

**COMMONWEALTH OF KENTUCKY  
BEFORE THE  
KENTUCKY PUBLIC SERVICE COMMISSION**

In the Matter of:

The Application of Duke Energy Kentucky, )  
Inc., for (1) a Certificate of Public )  
Convenience and Necessity Authorizing )  
the Construction of an Advanced Metering ) Case No. 2016-00152  
Infrastructure; (2) Request for Accounting )  
Treatment; and (3) All Other Necessary )  
Waivers, Approvals, and Relief. )

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**REBUTTAL TESTIMONY OF  
DONALD L. SCHNEIDER, JR.  
ON BEHALF OF  
DUKE ENERGY KENTUCKY, INC.**

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October 13, 2016

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**ATTACHMENTS:**

DLS-SUPP-1 Duke Energy Indiana IURC Order and Settlement Agreement,  
Cause No. 44720

DLS-SUPP-2 Copy of Duke Energy Indiana Press Release

**I. INTRODUCTION AND PURPOSE**

1 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A. My name is Donald L. Schneider, Jr., and my business address is 400 South  
3 Tryon Street, Charlotte, North Carolina 28202.

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

5 A. I am employed as Director, Advanced Metering by Duke Energy Business  
6 Services LLC, a service company subsidiary of Duke Energy Corporation (Duke  
7 Energy), and a non-utility affiliate of Duke Energy Kentucky, Inc. (Duke Energy  
8 Kentucky or Company).

9 **Q. ARE YOU THE SAME DONALD L. SCHNEIDER THAT SUBMITTED**  
10 **DIRECT TESTIMONY IN THIS PROCEEDING?**

11 A. Yes.

12 **Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS**  
13 **PROCEEDING?**

14 A. The purpose of my rebuttal testimony is to respond to testimony submitted by  
15 Paul Alvarez on behalf of the Office of the Attorney General of the  
16 Commonwealth of Kentucky regarding the Company's Application for a  
17 Certificate of Public Convenience and Necessity (CPCN) for its Advanced  
18 Metering Infrastructure (AMI) metering system upgrade (Meter Upgrade).  
19 Specifically, I am addressing three primary issues raised by Mr. Alvarez. The first  
20 issue involves Mr. Alvarez's comments regarding the timing of the Company's  
21 request for a CPCN. Next, I respond to Mr. Alvarez's unsubstantiated claims  
22 regarding the size of the Company's requested regulatory asset required for the

1 early retirement of its existing metering infrastructure and, in turn, the validity of  
2 the Company's cost-benefit analysis as it relates to the Company's request for  
3 such a regulatory asset. I also am offering clarification regarding allegations  
4 raised by Mr. Alvarez as it relates to regulatory proceedings involving Duke  
5 Energy affiliated operating companies and their own metering infrastructure  
6 improvement proceedings.

**II. TIMING OF THE COMPANY'S CPCN REQUEST**

7 **Q. PLEASE EXPLAIN MR. ALVAREZ'S POSITION REGARDING THE**  
8 **TIMING OF THE COMPANY'S CPCN REQUEST.**

9 A. Mr. Alvarez devotes the vast majority of his testimony to questioning the process  
10 of the Company's CPCN application as a stand-alone filing versus in a rate case.  
11 His primary recommendation is that the Commission should modify its existing  
12 practice for CPCN application by delaying consideration of the Company's Meter  
13 Upgrade until Duke Energy Kentucky files its next electric base rate case.

14 **Q. DO YOU HAVE AN OPINION ON MR. ALVAREZ'S POSITION AS TO**  
15 **THE TIMING OF THE CPCN APPLICATION?**

16 A. I disagree with Mr. Alvarez. The Commission has already addressed this issue by  
17 its Order dated September 28, 2016, denying the Attorney General's Motion to  
18 Dismiss that was based upon the same argument. Therefore, much of Mr.  
19 Alvarez's testimony on this issue is moot and irrelevant. Utilities and this  
20 Commission should have the flexibility to seek, consider, and receive approval,  
21 respectfully, of any capital investment or construction that is needed and/or is in  
22 the public interest at any time, including metering infrastructure enhancements.

1 The timing of such requests should not be limited solely to when the utility files a  
2 base rate case. Duke Energy Kentucky witness Ms. Laub explains implications of  
3 Mr. Alvarez's position more fully in her rebuttal testimony.

4 **Q. WILL YOU BRIEFLY EXPLAIN WHY THE COMPANY FILED ITS**  
5 **METER UPGRADE AS A STAND-ALONE CPCN APPLICATION?**

6 A. The Company filed its CPCN application outside of a rate case, following the path  
7 previously used by other jurisdictional utilities for their own advanced meter  
8 deployments and in response to the Commission's recent directive as part of its  
9 Order in Case No. 2012-00428 that utilities should file a CPCN to obtain approval  
10 for significant meter deployments.<sup>1</sup> There was no mention or any implication in  
11 the Commission's order in that proceeding that CPCN applications could or  
12 should only occur in a base rate proceeding.

### **III. COST-BENEFIT ANALYSIS**

13 **Q. PLEASE DESCRIBE MR ALVAREZ'S CONCERNS REGARDING DUKE**  
14 **ENERGY KENTUCKY'S COST-BENEFIT ANALYSIS AND THE**  
15 **REQUESTED REGULATORY ASSET FOR THE RETIREMENT OF THE**  
16 **COMPANY'S EXISTING METERING INFRASTRUCTURE.**

17 A. Mr. Alvarez makes several unsubstantiated claims questioning the Company's  
18 cost-benefit analysis. He first claims that the size of the Company's proposed  
19 regulatory asset as compared to the deployment costs is "significant" and believes  
20 the Company "misrepresents smart meter deployment economics" because it did  
21 not factor assumptions projecting stranded cost recovery into the cost-benefit

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<sup>1</sup> *In the Matter of the Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428 at 11 (Ky.PSC April 13, 2016).

1 analysis.<sup>2</sup> He also expresses a “concern” that it is “probable” that the benefits  
2 projected are “aggressive” and would prove “difficult for customers to realize...”<sup>3</sup>

3 **Q. DO YOU AGREE WITH MR. ALVAREZ’S CLAIMS?**

4 A. No, for several reasons. First, it must be recognized that Mr. Alvarez’s criticism  
5 of the Company’s cost-benefit analysis is not based upon any empirical analysis  
6 of the Company’s application and supporting documents. In response to  
7 Company-issued discovery, Mr. Alvarez indicated that he performed no such  
8 analysis.<sup>4</sup> His position in this regard is based upon experience in other  
9 proceedings, and not this case.<sup>5</sup> Second, as I will explain, the ratio of deployment  
10 costs to the proposed regulatory asset is a meaningless comparison. Third, the  
11 Company’s application is supported by a detailed cost-benefit analysis that relies  
12 upon experience and is based upon the best available data in terms of the  
13 Company’s costs and achievable savings, while avoiding needless speculation and  
14 hypothetical assumptions for amortization periods regarding undepreciated meter  
15 assets.

16 While it is true that the cost-benefit analysis did not incorporate the  
17 recovery of costs related to the undepreciated net-book value of the existing  
18 meters that will be retired, it should also be noted that this analysis was  
19 conservative and based only upon what the Company believes is achievable  
20 quantitative results, based upon actual experience. This cost-benefit analysis,  
21 intentionally did not factor the value of qualitative net benefits that will be

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<sup>2</sup> Alvarez Testimony at 8 and 20.

<sup>3</sup> *Id.*

<sup>4</sup> See Attorney General’s Responses to Data Request of Duke Energy Kentucky, Inc., Response to Data Request No. 7, August 15, 2016.

<sup>5</sup> Alvarez Testimony at 18.

1 unlocked through the Meter Upgrade, many of which are associated with the  
2 enhanced basic customer services described by Dr. Weintraub and are ignored by  
3 Mr. Alvarez in his testimony. Examples include carbon reduction from estimated  
4 energy savings due to better customer understanding of their usage; increased  
5 operational efficiencies with respect to outage restoration; the facilitation of  
6 integrating advanced technologies such as distributed generation, energy storage  
7 and electric vehicles with our distribution system; and the ability to offer  
8 expanded options for energy efficiency and demand response programing, etc.  
9 Those qualitative benefits would serve to increase the overall net benefits to  
10 customers beyond what is capable of quantification and reflected in Confidential  
11 Attachment DLS-4 to my direct testimony.

12 **Q. ARE THE ESTIMATED COSTS OF THE METER UPGRADE**  
13 **INVESTMENTS JUSTIFIED BY INCREMENTAL BENEFITS?**

14 A. Yes, the cost-benefit analysis demonstrates that there are quantifiable benefits that  
15 substantially outweigh the costs of the plan. Confidential Attachment DLS-4  
16 includes a Net Present Value (NPV) summary showing costs are justified by the  
17 benefits of the project.

18 **Q. HOW AND WHEN WILL CUSTOMERS EXPERIENCE THE SAVINGS**  
19 **FROM THE ESTIMATED QUANTIFIABLE BENEFITS OF THE METER**  
20 **UPGRADE INVESTMENT?**

21 A. The timing of when customers will experience such benefits depends entirely  
22 upon the nature of the benefit itself. The qualitative benefits attributable toward  
23 enhanced convenience and services will be available to customers upon full

1 deployment and operation. The quantifiable benefits attributable to efficiencies  
2 and cost savings will naturally flow to customers through the Company's  
3 Commission-approved rates in its next electric base rate case. For instance, the  
4 cost saving benefits associated with reduced meter operations costs and revenue  
5 protection associated with better theft detection, reduction of meter installation  
6 errors, and elimination of reduced registration from electro-mechanical meters,  
7 will be reflected through the Company's base rates in a future rate case.

8 **Q. PLEASE EXPLAIN WHY YOU DISAGREE WITH MR. ALVAREZ'S**  
9 **CHARACTERIZATION OF THE COMPANY'S REGULATORY ASSET**  
10 **REQUEST IN COMPARISON TO THE COST OF THE METER**  
11 **UPGRADE DEPLOYMENT?**

12 **A.** Mr. Alvarez is critical of the Company's request to create a regulatory asset for  
13 the amortization of the expense related to the early retirement of the Company's  
14 current metering infrastructure, arguing that it represents a significant expense  
15 relative to the total system deployment cost.<sup>6</sup> His comparison ratio of the old  
16 meters' remaining book value to deployment costs is an arbitrary and meaningless  
17 metric. Therefore, his characterization of the Company's "ratio" as significant is  
18 similarly arbitrary. This is especially true when one considers other advanced  
19 metering deployments and regulatory asset cases recently approved by this  
20 Commission. For example, the chart below summarizes recent Kentucky  
21 precedent involving utility advanced metering deployments' regulatory assets for  
22 early retirement of the existing metering system. In each instance, the deployment  
23 cost-to-meter retirement value is similar to or significantly greater than that of

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<sup>6</sup> Alvarez Testimony at 7.

1 Duke Energy Kentucky.

CPCN Case No.	Regulatory Asset/Rate Case No.	Utility	Deployment Cost (\$million)	Undepreciated Value (\$million)	Asset Deployment
2014-00376	2015-00141	Kenergy	\$9.70	\$3.88	40%
2009-00489	2011-00096	South Kentucky RECC	\$19.50	\$3.70	19%
2006-00286	2008-00376	Taylor County RECC	\$4.10	\$1.20	29%

2 It is noteworthy that, in each instance, the Commission approved the CPCN and,  
3 in some instances, the regulatory asset, outside of a base rate case. When viewed  
4 in context and as compared to prior deployments approved by this Commission,  
5 Duke Energy Kentucky's regulatory asset is approximately twenty percent of the  
6 total meter deployment cost and, as discussed below, is not significant at all,  
7 especially when compared to other recent CPCNs approved by the Commission.

8 To further demonstrate the meaningless nature of the comparison between  
9 the costs of deployment to the undepreciated value of early meter retirement,  
10 South Kentucky RECC's deferral represented approximately nineteen percent of  
11 its total AMI deployment cost when one ignores the fact that South Kentucky  
12 received approximately \$9.5 million in federal grants toward its AMI deployment.  
13 However, when one factors in the federal grant, which reduced the overall AMI  
14 deployment cost, Mr. Alvarez's ratio would result in a thirty-seven percent  
15 "premium," to use his vernacular, of early retired meter expense to South  
16 Kentucky RECC's AMI deployment costs.<sup>7</sup> The simple fact is that the cost to  
17 deploy a new system has no relevance or relation to the early retirement of

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<sup>7</sup> *In the Matter of the Application of South Kentucky Rural Electric Cooperative Corporation for an Adjustment of Electric Rates*, Case No. 2011-00096, (Ky. PSC March 30, 2012); *Approving*, among other things, accounting treatment of the \$3.7 million in early meter retirement expense and a 15-year amortization period. *See also, Id.* (Ky. PSC May 11, 2012); affirming regulatory treatment and amortization on rehearing.

1 meters. A comprehensive cost-benefit analysis, which Duke Energy Kentucky  
2 has developed in this case, is an industry recognized approach to determining the  
3 value of a project as opposed to looking at a ratio of the old meters' remaining  
4 book value to deployment costs.

5 **Q. DO YOU BELIEVE THAT IT IS NECESSARY TO INCLUDE THE**  
6 **EARLY RETIREMENT OF THE EXISTING METERING**  
7 **INFRASTRUCTURE AS PART OF THE COMPANY'S COST-BENEFIT**  
8 **ANALYSIS FOR THE COMMISSION TO EVALUATE THE**  
9 **REASONABLENESS OF THE COMPANY'S CPCN AND REQUEST TO**  
10 **CREATE A REGULATORY ASSET?**

11 A. No, I do not. As I previously indicated, this Commission has previously and  
12 separately approved metering upgrade CPCN requests and requests for creation of  
13 regulatory assets related to retirement of metering infrastructure due to upgrades.  
14 So one is clearly not dependent upon the other. The Company is not seeking  
15 actual rate recovery of either its metering deployment or the regulatory asset in  
16 this proceeding. The proposed deployment is justifiable under the submitted cost-  
17 benefit analysis.

18 **Q. ARE THERE ANY COMPELLING REASONS WHY THE REGULATORY**  
19 **ASSET REQUEST SHOULD BE EVALUATED SEPARATELY FROM**  
20 **THE METER UPGRADE COST-BENEFIT ANALYSIS?**

21 A. Yes. The undepreciated meters currently in use represent an existing investment  
22 or "sunk" cost that is already reflected in base rates and has no bearing on the net  
23 benefits achievable with a new investment. The costs of the Meter Upgrade

1 should not be viewed as artificially higher simply because there is a portion of  
2 costs related to the existing meters that have not been fully recovered in base  
3 rates. Such will always be the case, regardless of an investment, as long as the  
4 utility is replacing or retiring any asset prior to its full depreciation.

5 Including the costs of the undepreciated meters in a cost-benefit analysis  
6 would distort the purpose of the cost-benefit analysis for the new investment,  
7 which, is to compare the incremental costs of the new investment to its  
8 incremental benefits. It is not intended to be a comparison to a prior technology  
9 investment in need of replacement that is not capable of providing the newly  
10 enabled benefits. If Duke Energy Kentucky did not propose to upgrade its  
11 metering infrastructure, its customers would continue to pay the full amount of  
12 the prudently incurred costs of existing meters. Therefore, the cost of an AMI  
13 project should not be viewed as higher simply because there is a portion of the  
14 costs of existing meters that remain to be recovered. The nature of the Meter  
15 Upgrade investment should be evaluated in relation to its capabilities and the  
16 benefits that it can provide.

17 In addition, meters are accounted for as “mass assets” and depreciated on  
18 a composite group basis. Accounting for a system-wide upgrade requires the  
19 application of abandonment accounting treatment which reclassifies the plant in  
20 service asset to a financial or regulatory asset to account for the remaining  
21 undepreciated value, as I will address further on in this testimony.

22 **Q. BASED UPON THE DATA AND ANALYSIS THAT THE COMPANY HAS**  
23 **ALREADY PROVIDED, IS IT POSSIBLE TO EVALUATE THE IMPACT**

1           **OF THE EARLY RETIREMENT COSTS IN RELATION TO THE**  
2           **COMPANY'S COST-BENEFIT ANALYSIS?**

3    A.    Yes. Such a comparison can be easily made on a nominal basis using data that is  
4           already in the record.

5    **Q.    PLEASE EXPLAIN.**

6    A.    Although the Company did not include projections for how the proposed  
7           regulatory asset would be recovered through rates in its cost-benefit analysis, data  
8           is in the record to make such an evaluation already based upon the nominal value  
9           of net benefits and the early retirement expense. Such a comparison merely  
10          requires an understanding of utility rate making and the difference between  
11          nominal and NPV dollar calculations and correct comparisons.

12                 The Company's application and testimony supports that the estimated  
13                 undepreciated net book value of the current metering system that will have to be  
14                 retired will be \$9.6 million. This is a nominal figure representing the estimated  
15                 total of the undepreciated asset's net book value at the time of retirement, based  
16                 on the actual account value at the time of this filing. If the Commission approves  
17                 the Company's CPCN application, but denies the regulatory asset, and the  
18                 Company, in turn, decides to proceed with the Meter Upgrade deployment absent  
19                 the creation of the regulatory asset, this total amount will have to be written off at  
20                 once causing a direct and negative impact to Duke Energy Kentucky's financial  
21                 condition. However, if the Commission approves the Company's regulatory asset  
22                 request, this estimated \$9.6 million will not negatively impact the Company's  
23                 earnings and will, instead, be amortized over some period of time for inclusion

1 into utility rates. It is that lesser amortized amount (or NPV value) that will  
2 ultimately be reflected in the Company's base rates and recovered over a period  
3 of years, yet to be determined. Therefore, the nominal value of the proposed  
4 regulatory asset is quantifiable at this time. The NPV is not.

5 Duke Energy Kentucky's cost-benefit analysis reflected in Attachment  
6 DLS-4 to my direct testimony contains both the nominal (*i.e.*, total) dollars of the  
7 difference between the costs of deployment and estimated benefits (approx. \$46  
8 million), as well as the reduced NPV of such net benefits (approx. \$7 million). A  
9 simple, apples-to-apples comparison can be easily made on a nominal basis  
10 between the approximately \$46 million in net benefits of the Meter Upgrade and  
11 the estimated \$9.6 million in early meter system retirement expense.

$$12 \quad \$46 \text{ million} - \$9.6 \text{ million} = \$36.4 \text{ million}$$

13 Mr. Alvarez's suggestion that the Company's metering upgrade may not produce  
14 net benefits when the regulatory asset is factored in to the analysis is unsupported.  
15 Since Mr. Alvarez did not present any substantiation for this claim, one must  
16 assume that he was comparing the nominal value of the proposed regulatory asset  
17 against the NPV for the cost-benefit analysis. It is important to appreciate the  
18 distinction between nominal and NPV dollars and that comparing the nominal  
19 \$9.6 million value of the proposed regulatory asset to the estimated \$7 million  
20 NPV benefit is incorrect and equivalent to comparing apples to oranges. The  
21 former is a nominal or total value, while the latter is a reduced present value of  
22 the total.

23 **Q. COULD THE COMPANY EASILY HAVE PERFORMED A COST-**

1           **BENEFIT ANALYSIS THAT INCLUDED THE REGULATORY ASSET**  
2           **TREATMENT ON A NET-PRESENT VALUE BASIS?**

3    A.    No. The Company could not reasonably perform such an analysis on a NPV basis  
4           without making multiple assumptions and performing numerous iterations of such  
5           analysis to examine all possible outcomes. There are simply too many variable  
6           inputs to reasonably perform such an analysis, including, but not limited to,  
7           timing of approvals, amortization periods, depreciation rate relative to approval  
8           timing, the levels of interim meter replacements until deployment of the new  
9           system commences, and timing of the next base rate case, among others. The  
10          Company filed its request to create a regulatory asset along with the CPCN to be  
11          clear about the linkage of those issues in terms of the retirement costs of making  
12          the investments and the Company's ability to make the new technology  
13          investment. However, the final rate impact of the regulatory asset will depend  
14          greatly on the accounting treatment afforded by the Commission, including, but  
15          not limited to, the asset amortization.

16                 The Commission recognized those complexities in its Order allowing  
17                 Kenergy Corp. to create a regulatory asset in Case No. 2015-00141.<sup>8</sup> In that  
18                 Order, the Commission deferred approval of an amortization period until  
19                 Kenergy's next base rate case and also declined to approve a specific dollar  
20                 amount for the regulatory asset, instead instructing Kenergy to continue  
21                 depreciating meters until they were actually removed from service and the related

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<sup>8</sup> *In the Matter of the Request of Kenergy Corp for Approval to Establish a Regulatory Asset in the Amount of \$3,884,717 Amortized over a ten (10) Year Period, Case No. 2015-00141 (Ky.PSC. August 31, 2015);* authorizing Kenergy to record a regulatory asset for the loss on the disposal of its electro-mechanical meters based on the undepreciated balance of the meters retired at the time of their retirement, and that the amortization period for the asset will be addressed in their next rate case.

1           loss on disposal could be determined at that time.

2           Duke Energy Kentucky's estimated \$9.6 million system retirement costs  
3           could change if, for example, the Commission approval of the Company's  
4           application extends into 2017. This is because meters are accounted for as "mass  
5           assets" and Duke Energy Kentucky must continue to add new meters (service to  
6           new structures/customers) and replace existing meters (retirements and failures)  
7           under current protocols until the Company's application is approved. If the new  
8           installation and replacement rate (new capital costs) exceeds the depreciation rate  
9           of the existing infrastructure, the \$9.6 million figure could increase. Similarly, if  
10          depreciation exceeds the new capital additions, then the \$9.6 million figure will  
11          be reduced.

12          All else being equal, differences in the amortization periods alone will  
13          have a direct impact on the cost-benefit analysis outcome. For example, \$9.6  
14          million amortized over three years (chosen arbitrarily as a demonstration of this  
15          argument) would result in a larger annualized expense than that of a fifteen-year  
16          amortization period (\$3.2 million/yr vs. \$640,000/yr). Once the regulatory asset is  
17          authorized, and the Company's CPCN application approved, the regulatory asset  
18          value will be known. And the Commission will then be able to determine a  
19          reasonable amortization period as part of a following rate case. All parties will  
20          have the ability to evaluate and advocate for an appropriate amortization period  
21          for these expenses at that time. In fact, recent precedent demonstrates this fact.

