	2014	2015	2016
ASSETS					
Current Assets					
Cash and cash equivalents	$ 10,693	$ 13,038	$ 11,307	$ 9,141	$ 6,534
Receivables (net of allowance for doubtful accounts)	23,949	31,512	27,815	16,987	24,425
Inventory	38,591	41,667	52,900	44,141	49,037
Other	22,239	14,944	37,542	45,835	26,895
Totel current assets	95,472	101,161	129,564	116,104	106,891
Total investments and other assets	4,126	8,098	5,902	6,448	2,470
Property, Plant and Equipment					
Cost	1,728,326	1,741,308	1,711,836	2,079,761	2,116,219
Accumulated depreciation and amortization	(713,020)	(728,396)	(691,367)	(923,578)	(948,144)
Generation facilities to be retired, net	-	-	8,601	-	-
Net property, plant and equipment	1,015,306	1,012,912	1,029,070	1,156,183	1,168,075
Regulatory Assets and Deferred Debits					
Regulatory assets	55,610	41,437	47,694	61,411	92,462
Other	2,517	2,138	1,928	332	250
Total regulatory assets and deferred debits	58,127	43,575	49,622	61,743	92,712
Total Assets	$ 1,173,031	$ 1,165,746	$ 1,214,158	$ 1,340,478	$ 1,370,148
LIABILITIES AND COMMON STOCKHOLDER'S EQUITY					
Current Liabilities					
Accounts payable	$ 44,623	$ 43,740	$ 35,841	$ 40,080	$ 44,209
Notes payable to affiliated companies	-	-	37,609	55,743	19,656
Taxes accrued	11,959	10,306	14,483	10,550	14,082
Interest accrued	3,446	3,442	3,346	3,343	4,230
Current maturities of long-term debt	1,889	41,688	1,615	101,519	686
Other	25,865	20,852	18,350	21,928	30,734
Total current liabilities	87,782	120,028	111,244	233,163	113,597
Long-Term Debt	338,951	297,365	295,802	192,508	336,360
Long-Term Debt Payable to Affiliated Companies	-	-	25,000	25,000	25,000
Deferred Credits and Other Liabilities					
Deferred income taxes	242,787	257,220	271,308	289,642	311,636
Investment tax credits	1,009	1,304	1,095	-	-
Accrued pension and other post-retirement benefit costs	22,476	10,776	9,469	11,649	14,975
Asset retirement obligations	6,078	6,253	8,122	103,500	52,822
Regulatory liabilities	66,786	69,495	52,730	52,986	51,878
Other	34,277	25,351	26,132	27,598	26,865
Total deferred credits and other liabilities	373,413	370,399	368,856	485,375	458,176
Commitments and Contingencies					
Common Stockholder's Equity					
Common Stockholder's Equity	8,780	8,780	8,780	8,780	8,780
Additional paid-in-capital	167,494	167,494	167,494	167,494	167,494
Retained earnings	196,611	201,680	236,982	228,158	260,741
Total common stockholder's equity	372,885	377,954	413,256	404,432	437,015
Total Liabilities and Common Stockholder's Equity	$ 1,173,031	$ 1,165,746	$ 1,214,158	$ 1,340,478	$ 1,370,148

3. *HISTORICAL STATEMENTS OF CASH FLOWS*

($ in Thousands)

	Fiscal Year Ended December 31,				
	2012	2013	2014	2015	2016
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 28,221	$ 45,070	$ 35,302	$ 46,176	$ 42,584
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization	45,242	45,277	44,904	44,497	44,683
Community support and charitable contributions expense	660	-	-	-	-
Gains on sales of other assets and other, net	(447)	(3,439)	-	(245)	(28)
Impairment charges	-	-	-	-	-
Deferred income taxes	8,555	17,309	14,128	23,462	17,988
Accrued pension and other post-retirement benefit costs	1,854	3,065	2,122	2,152	1,527
Contributions to qualified pension plans	-	-	-	(2,203)	(1,443)
Payments for asset retirement obligations	-	-	-	(3,858)	(4,757)
(Increase) decrease in					
Net realized and unrealized mark-to-market and hedging transactions	(175)	81	-	-	-
Receivables	9,878	(7,622)	(8,504)	6,997	(7,464)
Inventory	(1,504)	(3,076)	(14,180)	9,017	(4,896)
Other current assets	(1,682)	4,225	(10,055)	(10,443)	15,180
Increase (decrease) in					
Accounts payable	(7,388)	(1,389)	(6,261)	(328)	(1,193)
Taxes accrued	(236)	(1,586)	3,496	2,645	7,028
Other current liabilities	838	(1,489)	(1,181)	1,743	8,235
Other assets	(2,375)	(1,770)	(9,661)	(10,207)	(8,862)
Other liabilities	3,080	(18,911)	(7,299)	527	14
Net cash provided by operating activities	84,521	75,745	42,811	109,932	108,596
CASH FLOWS FROM INVESTING ACTIVITIES					
Capital expenditures	(74,179)	(42,095)	(56,001)	(69,234)	(100,899)
Acquisitions	-	-	(10,596)	-	-
Net proceeds from the sales of other assets	-	10,397	-	-	-
Notes receivable from affiliated companies	2,678	290	1,267	-	-
Change in restricted cash	-	-	-	-	-
Other	(14)	(47)	(5)	(4,173)	(7,081)
Net cash used in investing activities	(71,515)	(31,455)	(65,335)	(73,407)	(107,980)
CASH FLOWS FROM FINANCING ACTIVITIES					
Proceeds from the issuance of long-term debt	-	-	-	-	94,385
Payments for the redemption of long-term debt	(2,036)	(1,877)	(41,724)	(1,615)	(51,520)
Notes payable to affiliated companies	-	-	62,609	18,134	(36,087)
Dividends to parent	(10,000)	(40,001)	-	(55,000)	(10,001)
Other	(151)	(67)	(92)	(210)	-
Net cash provided by (used in) financing activities	(12,187)	(41,945)	20,793	(38,691)	(3,223)
Net (decrease) increase in cash and cash equivalents	819	2,345	(1,731)	(2,166)	(2,607)
Cash and cash equivalents at beginning of period	9,874	10,693	13,038	11,307	9,141
Cash and cash equivalents at end of period	$ 10,693	$ 13,038	$ 11,307	$ 9,141	$ 6,534