FILED
March 30, 2020
INDIANA UTILITY
REGULATORY COMMISSION

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**

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR'S PROPOSED ORDER

Comes now, the Indiana Office of Consumer Counselor, by counsel, hereby submits its Proposed Order to the Commission for its approval.

Respectfully submitted,

____
Scott C. Franson
Attorney No. 27839-49
Deputy Consumer Counselor

CERTIFICATE OF SERVICE

The undersigned counsel hereby certifies that a copy of the OUCC's Proposed Order was served upon the following via electronic mail on this 30th day of March, 2020:

DEI
Kelley A. Karn
Melanie D. Price
Elizabeth A. Herriman
Andrew J. Wells
Duke Energy Business Services, LLC
kelley.karn@duke-energy.com
melanie.price@duke-energy.com
beth.herriman@duke-energy.com
andrew.wells@duke-energy.com

Kay E. Pashos
Mark R. Alson
Ice Miller LLP
kay.pashos@icemiller.com
mark.alson@icemiller.com

Nucor
Anne E. Becker
Amanda Tyler
Ellen Tennant
Lewis & Kappes, P.C.
abecker@Lewis-Kappes.com
atyler@Lewis-Kappes.com
etennant@Lewis-Kappes.com

Peter J. Mattheis
Shaun C. Mohler
Stone Mattheis Xenopoulos & Brew, PC
pjm@smxblaw.com
smohler@smxblaw.com

SDI
Robert K. Johnson, Esq.
rjohnson@utilitylaw.us

Damon E. Xenopoulos
Stone Mattheis Xenopoulos & Brew, PC
dex@smxblaw.com

ChargePoint
David T. McGimpsey
Dentons Bingham Greenebaum LLP
David.mcgimpsey@dentons.com

INDUSTRIAL GROUP
Tabitha L. Balzer
Aaron A. Schmoll
Todd A Richardson
Lewis & Kappes, P.C.
TBalzer@Lewis-Kappes.com
ASchmoll@LewisKappes.com
trichardson@LewisKappes.com

CAC, INCAA, EWG
Jennifer A. Washburn
Citizens Action Coalition of Indiana, Inc.
jwashburn@citact.org

Wabash Valley
Randolph G. Holt
Jeremy Fetty
Liane K. Steffes
r_holt@wvpa.com
jfetty@parrlaw.com
lsteffes@parrlaw.com

Sierra Club
Kathryn A. Watson
Cantrell Strenski & Mehringer, LLP
kwatson@csmlawfirm.com
Tony Mendoza
Joshua Smith
Kristin A. Henry
tony.mendoza@sierraclub.org
joshua.smith@sierraclub.org
kristin.henry@sierraclub.org

Kroger
Kurt J. Boehm, Esq.
Jody Kyler Cohn
Boehm, Kurtz & Lowry
kboehm@bkllawfirm.com
JKylerCohn@BKLlawfirm.com

Kevin Higgins
Energy Strategies, LLC
khiggins@energystrat.com

John P. Cook
John Cook & Associates
john.cookassociates@earthlink.net

EARTHJUSTICE
Shannon Fisk
Melissa Legge
sfisk@earthjustice.org
mlegge@earthjustice.org

Walmart
Eric E. Kinder
Barry A. Naum
Spilman Thomas & Battle, PLLC
ekinder@spilmanlaw.com
bnaum@spilmanlaw.com

FEA Dept. of Navy
Shannon M. Matera, Esq.
NAVFAC Southwest, Dept. of the Navy
Shannon.Matera@navy.mil

Cheryl Ann Stone, Esq.
NSWC Crane, Dept. of the Navy
cheryl.stone1@navy.mil

Kay Davoodi
Larry Allen
Utility Rates and Studies Office
NAVFAC HQ, Dept. of the Navy
Khojasteh.Davoodi@navy.mil
larry.r.allen@navy.mil

Hoosier Energy
Christopher M. Goffinet
Huber Goffinet & Hagedorn
cgoffinet@hepn.com

