DIRECT TESTIMONY OF DIANA L. DOUGLAS
DIRECTOR, RATES & REGULATORY PLANNING
DUKE ENERGY INDIANA, LLC
CAUSE NO. 44720 TDSIC-4 BEFORE THE
INDIANA UTILITY REGULATORY COMMISSION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Diana L. Douglas, and my business address is 1000 East Main Street, Plainfield, Indiana.

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

A. I am employed by Duke Energy Indiana, LLC ("Duke Energy Indiana," "Petitioner" or "Company") as Director, Rates & Regulatory Planning.

Q. PLEASE DESCRIBE YOUR DUTIES AS DIRECTOR, RATES & REGULATORY PLANNING.

A. As Director, Rates & Regulatory Planning, I am responsible for the preparation of financial and accounting data used in Company rate filings.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I am a graduate of Indiana University, holding a Bachelor of Science Degree in Business, with a major in Accounting, with additional post-graduate course-work within the MBA program of Indiana University. Since my employment as a permanent employee in 1980 with the Company (then known as Public Service Company of Indiana, Inc.), I have held various financial and accounting positions supporting the Company and its affiliates. My position prior to Director, Rates & Regulatory Planning, was that of manager responsible for fuel and joint ownership accounting. I have also had management responsibility for emission allowance accounting, general accounting for the Commercial Business Unit, and power marketing and trading settlements and back office operations. I have also held positions in Corporate Accounting, Budgets and Forecasts, and Payroll. I am a Certified Public Accountant ("CPA") and a member of the Indiana CPA Society.

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

A. The purpose of my testimony is to explain the Company's proposed timely recovery of Transmission, Distribution and Storage Infrastructure Improvement Charge ("TDSIC") costs associated with the 7-Year Transmission and Distribution ("T&D") Infrastructure Improvement Plan ("T&D Plan"), covering calendar years 2016 – 2022, that was approved by the Commission on June 29, 2016, in its Order in Cause No. 44720 ("TDSIC Order") and updates to which were approved by the Commission on March 22, 2017, in its Order in Cause No. 44720 TDSIC-1 ("TDSIC-1" or "TDSIC-1 Order"), on October 17, 2017 in its Order in Cause No. 44720 TDSIC-2 ("TDSIC-2" or "TDSIC-2 Order"), and on April 11, 2018 in its Order in Cause No. 44720 (TDSIC-3" or "TDSIC-3 Order"). My testimony shows calculations used to develop the Company's proposed Transmission and Distribution Infrastructure Improvement Cost Rate Adjustment Factors ("TDSIC Factors") and includes updated retail electric Tariff pages applicable to Standard Contract Rider No. 65 - Transmission and Distribution Infrastructure Improvement Cost Rate Adjustment ("Rider 65" or "TDSIC Rider"). The calculations are based on Company data using a December 31, 2017 Cutoff Date ("Cutoff Date"). The pre-filed direct testimonies of Mr. William H. (Howard) Fowler and Mr. Donald E. Broadhurst discuss the project costs, including capital and O&M costs, which were included in the rate calculations, in more detail.

II. RIDER 65 RATEMAKING AND PROPOSED RATES

Q. WHAT SPECIFIC RATEMAKING TREATMENT WAS APPROVED BY THE COMMISSION FOR USE IN THE TDSIC RIDER?

A. The ratemaking treatment approved by the Commission was presented in the direct and settlement testimony and exhibits of Mr. Brian P. Davey in Cause No. 44720 and included: (1) the timely recovery via a newly established tracking mechanism (Rider 65) of eighty percent (80%) of the retail jurisdictional share of the T&D Plan costs, subject to annual and cumulative caps on T&D Plan capital investment as set forth in the Settlement Agreement approved in the TDSIC Order,[1] including recovery of return on capital investments using the Company's weighted cost of capital at each Cutoff Date, using a 10% cost of equity, recovery of the costs of the investments via depreciation, and recovery of O&M and property tax costs; (2) the accrual and recovery of related post-in-service carrying costs at the Company's most recently approved overall weighted average cost of capital, using the 10% return on common equity approved in the TDSIC Order, until the T&D Plan projects are included in retail rates; (3) the Company's proposed use of forecasted depreciation, O&M, and property tax expenses in establishing the TDSIC Factors, with subsequent reconciliation to actual amounts; (4) the Company's proposed

[1] The caps on capital investment set forth in the Settlement Agreement (dollars are in millions) (p. 2) are as follows:

	2016	2017	2018	2019	2020	2021	2022
Annual Cap	$91.8	$213.7	$211.4	$197.5	$213.7	$227.3	$252.9
Cumulative Cap	$91.8	$305.5	$517.0	$714.4	$928.1	$1,155.4	$1,408.3

reconciliation of Rider 65 revenue requirements, including return, to amounts collected from customers; (5) the recovery via Rider 65 of Black & Veatch fees to be amortized over a three-year period; 6) the Company's proposal to allocate the Rider 65 transmission and distribution revenue requirements to rate groups based on the revenue requirement percentage by rate group from the Company's last retail base rate case, Cause No. 42359, using the respective delivery voltage revenue levels for the HLF and LLF rate groups;[2] and (7) the use in Rider 65 of kwh billing determinants for all rate groups except for High Load Factor ("HLF") and the use of non-coincident KW demand as the billing determinant for the HLF rate group.

For the twenty percent (20%) of approved jurisdictional capital expenditures and TDSIC costs not to be recovered in the TDSIC Rider, the Commission approved deferral for subsequent recovery in the Company's next retail base rate case, with carrying costs to be accrued using the overall weighted average cost of capital rate as most recently approved by the Commission.[3]

Q. HAVE YOU USED THIS APPROVED RATEMAKING TREATMENT IN DEVELOPING YOUR PROPOSED TDSIC FACTORS?

A. Yes.

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[2] In other words,

1) All TDSIC costs are identified by FERC function using FERC accounts and placed into Transmission or Distribution buckets before allocation.
2) The Transmission costs will then be allocated to rate groups based on each rate group's Transmission revenue requirement percentages from the last approved cost of service study. The Distribution costs will be similarly allocated using each rate group's Distribution revenue requirement percentages from the last approved cost of service study.

[3] The Company intends to use the 10% ROE approved for use in the T&D Plan Rider for both post-in-service carrying costs to be included in the Rider and for the post-in-service carrying costs on the 20% of capital expenditures and for carrying costs on the 20% of other TDSIC costs to be deferred until the next retail rate case.

Q. WHAT SPECIFIC RATEMAKING APPROVAL ARE YOU SEEKING IN THIS PROCEEDING?

A. Duke Energy Indiana is requesting that the Commission approve: (1) the amounts included in the TDSIC Rider for recovery of the T&D Plan costs; (2) the value of the T&D Plan investment on which the Company is authorized to earn a return; (3) the adjustment of Petitioner's retail electric rates via the proposed Rider 65 TDSIC Factors to include the revenue effect of such investment and cost recovery; and (4) the deferral of the remaining twenty percent (20%) of the expenditures with carrying costs as approved in the Order in Cause No. 44720, until the Company's next electric base rate case. The Company is also requesting the Commission adjust Duke Energy Indiana's authorized return for purposes of Ind. Code § 8-1-2-42(d)(3) to reflect the incremental earnings that will result from this TDSIC rider filing upon Commission approval.

Q. WHAT SPECIFIC COSTS WERE INCLUDED IN THE DEVELOPMENT OF THE PROPOSED TDSIC FACTORS FOR WHICH YOU ARE REQUESTING COMMISSION APPROVAL?

A. The following costs have been included in the development of the TDSIC Factors: Eighty percent (80%) of the retail jurisdictional costs of (1) Duke Energy Indiana's capital investment in the T&D Plan projects that are in-service as of the Cutoff Date, which will be recovered via depreciation; (2) twelve (12) months of return on the net book value (original investment less accumulated depreciation) of the included in-service projects; (3) depreciation incurred for the in-service projects during calendar year 2017; (4) O&M expenses, including fringe benefits and payroll taxes, incurred through the

Cutoff Date for the in-service T&D Plan projects, less amounts already included in the development of TDSIC-1 and TDSIC-2 rates; (5) the forecasted depreciation, O&M and property tax expenses for the twelve-month July 2018 through June 2019 period related to the in-service projects included in the updated T&D Plan; and (6) post-in-service carrying costs accrued for the in-service projects during calendar year 2017. In addition, an amount has been included in rate development for twelve (12) months of amortization of amounts incurred for plan development costs, to be amortized over three years. These plan development costs include Black & Veatch costs as approved by the Commission in the TDSIC Order. The forecasted depreciation, O&M and property tax expense will be trued up to actual expense in a future TDSIC rider filing.

Q. HAVE COSTS RELATED TO WHOLESALE CUSTOMERS BEEN REMOVED FROM COSTS FOR RATE DEVELOPMENT?

A. Yes, their share of costs were removed using the appropriate allocation factors for transmission costs and distribution costs from the cost of service study in the Company's last retail rate case in Cause No. 42359. These calculations can be seen on the rate development schedules of Petitioner's Exhibit 3-B.

Q. HAVE COSTS RELATED TO JOINT OWNERS BEEN REMOVED FROM COSTS FOR RATE DEVELOPMENT?

A. Yes. Work for projects owned by the Company's Joint Owners under the Transmission and Local Facilities ("T&LF") Agreement were specifically identified with unique project codes. These project codes (and their costs) were excluded from rate development workpapers, exhibits, and rate development.

