STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A STEP-IN OF NEW RATES AND CHARGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF A FEDERAL MANDATE CERTIFICATE UNDER IND. CODE § 8-1-8.4-1; (4) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING DEFERRAL RELIEF; AND (6) APPROVAL OF A REVENUE DECOUPLING MECHANISM FOR CERTAIN CUSTOMER CLASSES	)	**CAUSE NO. 45253**

VERIFIED DIRECT TESTIMONY
OF
SUZANNE E. SIEFERMAN

On Behalf of Petitioner,
DUKE ENERGY INDIANA, LLC

Petitioner's Exhibit 5

July 2, 2019

DIRECT TESTIMONY OF SUZANNE E. SIEFERMAN, DIRECTOR, RATES AND REGULATORY PLANNING ON BEHALF OF DUKE ENERGY INDIANA, LLC BEFORE THE INDIANA UTILITY REGULATORY COMMISSION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Suzanne E. Sieferman, and my business address is 1000 East Main Street, Plainfield, Indiana 46168.

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

A. I am employed by Duke Energy Indiana, LLC ("Duke Energy Indiana" or "Company") as Director, Rates and Regulatory Planning. Duke Energy Indiana is a wholly owned, indirect subsidiary of Duke Energy Corporation.

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

A. I am responsible for the preparation of financial and accounting data used in Company rate filings and petitions for changes in fuel cost adjustment factors and other tracking mechanisms.

Q. PLEASE STATE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I am a graduate of Indiana University, holding a Bachelor of Science Degree in Business, with a major in Accounting. I am a Certified Public Accountant ("CPA") and a member of the Indiana CPA Society. Since my employment with the Company in 1990, I have held various financial and accounting positions supporting the Company and its affiliates. Prior to my move to the Rates and

Regulatory Planning department in 2008, I held positions in Benefits Accounting, Corporate Accounting, Business Unit Financial Reporting and External Reporting groups.

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

A. My testimony will: 1) address certain rate base and operating income *pro forma* adjustments applicable to the twelve months ended December 2020 forecasted test period ("Test Period"); 2) explain and support proposed changes to certain of the Company's existing rate adjustment riders to be effective with the implementation of the Company's revised base rates, including the determination of the base cost of fuel to be used in FAC; and 3) explain and support the Company's requests for certain new deferral authority and cost recovery of certain expense items.

Q. WHICH RATE BASE *PRO FORMA* ADJUSTMENTS WILL YOU BE SPONSORING?

A. The rate base adjustments for 2020 that I am sponsoring are attached as Petitioner's Exhibit 5-D (SES), Schedule RB-3 which is a supporting schedule to Company witness Ms. Diana L. Douglas' Petitioner's Exhibit 4-F (DLD), Schedule RB-1 and includes adjustments to:

- Remove SO_2 Native Load Purchase Costs from the Emission Allowance ("EA") Inventory
- Defer Native SO_2 EA Costs into a Regulatory Asset

Q. WHICH OPERATING INCOME *PRO FORMA* ADJUSTMENTS WILL YOU BE SPONSORING?

A. I am sponsoring the following *pro forma* adjustments applicable to the Test Period. These are attached to my testimony as Petitioner's Exhibit 5-A (SES) through 5-C (SES).

Exhibit	*Pro Forma* Adjustments
Petitioner's Exhibit 5-A (SES)	Schedule REV4 – Remove Non-Native Sales Revenue Schedule REV5 – Remove Short-term Bundled Non-Native Sales Revenue Schedule REV6 – Remove Revenues for RECB/MVP Projects
Petitioner's Exhibit 5-B (SES)	Schedule COGS2 – Remove Fuel Expense Associated with Short-term Bundled Non-Native Sales Schedule COGS3 – Remove Fuel Expense Associated with Non-Native Sales Schedule COGS4 – Remove Retail Native SO2 Expenses Associated with Inventory Moved to Regulatory Asset
Petitioner's Exhibit 5-C (SES)	Schedule OM3 – Remove RECB/MVP O&M Expenses Schedule OM8 – Remove Indiana Electric Association ("IEA") O&M Expenses Schedule OM9 – Remove Brand Advertising O&M Expenses

Exhibit	***Pro Forma* Adjustments**
	Schedule OM10 – Remove Non-Jurisdictional Portion Henry County CT O&M Expenses Schedule OM11 – Remove Non-Utility Lighting O&M Expenses Schedule OM12 – Remove Premier Power O&M Expenses Schedule OM13 – Remove Electric Transportation Pilot Program O&M Expenses Schedule OM18 – Normalize Major Storm O&M Expenses Schedule OTX6 – Remove RECB/MVP Payroll Tax Expense Schedule OTX9 – Remove Non-Jurisdictional Portion Henry County CT Payroll Taxes Schedule OTX10 – Remove Non-Utility Lighting Payroll Taxes Schedule OTX11 – Remove Premier Power Payroll Taxes Schedule OTX12 – Remove Electric Transportation Pilot Program Payroll Taxes Schedule OTX14 – Normalize Major Storm Payroll Taxes

The Company's remaining operating income *pro forma* adjustments are sponsored by Duke Energy Indiana witnesses Ms. Douglas, Ms. Christa L. Graft, and Mr. Roger A. Flick II.

Q. WHICH EXISTING RATE ADJUSTMENT RIDERS WILL YOU ADDRESS IN YOUR TESTIMONY?

A. The rate adjustment riders that I will cover include the Company's:

- Standard Contract Rider No. 60 – Fuel Cost Adjustment ("FAC" or "Rider 60");
- Standard Contract Rider No. 68 – Midcontinent Independent System Operator "MISO" Management Costs and Revenue Adjustment ("Rider 68" or "RTO Rider");
- Standard Contract Rider No. 70 – Reliability Adjustment ("Rider 70" or "Reliability Rider"); and
- Standard Contract Rider No. 73 – Renewable Energy Project Revenue Adjustment ("Rider 73" or "Renewables Rider").

Copies of the red-lined and clean revised tariff sheets for the FAC, RTO, Rider 70 and Renewables Rider are attached to my testimony as Petitioner's Exhibit 5-G (SES) through 5-N (SES). These revised tariff sheets are also included with the complete set of base rate and other rider tariffs filed as Petitioner's Exhibit 9-A (RAF) and 9-B (RAF).

Q. WHAT REQUESTS FOR NEW DEFERRAL AUTHORITY AND RATE RECOVERY WILL YOU ADDRESS IN YOUR TESTIMONY?

A. I support the Company's requests for new deferral authority and current or future recovery of certain expense items as follows:

- Creation of a storm normalization reserve account to be used for amounts over and under the amount of storm restoration costs included in base rates;
- Deferral of electric transportation pilot program expenses for recovery in future base rates; and
- Deferral as a regulatory asset of the native SO_2 inventory balance with recovery over the average remaining life of the Company's steam generating stations.

Q. ARE YOU SPONSORING ANY WORKPAPERS TO SUPPORT EXHIBITS?

A. I will be sponsoring workpapers for my attached exhibits. See Petitioner's Exhibit 5-O (SES) for a list of sponsored workpapers and the related exhibits.

II. RATE BASE *PRO FORMA* ADJUSTMENTS

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 4-F (DLD) SCHEDULE RB1 AND PETITIONER'S EXHIBIT 5-D (SES) SCHEDULE RB3.

A. Schedule RB1, sponsored by Ms. Douglas, summarizes the *pro forma* adjustments made to rate base. I am sponsoring Schedule RB3 which summarizes the adjustments to remove native SO_2 EA costs currently included in the EA inventory and to transfer these costs to a regulatory asset to be included in base rates for proposed recovery. Ms. Douglas is sponsoring Petitioner's Exhibit 4-F

(DLD) Schedules RB2, RB4 and RB5, which adjust the value of other rate base items.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-D (SES) SCHEDULE RB3 ASSOCIATED WITH THE NATIVE SO_2 EA INVENTORY.

A. Schedule RB3 details the *pro forma* adjustments made to remove the estimated costs of $9.8 million associated with native SO_2 EAs as of 12/31/2020 from the forecasted EA inventory balance and to establish a new regulatory asset of $9.5 million to recover those costs over a proposed twelve-year period, which represents the estimated average remaining life of the Company's steam generation stations (specifically Cayuga and Gibson stations) that gave rise to these EAs. With changing environmental rules, the Company believes it is unlikely that it will recover the native SO_2 EA costs over a reasonable period of time if the amounts are left in the inventory account.

Q. PLEASE EXPLAIN WHY THE AMOUNT FOR THE *PRO FORMA* ASSOCIATED WITH ESTABLISHING THE REGULATORY ASSET IS DIFFERENT THAN THE *PRO FORMA* AMOUNT BEING REMOVED FROM EA INVENTORY.

A. As shown on Schedule RB3 (lines 2-5), to determine the amount of the *pro forma* adjustment for the regulatory asset as of 12/31/2020, the Company started with the $9.8 million removed from the forecasted EA inventory balance at 12/31/2020 and then added back the forecasted consumption expense for the July 2020 through December 2020 period and subtracted the forecasted regulatory asset amortization amounts for the same July 2020 through December 2020 period. This was done to reflect the Company's assumption that if this proposal is approved by the Commission and included in Step 1 of the rate update, as more fully described in the testimony of Ms. Douglas, then as of July 1, 2020, the native SO_2 consumption expense would be discontinued and the amortization of this newly established regulatory asset would begin. Therefore the 12/31/2020 balance of the regulatory asset would reflect the impact of these adjustments for the July 2020 through December 2020 period.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-E (SES) SCHEDULE RB3 ASSOCIATED WITH THE NATIVE SO_2 EA INVENTORY AS OF THE END OF 2019.

A. Petitioner's Exhibit 5-E (SES) Schedule RB3 reflects the amount that would be moved to a regulatory asset as of 12/31/2019 if that was the cut-off date for this proceeding. Ms. Douglas used this amount in her preparation of the Step 1 Rate Adjustment estimates.

III. OPERATING INCOME *PRO FORMA* ADJUSTMENTS

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 4-E (DLD) SCHEDULE REV1.

A. Schedule REV1, sponsored by Ms. Douglas, summarizes the *pro forma* adjustments made to Revenues on Schedules REV2 through REV6. I am sponsoring Schedules REV4, REV5 and REV6 on Petitioner's Exhibit 5-A (SES).

Ms. Graft and Mr. Flick sponsor the remaining Schedules supporting the Revenue *pro forma* adjustments.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-A (SES) SCHEDULE REV4 - REMOVE REVENUES FOR NON-NATIVE SALES.

A. Schedule REV4 removes $34,717,000 from Test Period revenues associated with non-native sales to reflect that these revenues are included in the off-system sales sharing mechanism of Rider 70. The Company is proposing in this case to continue sharing non-native sales margins 50/50 with customers through the tracking mechanism. See discussion on this topic later in my testimony in Section V as well as the Direct Testimony of Company witness Mr. John A. Verderame.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-A (SES) SCHEDULE REV5 - REMOVE REVENUES ASSOCIATED WITH A SHORT-TERM BUNDLED NON-NATIVE CONTRACT.

A. Schedule REV5 removes $23,976,000 from Test Period revenues for a short-term bundled non-native contract. See discussion later in my testimony regarding proposal for changes to Rider 70 as well as the Direct Testimony of Company witness Mr. Verderame.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-A (SES) SCHEDULE REV6 - REMOVE REVENUES FOR RECB/MVP PROJECTS.

A. Schedule REV6 removes $3,369,000 from Test Period revenues associated with certain of the Company's transmission projects recovered via MISO. As discussed in more detail in the testimony of Ms. Douglas, the Company received approval from MISO for certain Company-owned capital projects under MISO's Regional Expansion and Criteria and Benefits ("RECB") process and under MISO's Transmission Expansion Plan ("MTEP") as RECB projects or Multi-Value Projects ("MVP"). MISO reimburses the Company for the cost of these projects by charging all MISO transmission owners for the cost of the expansion projects through Schedule 26 and charging all market participants through Schedule 26A. As such, the Company excludes the revenues received and costs incurred associated with these projects from its retail ratemaking.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-B (SES).

A. Petitioner's Exhibit 5-B (SES) is a series of Schedules supporting the Cost of Goods Sold amounts included in the cost of service in this proceeding.

Petitioner's Exhibit 5-B (SES) Schedule COGS1 summarizes the *pro forma* adjustments made to Cost of Goods Sold on Schedules COGS2 through COGS5. I sponsor and discuss Schedules COGS2 through COGS4 on Petitioner's Exhibit 5-B (SES). Company witness Ms. Graft sponsors Schedule COGS5.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-B (SES) SCHEDULE COGS2 – REMOVE FUEL EXPENSE ASSOCIATED WITH A SHORT-TERM BUNDLED NON-NATIVE CONTRACT.

A. Schedule COGS2 removes $11,234,000 from Test Period fuel expense (and the proposed base cost of fuel amount) to reflect the Company's proposal in this filing to include such expenses associated with short-term bundled non-native contracts in Rider 70. This proposal is discussed later in Section V of my testimony, as well as the Direct Testimony of Company witness Mr. Verderame.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-B (SES) SCHEDULE COGS3 – REMOVE FUEL EXPENSE ASSOCIATED WITH NON-NATIVE SALES MARGIN.