22          On September 15, 2016, the Commission issued its Order in Kenergy's  
23          base electric rate case, Case No. 2015-00312, which, among other things,

1 approved Kenergy's recovery and amortization of the approximately \$3.88  
2 million in undepreciated meter expense resulting from its advanced meter  
3 deployment over a fifteen year period.

4 It is simply not necessary to determine now and unnecessarily and  
5 unreasonably complicates the cost-benefit analysis because it produces a number  
6 of assumptions and iterations.

7 **Q. IN LIGHT OF MR. ALVAREZ'S TESTIMONY, DO YOU CONTINUE TO**  
8 **BELIEVE THAT DUKE ENERGY KENTUCKY'S COST-BENEFIT**  
9 **ANALYSIS IS REASONABLE?**

10 A. Yes. Mr. Alvarez opted not to conduct any examination of the Company's cost-  
11 benefit analysis, beyond his claims regarding the size and presentation of Duke  
12 Energy Kentucky's proposed regulatory asset.

13 As I explained in my direct testimony, Duke Energy Kentucky's cost-  
14 benefit analysis was based upon actual costs and deployment and operational  
15 experiences from other Duke Energy jurisdictional deployments.

16 In fact, as I explained, so not to overstate benefits, the Company did not  
17 include the numerous qualitative benefits (such as carbon reductions) that will be  
18 eventually realized or the likely benefits and cost savings that will be achieved  
19 through the enhanced basic services discussed by Dr. Weintraub in his direct  
20 testimony. Including such benefits would serve to increase the overall net-benefits  
21 that are available to customers, not reduce them. If the Commission approves the  
22 Company's application, Duke Energy Kentucky's customers will immediately  
23 experience convenience, choice and control type benefits (usage data availability,

1 remote orders and other enhanced basic services) and eventually be able to  
2 experience all achieved benefits, in time, through rates.

**III. OTHER RECENT DUKE ENERGY UTILITY ADVANCED METER  
DEPLOYMENT PROCEEDINGS**

3 **Q. ON PAGE 13 OF HIS TESTIMONY, MR. ALVAREZ CITES TO A**  
4 **RECENT SETTLEMENT BY DUKE ENERGY INDIANA, INC. BOTH AS**  
5 **AN EXAMPLE OF UTILITIES NOT RECEIVING FAVORABLE**  
6 **TREATMENT OF WHAT HE REFERS TO AS STRANDED ASSET**  
7 **RECOVERY, AND “REGULATORS AND CONSUMER ADVOCATES**  
8 **RECOGNIZING CUSTOMER RISKS WITH SMART METER**  
9 **DEPLOYMENTS OUTSIDE OF A RATE CASE.” ARE MR. ALVAREZ’S**  
10 **CHARACTERIZATIONS OF THAT CASE ACCURATE?**

11 **A.** No they are not. Mr. Alvarez admitted in discovery that he was not involved in  
12 the Duke Energy Indiana, Inc. (Duke Energy Indiana) proceeding that he cites to  
13 in testimony.<sup>9</sup> I, however, was involved in that proceeding, having submitted  
14 testimony on behalf of Duke Energy Indiana, and thus have direct knowledge of  
15 Duke Energy Indiana’s application and the ultimate settlement.<sup>10</sup> In making his  
16 point, Mr. Alvarez quotes certain company statements out of context, which in  
17 turn, misconstrues the position and messages.

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<sup>9</sup> See Attorney General’s Responses to Data Request of Duke Energy Kentucky to Data Request Response No. 28, August 15, 2016.

<sup>10</sup> See *DLS-Supp-1. In Re: Verified Petition of Duke Energy Indiana, Inc. for: (1) Approval of Petitioner’s 7-Year Plan for Eligible Transmission Distribution and Storage System Improvements, Pursuant to Ind. Code 8-1-39-10; (2) Approval of a Transmission and Distribution Infrastructure Improvement Cost Rate Adjustment and Deferrals pursuant to Ind. Code 8-1-39-9; (3) Approval of Certain Regulatory Assets; (4) Approval of Voluntary Dynamic Pricing Riders; and (5) Approval of a new Depreciation Rate for Advanced Meters.* Cause No. 44720, Order at 23 (June 29, 2016).

1 **Q. PLEASE BRIEFLY SUMMARIZE THE DUKE ENERGY INDIANA**  
2 **PROCEEDING THAT MR. ALVAREZ DISCUSSES IN HIS TESTIMONY.**

3 A. Duke Energy Indiana's application in that proceeding involved a proposal to  
4 implement a comprehensive distribution and transmission infrastructure  
5 improvement program with surcharge recovery outside of a rate case (TDSIC).  
6 The TDSIC filing was far more expansive than the Meter Upgrade proposed by  
7 Duke Energy Kentucky in this case. In the Duke Energy Indiana TDSIC case, the  
8 company's AMI proposal was one small piece of a comprehensive, seven year,  
9 \$1.8 billion transmission and distribution infrastructure investment proposal.  
10 Ultimately, a settlement agreement was reached between Duke Energy Indiana  
11 and the nine intervening parties establishing a regulatory model for recovering  
12 \$1.4 billion of investments through the rider. I am including a copy of the Indiana  
13 Utility Regulatory Commission's (IURC) Order approving the settlement as  
14 Attachment DLS-SUPP-1 for ease of reference.

15 **Q. PLEASE SUMMARIZE THE SETTLEMENT REACHED IN THAT**  
16 **INDIANA PROCEEDING.**

17 A. As is the case in every regulatory settlement, parties negotiate and compromises  
18 are made. In that case, as can be seen in the settlement agreement attached to the  
19 IURC's Order, Duke Energy Indiana, in exchange for approval of the vast  
20 majority of its TDSIC tracker and associated projects, agreed not to include its  
21 AMI proposal in the cost recovery tracker.<sup>11</sup> In addition, Duke Energy Indiana  
22 agreed, that it would forego seeking recovery of the undepreciated metering

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<sup>11</sup> See DLS-Supp-1, page 33-49. The portion of the settlement agreement addressing AMI begins on page 35 of 49, Section 5a-h and Section 6.

1 infrastructure that would be replaced as part of the AMI deployment. The IURC  
2 ultimately approved the comprehensive settlement without modification.

3 **Q. WHY DO YOU DISAGREE WITH MR. ALVAREZ'S DEPICTION OF**  
4 **THE DUKE ENERGY INDIANA SETTLEMENT IN HIS TESTIMONY?**

5 A. Mr. Alvarez's characterization of this settlement as recognition by a regulatory  
6 body of "risks" of AMI deployment, or as an indication of our outright denial of  
7 cost recovery of early retirement of existing metering infrastructure, is inaccurate  
8 and misinterprets the settlement before the IURC and its subsequent approval. As  
9 I previously stated, the settlement in the Duke Energy Indiana case, like all  
10 regulatory settlements, involve parties making concessions to achieve the ultimate  
11 result. As part of that particular settlement, Duke Energy Indiana *agreed* to forego  
12 its right to seek recovery of early meter retirement in exchange for approval of all  
13 of the other investments enabled under the settlement agreement. The issues  
14 regarding meter retirement were not litigated. Admittedly, Duke Energy Indiana  
15 agreed not to pursue recovery of the early retirement of existing meters in the  
16 future. However, there were several other components to the settlement regarding  
17 the metering investment component of the Company's proposal that made such a  
18 concession feasible. For example, in exchange for approval of the other  
19 components of its proposal, the IURC's Order actually authorizes deferral of  
20 certain AMI deployment costs and approves immediate use of new AMI  
21 depreciation rates.<sup>12</sup> Moreover, the settlement further provides that the settling  
22 parties will not oppose the inclusion of prudently incurred AMI deployment costs

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<sup>12</sup> *Id.*

1 into base rates.<sup>13</sup> Duke Energy Indiana did not forego its ability to make the AMI  
2 investment immediately and the settlement did not in any way foreclose such an  
3 investment. Duke Energy Indiana is free to make the AMI investment now,  
4 without any further regulatory approval, and indeed, is making such an  
5 investment.

6 **Q. YOU ALSO MENTION THAT MR. ALVAREZ MISSTATED DUKE**  
7 **ENERGY INDIANA'S STATEMENTS REGARDING THE INDIANA**  
8 **PROCEEDING. PLEASE EXPLAIN.**

9 A. I am referring to page 13 of Mr. Alvarez's testimony where he quotes a press  
10 release that Duke Energy Indiana issued following the IURC approval of the  
11 settlement. Mr. Alvarez implies that this press release supports his position that  
12 regulators and consumer advocates recognize customer risks associated with  
13 considering smart meter investments outside of a rate case. Such is not the case.

14 Mr. Alvarez's characterization of that press release and the settlement  
15 described therein is inaccurate and incomplete. See Attachment DLS-SUPP-2 for  
16 a complete copy of the actual press release issued by Duke Energy Indiana. In  
17 sum, nothing in the subject settlement, IURC approval, or the Company's press  
18 release supports a conclusion that Duke Energy Indiana is not able to proceed  
19 with its proposed AMI investment immediately or that the regulatory  
20 authorization of such an investment is in question. To the contrary, as I previously  
21 noted, the settlement allows Duke Energy Indiana to deploy its AMI initiative  
22 outside of the TDSIC with deferral of 100 percent of depreciation of the AMI

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<sup>13</sup> *Id.* at Attachment 1, Settlement Agreement, page 4. Section 5 d.

1 investment for recovery in in a subsequent rate case, recovery of post-in-service  
2 carrying costs and an agreement by settling parties not to oppose such recovery.

3 **Q. DO YOU BELIEVE THE SETTLEMENTS OR REGULATORY ORDERS**  
4 **INVOLVING DUKE ENERGY KENTUCKY AFFILIATES SHOULD BE**  
5 **RELEVANT TO DUKE ENERGY KENTUCKY'S REQUEST BEFORE**  
6 **THIS COMMISSION?**

7 A. No. I believe that settlement agreements or orders in a different jurisdiction have  
8 no bearing on the current case before this Commission. Conversely, although Mr.  
9 Alvarez fails to mention any recent Kentucky AMI investment or regulatory  
10 treatment precedent in his direct testimony, I do believe that recent Kentucky  
11 advanced metering investment precedent is relevant indeed.

#### V. CONCLUSION

12 **Q. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?**

13 A. Yes.

14 **Q. ARE ATTACHMENTS DLS-SUPP -1, AND DLS-SUPP-2, TRUE AND**  
15 **ACCURATE COPIES OF REGULATORY ORDERS IN OTHER**  
16 **JURISDICTIONS AND COMPANY-ISSUED PRESS RELEASES?**

17 A. Yes.

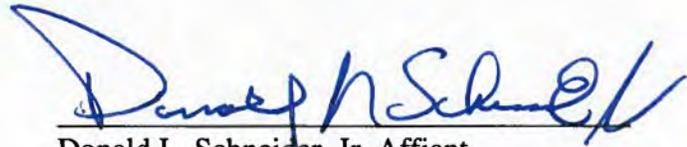
18 **Q. WERE THESE ATTACHMENTS PREPARED AND COMPILED BY YOU**  
19 **OR AT YOUR DIRECTION AND UNDER YOUR CONTROL?**

20 A. Yes.

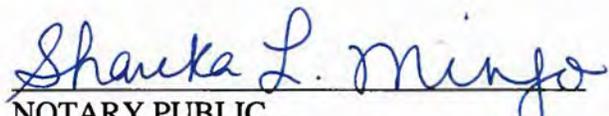
**VERIFICATION**

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

The undersigned, Donald L. Schneider, Jr., Director, Advanced Metering, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing rebuttal testimony are true and correct to the best of his knowledge, information and belief.

  
Donald L. Schneider, Jr, Affiant

Subscribed and sworn to before me by Donald L. Schneider, Jr. on this 13<sup>th</sup> day of October, 2016.

  
NOTARY PUBLIC

My Commission Expires: August 25, 2021



ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF DUKE ENERGY INDIANA, )  
INC. FOR; (1) APPROVAL OF PETITIONER'S 7-YEAR )  
PLAN FOR ELIGIBLE TRANSMISSION, )  
DISTRIBUTION AND STORAGE SYSTEM )  
IMPROVEMENTS, PURSUANT TO IND. CODE § 8-1-39- )  
10; (2) APPROVAL OF A TRANSMISSION AND )  
DISTRIBUTION INFRASTRUCTURE IMPROVEMENT )  
COST RATE ADJUSTMENT AND DEFERRALS, )  
PURSUANT TO IND. CODE § 8-1-39-9; (3) APPROVAL )  
OF CERTAIN REGULATORY ASSETS; (4) APPROVAL )  
OF VOLUNTARY DYNAMIC PRICING RIDERS; AND )  
(5) APPROVAL OF A NEW DEPRECIATION RATE FOR )  
ADVANCED METERS )

CAUSE NO. 44720

APPROVED: JUN 29 2016

ORDER OF THE COMMISSION

**Presiding Officers:**

**Carol A. Stephan, Commission Chair**

**Jeffery A. Earl, Administrative Law Judge**

On December 7, 2015, Duke Energy Indiana, LLC ("DEI") filed its Verified Petition in this Cause. DEI also filed the direct testimony and exhibits of the following witnesses:

- Melody Birmingham-Byrd, President of DEI;
- William H. Fowler, Vice President Design Engineering and Construction Planning-Midwest at Duke Energy Business Services, LLC ("DEBS");
- Donald E. Broadhurst, General Manager Transmission Construction & Maintenance at DEBS;
- Todd W. Pfennig, Director of Estimating, Americas Construction and Procurement Division at Black & Veatch Corporation;
- Donald L. Schneider, Jr., Director, Advanced Metering at DEBS;
- Jeffrey R. Bailey, Director, Pricing and Analysis at DEBS;
- Robert B. Hevert, Managing Partner at Sussex Economic Advisors, LLC; and
- Brian P. Davey, Director, Rates and Regulatory Strategy-Indiana at DEBS.

The following parties intervened in this Cause:

- Nucor Steel-Indiana, a division of Nucor Corporation ("Nucor");
- Citizens Action Coalition of Indiana, Inc. ("CAC");
- Duke Energy Indiana Industrial Group ("Industrial Group");
- Steel Dynamics, Inc. ("SDI");
- Hoosier Energy Rural Electric Cooperative, Inc. ("Hoosier Energy");

- Wabash Valley Power Association, Inc. (“WVPA”);
- Environmental Defense Fund (“EDF”);
- Companhia Siderurgica Nacional, LLC a/k/a CSN, LLC (“CSN”); and
- Indiana Municipal Power Agency (“IMPA”).

On February 18, 2016, SDI filed the direct testimony and exhibits of Kevin C. Higgins, Principal in the firm of Energy Strategies, LLC. WVPA filed the direct testimony and exhibits of Gregory E. Wagoner, Vice President, Transmission Operations and Development at WVPA. Hoosier Energy filed the direct testimony and exhibits of William C. Ware, Manager Power Delivery Engineering at Hoosier Energy. And IMPA filed the direct testimony and exhibits of Jack Alvey, Senior Vice President of Generation at IMPA. On February 19, 2016, EDF filed the direct testimony and exhibits of Ronny Sandoval, Director, Grid Modernization at EDF, and Jim Hawley, Director with Mission:data Coalition.

On March 7, 2016, DEI, the OUCC, the Industrial Group, SDI, Hoosier Energy, WVPA, CSN, IMPA, and EDF (collectively “Settling Parties”) submitted a Settlement Agreement.

On March 8, 2016, the OUCC filed Consumer Comments that it had received.

On March 17, 2016, the Settling Parties filed the settlement testimony and exhibits of the following witnesses:

- DEI – Ms. Birmingham-Byrd, Mr. Broadhurst, Mr. Fowler, and Mr. Davey;
- OUCC – Ray L. Snyder and Leon A. Golden, both Utility Analysts in the OUCC’s Resource Planning and Communications Division;
- EDF – Mr. Sandoval;
- Industrial Group – Nicholas Phillips, Jr., Managing Principal of Brubaker & Associates, Inc.;
- SDI – Mr. Higgins; and
- WVPA – Mr. Wagoner.

On April 7, 2016, CAC filed the settlement testimony and exhibits of Kerwin L. Olson, Executive Director of CAC.

On April 19, 2016, DEI filed the rebuttal testimony and exhibits of Ms. Birmingham-Byrd, Mr. Fowler, and Mr. Davey, and the Industrial Group filed the rebuttal testimony and exhibits of Mr. Phillips.

The Commission held an evidentiary hearing in this Cause at 9:30 a.m. on May 2, 2016, in Hearing Room 222, 101 West Washington Street, Indianapolis, Indiana. DEI, the OUCC, Nucor, CAC, Industrial Group, SDI, Hoosier Energy, WVPA, EDF, and CSN appeared by counsel and participated at the hearing. No members of the public participated at the hearing.

Based on the applicable law and the evidence presented, the Commission finds:

1. **Notice and Jurisdiction.** Notice of the hearing in this Cause was given and published as required by law. DEI is a public utility as that term is defined in Ind. Code § 8-1-2-1(a). Under Ind. Code § 8-1-39-10, the Commission has jurisdiction over a public utility's request for approval of a Seven-Year Plan for eligible transmission, distribution, and storage improvements. Under Ind. Code § 8-1-39-9, the Commission has jurisdiction over a public utility's request to recover eligible transmission, distribution, and storage system costs through a periodic rate adjustment. Therefore, the Commission has jurisdiction over DEI and the subject matter of this proceeding.

2. **DEI's Characteristics.** DEI is a public utility corporation organized and existing under the laws of the State of Indiana with its principal office in Plainfield, Indiana. DEI is a second-tier, wholly owned subsidiary of Duke Energy Corporation. DEI renders retail electric utility service in the State of Indiana and owns, operates, manages, and controls, among other things, plant and equipment within the State of Indiana used for the production, transmission, delivery, and furnishing of such service to the public.

3. **Relief Requested.** DEI requests approval of the Settlement Agreement, in its entirety, including approval of DEI's proposed Seven-Year Plan for eligible transmission, distributions, and storage system improvements ("Seven-Year Plan") under Ind. Code § 8-1-39-10. Specifically, DEI requests: (1) a finding that the projects contained in its Seven-Year Plan are "eligible transmission, distribution, and storage system improvements" as defined in Ind. Code § 8-1-39-1; (2) a finding that the best estimate of the cost of the eligible improvements was included in the Seven-Year Plan; (3) a determination that public convenience and necessity require or will require the eligible improvements summarized in the Settlement Agreement and included in the Seven-Year Plan; (4) a determination that the estimated costs of the eligible improvements included in the Seven-Year Plan as summarized in the Settlement Agreement are justified by incremental benefits attributable to the Seven-Year Plan; (5) if and to the extent the Commission determines that the Seven-Year Plan is reasonable, DEI requests the Commission approve the Seven-Year Plan and designate the eligible transmission, distribution and storage system improvements included in the Seven-Year Plan as eligible for Transmission, Distribution and Storage System Improvement Charge ("TDSIC") treatment under Ind. Code § 8-1-39-9; (6) deferral of 100% of the depreciation associated with AMI up to \$60 million for recovery in DEI's subsequent retail base rate proceeding; (7) recovery of deferred depreciation associated with AMI over a 10-year period without carrying costs in DEI's next general retail rate case; (8) deferral of post-in-service carrying costs associated with the AMI project up to \$15 million for recovery in DEI's subsequent retail base rate proceeding; (9) recovery of the deferred post-in-service carrying costs associated with the AMI project over a 10-year period without carrying costs in DEI's subsequent retail base rate case; (10) approval of DEI's ratemaking proposals, including the transmission and distribution ("T&D") Infrastructure Improvement Cost Rate Adjustment, Standard Contract Rider No. 65 ("T&D Rider" or "Rider 65"), for recovery of 80% of the \$1.408 billion Seven-Year Plan costs, and deferral with carrying costs of 20% of the Seven-Year Plan costs for subsequent recovery in DEI's next general retail electric base rate case; (11) approval of DEI's proposed process for updating the Seven-Year Plan in future annual proceedings consistent with the Settlement Agreement; and (12) approval of a depreciation rate specific to the advanced meters deployed as part of the AMI project.

**4. DEI's Case-In-Chief Evidence.**

**A. Ms. Birmingham-Byrd.** Ms. Birmingham-Byrd testified that in developing the Seven-Year Plan, DEI focused on improvements that maintain reliability and modernize the T&D grid to enable additional value-added customer services and options now and in the future. Ms. Birmingham-Byrd testified that while reliability is job number one for electric service providers, consumers have come to expect more, better, and faster information about all the services and products they consume. She testified that the Seven-Year Plan contains investments that will allow DEI to reduce unplanned outages, pinpoint fault locations faster, reduce the scope of customer outages, reduce the length of customer outages, and provide better, faster, more accurate information to customers about the cause of the outage and the expected time of restoration. In addition, certain resiliency investment projects are designed to strengthen the delivery system from threats due to severe weather, improving overall reliability.

Ms. Birmingham-Byrd testified that the Seven-Year Plan cost estimates are DEI's best estimates of the costs at this time, but that DEI expects the estimates to change over time as DEI moves to more detailed engineering and construction plans. The cost estimates have been reviewed for reasonableness by a third-party consultant, Black & Veatch. Ms. Birmingham-Byrd testified that as the Seven-Year Plan develops, engineering progresses, and contracts are entered into for labor, materials, and construction, DEI will update its cost estimates in future T&D Rider filings. Ms. Birmingham-Byrd also provided testimony concerning the reasonableness of the overall rate impact of the Seven-Year Plan. DEI is aware of the need to balance rate impacts with the need and value of the Seven-Year Plan. As a result, the average annual rate impact is slightly less than 1%—below the 2% annual cap permitted by Ind. Code § 8-1-39-14(a).

Ms. Birmingham-Byrd provided testimony regarding the economic development impacts on the State of Indiana. The proposed Seven-Year Plan is estimated to create or support an estimated average of 2,700 jobs per year in the U.S. for each of the seven years of the plan (or 840 jobs per year in Indiana). These jobs include both direct jobs and indirect or induced jobs that are created or supported by the Seven-Year Plan investment. The Seven-Year Plan is also estimated to produce about \$184 million in additional state and local tax revenue. The direct jobs created from this investment will be a mix of contractor and direct employee hires and could include construction and maintenance, engineering, project management, operating, and other technical support positions.