Q. GOING FORWARD, WHAT IS THE PLANNED FREQUENCY OF RIDER 65 FILINGS?

A. The Company plans to continue to make Rider 65 rate update filings annually in the Spring, covering in-service projects through December 31st of the prior calendar year, with the resulting rates planned to be billed to customers over a twelve-month period. The Company believes that using calendar year data for ongoing filings to set TDSIC Rider rates is administratively efficient for all parties, particularly in light of the calendar year caps that were included in the Settlement Agreement approved by the Commission in its TDSIC Order.

Q. PLEASE IDENTIFY THE DOCUMENT THAT HAS BEEN MARKED FOR PURPOSES OF IDENTIFICATION AS PETITIONER'S EXHIBIT 3-A.

A. Petitioner's Exhibit 3-A represents the pages of Duke Energy Indiana's Rider 65 Tariff sheets containing the second revisions to the original Tariff sheets last approved by the Commission in Cause No. 44720 TDSIC-2 on October 17, 2017. The TDSIC-4 Factors contained in the Tariff revision are proposed by the Company to be billed to customers upon Commission approval beginning with bills rendered on or after the first billing Cycle 1 following Commission approval.

Q. PLEASE EXPLAIN WHAT IS SHOWN ON PAGES 1 AND 2 OF PETITIONER'S EXHIBIT 3-A.

A. Pages 1 and 2 of this Exhibit show the two out of six Rider 65 Tariff sheets that require adjustment to support the rates proposed in this proceeding. Pages 3 and 6 of the Tariff, containing the revenue adjustment factors by retail rate group and the annual billing cycle kWh and/or non-coincident peak demands for the twelve months ended December 31, 2017, which were used to develop the TDSIC Factors, respectively, are the pages that require adjustment and are included in Exhibit 3-A. The other four Tariff pages do not require revision at this time, including the pages that cover the definitions of the various components of the formula that is used to develop the TDSIC Factors consistent within the provisions of I. C. 8-1-39 (Pages 1 and 2 of the Tariff) and the listings of retail allocation factors used to allocate the jurisdictional transmission and distribution revenue requirements to rate groups based on data from the Company's cost of service study approved by the Commission in Cause No. 42359, as adjusted to reflect the impact of the May 2014 customer migration between certain lighting rate classes (Pages 4 and 5).

Q. PLEASE IDENTIFY THE DOCUMENT THAT HAS BEEN MARKED FOR PURPOSES OF IDENTIFICATION AS PETITIONER'S EXHIBIT 3-B.

A. Petitioner's Exhibit 3-B includes a series of schedules that support and develop the proposed TDSIC Factors.[4] Pages 1 – 7 support the investment and TDSIC costs included in the revenue requirement calculations on Page 8 (for Transmission) and Page 9 (for Distribution). Pages 1 and 3 through 7 show amounts for Transmission and Distribution investments and costs, retail jurisdictional amounts, the eighty percent (80%) included for current recovery and used in development of the proposed TDSIC Factors, and the twenty percent (20%) deferred for future recovery.

[4] Petitioner's Exhibit 3-B is supported by Public Workpapers that will be filed as a part of this proceeding and also by certain Confidential Workpapers that will be filed upon issuance of a preliminary Order for Protection of Confidential Information.

Page 1 presents the capital investment in the Company's approved T&D Plan projects that were in-service by the Cutoff date. As shown on Page 1, the total capital investment for in-service TDSIC projects as of the December 31, 2017 is $276,530,079. As shown on Page 2, this amount is below the cumulative 2017 capital cost cap of $305,500,000, per the terms of the Settlement Agreement approved in the TDSIC Order, so no adjustments are needed to the investment amount to be included in the rider. The testimony, exhibits and workpapers of Mr. Fowler and Mr. Broadhurst provide additional support for these amounts.

Page 3 provides the amount of accumulated depreciation as of the Cutoff date, associated with the projects included in the investment amounts on Page 1, using the most recent Commission-approved depreciation rates (as approved in the Commission's Order in Cause No. 43114 IGCC 4S1) based on the FERC property accounts associated with the property to determine depreciation amounts. Page 4 provides total T&D amounts for the actual depreciation expense incurred in calendar year 2017 and the depreciation expense forecasted to be incurred for the July 2018 through June 2019 period over which the Company expects the TDSIC Factors to be billed. The forecasted depreciation was calculated using weighted average depreciation rates for transmission and distribution plant based on depreciation rates associated with in-service TDSIC investment as of December 2017. I will be filing supporting public and confidential workpapers with project detail by FERC account and depreciation calculations to support the amounts on Pages 3 and 4 of Exhibit 3-B.

Page 5 presents the actual amounts of project-related O&M expense incurred through the Cutoff Date in relation to the in-service projects included in the investment amounts from Page 1, less amounts already included in TDSIC-1 and TDSIC-2, and the O&M expense associated with additional in-service T&D Plan projects that is forecasted for the July 2018 through June 2019 period over which the Company expects the TDSIC Factors to be billed. The testimony, exhibits and workpapers of Mr. Fowler and Mr. Broadhurst provide additional support for these amounts.

Page 6 presents the property tax expense incurred in calendar year 2017 associated with in-service projects and the property tax forecasted to be incurred for the July 2018 through June 2019 period over which the Company expects the TDSIC Factors to be billed, using an average property tax rate for the Company's T&D property.

Page 7 presents the post-in-service carrying costs incurred during calendar year 2017 on the in-service projects included in the investment from Page 1.

Q. PLEASE EXPLAIN PAGES 8 THROUGH 14 OF PETITIONER'S EXHIBIT 3-B.

Page 8 supports the development of the Transmission improvements revenue requirement, and Page 9 supports the development of the Distribution improvements revenue requirement. Both pages include the return on net capital investment using the investment in in-service TDSIC projects (from Page 1) less the accumulated depreciation (from Page 3), as well as the revenue requirements associated with depreciation expense (from Page 4), O&M expense (from Page 5), property tax expense (from Page 6), post-in-service carrying costs (from Page 7), and amortization of plan development costs (with a workpaper filed to support the amortization amount included). The calculation also includes a reconciliation of actual amounts of depreciation, O&M, and property tax expense incurred in calendar year 2017 to amounts previously forecasted in TDSIC-1 and TDSIC-2 for the same period. The return is calculated using the Company's weighted average cost of capital as of the Cutoff Date, as shown on Page 10, which was computed consistent with 170 Ind. Admin. Code 4-6-14, using the 10% return on equity rate approved for use in the TDSIC rider in Cause No. 44720.[5] Page 11 presents the AFUDC rates that were used by the Company during January through December 2017 to accrue financing costs before the projects included in the investment from Page 1 were placed in-service.

Page 12 presents the Company's calculations for purposes of the statutory 2% revenue cap, as required by I. C. § 8-1-39-14. As shown on Page 12, the incremental revenue requirement increase that will result from implementation of TDSIC-4 rates will be less than the 2% statutory cap, so no additional revenue requirement reductions or cost deferrals are required. Page 13 presents the reconciliation of the approved January through December 2017 revenue requirements, as approved in the TDSIC-1 and TDSIC-2 Orders, to actual customer billings for calendar year 2017. This is the first time a revenue reconciliation has been included in the TDSIC Rider. Page 14 develops the TDSIC Factors using the revenue requirement amounts from Pages 8, 9, 12, and 13.

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[5] Consistent with the most recent weighted average cost of capital calculations in the Company's other capital cost recovery riders, including most recently in Cause No. 43114 IGCC-17, the deferred income tax amount in the weighted average cost of capital calculation on Page 10 excludes the net impact of any tax benefits or liabilities associated with the portion of the IGCC plant shareholders will pay for under the terms of the 2012 Settlement in Cause No. 43114 IGCC 4S1.

Q. PLEASE DESCRIBE THE DETERMINATION OF THE REVENUE CONVERSION FACTORS USED TO DEVELOP THE REVENUE REQUIREMENTS FOR THIS FILING.

A. For the return component, separate revenue conversion factors are developed for the debt and equity components of the after-tax return to reflect the different tax treatments for each component. An effective rate is computed for each component, including effective rates for applicable state and federal taxes, public utility fees, and uncollectible accounts expense.

For the operating expense items other than depreciation and the amortization of post-in-service carrying costs, the revenue requirement was developed using a revenue conversion factor that assumes the expenses are deductible for both state and federal income tax purposes and, therefore, includes only Indiana's utility receipts tax, public utility fees, and uncollectible accounts expense.

Total depreciation and amortization of post-in-service carrying costs were separated into two components before converting to revenue requirements: (1) the portion related to equity return (equity AFUDC for depreciation and the equity portion of post-in-service carrying costs); and (2) the portion related to all other costs (debt AFUDC and the investment being depreciated for depreciation and the debt portion of post-in-service carrying costs). The portion of depreciation and post-in-service carrying costs related to equity AFUDC/equity return was converted to revenue requirements using the same revenue conversion factor as was used for the equity component of return on net investment value. This treatment includes a provision for both state and federal income taxes, reflecting that under current tax regulations, equity return does not have an offsetting tax deduction when computing income taxes and the equity AFUDC component of depreciation expense is not a deductible item. Therefore, utility revenues representing the recovery of equity return or the equity AFUDC component of depreciation expense are not offset by a deductible expense item, which causes the utility to incur an income tax liability. The remainder of the depreciation and post-in-service carrying costs was converted to revenue requirements using the same revenue conversion factor as for other operating expenses, because these debt interest and other investment costs are assumed to be deductible for state and federal income tax purposes. The determination of the revenue conversion factors can be found on the bottom of Pages 8 and 9 of Petitioner's Exhibit 3-B.