A. Schedule COGS3 removes $32,217,000 from Test Period expenses to reflect that these expenses are included in the off-systems sales sharing mechanism of the Company's Rider 70.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-B (SES) SCHEDULE COGS4 - REMOVE RETAIL NATIVE SO_2 EXPENSES ASSOCIATED WITH INVENTORY MOVED TO REGULATORY ASSET.

A. Schedule COGS4 removes $213,000 from Test Period EA expense to reflect the Company's proposal (discussed earlier) that the retail portion of the native SO_2 EAs are moved from the EA inventory to a regulatory asset for recovery over the life of the Company's steam generating assets. The wholesale portion of the EA expense was left in the Test Period.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 4-E (DLD) SCHEDULE OM2 AND PETITIONER'S EXHIBIT 4-E (DLD) SCHEDULE OTX1.

A. Schedule OM2, sponsored by Ms. Douglas, summarizes the *pro forma* adjustments made to O&M (excluding fuel, EAs and purchased power) on Schedules OM3 through OM20. Schedule OTX1, also sponsored by Ms. Douglas, summarizes the *pro forma* adjustments made to Other Taxes on

Schedules OTX2 through OTX14. I am sponsoring Schedules OM3, OM8, OM9, OM10, OM11, OM12, OM13, OM18, OTX6, OTX9, OTX10, OTX11, OTX12 and OTX14, which summarize some of the *pro forma* adjustments made to O&M and Other Taxes, on Petitioner's Exhibit 5-C (SES). Ms. Douglas and Ms. Graft sponsor the remaining Schedules supporting the O&M and Other Taxes *pro forma* adjustments.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OM3 – REMOVE RECB/MVP RELATED COSTS.

A. Schedule OM3 is to remove $733,000 from Test Period O&M expenses for the Company's RECB and MVP projects, as discussed earlier with regards to the related revenues for these projects.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OM8 – REMOVE EXPENSES FOR INDIANA ELECTRIC ASSOCIATION ("IEA").

A. Schedule OM8 is to remove $711,000 from test period expenses associated with the Company's membership in the IEA. Such adjustment is consistent with past practices in electric utility rate cases before this Commission.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OM9 – REMOVE EXPENSES ASSOCIATED WITH BRAND ADVERTISING.

A. Schedule OM9 is to remove $414,000 from test period expenses related to costs incurred for image/brand advertising. Such adjustment is consistent with past practices in electric utility rate cases before this Commission.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OM10 – REMOVE O&M EXPENSES ASSOCIATED WITH THE NON-JURISDICTIONAL PORTION OF HENRY COUNTY COMBUSTION TURBINE ("CT").

A. Schedule OM10 is to remove $1,015,000 from test period O&M expenses associated with the non-jurisdictional portion of the Company's Henry County Generating Station ("Henry County"). As discussed in detail in the testimony of Ms. Douglas, the Commission previously ordered in Cause No. 42145 that for retail ratemaking purposes the Company should separate out and exclude costs and revenues associated with 50 MWs of capacity at Henry County, which had previously been committed to a non-jurisdictional sale to Wabash Valley Power Association ("WVPA"). Ms. Douglas sponsors the *pro forma* adjustment to remove rate base associated with the non-jurisdictional portion. Workpaper OM1-SES details the calculation of the O&M adjustment and shows the derivation of the 36.56% used within the calculation.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OM11 – REMOVE NON-UTILITY LIGHTING EXPENSES.

A. Schedule OM11 is to remove $3,622,000 from Test Period O&M expenses associated with non-utility lighting programs to ensure these expenses were not included in the cost of service to all customers. The Company is being reimbursed for the O&M costs for this lighting by specific customers under the terms of customer-specific Outdoor Lighting Equipment Service ("OLES") agreements.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OM12 – REMOVE PREMIER POWER EXPENSES.

A. Schedule OM12 is to remove $632,000 from Test Period O&M expenses to ensure these expenses were not included in the cost of service to all customers as the expenses for this program are considered non-utility.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OM13 – REMOVE ELECTRIC TRANSPORTATION PILOT PROGRAM EXPENSES.

A. Schedule OM13 is to remove $333,000 from Test Period operating expenses for O&M costs associated with the Electric Transportation Pilot Program. As discussed later in my testimony, the Company is requesting authority to defer O&M costs associated with the Electric Transportation Pilot Program, with carrying costs, for recovery in a future base rate case.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OM18 – NORMALIZE MAJOR STORM EXPENSES.

A. As discussed in more detail later in Section VI of my testimony, the Company is requesting to build into base rates a normalized level of major storm expenses based on a five-year historical average. Schedule OM18 increases the Test Period operating expenses by $2,454,000 to reflect this normalized level of major storm expenses.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OTX6 – REMOVE OTHER TAX EXPENSE FOR RECB/MVP PROJECTS.

A. Schedule OTX6 is to remove $21,000 from Test Period payroll taxes for the Company's RECB and MVP projects, as discussed earlier with regards to the related revenues and O&M expenses for these projects.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OTX9 – REMOVE OTHER TAX EXPENSE FOR THE NON-JURISDICTIONAL PORTION OF HENRY COUNTY CT.

A. Schedule OTX9 removes $32,000 of payroll taxes from the Test Period for the non-jurisdictional portion of Henry County CT, as discussed earlier with regards to the related O&M expenses.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OTX10 – REMOVE OTHER TAX EXPENSE FOR NON-UTILITY LIGHTING PROGRAMS.

A. Schedule OTX10 removes $112,000 from Test Period payroll taxes associated with non-utility lighting programs, where the Company's cost recovery is pursuant to the customer-specific OLES agreements.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OTX11 – REMOVE OTHER TAX EXPENSE FOR PREMIER POWER PROGRAM.

A. Schedule OTX11 removes $17,000 from Test Period payroll taxes associated with the Premier Power Program, which is a non-utility program as previously discussed.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OTX12 – REMOVE OTHER TAX EXPENSE FOR ELECTRIC TRANSPORTATION PILOT PROGRAM.

A. Schedule OTX12 removes $5,000 from Test Period payroll tax expenses associated with the Electric Transportation Pilot Program. As discussed later in my testimony, the Company is requesting authority to defer payroll tax expenses associated with this Electric Transportation Pilot Program, with carrying costs, for recovery in a future base rate case.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 5-C (SES) SCHEDULE OTX14 – REMOVE OTHER TAX EXPENSE FOR MAJOR STORM NORMALIZATION.

A. Schedule OTX14 increases Test Period payroll taxes by $221,000 to reflect a normalized level of major storm expenses. As discussed in more detail later in Section VI of my testimony, the Company is requesting to build into base rates a normalized level of major storm expenses based on a five-year historical average.

IV. <u>BASE COST OF FUEL</u>

Q. PLEASE EXPLAIN THE DOCUMENT THAT HAS BEEN MARKED FOR PURPOSES OF IDENTIFICATION AS PETITIONER'S EXHIBIT 5-F (SES) SCHEDULE COGS6.

A. Schedule COGS6 shows the derivation of the proposed base cost of fuel to be included in Petitioner's schedules of rates and charges. This exhibit reflects the Company's forecasted dispatch of system resources for 2020. Company witness Mr. Christopher M. Jacobi explains the development of the forecasted fuel and purchased power expenses and Company witnesses Mr. Verderame and Mr. Brett J. Phipps discusses the production cost model used to simulate generation output and associated costs used in developing that forecast. As shown in Exhibit 5-F (SES), the proposed base cost of fuel is 26.955 mills per kWh. By comparison, the Company's current base cost of fuel, which was established in Cause No. 42359 approved by the Commission on May 18, 2004, is 14.484 mills per kWh.

V. RATE ADJUSTMENT RIDERS

A. FAC Rider

Q. WHAT CHANGES IS THE COMPANY PROPOSING TO ITS FAC RIDER?

A. The Company is proposing the following changes to the FAC Rider:

- Add fuel-related PJM Interconnection LLC ("PJM") charges and credits on a prospective basis to the native fuel cost recovered through the FAC;
- Discontinue the benchmark application to purchased power costs eligible to be recovered through the FAC;
- Implement changes to the calculation of the native/non-native sales stacking logic for long-term commitment generating units;
- Update the base cost of fuel amount; and

- Make administrative updates to the tariff page for consistency across riders and to reflect specific requests being made in this proceeding.

Q. PLEASE DISCUSS WHAT THE COMPANY IS PROPOSING FOR FUEL-RELATED PJM CHARGES AND CREDITS.

A. The Company's Madison Generating Station ("Madison") is considered an Indiana resource for MISO purposes, but is not physically located within the MISO footprint; instead it is connected to the PJM transmission grid. As discussed in more detail in the testimony of Mr. Verderame, energy from the station is transferred to MISO using firm transmission service and from an energy perspective it appears the same as other generating units within MISO. In addition to the settlement statements the Company receives from MISO, it also receives settlement statements from PJM, which includes additional charges and credits associated with Madison. Fuel-related charges and credits from MISO have been included in the Company's FAC filings since it began participating in the MISO energy market in 2005. The Company did not begin receiving the PJM settlement statements for Madison until 2012. To date, Duke Energy Indiana has paid or received all the charges and credits associated with Madison and not passed any of the amounts onto the Company's retail customers.

The PJM charges and credits for Madison vary month-to-month. In some months the net amount on the settlement statement is a charge and in other months it's a credit. The total net of the charges and credits for 2012 through 2018 time period is a net credit (payment from PJM) of approximately $1.6

million. Madison station, similar to Duke Energy Indiana's other generating stations, is operated for the benefit of the Duke Energy Indiana customers regardless of its location with the PJM footprint; therefore, the Company believes it is appropriate to include the comparable fuel-related PJM charges and credits, in addition to the MISO fuel-related charges and credits, in the FAC rider on a prospective basis.

Q. PLEASE EXPLAIN WHAT THE COMPANY IS PROPOSING RELATED TO THE PURCHASED POWER BENCHMARK.

A. The Company is currently subject to a purchased power benchmark established by the Commission's August 18, 1999 Order in Cause No. 41363 and the guidance of the Commission in Cause Nos. 38706 FAC45, 38708 FAC45, 38707 FAC56 and 38707 FAC59. The benchmark is not intended to be a cap on recovery but instead has been used to identify when additional review may be needed to ensure the Company's cost of purchased power is reasonable. In his testimony Mr. Verderame discusses how the benchmark is calculated and what requirements must be met in order to recover any purchased power costs above the benchmark in the Company's FAC rider. He further explains that with the operation of the MISO market, the risks that the benchmark was intended to address have been heavily mitigated. The Company is requesting that the purchased power benchmark procedures currently in place for Duke Energy Indiana be permanently waived by the Commission. Even absent the benchmark, the Company's purchased power costs would continue to remain subject to review and approval in each of the Company's FAC rider filings.

Q. PLEASE EXPLAIN WHAT THE COMPANY IS PROPOSING RELATED TO THE CALCULATION METHODOLOGY USED TO DETERMINE THE NATIVE/NON-NATIVE STACKING OF THE COMPANY'S GENERATION.

A. Today the Company determines what fuel costs are allocated to native customers (included in the FAC Rider) versus non-native customers (included in the Reliability Rider) using a production costing model. At a high-level, the model stacks based on average production costs ranked lowest to highest, with native customers generally being assigned the lowest cost resources. The Company is proposing to change the stacking logic from the current "average production cost" basis to an "incremental production cost basis" for long-term commitment generating units such as coal-fired and combined-cycle natural gas units. Duke Energy Indiana would continue to allocate costs for short-term commitment units, such as combustion turbines, on the existing average production cost basis.

If native fuel costs increase as a result of this change, the additional costs would increase the fuel costs flowing through the FAC rider. Similarly, any decreases to native fuel costs would lower the fuel costs included in the FAC Rider. Changes to non-native fuel costs will be reflected in the Company's non-native sharing mechanism included in the Reliability Rider.

The Company believes this request is reasonable as the incremental cost approach will better align with MISO's actual dispatch logic and will more equitably and appropriately allocate fuel costs between native and non-native customers.

Please refer to Company witness Mr. Verderame's testimony for a more in-depth discussion of the Company's stacking process and the proposed changes to the calculation methodology.

Q. ARE YOU PROPOSING ANY CHANGES TO THE CURRENT FAC RIDER TARIFF?

A. As discussed earlier in my testimony, the Company is proposing to update the base cost of fuel used to calculate the FAC Rider rate. The new proposed base cost of fuel is 26.955 mills per kWh, as compared to the current factor of 14.484 mills per kWh.