Ms. Birmingham-Byrd testified that the Seven-Year Plan is reasonable and provides substantial customer benefits, while limiting investments to those needed to maintain a reasonable level of reliability, to modernize the grid responsibly, and to maintain a manageable rate impact.

**B. Mr. Fowler.** Mr. Fowler provided testimony on the Distribution portion of the Seven-Year Plan. Mr. Fowler testified that the majority of year-one estimates are AACE Class 2 estimates with all units identified by substation and circuit, with 30% to 70% of detailed engineering complete. The majority of year-two estimates are AACE Class 3 estimates with units identified by substation and circuit. The unit cost is a combination of the historical actual cost with approximately 10% to 40% of the total units engineered. Estimates for years three through seven are AACE Class 4 estimates with units identified by substation and circuit. The units are then

parametrically modeled (a cost estimating methodology that combines actual historical data with statistical data to develop cost estimates) using historical actual cost and a standard 3% escalation per year to derive projected cost. As the project implementation year approaches, actual engineering design estimates will be developed at a Class 3, and then at a Class 2 level prior to being submitted to the Commission as part of DEI's annual detailed work plan. Mr. Fowler testified that contingency is included in the project cost estimates and is the result of the Monte Carlo simulation at the 50% Probability ("P50") confidence level. Since projects go into service each year, contingency is broken out for each year. At the end of each year any unused contingency held for that year is eliminated and does not carry over into future years. Mr. Fowler testified that DEI will make updates to its Plan at least annually. He testified that DEI is requesting recovery of project-related O&M that is incurred while the capital projects are under construction, as is standard practice in the utility industry. Mr. Fowler testified that he has a high confidence in the estimating process.

Mr. Fowler provided Petitioner's Exh. 2-A, which is an overview of the Seven-Year Plan, including a seven-year summary of the projects and cost estimates. He also provided an overview of DEI's electric distribution system. DEI serves over 800,000 customers through approximately 22,000 miles of distribution lines. A significant portion of DEI's system was constructed in the 1960s, 70s, and 80s, and is approaching its life expectancy. Mr. Fowler explained that DEI used an organic, bottom-up approach to selecting the projects included in the Seven-Year Plan. System planners and engineers selected projects based upon age, system conditions, and the availability of grid modernization equipment. Numerous factors were analyzed to determine an appropriate timeline for constructing the projects in a planned and risk-based manner, including availability of materials and labor resources. Projects were selected based on their improvement to system integrity and reliability, with the benefit to customers in mind.

Mr. Fowler testified that projects were included in a risk model to quantify the level of risk reduction benefits achieved by the Plan and to prioritize specific assets for investment within some of the projects. No projects were intentionally included or excluded based on risk reduction levels. Rather, the experience and expertise of DEI's engineering staff was used to ultimately select projects for the Seven-Year Plan. The replacement assets chosen are aging or deteriorating assets.

Mr. Fowler identified the distribution projects included in the Seven-Year Plan in Petitioner's Exh. 2-C and Confidential Exhs. 2-B and 2-D. He testified that the Distribution Workplan includes inspection-based projects that are on planned cycles. These assets require a dedicated inspection per location to evaluate each component condition based on criteria often unique to each project category and specific to each site condition. These assets are so numerous that they require inspection on planned cycles over a period of years. He testified that DEI only proposed inspection-based projects where the work involved is highly repetitive, the assets are numerous, and the projects have well-defined, unitized cost estimates. Mr. Fowler testified that not all of DEI's annual T&D spending was included in the Plan. DEI has a multitude of projects and programs that are not included in the Seven-Year Plan. He testified that DEI will routinely reprioritize projects within the submitted Seven-Year Plan based on the best interest of its customers.

Mr. Fowler testified that the Integrated Volt-VAR Controls (“IVVC”) project provides real-time monitoring and the ability to make voltage adjustments to the distribution system, which is estimated to ultimately reduce overall system voltage by approximately 2% on impacted circuits. This equates to an estimated 1.4% load reduction for impacted circuits, providing cost savings to customers. Engineering studies were completed by DEI to determine which circuits to deploy IVVC on to deliver the best results. The studies resulted in a plan for IVVC to be installed on approximately 50% of the total quantity of Company-owned substations and circuits. This represents approximately 6,800 MW of peak retail load under IVVC control. DEI completed a cost-benefit analysis, which demonstrated that the IVVC project is estimated to provide a benefit of \$219 million over a 20-year life.

Mr. Fowler also described how DEI will update the Commission and intervenors if there are changes to the Seven-Year Plan. DEI plans to make updates to its Seven-Year Plan annually. The Seven-Year Plan includes alternate projects to attempt to deal with the likelihood of change. DEI proposes that the Commission designate these alternate projects as eligible projects, to allow for the option of moving them into the Seven-Year Plan. DEI commits that the overall costs of the Seven-Year Plan would not be substantially changed by substituting these alternate plans.

Mr. Fowler testified that Black & Veatch conducted an independent cost review of DEI’s Seven-Year Plan capital cost estimates and estimating process. Black & Veatch concluded that the process used for project cost estimating and the project cost estimates were reasonable and within the typical band of uncertainty seen across the industry for capital planning and cost forecasting purposes.

Mr. Fowler testified that Black & Veatch also helped DEI develop a risk profile analysis. The results of the risk profile analysis shows a total T&D system risk reduction of 31% over the Seven-Year Planning period. The risk profile analysis demonstrates that the Seven-Year Plan results in tangible risk reduction and reliability benefits. The Seven-Year Plan also improves the operational efficiency of DEI’s T&D system, as well as improves upon the overall customer experience and enables a number of customer benefits and programs in this filing and in future years. Mr. Fowler testified that the project and programs included in the Seven-Year Plan are reasonable, necessary, and justified by significant reliability and modernization benefits.

C. **Mr. Broadhurst.** Mr. Broadhurst provided details of the Transmission Line and Transmission and Distribution Substation components of the Seven-Year Plan. He testified that the T&D Substation and Transmission Line projects will reduce outage occurrences and outage durations and improve power quality for transmission level and distribution level residential, commercial, and industrial customers. Mr. Broadhurst provided Petitioner’s Confidential Exh. 3-A, which is a cost estimate for the Transmission Line and T&D Substation components of the Seven-Year Plan. In addition, the individual project workplans and additional, supporting cost estimate information was provided in Confidential Exhs. 3-D and 3-E.

Mr. Broadhurst explained how the Transmission Line and T&D Substation project cost estimates were developed. The T&D substations or transmission lines were identified as candidate projects based on numerous factors, including history of outages caused by equipment issues and equipment identified for replacement due to poor performance or operational issues. Once a

substation or line was selected for an upgrade project, a detailed project scope was identified. From this detailed, asset-specific project scope, an AACE Class 4 estimate of the project was calculated and used for the majority of projects in Years 4-7 of the Seven-Year Plan. Class 4 estimates for T&D Substation-related projects are parametric estimates calculated based on the estimated cost for a typical unit of work, and the number of such units to be included in the project. To identify the unit costs, project estimates were developed for approximately 65 different asset replacement activities by DEI Energy estimating engineers. Also, for some activities the project estimate for a specific comparable recent project was used as the typical unit cost. Class 4 estimates for Transmission Line projects were created by developing averages of recently bid capital projects and calculating average costs per mile and per support structure. These unit costs were then applied to Seven-Year Plan project work scopes. Mr. Broadhurst testified that as these projects approach their targeted in-service year, a detailed AACE Class 3 estimate will be prepared utilizing the project estimation workbook. He stated that all projects planned for Year 2 of the Seven-Year Plan (2017) and many of the projects planned for Year 3 (2018) currently have Class 3 or better estimates prepared. He explained that as projects come even closer to their targeted in-service year, updated materials and labor cost estimates are used to further update the project estimation workbook as an AACE Class 2 estimate. Mr. Broadhurst testified that all projects included in Year 1 of the Seven-Year Plan currently have a Class 2 estimate prepared. Mr. Broadhurst explained that providing better than a Class 4 AACE estimate for the latter years of the Seven-Year Plan would be inefficient and unrealistic due to the influence of many external factors over the next seven years, including changes to labor rates, materials rates, engineering or design analysis, changes to project scope, rules and standards changes, and system growth or other load changes.

Mr. Broadhurst testified that specific project-related O&M, incurred during the construction of the capital projects, has been estimated and requested in this proceeding. The T&D Substation project-related O&M and capital estimates are in Petitioner's Confidential Exhibits 3-A and 3-D. The Transmission Line project-related O&M and capital estimates are in Petitioner's Confidential Exhibits 3-A and 3-E. In addition, examples of work orders for both T&D Substation and Transmission Line projects have been provided in Petitioner's Confidential Exhibit 3-F.

Mr. Broadhurst testified that the Commission can be assured that the estimates are "best estimates" because DEI's engineering team has decades of experience developing cost estimates and constructing the assets that are included in the T&D Substation and Transmission Line plans. Further, Black & Veatch reviewed DEI's cost estimates and cost estimating methodology, finding the process reasonable and the cost estimates and AACE estimate levels accurate. Mr. Broadhurst also testified that contingency is added to the base cost estimates of the project categories to cover estimated uncertainty and risk, as recommended per AACE guidelines.

Mr. Broadhurst testified that from the 615 potential projects scoped and estimated, DEI selected 323 projects at 280 T&D Substations and 144 projects on 81 Transmission Lines for inclusion in the Seven-Year Plan. The Seven-Year Plan also identifies 46 projects at 42 T&D substations, and 8 projects on 8 transmission lines that DEI plans to complete on the transmission system jointly owned with IMPA and WVPA. Mr. Broadhurst explained that these projects are not included for cost recovery in the Seven-Year Plan. In addition, DEI identified 36 projects at 35 T&D Substations and 58 projects on 26 Transmission Lines as "Alternate" projects. Mr. Broadhurst testified that project summaries for the Transmission Line and T&D Substation

projects are in Petitioner's Exhibits 3-B and 3-C. The summaries include what assets have been selected for replacement, how they were selected, the types of equipment that will be replaced, and the significant customer benefits that will result from the projects.

Mr. Broadhurst testified that flexibility and the ability to update the Seven-Year Plan with additional projects is critical, as system conditions change over time. He testified that DEI plans to file annual updates to the Seven-Year Plan. In addition to updating project costs, schedule, and benefits, there could be a need to move some projects into or out of the Plan. DEI requested that the Commission designate the Alternate projects it has identified in its case-in-chief as eligible projects, so that in future TDSIC mechanism filings DEI would have the option of moving them into the Seven-Year Plan without substantially changing the overall costs of the Seven-Year Plan. Mr. Broadhurst further testified that the projects and programs included in the Seven-Year Plan are reasonable, necessary, and justified by significant reliability and modernization benefits.

**D. Mr. Pfennig.** Mr. Pfennig testified that Black & Veatch conducted an independent cost review of DEI's Seven-Year Planning capital cost estimates and estimating process. The review evaluated estimates for reasonableness based on Black & Veatch's experience and the information and backup data received from DEI for its cost estimates. He testified that Black & Veatch concluded that the process DEI used for T&D project cost estimating was reasonable and the project cost estimates reviewed were reasonable and within the typical band of uncertainty seen across the industry for capital planning and cost forecasting purposes. He further testified that DEI spent an incredible amount of time and resources in developing the Seven-Year Plan and associated cost estimates and, in his opinion, have met the requirement for what is necessary to show that they provided a best estimate.

Mr. Pfennig explained how Black & Veatch conducted its analysis. He testified that a total of nearly 24% of the entire Seven-Year Plan capital costs were reviewed, which is statistically significant. Mr. Pfennig testified that it is not reasonable for DEI to have Class 2 or 3 estimates for years 3-7 of the Seven-Year Plan due to the amount of engineering and site investigation that would be needed. Mr. Pfennig concluded that DEI's estimates are the best estimate of the projects identified in the Seven-Year Plan, given the available data and a reasonable balance of the cost and benefit to develop the estimates. He also testified that the assumptions DEI used in its cost estimating process are reasonable.

**E. Mr. Schneider.** Mr. Schneider provided a detailed overview of the Advanced Metering Infrastructure ("AMI") proposal. He testified that the project involves a 4.5 year phased deployment of approximately 829,500 meters, a communications network, and back office systems. DEI will install advanced meters for its residential and commercial customers and for any large commercial and industrial customers that do not already have advanced meters installed. Deployment will occur over the first 4.5 years of the Seven-Year Plan, with a ramp up in years two and three. He explained that the AMI meters and communication infrastructure will be deployed by district on a rolling basis triggered by district completion metrics, rather than waiting to complete one district completely before beginning on a neighboring district.

Mr. Schneider testified that advanced meters have two-way communications capability and can be used for interval usage measurement, tamper detection, voltage and reactive power

measurement, and net metering. He testified that DEI will install a neighborhood area network (“NAN”) and use a third-party-provided wide area network (“WAN”) to make use of the advanced meters’ two-way communications capability. The NAN represents the network connecting advanced meters to grid routers through a radio frequency (“RF”) mesh architecture. Range extenders may be used to extend the mesh signal to meters that would otherwise be outside the reach of the mesh network. He explained that routers aggregate the communications from advanced meters within the NAN and transmit them to the WAN. They also communicate commands, firmware/program updates, and instructions from the WAN out to the advanced meters within the NAN. DEI will utilize secured communications over public cellular networks in Indiana as its WAN. The back office systems consist of the Meter Data Management (“MDM”) system, which processes usage and event data from the advanced meters. Processing involves validating, editing, estimating, and packaging data for billing and other uses. Mr. Schneider testified that all meters will transmit interval kilowatt-hour (“kWh”) usage data for billing purposes as well as time-tagged event and alert data such as tamper alerts. Some meters will transmit voltage, amperage, phase angle, or other data, as needed to improve system models for system planning, increased efficiencies with respect to outage restoration, and other system operations purposes.

Mr. Schneider testified that DEI is proposing technology proven not only across the industry, but specifically proven by Duke Energy in other jurisdictions, particularly in Ohio and in the Carolinas, that DEI will benefit from. Mr. Schneider described the changes customers will see in their service after the new metering solution is installed, including the ability to view hourly interval usage data from the previous day via the customer web portal, the elimination of monthly walk-by meter reads, remote service activation or deactivation, and improved outage restoration.

Mr. Schneider testified that DEI performed a customer cost-benefit analysis for the new metering solution, which showed a net present value (“NPV”) of approximately \$113 million. The payback period for the investment is approximately 8.6 years and 10.1 years on a net present value basis. Additionally, a sensitivity run for the AMI cost-benefit analysis that recognizes the potential for additional benefits that AMI could enable in the future results in a NPV of approximately \$193 million. Mr. Schneider testified that the estimated cost for deploying the AMI solution is about \$192 million over the Seven-Year Plan. The cost estimate is at least an AACE Class 3 level. He testified that the base cost-benefit analysis and the sensitivity both demonstrate that there are quantifiable benefits that substantially outweigh the costs of the Plan. Mr. Schneider also testified that many of the benefits included in the Plan will naturally flow to customers through DEI’s existing riders, such as the fuel adjustment clause rider. A large part of the customer benefits are operational cost savings gained through expense reductions related to meter reading, truck roll reductions, consumer order worker reductions, and outage assessment reductions. Smaller operational cost savings include reduced estimated bills and improved vegetation management utilizing voltage sag data from meters. He testified that the TDSIC mechanism will include a credit equivalent to the ongoing AMI operating costs minus the quantifiable ongoing AMI benefits that do not already flow to customers in other riders. Mr. Schneider testified that the cost-benefit estimates are reasonable.

**F. Mr. Bailey.** Mr. Bailey provided testimony regarding four optional rate offerings DEI intends to offer upon approval and implementation of AMI, two for residential and two for small commercial service. He explained that these are time-of-use rates with seasonal and

time-based on-peak and off-peak price differentiation. He testified that the time-of-use rates are revenue neutral. Mr. Bailey described the variable peak pricing component of the rate design where customers are incented to either reduce load or pay a more appropriate price for the electricity they do consume during high-priced time periods. Mr. Bailey testified that these new rates will be entirely voluntary. In addition, DEI will offer customers a first-year, one-time bill guarantee. At the end of the first year of service, a bill comparison will be presented to the customer and if the customer paid more under the new rates relative to the standard rate, they will receive a credit for the difference. He testified that DEI will attempt to obtain at least 5,000 customers per year for five years following approval and implementation of the AMI metering solution. Mr. Bailey also described DEI's request for authority to modify certain Standard Contract Riders such that they include a kW demand charge applicable to these new rate schedules.

**G. Mr. Hevert.** Mr. Hevert testified that DEI's currently authorized return on equity ("ROE") of 10.50% is within a reasonable range of analytical results, and neither capital market conditions nor the presence of the TDSIC mechanism justifies a reduction to the ROE. Mr. Hevert provided an overview of the analyses that led to his ROE recommendation. He testified that he relied on three widely accepted approaches: (1) the Discounted Cash Flow model, including the Constant Growth, and Multi-Stage forms; (2) the Capital Asset Pricing Model; and (3) the Bond Yield Plus Risk Premium approach. In addition, his recommendation takes into consideration DEI's cost recovery mechanisms and the current capital market environment.

**H. Mr. Davey.** Mr. Davey provided testimony about the rate impacts of the Seven-Year Plan. Mr. Davey testified that DEI is requesting authority to recover 80% of the retail jurisdictional share of the Seven-Year Plan costs through the new proposed Rider 65 under Ind. Code § 8-1-39-9(a). He stated that this would include depreciation, O&M, extensions and replacements, property taxes, and pretax returns on eligible transmission, distribution, and storage system improvements incurred both while the improvements are under construction and post-in-service. In addition, DEI requests authority to accrue post-in-service carrying costs until the Seven-Year Plan projects are included in retail rates. He testified that DEI requests deferral for subsequent recovery of the retail jurisdictional portion of the remaining 20% of allowance for funds used during construction ("AFUDC"), post-in-service carrying costs, operation and maintenance expense, taxes, and depreciation expense using a regulatory asset account (FERC CFR Account 182.3) until such costs are fully reflected in DEI's retail base rates after a general retail electric base rate case. DEI also requests that carrying costs on these deferred costs be accrued using DEI's overall weighted cost of capital as most recently approved by the Commission. He stated that AFUDC will be applied to project costs until such project costs are included for recovery under Rider 65, in base rates or when the projects are placed in service. He testified that the post-in-service carrying costs will be accrued on approved capital expenditures, including accrual on previously computed post-in-service cost amounts, from the in-service date until such costs are included in DEI's rates under Rider 65 or in base rates.

Mr. Davey also testified that the retail jurisdictional portion of post-in-service operation and maintenance, depreciation, tax expense, and post-in-service carrying costs will be deferred with respect to Seven-Year Plan costs from the in-service date until the cost is included in DEI's rates under Rider 65 or in base rates. He testified that for purposes of inclusion in the T&D Rider, DEI will consider both the FERC accounting and whether the function is a transmission or

distribution service. Mr. Davey testified that DEI will not be netting depreciation for retired assets against the depreciation for the new assets being added in the Seven-Year Plan, as this is more appropriately accomplished in a base rate case. He testified that the requested depreciation rate of 6.67% for the new meters is based on their 15-year expected useful life.

Mr. Davey testified that DEI is requesting approval for the creation of a regulatory asset for the existing meters that will be replaced under the Seven-Year Plan. The estimated increase in depreciation expense to fully depreciate the meters over their shorter estimated remaining life would be \$9 million over the first 4.5 years of the plan. He testified that rather than recovering the higher amount of depreciation expense over the shorter remaining lives of the meters, DEI proposes to include the difference between the depreciation expense under the current depreciation rate and what the new depreciation rate would be in a regulatory asset and amortize it over the estimated remaining life of the meters (approximately 17 years). DEI also requests the authority to continue to earn a return on these meters whether in rate base or a regulatory asset. Mr. Davey testified that this accounting treatment is in accordance with Generally Accepted Accounting Principles ("GAAP").

Mr. Davey testified that DEI proposes to update Rider 65 at least annually. He testified that Rider 65 recovers 80% of the retail jurisdictional portion of the costs associated with the Seven-Year Plan projects and would include financing costs, O&M directly associated with the construction of the project, O&M savings and O&M expenses associated with AMI, depreciation, and taxes. The costs also include the program plan development and support costs from Black & Veatch. In addition, DEI proposes to include the estimated \$40.5 million net AMI savings credit in the T&D Rider. Mr. Davey testified that DEI proposes to use the return on common equity approved by the Commission in the most recent general retail electric base rate case of 10.5%. He testified that DEI proposes to allocate the transmission, distribution excluding meters, and meters revenue requirement developed for Rider 65 to the rate groups based on the revenue requirement by rate group for these same three categories from the last retail base rate case, Cause 42359. Costs will be billed to individual customers within a rate group based on kilowatt-hour sales except for customers served under Rate HLF, which will be based on non-coincident kW demands. Wholesale customers will also be allocated a portion of the Seven-Year Plan costs. Mr. Davey testified that DEI proposes to use forecasted amounts for O&M, depreciation, and property taxes, based on annual cut-off dates. The financing costs on invested capital would be on an actual basis based on the same annual cut-off dates. He stated that DEI would true-up both of these amounts to actual levels of O&M, depreciation, and property taxes and to actual kWh sales levels in subsequent Rider proceedings. He testified that DEI proposes to make annual filings of Rider 65 that would include an update to the remaining years of the Seven-Year Plan. Mr. Davey also testified that DEI is proposing to include the expenses incurred for retaining Black & Veatch in this proceeding, and to include the Black & Veatch costs associated with providing testimony and supporting DEI's filing in this proceeding and amortizing all Black & Veatch costs over a three-year period.

Mr. Davey testified that although the rate impact of the Seven-Year Plan will vary based on a number of variables, the total annual average retail rate impact compared to retail revenue is estimated to be slightly less than 1% over the seven-year period. Mr. Davey stated that if an actual

amount exceeds the two percent annual statutory cap, DEI requests approval to defer recovery of the TDSIC costs above the cap under Ind. Code §8-1-39-14(b).

**5. Intervenor's Case-in-Chief Evidence.**

A. **EDF.** Mr. Hawley recommended that DEI be required, as part of its AMI deployment, to embrace customer and authorized third party access to smart meter data for energy management services so customers can receive the significant energy savings made possible by AMI technology. Mr. Hawley testified that DEI should be providing customers with their usage and billing data as part of basic utility service, without charge, via Green Button Connect My Data. In addition, customers should receive real-time access to detailed energy usage data in order to get the full availability of customized energy efficiency and demand response programs through the home area network radios contained in the advanced meter.