Q. DO THE PROPOSED RATES REFLECT THE PASSAGE OF THE 2017 TAX CUTS AND JOBS ACT?

A. Yes. On December 22, 2017, the Tax Cuts and Jobs Act ("Tax Act") was signed into law. We have used the new, lower 21.0% federal income tax rate in the development of the revenue conversion factors used in this filing. This can be seen on the bottom of Pages 8 and 9 of Petitioner's Exhibit 3-B. The new lower tax rates affected the amount of revenue requirements included for return on investment, as well as for depreciation and post-in-service carrying costs.

Q. WERE THERE ANY CHANGES MADE TO THE COST OF CAPITAL CALCULATION OR PRESENTATION SHOWN ON PETITIONER'S EXHIBIT

3-B, PAGE 10 AS A RESULT OF CHANGES DUE TO THE TAX CUTS AND JOBS ACT OF 2017?

A. Yes. As a result of the Tax Cuts and Jobs Act of 2017, which reduced the federal income tax rate for the Company from 35% to 21%, the amounts collected from customers when the federal income tax rate was 35% that were included in the deferred income tax accounts were recalculated using the new, lower 21% federal rate, with the difference reclassified into a separate regulatory liability account ("excess deferred income taxes"). To ensure customers will not be harmed by the reclassification from deferred income tax accounts, which are shown as a zero cost source of capital in the cost of capital calculation, to a regulatory liability, we have included the balance of the excess deferred income tax regulatory liability account in the deferred income tax amount shown on line 5 as a zero cost source of capital. This is a transparent way to show that our customers will continue to get the benefit for return calculation purposes in this rider of this excess deferred income tax regulatory liability resulting from the Tax Cuts and Jobs Act of 2017 until the excess deferred income taxes are returned to customers. The timing of returning the excess deferred income taxes to customers is currently the subject of Cause No. 45032. Workpaper 23 (DLD) supports the amount included on line 5 of Petitioner's Exhibit 3-B, Page 10.

Q. WHEN WILL TDSIC RIDER RATEMAKING TREATMENT CEASE FOR THE T&D PLAN PROJECTS?

A. Pursuant to I. C. § 8-1-39-15 and the Settlement Agreement approved in the TDSIC Order, Duke Energy Indiana will continue to collect revenues through Rider 65 for the jurisdictional costs associated with the approved TDSIC projects until the costs of the T&D improvements that are in-service by the rate base cut-off date for a future retail base rate case are included in base rates. Amounts deferred related to the T&D improvements will also be included in base rates at the time of the future retail base rate case. If there remain years in the 7-year plan (or a new T&D plan) after the future retail base rate case order, the TDSIC rider would be adjusted to use the new ROE and allocation factors approved in the subsequent retail base rate case and to reflect the inclusion of the costs related to the T&D improvements in base rates.

Q. PLEASE IDENTIFY THE DOCUMENT THAT HAS BEEN MARKED FOR PURPOSES OF IDENTIFICATION AS PETITIONER'S EXHIBIT 3-C.

A. Page 1 of Petitioner's Exhibit 3-C compares the proposed TDSIC factors to the current TDSIC factors. Page 2 of Petitioner's Exhibit 3-C shows the impact of the proposed TDSIC ratemaking, should the Commission approve it, on the monthly bill of a typical residential customer using 1,000 kilowatt-hours. Upon approval of the proposed factors, the monthly bill of a residential customer using 1,000 kilowatt-hours will increase by $1.61 or approximately 1.32% from their current total bill (using rates effective as of April 2018 Bill Cycle 1.) For total retail, the average increase in revenue requirements is 0.96%, relative to revenue for the twelve months ended December 2017, as shown on Petitioner's Exhibit 3-B, Page 12.

Q. WHAT AMENDMENTS TO DUKE ENERGY INDIANA'S RATE SCHEDULES ARE BEING PROPOSED TO REFLECT THE RIDER 65 RATEMAKING TREATMENT REQUESTED IN THIS PROCEEDING?

A. Duke Energy Indiana is proposing to update its Rider 65, Sheet No. 65, First Revised Pages 3 and 6 (shown in Petitioner's Exhibit 3-A, Pages 1 and 2) should the Commission approve the proposed rates. Upon approval and upon Duke Energy Indiana's filing of the updated Rider 65 with the Commission's Electricity Division, the factors are proposed to be billed to customers beginning with bills rendered on or after the first billing Cycle 1 following Commission approval.

Q. PLEASE EXPLAIN THE DOCUMENT THAT HAS BEEN MARKED FOR PURPOSES OF IDENTIFICATION AS PETITIONER'S EXHIBIT 3-D.

A. Petitioner's Exhibit 3-D is an exhibit showing the 20% deferral amounts from each TDSIC filing and the cumulative 20% amount deferred for future recovery in the Company's next base rate case for in-service projects as of the Cutoff Date.

III. CONCLUSION

Q. WERE PETITIONER'S EXHIBITS 3-A THROUGH 3-D PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PREPARED TESTIMONY?

A. Yes.

DUKE ENERGY INDIANA, LLC
1000 E. Main Street
Plainfield, IN 46168

IURC No. 14
Sheet No. 65
Second Revised Page 3 of 6
Cancels and Supersedes
First Revised Page 3 of 6

STANDARD CONTRACT RIDER NO. 65
TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE IMPROVEMENT COST RATE ADJUSTMENT APPLICABLE TO RETAIL RATE GROUPS

Line No.	Rate Groups	Transmission and Distribution Infrastructure Improvement Cost Rate Adjustment Factor Per KWH (A)	Transmission and Distribution Infrastructure Improvement Cost Rate Adjustment Factor Per Non-Coincident KW (B)	Line No.
1	Rate RS	$0.003667		1
2	Rate CS	$0.003560		2
3	Rate LLF - Secondary	$0.001871		3
4	Rate LLF - Primary	$0.000596		4
5	Rate LLF - Primary Direct	$0.000574		5
6	Rate LLF - Transmission	$0.000754		6
7	Rate HLF - Secondary		$0.987476	7
8	Rate HLF - Primary		$0.900776	8
9	Rate HLF - Primary Direct		$0.491840	9
10	Rate HLF - Common Transmission		$0.266470	10
11	Rate HLF - Bulk Transmission		$0.147451	11
12	Customer L	$0.000290		12
13	Customer D	$0.000000		13
14	Customer O	$0.002231		14
15	Rate WP	$0.001615		15
16	Rate SL	$0.003273		16
17	Rate MHLS	$0.003889		17
18	Rates MOLS and UOLS	$0.002867		18
19	Rates TS, FS and MS	$0.003180		19

Issued: Effective:

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IURC No. 14
Sheet No. 65
Second Revised Page 6 of 6
Cancels and Supersedes
First Revised Page 6 of 6

STANDARD CONTRACT RIDER NO. 65
TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE IMPROVEMENT COST RATE ADJUSTMENT APPLICABLE TO RETAIL RATE GROUPS

BILLING CYCLE KWH SALES AND HLF MONTHLY NON-COINCIDENT PEAKS
FOR THE COMPANY'S RETAIL CUSTOMERS BY RATE GROUP
BASED ON THE TWELVE-MONTH PERIOD ENDED DECEMBER 31, 2017

Line No.	Rate Groups	KWH Sales	Sum Of Monthly Non-Coincident Peak Demands	Line No.
		(A)	(B)	
1	Rate RS	8,550,451,791		1
2	Rate CS	1,031,535,953		2
3	Rate LLF - Secondary	4,060,910,075		3
4	Rate LLF - Primary	451,746,245		4
5	Rate LLF - Primary Direct	214,638,759		5
6	Rate LLF - Transmission	167,165,596		6
7	Rate HLF - Secondary	4,046,223,440	8,315,814	7
8	Rate HLF - Primary	2,065,555,308	3,841,365	8
9	Rate HLF - Primary Direct	2,372,539,933	4,121,227	9
10	Rate HLF - Common Transmission	1,183,687,980	2,185,811	10
11	Rate HLF - Bulk Transmission	1,238,584,095	2,133,697	11
12	Customer L	114,806,810		12
13	Customer D	0		13
14	Customer O	157,645,853		14
15	Rate WP	147,089,202		15
16	Rate SL	39,648,920		16
17	Rate MHLS	5,624,930		17
18	Rates MOLS and UOLS	109,646,147		18
19	Rates TS, FS and MS	9,607,314		19
20	Total Retail	25,967,108,351		20

Issued:

Effective:

DUKE ENERGY INDIANA, LLC

INVESTMENT IN TRANSMISSION AND DISTRIBUTION PROJECTS IN-SERVICE AS OF DECEMBER 31, 2017 TO BE REFLECTED IN THE TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE IMPROVEMENT COST RATE ADJUSTMENT ("TDSIC RIDER")