The Company is proposing some minor cosmetic and format changes to get more consistency across its various rider and rate tariffs and resetting the tariff numbering. Also, the Company is proposing to remove the gross-up factor currently reflected in the FAC, assuming the Commission approves the proposal discussed in Ms. Graft's testimony to add Utility Receipts Tax ("URT") directly to the customers' bills rather than including in each rider factor.[1]

Copies of the red-lined and clean revised tariff sheets containing the language, header and format changes for the FAC Rider are attached to my testimony as Petitioner's Exhibit 5-G (SES) and 5-H (SES). They are also

[1] The Direct Testimony of Company witness Ms. Graft will explain the Company's proposal to include URT on customer bills in lieu of including it as a cost of service item and will support the *pro forma* adjustment to remove URT from the cost of service.

included with the complete set of base rate and other rider tariffs that are filed with the testimony of Mr. Flick as Petitioner's Exhibit 9-A (RAF) and 9-B (RAF). The complete rider with revised rates and new allocation factors will be filed as a compliance filing following approval of the Company's proposed base rates.

B. <u>Regional Transmission Operator ("RTO") Rider</u>

Q. WHAT CHANGES IS THE COMPANY PROPOSING TO ITS RTO RIDER?

A. The Company is proposing the following changes to the RTO Rider:

- Add non-fuel related PJM charges and credits on a prospective basis to the comparable MISO amounts currently included in the rider;
- Update the proposed annual base amounts for RTO non-fuel costs and RTO transmission revenues used in the rider calculation;
- Modify the factor calculation for HLF customers to be billed on KW demand rather than on kWh sales; and
- Make administrative updates to the tariff page for consistency across riders and to reflect specific requests being made in this proceeding.

Q. WHAT IS THE COMPANY PROPOSING FOR NON-FUEL RELATED PJM CHARGES AND CREDITS?

A. As discussed in more detail above for the FAC Rider, the Company is currently receiving settlement statements from both PJM (for Madison) and MISO, but is only including the charges and credits from the MISO statements in its base rates and/or applicable rider rates to retail customers. The Company is proposing in this proceeding to include all RTO non-fuel charges and credits and transmission revenues (both from PJM and MISO) on a prospective basis in its RTO rider filings. The Company believes this request is reasonable as Madison is operated for the benefit of the Duke Energy Indiana customers.

Q. ARE YOU PROPOSING ANY CHANGES TO THE CURRENT RTO RIDER TARIFF?

A. The Company is proposing to update the RTO non-fuel and transmission revenues amounts built into base rates and track the actual amounts experienced for these items above and below the amounts in base rates. In accordance with the Company's proposal, the new base amounts reflect both PJM and MISO charges and credits.

The Company is also proposing to update the calculation of the RTO Rider factor for HLF customers to bill on KW demand rather than kWh sales. This proposed methodology is consistent with how the HLF factors are currently calculated for the Company's Environmental and Renewables Riders.

The Company is proposing some minor cosmetic and format changes to get more consistency across its various rider and rate tariffs and resetting the tariff numbering, including modifying the name of this rider from MISO to RTO to reflect the inclusion of applicable amounts from both MISO and PJM. In addition, the Company is proposing to update the revenue conversion factors to reflect the provision for uncollectible accounts expense and public utility fee approved in this proceeding and remove the provision for utility receipts tax.

Copies of the red-lined and clean revised tariff sheets containing the language, header and format changes for the RTO Rider are attached to my testimony as Petitioner's Exhibit 5-I (SES) and 5-J (SES). They are also included with the complete set of base rate and other rider tariffs that are filed with the testimony of Mr. Flick as Petitioner's Exhibit 9-A (RAF) and 9-B (RAF). The complete rider with revised rates and new allocation factors will be filed as a compliance filing following approval of the Company's proposed base rates.

C. <u>Reliability Rider</u>

Q. WHAT CHANGES IS THE COMPANY PROPOSING TO ITS RELIABILITY RIDER?

A. The Company is proposing the following changes to the Reliability Rider (Rider 70):

- Retaining the non-native margin sharing mechanism but resetting the base amount to zero. The Company proposes to continue sharing 50/50 between customers and shareholders non-native margins realized during the reporting period for the rider, including both positive and potentially negative margins;
- Implementing a new sharing mechanism (or modify the existing non-native mechanism) to share 50/50 between customers and shareholders in margins realized on short-term bundled non-native sales.
- Implement changes to the calculation of the native/non-native sales stacking logic for long-term commitment generating units;
- Modify the capacity portion of the rider to allow for any differential in

capacity costs and/or revenues related to Madison station;

- Update the proposed annual base amount for Power Share® bill credits;
- Modify the factor calculation for HLF customers to be billed on KW demand rather than on kWh sales; and
- Make administrative updates to the tariff page for consistency across riders and to reflect specific requests being made in this proceeding.

Q. WHAT CHANGE IS THE COMPANY PROPOSING TO THE CURRENT NON-NATIVE SHARING MECHANISM WITHIN THIS RIDER?

A. The Company is proposing to retain this mechanism but reset the base amount to zero. Non-native margins, both above and below zero, would be shared equally between the Company and customers with no specific amount embedded in base rates. As described in more detail in the testimony of Company witness Mr. Verderame, this proposal is reasonable as the Company has experienced significant variability in actual non-native margins realized since the Rider was implemented in the last base rate case. Given this variability, the Company believes that accounting for this item through a tracking mechanism is more appropriate than building an amount into base rates.

Q. CAN YOU PLEASE DESCRIBE WHAT THE COMPANY IS REFERRING TO AS SHORT-TERM BUNDLED NON-NATIVE SALES?

A. Yes. The Company is using this term to describe a newer type of non-native contract that combines sales of both capacity and energy and is short-term in nature (five years or less). The negotiated contract prices will cover the energy costs and will make a contribution to fixed costs. The Company believes that these short-term bundled non-native agreements can be structured to meet a changing wholesale customer need and can be priced to compete at current market prices. For a more detailed discussion on this topic, please refer to the testimony of Company witness Mr. Verderame.

Q. PLEASE EXPLAIN HOW THE COMPANY IS CURRENTLY ACCOUNTING FOR THE ONE EXISTING SHORT-TERM BUNDLED NON-NATIVE CONTRACT.

A. The Company currently has one short-term bundled non-native contract expiring in 2021. As the contract terms for traditional native wholesale contracts have come to an end, some have not been renewed due to the current low-cost energy and capacity pricing available in MISO. This one short-term bundled non-native contract was priced to be competitive within the MISO market. The pricing for this contract is below the Company's fully embedded costs, but above the variable costs, such that it results in an overall net contribution to the Company's fixed costs. Absent this contribution, the retail customers would bear these costs coming out of a retail base rate case where a new cost of service study is completed. Between retail rate cases, the Company has not updated its cost of service study and therefore no ratemaking impacts have been recognized to date for customers as a result of this one particular contract.

Q. WHAT IS THE COMPANY PROPOSING IN THIS PROCEEDING FOR THE CURRENT (AND ANY FUTURE) SHORT-TERM BUNDLED NON-

NATIVE SALES?

A. The Company is proposing to include the margin from the one existing short-term bundled non-native sale, and any similar sales made in the future, within the Reliability Rider to be shared equally (50/50) between the Company and customers. This proposal provides a way for retail customers to realize a benefit as a result of the contribution to fixed costs made from these sales on a prospective basis.

Q. WHAT CHANGES ARE BEING PROPOSED TO THE NATIVE/NON-NATIVE COST ALLOCATIONS?

A. As discussed in more detail above for the FAC Rider, and in the testimony of Company witness Mr. Verderame, the Company is proposing to change the stacking logic in its production costing model from the current "average production cost" basis to an "incremental production cost" basis for long-term commitment generating units (*i.e.*, coal-fired and combined-cycle natural gas units). This production costing model is used to determine native versus non-native fuel costs. Any changes to native fuel costs resulting from a change in the stacking logic would be reflected in the FAC Rider and any impacts to non-native fuel costs would flow through the non-native sharing mechanism in the Reliability Rider. The Company believes this proposal is reasonable as it more closely aligns with MISO's dispatch logic and will result in a more equitable allocation of fuel costs between native and non-native customers.

Q. WHAT CHANGES ARE BEING PROPOSED TO THE RIDER WITH REGARDS TO CAPACITY COSTS AND/OR REVENUES?

A. As more fully described in the testimony of Mr. Verderame, there have been changes recently to the MISO Resource Adequacy Construct that impact Duke Energy Indiana's use of Madison as a capacity resource. MISO has made a change, effective June 1, 2019 for the 2019/2020 Delivery Year, in how it will value capacity resources located outside the MISO footprint. This change has impacted the Company's Madison station, which is now being considered a PJM external zone resource and could therefore clear the annual MISO capacity auction at a different price than the Company's other generating assets. There was no price difference experienced during the 2019/2020 auction; however, price separation could occur in future auctions. To address situations like Madison and other similarly situated generation units, MISO created a hedge instrument called Historical Unit Consideration ("HUC") that are allocated to generators like Madison and are intended to fund the differential. Given these recent changes, the Company is proposing that in prospective Reliability Rider filings no capacity revenues would flow through the rider until the native load charges have been met. If capacity costs have been offset, further revenues from capacity sales and HUC payments could be allocated as non-native sales margin and shared equally through the rider. If capacity costs for native load exceed all capacity revenues, the differential will be recovered in the same way it is today.

Q. ARE YOU PROPOSING ANY CHANGES TO THE CURRENT TARIFF FOR THE RELIABILITY RIDER?

A. Yes. The Company is proposing to update the annual base amount for bill credits under the Power Share® program.

The Company is also proposing to update the calculation of the Reliability Rider factor for HLF customers to bill on KW demand rather than kWh sales. This proposed methodology is consistent with how the HLF factors are currently calculated for the Company's Environmental and Renewables Riders and with what is proposed for the RTO Rider.

The Company is also proposing some minor cosmetic and format changes to get more consistency across its various rider and rate tariffs and resetting the tariff numbering. Further, the Company is proposing to update the revenue conversion factors to reflect the provision for uncollectible accounts expense and public utility fee approved in this proceeding and remove the provision for utility receipts tax.

Copies of the red-lined and clean revised tariff sheets containing the language, header and format changes for the Reliability Rider are attached to my testimony as Petitioner's Exhibit 5-K (SES) and 5-L (SES). They are also included with the complete set of base rate and other rider tariffs that are filed with the testimony of Mr. Flick as Petitioner's Exhibit 9-A (RAF) and 9-B (RAF). The complete rider with revised rates and new allocation factors will be filed as a compliance filing following approval of the Company's proposed base rates.

D. Renewables Rider

Q. WHAT CHANGES IS THE COMPANY PROPOSING TO ITS RENEWABLES RIDER?

A. The Company is proposing to roll the net book value (original cost investment less accumulated depreciation) of all in-service renewables plant as of the end of the Test Period into base rates. Additionally, the Test Period level of O&M will be included in base rates, as will the depreciation associated with the investment rolled into rate base.

At the time of implementation of the new base rates resulting from this proceeding, the Renewables Rider will be revised to:

- remove the investment and O&M amounts included in base rates;
- recalculate the depreciation on the remaining investment (if any) using the new depreciation rates approved in this proceeding;
- change the 10.5% ROE used in the cost of capital calculation to the new ROE approved in this proceeding;
- update the calculation to begin reconciling return, in addition to the current practice of reconciling operating expenses; and,
- change the allocations to rate classes used in the calculation of rates to use the final 4CP production demand allocators from this proceeding instead of the revenue requirements from Cause No. 42359; and
- make administrative updates to the tariff page for consistency across riders and to reflect specific requests being made in this proceeding.

This proposed treatment and changes are in accordance with the terms of the Settlement Agreements approved in Cause Nos. 44734 and 44767 approving rate recoveries for Crane Solar and Markland Uprate projects, respectively.

Q. UNDER THE COMPANY'S PROPOSAL, ARE THERE ANY OTHER ITEMS INCLUDED IN THE RENEWABLES RIDER THAT WILL NOT BE BUILT INTO BASE RATES?

A. Yes. The Company is proposing that post-in-service carrying costs and any credits from the sale of RECs not be included in base rates, but rather continue to be tracked in the Renewables Rider. The post-in-service carrying costs and REC sales are non-recurring and variable in nature, so these items would be best managed through the tracker, until such time as the Renewable Rider is no longer warranted.

In addition, once the Company is able to utilize the investment tax credits ("ITC") for the applicable renewable projects on its corporate consolidated federal income tax return, an additional credit for the retail jurisdictional portion of the associated ITC amortization would be included in the Renewable Rider. These credits have not been included in the proposed base rates in this proceeding to ensure compliance with the federal income tax normalization requirements because the Company will not be able to utilize the credits until after the Test Period, as discussed in the Direct testimonies of Company witnesses Ms. Douglas and Mr. John R. Panizza.

Q. ARE THE COMPANY'S RATEMAKING PROPOSALS REGARDING RENEWABLES INVESTMENT AND COSTS CURRENTLY INCLUDED IN THE RENEWABLES RIDER REASONABLE?

A. Yes. The Company's proposal is consistent with past practice in Indiana to subsequently include in base rates in-service plant receiving CWIP ratemaking treatment via a tracker. The Company's proposed treatment is also in accordance with the terms of the Crane Solar and Markland Uprate Settlement Agreements. To continue to track the post-in-service carrying costs and any REC sale net proceeds in the Renewables Rider, along with any incremental new investment and related depreciation and O&M, is a reasonable way to recover the non-routine and variable Renewables Rider costs.