Mr. Sandoval testified that DEI's IVVC proposal is generally reasonable and should be approved by the Commission. He testified that although DEI's proposed number of IVVC installations is significant, DEI should continue to periodically examine the cost-effectiveness of potential IVVC deployments across circuits that have been excluded from the existing selection criteria. He recommended that DEI file periodic reports on the voltage reductions achieved by IVVC and the resulting energy usage reductions. The updates should also include the carbon reduction and greenhouse gas impact of its IVVC deployment. In addition, Mr. Sandoval testified that DEI's Integrated Resource Planning ("IRP") should be used to inform and quantify the potential benefits that may be realized through IVVC and distribution automation deployment. If the investments identified in the proposed Seven-Year Plan can defer investments or reduce operational costs identified in the IRPs or other capital investment plans, those benefits should be recognized and accounted for in the Seven-Year Plan.

B. **Hoosier Energy.** Mr. Ware testified regarding the relationship between Hoosier Energy and DEI regarding transmission, substation and distribution delivery points, and interconnections. He testified that Hoosier Energy is supportive of DEI's Seven-Year Plan because increased investment in the power delivery system will reduce the number and duration of transmission-related outages thus improving overall reliability to retail consumers. Mr. Ware testified that Hoosier Energy has worked with DEI to identify specific transmission and substation upgrades and replacements that will have the most beneficial impacts. He testified that Hoosier Energy and DEI have met on several occasions to understand the nature and scope of DEI's Seven-Year Plan and have agreed to biannual meetings to address progress and discuss potential future upgrades. Mr. Ware testified that Hoosier Energy supports Plaintiff's Seven-Year Plan as a reasonable method of providing transmission system upgrades and improvements.

C. **IMPA.** Mr. Alvey testified that IMPA currently provides the full electric power requirements of 59 member communities in Indiana and one Ohio town and owns generation assets in Indiana, Illinois, and Kentucky. IMPA also owns transmission assets known as the Joint Transmission System (or "JTS") through an agreement with DEI and WVPA. He testified that transmission performance is important to IMPA's members, who provide electric distribution service to more than 100,000 retail customers. Mr. Alvey testified that increased investment in the JTS, as described in DEI's Seven-Year Plan, will improve reliability of service

to IMPA's members and their retail customers. He testified that IMPA estimates that it will invest approximately \$60 million as its share of the costs in the Joint Transmission System over the next seven years to improve reliability and accommodate additional load growth. IMPA and its members are most interested in infrastructure replacement to remove outdated and worn structures and the upgrade from manual switches to automatic switches. Mr. Alvey testified that IMPA has met with DEI on several occasions to understand the nature and scope of its Seven-Year Plan and will continue to meet to discuss work plans and help identify projects that will directly improve transmission service operated and maintained by DEI through the JTS.

**D. SDI.** Mr. Higgins recommended that DEI's AMI proposal be rejected as part of the TDSIC. However, in the event the AMI proposal is approved as part of the TDSIC recovery, DEI's request for deferred accounting treatment for its retiring meters should be rejected and TDSIC recovery for AMI should be limited to plant classified in FERC accounts 350 through 374. Mr. Higgins further testified that DEI's proposed allocation of TDSIC mechanism revenue requirement is unreasonable and inequitable and should be rejected. He argued that the revenue requirement is insufficiently specific within the HLF customer group because it did not recognize voltage differentiation. HLF tariff rates are properly differentiated by voltage consistent with the principle of cost causation, reflecting among other things, the fact that customers taking service at transmission voltage use either none, or very little of, the distribution system. DEI's TDSIC mechanism for HLF customers should be modified to properly reflect voltage differentiation applicable to the cost categories in the Seven-Year Plan using the cost allocation factors determined in Cause No. 42359. Mr. Higgins also testified that DEI should be required to include the effects of any applicable bonus tax depreciation in DEI's TDSIC revenue recovery and further testified that the TDSIC mechanism should not apply to non-firm or interruptible load.

**E. WVPA.** Mr. Wagoner testified that transmission performance is very important to WVPA's members. WVPA has 393 wholesale delivery points serving its 23 distribution cooperatives, which in turn are providing electric service to approximately 350,000 retail customers. Increased investment in the JTS will reduce the number and duration of transmission related outages, thus improving overall reliability to its distribution cooperative members and their retail customers. Mr. Wagoner testified that WVPA and its members have experienced an increasing trend in the number and duration of transmission-related outages due to the aging transmission infrastructure. Increased investment in the transmission systems from which its members receive service, such as the JTS owned by DEI, WVPA, and IMPA, will result in a demonstrable improvement in the overall reliability of service by its members to their customers. Mr. Wagoner testified that WVPA estimates that it will invest approximately \$100 million in the JTS related to normal activity, and an additional \$42 million under DEI's Seven-Year Plan over the next seven years to improve reliability and accommodate additional load growth. He testified that WVPA and its members have met with DEI on several occasions to understand the nature and scope of DEI's Seven-Year Plan, and will continue to meet at least twice a year.

## **6. Evidence Supporting the Settlement Agreement.**

**A. DEI.** Ms. Birmingham-Byrd provided an overview of the Settlement Agreement, including the following terms: (1) a cap on Seven-Year Plan costs of \$1.408 billion,

with the flexibility for DEI to adjust the projects within the Plan as circumstances dictate, such as system changes, reliability issues, or reasonable and prudent cost changes; (2) recovery of a maximum of 80% of \$1.408 billion in capital and associated project O&M via Rider 65 over the seven-year period, with 20% authorized to be deferred for subsequent recovery; (3) removal of AMI project capital and O&M costs from the Plan; (4) deferral of certain AMI project capital costs; (5) a reduced return on equity of 10% for the T&D Rider; and (6) associated ratemaking treatment. She testified that the \$1.408 billion cap constitutes a reduction in capital costs of \$397 million from the December 7, 2015, Seven-Year Plan (“Original Plan”). The Settlement Agreement removes approximately \$192 million in AMI projects from the Seven-Year Plan and from the TDSIC ratemaking treatment; approximately \$175 million in transmission capital improvements; and approximately \$30 million in distribution capital improvements from the TDSIC ratemaking treatment.

Ms. Birmingham-Byrd explained that the Settlement Agreement authorizes DEI to use any project or program included in the Original Plan (excluding AMI) to make up the \$1.408 billion total Plan cap. In other words, the \$30 million in distribution projects and the \$175 million in transmission projects that were removed from TDSIC ratemaking treatment are still considered part of the Seven-Year Plan as alternate projects and can be used to replace projects in the Plan, if needed. However, the cumulative cost caps included in the Settlement Agreement limit the TDSIC ratemaking treatment to \$1.408 billion in capital costs over seven years. The Settling Parties agree that DEI should have the flexibility to move projects from one year to another within the Seven-Year Plan. In addition, DEI is not obligated to implement the entirety of the Seven-Year Plan or to implement the full \$1.408 billion capital cost cap amount over seven years. As a result, Ms. Birmingham-Byrd testified that the Settling Parties request that DEI be authorized to implement components of the Seven-Year Plan in good faith up to the \$1.408 billion cap over a seven-year period. Under the Settlement Agreement, DEI will update its Seven-Year Plan at least annually, at which time it will present Seven-Year Plan updates to the Commission and Settling Parties, consistent with the TDSIC statute.

Ms. Birmingham-Byrd testified that DEI has agreed to remove AMI capital and O&M costs from the Seven-Year Plan. If DEI proceeds with AMI, the estimated net savings associated with the AMI project will be retained by DEI until a subsequent retail base rate case. The Settlement Agreement also authorizes the deferral, without carrying costs, of 100% of the depreciation associated with the AMI project up to \$60 million for recovery in a subsequent retail base rate proceeding. In addition, the Settling Parties agree that DEI should be authorized to defer post-in-service carrying costs associated with the AMI project up to \$15 million for recovery in a subsequent retail base rate proceeding. DEI will recover these amounts over a ten-year period without carrying costs in its subsequent retail rate case. Ms. Birmingham-Byrd testified that the Settling Parties have agreed not to oppose inclusion of an AMI project into rate base and DEI’s base rates at the time of its retail base rate case, subject to normal prudence review, including a review of the associated AMI costs. In addition, the Settling Parties agree to request approval of a new depreciation rate for the new AMI meters based on a 15-year life. Ms. Birmingham-Byrd testified that DEI agrees to drop its request for a regulatory asset associated with the current meters and if DEI proceeds with AMI, not to request recovery of or on the undepreciated value of such meters at the time of a subsequent retail base rate case or at any other time or in any manner. In

addition, as part of the Settlement Agreement, DEI agrees to withdraw its proposal to offer time of use rates.

Ms. Birmingham-Byrd testified that DEI agrees to develop, evaluate, and project the cost-effectiveness for an energy efficiency/demand response pilot program that leverages smart thermostats and customer engagement platforms for energy and demand savings. DEI will consult with its Energy Efficiency Oversight Board (“OSB”) and EDF in designing the program. Ms. Birmingham-Byrd testified that DEI will present its proposal to its OSB on or before such time as the AMI meters are certified for approximately 25% of DEI’s system. In addition, DEI commits to good faith discussions with EDF to evaluate the feasibility of technology tests and an initial pilot that will allow for near real-time energy data access to customers. Ms. Birmingham-Byrd testified that the Settlement Agreement is reasonable and in the public interest.

Mr. Fowler provided settlement testimony related to the distribution portion of DEI’s Seven-Year Plan. He testified that DEI has agreed to reduce the distribution circuit improvements by a cumulative \$30 million, consisting of a targeted reduction of \$6 million in each year from 2018-2022. He explained that the \$30 million in distribution projects will remain available as alternate projects to provide flexibility in implementing the Seven-Year Plan. The alternate projects contained in the Original Plan have been removed from the Seven-Year Plan. Mr. Fowler testified that the contingency amounts for the distribution projects in years 2018-2022 were reduced in an amount proportional to the reduction in planned work for each of those years, based against the Original Plan. He testified that the revised Plan includes \$54.2 million of distribution project-related O&M, which was also decreased. Mr. Fowler explained that DEI leveraged the knowledge of its internal company resources to identify the reduction of projects that pose the lowest impact to the plan objectives. No projects were totally eliminated; instead, DEI reduced the scope on selected projects. DEI elected not to reduce scope on any projects that support Distribution Automation (“DA”) or IVVC, both of which have significant customer benefits. Mr. Fowler testified that DEI will update the Seven-Year Plan annually in TDSIC mechanism proceedings. In addition, DEI will provide a report on its IVVC plan in each rider proceeding. DEI has also agreed to review further expansion of IVVC to include additional circuits, and will provide a cost/benefit analysis of this expansion in a future TDSIC mechanism proceeding or base rate case.

Mr. Fowler provided a revised Risk Profile Analysis showing a total T&D system risk reduction of 29% over the Seven-Year Planning period—compared to 31% in its Original Plan. He testified that the overall risk on the T&D system will be reduced from the risk that exists today, and will lead to an increase in the reliability and integrity of DEI’s transmission and distribution system. The revised Seven-Year Plan will provide significant customer benefits like real-time outage notifications, shorter outage duration, fault isolation, and fewer overall outages. In addition, the implementation of IVVC will reduce energy usage on enabled circuits, resulting in lower generation fuel usage and less emissions.

Mr. Broadhurst provided settlement testimony regarding the changes to the transmission and distribution substation portion of the Seven-Year Plan. He testified that DEI has agreed to reduce the transmission line and substation investment by a cumulative \$175 million in capital costs from the Original Plan, consisting of a reduction of approximately \$43.8 million in each year

from 2018-2021. The \$175 million in transmission projects will remain available as alternate projects to provide DEI needed flexibility in implementing its Seven-Year Plan. Mr. Broadhurst testified that the contingency allocated for transmission projects in years 2018-2021 was reduced in an amount proportional to the reduction in planned work for each of those years. The revised Plan also includes a reduced amount of transmission project-related O&M of about \$4.8 million. Mr. Broadhurst explained that DEI did not remove any type of transmission project from the Seven-Year Plan in its entirety. Projects were selected for elimination to achieve the reduction targets with as little reduction as possible to the benefits provided by the Plan. He also explained that the alternate projects contained in the Original Plan were removed as part of the Settlement Agreement. Under the Settlement Agreement, DEI will be able to use the \$175 million in projects eliminated from the transmission portion of the Seven-Year Plan as alternative projects. Mr. Broadhurst testified that although the Plan was reduced in scope, the Seven-Year Plan will improve the reliability, resiliency, and integrity of the transmission and distribution systems in Indiana. It will also provide significant customer benefits like real-time outage notifications, shorter outage durations, fault isolation, and fewer overall outages.

Mr. Davey testified that the revised proposed Rider 65 will have two categories of revenue requirements, transmission and distribution excluding meters. DEI proposes to allocate the transmission and distribution (excluding meters) revenue requirements developed for Rider 65 to the rate groups based on the revenue requirement by rate group for these same two categories from DEI's last retail base rate case, Cause No. 42359. He testified that under the terms of the Settlement Agreement, DEI agrees to modify its proposed Rider 65 allocation factors for rate HLF and LLF customers by using the respective delivery voltage revenue levels approved in DEI's last base rate case. Other rate groups are unaffected by this change. Regarding SDI's special contracts, the TDSIC mechanism will be applicable to the HLF portion of their demand, but not the Day-Ahead Pricing portion. Mr. Davey testified that the Settling Parties have agreed to an ROE for the Seven-Year Plan rider of 10.0%. In addition, the depreciation expense and/or return associated with retired and replaced equipment will not be netted against the depreciation expense and/or return associated with new equipment in the TDSIC mechanism, and base retail rates will not be adjusted for these items.

Mr. Davey testified that at the time of DEI's subsequent base rate case, the Settling Parties agree that the T&D improvements in-service by the rate base cut-off date will, subject to a normal prudence review in the TDSIC mechanism proceedings, be included in rate base and DEI's new base rates and subject to the ROE and allocation factors that are ultimately determined by the IURC in such retail base rate case. Similarly, the 20% of the T&D improvements that have been deferred with carrying costs will be included in retail rates and rate base and any AMI deferrals will be included in rates. He testified that if there remain years in the Seven-Year Plan after the subsequent retail base rate case order, all caps will remain in effect for 2016-2022 and any TDSIC mechanism would be adjusted to use the new ROE and allocation factors approved in the subsequent retail base rate case. He also testified that the Settlement Parties agree that the Seven-Year Plan starts in calendar year 2016 and Year One of the Plan includes projects that go in-service in 2016.

Mr. Davey testified that the total annual average retail rate impact of the Seven-Year Plan compared to retail revenue is estimated to be slightly less than 0.75% over the seven-year period,

which is below the 2% annual average cap provided for in Ind. Code § 8-1-39-14. However, should an actual amount exceed the two percent annual cap and cumulative capital expenditures are below the cumulative capital costs cap, DEI requests approval to defer recovery of the TDSIC costs above the two percent annual cap pursuant to I.C. § 8-1-39-14(b).

Mr. Davey testified that the Settling Parties agree that DEI should be allowed to defer 100% of the depreciation associated with the AMI project up to \$60 million for recovery in a subsequent retail base rate proceeding. DEI will recover the deferred depreciation over a 10 year period, without carrying costs, in its subsequent retail rate case. In addition, the Settling Parties agree that DEI should be authorized to defer post-in-service carrying costs associated with the AMI project up to \$15 million for recovery in a subsequent retail base rate case proceeding. The Settling Parties agree that DEI should be approved to recover the deferred post-in-service carrying costs over a ten-year period without carrying costs in its subsequent retail rate case. To calculate the carrying costs on the AMI project, DEI will use the debt only post-in-service carrying costs rate of 4.72% until the \$15 million is reached after which no additional post-in-service carrying costs will be deferred. Mr. Davey testified that there could be a materially adverse earnings impact to DEI if the AMI deferrals are not approved. He also testified that the Settling Parties agreed to a new depreciation rate for the new AMI meters based on a 15 year life. DEI has agreed to drop its request for a regulatory asset associated with the current meters and if DEI proceeds with AMI, not to request recovery of or on the undepreciated value of such meters at the time of a subsequent retail base rate case or at any other time or in any manner. He testified that there would no changes to current base rates for this issue. Mr. Davey testified that the Settling Parties have agreed that if DEI proceeds with AMI, the estimated net savings associated with the AMI project (\$39.69 million over seven years) will be retained by DEI until a subsequent retail base rate case. In addition, the Settling Parties agree not to oppose inclusion of an AMI project into rate base and DEI base rates at the time of the subsequent retail base rate case subject to normal prudence review, including a review of the costs associated with the project. Mr. Davey also testified that DEI agrees to drop its request for approval of the new proposed rate options.

**B. Industrial Group.** Mr. Phillips testified that the Industrial Group recommends approval of the Settlement Agreement. Mr. Phillips testified that the Settlement Agreement reduces DEI's requested capital expenditures by \$397 million and reduces the return on equity used in the determination of revenue requirements for the TDSIC mechanism from 10.5% to 10.0%. He also testified that the cost caps contained in the settlement are important because they reduce the risk of construction cost increases to ratepayers over the Seven-Year Plan. The Settlement Agreement also spreads the reductions over the seven years of the plan to protect ratepayer savings. Mr. Phillips testified that cost-based revenue allocation factors used in the Settlement Agreement appropriately apportion the TDSIC costs among and within DEI's rate classes. Mr. Phillips testified that the Settlement Agreement is reasonable and in the public interest. It reasonably mitigates the rate increase for all classes including the residential class, provides DEI's large industrial customers a better chance to be competitive in the national and global markets they compete in, allows DEI to receive sufficient revenues to efficiently and economically provide service within its service area, and helps maintain the economic stability of DEI's large industrial customers and the economic viability of the entire area.

C. **EDF.** Mr. Sandoval testified that EDF is satisfied with the changes DEI made in the Seven-Year Plan as a result of the settlement negotiations, and believes the Plan is reasonable and should be approved. He testified that DEI has agreed to file periodic reports on its IVVC system, which will show the voltage reductions, energy savings, and greenhouse gas emission reductions from IVVC. Also, DEI will consider expanding its IVVC system at the time of its next Seven-Year Plan or base rate case, and to provide a cost/benefit analysis of system expansion at that time. Mr. Sandoval testified that DEI has agreed to develop two innovative energy efficiency pilot programs: (1) “bring your own thermostat” program to allow customers to link the smart meter to their existing thermostat; and (2) “home energy monitor” to provide customers with a device to monitor how much energy they are using in real-time. With the “bring your own thermostat” program, customers could volunteer to receive an alert during high load conditions. DEI would briefly shut off the compressor on the customer’s air conditioner, with the fan continuing to circulate cool air.

D. **OUC.** Mr. Golden testified that DEI’s Seven-Year Plan distribution system circuit improvement projects focus on safety, reliability, system modernization, or most often, some combination of the three. He testified that DEI’s evidence explains the nature of the project, the expected benefits, and provides sufficient engineering background and support for the OUC to conclude that each project is reasonable from an engineering standpoint.

Mr. Golden testified that DEI’s transmission line upgrade projects focus primarily on replacing obsolete equipment and addressing system reliability issues. As a result of the Settlement Agreement, DEI has reduced the number of transmission line upgrade projects to 124 specific projects on 77 transmission lines, including replacements of transmission poles, crossarms, static wires, and 69 kV line rebuilds. Mr. Golden testified that each transmission substation and transmission line upgrade project will improve safety, reliability, or system modernization. DEI has explained the nature of the projects, expected benefits, and provided sufficient engineering background and support for the OUC to conclude each project is reasonable from an engineering standpoint.

Mr. Golden testified that the benefits of these projects, when considered in conjunction with the annual TDSIC cost caps, total Seven-Year Plan cost cap, the cost reductions for both transmission and distribution customers and all other terms of the Settlement Agreement, form a fair and balanced compromise. He testified that the Settlement Agreement promotes the ongoing improvement of DEI’s infrastructure at a reasonable cost, and the public interest is served by fairly balancing both customers’ and the utility’s interests. Mr. Golden testified that the OUC recommends the Commission approve the Settlement Agreement in its entirety.

Mr. Snyder explained the OUC’s investigation into the reasonableness of DEI’s proposed estimated capital expenditures in the Seven-Year Plan. Mr. Snyder testified that DEI’s confidential workpapers provide work order level detail and support for each of the distribution system category and transmission system category projects. He recommended the Commission accept the cost support data provided as sufficient for DEI’s transmission system and distribution system estimates to qualify as “best” estimates as required by I.C. § 8-1-39-10(b)(1). Mr. Snyder also recommended the Commission approve, as “eligible improvements” the projects and programs summarized in Petitioner’s Exhibit 2-A, and approval of the Settlement Agreement.

**E. SDI.** Mr. Higgins testified that the Settlement Agreement reflects a reasonable balancing of interests among the Settling Parties and produces a result that is in the public interest. Through negotiation among the Settling Parties, the overall TDSIC funding level has been reduced relative to DEI's initial filing, AMI costs have been removed from TDSIC funding while allowing for capped deferrals of specified AMI costs, and voltage differentiation is properly recognized for HLF and LLF customers in the TDSIC mechanism. Mr. Higgins testified that the Settlement Agreement appropriately and reasonably addresses voltage differentiation by modifying DEI's initially-proposed allocation factors to allocate the Seven-Year Plan revenue recovery for rate HLF and LLF customers using the respective delivery voltage revenue levels approved in Cause No. 42359. Further, this modification does not affect the total TDSIC costs allocated to HLF (or LLF), nor does it affect the total TDSIC costs allocated to any other customer group. The incorporation of this modification into the Settlement Agreement produces a result that is clearly in the public interest. Failure to recognize voltage differentiation in the TDSIC mechanism as provided in the Settlement Agreement would be inconsistent with the principles of cost causation and would be inconsistent with the statutory requirement to use the customer class revenue allocation factor based on firm load approved in the public utility's most recent retail base rate case order. Absent recognition of voltage differentiation in the TDSIC mechanism, each HLF customer would pay the same TDSIC mechanism charge for the distribution system cost category, irrespective of the voltage at which the customer takes service. Similarly, absent recognition of voltage differentiation in the TDSIC mechanism, each LLF customer would pay the same TDSIC mechanism charge for the distribution system cost category, irrespective of the voltage at which the customer takes service. Mr. Higgins testified that such outcomes would be fundamentally unreasonable.