Line No.	Description	Investment Dec 2017	Retail Investment (1) Dec 2017	Line No.
		(A)	(B)	
	Transmission (2)			
1	Total In-Service Investment - Transmission Projects	$ 107,099,041		1
2	Less Capital Cost Cap Adjustment (3)	-		2
3	Total Capped In-Service Investment - Transmission Projects	$ 107,099,041	$ 103,438,396	3
4	Transmission Investment Deferred for Future Recovery (20%)		20,687,679	4
5	Transmission Investment Eligible for Rider Recovery (80%)		$ 82,750,717	5
	Distribution (2)			
6	Total In-Service Investment - Distribution Projects	$ 169,431,038		6
7	Less Capital Cost Cap Adjustment (3)	-		7
8	Total Capped In-Service Investment - Distribution Projects	$ 169,431,038	$ 167,909,547	8
9	Distribution Investment Deferred for Future Recovery (20%)		33,581,909	9
10	Distribution Investment Eligible for Rider Recovery (80%)		$ 134,327,638	10
	Total Transmission and Distribution			
11	Total In-Service Investment	$ 276,530,079		11
12	Less Capital Cost Cap Adjustment	-		12
13	Total Capped In-Service Investment	$ 276,530,079	$ 271,347,943	13
14	Investment Deferred for Future Recovery (20%)		54,269,588	14
15	Investment Eligible for Rider Recovery (80%)		$ 217,078,355	15

(1) Retail amount based on separation study from IURC Cause No. 42359:
Transmission: 96.582%
Distribution: 99.102%

(2) See Workpaper 26-DLD for project detail support by FERC account and for functional totals:

	Transmission	Distribution
Operational Functional Totals per Exhibit 1-B (WHF)	$ 107,673,097	$ 168,856,982
Re-classified amount (See Workpaper 26-DLD)	(574,056)	574,056
FERC Plant Account Functional Totals used for Rate Making	$ 107,099,041	$ 169,431,038

(3) See Exhibit3-B (DLD) page 2 of 14.

DUKE ENERGY INDIANA, LLC

COMPARISON OF TDSIC RIDER CAPITAL COST CAP AMOUNTS TO INVESTMENT IN-SERVICE AS OF DECEMBER 31, 2017

Line No.	Description	Total Investment In-Service (A)	Percentage (B)	Total (C)	Line No.
	Cumulative Capital Cost Caps per Settlement Agreement (1)				
1	December 31, 2016			$ 91,800,000	1
2	December 31, 2017			305,500,000	2
3	December 31, 2018			517,000,000	3
4	December 31, 2019			714,400,000	4
5	December 31, 2020			928,100,000	5
6	December 31, 2021			1,155,400,000	6
7	December 31, 2022			1,408,300,000	7
	Over (Under) the Settlement Cap Calculation				
8	Total Capital Investment In-Service as of December 31, 2017 (2)			$ 276,530,079	8
9	Cumulative Capital Cost Cap as of December 31, 2017			305,500,000	9
10	Amount Over (Under) Settlement Cap			$ (28,969,921)	10
11	Adjustment to Investment In-Service due to Settlement Cap (3)			$ -	11
	Allocation of Adjustment to FERC Function:				
12	Transmission (4)	$ 107,099,041	38.73%	$ -	12
13	Distribution (5)	169,431,038	61.27%	-	13
14	Total	$ 276,530,079	100.00%	$ -	14

(1) Per IURC 44720 - Petitioner's Exhibit 12 - Settlement Testimony of Brian P. Davey Page 3.
Caps are total in-service investment amounts, not retail amounts.
(2) See Exhibit 3-B (DLD) page 1 of 14, line 11, column (A).
(3) If line 10 is negative, then zero. Otherwise use line 10 amount.
(4) See Exhibit 3-B (DLD) page 1 of 14, line 1, column (A).
(5) See Exhibit 3-B (DLD) page 1 of 14, line 6, column (A).

DUKE ENERGY INDIANA, LLC

SUMMARY OF ACCUMULATED DEPRECIATION FOR QUALIFYING IN-SERVICE TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE IMPROVEMENT PROJECTS AS OF DECEMBER 31, 2017

Line No.	Description	Accumulated Depreciation Dec 2016 (1)	Depreciation Expense (2) Jan 2017-Dec 2017	Accumulated Depreciation Dec 2017	Retail Accumulated Depreciation (3) Dec 2017	Line No.
		(A)	(B)	(C)	(D)	
	Transmission					
1	Total Transmission Projects Accumulated Depreciation	$ 132,413	$ 1,363,081	$ 1,495,494	$ 1,444,378	1
2	Transmission Accumulated Depreciation Deferred for Future Recovery (20%)				288,876	2
3	Transmission Accumulated Depreciation Eligible for Rider Recovery (80%)				$ 1,155,502	3
	Distribution					
4	Total Distribution Projects Accumulated Depreciation	$ 537,368	$ 2,762,856	$ 3,300,224	$ 3,270,588	4
5	Distribution Accumulated Depreciation Deferred for Future Recovery (20%)				654,118	5
6	Distribution Accumulated Depreciation Eligible for Rider Recovery (80%)				$ 2,616,470	6
	Total Transmission and Distribution					
7	Total Accumulated Depreciation	$ 669,781	$ 4,125,937	$ 4,795,718	$ 4,714,966	7
8	Accumulated Depreciation Deferred for Future Recovery (20%)				942,994	8
9	Accumulated Depreciation Eligible for Rider Recovery (80%)				$ 3,771,972	9

(1) See TDSIC-2 Exhibit 3-B (DLD) page 3.
(2) See Exhibit 3-B (DLD) page 4 of 14.
(3) Retail amount based on separation study from IURC Cause No. 42359:
Transmission: 96.582%
Distribution: 99.102%

DUKE ENERGY INDIANA, LLC

SUMMARY OF DEPRECIATION EXPENSE FOR QUALIFYING IN-SERVICE TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE IMPROVEMENT PROJECTS AS OF DECEMBER 31, 2017 AND FORECASTED DEPRECIATION EXPENSE FOR THE PERIOD JULY 1, 2018 THROUGH JUNE 30, 2019

Line No.	Description	Depreciation Expense (1) Jan 2017 - Dec 2017 Total	Retail (2)	Forecasted Retail Depreciation Jul 2018 - Jun 2019 (3)	Line No.
		(A)	(B)	(C)	
	Transmission				
1	Total Transmission Projects Depreciation Expense	$ 1,363,081	$ 1,316,491	$ 5,218,050	1
2	Transmission Depreciation Deferred for Future Recovery (20%)		263,298	1,043,610	2
3	Transmission Depreciation Eligible for Rider Recovery (80%)		$ 1,053,193	$ 4,174,440	3
	Distribution				
4	Total Distribution Projects Depreciation Expense	$ 2,762,856	$ 2,738,046	$ 9,153,224	4
5	Distribution Depreciation Deferred for Future Recovery (20%)		547,609	1,830,645	5
6	Distribution Depreciation Eligible for Rider Recovery (80%)		$ 2,190,437	$ 7,322,579	6
	Total Transmission and Distribution				
7	Total Depreciation Expense	$ 4,125,937	$ 4,054,537	$ 14,371,274	7
8	Depreciation Expense Deferred for Future Recovery (20%)		810,907	2,874,255	8
9	Depreciation Expense Eligible for Rider Recovery (80%)		$ 3,243,630	$ 11,497,019	9

(1) See Workpaper 8-DLD.
(2) Retail amount based on separation study from IURC Cause No. 42359:
Transmission: 96.582%
Distribution: 99.102%
(3) Forecast based on projected retail plant in-service. See Workpaper 9-DLD.

DUKE ENERGY INDIANA, LLC

SUMMARY OF OPERATION AND MAINTENANCE EXPENSE RELATED TO QUALIFYING TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE IMPROVEMENT PROJECTS PLACED IN-SERVICE THROUGH DECEMBER 31, 2017 AND FORECASTED OPERATION AND MAINTENANCE FOR THE PERIOD JULY 1, 2018 THROUGH JUNE 30, 2019

Line No.	Description	Operation and Maintenance Total (1)(2)	Operation and Maintenance Retail (3)	Forecasted Retail O&M Jul 2018 - Jun 2019 (4)	Line No.
		(A)	(B)	(C)	
	Transmission				
1	Total Transmission Projects Operation and Maintenance Expense	$ 4,694,682	$ 4,534,218	$ 3,598,000	1
2	Transmission O&M Expense Deferred for Future Recovery (20%)		906,844	719,600	2
3	Transmission O&M Expense Eligible for Rider Recovery (80%)		$ 3,627,374	$ 2,878,400	3
	Distribution				
4	Total Distribution Projects Operation and Maintenance Expense	$ 13,633,863	$ 13,511,431	$ 14,908,000	4
5	Distribution O&M Expense Deferred for Future Recovery (20%)		2,702,286	2,981,600	5
6	Distribution O&M Expense Eligible for Rider Recovery (80%)		$ 10,809,145	$ 11,926,400	6
	Total Transmission and Distribution				
7	Total Operation and Maintenance Expense	$ 18,328,545	$ 18,045,649	$ 18,506,000	7
8	Operation and Maintenance Expense Deferred for Future Recovery (20%)		3,609,130	3,701,200	8
9	Operation and Maintenance Expense Eligible for Rider Recovery (80%)		$ 14,436,519	$ 14,804,800	9

(1) Operation and Maintenance Expense includes fringe benefits and payroll taxes associated with Company labor.
(2) See Workpaper 27-DLD project detail support by FERC account and for functional totals:

	Transmission	Distribution	Total
Operational Functional Totals per Exhibit 1-B (WHF)	$ 5,918,766	$ 23,965,816	$ 29,884,582
Less: Amounts included in prior TDSIC Filings	(1,059,556)	(10,496,481)	(11,556,037)
Re-classified amounts (See Confidential Workpaper 33-DLD)	(164,528)	164,528	-
FERC Expense Account Functional Totals used for Rate Making	$ 4,694,682	$ 13,633,863	$ 18,328,545

(3) Retail amount based on separation study from IURC Cause No. 42359:
Transmission: 96.582%
Distribution: 99.102%
(4) Forecasted O&M based on 7-year Plan update in TDSIC-3 Workpaper 6-DLD.