Q. HOW WILL THE COMPANY IMPLEMENT THE CHANGES TO THE RENEWABLES RIDER ONCE NEW BASE RATES ARE APPROVED?

A. The Company will file revised rate schedules resetting the then-current rates to remove the amounts included in base rates and adjust the ROE, revenue conversion factors, and allocation factors. This will be done concurrently with filing the new base rate tariffs, with both base rates and rider rate changes to be implemented on a service-rendered basis.

Q. ARE YOU PROPOSING ANY CHANGES TO THE CURRENT RENEWABLES RIDER TARIFF?

A. Yes. The Company is proposing some minor cosmetic and format changes to get more consistency across its various rider and rate tariffs and resetting the tariff numbering. In addition, the Company is proposing reconciliation of the return component of the Renewable Rider in addition to the operating costs portion, consistent with its proposal for Rider 62, and is updating its language to reflect that change. Further, the Company is proposing to update the revenue conversion factors to reflect the provision for uncollectible accounts expense and public utility fee approved in this proceeding and remove the provision for utility receipts tax.

Copies of the red-lined and clean revised tariff sheets containing the language, header and format changes for the Renewables Rider are attached to my testimony as Petitioner's Exhibit 5-M (SES) and 5-N (SES). They are also included with the complete set of base rate and other rider tariffs that are filed with the testimony of Mr. Flick as Petitioner's Exhibit 9-A (RAF) and 9-B (RAF). The complete rider with revised rates and new allocation factors will be filed as a compliance filing following approval of the Company's proposed base rates.

VI. DEFERRAL AND COST RECOVERY REQUESTS

A. Storm Normalization Reserve

Q. WHAT IS THE COMPANY PROPOSING RELATED TO MAJOR STORM EXPENSES?

A. The Company is seeking approval of its request to build into retail base rates a normalized level of major storm expenses of approximately $12.7 million based on a five-year historical average of such costs for calendar years 2013 through 2018. A *pro forma* adjustment was made to increase the Test Period amount for storms from $10.0 million to the $12.7 million level. In addition to establishing a normalized level in base rates, the Company is proposing to establish a Major Storm Damage Restoration Reserve ("Major Storm Reserve") to track differences between the operating costs incurred and the amount collected in base rates. Any under-recovery would be recorded to a Regulatory Asset and any over-recovery would be recorded as a Regulatory Liability. The net amount for the Major Storm Reserve would be addressed for recovery in the next retail base rate case.

Q. FOR PURPOSES OF THIS PROPOSAL, HOW IS THE COMPANY DEFINING A MAJOR STORM?

A. Company witness Ms. Cicely M. Hart provides information in her testimony on this subject. Ms. Hart's testimony includes a table showing Duke Energy Indiana's historical 2013 through 2018 transmission and distribution costs incurred for major storms based on Major Event Days. Generally speaking, a storm is classified as a Major Event Day when a major reliability event causes a utility to shift into a crisis mode of operation in order to adequately respond. As further described in Ms. Hart's testimony, the Institute of Electrical and Electronic Engineers ("IEEE") 1366 statistically defines a major event day as a day in which the daily system Average Interruption Duration Index ("SAIDI") exceeds a threshold value (calculated from a 5-year average daily SAIDI). See Workpaper OM3-SES for the supporting calculation for five-year historical average for major storm costs that was used to determine the normalized level.

Q. HOW DOES THE COMPANY PLAN TO ADDRESS ANY UNDER- OR

OVER-RECOVERY IN THE MAJOR STORM RESERVE IN THE NEXT BASE RATE CASE?

A. In its next retail base rate case, Duke Energy Indiana proposes to include an amortization in the cost of service to either reduce the cost of service for any over-recovery or increase the cost of service for any under-recovery in the Major Storm Reserve at the end of the historical base period.

Q. WHY DOES THE COMPANY BELIEVE IT IS APPROPRIATE TO ESTABLISH A MAJOR STORM RESERVE?

A. As evidenced by the historical cost information shown in Ms. Hart's testimony, the costs for Major Storms vary significantly year-to-year based on the actual number of Major Event Days declared and the types of restoration efforts required. During the 2013 to 2018 historical period alone, costs varied from a low of $6.5 million in one year to a high of $21.4 million in another year. Although the Company is proposing to normalize Major Storm costs for establishing base rates, the timing, frequency, and costs for such Major Storms are unpredictable and therefore challenging for the Company to establish a precise amount in base rates to cover its prudently incurred costs (nothing more or nothing less). The Company believes its proposal to establish a Major Storm Reserve is reasonable and balances the interests of both the Company and its customers by smoothing out these costs and providing for the Company to be able to recover no more or less than its actual costs.

B. <u>Electric Transportation Pilot Expenses</u>

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S ELECTRIC TRANSPORTATION PILOT PROGRAM.

A. As discussed in detail in the testimony of Duke Energy Indiana witness Mr. Lang W. Reynolds, the Company is requesting authorization for an Electric Transportation Pilot Program ("Pilot Program") that will allow Duke Energy Indiana to deploy electric vehicle ("EV") infrastructure to meet growing market needs. Duke Energy Indiana's proposal consists of five (5) distinct programs, which are designed to accomplish the following overall goals:

- Deploy a foundational level of fast charging infrastructure in Indiana;
- Research the effects of increasing adoption of different types of electric vehicles on the electric system;
- Research customer EV charging behavior; and
- Determine the potential financial and environmental benefits for Indiana.

Q. WHAT IS THE FORECASTED COST OF THE ELECTRIC TRANSPORTATION PILOT PROGRAM?

A. The total forecasted cost of the Pilot Program is approximately $15.3 million over the 2019 through 2023 time period, which is comprised of approximately $11.4 million of capital spend and approximately $3.9 of O&M spend. Although the actual costs will likely vary somewhat from the forecast, the Company's proposal is to cap cost recovery at $15.3 million excluding the proposed carrying costs discussed below.

Q. HOW DOES THE COMPANY PROPOSE TO RECOVER THE CAPITAL COSTS FOR THE PILOT PROGRAM?

A. Capital components for this program that are in-service as of the end of the Test Period will be included in the base rates proposed in this proceeding. For capital components that are not in-service as of the end of the Test Period, the Company is proposing to defer depreciation expense and post-in-service carrying costs at the weighted average cost of capital rate as regulatory assets until these capital components are deemed to be used and useful in a future base rate case.

Q. HOW DOES THE COMPANY PROPOSE TO RECOVER THE O&M COSTS FOR THE EV PILOT PROGRAM?

A. The Company is proposing to defer O&M costs incurred from 2019 through 2023 for the Pilot Program, with carrying costs at the weighted average cost of capital rate, as a regulatory asset to be held for recovery in a future base rate case. As discussed earlier in my testimony, a *pro forma* adjustment was made to remove the forecasted 2020 O&M costs from the Company's Test Period, such that a level has not been built into base rates for these costs. The total amount of O&M to be deferred for the life of the pilot program, excluding carrying costs, is currently estimated to be approximately $3.9 million.

Q. IS THE COMPANY'S RATEMAKING PROPOSAL REASONABLE?

A. Yes. The proposed Electric Transportation Pilot Program provides many potential benefits to customers, as described fully in the testimony of Mr. Reynolds, and it is reasonable and prudent to allow the Company to recover the associated costs.

C. Regulatory Asset Request for Native SO_2 EA Recovery

Q. WHAT SPECIFICALLY IS THE COMPANY REQUESTING?

A. As discussed earlier in my testimony, the Company is proposing to transfer the native SO_2 EAs from the EA inventory account to a new Regulatory Asset account. The new Regulatory Asset would be amortized over a proposed twelve-year period, which represents the estimated average remaining life of the Company's steam generation stations (specifically Cayuga and Gibson stations). Assuming the Commission approves this request, at the time new rates go into effect, the native SO_2 EA consumption expense would decrease to zero and the Company would begin recognizing the regulatory asset amortization expense.

Q. WHY IS THE COMPANY REQUESTING THIS NEW REGULATORY ASSET?

A. With changing environmental rules, the Company believes it is unlikely that it will recover the native SO_2 EA costs over a reasonable period of time if the amounts are left in the inventory account. Based on the forecasted native SO_2 consumption expense for 2020, if the Company received no additional allotments of zero cost SO_2 EAs from the EPA after 2020, it will take over 43 years to utilize the forecasted EA inventory balance at the end of 2020. Adding these zero-cost

EAs to the inventory at the beginning of each year will continue to lower the associated weighted average cost of inventory that is then used to calculate the associated native consumption expense currently recovered through the Company's Standard Contract Rider No. 63 – SO_2, NOx and Hg Emission Allowance Adjustment. Absent special regulatory treatment, it is unlikely that the Company will ever fully recover these costs.

Q. IS THE COMPANY'S PROPOSAL REASONABLE?

A. Yes, the costs for the native SO_2 EAs were prudently incurred on behalf of the Company's native customers. The Company's proposal to recover these costs over the estimated remaining lives of the generating assets driving these costs is reasonable.

D. <u>Requested Accounting Treatment</u>

Q. IS THE ACCOUNTING TREATMENT PROPOSED BY THE COMPANY FOR POST-IN-SERVICE CARRYING COSTS, DEFERRED DEPRECIATION AND DEFERRED O&M IN ACCORDANCE WITH GENERALLY ACCEPTED ACCOUNTING PRINCIPLES ("GAAP")?

A. Yes. GAAP specifically discusses the accounting for a regulator's actions designed to protect a utility from the effects of regulatory lag. Topic 980 of the Financial Accounting Standards Board's Accounting Standards Codification ("ASC") covers the accounting guidance for regulated operations formerly provided in Statement of Financial Accounting Standards No. 71. Costs associated with regulatory lag can be capitalized for accounting purposes, provided the provisions of ASC 980-340-25-1 are met. The guidance states:

> Rate actions of a regulator can provide reasonable assurance of the existence of an asset. An entity shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met: (a) It is probable (as defined in Topic 450) that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for ratemaking purposes and (b) Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost. A cost that does not meet these asset recognition criteria at the date the cost is incurred shall be recognized as a regulatory asset when it does meet those criteria at a later date.

Q. DO YOU HAVE AN OPINION AS TO THE APPROPRIATENESS OF AND THE ACTION REQUIRED BY THE COMMISSION TO ALLOW FOR THE REQUESTED ACCOUNTING TREATMENT?

A. Yes. In my opinion, deferral in a regulatory asset of the retail jurisdictional portion of the post-in-service carrying costs, depreciation, and O&M costs incurred for the benefit of customers until they can be included in retail base rates or rider rates is appropriate from a ratemaking perspective, and such treatment will minimize the timing differences between cost recognition on the Company's books and cost recovery. In order for the Company to defer the Major Storm Reserve, Electric Transportation Pilot Program and native SO_2 EA costs as regulatory assets, it must be probable that such costs will be recovered through rates in future periods. In order to satisfy the probability standard, the Commission's Order in this proceeding should specifically approve the accounting and ratemaking treatment proposed by Duke Energy Indiana.

VII. CONCLUSION

Q. WERE PETITIONER'S EXHIBITS 5-A (SES) THROUGH 5-O (SES) PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PREFILED DIRECT TESTIMONY?

A. Yes, it does.

DUKE ENERGY INDIANA, LLC
Pro Forma Adjustment to
Wholesale Revenue - Non-Native Sales
(Thousands of Dollars)

This pro forma adjustment is to remove revenues associated with non-native wholesale sales.

Line No.	Description	2020 Forecast Amount (A)	Adjusted Amount (B)	Pro Forma Adjustment [1/] (C) (B) - (A)	Line No.
1	Non-Native Sales Revenue	$ 34,717	$ -	$ (34,717)	1
2	**Total**	**$ 34,717**	**$ -**	**$ (34,717)**	2

[1/] To PETITIONER'S EXHIBIT 4-E (DLD) Schedule REV1.

DUKE ENERGY INDIANA, LLC

Pro Forma Adjustment to

Wholesale Revenue - Short-term Bundled Non-Native Sales

(Thousands of Dollars)

This pro forma adjustment is to remove revenues associated with short-term bundled non-native sales.

Line No.	Description	2020 Forecast Amount (A)	Adjusted Amount (B)	Pro Forma Adjustment [1/] (C) (B) - (A)	Line No.
1	Short-term Bundled Non-Native Sales Revenue [2/]	$ 23,976	$ -	$ (23,976)	1
2	**Total**	**$ 23,976**	**$ -**	**$ (23,976)**	2

[1/] To PETITIONER'S EXHIBIT 4-E (DLD) Schedule REV1.
[2/] See: MSFR Workpaper REV1-SES.

DUKE ENERGY INDIANA, LLC

Pro Forma Adjustment to
Other Operating Revenues - MISO RECB/MVP Projects

(Thousands of Dollars)

This pro forma adjustment is to remove the revenues received related to MISO RECB and MVP Projects.

Line No.	Description	2020 Forecast Amount (A)	Adjusted Amount (B)	Pro Forma Adjustment [1/] (C) (B) - (A)	Line No.
1	Account 456110 - Transmission Revenues [2/]	$ 3,369	$ -	$ (3,369)	1
2	Total	$ 3,369	$ -	$ (3,369)	2

[1/] To PETITIONER'S EXHIBIT 4-E (DLD) Schedule REV1.
[2/] See: MSFR Workpaper OM6-SES.