Mr. Higgins further testified that the Settlement Agreement provides that the TDSIC mechanism will be applicable to the HLF portion of SDI's special contract demand, but not to the Day-Ahead Pricing portion. He explained that because the SDI special contract did not exist in 2004 when DEI's revenue allocation was set, there were no costs allocated to what is now the Day-Ahead Pricing portion of SDI's special contract. Under the terms of the Settlement Agreement, the majority of SDI's load will be subject to the HLF-Transmission-Bulk charge. Mr. Higgins recommended that the Commission approve the Settlement Agreement in its entirety, without changes or conditions.

**F. WVPA.** Mr. Wagoner testified that the Settlement Agreement reaches an acceptable balance between future investment in DEI's transmission and distribution systems to improve reliability and performance at an acceptable financial level. WVPA recommends that the Commission approve the Settlement Agreement, without modification.

**7. CAC's Evidence Opposing the Settlement Agreement.** Mr. Olson testified that the CAC is concerned that DEI has not filed a base rate case since 2002. He stated that the most equitable method to determine whether rates charged by a monopoly utility are just and reasonable is to go through the process of a general rate case, rather than through CPCNs and other trackers. He testified that CPCNs and their associated cost recovery allow utilities to recover costs from ratepayers for projects, which are not, and may never be, used and useful in providing actual utility service to ratepayers. This pre-approval process shifts the burden of proving that costs were

prudently incurred onto the public, and shifts the majority of the investment risk onto captive ratepayers and away from DEI's voluntary investors. Mr. Olson testified that the CAC opposes the use of most trackers, as they are inherently unfair to ratepayers as they allow the monopoly utilities to raise rates when their costs go up without looking at where their costs have gone down.

Mr. Olson testified that, according to the IURC 2015 Residential Bill Survey, over 34% of DEI's monthly bill comes from trackers, which is a much higher percentage when compared to the customers of I&M, NIPSCO, and Vectren. In addition, DEI is the only investor-owned electric utility in Indiana that has not been before the Commission for a base rate case in more than 5 years. Mr. Olson testified that the percentage of a monthly bill coming from trackers has steadily increased since 2009, peaking at nearly 22%, according to the 2015 Residential Bill Survey. He said that DEI's non-FAC related trackers have increased from 10.78% of the monthly bill in 2009 to 21.62% in 2015.

Mr. Olson testified that under the TDSIC statute, a public utility may not file a petition within 9 months after the date on which the commission issues an order changing the public utility's basic rates and charges. He testified that 138 months have elapsed between DEI's current base rates (May 18, 2004) and the filing of the petition in this case. From a policy perspective, a reasonable person could deduce that the legislature would not find it reasonable to approve a TDSIC tracker for a utility with base rates established over 138 months ago, more than the 9-month trigger included by the legislature. Mr. Olson also testified that the TDSIC statutory requirement that a utility file a base rate case before the end of its approved Seven-Year Plan would lead a reasonable person to draw the conclusion that the legislature contemplated that no more than seven years was the appropriate interval between base rate cases. Should the Commission award DEI the use of the TDSIC tracker, DEI would not be required to file a base rate case until 2023, which would mean 21 years would lapse between DEI's petitions for a base rate case.

Mr. Olson testified that allowing another substantial tracker on captive customers' bills is neither just nor reasonable. The tracker reduces DEI's exposure to risk and uncertainty, but in doing so, it transfers that exposure to risk to DEI's customers, who can least afford it. He testified that the poverty rate in Indiana has increased to 29.3% between 2007 and 2013. He believes that it is immoral and unethical to require these already struggling entities and households to realize even higher monthly electric bills, when the reality is that DEI can afford and is obligated to make these investments. Mr. Olson testified that since DEI has increased its transmission and distribution investment since the last rate case by \$800 million, it must not need to recover that money in the short term or it would file a base rate case. So evidently, DEI does not need the upfront capital, which means DEI does not need the tracker.

Mr. Olson testified that DEI's Seven-Year Plan, as modified by the Settlement Agreement, does not satisfy the public convenience and necessity threshold or provide incremental benefits for the estimated costs. He stated that DEI has not adequately considered the public's convenience and necessity in investing in energy efficiency and other *non-wires* alternatives in lieu of sinking substantial ratepayer money into costly T&D upgrades. Mr. Olson also recommend that the Commission investigate DEI's zero customer participation in its demand response, especially as a *non-wires* alternative to costly T&D investments. He believes distributed generation is another *non-wires* alternative. Mr. Olson cites to a Northeast Energy Efficiency Partnerships report which

discusses passive and active deferral as two ways in which energy efficiency programs can defer T&D investments.

In conclusion, Mr. Olson suggests the Commission deny DEI's Seven-Year Plan until DEI sufficiently invests in energy efficiency as a resource and irons out problems with its demand response tariff and low distributed generation penetration. The Commission should also require DEI to do a more robust analysis of such *non-wires* alternatives prior to submitting its TDSIC proposals. However, if the Commission approves DEI's Seven-Year Plan, pursuant to the Settlement Agreement, Mr. Olson suggests DEI should be required to make a determination as to whether each project might be a good candidate for a *non-wires* approach with criteria determined by the Commission, analyze the types of customers in the affected load areas and identify the types of *non-wire* alternatives that could potentially be applicable and effective, and immediately implement a pilot project to test the efficacy of *non-wires* alternatives in deferring future T&D investments that would be run by an independent third party.

#### **8. Settling Parties' Rebuttal Testimony.**

A. **DEI.** Ms. Birmingham-Byrd testified that the Settling Parties disagree with the CAC's assertion that the benefits of the Seven-Year Plan, as modified by the Settlement Agreement, do not justify the costs of the Plan. She testified that replacing aging infrastructure, targeting degrading components, upgrading equipment, and improving poor performing circuits all will benefit customers through maintaining and modernizing a safe, reliable T&D system. In addition, the modernization components of the Plan will enable deployment of enhanced equipment providing more timely and accurate information about outages to customers and will enable additional customer products and service offerings today and in the future. DEI's testimony related to risk reduction on the T&D system and the cost/benefit analysis for IVVC and AMI fully support the benefits of the Seven-Year Plan and the AMI deferrals.

As to the CAC's testimony regarding DEI's insufficient investment in energy efficiency and demand response, Ms. Birmingham-Byrd testified that, although not relevant to investments included in the Seven-Year Plan, DEI has an extensive history of strong support for energy efficiency and demand response programs going back to the 1990s. DEI's latest energy efficiency plan was recently approved by the Commission, and DEI has very successful demand response programs for commercial and industrial customers under its PowerShare<sup>®</sup> and Power Manager<sup>®</sup> programs. DEI added two new demand response programs to its recently approved 2016 portfolio of programs. DEI's IVVC Project included in the Seven-Year Plan, is estimated to provide energy reductions of over 1% on impacted circuits.

Ms. Birmingham-Byrd testified that DEI considered its low income customers in developing the Seven-Year Plan, which includes investments that improve the efficiency of the system and enables additional energy efficiency programs. DEI actively works with customers on issues such as billing payment arrangements and deferring service disconnects, as well as providing energy efficiency programs targeted to low income customers. Ms. Birmingham-Byrd testified that DEI's Seven-Year Plan considered the impact on customer rates by ensuring that the average rate increase was initially no more than 1% per year. The Settlement Agreement further

reduces this rate impact to approximately 0.75% per year, which is significantly below the 2% provided for in the TDSIC statute.

Mr. Fowler testified that there are no efficiency measures that remove the need to replace aging assets that are impacting DEI's system power quality and reliability. Those assets need to be replaced to deliver the related benefits to customers. Mr. Fowler testified that DEI has no load growth projects in its Seven-Year Plan. All projects are related to repairing, replacing, or modernizing existing T&D assets. He stated that there are no projects in the Seven-Year Plan that are related to load growth that could potentially be delayed by investment in energy efficiency or demand response. Mr. Fowler testified that the IVVC project within DEI's Seven-Year Plan enables the distribution grid to operate more efficiently, allowing for the voltage to be lowered an average of approximately 2% at the distribution substation on enabled circuits, while maintaining voltage within regulatory limits for all customers. He testified that this equates to an estimated 1.4% reduction in demand load on these circuits, resulting in cost savings to customers through lower energy usage and generation fuel savings. In response to Mr. Olson's proposal to halt DEI's Seven-Year Plan until DEI "sufficiently invests in energy efficiency," Mr. Fowler responded that prolonging the relief requested in this proceeding will do nothing beneficial for DEI's customers. Rather, it will prolong the upgrades necessary for DEI to maintain its transmission and distribution systems. Additionally, DEI's Risk Model Profile shows doing nothing will erode DEI's system performance and actually increase costs if the improvements are delayed.

Mr. Davey testified that the 2015 IURC bill survey referenced by Mr. Olson shows that DEI's 2015 total residential monthly bill was below the Indiana average. This demonstrates that DEI's use of riders has not resulted in unreasonable residential rates compared to other Indiana investor-owned electric utilities. He testified that a larger portion of a customer's bill being recovered via tracker rates just means that a larger portion of the total rates are under continuous detailed review and scrutiny in tracker proceedings. In addition, as utilities have been required to comply with various environmental and other federal mandates over time, the General Assembly has recognized these increased and continuing cost pressures and responded with legislation that enables the costs resulting from these mandates to be recovered through customer rates via the use of trackers. Mr. Davey also points out that DEI has not over-earned under the earnings test during 2009-2015, which is another data point supporting that DEI's rates, including rates as a result of using trackers, are reasonable. Mr. Davey testified that the TDSIC statute does not require a utility to have a base rate case prior to filing for a TDSIC Plan. DEI plans to petition the Commission for a review and approval of its rates charges before the expiration of the Seven-Year Plan, as required by the TDSIC statute.

**B. Industrial Group.** Mr. Phillips testified that he disagreed with Mr. Olson's statement related to the effect of the issuance of a CPCN in a TDSIC case. Mr. Phillips testified that he does not believe that the effect of the issuance of a CPCN under Ind. Code 8-1-8.5 and Ind. Code 8-1-8.7 is the same as the effect of a CPCN issued under the TDSIC statute, and that the "used and useful" requirement still applies to TDSIC costs. Mr. Phillips testified that the Industrial Group does not believe that Mr. Olson's conclusion on this point presents a reason to reject the Settlement Agreement.

9. **Terms of Settlement Agreement.** The Settling Parties entered into a Settlement Agreement that resolved all of their issues in this proceeding. The significant terms of the Settlement Agreement are as follows:

A. **Overall Scope of Seven-Year Plan.** DEI reduced the projects and programs that are eligible for TDSIC ratemaking treatment in its Seven-Year Plan to a maximum of \$1.408 billion of capital expenditures plus related project O&M and TDSIC Costs. This includes eliminating the AMI project, approximately \$175 million in transmission capital improvements, and \$30 million in distribution capital improvements from TDSIC ratemaking treatment. The Settling Parties agreed that DEI provided sufficient project detail and program descriptions and sufficient cost estimates. Further, the Settling Parties agreed that the costs of the Seven-Year Plan are justified by the incremental benefits of the plan.

B. **Alternative Project List.** The Settling Parties agreed to authorize DEI to utilize any non-AMI project as proposed in this Seven-Year Plan to make up the \$1.408 billion in total plan expenditures.

C. **Cost Cap.** The Settling Parties agreed to cap the capital investment in each year of the Seven-Year Plan as proposed in the chart below.

	2016	2017	2018	2019	2020	2021	2022	Total
Capital cost as filed	\$ 113.9	\$ 269.9	\$ 318.2	\$ 295.6	\$ 270.1	\$ 277.8	\$ 259.6	\$ 1,805.1
Remove AMI capital cost	\$ (22.0)	\$ (56.2)	\$ (57.0)	\$ (48.4)	\$ (6.7)	\$ (0.7)	\$ (0.7)	\$ (191.8)
Remove a portion of transmission capital cost			\$ (43.8)	\$ (43.8)	\$ (43.8)	\$ (43.8)	\$ -	\$ (175.0)
Remove a portion of distribution capital cost	\$ -	\$ -	\$ (6.0)	\$ (6.0)	\$ (6.0)	\$ (6.0)	\$ (6.0)	\$ (30.0)
Capital cost as adjusted	\$ 91.8	\$ 213.7	\$ 211.4	\$ 197.5	\$ 213.7	\$ 227.3	\$ 252.9	\$ 1,408.3
Cumulative capital cost as adjusted	\$ 91.8	\$ 305.5	\$ 517.0	\$ 714.4	\$ 928.1	\$ 1,155.4	\$ 1,408.3	

D. **AMI.** DEI agreed to remove AMI project capital and O&M from the Seven-Year Plan. To the extent DEI implements the AMI project before its next base rate case, DEI may retain any savings associated with the AMI project. The Settling Parties agreed to allow DEI to defer 100% of the depreciation without carrying costs associated with the AMI project, up to a maximum of \$60 million. The Settling Parties have also agreed to defer post-in-service carrying costs associated with the AMI project up to \$15 million for recovery in DEI's next base rate case. The carrying costs will be calculated using DEI's long-term debt cost rate of 4.72% until the \$15 million is reached. In addition, DEI agreed to drop its request for a regulatory asset associated with its current meters.

E. **Customer Programs.** DEI agreed to develop, evaluate, and project the cost effectiveness of an EE/DSM pilot program that leverages smart thermostats and customer engagement platforms. If DEI pursues the AMI program outside of the Seven-Year Plan, it will activate the meters' internal radio. DEI committed to good faith discussions with EDF to evaluate the feasibility of technology tests and initial pilot that will allow for near real time energy data access to customers.

F. **Reporting Requirements.** DEI agreed to provide a report on its IVVC project in the TDSIC mechanism proceedings because the related investments will not be included in DEI's energy efficiency rider.

G. **Return on Equity.** DEI agreed that the ROE for projects in the Seven-Year Plan will be 10.0%.

H. **Allocation Factors.** There are no changes to DEI's proposed allocation factors among rate classes. DEI agreed to modify its proposed allocation factors and allocate Seven-Year Plan revenue for rate HLF and LLF customers using the delivery voltage revenue levels approved in DEI's last base rate case.

## 10. **Commission Discussion and Findings.**

A. **Statutory Requirements.** Ind. Code § 8-1-39-10(a) permits a public utility to petition the Commission for approval of the public utility's Seven-Year Plan for eligible transmission, distribution, and storage improvements.

Ind. Code § 8-1-39-10(b) states that after notice and a hearing, and not more than 210 days after the petition is filed, the Commission shall issue an order that includes the following:

- (1) A finding of the best estimate of the cost of the eligible improvements included in the plan;
- (2) A determination whether public convenience and necessity require or will require the eligible improvements included in the plan; and
- (3) A determination whether the estimated costs of the eligible improvements included in the plan are justified by the incremental benefits attributable to the plan.

If the Commission determines that the public utility's seven (7) year plan is reasonable, the Commission shall approve the plan and designate the eligible transmission, distribution, and storage improvements included in the plan as eligible for the TDSIC treatment.

Ind. Code § 8-1-39-2 states:

As used in this chapter, "eligible transmission, distribution, and storage system improvements" means new or replacement electric or gas transmission, distribution, or storage utility projects that: (1) a public utility undertakes for purposes of safety, reliability, system modernization, or economic development, including the extension of gas service to rural areas . . . .

Therefore, we will first review DEI's Seven-Year Plan as provided in the Settlement Agreement, then determine whether the projects outlined meet the definition of "eligible transmission, distribution, and storage system improvements" and whether public convenience and necessity require or will require the proposed projects. We will then determine whether DEI has provided a best estimate of the costs of the projects and whether the estimated costs of the projects are justified by their incremental benefits.

**B. Settlement Agreements.** Settlements presented to the Commission are not ordinary contracts between private parties. *United States Gypsum, Inc. v. Indiana Gas Co.*, 735 N.E.2d 790, 803 (Ind. 2000). Any settlement agreement that is approved by the Commission “loses its status as a strictly private contract and takes on a public interest gloss.” *Id.* (quoting *Citizens Action Coalition v. PSI Energy, Inc.*, 664 N.E.2d 401, 406 (Ind. Ct. App. 1996)). Thus, the Commission “may not accept a settlement merely because the private parties are satisfied; rather [the Commission] must consider whether the public interest will be served by accepting the settlement.” *Citizens Action Coalition*, 664 N.E.2d at 406.

Further, any Commission decision, ruling, or order, including the approval of a settlement, must be supported by specific findings of fact and sufficient evidence. *United States Gypsum*, 735 N.E.2d at 795 (citing *Citizens Action Coalition of Ind., Inc. v. Public Service Co. of Ind., Inc.*, 582 N.E.2d 330, 331 (Ind. 1991)). The Commission’s own procedural rules require that settlements be supported by probative evidence. 170 IAC 1-1.1-17(d). Therefore, before the Commission can approve the Settlement Agreement, we must determine whether the evidence in this Cause sufficiently supports the conclusions that the Settlement Agreement is reasonable, just, and consistent with the purpose of Indiana Code ch. 8-1-2, and that such agreement serves the public interest.

**C. DEI’s Seven-Year Plan.** The initial question we must answer is whether DEI’s Seven-Year Plan is a plan as required by Section 10(a). In construing a statute, the primary goal is to determine and give effect to the intent of the Legislature. *Ind. Civil Rights Comm’n v. Alder*, 714 N.E.2d 632, 637 (Ind. 1999). When the statute is clear and unambiguous, we need not apply any rules of construction other than to require that words and phrases be given their plain, ordinary and usual meanings. *City of Carmel v. Steele*, 865 N.E.2d 612, 618 (Ind. 2007). The Merriam-Webster Dictionary defines a plan as “a set of actions that have been thought of as a way to do or achieve something.”

The Settling Parties request approval of a plan that includes an estimated \$1.408 billion of capital improvement projects over calendar years 2016 through 2022. DEI has provided a detailed list of discrete projects for inclusion in its Seven-Year Plan. Ms. Birmingham-Byrd testified that DEI “spent thousands of hours defining individual projects for all seven years of the plan, including location, expected project scope, and cost estimates broken down into material, labor, indirects, allowance for funds used during construction (“AFUDC”), O&M, and contingency.”

The Settling Parties agreed to reduce the capital expenditures eligible for TDSIC ratemaking treatment to \$1.408 billion. The Settling Parties also agreed, however, to allow DEI to include all projects summarized in Petitioner’s Exhibit 2-A and detailed in the exhibits and workpapers of Mr. Howard Fowler and Mr. Donald Broadhurst (other than AMI) as eligible improvements in its Seven-Year Plan. This represents approximately \$1.613 billion in possible projects. Under the terms of the Settlement Agreement, DEI will have approximately \$205 million in alternate projects designated as eligible projects for the Seven-Year Plan that subsequently may be moved into the Seven-Year Plan for recover under the TDSIC mechanism. Each of the newly identified alternate projects includes a detailed cost estimate. DEI testified that these alternate projects are needed to maintain the flexibility to make needed reliability and modernization

improvements. To the extent that DEI uses projects on the alternate list, DEI shall explain its decision in future TDSIC proceedings.

The evidence of record is that DEI reviewed its T&D system and came up with a plan that addresses aging infrastructure and modernizes the electric grid in DEI's service territory. The Seven-Year Plan includes projects designed to improve the reliability and integrity of the system and projects that will modernize an aging system. Further, DEI used a third party to analyze the current risk of its T&D system and quantify how the proposed plan expenditures would reduce that risk over time. DEI provided detailed descriptions of each component of its plan, how each project provides customer benefits, and how each project helps to maintain safe, reliable service. No party provided any evidence that DEI's Seven-Year Plan does not meet the requirements of Ind. Code § 8-1-39-10(a). Based on the evidence presented, we find that DEI provided a plan that meets the requirements of Ind. Code § 8-1-39-10(a).

**D. Eligible Improvements and Public Convenience and Necessity.** Ind. Code § 8-1-39-2 defines eligible transmission, distribution, and storage system improvements as projects undertaken for purposes of safety, reliability, system modernization, or economic development. Ms. Birmingham-Byrd testified that the Seven-Year Plan will increase the safety, reliability, and integrity of the T&D system. No party provided any evidence that any of the projects or improvements in the Seven-Year Plan did not meet the statutory requirements of the TDSIC Statute.

Based on the evidence provided in this proceeding, we find that DEI has sufficiently supported the investments described in its Seven-Year Plan. These projects are reasonably necessary for DEI to continue to provide adequate retail electric service to its customers. No party opposed the inclusion of any particular project in the Seven-Year Plan or provided evidence that a particular project does not meet the criteria outlined in Ind. Code § 8-1-39-2. Therefore, based on the evidence presented in this proceeding, we find that the projects included in the Seven-Year Plan constitute eligible transmission, distribution, and storage system improvements and that public convenience and necessity require or will require the eligible improvements included in Seven-Year Plan.

**E. Best Estimate of the Cost of the Eligible Improvements.** Ind. Code § 8-1-39-10(b)(1) requires a finding that the best estimate of the cost of the eligible improvements was included in the Seven-Year Plan. No party contested DEI's cost estimates, cost estimating techniques, or Black & Veatch's independent review and concurrence with the Seven-Year Plan's cost estimates and DEI's cost estimating process.

While we have encouraged utilities to improve the level of accuracy and completeness of their cost estimates prior to seeking Commission pre-approval for a project, we have also recognized that the circumstances of a project may dictate the appropriate range of accuracy. *See Northern Indiana Public Service Company*, Cause No. 44012 at 18 (IURC 12/28/2011). In evaluating the best estimate of the Plan, we note that DEI identified specific projects and cost estimates for each year of its Seven-Year Plan. Further, DEI had Black & Veatch perform an independent review of its cost estimates and cost estimating techniques, and Black & Veatch concluded that DEI's cost estimates and cost estimating process are reasonable. We also note that

DEI has agreed to cap the overall amount of costs included in the TDSIC mechanism, which provides additional certainty of the cost to customers. Accordingly, we find that that DEI has provided reasonable cost estimates for its proposed Seven-Year Plan and has provided sufficient support for its cost estimates and that the cost estimates provided by DEI are the best estimates of the Seven-Year Plan components. Notwithstanding this finding, we retain our continuing jurisdiction over these matters and will, in the future, review any updates to the Seven-Year Plan and Seven-Year Plan cost estimates, consistent with the statute and the Settlement Agreement.