DUKE ENERGY INDIANA, LLC

SUMMARY OF PROPERTY TAX EXPENSE RELATED TO QUALIFYING TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE IMPROVEMENT PROJECTS PLACED IN-SERVICE THROUGH DECEMBER 31, 2017 AND FORECASTED PROPERTY TAX EXPENSE FOR THE PERIOD JULY 1, 2018 THROUGH JUNE 30, 2019

Line No.	Description	Property Tax Expense Jan 2017 - Dec 2017 Total (1)	Retail (2)	Forecasted Retail Prop. Tax Jul 2018-Jun 2019 (3)	Line No.
		(A)	(B)	(C)	
	Transmission				
1	Transmission Property Tax Expense	$ 78,472	$ 75,790	$ 395,943	1
2	Transmission Property Tax Expense Deferred for Future Recovery (20%)		15,158	79,189	2
3	Transmission Property Tax Expense Eligible for Rider Recovery (80%)		$ 60,632	$ 316,754	3
	Distribution				
4	Distribution Property Tax Expense	$ 126,054	$ 124,922	$ 592,460	4
5	Distribution Property Tax Expense Deferred for Future Recovery (20%)		24,984	118,492	5
6	Distribution Property Tax Expense Eligible for Rider Recovery (80%)		$ 99,938	$ 473,968	6
	Total Transmission and Distribution				
7	Total Transmission and Distribution Property Tax Expense	$ 204,526	$ 200,712	$ 988,403	7
8	Property Tax Expense Deferred for Future Recovery (20%)		40,142	197,681	8
9	Property Tax Expense Eligible for Rider Recovery (80%)		$ 160,570	$ 790,722	9

(1) See Workpaper 10-DLD.
(2) Retail amount based on separation study from IURC Cause No. 42359:
Transmission: 96.582%
Distribution: 99.102%
(3) Forecasted Property Taxes based on 7-year Plan update projected plant in-service. See Workpaper 10-DLD.

DUKE ENERGY INDIANA, LLC

SUMMARY OF POST IN-SERVICE CARRYING COSTS INCURRED JANUARY 1, 2017 THROUGH DECEMBER 31, 2017 FOR QUALIFYING TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE IMPROVEMENT PROJECTS IN-SERVICE AS OF DECEMBER 31, 2017

Line No.	Description	Debt Related (1)(2)	Equity Related (1)(2)	Total	Line No.
		(A)	(B)	(C)	
	Post In-Service Carrying Cost Related to 80% Investment Eligible for Rider Recovery:				
1	Transmission	$ 494,885	$ 1,097,648	$ 1,592,533	1
2	Distribution	851,573	1,893,382	2,744,955	2
3	Total Transmission and Distribution	$ 1,346,458	$ 2,991,030	$ 4,337,488	3
	Post In-Service Carrying Costs Related to 20% Investment Deferred for Future Recovery:				
4	Transmisison	$ 188,403	$ 418,803	$ 607,206	4
5	Distribution	338,783	753,118	1,091,901	5
6	Total Transmission and Distribution	$ 527,186	$ 1,171,921	$ 1,699,107	6
	Total Post In-Service Carrying Costs:				
7	Transmisison	$ 683,288	$ 1,516,451	$ 2,199,739	7
8	Distribution	1,190,356	2,646,500	3,836,856	8
9	Total Transmission and Distribution	$ 1,873,644	$ 4,162,951	$ 6,036,595	9

(1) Post In-Service Carrying Costs are accrued on the retail portion of investment only. See Workpaper 29-DLD.
(2) The most recently approved weighted average cost of capital for the periods during which post in-service carrying costs were accrued are:
- For January 2017 the December 31, 2015 calculation approved in IURC Cause No. 42601 - ECR 27 (approved by the Commission on August 31, 2016).
- For February through August 2017 the June 30, 2016 calculation approved in IURC Cause No. 42061 - ECR 28 (approved by the Commission on February 8, 2017).
- For September through December 2017 the December 31, 2016 calculation approved in IURC Cause No. 42061 - ECR 29 (approved by the Commission on August 30, 2017).

The calculations were modified to replace the 10.5% equity cost of capital approved in IURC Cause No. 42359 with the 10.0% equity cost of capital approved for use in the TDSIC rider in IURC Cause No. 44720. See Workpaper 25-DLD for this weighted average cost of capital calculation supporting the rate used for the post in-service carrying costs.

DUKE ENERGY INDIANA, LLC

DETERMINATION OF THE JURISDICTIONAL REVENUE REQUIREMENTS APPLICABLE TO QUALIFYING TRANSMISSION INFRASTRUCTURE IMPROVEMENT PROJECTS TO BE RECOVERED IN THE TDSIC RIDER FOR THE PROJECTED TWELVE MONTH PERIOD JULY 2018 THROUGH JUNE 2019

Line No.	Description	Applicable to Retail Customers				Line No.
		Debt	Equity	Amount	Total	
		(A)	(B)	(C)	(D)	
	Return on Investment:					
1	Investment in Plant as of December 31, 2017 (Exhibit 3-B (DLD) page 1)			$ 82,750,717		1
2	Accumulated Depreciation as of December 31, 2017 (Exhibit 3-B (DLD) page 3)			1,155,502		2
3	Net Investment as of December 31, 2017				$ 81,595,215	3
4	Rate of Return (Exhibit 3-B (DLD) page 10)	1.81%	4.12%		5.93%	4
5	Return on Investment				4,838,596	5
6	Revenue Conversion Factor (1)	1.02112	1.37140		1.26449	6
7	Annual Return on Investment Revenue Requirement				$ 6,118,356	7
		All Other	Applicable to Equity AFUDC			
	Depreciation Expense:	98.096%	1.904%	(workpaper 7-DLD)		
	Reconciliation of Actual Depreciation Expense					
8	Depreciation Expense Incurred Jan 2017 - Dec 2017 (Exhibit 3-B (DLD) page 4)			$ 1,053,193		8
9	Less: Projected Depr.Exp. Incl. in previous filings for Jan 2017 - Dec 2017 (2)			1,522,382		9
10	Depreciation Expense Reconciliation			(469,189)		10
11	Forecasted Depreciation Expense Jul 2018-Jun 2019 (Exhibit 3-B (DLD) page 4)			4,174,440		11
12	Total Depreciation Expense	$ 3,634,703	$ 70,548	3,705,251		12
13	Revenue Conversion Factor (1)	1.02112	1.37140			13
14	Depreciation Expense Revenue Requirement	3,711,468	96,750		3,808,218	14
	Operation and Maintenance Expense:					
	Reconciliation of Actual Operation and Maintenance Expense					
15	O&M Expense for Projects In-Service through December 31, 2017 (Exh 3-B (DLD) page 5)			3,627,374		15
16	Less: Projected O&M Exp. Incl. in previous filings for Jan 2017 - Dec 2017 (2)			4,481,502		16
17	O&M Expense Reconciliation			(854,128)		17
18	Forecasted O&M Expense Jul 2018-Jun 2019 (Exhibit 3-B (DLD) page 5)			2,878,400		18
19	Total Operation and Maintenance Expense			2,024,272		19
20	Revenue Conversion Factor (1)			1.02112		20
21	Operation and Maintenance Expense Revenue Requirement				2,067,025	21
	Property Tax Expense					
	Reconciliation of Actual Property Tax Expense					
22	Property Tax Expense through December 31, 2017 (Exhibit 3-B (DLD) page 6)			60,632		22
23	Less: Projected Property Tax Exp. Incl. in previous filings for Jan 2017 - Dec 2017 (2)			79,437		23
24	Property Tax Expense Reconciliation			(18,805)		24
25	Forecasted Property Tax Expense Jul 2018-Jun 2019 (Exhibit 3-B (DLD) page 6)			316,754		25
26	Total Property Tax Expense			297,949		26
27	Revenue Conversion Factor (1)			1.02112		27
28	Property Tax Expense Revenue Requirement				304,242	28
	Post In-Service Carrying Costs Expense:	Debt Costs	Equity Costs			
29	Post In-Service Carrying Costs Incurred Jan 2017-Dec 2017 (Exhibit 3-B (DLD) page 7)	494,885	1,097,648	1,592,533		29
30	Revenue Conversion Factor (1)	1.02112	1.37140			30
31	Post In-Service Carrying Costs Revenue Requirement	505,337	1,505,314		2,010,651	31
	Plan Development Costs Amortization:					
32	Plan Development Costs Amortization (Workpaper 6-DLD) (12 months of 36 months)			151,284		32
33	Revenue Conversion Factor (1)			1.02112		33
34	Plan Development Costs Amortization Revenue Requirement				154,479	34
35	Total 12 Month Transmission Revenue Requirement				$ 14,462,971	35
36	Less: Prior Approved Transmission Revenue Requirements (annualized)				9,358,622	36
37	Incremental 12 Month Transmission Revenue Requirement Increase / (Decrease)				$ 5,104,349	37

(1) Components of Revenue Conversion Factor:	Statutory Rates	Effective Rates: Debt	Effective Rates: Equity		
Utility Receipts Tax	1.400%	1.400%	1.400%		
Uncollectible Accounts Expense	0.450%	0.450%	0.450%		
Public Utility Fee	0.133%	0.133%	0.133%		
State Income Tax (a)	5.750%	0.085%	5.716%		
Federal Income Tax (b)	21.000%	0.000%	19.383%		
Total Effective Rate		2.068%	27.082%	Weighted	
Revenue Conversion 1/(1- effective rate)		1.02112	1.37140	1.26449	(c)

(a) The effective tax rate for debt for state income tax reflects tax on the utility receipts tax portion of revenues. The effective tax rate for equity for state income tax reflects the deductibility of uncollectible accounts expense and public utility fee.