DUKE ENERGY INDIANA, LLC

Summary of Cost of Goods Sold Forecast and Pro Forma Adjustments

(Thousands of Dollars)

			Pro Forma Adjustments						
Line No.	Description	2020 Forecast (A)	Remove Short-term Bundled Non-Native Expenses	Remove Non-Native Sales Expenses	Remove Retail Allowance Expenses	Remove Rider Related Deferrals	Total Pro Forma Adjustments (B)	2020 Forecast As Adjusted	Line No.
	Steam Production Fuel Expense:								
1	0501110-Cayuga-Coal Consumed-Fossil Steam	$ 106,621	$ -	$ -	$ -	$ -	$ -	$ 106,621	1
2	0501110-Coal Consumed-Fossil Steam	410,794	(11,234)	-	-	-	(11,234)	399,560	2
3	0501996 - Fuel Expense	32,217	-	(32,217)	-	-	(32,217)	-	3
4	Total Steam Production Fuel Expense	549,632	(11,234)	(32,217)	-	-	(43,451)	506,181	4
	Emission Allowance Expense:								
5	0509030-SO2 Emission Expense	231	-	-	(213)	-	(213)	18	5
	Other Production Fuel Expense:								
6	0547000-Fuel Expense-CT	105,303	-	-	-	-	-	105,303	6
	Purchased Power Expense:								
7	0555202-Purch Power-Fuel Clause	227,078	-	-	-	-	-	227,078	7
8	0555998 - Deferral MISO Charges and Credits	5,938	-			(5,938)	(5,938)	-	8
9	Total Purchased Power Expense	233,016	-	-	-	(5,938)	(5,938)	227,078	9
	Other Production Cost of Goods Sold:								
10	0557980-Retail Deferred Fuel Expenses	(3,866)	-	-	-	3,866	3,866	-	10
11	**Total Cost of Goods Sold Expense**	**$ 884,316**	**$ (11,234)**	**$ (32,217)**	**$ (213)**	**$ (2,072)**	**$ (45,736)**	**$ 838,580**	11
	Reference:		Schedule COGS2	Schedule COGS3	Schedule COGS4	Schedule COGS5			

DUKE ENERGY INDIANA, LLC

Pro Forma Adjustment to Fuel Expense

(Thousands of Dollars)

This pro forma adjustment is to remove fuel expense associated with short-term bundled non-native sales.

Line No.	Description	Account	2020 Forecast Amount (A)	Adjusted Amount (B)	Pro Forma Adjustment [1/] (C)	Line No.
1	Short-term bundled non-native Cost of Goods Sold [2/]	501	$ 11,234	$ -	$ (11,234)	1
2	Total		$ 11,234	$ -	$ (11,234)	2

[1/] To: Exhibit 5-B (SES) Schedule COGS1.

[2/] See: MSFR Workpaper REV1-SES

DUKE ENERGY INDIANA, LLC
Pro Forma Adjustment to Fuel Expense
(Thousands of Dollars)

This pro forma adjustment is to remove fuel expense associated with non-native wholesale sales.

Line No.	Description	Account	2020 Forecast Amount	Adjusted Amount	Pro Forma Adjustment [1/]	Line No.
			(A)	(B)	(C)	
1	Non-Native Cost of Goods Sold	501	$ 32,217	$ -	$ (32,217)	1
2	Total		$ 32,217	$ -	$ (32,217)	2

[1/] To: Exhibit 5-B (SES) Schedule COGS1.

PETITIONER'S EXHIBIT 5-B (SES)
Duke Energy Indiana 2019 Base Rate Case
Cost of Goods Sold
Schedule COGS4

DUKE ENERGY INDIANA, LLC

Pro Forma Adjustment to Emission Allowance Expense

(Thousands of Dollars)

This pro forma adjustment is to remove emission allowance expense associated with the inventory balance moved to regulatory asset in this case.

Line No.	Description	Account	2020 Forecast Amount	Adjusted Amount	Pro Forma Adjustment [1/]	Line No.
			(A)	(B)	(C)	
1	Emission Allowance Expense	509	$ 231	$ 18 [2/]	$ (213)	1
2	Total		$ 231	$ 18	$ (213)	2

[1/] To: Exhibit 5-B (SES) Schedule COGS1.

[2/] Calculation of Remaining Wholesale Emission Allowance Expense:

Forecasted 2020 Emission Allowance Expense		$ 231
Steam Net Generation Allocation Factor (SR)	0.476% [(a)]	
Retail Production Energy Allocation Factor (RR)	92.200% [(b)]	
Steam and Retail Combined Allocation Factor: (1 - SR) x RR + SR	92.237%	
Wholesale Percentage (1 - Steam and Retail Combined Allocation Factor)		7.763%
Wholesale Portion Remaining after moving Retail Balance to Regulatory Asset		$ 18

(a) See Exhibit 7-C (MTD)
(b) See Exhibit 7-B (MTD)

DUKE ENERGY INDIANA, LLC

Pro Forma Adjustment to

Operation and Maintenance Expense - RECB/MVP Projects

(Thousands of Dollars)

This pro forma adjustment is to remove the expenses associated with MISO RECB and MVP Projects.

Line No.	Description	Account	2020 Forecast Amount (A)	Adjusted Amount (B)	Pro Forma Adjustment [1/] (C) (B) - (A)	Line No.
1	Transmission O&M [2/]	560	$ 500	$ -	$ (500)	1
2	Administrative and General Expense [2/]	920	233	-	(233)	2
3	Total		$ 733	$ -	$ (733)	3

[1/] To: PETITIONER'S EXHIBIT 4-E (DLD) Schedule OM2
[2/] See: MSFR Workpaper OM6-SES

DUKE ENERGY INDIANA, LLC

Pro Forma Adjustment to

Operation and Maintenance Expense - IEA Dues

(Thousands of Dollars)

This pro forma adjustment is to remove the expenses associated with the Indiana Energy Association (IEA).

Line No.	Description	Account	2020 Forecast Amount	Adjusted Amount	Pro Forma Adjustment [1/]	Line No.
			(A)	(B)	(C) (B) - (A)	
1	Miscellaneous General Expenses	930.2	$ 711	$ -	$ (711)	1
2	Total		$ 711	$ -	$ (711)	2

[1/] To: PETITIONER'S EXHIBIT 4-E (DLD) Schedule OM2

DUKE ENERGY INDIANA, LLC

Pro Forma Adjustment to

Operation and Maintenance Expense - Brand Advertising

(Thousands of Dollars)

This pro forma adjustment is to remove the expenses associated with brand advertising.

Line No.	Description	Account	2020 Forecast Amount (A)	Adjusted Amount (B)	Pro Forma Adjustment [1/] (C) (B) - (A)	Line No.
1	Miscellaneous Advertising Expense [2/]	930.1	$ 414	$ -	$ (414)	1
2	Total		$ 414	$ -	$ (414)	2

[1/] To: PETITIONER'S EXHIBIT 4-E (DLD) Schedule OM2
[2/] See: MSFR Workpaper OM5-SES.

PETITIONER'S EXHIBIT 5-C (SES)
Duke Energy Indiana 2019 Base Rate Case
O&M
Schedule OM10

DUKE ENERGY INDIANA, LLC

Pro Forma Adjustment to

Operation and Maintenance Expense - Henry County CT

(Thousands of Dollars)

This pro forma adjustment is to remove the non-jurisdictional portion of the Henry County Combustion Turbine.

Line No.	Description	Account	2020 Forecast Amount (A)	Adjusted Amount (B)	Pro Forma Adjustment [1/] (C) (B) - (A)	Line No.
1	Suprvsn and Engrg - Steam Oper	500	$ 213	$ 135	$ (78)	1
2	Fossil Steam Exp-Other	502	9	6	(3)	2
3	Misc Fossil Power Expenses	506	34	22	(12)	3
4	Suprvsn and Engrng-Steam Maint	510	58	37	(21)	4
5	Suprvsn & Engrng-Steam Maint R	510	(1)	(1)	-	5
6	Suprvsn and Enginring-CT Oper	546	240	152	(88)	6
7	Natural Gas Handling-CT	547	15	10	(5)	7
8	Prime Movers - Generators- CT	548	621	394	(227)	8
9	Misc-Power Generation Expenses	549	336	213	(123)	9
10	Suprvsn and Enginring-CT Maint	551	53	34	(19)	10
11	Maintenance Of Structures-CT	552	68	43	(25)	11
12	Maint-Gentg and Elect Equip-CT	553	607	385	(222)	12
13	Misc Power Generation Plant-CT	554	138	88	(50)	13
14	A & G Salaries	920	64	40	(24)	14
15	Employee Expenses	921	4	3	(1)	15
16	Office Expenses	921	1	1	-	16
17	Computer Services Expenses	921	1	1	-	17
18	Outside Services Employed	923	4	3	(1)	18
19	Employee Benefits-Transferred	926	314	199	(115)	19
20	Miscellaneous Advertising Exp	930	2	1	(1)	20
21	Total		$ 2,781	$ 1,766	$ (1,015)	21
	Reference		WP OM1-SES	WP OM1-SES		

[1/] To: PETITIONER'S EXHIBIT 4-E (DLD) Schedule OM2

DUKE ENERGY INDIANA, LLC

Pro Forma Adjustment to

Operation and Maintenance Expense - Non-Utility Lighting

(Thousands of Dollars)

This pro forma adjustment is to remove the expenses associated with non-utility lighting.

Line No.	Description	Account	2020 Forecast Amount (A)	Adjusted Amount (B)	Pro Forma Adjustment [1/] (C) (B) - (A)	Line No.
1	Maint-StreetLightng/Signl-Dist	596	$ 4,448	$ 1,913	$ (2,535)	1
2	Misc Cust Serv/Inform Exp	910	423	182	(241)	2
3	Demonstrating & Selling Exp	912	787	338	(449)	3
4	Advertising Expense	913	7	3	(4)	4
5	Employee Benefits-Transferred	926	689	296	(393)	5
6	Total		$ 6,354	$ 2,732	$ (3,622)	6
	Reference			WP OM2-SES		

[1/] To: PETITIONER'S EXHIBIT 4-E (DLD) Schedule OM2

DUKE ENERGY INDIANA, LLC

Pro Forma Adjustment to

Operation and Maintenance Expense - Premier Power

(Thousands of Dollars)

This pro forma adjustment is to remove expenses associated with the Premier Power Program.

Line No.	Description	Account	2020 Forecast Amount (A)	Adjusted Amount (B)	Pro Forma Adjustment [1/] (C) (B) - (A)	Line No.
1	Exp-Rs Reg Prod/Svces-CstAccts	910	$ 157	$ -	$ (157)	1
2	Demonstrating & Selling Exp	912	428	-	(428)	2
3	Employee Benefits - Transferred	926	47	-	(47)	3
4	Total		$ 632	$ -	$ (632)	4

[1/] To: PETITIONER'S EXHIBIT 4-E (DLD) Schedule OM2

PETITIONER'S EXHIBIT 5-C (SES)
Duke Energy Indiana 2019 Base Rate Case
O&M
Schedule OM13

DUKE ENERGY INDIANA, LLC

Pro Forma Adjustment to

Operation and Maintenance Expense - Electric Vehicle Pilot

(Thousands of Dollars)

This pro forma adjustment is to remove expenses associated with the Electric Vehicle Pilot program.

Line No.	Description	Account	2020 Forecast Amount [1/] (A)	Adjusted Amount (B)	Pro Forma Adjustment [2/] (C) (B) - (A)	Line No.
1	A&G Salaries	920	$ 72	$ -	$ (72)	1
2	Outsides Services Employed	923	92	-	(92)	2
3	Employee Benefits - Transferred	926	19	-	(19)	3
4	Miscellaneous Advertising Expense	930	150	-	(150)	4
5	Total		$ 333	$ -	$ (333)	5

[1/] See: MSFR Workpaper OM4-SES.
[2/] To: PETITIONER'S EXHIBIT 4-E (DLD) Schedule OM2

DUKE ENERGY INDIANA, LLC

Pro Forma Adjustment to

Operation and Maintenance Expense - Major Storms

(Thousands of Dollars)

The following pro forma adjustment reflects a normalization of storm O&M costs.

Line No.	Description	Account	2020 Forecast Amount (A)	Adjusted Amount (B)	Pro Forma Adjustment [1/] (C) (B) - (A)	Line No.
	Storm-Related O&M Costs by FERC Account					
1	Maintenance Overhead Lines - Distr	593	$ 10,023	$ 11,169	$ 1,146	1
2	Maintenance Overhead Lines - Trans	571	-	514	514	2
3	Employee Benefits Transferred	926	4	798	794	3
4	Total		$ 10,027	$ 12,481	$ 2,454	4
	Reference			WP OM3-SES		

[1/] To: PETITIONER'S EXHIBIT 4-E (DLD) Schedule OM2

DUKE ENERGY INDIANA, LLC

Pro Forma Adjustment to

Allocated Payroll Tax Expense for RECB/MVP Projects

(Thousands of Dollars)

This pro forma adjustment is to remove allocated payroll taxes associated with the MISO RECB and MVP Projects.