**F. Incremental Benefits Attributable to the Seven-Year Plan.** The evidence presented shows that DEI has considerable aging infrastructure on its electric transmission and distribution system. The evidence supports DEI's position that these assets need to be replaced. DEI's Seven-Year Plan puts forth a plan that addresses these needed replacements in a cost efficient and prioritized manner. DEI engaged Black & Veatch to perform a quantitative risk assessment of these assets. The analysis demonstrates that DEI will maintain a reasonable level of risk on its T&D system after investing in the Seven-Year Plan components. These investments are necessary to maintain reliability of the T&D system. We find the analysis performed, along with the qualitative improvements and customer benefits identified provides sufficient evidence to support the assertion that the Seven-Year Plan provides incremental benefits justifying the estimated costs of the projects. Additionally, DEI provided a robust cost-benefit analysis for the IVVC project. This analysis indicates that there is a significant, quantifiable benefit attributable to that project.

The CAC opposed the Settlement Agreement on the grounds that DEI should review various EE and DSM options before proceeding with a Seven-Year Plan. As DEI provided in its rebuttal testimony, however, the Seven-Year Plan provides improvements to and replacement of existing assets. The evidence that the CAC relied upon indicates that EE and DSM will have little to no effect on reducing the need for upgrades on existing T&D equipment.

Based on the direct testimony of DEI and the settlement testimony of the Settling Parties, we find that DEI has provided sufficient evidence that the estimated costs of the eligible improvements included in the Seven-Year Plan are justified by the reasonably expected incremental benefits attributable to the plan.

**G. Whether DEI's Seven-Year Plan is Reasonable.** Based upon our review of the evidence presented and our discussion above, we find that DEI's Seven-Year Plan is reasonable. We also find that DEI has provided sufficient evidence that its cost estimates are best estimates, that public convenience and necessity require or will require the eligible improvements in the Seven-Year Plan, and that the benefits of the Seven-Year Plan project benefits justify its costs. Therefore, we find that the Seven-Year Plan is reasonable, and we approve the Seven-Year Plan.

**H. Establishment of a TDSIC.** DEI requests approval of its proposed T&D Rate Schedule and accompanying changes to its electric service tariff, which will allow for timely recovery of 80% of eligible and approved capital expenditures and TDSIC costs under Ind. Code § 8-1-39-9. We must first determine whether DEI's petition in this Cause meets the various requirements of Section 9. Ind. Code § 8-1-39-9(a) states:

Subject to subsection (c), a public utility that provides electric or gas utility service may file with the commission rate schedules establishing a TDSIC that will allow the periodic automatic adjustment of the public utility's basic rates and charges to provide for timely recovery of eighty percent (80%) of approved capital expenditures and TDSIC costs. The petition must:

- (1) use the customer class revenue allocation factor based on firm load approved in the public utility's most recent retail base rate case order;
- (2) include the public utility's seven (7) year plan for eligible transmission, distribution, and storage system improvements; and
- (3) identify projected effects of the plan described in subdivision (2) on retail rates and charges.

1. **Customer Class Revenue Allocation.** DEI requested approval to use its customer class revenue allocation factors based on firm load that was approved in its last general base rate case. In the Settlement Agreement, the Settling Parties agreed to a modification of the proposed allocation factors to allocate the Seven-Year Plan revenue for rate HLF and LLF customers within each rate group using the respective delivery voltage revenue levels approved in DEI's last base rate case. Other rate groups are unaffected by this change. The Settling Parties agreed that using such factors complies with the TDSIC statute.

Ind. Code § 8-1-39-9(a) requires DEI to use the customer class revenue allocation factor based on firm load developed in the most recent retail base rate case. The evidence shows that, as required in the statute, the revenue allocation factors proposed by the Settling Parties correspond with the allocation factors approved by the Commission in Cause No. 42359.

2. **Adjustment of Net Operating Income for Purposes of Ind. Code § 8-1-2-42(d)(2).** As provided for in Ind. Code 8-1-39-13(b), DEI requests authority to increase the authorized net operating income initially approved in Cause No. 42359 and modified by subsequent Commission orders, to include the earnings associated with the TDSIC projects for purposes of the Ind. Code § 8-1-2-42(d)(3) earnings test. Based on our review of the TDSIC statute and the evidence in this Cause, we find that DEI's request is reasonable and should be approved.

3. **TDSIC Mechanism.** Pursuant to Ind. Code § 8-1-39-9, DEI proposes to recover approved capital expenditures and TDSIC costs through Rider 65, as submitted in the settlement testimony of Mr. Davey. Rider 65 would recover 80% of the retail jurisdictional portion of the costs associated with the Seven-Year Plan projects and would include financing costs, depreciation, project O&M, and taxes.

DEI also requests authority from the Commission to accrue post-in-service carrying costs until the TDSIC ratemaking treatment eligible Seven-Year Plan projects are included in retail rates. These carrying costs will accrue at rates equal to DEI's overall weighted cost of capital most

recently approved by the Commission.<sup>1</sup> AFUDC will be applied to project costs until such project costs are included for recovery under Rider 65, in base rates or when the projects are placed in service. DEI proposes that the retail jurisdictional portion of operation and maintenance, depreciation, tax expense, and post-in-service carrying costs be deferred with respect to Seven-Year Plan costs from the in-service date until the cost is included in DEI's rates under Rider 65 or in base rates.

No party took issue with DEI's proposed Rider 65 tracking mechanism. Based on our review of the evidence in this Cause, we approve DEI's proposed TDSIC mechanism.

**I. Recovery of Consultant and Expert Witness Fees.** DEI has requested recovery of the expenses incurred for retaining Black & Veatch as a consultant and expert witness for this proceeding. Black & Veatch performed a risk analysis of the DEI system, validated the cost estimates provided in this proceeding, and provided an economic development analysis. As a part of this proceeding, Mr. Pfennig of Black & Veatch provided testimony that summarizes these analyses.

Based on the evidence provided by DEI, we find that this is a reasonable request and should be approved. To qualify for TDSIC rate treatment, DEI was required to provide evidence that public convenience and necessity require the projects, that the benefits of the projects outweigh their costs, and that the cost estimates constituted best estimates. DEI hired Black & Veatch to assist with their analysis of those items and to assist in development of the Seven-Year Plan. We have approved similar project development costs in the environmental compliance regulatory proceedings, and find that such treatment is appropriate in this case. DEI is authorized to recover the Black & Veatch fees related to performing its risk analysis, cost estimate review, and economic development analysis and providing support for DEI's filing. DEI shall amortize these fees over a three-year period.

**J. Deferral of Remaining 20% of Approved Capital Expenditures and TDSIC Costs.** Ind. Code § 8-1-39-9(b) provides that 20% of approved capital expenditures and TDSIC Costs should be deferred for recovery in the utility's next general base rate case. We have approved DEI's Seven-Year Plan and the TDSIC tracker mechanism. We find that the evidence demonstrates that DEI should be authorized to defer as a regulatory asset and recover in DEI's next general base rate case the approved capital expenditures and other TDSIC costs that are not recovered in the tracker proceedings and AFUDC, post-in-service carrying costs, O&M expense, taxes, and depreciation expense until such costs are fully reflected in DEI's retail base rates after a general retail electric base rate case. The carrying costs shall be accrued using DEI's overall weighted cost of capital as most recently approved by the Commission.

**K. Average Aggregate Increase in Total Retail Revenues.** Ind. Code § 8-1-39-14(a) states that the Commission may not approve a TDSIC rate mechanism if it would result in "an average aggregate increase in a public utility's total retail rates of more than two percent (2%) in a twelve (12) month period." Based on the unambiguous language of Section 14, we find that DEI's proposed calculation that compares the increase in TDSIC revenue in a given year with

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<sup>1</sup> The ROE to be used for the T&D Plan Rider is 10.0% as explained by Mr. Davey in his settlement testimony.

the total retail revenues for the past 12 months is consistent with the TDSIC statute. Therefore, we find that DEI's proposed calculation is consistent with Section 14 and should be approved.

**L. TDSIC Timing.** Ind. Code § 8-1-39-9(c) states that “[e]xcept as provided in section 15 of this chapter, a public utility may not file a petition under subsection (a) within nine (9) months after the date on which the commission issues an order changing the public utility’s basic rates and charges with respect to the same type of utility service.” The evidence in this proceeding shows that DEI has not received an order in a base rate case since 2004. DEI filed its petition in this Cause on December 7, 2015. We find that this Cause was filed more than 9 months after DEI’s last general rate case in accordance with Ind. Code § 8-1-39-9(c).

The CAC provided testimony regarding the rate impact and timing of DEI’s Seven-Year Plan. The CAC argues that the Commission should deny the Seven-Year Plan proposed by DEI because the base rates were last approved in 2004. Further, the CAC takes issue with the use of trackers by DEI. The CAC also made an argument that the TDSIC statute requires a rate case every seven years and, therefore, if DEI has not had a rate case within seven years, then it cannot utilize the TDSIC Statute.

The TDSIC Statute, although the subject of much litigation over the past few years, specifically requires that a utility wait at least 9 months after a rate case until it files for a TDSIC. Further, a utility must initiate a rate case within seven years after a TDSIC plan begins. DEI has met the nine-month waiting period, and DEI plans to file for a rate case before the expiration of its Seven-Year Plan. We reject the CAC’s argument on these ratemaking issues.

Ind. Code § 8-1-39-9(d) states that “[a] public utility that implements a TDSIC under this chapter shall, before the expiration of the public utility’s approved seven (7) year plan, petition the commission for review and approval of the public utility’s basic rates and charges with respect to the same type of utility service.” Therefore, we order DEI to petition the Commission for review and approval of DEI’s basic retail electric rates and charges by December 31, 2022, which is the last day of DEI’s Seven-Year Plan.

Mr. Davey testified that DEI planned to make filings at least annually. We find that DEI’s proposed timeline for TDSIC filings is consistent with Ind. Code § 8-1-39-9 and is reasonable and should be approved. Therefore, DEI’s initial filing following the issuance of this Order shall be filed under Cause No. 44720 TDSIC 1.

**M. AMI.** The Settling Parties request that the Commission make limited findings regarding the AMI project proposed by DEI. The capital costs associated with the AMI project were removed from the Seven-Year Plan. In an effort to compromise, the Settling Parties have agreed to allow DEI to defer up to \$60 million in depreciation costs for recovery in a subsequent DEI retail base rate proceeding. Additionally, the Settling Parties have agreed to allow DEI to defer post-in-service carrying costs associated with the AMI project up to \$15. The post-in-service carrying costs will be accrued at DEI’s long-term debt cost of 4.72%. DEI requests to depreciate the meters over 15 years.

Although the capital costs of the AMI project are no longer part of this proceeding, the Settling Parties have requested that we make some limited findings related to the ratemaking treatment of the new meters. We find that the AMI deferrals and proposed depreciation rate are reasonable. The evidence supports the deferral of limited amounts of depreciation and carrying costs as fully set forth in the Settlement Agreement. If DEI pursues its AMI project, the inclusion of AMI in rate base will be subject to a normal prudence review in the next rate case. Further, we find that the evidence supports the request to depreciate the new AMI meters over 15 years.

**N. Approval of Settlement Agreement.** The Settling Parties presented a Settlement Agreement to the Commission for its approval. Having reviewed all of the evidence in this proceeding, we find that the Settlement Agreement represents a reasonable resolution to this proceeding, and we approve the Settlement Agreement. The Settling Parties agree that the Settlement Agreement should not be used as precedent in any other proceeding or for any other purpose, except to the extent necessary to implement or enforce its terms. Consequently, with regard to future citation of the Settlement Agreement, we find our approval herein should be construed in a manner consistent with our finding in *Richmond Power & Light*, Cause No. 40434, 1997 Ind. PUC LEXIS 459 at \*19-22 (IURC March 19, 1997).

**O. Confidentiality.** DEI filed a motion for protection of confidential and proprietary information on December 7, 2015. In the motion and supporting affidavits, DEI demonstrated a need for confidential treatment for: (i) information related to DEI's prospective transmission and distribution projects specific to the identity of transmission and distribution system assets; (ii) detailed cost information for the T&D projects; (iii) internal modeling information that contains generation pricing, fuel forecasts, projected future capital costs for generation projects, and electric market pricing information; and (iv) information independently compiled and developed by third parties used in measuring the financial risk of companies. On January 4, 2016, the Presiding Officers made preliminary determinations that such information should be subject to confidential procedures. We find that all such information is confidential pursuant to Ind. Code § 5-14-3-4 and Ind. Code § 24-2-3-2, is exempt from public access and disclosure by Indiana law, and shall be held confidential and protected from public access and disclosure by the Commission.

**IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:**

1. The Settlement Agreement is approved.
2. The projects contained in DEI's revised Seven-Year Plan are "eligible transmission, distribution, and storage system improvements" within the meaning of Indiana Code § 8-1-39-2.
3. DEI is authorized to implement its TDSIC Rate Schedule as described in Petitioner's Exhibit 12-A pursuant to Ind. Code § 8-1-39-9(a) to effectuate the timely recovery of 80% of eligible and approved capital expenditures and TDSIC costs.

4. DEI is authorized to defer 100% of the depreciation associated with the AMI up to \$60 million for recovery in DEI's subsequent retail base rate proceeding. In addition, DEI is authorized to recover the deferred depreciation associated with AMI over a 10-year period, without carrying costs, in its subsequent retail rate case.

5. DEI is authorized to defer post-in-service carrying costs associated with the AMI project up to \$15 million for recovery in DEI's subsequent retail base rate proceeding. In addition, DEI is authorized to recover the post-in-service carrying costs associated with the AMI project over a 10-year period, without carrying costs, in DEI's subsequent retail base rate case. DEI is authorized to depreciate the new meters over a 15-year time period.

6. DEI is authorized to recover 80% of DEI's \$1.408 billion Seven-Year Plan costs through DEI's proposed TDSIC mechanism, Standard Contract Rider No. 65.

7. DEI is authorized to defer 20% of eligible and approved capital expenditures and TDSIC costs with carrying costs under Ind. Code § 8-1-39-9(b) and DEI is hereby authorized to recover the deferred capital expenditures and TDSIC costs as part of DEI's next general rate case.

8. DEI's proposed allocation factors based on the revenue requirement by rate group from the last retail base rate case in Cause No. 42359 are approved.

9. The information filed by DEI in this Cause pursuant to its Motion for Protective Order is deemed confidential pursuant to Indiana Code § 5-14-3-4 and Indiana Code § 24-2-3-2, is exempt from public access and disclosure by Indiana law, and shall be held confidential and protected from public access and disclosure by the Commission.

10. This Order shall be effective on and after the date of its approval.

**STEPHAN, HUSTON, WEBER, AND ZIEGNER CONCUR:**

**APPROVED:** JUN 29 2016

**I hereby certify that the above is a true  
and correct copy of the Order as approved.**

  
Mary M. Becerra  
Secretary of the Commission

**Duke Energy Indiana, IURC Cause No. 44720**

**7-Year Plan and Transmission, Distribution and Storage Improvement Charge ("TDSIC")  
Settlement Agreement**

**1. Introduction**

This Settlement Agreement ("Settlement" or "TDSIC Settlement") is entered into by and between Duke Energy Indiana, LLC (and its successors), the Indiana Office of Utility Consumer Counselor, the Duke Energy Indiana Industrial Group, Companhia Siderurgica Nacional, LLC a/k/a CSN, LLC, Steel Dynamics, Inc., Wabash Valley Power Association, Inc., Indiana Municipal Power Agency, Hoosier Energy Rural Electric Cooperative, Inc., and the Environmental Defense Fund (collectively, the "Settling Parties") solely for purposes of compromise and settlement. The Settling Parties agree that this Settlement resolves all disputes, claims and issues from the Indiana Utility Regulatory Commission ("Commission") proceeding regarding Duke Energy Indiana's TDSIC filing in Commission Cause No. 44720, as between the Settling Parties.

**2. Duke Energy Indiana T&D Plan**

The Settling Parties agree that the Commission should approve, as "eligible improvements" within the meaning of the TDSIC statute (Ind. Code ch. 8-1-39), the projects and programs summarized in Petitioner's Exhibit 2-A, and detailed in the exhibits and workpapers of Mr. Howard Fowler and Mr. Donald Broadhurst (the "T&D Plan"), with the exception of the advanced metering infrastructure ("AMI") project. This T&D Plan consists of capital expenditures of up to \$1.613 billion and related project O&M expenditures of up to \$61.9 million over the 7-year period from 2016 through 2022; however, the Settling Parties agree that a maximum of \$1.408 billion of capital, plus related project O&M and TDSIC Costs (as defined in Ind. Code 8-1-39-7) shall be eligible for the TDSIC ratemaking treatment, as discussed further below.

The Settling Parties agree that Duke Energy Indiana has provided detailed project and program descriptions for the T&D Plan, as well as sufficient cost estimates for the projects and programs, as would support a Commission finding that the T&D Plan is reasonable and in the public interest, that the costs of the T&D Plan are justified by the benefits of the plan, and that the estimates summarized on Petitioner's Exhibit 2-A reflect the best estimates of the T&D Plan costs.

**3. Capital Cost Reductions and Cost Cap**

a. Notwithstanding the T&D Plan described above, in order to compromise and settle this case, Duke Energy Indiana has agreed to limit recovery through the TDSIC ratemaking treatment of its capital costs actually expended upon its T&D Plan to \$1.408 billion over the

seven-year TDSIC period – a reduction in capital costs of \$397 million from its as-filed T&D Plan. Pursuant to the TDSIC statute, eighty percent (80%) of TDSIC costs shall be recovered through the TDSIC Rider and twenty percent (20%) shall be authorized to be deferred for subsequent recovery with carrying costs (calculated at Duke Energy Indiana’s weighted average cost of capital) in a subsequent rate case. As part of this limit on capital cost recovery, the Settling Parties understand that the total related project O&M amount could also be reduced depending on which projects are ultimately excluded from the TDSIC Rider.

b. The Settling Parties agree that Duke Energy Indiana will remove capital projects from the TDSIC ratemaking treatment as follows: approximately \$192 million in Advanced Metering Infrastructure (“AMI”) project,<sup>1</sup> approximately \$175 million in transmission capital improvements and approximately \$30 million in distribution capital improvements. The Settling Parties request that the IURC approve all (non-AMI) projects and programs included in the T&D Plan and that Duke Energy Indiana be authorized to use any project or program included in its \$1.613 billion T&D Plan to make up the up to \$1.408 billion in total plan capital expenditures over the 7-year period. The Settling Parties further agree that Duke Energy Indiana should have the flexibility to move projects from one year to another within the 7-year plan.

c. The Settling Parties agree that the total 7 year capital to be included in the plan and eligible for TDSIC ratemaking treatment will not exceed \$1.408 billion. This exclusion of projects and programs from the TDSIC Rider recovery and 20% deferred recovery purposes will consist of:

- transmission improvement capital by \$43.8 million per year in 2018 through 2021 of the T&D Plan;
- distribution improvement capital by \$6 million per year in 2018 – 2022.

The table below reflects the agreed upon cumulative capital cost caps as adjusted per year:

**Duke Energy Indiana T&D Plan Capital Cost (as adjusted)<sup>2</sup>**

	2016	2017	2018	2019	2020	2021	2022	Total
Capital cost as filed	\$ 113.9	\$ 269.9	\$ 318.2	\$ 295.6	\$ 270.1	\$ 277.8	\$ 259.6	\$ 1,805.1
Remove AMI capital cost	\$ (22.0)	\$ (56.2)	\$ (57.0)	\$ (48.4)	\$ (6.7)	\$ (0.7)	\$ (0.7)	\$ (191.8)
Remove a portion of transmission capital cost			\$ (43.8)	\$ (43.8)	\$ (43.8)	\$ (43.8)	\$ -	\$ (175.0)
Remove a portion of distribution capital cost	\$ -	\$ -	\$ (6.0)	\$ (6.0)	\$ (6.0)	\$ (6.0)	\$ (6.0)	\$ (30.0)
Capital cost as adjusted	\$ 91.8	\$ 213.7	\$ 211.4	\$ 197.5	\$ 213.7	\$ 227.3	\$ 252.9	\$ 1,408.3
Cumulative capital cost as adjusted	\$ 91.8	\$ 305.5	\$ 517.0	\$ 714.4	\$ 928.1	\$ 1,155.4	\$ 1,408.3	

As an example of the TDSIC cost caps effect, if Duke Energy Indiana spent \$81.8 million in 2016, then in 2017 Duke Energy Indiana could spend \$213.7 million plus \$10 million carried

<sup>1</sup> See Section 5; AMI is removed from TDSIC ratemaking treatment and from the 7-year T&D Plan.

<sup>2</sup> The capital spend that makes up the \$1.408 billion will be identified in settlement supporting testimony.

forward from 2016. As another example, if Duke Energy Indiana spent \$111.8 million in 2016, then Duke Energy Indiana would only put through the TDSIC Rider 80% of the capital associated with \$91.8 million for 2016, and retain the ability to move \$20 million into a future year of the plan as long as the cumulative capital cost as adjusted is not exceeded in any year (for instance, if 2017 expenditures were \$193.7 million, the cumulative capital cost as adjusted plus the \$20 million from 2016 would be the capped amount of \$305.5 million for 2017).

d. The Settling Parties agree that the T&D Plan starts in calendar year 2016 and Year one of the plan includes projects that go in-service in 2016.

#### **4. Plan Flexibility**

a. Nothing in this Settlement or in the T&D Plan obligates Duke Energy Indiana to implement the entirety of the T&D Plan (approximately \$1.613 in capital costs over 7 years) or to implement the full \$1.408 billion capital cost cap amount over 7 years. Rather, Duke Energy Indiana shall be authorized to implement components of the T&D Plan in good faith up to the \$1.408 billion cap over a seven year period, as outlined herein, but shall have flexibility to adjust the plan as circumstances dictate, consistent with paragraph 3(b) above, such as system changes, reliability issues, or reasonable and prudent cost changes. Duke Energy Indiana shall update its T&D Plan at least annually, and shall present such T&D Plan updates to the Commission and Settling Parties, consistent with the TDSIC statute.

b. As to the addition of new projects in the 7-year T&D Plan (or the projects identified as alternates in Duke Energy Indiana's case-in-chief), the Settling Parties each reserve the right to take any position on such issue in future proceedings. However, the recovery of a maximum of 80% of the incurred costs associated with the \$1.408 billion in capital and associated project O&M via the TDSIC Rider, and 20% deferral of such costs shall not be adjusted.