(b) The effective tax rate for equity for federal income tax reflects the deductibility of utility receipts tax, uncollectible accounts expense, public utility fee and state income tax.

(c) See calculation on Exhibit 3-B (DLD) page 10 of 14.

(2) See Workpaper 30-DLD.

DUKE ENERGY INDIANA, LLC

DETERMINATION OF THE JURISDICTIONAL REVENUE REQUIREMENTS APPLICABLE TO QUALIFYING DISTRIBUTION INFRASTRUCTURE IMPROVEMENT PROJECTS TO BE RECOVERED IN THE TDSIC RIDER FOR THE PROJECTED TWELVE MONTH PERIOD JULY 2018 THROUGH JUNE 2019

Line No.	Description	Applicable to Retail Customers: Debt	Equity	Amount	Total	Line No.
		(A)	(B)	(C)	(D)	
	Return on Investment:					
1	Investment in Plant as of December 31, 2017 (Exhibit 3-B (DLD) page 1)			$ 134,327,638		1
2	Accumulated Depreciation as of December 31, 2017 (Exhibit 3-B (DLD) page 3)			2,616,470		2
3	Net Investment as of December 31, 2017				$ 131,711,168	3
4	Rate of Return (Exhibit 3-B (DLD) page 10)	1.81%	4.12%		5.93%	4
5	Return on Investment				7,810,472	5
6	Revenue Conversion Factor (1)	1.02112	1.37140		1.26449	6
7	Annual Return on Investment Revenue Requirement				$ 9,876,264	7
		All Other	Applicable to Equity AFUDC			
	Depreciation Expense:	99.192%	0.808%	(workpaper 7-DLD)		
	Reconciliation of Actual Depreciation Expense					
8	Depreciation Expense Incurred Jan 2017 - Dec 2017 (Exhibit 3-B (DLD) page 4)			$ 2,190,437		8
9	Less: Projected Depr.Exp. Incl. in previous filings for Jan 2017 - Dec 2017 (2)			2,827,684		9
10	Depreciation Reconciliation Expense			(637,247)		10
11	Forecasted Depreciation Expense Jul 2018-Jun 2019 (Exhibit 3-B (DLD) page 4)			7,322,579		11
12	Total Depreciation Expense	$ 6,631,315	$ 54,017	6,685,332		12
13	Revenue Conversion Factor (1)	1.02112	1.37140			13
14	Depreciation Expense Revenue Requirement	6,771,368	74,079		6,845,447	14
	Operation and Maintenance Expense:					
	Reconciliation of Actual Operation and Maintenance Expense					
15	O&M Expense for Projects In-Service through December 31, 2017 (Exh 3-B (DLD) page 5)			10,809,145		15
16	Less: Projected O&M Exp. Incl. in previous filings for Jan 2017 - Dec 2017 (2)			9,357,604		16
17	O&M Expense Reconciliation			1,451,541		17
18	Forecasted O&M Expense Jul 2018-Jun 2019 (Exhibit 3-B (DLD) page 5)			11,926,400		18
19	Total Operation and Maintenance Expense			13,377,941		19
20	Revenue Conversion Factor (1)			1.02112		20
21	Operation and Maintenance Expense Revenue Requirement				13,660,483	21
	Property Tax Expense					
	Reconciliation of Actual Property Tax Expense					
22	Property Tax Expense through December 31, 2017 (Exhibit 3-B (DLD) page 6)			99,938		22
23	Less: Projected Property Tax Exp. Incl. in previous filings for Jan 2017 - Dec 2017 (2)			118,322		23
24	Property Tax Expense Reconciliation			(18,384)		24
25	Forecasted Property Tax Expense Jul 2018-Jun 2019 (Exhibit 3-B (DLD) page 6)			473,968		25
26	Total Property Tax Expense			455,584		26
27	Revenue Conversion Factor (1)			1.02112		27
28	Property Tax Expense Revenue Requirement				465,206	28
	Post In-Service Carrying Costs Expense:	Debt Costs	Equity Costs			
29	Post In-Service Carrying Costs Incurred Jan 2017-Dec 2017 (Exhibit 3-B (DLD) page 7)	851,573	1,893,382	2,744,955		29
30	Revenue Conversion Factor (1)	1.02112	1.37140			30
31	Post In-Service Carrying Costs Revenue Requirement	869,558	2,596,584		3,466,142	31
	Plan Development Costs Amortization:					
32	Plan Development Costs Amortization (Workpaper 6-DLD) (12 months of 36 months)			188,820		32
33	Revenue Conversion Factor (1)			1.02112		33
34	Plan Development Costs Amortization Revenue Requirement				192,808	34
35	Total 12 Month Distribution Revenue Requirement				$ 34,506,350	35
36	Less: Prior Approved Distribution Revenue Requirements (annualized)				25,301,127	36
37	Incremental 12 Month Distribution Revenue Requirement Increase / (Decrease)				$ 9,205,223	37

(1) Components of Revenue Conversion Factor:	Statutory Rates	Effective Rates: Debt	Effective Rates: Equity	Weighted	
Utility Receipts Tax	1.400%	1.400%	1.400%		
Uncollectible Accounts Expense	0.450%	0.450%	0.450%		
Public Utility Fee	0.133%	0.133%	0.133%		
State Income Tax (a)	5.750%	0.085%	5.716%		
Federal Income Tax (b)	21.000%	0.000%	19.383%		
Total Effective Rate		2.068%	27.082%		
Revenue Conversion 1/(1- effective rate)		1.02112	1.37140	1.26449	(c)

(a) The effective tax rate for debt for state income tax reflects tax on the utility receipts tax portion of revenues. The effective tax rate for equity for state income tax reflects the deductibility of uncollectible accounts expense and public utility fee.

(b) The effective tax rate for equity for federal income tax reflects the deductibility of utility receipts tax, uncollectible accounts expense, public utility fee and state income tax.

(c) See calculation on Exhibit 3-B (DLD) page 10 of 14.

(2) See Workpaper 30-DLD.

DUKE ENERGY INDIANA, LLC

WEIGHTED COST OF CAPITAL AS OF DECEMBER 31, 2017
REFLECTING THE 10.00% RETURN ON COMMON
EQUITY APPROVED IN IURC CAUSE NO. 44720
(DOLLARS IN THOUSANDS)

Line No.		Capitalization	Capital Structure Ratio: Financial Concept	Capital Structure Ratio: Regulatory Concept	Cost Rate	Weighted Cost Rate: Financial Concept	Weighted Cost Rate: Regulatory Concept	Weighted Cost Rate: Synch. Interest	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	
1	Common Equity	$4,099,984	52.30%	40.13%	10.00%	5.23%	4.01%		1
2	Preferred Stock	0	0.00%	0.00%	0.00%	0.00%	0.00%		2
3	Long-Term Debt	3,739,600	47.70%	36.61%	4.87%	2.32%	1.78%	1.81%	3
4	Total Financial Capitalization	7,839,584	100.00%	76.74%		7.55%			4
5	Deferred Income Taxes Including Excess Deferred Taxes (1)	2,183,512		21.38%	0.00%		0.00%		5
6	Unamortized ITC - Crane Solar	10,698		0.10%	7.55%		0.01%		6
7	Unamortized ITC - 1971 & Later	3,156		0.03%	7.55%		0.00%		7
8	Unamortized ITC - Advanced Coal (IGCC)	133,500		1.31%	7.55%		0.10%		8
9	Customer Deposits	44,667		0.44%	6.00%		0.03%		9
10	Total Regulatory Capitalization	$10,215,117		100.00%			5.93%	1.81%	10

Revenue Requirement Conversion Factor

Line No.		Weighted Cost Rate	Revenue Conversion		Revenue Requirement Rate	Line No.
11	Debt	1.81%	1.02112	(2)	1.8482%	11
12	Equity	4.12%	1.37140	(2)	5.6502%	12
13	Total	5.93%	1.26449		7.4984%	13

(1) Excess deferred taxes are recorded as a regulatory asset/liability.
(2) See calculation in footnote on Exhibit 3-B (DLD) page 8 of 14.