Line No.	Description	2020 Forecast Amount (A)	Adjusted Amount (B)	Pro Forma Adjustment [1/] (C) (B) - (A)	Line No.
1	Account 0408960 - Allocated Payroll Taxes [2/]	$ 21	$ -	$ (21)	1
2	Total	$ 21	$ -	$ (21)	2

[1/] To PETITIONER'S EXHIBIT 4-E (DLD).
[2/] See: MSFR Workpaper OM6-SES.

DUKE ENERGY INDIANA, LLC

Pro Forma Adjustment to

Allocated Payroll Tax Expenses for WVPA Portion of the Henry County CT

(Thousands of Dollars)

This pro forma adjustment is to remove allocated payroll taxes associated with WVPA's portion of the Henry County Combustion Turbine.

Line No.	Description	2020 Forecast Amount (A)	Adjusted Amount (B)	Pro Forma Adjustment [1/] (C) (B) - (A)	Line No.
1	Account 0408960 - Allocated Payroll Taxes	$ 32	$ -	$ (32)	1
2	Total	$ 32	$ -	$ (32)	2

[1/] To PETITIONER'S EXHIBIT 4-E (DLD).

DUKE ENERGY INDIANA, LLC

Pro Forma Adjustment to

Allocated Payroll Tax Expenses for Non-Utility Lighting

(Thousands of Dollars)

This pro forma adjustment is to remove allocated payroll taxes associated with non-utility lighting programs.

Line No.	Description	2020 Forecast Amount (A)	Adjusted Amount (B)	Pro Forma Adjustment [1/] (C) (B) - (A)	Line No.
1	Account 0408960 - Allocated Payroll Taxes	$ 112	$ -	$ (112)	1
2	Total	$ 112	$ -	$ (112)	2

[1/] To PETITIONER'S EXHIBIT 4-E (DLD).

DUKE ENERGY INDIANA, LLC

Pro Forma Adjustment to
Allocated Payroll Tax Expenses for Premier Power Program

(Thousands of Dollars)

This pro forma adjustment is to remove allocated payroll taxes associated with the Premier Power Program.

Line No.	Description	2020 Forecast Amount (A)	Adjusted Amount (B)	Pro Forma Adjustment [1/] (C) (B) - (A)	Line No.
1	Account 0408960 - Allocated Payroll Taxes	$ 17	$ -	$ (17)	1
2	Total	$ 17	$ -	$ (17)	2

[1/] To PETITIONER'S EXHIBIT 4-E (DLD).

DUKE ENERGY INDIANA, LLC

Pro Forma Adjustment to

Allocated Payroll Tax Expense for Electric Vehicle Pilot Program

(Thousands of Dollars)

This pro forma adjustment is to remove allocated payroll taxes associated with the Electric Vehicle Pilot Program.
Amounts to be proposed for deferral in this proceeding.

Line No.	Description	2020 Forecast Amount (A)	Adjusted Amount (B)	Pro Forma Adjustment [1/] (C) (B) - (A)	Line No.
1	Account 0408960 - Allocated Payroll Taxes [2/]	$ 5	$ -	$ (5)	1
2	Total	$ 5	$ -	$ (5)	2

[1/] To PETITIONER'S EXHIBIT 4-E (DLD).
[2/] See: MSFR Workpaper OM4-SES.

DUKE ENERGY INDIANA, LLC

Pro Forma Adjustment to

Allocated Payroll Tax Expenses to Normalize Major Storms Costs

(Thousands of Dollars)

This pro forma adjustment is to normalize payroll taxes associated with major storm costs.

Line No.	Description	2020 Forecast Amount (A)	Adjusted Amount (B)	Pro Forma Adjustment [1/] (C) (B) - (A)	Line No.
1	Account 0408960 - Allocated Payroll Taxes	$ -	$ 221	$ 221	1
2	Total	$ -	$ 221	$ 221	2
	Reference:		WP OTX1-SES		

[1/] To PETITIONER'S EXHIBIT 4-E (DLD).

DUKE ENERGY INDIANA, LLC

Pro Forma Adjustment to Emission Allowance Inventory

(Thousands of Dollars)

Line No.	Description	Reference	Dec. 31, 2020 Balance (A)	Adjusted Amount (B)	Pro Forma Adjustment (C)	Line No.
	This pro forma adjustment is to remove the retail jurisdictional and steam portion of the SO2 native load emission allowance inventory that is being requested to be moved from inventory to a new regulatory asset.					
1	Total Native Load Emission Allowance Inventory (158)	WP RB2-SES	$ 10,733	$ 920	$ (9,813)	1
2	SO2 Deferred Purchase Costs Transferred from Inventory		$ -	$ 9,813	$ 9,813	2
3	Addback: Jul-Dec 2020 EA Consumption Expense	WP RB3-SES	-	121	121	3
4	Subtract: Jul-Dec 2020 Regulatory Asset Amortization	WP RB3-SES	-	(414)	(414)	4
5	New Regulatory Asset - SO2 Deferred Purchase Costs as of Dec. 31, 2020 (182)		$ -	$ 9,520	$ 9,520	5
6	Total Impact on Rate Base				$ (293)	6

DUKE ENERGY INDIANA, LLC

Pro Forma Adjustment to Emission Allowance Inventory

(Thousands of Dollars)

Line No.	Description	Reference	Dec. 31, 2019 Balance (A)	Adjusted Amount (B)	Pro Forma Adjustment (C)	Line No.
	This pro forma adjustment is to remove the retail jurisdictional and steam portion of the SO2 native load emission allowance inventory that is being requested to be moved from inventory to a new regulatory asset.					
1	Total Native Load Emission Allowance Inventory (158)	WP RB2-SES	$ 10,964	$ 938	$ (10,026)	1
2	SO2 Deferred Purchase Costs Transferred from Inventory		$ -	$ 10,026	$ 10,026	2
3	Addback: Jul-Dec 2020 EA Consumption Expense	WP RB3-SES	-	-	-	3
4	Subtract: Jul-Dec 2020 Regulatory Asset Amortization	WP RB3-SES	-	-	-	4
5	New Regulatory Asset - SO2 Deferred Purchase Costs as of Dec. 31, 2020 (182)		$ -	$ 10,026	$ 10,026	5
6	Total Impact on Rate Base				$ -	6

PETITIONER'S EXHIBIT 5-F (SES)
Duke Energy Indiana 2019 Base Rate Case
Cost of Goods Sold
Schedule COGS6

DUKE ENERGY INDIANA, LLC

Determination of the Base Cost of Fuel

(Thousands of Dollars)

Line No.	Description	2020 Forecast (A)	Pro Forma Adjustments (1) (B)	2020 Forecast With Pro Forma Adjustments (C)	Line No.
	FUEL COST				
1	Steam Generation	$ 440,640			1
2	Hydro and Solar Generation	-			2
	Other Generation				
3	Internal Combustion	-			3
4	Gas Combustion Turbine	79,125			4
5	Integrated Gasification Combined Cycle	102,953			5
6	Purchased Power	188,295			6
7	Net RTO Energy Market	28,871			7
8	Net RTO Ancillary Services Market	-			8
	Less:				
9	Steam Sales	4,079			9
10	Total Fuel Cost (F)	$ 835,805	$ (11,234)	$ 824,571	10
	SALES (MWH)				
11	Steam Generation	18,620,243			11
12	Hydro and Solar Generation	355,573			12
	Other Generation				
13	Internal Combustion	-			13
14	Gas Combustion Turbine	3,281,271			14
15	Integrated Gasification Combined Cycle	4,136,944			15
16	Purchased Power	6,286,726			16
	Less:				
17	Losses & Company Use	1,650,840			17
18	Total Sales (S)	31,029,917	(439,200)	30,590,717	18
19	Proposed Base Cost of Fuel ($/MWH) (F/S)			26.955	19

(1) ProForma adjustments reflects removal of fuel expense and associated MWH sales for short-term bundled non-native sale being moved from the FAC rider to the Reliability rider (see Schedule COGS-2).

Duke Energy Indiana, LLC
1000 East Main Street
Plainfield, Indiana 46168

IURC No. 1~~5~~4
~~Sixty-first~~ Original ~~Revised~~ Sheet No. 60
~~Canceling Sixtieth Revised Sheet No. 60~~

STANDARD CONTRACT RIDER NO. 60 -
FUEL COST ADJUSTMENT ~~APPLICABLE~~
~~TO ALL RETAIL RATE SCHEDULES~~

Calculation of Adjustment

A. The applicable charges for electric service to the Company's retail customers shall be increased or decreased, to the nearest 0.001 mill ($.000001) per KWH to recover and/or credit the cost for fuel in accordance with the following formula:

Fuel Cost Adjustment Factor = F/S — ~~$0.014484~~BF

where:

1. "F" is the estimated expense of fuel based on a three-month average cost beginning with the first month of the billing cycle and consisting of the following costs:

   (a) the average cost of fossil fuel consumed due to the operation of Company's own generating units incurred to serve native load customers, including only those items listed in Account 151, of the Federal Energy Regulatory Commission's Uniform System of Accounts for Class A and B Public Utilities and Licensees ~~(FERC US of A)~~;

   (b) the actual identifiable fossil ~~and nuclear~~ fuel costs, or, if fuel costs are not specifically identified, costs computed in accordance with applicable Commission Orders, associated with energy purchased or transferred to serve native load customers for reasons other than identified in (c) below;

   (c) the net energy cost, exclusive of capacity or demand charges, of energy purchased or transferred to serve native load customers on an economic dispatch basis, and energy purchased or transferred to serve native load customers resulting from the scheduled outage of a Company owned generating unit, when the costs thereof are less than the Company's fuel costs of replacement net generating from its own system, as computed in accordance with applicable Commission Orders;~~.~~

   (d) fuel-related Regional Transmission Operator ("RTO") costs and credits approved by the Commission for recovery in the FCA;

   ~~(d)~~(e) other revenues or costs approved by the Commission for recovery in this rider.

2. "S" is the estimated kilowatt-hour sales ~~as recorded on the Company's books and records in accordance with the FERC US of A~~ for the same estimated period set forth in "F."

3. "BF" is the base cost of fuel pursuant to the Commission's Order in Cause No. XXXXX equal to $0.026955 per kWh.

Issued: Effective:

Duke Energy Indiana, LLC
1000 East Main Street
Plainfield, Indiana 46168

IURC No. 1~~5~~4
~~Sixty-first~~ Original ~~Revised~~ Sheet No. 60
~~Canceling Sixtieth Revised Sheet No. 60~~

STANDARD CONTRACT RIDER NO. 60 -
FUEL COST ADJUSTMENT
~~APPLICABLE TO ALL RETAIL RATE SCHEDULES~~

~~B. The factor as computed above shall be modified to allow the recovery of utility receipts taxes and/or other similar revenue based taxes incurred due to the recovery of fuel costs.~~

~~C.~~B. The factor shall be further modified commencing with the fifth succeeding billing cycle month to reflect the difference between the estimated incremental fuel cost billed and the incremental fuel cost actually incurred during the first and succeeding billing cycle month(s) in which such estimated incremental fuel cost was billed.

~~D~~C. Effective for all bills rendered beginning with and subsequent to the later of the effective date of the Commission's Order or the first billing cycle of ______ ______ the fuel cost adjustment shall be:

$0.000000 per kilowatt-hour.

~~E. From time to time, and subject to approval of the Commission, the factor shall be further modified to include the separate recovery, pursuant to Ind. Code 8-1-2-42(a), of costs applicable to certain power purchases in excess of the monthly purchased power benchmark.~~

Duke Energy Indiana, LLC
1000 East Main Street
Plainfield, Indiana 46168

IURC No. 15
Original Sheet No. 60

STANDARD CONTRACT RIDER NO. 60 -
FUEL COST ADJUSTMENT

Calculation of Adjustment

A. The applicable charges for electric service to the Company's retail customers shall be increased or decreased, to the nearest 0.001 mill ($.000001) per KWH to recover and/or credit the cost for fuel in accordance with the following formula:

Fuel Cost Adjustment Factor = F/S — BF

where:

1. "F" is the estimated expense of fuel based on a three-month average cost beginning with the first month of the billing cycle and consisting of the following costs:

   (a) the average cost of fossil fuel consumed due to the operation of Company's own generating units incurred to serve native load customers, including only those items listed in Account 151, of the Federal Energy Regulatory Commission's Uniform System of Accounts for Class A and B Public Utilities and Licensees;

   (b) the actual identifiable fossil fuel costs, or, if fuel costs are not specifically identified, costs computed in accordance with applicable Commission Orders, associated with energy purchased or transferred to serve native load customers for reasons other than identified in (c) below;

   (c) the net energy cost, exclusive of capacity or demand charges, of energy purchased or transferred to serve native load customers on an economic dispatch basis, and energy purchased or transferred to serve native load customers resulting from the scheduled outage of a Company owned generating unit, when the costs thereof are less than the Company's fuel costs of replacement net generating from its own system, as computed in accordance with applicable Commission Orders;

   (d) fuel-related Regional Transmission Operator ("RTO") costs and credits approved by the Commission for recovery in the FCA;

   (e) other revenues or costs approved by the Commission for recovery in this rider.