Mike Mooney
Hoosier Energy REC, Inc.
mmooney@hepn.com

ICC
Jeffery A. Earl
Bose McKinney LLP
jearl@boselaw.com

ILDC
Neil E. Gath
Gath Law Office
ngath@gathlaw.com

Erin Hutson
LIUNA
ehutson@liuna.org

Zeco Systems d/b/a Greenlots
Erin C. Borissov
Parr Richey
eborissov@wvpa.com

OUCC Consultants
David J. Garrett
Resolve Utility Consulting PLLC
dgarrett@resolveuc.com

Glenn A. Watkins
Jennifer R. Dolen
Technical Associates, Inc.
watkinsg@tai-econ.com
jenny.dolen@tai-econ.com

Lane Kollen
J. Kennedy & Associates
lkollen@jkenn.com

David Dismukes
Julie McKenna
Acadian Consulting
daviddismukes@acadianconsulting.com
juliemckenna@acadianconsulting.com

Scott C. Franson
Deputy Consumer Counselor

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
PNC CENTER
115 West Washington Street, Suite 1500 South
Indianapolis, IN 46204
infomgt@oucc.in.gov
317/232-2494 – Telephone
317/232-5923 – Facsimile

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

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OFFICE OF UTILITY CONSUMER COUNSELOR'S PROPOSED FORM OF ORDER

Presiding Officers:
James F. Huston, Chairman
Sarah E. Freeman, Commissioner
David E. Veleta, Senior Administrative Law Judge

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INTRODUCTION

The OUCC does not have any exceptions to this section

1. **Notice and Jurisdiction**. The OUCC has no objection to this section.

2. **Petitioner's Organization and Business**. The OUCC has no objection to this section.

3. **Relief Requested**. The OUCC has no objection to this section.

4. **Present Rates**. The OUCC has no objection to this section.

5. **Test Year and Duke Energy Indiana Forecast**. The OUCC has no objection to this section.

6. Burden of Proof. This rate case is of a magnitude seldom experienced in Indiana. The massive rate request, along with the myriad issues attendant thereto is extremely complicated. Issues like DEI's requests to decouple residential rates and for approval of the CCR CPCN take it beyond a normal rate case. Another complicating factor is that DEI has not come to the Commission for base rate review in 16 years. The record is replete with difficulties experienced throughout the processing of the case. Several parties and witnesses have raised the question of the sufficiency of DEI's case-in-chief through testimony and pleadings.

The OUCC's case pointed out the deficiency of the evidence in several testimonies. OUCC witness Eckert testified:

> As pointed out in the Joint Motion To Amend Procedural Schedule (which was joined by OUCC, CAC, Environmental Working Group, Indiana Community Action Association, Indiana Laborers District Council, The Kroger Co., Sierra Club and Walmart; and by separate joinders filed by Duke Industrial Group and Nucor Steel Indiana), prompt, thorough and consistent attempts were made through formal and informal data requests, as well as many phone and office meetings, to clarify noted inconsistencies and omissions that appeared on the face and through deeper and more informed examination of certain DEI testimony. While the OUCC and intervenors diligently attempted to comply with the already extended case filing schedule, these repeated efforts were necessary to address defective testimony. DEI's delays in providing some answers and the complete omission of other key data made it difficult and sometimes impossible for analysts to complete a thorough review of key DEI evidence. OUCC Ex. 1, pages 1-2.

Additionally, OUCC witness Armstrong testified that DEI did not have the level of support for estimates of past coal ash closure costs OUCC Ex. 3, pages 10-11, 17-20. Ms. Armstrong also testified that DEI did not submit supporting testimony regarding the Clean Water Act study costs. Pages 21, 26-28; OUCC witness Aguilar testified regarding the lack of support and unconvincing evidence in regard to the EV Pilot (now in a sub-docket), fee-free payment program, and meter tampering penalty OUCC Ex. 8, pages 11, 17, 19; OUCC witness Dismukes testified that DEI provided no evidence or estimates that a negative financial impact will arise OUCC Ex. 10, page 16. Dr. Dismukes also testified that DEI provided no details regarding the impact its future EE programs may have on revenue losses. Page 17; OUCC witness Hand testified as to the lack of supporting evidence for DEI's vegetation management request. OUCC Ex. 6, pages 4-7; OUCC witness Kollen testified that DEI made no argument in support of its of unbilled revenues adjustment except to assert unbilled revenues are "properly excluded". OUCC Ex. 2, page 47; and OUCC witness Watkins testified regarding the lack of transparency and inconsistencies in DEI's cost of service study. OUCC Ex.13, pages 2-4.