DUKE ENERGY INDIANA, LLC

AFUDC RATES APPLICABLE TO QUALIFIED TRANSMISSION AND DISTRIBUTION PROJECTS

Line No.	Month	AFUDC Rates Debt	AFUDC Rates Equity	AFUDC Rates Total	Line No.
		(A)	(B)	(C)	
1	January 2017	2.27%	5.44%	7.71%	1
2	February 2017	2.25%	5.48%	7.73%	2
3	March 2017	2.25%	5.48%	7.73%	3
4	April 2017	2.24%	5.50%	7.74%	4
5	May 2017	2.29%	5.42%	7.71%	5
6	June 2017	2.28%	5.44%	7.72%	6
7	July 2017	2.26%	5.48%	7.74%	7
8	August 2017	2.25%	5.50%	7.75%	8
9	September 2017	2.24%	5.53%	7.77%	9
10	October 2017	2.27%	5.45%	7.72%	10
11	November 2017	2.27%	5.47%	7.74%	11
12	December 2017	2.26%	5.50%	7.76%	12

DUKE ENERGY INDIANA, LLC

TDSIC RIDER 2% REVENUE CAP TEST
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2017

Line No.	Description	Total	Line No.
		(A)	
	Retail Revenue Cap for 12 Months		
1	Retail Revenue for the Twelve Months Ended December 31, 2017 (1)	$ 2,525,252,086	1
2	Multiplied by 2% Limit	2.00%	2
3	Total Retail Cap	$ 50,505,042	3
4	TDSIC-4 Annual Revenue Requirement Before 2% Cap (2)	$ 58,853,486	4
5	Revenue Requirement TDSIC-2	34,659,749	5
6	Incremental TDSIC Revenue Requirement (line 4 - line 6)	$ 24,193,737	6
7	Amount in Excess of 2% Retail Revenue Cap (line 7 - line 3 [zero if below cap])	$ -	7
8	Incremental Annual TDSIC Revenue Requirement Adjusted for Cap (line 7 - line 8)	$ 24,193,737	8
9	Average Retail Rate Increase from TDSIC-1 (Line 7 / Line 1)	0.96%	9

(1) See Workpaper 1-DLD
(2) See Exhibit 3-B (DLD) page 14 of 14 column (F).

DUKE ENERGY INDIANA, LLC

DETERMINATION OF TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE IMPROVEMENT COST RATE
RECONCILIATION ADJUSTMENT BY RATE SCHEDULE FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2017

		Revenue Requirement for the Twelve Months Ended December 31, 2017										
		TDSIC-1		TDSIC-2								
Line No.	Rate Schedule	Jan-Jun 2017 Revenue Requirement Excluding Reconciliation (2)	100.00% of TDSIC-1 Related to the Twelve Months Ended Dec 2017	Jul 2017-Jun 2018 Revenue Requirement Excluding Reconciliation (3)	50.00% of TDSIC-2 Related to the Twelve Months Ended Dec 2017	Twelve Months Ended Dec 2017 Revenue Requirement Excluding Reconciliation	Adjusted Twelve Months Ended Dec 2017 TDSIC Revenues Billed (4)	Twelve Months Ended Dec 2017 Reconciliation Adjustment Included In Billed Revenues (2)(3)	Twelve Months Ended Dec 2017 TDSIC Revenues Billed Excluding Reconciliation	Twelve Months Ended Dec 2017 TDSIC Revenues (Over)/Under Collected	Adjusted Twelve Months Ended Dec 2017 TDSIC Revenues (Over)/Under Collected (5)	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	
1	Rate RS	$ 6,612,826	$ 6,612,826	$ 18,339,446	$ 9,169,723	$ 15,782,549	$ 9,960,576	$ -	$ 9,960,576	$ 5,821,973	$ 5,703,913	1
2	Rate CS	783,578	783,578	2,170,401	1,085,201	1,868,779	1,241,540	-	1,241,540	627,239	614,520	2
3	Rate LLF - Secondary	1,668,104	1,668,104	4,617,364	2,308,682	3,976,786	2,888,786	-	2,888,786	1,088,000	1,065,938	3
4	Rate LLF - Primary (1)	54,985	54,985	152,042	76,021	131,006	77,101	-	77,101	53,905	52,812	4
5	Rate LLF - Primary Direct	35,079	35,079	96,764	48,382	83,461	100,116	-	100,116	(16,655)	(16,317)	5
6	Rate LLF - Transmission	24,490	24,490	66,727	33,364	57,854	34,389	-	34,389	23,465	22,989	6
7	Rate HLF - Secondary	1,752,134	1,752,134	4,844,690	2,422,345	4,174,479	2,830,538	-	2,830,538	1,343,941	1,316,689	7
8	Rate HLF - Primary	746,785	746,785	2,061,381	1,030,691	1,777,476	1,269,598	-	1,269,598	507,878	497,579	8
9	Rate HLF - Primary Direct	423,861	423,861	1,165,046	582,523	1,006,384	688,343	-	688,343	318,041	311,592	9
10	Rate HLF - Common Transmission	115,407	115,407	314,450	157,225	272,632	174,137	-	174,137	98,495	96,498	10
11	Rate HLF - Bulk Transmission	64,889	64,889	176,922	88,461	153,350	110,269	-	110,269	43,081	42,207	11
12	Customer L	6,979	6,979	19,136	9,568	16,547	11,743	-	11,743	4,804	4,707	12
13	Customer D (1)	-	-	-	-	-	-	-	-	0	-	13
14	Customer O	71,271	71,271	194,191	97,096	168,367	115,777	-	115,777	52,590	51,524	14
15	Rate WP	50,898	50,898	140,816	70,408	121,306	82,695	-	82,695	38,611	37,828	15
16	Rate SL	28,067	28,067	78,032	39,016	67,083	44,380	-	44,380	22,703	22,243	16
17	Rate MHLS	4,760	4,760	13,240	6,620	11,380	7,640	-	7,640	3,740	3,664	17
18	Rates MOLS and UOLS	68,714	68,714	191,032	95,516	164,230	112,188	-	112,188	52,042	50,987	18
19	Rates TS, FS and MS	6,537	6,537	18,069	9,035	15,572	10,681	-	10,681	4,891	4,792	19
20	Total Retail	$ 12,519,364	$ 12,519,364	$ 34,659,749	$ 17,329,877	$ 29,849,241	$ 19,760,497	$ -	$ 19,760,497	$ 10,088,744	$ 9,884,165	20
21	Equity Related Percentage (6)									11.294%		21
22	Equity Portion of Reconciliation Adjustment									1,139,423		22
23	All Other Portion of Reconciliation Adjustment									8,949,321		23
24	Total Reconciliation Before Adjusting for Changes in Revenue Conversion									$ 10,088,744		24
							2017 Factors (6)	2018 Factors (7)	Change Impact			
25	Equity Portion - Change in Revenue Conversion Factors						1.67328	1.37140	81.959%	933,860		25
26	All Other Portion - Change in Revenue Conversion Factors						1.02101	1.02112	100.011%	8,950,305		26
27	Total Reconciliation After Adjusting for Changes in Revenue Conversion									$ 9,884,165		27

(1) Adjusted to reflect Customer D moving to LLF Primary.
(2) See IURC CAUSE NO. 44720 TDSIC-1 Exhibit 3-B (DLD) page 12.
(3) See IURC CAUSE NO. 44720 TDSIC-2 Exhibit 3-B (DLD) page 13.
(4) See Workpaper 28-DLD.
(5) Allocated to Rate Schedule based on Column (I)
(6) See Workpaper 34-DLD
(7) See Exhibit 3-B (DLD) Page 8.

DUKE ENERGY INDIANA, LLC

DETERMINATION OF TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE IMPROVEMENT COST RATE ADJUSTMENT FACTORS BY RATE SCHEDULE TO BE APPLIED TO CUSTOMERS' BILLS BEGINNING WITH THE EFFECTIVE DATE OF THE COMMISSION'S FINAL ORDER