2. "S" is the estimated kilowatt-hour sales for the same estimated period set forth in "F."

3. "BF" is the base cost of fuel pursuant to the Commission's Order in Cause No. XXXXX equal to $0.026955 per kWh.

B. The factor shall be further modified commencing with the fifth succeeding billing cycle month to reflect the difference between the estimated incremental fuel cost billed and the incremental fuel cost actually incurred during the first and succeeding billing cycle month(s) in which such estimated incremental fuel cost was billed.

C. Effective for all bills rendered beginning with and subsequent to the later of the effective date of the Commission's Order or the first billing cycle of _______ _______ the fuel cost adjustment shall be:

$0.000000 per kilowatt-hour.

Issued: Effective:

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

STANDARD CONTRACT RIDER NO. 68
~~MIDCONTINENT INDEPENDENT SYSTEM OPERATOR ("MISO")~~
~~MANAGEMENT COST~~ REGIONAL TRANSMISSION OPERATOR ("RTO") NON-FUEL COSTS AND REVENUE ADJUSTMENT
~~APPLICABLE TO RETAIL RATE GROUPS~~

The applicable charges for electric service to the Company's retail electric customers shall be increased or decreased for operation and maintenance expense treatment of ~~MISO Management Cost~~RTO Non-Fuel Costs and Revenues ~~received from the MISO~~. The revenue adjustment to the applicable charges for electric service will be determined under the following provision:

Calculation of Adjustment

A. The ~~MISO Management Cost~~RTO Non-Fuel Costs and Revenue Adjustment by Rate Group shall be determined by multiplying the ~~MISO Management Cost~~RTO Non-Fuel Costs and Revenue Adjustment Factor, as determined to the nearest 0.001 mill ($0.000001) per kilowatt-hour in accordance with the following formula, by the monthly billed kilowatt-hours for the applicable billing cycle months in the case of customers receiving metered service and by the estimated monthly kilowatt-hours used for rate determination in the case of customers receiving unmetered service. ~~MISO Management Cost~~RTO Non-Fuel Costs and Revenue Adjustment Factor Per Rate Group =

~~[((a + b + c + d - e) – ($5,556,000 - $10,904,000)) h] f~~(NFC – (a – b) c) d
~~g~~s

where:

1. "NFC" is the net Non-Fuel ~~"a" is the MISO Mangagement~~ Costs and Credits forecasted to be billed Duke Energy Indiana, LLC, or a designee of Duke for mandated participation in regional transmission organizations ~~, under Service Schedule 10 – ISO Cost Recovery Adder~~ under~~of~~ the Open Access Transmission and Energy Markets Tariff for the MISO ("MISO TEMT") or any successor Tariff, including applicable PJM non-fuel charges and credits related to the operation of Duke Energy Indiana's Madison Generating Station.

2. "a~~b~~" is the annual level of forecasted RTO Non-Fuel ~~MISO Management~~Costs included in the determination of basic charges for service in Cause No. XXXXX ($67,936,000)~~forecasted to be billed Duke Energy Indiana, LLC, or a designee of Duke, under Service Schedule 16 – Financial Transmission Rights Administrative Service Cost Recovery Adder of the MISO TEMT or any successor Tariff~~.

3. "b~~c~~" is the annual level of forecasted RTO transmission revenues included in the determination of basic charges for service in Cause No. XXXXX ($4,222,000)~~MISO Management Costs forecasted to be billed Duke Energy Indiana, LLC, or a designee of Duke, under Service Schedule 17 – Energy and Operating Reserve Markets Market Support Administrative Service Cost Recovery Adder of the MISO TEMT or any successor tariff~~.

~~4. "d" is the MISO Standard Market Design Costs forecasted to be billed Duke Energy Indiana, LLC, or a designee of Duke, or other Government mandated transmission costs Duke Energy Indiana, LLC, or a designee of Duke, is required to pay on behalf of retail customers.~~
~~5.~~

STANDARD CONTRACT RIDER NO. 68
~~MIDCONTINENT INDEPENDENT SYSTEM OPERATOR ("MISO")~~
~~MANAGEMENT COST~~ REGIONAL TRANSMISSION OPERATOR ("RTO") NON-FUEL COSTS AND REVENUE ADJUSTMENT
~~APPLICABLE TO RETAIL RATE GROUPS~~

~~6. "e" is the MISO transmission revenues assigned to the Company, forecasted to be collected by the MISO under the MISO TEMT or any successor Tariff.~~

~~7. $5,556,000 is the annual pro forma level of MISO Management Costs of which the jurisdictional electric allocated share is included by the Company in Cause No. 42359 in the determination of basic charges for service in its Electric Tariff.~~

~~8. $10,904,000 is the annual pro forma level of MISO transmission revenues, of which the jurisdictional electric allocated share is included by the Company in Cause No. 42359 in the determination of basic charges for services in its Electric Tariff.~~

4. "c~~f~~" is the individual retail rate group's allocated share of the Company's retail peak demand developed for cost of service purposes in Cause No. XXXXX~~42359~~ expressed as a percentage of the Company's total retail peak demand~~, as adjusted for rate migrations between HLF and LLF rate classes and migrations of AL and OL rate classes to the UOLS rate class.~~

~~9.~~5. "d" is the revenue conversion factor used to convert the applicable charges to operating revenues.

~~10.~~6. "s~~g~~" is the individual retail rate group's reported kilowatt-hour sales for the twelve~~- (12)~~ month period from July through June as a proxy for the relevant billing cycle months for all retail rate groups other than retail customers served under Rate HLF. The revenue adjustment for retail customers served under Rate HLF shall be based on demands within the Rate HLF customer group such that "s" shall be the sum of kilowatts billed for the applicable twelve-month period.

~~11. "h" is the revenue conversion factor used to convert the applicable charges to operating revenues.~~

~~12.~~7. The ~~MISO Management Cost~~RTO Non-Fuel Costs ~~Adjustment~~ and Revenue Adjustment Factor per Rate Group shall be further modified to reflect the difference between the incremental base monthly fees actually charged or credited to the retail electric customers and the incremental base monthly fees to be charged or credited to the retail electric customers during billing cycle months, as determined above.

STANDARD CONTRACT RIDER NO. 68
REGIONAL TRANSMISSION OPERATOR ("RTO") NON-FUEL COSTS AND REVENUE ADJUSTMENT

The applicable charges for electric service to the Company's retail electric customers shall be increased or decreased for operation and maintenance expense treatment of RTO Non-Fuel Costs and Revenues. The revenue adjustment to the applicable charges for electric service will be determined under the following provision:

Calculation of Adjustment

A. The RTO Non-Fuel Costs and Revenue Adjustment by Rate Group shall be determined by multiplying the RTO Non-Fuel Costs and Revenue Adjustment Factor, as determined to the nearest 0.001 mill ($0.000001) per kilowatt-hour in accordance with the following formula, by the monthly billed kilowatt-hours for the applicable billing cycle months in the case of customers receiving metered service and by the estimated monthly kilowatt-hours used for rate determination in the case of customers receiving unmetered service. RTO Non-Fuel Costs and Revenue Adjustment Factor Per Rate Group =

$$\frac{(NFC - (a - b)\ c)\ d}{s}$$

where:

1. "NFC" is the net Non-Fuel Costs and Credits forecasted to be billed Duke Energy Indiana, LLC, or a designee of Duke for mandated participation in regional transmission organizations under the Open Access Transmission and Energy Markets Tariff for the MISO ("MISO TEMT") or any successor Tariff, including applicable PJM non-fuel charges and credits related to the operation of Duke Energy Indiana's Madison Generating Station.

2. "a" is the annual level of forecasted RTO Non-Fuel Costs included in the determination of basic charges for service in Cause No. XXXXX ($67,936,000).

3. "b" is the annual level of forecasted RTO transmission revenues included in the determination of basic charges for service in Cause No. XXXXX ($4,222,000).

4. "c" is the individual retail rate group's allocated share of the Company's retail peak demand developed for cost of service purposes in Cause No. XXXXX expressed as a percentage of the Company's total retail peak demand.

5. "d" is the revenue conversion factor used to convert the applicable charges to operating revenues.

6. "s" is the individual retail rate group's reported kilowatt-hour sales for the twelve-month period from July through June as a proxy for the relevant billing cycle months for all retail rate groups other than retail customers served under Rate HLF. The revenue adjustment for retail customers served under Rate HLF shall be based on demands within the Rate HLF customer group such that "s" shall be the sum of kilowatts billed for the applicable twelve-month period.

7. The RTO Non-Fuel Costs and Revenue Adjustment Factor per Rate Group shall be further modified to reflect the difference between the incremental base monthly fees actually charged or credited to the retail electric customers and the incremental base monthly fees to be charged or credited to the retail electric customers during billing cycle months, as determined above.

Duke Energy Indiana, LLC
1000 East Main Street
Plainfield, Indiana 46168

STANDARD CONTRACT RIDER NO. 70 -
RELIABILITY ADJUSTMENT
~~**APPLICABLE TO ALL RETAIL RATE SCHEDULES**~~

Calculation of Adjustment

A. The applicable charges for electric service to the Company's retail electric customers shall be increased or decreased, to the nearest 0.001 mill ($0.000001) per kWh to recover and/or credit the net jurisdictional cost of reliability purchases, peak load management costs, and net profits from non-native sales, in accordance with the following formula:

Reliability Adjustment Factor:

$$\left((a*c)d+(b*d)-\left(\frac{(e*c)\cancel{-\$14{,}747{,}000}}{2}\right)d\right)*\left(\frac{1}{s}\right)$$

where:

1. "a" equals year-round purchased power capacity costs (i.e., total cost of purchases, less fuel costs attributable to such purchases recoverable via Standard Contract Rider No. 60) associated with reliability purchases as approved by the Commission. The total cost of reliability purchases shall include all charges relating to such purchases including, but not limited to, transmission, demand, capacity, reservation, and/or, option payments, or other equivalent charges, including profits thereon.

2. "b" is the total year-round amount of bill credit provided to customers under the Company's PowerShare® program including any additional demand response amounts determined to be includable by the Commission, less the annual level built into base rates in Cause No. XXXXX~~42359~~ ($9,911,000~~1,023,000~~).

3. "c" is the total retail rate group's allocated percentage share of the Company's average twelve monthly coincident system peak demands as developed for cost of service purposes in Cause No. XXXXX~~42359~~.

4. "d" is the individual retail rate group's allocated percentage share of the Company's average four~~twelve~~ monthly coincident retail peak demands as developed for cost of service purposes in Cause No. XXXXX~~42359, as adjusted for rate migration between HLF and LLF rate classes, between the AL, OL, and UOLS rate classes and the Customer D move to LLF~~.

5. "e" represents actual net profits realized from non-native sales, including short-term bundled non-native bundled sales, which shall not be less than zero. ~~Actual non-native sales revenues shall be reduced by a fixed trading expense value of $3,953,000.~~

6. "s" represents actual monthly kilowatt-hour sales by individual retail rate groups for the applicable twelve-month period for all retail rate groups other than retail customers served under Rate HLF. The revenue adjustment for retail customers served under Rate HLF shall be based on demands within the Rate HLF customer group such that "s" shall be the sum of kilowatts billed for the applicable twelve-~~-~~month~~s ended May 31, 2018~~ period.

Duke Energy Indiana, LLC
1000 East Main Street
Plainfield, Indiana 46168

STANDARD CONTRACT RIDER NO. 70 -
RELIABILITY ADJUSTMENT
~~APPLICABLE TO ALL RETAIL RATE SCHEDULES~~

B. The factor as computed above shall be modified to allow for the recovery of the public utility fee and uncollectible expense~~utility receipts taxes~~ and/or other similar revenue based taxes incurred due to the recovery of net reliability costs.

C. The factor shall be further modified to reflect the reconciliation of annual net costs approved for recovery, by retail rate group, and actual annual amounts billed customers.

D. The reliability factor by rate group is as follows:

Duke Energy Indiana, LLC
1000 East Main Street
Plainfield, Indiana 46168

IURC No. 15
Original Sheet No. 70
Page 1 of 3

STANDARD CONTRACT RIDER NO. 70 -
RELIABILITY ADJUSTMENT

Calculation of Adjustment

A. The applicable charges for electric service to the Company's retail electric customers shall be increased or decreased, to the nearest 0.001 mill ($0.000001) per kWh to recover and/or credit the net jurisdictional cost of reliability purchases, peak load management costs, and net profits from non-native sales, in accordance with the following formula:

Reliability Adjustment Factor:

$$\left((a*c)d+(b*d)-\left(\frac{(e*c)}{2}\right)d\right)*\left(\frac{1}{s}\right)$$

where:

1. "a" equals year-round purchased power capacity costs (i.e., total cost of purchases, less fuel costs attributable to such purchases recoverable via Standard Contract Rider No. 60) associated with reliability purchases as approved by the Commission. The total cost of reliability purchases shall include all charges relating to such purchases including, but not limited to, transmission, demand, capacity, reservation, and/or, option payments, or other equivalent charges, including profits thereon.