The Commission has addressed the issue of the sufficiency of utilities' cases-in-chief in several orders. As recent as February 19, 2020, we stated:

> The OUCC's witnesses correctly noted that l&M bore the burden of proof in its case-in-chief, and we agree with the OUCC that Petitioner's case-in-chief was initially incomplete. Specifically, l&M's witnesses made certain claims in support of the SBSP based on the terms of the Notre Dame Contract and the

> EPC Contract, neither of which were included with Petitioner's case-in-chief and neither of which had been finalized or executed yet when I&M's case-in-chief was filed. Thus, we also remind l&M of the importance of submitting a complete case-in-chief to facilitate OUCC and Commission review and to avoid unnecessary discovery and motion practice.[1]

Again, on January 29, 2020, the Commission stated:

> We remind NIPSCO that as the petitioning party, its case-in-chief filing must include sufficient detail to support its requested relief in order to carry its evidentiary burden. As our recent Orders in the City of Evansville and Indiana-American Water Company cases reiterate, when a petitioning party fails to provide basic supporting information in its direct evidence and does so only in response to discovery or in rebuttal testimony, time and resources are needlessly wasted.[2]

The Commission also recognized that the OUCC testimony solicited voluminous rebuttal testimony, without which the evidentiary record would have been deficient.[3]

In the recent Indiana Michigan Power Company (I&M) rate case, the OUCC challenged the sufficiency of the evidence regarding I&M's proposed 2019 - 2020 Distribution Management Plan, Asset Renewal, and Reliability Program. The Commission stated "our review of the record supports that I&M submitted the information 170 IAC 1-5-9 and -10 require with respect to capital projects and rate base additions; therefore, we find I&M reasonably concluded it had submitted a complete case-in-chief, particularly in the absence of procedural challenges asserting otherwise."[4] Title 170 IAC 1-5-2.1(c) provides that issues of the completeness of the application can be addressed at the prehearing conference, and 170 IAC 1-5-4(a) allows for any party to file notice with the Commission within 20 days of filing that the information contained in the filing does not comply with the MSFR rules.

The Commission finds some clarification is necessary. There is a difference between procedural and substantive deficiencies in a rate case application. The MSFRs provide a "checklist" for the information that should be included with an application. This provides a procedural mechanism to ensure that certain minimum identified subject matter is filed, upon which the parties can begin their substantive review of the application. We recognize the parties cannot substantively review a full rate case filing within 20 days to ensure that all information fully supports the utility's request. While the procedural requirement of the rule is satisfied by filing some information on a topic listed in the MSFR, only after a substantive review can a party determine that the information was insufficient to support a request. Therefore, it is reasonable for petitioners to assume their case is complete as far as the MSFR list requires; however, it is not reasonable to assume all of the evidence has been examined and will withstand any burden of proof

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[1] *Indiana Michigan Power Company*, Cause No. 45245, Final Order at p. 10 (February 19, 2020).

[2] *NIPSCO,* Cause No. 44340 FMCA 12, Final Order at p. 11 (January 29, 2020) citing *City of Evansville, Indiana,* Cause No. 45073, Final Order at p. 8 (December 19, 2018) and *Indiana-American Water Company,* Cause No. 45142, Final Order at p. 23 (June 26, 2019).

[3] *Id.*

[4] *Indiana Michigan Power Company*, Cause No. 45245, Final Order at p. 14 (February 19, 2020).

arguments throughout the case. A substantive deficiency in a case-in-chief cannot be overcome simply because there was no procedural challenge as to whether all requisite topics were addressed within the 20-day deadline. This position is supported by the fact that Indiana Trial Rule 41(B) states that after the party with the burden of proof has completed the presentation of his evidence, the opposing party, without waiving his right to offer evidence in the event the motion is not granted, may move for a dismissal on the ground that upon the weight of the evidence and the law there has been shown no right to relief. Further Indiana Trial Rule 56 provides that a defending party may, at any time, move for a summary judgment in his favor as to all or any part thereof. If we read the MSFRs too narrowly, responding parties would have no opportunity to file motions for dismissal or summary judgment.