Line No.	Rate Schedule	Percent of Transmission Revenue Requirement from IURC Cause No. 42359 (1)(2)	Transmission Revenue Requirement	Percent of Distribution Revenue Requirement from IURC Cause No. 42359 (1)(2)	Distribution Revenue Requirement	Reconciliation Adjustment For Prior TDSIC Riders	Total Transmission and Distribution Revenue Requirement	Reduction in Revenue Requirement Due to 2% Cap (3)	Adjusted Total Revenue Requirement	Kilowatt-Hour Sales For The Twelve Months Ended December 31, 2017	Transmission and Distribution Infrastructure Improvement Cost Rate Adjustment Factors Per KWH	Sum Of Monthly Non-Coincident Peak Demands For The Twelve Months Ended December 31, 2017	Transmission and Distribution Infrastructure Improvement Cost Rate Adjustment Factor Per KW	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	
1	Rate RS	37.432%	$ 5,413,779	58.639%	$ 20,234,179	$ 5,703,913	$ 31,351,871	$ -	$ 31,351,871	8,550,451,791	$0.003667			1
2	Rate CS	5.743%	830,608	6.454%	2,227,040	614,520	3,672,168	-	3,672,168	1,031,535,953	$0.003560			2
3	Rate LLF - Secondary	13.695%	1,980,704	13.184%	4,549,317	1,065,938	7,595,959	-	7,595,959	4,060,910,075	$0.001871			3
4	Rate LLF - Primary (1)	0.527%	76,220	0.406%	140,096	52,812	269,128	-	269,128	451,746,245	$0.000596			4
5	Rate LLF - Primary Direct	0.450%	65,083	0.216%	74,534	(16,317)	123,300	-	123,300	214,638,759	$0.000574			5
6	Rate LLF - Transmission	0.713%	103,121	0.000%	-	22,989	126,110	-	126,110	167,165,596	$0.000754			6
7	Rate HLF - Secondary	16.927%	2,448,147	12.887%	4,446,833	1,316,689	8,211,669	-	8,211,669	4,046,223,440		8,315,814	$0.987476	7
8	Rate HLF - Primary	8.901%	1,287,349	4.855%	1,675,283	497,579	3,460,211	-	3,460,211	2,065,555,308		3,841,365	$0.900776	8
9	Rate HLF - Primary Direct	7.442%	1,076,334	1.852%	639,058	311,592	2,026,984	-	2,026,984	2,372,539,933		4,121,227	$0.491840	9
10	Rate HLF - Common Transmission	3.360%	485,956	0.000%	-	96,498	582,454	-	582,454	1,183,687,980		2,185,811	$0.266470	10
11	Rate HLF - Bulk Transmission	1.831%	264,817	0.022%	7,591	42,207	314,615	-	314,615	1,238,584,095		2,133,697	$0.147451	11
12	Customer L	0.145%	20,971	0.022%	7,591	4,707	33,269	-	33,269	114,806,810	$0.000290			12
13	Customer D (1)	0.000%	-	0.000%	-	-	-	-	-	-	$0.000000			13
14	Customer O	2.075%	300,107	0.000%	-	51,524	351,631	-	351,631	157,645,853	$0.002231			14
15	Rate WP	0.453%	65,517	0.389%	134,230	37,828	237,575	-	237,575	147,089,202	$0.001615			15
16	Rate SL	0.066%	9,546	0.284%	97,998	22,243	129,787	-	129,787	39,648,920	$0.003273			16
17	Rate MHLS	0.009%	1,302	0.049%	16,908	3,664	21,874	-	21,874	5,624,930	$0.003889			17
18	Rates MOLS and UOLS (2)	0.165%	23,864	0.694%	239,474	50,987	314,325	-	314,325	109,646,147	$0.002867			18
19	Rates TS, FS and MS	0.066%	9,546	0.047%	16,218	4,792	30,556	-	30,556	9,607,314	$0.003180			19
20	Total Retail	100.000%	$ 14,462,971	100.000%	$ 34,506,350	$ 9,884,165	$ 58,853,486	$ -	$ 58,853,486	25,967,108,351				20
	Sources:		Exhibit 3-B (DLD) page 8 of 14		Exhibit 3-B (DLD) page 9 of 14	Exhibit 3-B (DLD) page 13 of 14		Exhibit 3-B (DLD) page 12 of 14		Workpaper 1-DLD and Workpaper 3-DLD		Workpaper 3-DLD		

(1) Adjusted to reflect Customer D moving to LLF Primary.
(2) As adjusted for migrations of AL and OL rate groups to UOLS rate group.
(3) Allocated to Rate Schedule based on total revenue requirement before 2% cap.

DUKE ENERGY INDIANA, LLC

COMPARISON OF TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE IMPROVEMENT COST RATE ADJUSTMENT FACTORS

Line No.	Description	TDSIC-4		TDSIC-2		Change		Line No.
		(A)		(B)		(C)		
1	Rate RS	$ 0.003667	/KWH	$ 0.002062	/KWH	$ 0.001605	/KWH	1
2	Rate CS	0.003560	/KWH	0.002016	/KWH	0.001544	/KWH	2
3	Rate LLF - Secondary	0.001871	/KWH	0.001141	/KWH	0.000730	/KWH	3
4	Rate LLF - Primary (1)	0.000596	/KWH	0.000209	/KWH	0.000387	/KWH	4
5	Rate LLF - Primary Direct	0.000574	/KWH	0.000741	/KWH	(0.000167)	/KWH	5
6	Rate LLF - Transmission	0.000754	/KWH	0.000352	/KWH	0.000402	/KWH	6
7	Rate HLF - Secondary	0.987476	/KW	0.559489	/KW	0.427987	/KW	7
8	Rate HLF - Primary	0.900776	/KW	0.531675	/KW	0.369101	/KW	8
9	Rate HLF - Primary Direct	0.491840	/KW	0.272841	/KW	0.218999	/KW	9
10	Rate HLF - Common Transmission	0.266470	/KW	0.140312	/KW	0.126158	/KW	10
11	Rate HLF - Bulk Transmission	0.147451	/KW	0.085414	/KW	0.062037	/KW	11
12	Customer L	0.000290	/KWH	0.000169	/KWH	0.000121	/KWH	12
13	Customer D (1)	-	/KWH	0.001690	/KWH	(0.001690)	/KWH	13
14	Customer O	0.002231	/KWH	0.001229	/KWH	0.001002	/KWH	14
15	Rate WP	0.001615	/KWH	0.000967	/KWH	0.000648	/KWH	15
16	Rate SL	0.003273	/KWH	0.001923	/KWH	0.001350	/KWH	16
17	Rate MHLS	0.003889	/KWH	0.002436	/KWH	0.001453	/KWH	17
18	Rates MOLS and UOLS	0.002867	/KWH	0.001742	/KWH	0.001125	/KWH	18
19	Rates TS, FS and MS	0.003180	/KWH	0.001912	/KWH	0.001268	/KWH	19

(1) TDSIC-4 reflects Customer D moving to LLF Primary.

DUKE ENERGY INDIANA, LLC

COMPARISON OF THE EFFECT OF A CHANGE IN THE TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE IMPROVEMENT COST RATE ADJUSTMENT FACTOR (RIDER NO. 65) ON THE TOTAL BILL OF A TYPICAL RESIDENTIAL CUSTOMER USING 1,000 KWHS AS OF APRIL 2018 CYCLE 1

Line No.	Description	Revenue Adjustment Factor for TDSIC Rider No. 65	Base Bill for Typical Residential Customer (1)	All Other Riders Excluding TDSIC Rider (2)	Total Bill for Typical Residential Customer Excl. TDSIC Rider	TDSIC Rider Rider No. 65 Revenue Adjustment for 1,000 KWHs	Total Bill Including TDSIC Rider No. 65 Revenue Adjustment	Increase/ (Decrease) in Total Bill From Current Factor	% Increase/ (Decrease) in Total Bill From Current Factor	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	
1	Proposed TDSIC-4 Factor	$0.003667	$75.20	$45.09	$120.29	$3.67	$123.96	$1.61 (3)	1.32%	1
2	TDSIC-2 Factor	$0.002062	$75.20	$45.09	$120.29	$2.06	$122.35	N/A	N/A	2

(1) Reflects rates approved in Cause No. 42359.
(2) Rates in effect as of April 2018 Cycle 1.
(3) Line 1, Column F less Line 2, Column F.

DUKE ENERGY INDIANA, LLC

20% AMOUNTS DEFERRED FOR TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE IMPROVEMENT

Line No.	Filing	Investment	Accum. Depreciation	Net Book Value	Depreciation Expense	Oper. & Mtc. and Payroll Tax	Property Taxes	Post In-Serv. Carrying Cost	Carrying Cost on O&M and Prop. Taxes (3)	Total	Line No.
		(A)	(B)	(C) ((A)-(B))	(D)	(E)	(F)	(G)	(H)	(I) (Sum (C) through (H))	
1	TDSIC-1 June 30, 2016 (1)	$ 4,512,461	$ 19,157	$ 4,493,304	$ 19,157	$ 609,234	$ -	$ 46,617	$ -	$ 5,168,312	1
2	TDSIC-2 December 31, 2016 (1)	11,291,625	112,928	11,178,697	112,928	1,675,879	-	238,861	-	13,206,365	2
3	TDSIC-4 December 31, 2017 (2)	38,465,502	810,909	37,654,593	810,907	3,609,130	40,142	1,699,107	286,182	44,100,061	3
4	TDSIC-6	-	-	-	-	-	-	-	-	-	4
5	TDSIC-8	-	-	-	-	-	-	-	-	-	5
6	TDSIC-10	-	-	-	-	-	-	-	-	-	6
7	TDSIC-12	-	-	-	-	-	-	-	-	-	7
8	TDSIC-14	-	-	-	-	-	-	-	-	-	8
9	Cumulative	$ 54,269,588	$ 942,994	$ 53,326,594	$ 942,992	$ 5,894,243	$ 40,142	$ 1,984,585	$ 286,182	$ 62,474,738	9

(1) IURC Cause No. 44720 TDSIC-2 Exhibit 3-D
(2) Columns A and B are cumulative amounts shown on Exhibit 3-B (DLD) pages 1 and 3 less TDSIC-1 and TDSIC-2 amounts.
Columns D through H are current period amounts shown on Exhibit 3-B (DLD) pages 4-6 in column B, and on page 7 in column C.
(3) Prior to 12/31/2016, Duke Energy Indiana had not yet recorded these carrying costs.

VERIFICATION

I hereby verify under the penalties of perjury that the foregoing representations are true to the best of my knowledge, information and belief.

Signed: Diana L. Douglas
Diana L. Douglas

Dated: 4/25/2018