2. "b" is the total year-round amount of bill credit provided to customers under the Company's PowerShare® program including any additional demand response amounts determined to be includable by the Commission, less the annual level built into base rates in Cause No. XXXXX ($9,911,000).

3. "c" is the total retail rate group's allocated percentage share of the Company's average twelve monthly coincident system peak demands as developed for cost of service purposes in Cause No. XXXXX.

4. "d" is the individual retail rate group's allocated percentage share of the Company's average four monthly coincident retail peak demands as developed for cost of service purposes in Cause No. XXXXX.

5. "e" represents actual net profits realized from non-native sales, including short-term bundled non-native sales, which shall not be less than zero.

6. "s" represents actual monthly kilowatt-hour sales by individual retail rate groups for the applicable twelve-month period for all retail rate groups other than retail customers served under Rate HLF. The revenue adjustment for retail customers served under Rate HLF shall be based on demands within the Rate HLF customer group such that "s" shall be the sum of kilowatts billed for the applicable twelve-month period.

B. The factor as computed above shall be modified to allow for the recovery of the public utility fee and uncollectible expense and/or other similar revenue based taxes incurred due to the recovery of net reliability costs.

C. The factor shall be further modified to reflect the reconciliation of annual net costs approved for recovery, by retail rate group, and actual annual amounts billed customers.

D. The reliability factor by rate group is as follows:

Duke Energy Indiana, LLC
~~14~~15
1000 East Main Street
Plainfield, Indiana 46168

STANDARD CONTRACT RIDER NO. 73 --
RENEWABLE ENERGY
PROJECT ~~REVENUE~~ ADJUSTMENT
~~APPLICABLE TO RETAIL RATE GROUPS~~

Calculation of Adjustment

The applicable charges for electric service to the Company's retail electric customers shall be increased or decreased to the nearest 0.001 mill ($.000001) per kWh to reflect rate base treatment for investments in utility-owned renewable energy projects approved by the Commission as clean energy projects under Indiana Code 8-1-8.8 ("Renewable Energy Projects") and recovery of related Renewable Energy Projects operating costs (depreciation, property taxes, operation and maintenance, etc.). The revenue adjustment applicable to the Company's charges for electric service will be determined based on the following provisions:

Renewable Energy
Project ~~Revenue~~ Adjustment Factor by Rate Group =

$$\frac{[(a \times b \times c) + (e + f + g + h - i)] \times d}{j}$$

Where:

1. "a" is the jurisdictional cost of the Company's cumulative capital investment in Renewable Energy Projects, including costs of completed capital projects, costs of capital projects under construction and applicable post-in-service carrying costs, net of accumulated depreciation at applicable cut-off dates. For purposes of determining the value of such capital projects for this rate mechanism, the Company's cost as recorded in its books of account in accordance with the Uniform System of Accounts prescribed for Public Utilities and Licensees subject to the provisions of the Federal Power Act shall be used, subject to any limits approved by the Commission.

2. "b" is the Company's weighted average cost of capital in accordance with Commission rule 170 IAC 4-6-14 as of the date of valuation of the Renewable Energy Projects.

3. "c" is the revenue conversion factor used to convert return to operating revenues.

4. "d" is the individual retail rate group's jurisdictional production demand allocator used for allocation purposes in the cost of service study last approved by the Commission, as adjusted for rate migrations ~~between HLF and LLF rate classes and migrations of AL and OL rate classes to the UOLS rate class~~approved by the Commission.

Duke Energy Indiana, LLC
~~14~~15
1000 East Main Street
Plainfield, Indiana 46168

STANDARD CONTRACT RIDER NO. 73 --
RENEWABLE ENERGY
PROJECT ~~REVENUE~~ ADJUSTMENT
~~APPLICABLE TO RETAIL RATE GROUPS~~

5. "e" is the twelve-month forecasted jurisdictional depreciation expense applicable to the Renewable Energy Projects using Commission-approved depreciation rates converted to revenue requirements.

6. "f" is the sum of the twelve-month forecasted jurisdictional operating expenses applicable to the Renewable Energy Projects which shall include operation and maintenance expenses, property insurance expenses, real estate and property taxes, payroll taxes, and employee benefit costs converted to revenue requirements.

7. "g" is the jurisdictional portion of federal investment tax credits applicable to the Renewable Energy Projects, amortized by the Company during the applicable twelve-month ended period, converted to revenue requirements.

8. "h" is the actual jurisdictional portion of amortizations, approved by the Commission, that were recorded during the applicable twelve-month ended period converted to revenue requirements.

9. "i" is the actual jurisdictional portion of net renewable energy credit ("REC") proceeds from any sales during the applicable twelve-month ended period converted to revenue requirements.

10. "j" is the individual retail rate group's adjusted billing cycle kilowatt-hour sales for the applicable twelve-month period for all retail rate groups other than industrial customers served under Rate HLF. The revenue adjustment for industrial customers served under Rate HLF shall be based on demands within the HLF customer group such that "k" shall be the sum of kilowatts billed for the same twelve-month period.

The factor shall be further modified to reflect the difference between estimated operating costs billed and operating costs actually incurred for those costs that are recovered on a projected basis and to reflect the difference between operating costs and credits actually incurred, including return revenue requirements, ~~and~~ operating costs, ~~and~~ credits, and return collected from customers for operating costs and credits that are recovered on an actual basis.

Issued: ~~June 27, 2018~~

Effective: ~~July 2018 – Billing Cycle 1~~

STANDARD CONTRACT RIDER NO. 73 --
RENEWABLE ENERGY
PROJECT ~~REVENUE~~ ADJUSTMENT
~~**APPLICABLE TO RETAIL RATE GROUPS**~~

The Renewable Energy Project ~~revenue a~~Adjustment factor applicable to retail rate groups shall be as follows:

Duke Energy Indiana, LLC
1000 East Main Street
Plainfield, Indiana 46168

IURC No. 15
Original Sheet No. 73

STANDARD CONTRACT RIDER NO. 73 --
RENEWABLE ENERGY
PROJECT ADJUSTMENT

Calculation of Adjustment

The applicable charges for electric service to the Company's retail electric customers shall be increased or decreased to the nearest 0.001 mill ($.000001) per kWh to reflect rate base treatment for investments in utility-owned renewable energy projects approved by the Commission as clean energy projects under Indiana Code 8-1-8.8 ("Renewable Energy Projects") and recovery of related Renewable Energy Projects operating costs (depreciation, property taxes, operation and maintenance, etc.). The revenue adjustment applicable to the Company's charges for electric service will be determined based on the following provisions:

Renewable Energy
Project Adjustment Factor by Rate Group =

$$\frac{[(a \times b \times c) + (e + f + g + h - i)] \times d}{j}$$

Where:

1. "a" is the jurisdictional cost of the Company's cumulative capital investment in Renewable Energy Projects, including costs of completed capital projects, costs of capital projects under construction and applicable post-in-service carrying costs, net of accumulated depreciation at applicable cut-off dates. For purposes of determining the value of such capital projects for this rate mechanism, the Company's cost as recorded in its books of account in accordance with the Uniform System of Accounts prescribed for Public Utilities and Licensees subject to the provisions of the Federal Power Act shall be used, subject to any limits approved by the Commission.

2. "b" is the Company's weighted average cost of capital in accordance with Commission rule 170 IAC 4-6-14 as of the date of valuation of the Renewable Energy Projects.

3. "c" is the revenue conversion factor used to convert return to operating revenues.

4. "d" is the individual retail rate group's jurisdictional production demand allocator used for allocation purposes in the cost of service study last approved by the Commission, as adjusted for rate migrations approved by the Commission.

STANDARD CONTRACT RIDER NO. 73 --
RENEWABLE ENERGY
PROJECT ADJUSTMENT

5. "e" is the twelve-month forecasted jurisdictional depreciation expense applicable to the Renewable Energy Projects using Commission-approved depreciation rates converted to revenue requirements.

6. "f" is the sum of the twelve-month forecasted jurisdictional operating expenses applicable to the Renewable Energy Projects which shall include operation and maintenance expenses, property insurance expenses, real estate and property taxes, payroll taxes, and employee benefit costs converted to revenue requirements.

7. "g" is the jurisdictional portion of federal investment tax credits applicable to the Renewable Energy Projects, amortized by the Company during the applicable twelve-month ended period, converted to revenue requirements.

8. "h" is the actual jurisdictional portion of amortizations, approved by the Commission, that were recorded during the applicable twelve-month ended period converted to revenue requirements.

9. "i" is the actual jurisdictional portion of net renewable energy credit ("REC") proceeds from any sales during the applicable twelve-month ended period converted to revenue requirements.

10. "j" is the individual retail rate group's adjusted billing cycle kilowatt-hour sales for the applicable twelve-month period for all retail rate groups other than retail customers served under Rate HLF. The revenue adjustment for retail customers served under Rate HLF shall be based on demands within the HLF customer group such that "k" shall be the sum of kilowatts billed for the same twelve-month period.

The factor shall be further modified to reflect the difference between estimated operating costs billed and operating costs actually incurred for those costs that are recovered on a projected basis and to reflect the difference between operating costs and credits actually incurred, including return revenue requirements, operating costs, credits, and return collected from customers for operating costs and credits that are recovered on an actual basis.

The Renewable Energy Project Adjustment factor applicable to retail rate groups shall be as follows:

Summary of Exhibits and Supporting Workpapers
for Witness Suzanne E. Sieferman

Line No	Exhibit Number	Schedule Number	Schedule Description	Work Paper Reference Number	MSFR Reference Number	Line No
1	Exhibit 5-A (SES)	REV4	Remove revenues for non-native sales			1
2		REV5	Remove revenues for short-term bundled non-native sales	REV1-SES	1-5-8(a)(2)	2
3		REV6	Remove other revenues for RECB/MVP projects	OM6-SES	1-5-8(a)(2)	3
4	Exhibit 5-B (SES)	COGS2	Remove fuel expense for short-term bundled non-native sales	REV1-SES	1-5-8(a)(2)	4
5		COGS3	Remove fuel expense for non-native sales			5
6		COGS4	Remove EA expense for native SO2 Eas moved to Reg Asset	RB3-SES	1-5-8(a)(2)	6
7	Exhibit 5-C (SES)	OM3	Remove expenses associated with RECB/MVP projects	OM6-SES	1-5-8(a)(2)	7
8		OM8	Remove expenses associated with IEA			8
9		OM9	Remove expenses for brand advertising	OM5-SES	1-5-8(a)(2)	9
10		OM10	Remove expenses for non-jurisdictional portion of Henry Co. CT	OM1-SES	1-5-8(a)(2)	10
11		OM11	Remove expenses associated with non-utility lighting	OM2-SES	1-5-8(a)(2)	11
12		OM12	Remove expenses associated with Premier Power program			12
13		OM13	Remove expenses associated with proposed electric transportation pilot program	OM4-SES	1-5-8(a)(2)	13
14		OM18	Normalize major storm expense	OM3-SES	1-5-8(a)(2)	14
15		OTX6	Remove other tax expense for RECB/MVP projects	OM6-SES	1-5-8(a)(2)	15
16		OTX9	Remove other tax expense for non-jurisdictional portion of Henry County	OM1-SES	1-5-8(a)(2)	16
17		OTX10	Remove other tax expense for non-utility lighting programs	OM2-SES	1-5-8(a)(2)	17
18		OTX11	Remove other tax expense for Premier Power program			18
19		OTX12	Remove other tax expense for electric transportation pilot program	OM4-SES	1-5-8(a)(2)	19
20		OTX14	Adjust other tax expense for Major Storm normalization	OM3-SES	1-5-8(a)(2)	20
21	Exhibit 5-D (SES)	RB-3	Move native SO2 inventory balance from rate base to regulatory asset	RB2-SES; RB3-SES	1-5-9(a)(1)	21
22	Exhibit 5-E (SES)	RB19-3	Move native SO2 inventory balance from rate base to regulatory asset for 2019	RB2-SES; RB3-SES	1-5-9(a)(1)	22
23	Exhibit 5-F (SES)	COGS6	Base Cost of Fuel			23
24	Exhibit 5-G (SES)		Rider 60 Red-line Tariff			24
25	Exhibit 5-H (SES)		Rider 60 Clean Tariff			25
26	Exhibit 5-I (SES)		Rider 68 Red-line Tariff			26
27	Exhibit 5-J (SES)		Rider 68 Clean Tariff			27
28	Exhibit 5-K (SES)		Rider 70 Red-line Tariff			28
29	Exhibit 5-L (SES)		Rider 70 Clean Tariff			29
30	Exhibit 5-M (SES)		Rider 73 Red-line Tariff			30
31	Exhibit 5-N (SES)		Rider 73 Clean Tariff			31
32	Exhibit 5-O (SES)		Summary of Exhibits and Supporting Workpapers			32

VERIFICATION

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

Signed: ______________________
Suzanne E. Sieferman

Dated: 7/2/2019