There is no dispute that petitioning utilities' bear the burden of proof to demonstrate the reasonableness and accuracy of their requests. It is incumbent on the utility to make this demonstration in its case-in-chief. It is unfair and highly prejudicial to allow the utilities to cure deficiencies in rebuttal, only after the OUCC and other intervenors have discovered and testified regarding those deficiencies. Once rebuttal is filed, the other parties have no ability to respond with testimony. In addition, there is very little time to conduct discovery on the new evidence. Due process requires more, and such inadequacies prevent this Commission from reaching an informed decision.

After due consideration given to the voluminous testimony submitted in this case demonstrating critical deficiencies, we now give notice that the growing practice of curing substantive defects through responses to data requests or rebuttal testimony will not be tolerated. It is the policy of this Commission that cases in chief that meet procedural, but not substantive prerequisites to establish a prima facie case, will be subject to summary judgment or dismissal. The Commission will continue to review the entirety of the record as it stands at the close of the evidentiary record in making its determinations.

7. Petitioner's Rate Base. The OUCC has no objections to this section.

a. Utility Plant in Service – Edwardsport IGCC Plant.

i. Petitioner's Evidence. The OUCC does not have any objections to Petitioner's recitation of its evidence.

ii. OUCC's Evidence. OUCC witness Kollen recommended that a rate adjustment rider (either the ECR Rider or Rider 67) be used to track the return on the IGCC plant that is included in base rates, to reflect the impact of declining net book value due to increasing accumulated depreciation and the related impact on accumulated deferred income tax ("ADIT") balances over time. In other words, Mr. Kollen proposed to track and credit customers so that customers would pay the same amount of return as they would have if the plant were left in the IGCC Rider. Mr. Kollen testified he made this recommendation because IGCC accounts for approximately 20% of Petitioner's rate base. Including the IGCC revenue requirement in base rates will fix the revenue requirement and it will not decline as the IGCC cost curve declines. He explains this will cause Petitioner's rates to be higher than needed and customers will lose the existing benefit of the declining IGCC cost curve.

iii. **Petitioner's Rebuttal Evidence**. The OUCC does not have any objections to Petitioner's recitation of its evidence.

iv. **Commission Discussion and Findings**. The evidence demonstrates that the Edwardsport Plant is in-service and used and useful in providing service to customers. Accordingly, the net book value of the Plant as of 12/31/2019 for Step 1 and 12/31/2020 for Step 2 should be included in Petitioner's rate base. The only rate base issue related to the Plant is whether the return on the Plant should be periodically adjusted for ratemaking purposes as the Plant is depreciated, as proposed by the OUCC.

We find the OUCC's proposal to be a fair and symmetrical proposal to address known reductions in the IGCC revenue requirement that is similar in concept to the Company's proposals to address and recover other changes in future costs through the Credits Rider and ECR Rider. We find the magnitude of the IGCC costs merits the adoption of the OUCC proposal, just as the magnitude of the expiration of the IGCC tax benefits merits treatment of these costs through the same Credits Rider and the completion of the amortization of the short-term regulatory assets merits treatment of those costs through the ECR Rider.

b. **Utility Plant in Service – Solar and Battery Storage Projects**

i. **Petitioner's Evidence**. The OUCC does not have any objections to Petitioner's recitation of its evidence.

ii. **OUCC's Evidence**. OUCC witnesses Alvarez and Haselden testified in opposition to inclusion of the Crane battery energy storage system ("BESS") Project, the Tippecanoe Solar Power Plant, and the B-Line Heights Solar Power Plant in the Company's rate base. With respect to the Crane BESS Project, Mr. Alvarez testified that: (1) the microgrid as proposed by DEI is not a "real" microgrid; (2) the proposed battery project will not provide the stated operational and financial benefits to customers; (3) no lessons learned will be gained from this proposed battery project; (4) the battery project may explode; (5) the Company has not secured corporate management approval for this battery project; and (6) the proposed battery project is not in the best interest of customers. He addressed DEI's proposal regarding the microgrid and BESS at NSA Crane and recommended a $10 million adjustment (including AFUDC) to remove capital expenditures, including all O&M expenditures associated with DEI's solar and BESS interconnection project from the forecasted Test Year.