#### **5. AMI**

a. Duke Energy Indiana agrees to remove the AMI project capital and O&M from the TDSIC ratemaking treatment and 7-year T&D Plan.

b. The Settling Parties agree that if Duke Energy proceeds with AMI, the estimated net savings associated with the AMI project (*i.e.*, \$39.69 M over 7 years) will be retained by Duke Energy Indiana until a subsequent retail base rate case.

c. The Settling Parties agree to support an amended petition in this proceeding, citing the IURC's general accounting authority, seeking approval of the Settling Parties' agreement that Duke Energy Indiana should be authorized to:

i. Defer 100% without carrying costs of the depreciation associated with the AMI project up to \$60 million for recovery in a subsequent Duke Energy Indiana retail base rate proceeding. Duke Energy Indiana will recover the deferred depreciation over a 10 year period without carrying costs in its subsequent retail rate case.

ii. Defer post-in-service carrying costs associated with the AMI project up to \$15 million for recovery in a subsequent Duke Energy Indiana retail base rate proceeding. Duke Energy Indiana will recover the deferred post-in-service carrying costs over a 10 year period without carrying costs in its subsequent retail rate case. To calculate the carrying costs on the AMI project, Duke Energy Indiana will use the debt only post-in-service carrying costs rate of 4.72% until the \$15 million is reached after which no additional post-in-service carrying costs will be deferred.

d. The Settling Parties agree not to oppose inclusion of an AMI project into rate base and Duke Energy Indiana base rates at the time of the subsequent Duke Energy Indiana retail base rate case subject to normal prudence review, including a review of the costs associated with the project.

e. The Settling Parties agree to the request for IURC approval of a new depreciation rate for the new AMI meters based on a 15 year life, as proposed by Duke Energy Indiana.

f. Duke Energy Indiana agrees to drop its request for approval of the new proposed rate options. Duke Energy Indiana agrees to meet in good faith with interested settling parties prior to re-filing for approval of such proposed rate options.

g. Duke Energy Indiana will develop, evaluate, and project the cost effectiveness for an energy efficiency /demand response pilot program that leverages smart thermostats and customer engagement platforms for energy and demand savings. The proposal will allow customers to use existing thermostats if the thermostats are compatible with the program and using existing thermostats will improve the cost-effectiveness of the pilot program. Duke Energy Indiana will consult with its Energy Efficiency Oversight Board (OSB) and Environmental Defense Fund in designing the program and will use good faith efforts to include more than one choice of compatible thermostats. Duke Energy Indiana will present such proposal to its OSB on or before such time as the AMI meters are certified for approximately 25% of the Duke Energy Indiana system. Environmental Defense Fund may join the OSB as a non-voting member.

h. The company intends to install the AMI meters with the radio activated. However, given cyber security rules/guidelines/regulations Duke Energy Indiana must test the feasibility and security of enabling the pairing of home energy system devices and/or applications to the AMI radios. Duke Energy Indiana commits to good faith discussions with EDF to evaluate the feasibility of technology tests and an initial pilot that will allow for near real time energy data access to customers (such as a smart meter app), after the AMI meters are certified for approximately 25% of the Duke Energy Indiana system. No particular technology or method of allowing for the near real time energy data access to customers has been decided as that will part of the evaluation.

## **6. Existing Meters**

Duke Energy Indiana agrees to drop its request for a regulatory asset associated with the current meters and if Duke Energy Indiana proceeds with AMI, not to request recovery of or on the undepreciated value of such meters at the time of a subsequent retail base rate case or at any other time or in any manner.

## **7. Other Ratemaking Terms**

### **a. Integrated Volt Var Control (“IVVC”).**

i. Duke Energy Indiana has included its IVVC investment in the TDSIC plan and does not intend to include such investments in its energy efficiency rider.

ii. Duke Energy Indiana intends to move forward with its IVVC plan as proposed in its case-in-chief. Duke Energy Indiana estimates it will spend approximately \$198 million in capital and project O&M on its IVVC project in the seven-year TDSIC period.

iii. Duke Energy Indiana will provide a report on its IVVC plan in its TDSIC Rider proceedings substantially similar to the Duke Energy Ohio Distribution System Efficiency Metrics-IVVC and including the estimated greenhouse gas emission reductions.

iv. Duke Energy Indiana agrees to consider a further expansion of the IVVC plan to additional circuits after the 7 year TDSIC plan and to provide the costs/benefits of such expansion in a subsequent TDSIC proceeding and/or subsequent retail base rate case. Settling Parties understand there are constraints to providing IVVC on some circuits due to distribution substation and/or circuit ownership.

b. **ROE.** The ROE for the TDSIC Rider will be 10%.

c. **Netting of Depreciation.** There is no netting in the TDSIC Rider of depreciation or return, meaning, the depreciation expense and/or return associated with retired and replaced equipment will not be netted against the depreciation expense and/or return associated with new equipment in the TDSIC Rider, and base retail rates will not be adjusted for these items.

d. **Allocation Factors.** There are no changes to Duke Energy Indiana's proposed allocation factors for the TDSIC rider among rate classes. Duke Energy Indiana agrees to modify its proposed allocation factors and allocate the T&D Plan revenue recovery for rate HLF and LLF customers using the respective delivery voltage revenue levels approved in Duke Energy Indiana's last base rate case (IURC Cause No. 42359). Other rate groups are unaffected by this change. The Settling Parties agree that using such factors complies with the TDSIC statute. Regarding the Steel Dynamics Inc. special contract, the TDSIC Rider will be applicable to the HLF portion of their demand, but not to the Day-Ahead Pricing portion.

e. **Base Rate Case.** There are no commitments related to retail rate case timing beyond what is required in the TDSIC Statute. At the time of the subsequent base rate case, the Settling Parties agree that the T&D improvements in-service by the rate base cut-off date will, (subject to a normal prudence review in the TDISC Rider proceedings), be included in rate base and the Duke Energy Indiana's new base rates and subject to the ROE and allocation factors that are ultimately determined by the IURC in such retail base rate case. Similarly, the 20% of the T&D improvements that have been deferred with carrying costs will be included in retail rates and rate base and any AMI deferrals will be included in rates. If there remain years in the 7 year T&D Plan (or a new T&D plan) after the subsequent retail base rate case order, all caps will remain in effect for 2016 – 2022 and any TDSIC Rider would be adjusted to use the new ROE and allocation factors approved in the subsequent retail base rate case.

f. **Other.** All other issues are as proposed in Duke Energy Indiana's case in chief testimony and exhibits.

## **8. Regulatory and Procedural Terms**

a. The Settling Parties agree that the evidence to be submitted in support of this Settlement, along with the evidence of record, together constitute substantial evidence to support this Settlement and provide a sufficient evidentiary basis upon which the Commission can make any findings of fact and conclusions of law necessary for the approval of this Settlement. The Settling Parties shall prepare and file with the Commission as soon as reasonably possible, testimony and proposed order(s) in support of and consistent with this Settlement.

b. This Settlement is a complete and interrelated package that is intended to resolve all issues between the Settling Parties as to Duke Energy Indiana's filing in Cause No. 44720, including the amended petition, that were or could have been raised.

c. The Settling Parties will not appeal or seek rehearing, reconsideration or a stay of a Final Order approving this Settlement in its entirety or without change or condition(s) unacceptable to any adversely affected Party (or related orders to the extent such orders are specifically implementing the provisions of this Settlement), except with the agreement of all Settling Parties on the issues to be subject to rehearing, reconsideration or appeal.

d. The Settling Parties agree to support in good faith the terms of this Settlement before the Commission and further agree not to take any positions adverse to or inconsistent with the Settlement or any adverse positions against each other with respect to the Settlement before any appellate courts, or on rehearing, reconsideration, remand or subsequent or additional related proceedings before the Commission.

e. The Settling Parties also agree to support or not oppose this Settlement in the event of any request for a stay by a person not a party to this Settlement or if this Settlement is the subject matter of any other state proceeding.

f. The Settling Parties shall remain bound by the terms of this Settlement Agreement and shall continue to support or not oppose all the terms of the Settlement on appeal, remand, reconsideration, etc., even if the Commission rejects the Settlement. However, in the event that the Settlement is rejected by the Commission and such rejection is ultimately upheld on rehearing, reconsideration, and/or appeal, at the point when all such proceedings and appeals are complete, this Settlement Agreement shall become void and of no further effect (except for provisions which have already been fully implemented or that are explicitly stated herein to survive termination/voiding).

g. If the Commission approves the Settlement in its entirety, or approves the Settlement with modifications that are not unacceptable to affected Settling Parties, and such Commission approval is ultimately vacated or reversed on appeal, the Settling Parties agree to support or not oppose the terms of this Settlement in any additional proceedings before the Commission (as well as any subsequent appeals). In such situation, the Settling Parties agree not to take any positions adverse to or inconsistent with the Settlement or any adverse positions against each other with respect to the Settlement or the subject matters herein, on remand or in additional related proceedings before the Commission.

h. The positions taken by the Settling Parties in this Settlement shall not be deemed to be admissions by any of the Settling Parties and shall not be used as precedent, except as necessary to implement the terms of this Settlement. This provision shall survive termination/voiding of this Agreement.

i. It is understood that this Settlement is reflective of a good faith negotiated settlement and neither the making of the Settlement nor any of its provisions shall constitute an admission by any Settling Party in this or any other litigation or proceeding except as necessary to implement or enforce this Settlement Agreement. It is also understood that each and every term of the Settlement Agreement is in consideration and support of each and every other term.

j. The Settling Parties will support this Settlement before the Commission and request that the Commission expeditiously accept and approve the Settlement. This Settlement is a complete, interrelated package and is not severable, and shall be accepted or rejected in its entirety without modification or further condition(s) that may be unacceptable to any Settling Party.

k. The Settling Parties will file this Settlement and testimony in support of this Settlement. Such supportive testimony will be agreed-upon by the Settling Parties and offered into evidence without objection by any Settling Party and the Settling Parties hereby waive cross-examination of each other's witnesses. The Settling Parties propose to submit this Settlement and evidence conditionally, and if the Commission fails to approve this Settlement in its entirety without any change or with condition(s) unacceptable to any adversely affected Settling Party, the Settlement and supporting evidence may be withdrawn and the Commission will continue to proceed to decision in the affected proceedings, without regard to the filing of this Settlement.

l. The communications and discussions during the negotiations and conferences and any materials produced and exchanged concerning this Settlement all relate to offers of settlement and shall be privileged and confidential, without prejudice to the position of any Settling Party, and are not to be used in any manner in connection with any other proceeding or otherwise. This provision shall survive termination/voiding of this Agreement.

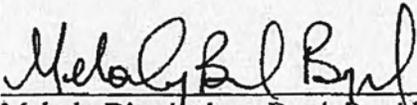
m. The undersigned Settling Parties have represented and agreed that they are fully authorized to execute the Settlement on behalf of their designated clients, and their successors and assigns, who will be bound thereby.

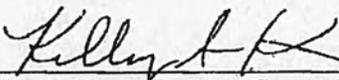
n. This Settlement may be executed in two (2) or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

ACCEPTED AND AGREED TO THIS 7<sup>th</sup> day of MARCH 2016:

[Signature pages to follow]

**For Duke Energy Indiana, LLC**

  
\_\_\_\_\_  
Melody Birmingham-Byrd, President  
Duke Energy Indiana, LLC

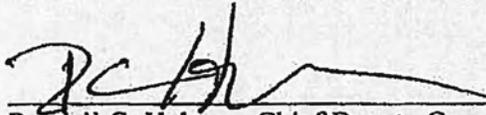
  
\_\_\_\_\_  
Kelley A. Karn, Deputy General Counsel  
Duke Energy Indiana, LLC

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**For the Indiana Office of Utility Consumer Counselor:**



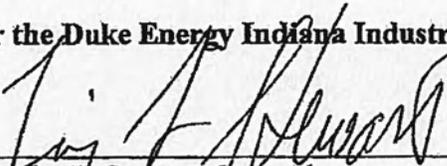
A. David Stippler, Consumer Counselor  
Indiana Office of Utility Consumer Counselor



Randall C. Helmen, Chief Deputy Consumer Counselor  
Indiana Office of Utility Consumer Counselor

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**For the Duke Energy Indiana Industrial Group:**



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Timothy L. Stewart, Counsel  
Duke Energy Indiana Industrial Group

[This is a signature page for the 2016 Duke Energy Indiana TDSIC Settlement before the Indiana Utility Regulatory Commission (Cause No. 44720). Remainder of page intentionally left blank.]

**For Companhia Siderurgica Nacional, LLC a/k/a CSN, LLC:**

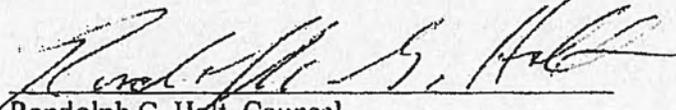


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Nikki G. Shoultz, Counsel  
Companhia Siderurgica Nacional, LLC a/k/a CSN, LLC

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**For Wabash Valley Power Association, Inc.:**

A handwritten signature in black ink, appearing to read "Randolph G. Holt", is written over a horizontal line.

Randolph G. Holt, Counsel  
Wabash Valley Power Association, Inc.

[This is a signature page for the 2016 Duke Energy Indiana TDSIC Settlement before the Indiana Utility Regulatory Commission (Cause No. 44720). Remainder of page intentionally left blank.]

**For Indiana Municipal Power Agency:**

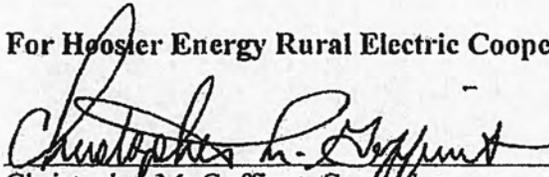


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Peter J. Prettyman, General Counsel  
Indiana Municipal Power Agency

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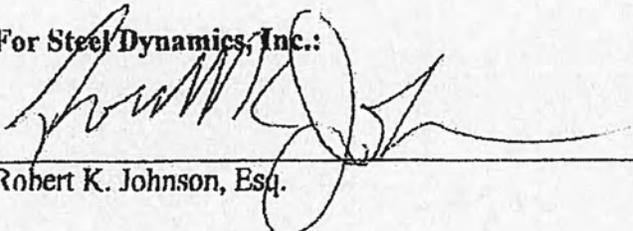
For Hoosier Energy Rural Electric Cooperative, Inc.:

A handwritten signature in cursive script, appearing to read "Christopher M. Goffinet", written over a horizontal line.

Christopher M. Goffinet, Counsel  
Hoosier Energy Rural Electric Cooperative, Inc.

[This is a signature page for the 2016 Duke Energy Indiana TDSIC Settlement before the Indiana Utility Regulatory Commission (Cause No. 44720). Remainder of page intentionally left blank.]

For Steel Dynamics, Inc.:

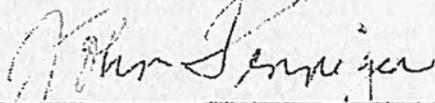


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Robert K. Johnson, Esq.

[This is a signature page for the 2016 Duke Energy Indiana TDSIC Settlement before the Indiana Utility Regulatory Commission (Cause No. 44720). Remainder of page intentionally left blank.]

**For Environmental Defense Fund**



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John Finnigan, Lead Attorney

[This is a signature page for the 2016 Duke Energy Indiana TDSIC Settlement before the Indiana Utility Regulatory Commission (Cause No. 44720). Remainder of page intentionally left blank.]



## Indiana state utility regulators approve Duke Energy's plan to modernize its statewide energy grid

🕒 June 29, 2016

### Share This Story

15

- **Indiana Utility Consumer Counselor, industrial consumers, and other groups support seven-year energy grid improvement plan**
- **Advanced technology, infrastructure upgrades to improve customer service**

PLAINFIELD, Ind. -- The Indiana Utility Regulatory Commission Wednesday approved Duke Energy's settlement with some of Indiana's key consumer groups on the company's plan to build a smarter energy infrastructure that delivers power to more than 800,000 Hoosier homes, businesses and industries.

In March, the company reached agreement with the Indiana Office of Utility Consumer Counselor, the Duke Energy Indiana Industrial Group, Companhia Siderurgica Nacional, Steel Dynamics, Wabash Valley Power Association, Indiana Municipal Power Agency, Hoosier Energy Rural Electric Cooperative and the Environmental Defense Fund on a seven-year plan using a combination of advanced technology and infrastructure upgrades to improve service to customers.

"We have an aging energy grid -- some equipment that is decades old -- and our work will focus on replacing some older infrastructure to reduce power outages," said Duke Energy Indiana President Melody Birmingham-Byrd. "We'll also be building a smarter energy structure with technology to provide the type of information and services that consumers have come to expect."

In May 2015, the Indiana Utility Regulatory Commission denied Duke Energy Indiana's original plan, asking for more details and more focus on electric grid projects. In December, the company filed a revised plan addressing the commission's issues. The company then reached a settlement with key consumer groups. The commission has approved the settlement without changes.

As part of the settlement, Duke Energy reduced the level of capital investments recovered through the plan's customer bill tracker from approximately \$1.8 billion to approximately \$1.4 billion. Part of the reduction came from \$192 million earmarked for new advanced digital meters -- known as smart meters -- but the company retains the ability to pursue the meters and defer some of their costs for consideration in a future rate case rather than through a monthly bill tracker as other items in the plan.

The company also agreed to reduce its return on equity on plan investments from 10.5 to 10 percent for investments that flow through the plan's bill tracker. This does not affect the company's 10.5 percent allowed return on equity on its other remaining investments.

As a result of the plan, customers will see a gradual rate increase averaging 0.75 percent per year between 2017 and 2022.

Some of the plan's consumer benefits include:

- Improved energy reliability and safety from updating and replacing aging energy grid infrastructure, including substations, utility poles, power lines and transformers.
- Fewer and shorter power outages where "self-healing" systems are installed. Today, when a tree or other object comes in contact with a power line causing an outage, every customer served by that line — and other lines connected to it — loses power. With self-

healing technology, the company can automatically detect the problem, isolate it and reroute energy — so fewer customers are affected while repairs are made.

- Improved information for consumers. Equipment such as line sensors will enable the company to provide customers more information about power outages affecting them and estimated restoration times. In some cases, the equipment can reduce the need to dispatch field personnel to find an outage's location, which speeds power restoration.
- Energy savings from technology that optimizes voltage and reduces overall power consumption by about 1 percent on upgraded power lines.
- If the company pursues smart meters, as part of the settlement, it committed to exploring energy efficiency pilot programs that are now possible with smart meter technology.

Smart meters have additional benefits, including fewer estimated customer bills because meters can be read automatically. There also is quicker service because some customer requests can be performed remotely through the new meters without having to wait for a technician to arrive. Smart meters also provide customers with greater, quicker access to information on their energy use, which can help consumers make wise energy decisions. Approximately 40 percent of the nation already has made the transition to smart meter technology.

The company filed the plan under the provisions of Indiana Senate Enrolled Act 560, state legislation which was passed in 2013 and is aimed at improving utility infrastructure.

Under the law, a utility can file a seven-year infrastructure improvement plan with state utility regulators.

If approved, a utility can request recovery of 80 percent of its investment through a customer bill tracker. Recovery of the remaining 20 percent would be deferred for review until the energy company's next base rate case. Under the new law, utilities must file a base rate case before the end of their seven-year plans.

### **About Duke Energy**

Duke Energy is one of the largest electric power holding companies in the United States. Its regulated utility operations serve approximately 7.4 million electric customers located in six states in the Southeast and Midwest, representing a population of approximately 24 million people. Its Commercial Portfolio and International business segments own and operate diverse power generation assets in North America and Latin America, including a growing portfolio of renewable energy assets in the United States.

Headquartered in Charlotte, N.C., Duke Energy is an S&P 100 Stock Index company traded on the New York Stock Exchange under the symbol DUK. More information about the company is available at [duke-energy.com](http://duke-energy.com).

The [Duke Energy News Center](#) serves as a multimedia resource for journalists and features news releases, helpful links, photos and videos. Hosted by Duke Energy, [illumination](#) is an online destination for stories about remarkable people, innovations, and community and environmental topics. It also offers glimpses into the past and insights into the future of energy.

Follow Duke Energy on [Twitter](#), [LinkedIn](#), [Instagram](#) and [Facebook](#).

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[@DE\\_AngelineP](#)

Analysts: Mike Callahan  
Office: 704.382.0459 [📞](#)

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**COMMONWEALTH OF KENTUCKY  
BEFORE THE  
KENTUCKY PUBLIC SERVICE COMMISSION**

In the Matter of:

The Application of Duke Energy Kentucky, )  
Inc., for (1) a Certificate of Public )  
Convenience and Necessity Authorizing ) Case No. 2016-00152  
the Construction of an Advanced Metering )  
Infrastructure; (2) Request for Accounting )  
Treatment; and (3) All Other Necessary )  
Waivers, Approvals, and Relief. )

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**REBUTTAL TESTIMONY OF  
PEGGY LAUB  
ON BEHALF OF  
DUKE ENERGY KENTUCKY, INC.**

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October 13, 2016

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**I. INTRODUCTION AND PURPOSE**

1 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A. My name is Peggy A. Laub. My business address is 139 East Fourth Street, Cincinnati,  
3 Ohio 45202.

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

5 A. I am employed by Duke Energy Business Services LLC, (DEBS) an affiliate service  
6 company of Duke Energy Kentucky, Inc., (Duke Energy Kentucky or Company) as  
7 Director, Rates and Regulatory Planning. DEBS provides various administrative and  
8 other services to Duke Energy Kentucky, Inc., (Duke Energy Kentucky or the Company)  
9 and other affiliated companies of Duke Energy Corporation (Duke Energy).

10 **Q. ARE YOU THE SAME PEGGY A. LAUB THAT SUBMITTED DIRECT**  
11 **TESTIMONY IN THIS PROCEEDING?**

12 A. Yes.

13 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

14 A. The purpose of my testimony is to respond to several opinions and recommendations  
15 expressed by Paul Alvarez on behalf of the office of the Attorney General of the  
16 Commonwealth of Kentucky (AG). Specifically, I am responding to Mr. Alvarez's  
17 statements and recommendations that relate to the Company's request for a creation of a  
18 regulatory asset for the early retirement of the existing metering infrastructure and several  
19 of his claims regarding utility rate making. The early retirement of the existing metering  
20 infrastructure will necessarily occur if the Commission approves Duke Energy  
21 Kentucky's application for a Certificate of Public Convenience and Necessity (CPCN) to  
22 deploy an Advanced Metering Infrastructure (AMI) for its electric and combination

1 electric and natural gas operations and an Automated Meter Reading (AMR) solution for  
2 the Company's natural gas-only customers (Metering Upgrade). I am also responding to  
3 several of Mr. Alvarez's statements regarding utility rate making and addressing the  
4 recommendations he makes on page 22 of his testimony.

## II. DISCUSSION

5 **Q. PLEASE EXPLAIN MR. ALVAREZ'S PRIMARY RECOMMENDATION IN HIS**  
6 **TESTIMONY?**

7 **A.** Mr. Alvarez's primary recommendation is that the Company's CPCN request to begin its  
8 Metering Upgrade should be denied now, and instead only be considered as part of a base  
9 rate proceeding, rather than as part of a separate CPCN application. The basis of Mr.  
10 Alvarez's premise is that the ultimate rate impact can only be determined in a rate case.  
11 He also claims that customers will pay carrying costs until the Company files and  
12 adjudicates its next rate case. Mr. Alvarez further alleges that risks are being shifted from  
13 shareholders to customers because the Company filed a separate CPCN application and  
14 that "bill creep" will occur if the Company's CPCN is approved outside of a rate case.  
15 Finally, Mr. Alvarez argues that the design of new rates made possible by smart meters  
16 can be determined in advance if a CPCN is considered as part of a rate case.

17 **Q. DO YOU AGREE WITH MR. ALVAREZ'S PRIMARY RECOMMENDATION**  
18 **THAT THE COMPANY'S CPCN APPLICATION SHOULD BE DENIED AND**  
19 **BROUGHT AS PART OF A BASE RATE PROCEEDING?**

20 **A.** No, I do not. Mr. Alvarez's claims are incorrect and his proposal to delay consideration  
21 of the Company's application is impractical, and will result in increased costs to

1 customers. His recommendation stifles utility investment, and is a significant departure  
2 from the Commission's long-standing regulatory process.

3 **Q. PLEASE EXPLAIN.**

4 A. First, as indicated in the Company's CPCN application, Duke Energy Kentucky is not  
5 seeking to increase customer rates as part of this proceeding. So, until there is a base rate  
6 case, there is zero impact to customer rates. Second, while Mr. Alvarez is correct that the  
7 Company will eventually seek recovery, the Commission will have all of its statutorily  
8 vested authority to review the Company's future rate case applications to determine to  
9 what extent the Company's future rate filings result in fair, just, and reasonable rates. The  
10 Commission has no less authority if it approves a CPCN first followed by a prudence of  
11 recovery determined in a later rate case. Similarly, the AG's rights to participate in such  
12 a case are not diminished in the slightest. The Commission has approved capital  
13 construction projects, including advanced meter deployments, through the CPCN process  
14 separate and apart from rate case proceedings for many years. The Company's proposal  
15 to deploy an estimated \$49 million to construct its Metering Upgrade is no different than  
16 any other CPCN proposed by a utility outside of a base rate proceeding.

17 **Q. IS A CPCN AN APPROPRIATE APPROVAL PATH FOR A UTILITY  
18 CONSIDERING A COMPREHENSIVE METERING UPGRADE?**

19 A. Yes. First, it should be noted that the Commission just recently directed Kentucky  
20 utilities to file a CPCN for major metering and other specific advanced grid infrastructure  
21 investments.<sup>1</sup> The Commission's direction, therefore, eliminated any ambiguity regarding  
22 the need for utilities to file a CPCN in order to make the type of investment contemplated

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<sup>1</sup> *In the Matter of the Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428 (Ky.PSC April 13, 2016) at 10.

1 in the Company's Metering Upgrade. The requirements to support a CPCN application  
2 are specific and are set forth by Commission regulation. The requirements for creating a  
3 regulatory asset for deferral authority are also well established by Commission legal  
4 precedent. The respective filing requirements and the standard for approval are fully  
5 explained in the Company's Application. The Company's Application and supporting  
6 testimony explain how the Company has met those requirements and standards.

7 With respect to his opinions regarding information that can be reviewed in a rate  
8 case, Mr. Alvarez acknowledges that "none of [his] arguments are necessarily true of a  
9 CPCN proceeding,"<sup>2</sup> and I wholly agree with that statement. There is nothing in the  
10 statutes, Commission regulations, or Commission precedent suggesting that Duke Energy  
11 Kentucky, or any other utility in the Commonwealth, is limited or otherwise constrained  
12 to submit its CPCN or regulatory asset requests only in a rate case filing. The filing  
13 requirements for a base rate case are not the same as that of a CPCN or request to  
14 establish a regulatory asset. Nor should they be imputed in this proceeding.

15 **Q. DO YOU BELIEVE THAT LIMITING CPCN FILINGS UNTIL A BASE RATE**  
16 **PROCEEDING IS GOOD POLICY?**

17 **A.** No. As a policy, delaying consideration of a utility metering upgrade CPCN, or any  
18 CPCN, until a rate case is a disservice to customers. As a broad policy, limiting a CPCN  
19 consideration to a rate case means that a utility will have to delay important investments  
20 and improvements in its system until it can justify a rate case filing and after it receives  
21 an order in a lengthy base rate case proceeding. Not only is such a policy harmful to  
22 customers in that it would likely result in increased costs, but the proposal from the Mr.  
23 Alvarez has the potential to frustrate the efforts of all utilities in Kentucky in making

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<sup>2</sup> Alvarez Testimony at 4.

1 major additions and improvements to the utility systems. Utilities are distinguished from  
2 many other industries in that significant investments made over a number of years are  
3 quite common. For any multiple-year deployment plan involving large capital  
4 investment, Mr. Alvarez's proposal would mean that successive and back-to-back rate  
5 case proceedings (first for initial approval and then subsequent cases to address ongoing  
6 cost recovery) may be required, potentially, for every major project for which a CPCN is  
7 required. This unnecessarily increases the regulatory burden to the Commission, the  
8 Company, and ultimately costs to all customers. Such a policy would undermine the  
9 utilities' ability to efficiently and effectively maintain and improve the reliability of its  
10 system. Utilities should have the flexibility to make investment decisions and to timely  
11 present such proposals to the Commission for its review when the need is determined, not  
12 just when the utility files a base rate proceeding.

13 **Q. CAN YOU GIVE AN EXAMPLE WHY MR ALVAREZ'S POSITION IS**  
14 **IMPRACTICAL?**

15 **A.** Yes, I can actually give several such examples that demonstrate the impracticality of Mr.  
16 Alvarez's position.

17 Under the scenario where the utility would first have to file a rate case to receive  
18 approval to begin a construction project, multiple rate cases would be required before the  
19 utility could recover capital costs or customers could experience benefits such as  
20 Operations and Maintenance (O&M) savings. Kentucky regulations permit a utility to use  
21 either a twelve-month historic test period or a fully forecasted twelve-month period upon  
22 which to base its rates. Limiting CPCN approval to the confines of a rate case  
23 unnecessarily binds the hands of the Commission and the utility. If the utility uses a

1 historic test period to set its base rates and to receive a CPCN approval there would be  
2 zero costs or benefits included in that base rate case, because no costs would have been  
3 incurred in the test year. Additionally, the utility would have no way of knowing whether  
4 or not the Commission would ultimately approve its CPCN until the conclusion of the  
5 rate case, so it could not include any assumptions as “known and measurable”  
6 adjustments to its test period. Therefore, a subsequent rate case would be necessary  
7 before the utility could begin to recover capital costs or customers could begin to  
8 experience benefits of O&M cost reductions. Moreover, because Duke Energy Kentucky  
9 is a combination natural gas and electric utility and its Metering Upgrade has both gas  
10 and electric benefits, limiting a CPCN to a base rate proceeding would actually require  
11 the Company to file multiple electric and gas base rate cases.

12 If the utility uses a forecasted test period in its CPCN/base rate case approval  
13 strategy, under Kentucky regulations, again, there could only be twelve-months of capital  
14 investment or O&M savings included in the test year. That means for any metering  
15 infrastructure deployment (or any CPCN project) that spans multiple years, and is limited  
16 to base rate recovery, additional rate case proceedings would be necessary before all costs  
17 or benefits are realized. In Duke Energy Kentucky’s case, based upon the cost-benefit  
18 analysis contained in DLS-4 to Mr. Schneider’s direct testimony, the O&M savings that  
19 drive the net benefits of the deployment occur in subsequent years, after the first year of  
20 construction. Yet, under Mr. Alvarez’s hypothetical CPCN filing in a rate case, assuming  
21 a utility uses a twelve month forecasted test period, only the first twelve months of costs  
22 and benefits would be includable in utility rates.

1           Mr. Alvarez's proposal fails to consider that utilities and intervenors are  
2 frequently able to reach settlement of regulatory issues before the Commission through  
3 negotiation in advance of a full evidentiary hearing. Sometimes, as has been the recent  
4 case with settlements, base rate case stay-out terms or rate freezes have been a key  
5 component of such settlements. If a utility has agreed to such a stay-out as part of one  
6 proceeding, and is further limited to seeking CPCN authority in a base rate case, it would  
7 essentially bar a utility from making any other capital investment during that "freeze"  
8 period. For example, the Company only recently (January 1, 2016) exited a commitment  
9 for an electric base rate case stay-out that resulted from a settlement in Case No. 2014-  
10 00201. Similarly, as part of Duke Energy Kentucky's recently approved settlement in  
11 Case No. 2015-00210, the Company agreed to a twelve-month gas base rate case stay-  
12 out. If the Company were limited to seeking its Metering Upgrade CPCN to a base rate  
13 proceeding, the Company could only recently have been able to do so on the electric side  
14 of its business, but would not be able to include the natural gas portion of its gas meter  
15 upgrade, because the Company agreed not to seek a natural gas base rate increase for  
16 twelve-months by regulatory settlement. This bifurcation would mean that the anticipated  
17 efficiencies through reduction in meter reading expense (gas and electric) would be less.  
18 The Company's business case could not include a reduction for a significant portion of its  
19 meter reading expense attributable to both natural gas only and combination  
20 electric/natural gas customers. Limiting CPCN's to base rate proceedings will take a  
21 valuable consumer benefit (*i.e.*, rate freezes) off-the table by making any utility unable to  
22 agree to or even consider such a concession for fear of stymying future necessary  
23 investments.

1 **Q. DO YOU BELIEVE THE PRESENT PROCESS WHERE A UTILITY HAS THE**  
2 **FLEXIBILITY TO FILE A CPCN OUTSIDE OF A BASE RATE PROCEEDING**  
3 **IS THE OPTIMAL STRATEGY FOR CUSTOMERS AND THE COMPANY?**

4 A. Yes. Again, the Commission has every opportunity to evaluate the need for the CPCN  
5 and determine whether or not the Company should proceed. If approved, the Company  
6 can then time its next base rate proceeding such that both estimated benefits and costs are  
7 included and eliminate the need for multiple and successive costly base rate cases. The  
8 Company will have certainty regarding whether or not it has authority to make the  
9 investments and what those financial impacts will ultimately be at the time of the next  
10 rate case.

11 Another benefit from the existing CPCN process is avoiding the burden of filing  
12 multiple rate cases even when there may be no need for such frequent rate adjustments.  
13 Rate cases are typically a complicated exercise requiring a significant investment of time  
14 and resources by a number of parties including the Company, Staff, the AG, and any  
15 intervenors. Requiring the Commission's regulated utilities and all of the potential  
16 stakeholders to undertake the amount of work involved in a general rate case, for no other  
17 reason than to consider approval of a CPCN is overly burdensome. In fact, if CPCNs  
18 were only allowed during rate cases, the utility and all potential stakeholders would have  
19 to review multiple CPCNs for a wide range of projects that had built up since the last rate  
20 case, in addition to the standard rate case review. Conversely, allowing the utilities to  
21 seek and gain approval of CPCN requests outside of a rate case promotes the types of  
22 investments required to continually improve utility systems without delay and without

1 inefficiently requiring all stakeholders to engage in unnecessarily frequent and costly rate  
2 cases.

3 **Q. WHAT ABOUT MR. ALVAREZ'S CONCERN THAT CUSTOMERS WILL BE**  
4 **PAYING CARRYING COSTS ON THE COMPANY'S RETIRED METER ASSET**  
5 **BALANCE?**

6 A. Our customers current rates do include an implied return on assets that were included in  
7 our last base rate case. Notably, Mr. Alvarez neglects to point out that existing rates  
8 include no return on assets added in the ten years or so since the Company's last electric  
9 rate case. Duke Energy Kentucky would welcome a discussion to remedy Mr. Alvarez's  
10 concern by instituting something like a formula rate or performance based ratemaking  
11 that essentially tracks incremental investment (increases or decreases); however, that is  
12 not the current regulatory model in Kentucky. The current model provides that rates are  
13 based on the utility's investment at the time of the rate case and, in between rate cases,  
14 additions and retirements that increase or decrease the Company's investment, are simply  
15 considered regulatory lag (positive or negative).

16 It is worth noting further that Duke Energy Kentucky did not request carrying  
17 costs as part of its deferral request. With the retirement of the existing meters, the  
18 accounting will credit the balance of the meters account and, with Commission approval,  
19 will debit a regulatory asset. The Company has not requested to include carrying costs on  
20 the unrecovered balance of the regulatory asset. At the time of the next rate case, the  
21 Company will include a proposal to amortize the balance of that regulatory asset over  
22 some number of years without carrying costs.

1 **Q. DO YOU AGREE WITH MR. ALVAREZ'S CLAIM THAT CPCN APPROVAL**  
2 **OUTSIDE A BASE RATE CASE RESULTS IN FRAGMENTED RATE MAKING**  
3 **AND "BILL CREEP"?**

4 A. No. Again, Duke Energy Kentucky is not seeking to adjust customer rates now. Rates  
5 will be examined in a future filing where the Commission will have all of its statutory  
6 authority to approve a fair, just, and reasonable rate and the Attorney General will have  
7 all of its customary rights to intervention. The Commission will have the benefit of  
8 seeing the actual costs incurred and necessary for the Company to provide adequate  
9 service at a fair, just and reasonable rate. Nothing changes that fact with the consideration  
10 of the current CPCN at this time.

11 In Mr. Alvarez's example of piecemeal ratemaking, he states that the "Company  
12 will recover from customers depreciation expenses it is no longer incurring" once the  
13 assets are reclassified to a regulatory asset. He fails to recognize that, during that same  
14 period, the Company will not be recovering any of the depreciation expense related to the  
15 new metering equipment.

16 Mr. Alvarez's proposal to limit CPCN filings to base rate proceedings would  
17 actually result in more bill creep because utilities would have to file more and multiple  
18 rate cases in order to invest in its systems.

19 **Q. WHAT ABOUT MR. ALVAREZ'S CLAIM THAT THE DESIGN OF NEW**  
20 **RATES MADE POSSIBLE BY SMART METERS CAN BE DETERMINED IN**  
21 **ADVANCE IF A CPCN IS CONSIDERED AS PART OF A RATE CASE, DO YOU**  
22 **AGREE WITH THAT?**

1 A. No, I don't. It is not practical to determine the impact of rates enabled by advanced  
2 meters before the meters are even deployed, supporting infrastructure is in place, and full  
3 functionality is achieved. The rates Mr. Alvarez speaks to and that are possible through  
4 advanced metering, such as time of use rates, should be implemented after an advanced  
5 metering deployment is completed and the supporting infrastructure (hardware and  
6 software) is in place. Otherwise, the result is confusion, and customer dissatisfaction  
7 because the new rate would only available to the customer once the deployment in their  
8 area is completed. Under the current deployment timeframe, that could be years  
9 depending upon the area of the Company's service territory.

10 Suppose, for example, that Duke Energy Kentucky had a rate case pending at this  
11 very moment with its CPCN application. The deployment of meters would not commence  
12 until after the rate case is fully adjudicated, and approved. Following that approval,  
13 infrastructure and system-wide meter deployment will take two years to complete. So the  
14 new rates that Mr. Alvarez believes must be considered now, could not even go into  
15 effect until at least two years from now when the infrastructure enabling such rates is in  
16 place. Logically, CPCN approval now, and outside of a base rate case, will allow the  
17 Company to put the Metering Upgrade system in place, begin to reduce its operation and  
18 maintenance costs, and time a subsequent rate case to coincide with deployment  
19 completion so that new rate structures can go into effect immediately upon approval.

20 **Q. DO YOU AGREE WITH MR. ALVAREZ'S RECOMMENDATION THAT IF**  
21 **THE COMMISSION PROCEEDS WITH CONSIDERING THE COMPANY'S**  
22 **CPCN APPLICATION IN THIS PROCEEDING, INSTEAD OF IN A BASE RATE**

1           **CASE, THAT THE COMMISSION SHOULD ESTABLISH THE TREATMENT**  
2           **OF THE EARLY RETIRED METERING INFRASTRUCTURE NOW?**

3    A.    The Company does not object if the Commission wants to establish parameters related to  
4           the method of recovery for these costs including establishing the amortization period of  
5           the regulatory asset in this proceeding. As previously stated, Commission approval to  
6           create this regulatory asset is a key component of Duke Energy Kentucky's decision to  
7           proceed with its CPCN deployment. If the Commission denies approval to create the  
8           regulatory asset, but approves the CPCN for deployment of the Metering Upgrade, the  
9           Company would then be required to write-off the entire balance of its undepreciated  
10          meters, approximately \$9 million. This write-off would have a significant and material  
11          impact to the Company's financial position.

12   **Q.    DO YOU AGREE WITH MR. ALVAREZ'S RECOMMENDATION TO**  
13           **DEVELOP A MECHANISM TO ALLOCATE COST OVERRUNS IN THIS**  
14           **PROCEEDING?**

15   A.    No. First of all, cost over-runs, unless determined by the Commission to be imprudently  
16          incurred, should be recoverable and, like any cost of service, should be considered in a  
17          base rate proceeding along with all prudently incurred costs with the ultimate goal of  
18          resulting in a fair, just and reasonable rate. A cost over-run may result from any number  
19          of factors that are outside the control of the utility but may still qualify as a prudent  
20          investment. As with any new project, the Company uses its best efforts to project the  
21          costs of the project but variances between actual and projected will inevitably result such  
22          that the ultimate cost could be higher or lower than assumed. However, a discrepancy  
23          between actual and projected costs does not necessarily mean the Company was

1 imprudent. The Company should have its right to seek recovery of any prudently incurred  
2 cost, just as customers should be able to benefit from any deployment savings that could  
3 occur if the deployment comes under budget.

4 **Q. DO YOU AGREE WITH MR. ALVAREZ'S RECOMMENDATION THAT**  
5 **FUTURE RATE DESIGN PARAMETERS SHOULD BE DETERMINED IN THIS**  
6 **PROCEEDING?**

7 A. No. While the Company is willing to work with the Attorney General and the  
8 Commission Staff to design new retail electric rates that are enabled by smart meters, that  
9 should be left to a future base rate proceeding, rather than setting some arbitrary structure  
10 today. There are many more stakeholders that could be impacted by potential rate  
11 structures that are enabled by advanced metering installations. These rate designs should  
12 be examined in a rate case where more stakeholders than just the AG typically  
13 participate. Because rate design is a common issue in base rate proceedings, all  
14 stakeholders are on notice of potential rate design issues when the Company files for a  
15 base rate case. Establishing rate design criteria now is impractical as those rates could not  
16 even go into effect for at least two years once deployment is completed and the  
17 infrastructure is in place. By that time, the AG or other stakeholders may want some  
18 alternative form of rate design. Duke Energy Kentucky is willing to commit, as it has  
19 previously stated, that participation in any time of use rate offering for residential  
20 customers would be voluntary on the customer's part.

21 **Q. DO YOU AGREE WITH MR. ALVAREZ'S RECOMMENDATION THAT**  
22 **SPECIFIC REQUIREMENTS FOR TIME-VARYING RATES, SUCH AS**  
23 **PARTICIPATION GOALS, DEMAND REDUCTION GOALS, DEMAND**

1           **REDUCTION FEATURES, AND MARKETING PLANS AND BUDGETS**  
2           **SHOULD BE ESTABLISHED NOW?**

3    A.    No, and for the same reasons I previously stated. All of this can and should be done later  
4           and at a time more contemporaneous with the completion of the Metering Upgrade  
5           Deployment and the Company's ability to actually implement the rates. Agreeing to  
6           participation goals and marketing budgets more than two years from when the actual  
7           deployment of equipment to enable the rate structures is in place is premature, a waste of  
8           resources, and illogical. Neither the Company nor the AG actually proposed any such  
9           requirements or budgets in this proceeding.

10   **Q.    DO YOU AGREE WITH MR. ALVAREZ'S RECOMMENDATION TO**  
11           **IMPLEMENT A PENALTY TO THE COMPANY IF IT DOES NOT SECURE**  
12           **THE LEVEL OF ANTICIPATED BENEFITS?**

13   A.    No. Mr. Alvarez's suggestion is confiscatory, one sided, and results in a hindsight  
14           review, even before we have the benefit of hindsight. Not surprisingly, he is not  
15           suggesting a symmetrical reward to the Company if Metering Upgrade exceeds projected  
16           benefits or if it is completed for less than the projected cost. Duke Energy Kentucky  
17           should be able to recover its costs of service and charge customers a fair, just and  
18           reasonable rate in accordance with Kentucky law and Commission regulation. No more,  
19           no less. The Company is not seeking to recover its costs of deployment through any  
20           mechanism. So, the Company is wearing all of the risk of costs of deployment until it  
21           comes in for a base rate proceeding. At which time, assuming its application is approved,  
22           the prudence of the Company's costs, all costs, will be examined, and a fair just and  
23           reasonable rate of return established.

**III. CONCLUSION**

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

2 **A. Yes.**

**VERIFICATION**

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

The undersigned, Peggy A. Laub, Director, Rates and Regulatory Planning, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing rebuttal testimony are true and correct to the best of her knowledge, information and belief.

*Peggy A Laub*  
\_\_\_\_\_  
Peggy A. Laub, Affiant

Subscribed and sworn to before me by Peggy A. Laub on this 13<sup>th</sup> day of October, 2016.

*Adele M Frisch*  
\_\_\_\_\_  
NOTARY PUBLIC

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

My Commission Expires: 1/19/16