Mr. Alvarez reviewed the "NSA Crane Microgrid Design Study" ("Microgrid Study") completed by Doosan GridTech ("Doosan") on August 30, 2018 for the Department of Navy ("Navy") and DEI. He testified DEI's proposed BESS project is not a "microgrid," as defined by Petitioner's witness Mr. Ritch. He explained the Department of Energy ("DOE") defines a microgrid as "a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that act[s] as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island mode." Mr. Alvarez explained Duke Energy's BESS project is not a microgrid because the BESS has no interconnected load or any operational control of the NSA Crane microgrid loads. DEI will actually use the $10 million of ratepayer dollars to install a 5-MW battery energy storage system facility and connect it with the existing 17 MW Crane Solar facility. Under certain circumstances, the BESS could, at times, and only with Navy approval, be permitted to connect with the planned NSA Crane microgrid.

Mr. Alvarez described the current DEI utility service or feed to NSA during normal operations and during a major bulk power system or grid outage event. He testified there are two 69 kilovolt ("kV") sub-transmission lines serving the NSA Crane facility; one owned and operated by DEI (primary) and the other (backup) owned by a different electric utility (but operated by DEI). He stated the Navy wanted to maintain electrical power at NSA Crane to operate critical loads during a major grid outage where both the primary and backup services were without power. To do this, he explained, the Navy is creating a microgrid to isolate and power its critical load with its own power resources. Meanwhile, DEI will install and operate electrical lines and equipment that will allow the Company's existing solar and proposed BESS projects to interconnect with the NSA Crane microgrid, but DEI's solar and BESS will remain secondary or supplementary power sources for the NSA Crane microgrid.

Mr. Alvarez discussed DEI's claim that "three generation and storage assets would be required to provide electrical service to NSA Crane microgrid in the event of a major grid outage: 1) the existing 17 MWac Crane Solar facility owned by Duke Energy, 2) a new [BESS]), and 3) new diesel generators." He explained why the new diesel generators would serve as the primary source for the NSA Crane microgrid while DEI's solar and battery would remain secondary or supplemental sources for the microgrid. He testified the solar and battery were uneconomical solutions to meet the initial system support requirements of the microgrid because it would be impractical to reconfigure the system and allow BESS to take the initial system support role for the microgrid. He stated based on the NSA Crane Microgrid Study, both solar and battery could only support the microgrid critical loads for a very short duration in case of an outage event because it would require a far larger battery capacity to do so. He explained that during a major grid outage event with the microgrid in island mode, it is critical to have the diesel generators as the microgrid's main source of power with the solar and battery as secondary or supplemental support to serve only when called upon or dispatched.

Mr. Alvarez testified the NSA Crane microgrid will operate without the solar and BESS. He described how the design and configuration of the NSA Crane microgrid allows it to electrically isolate and island itself and its loads from its normal power sources including the existing solar and proposed battery during a major grid outage. He stated once isolated and islanded, the diesel generators will power up the microgrid. He explained the microgrid controller, topology and load shedding capability would allow it to configure and reconfigure its systems and loads to optimize generation capacity and load requirements. Further, he explained, once on an island mode, NSA Crane microgrid operators would require DEI operators to first request permission and clearance, receive approval, and then follow necessary switching sequences and protocols before DEI could interconnect its solar and BESS with the microgrid, which would take up to an hour to accomplish. He testified that with diesel generators online and providing sufficient power the microgrid, the critical switching sequences and protocols were necessary to prevent tripping or dropping of critical loads, which also lowers the position of the solar and battery in the microgrid's hierarchy of resources.

Mr. Alvarez testified BESS will not provide NSA Crane any support during normal operations when DEI existing lines would provide primary utility service to NSA Crane. He explained the battery will be charging to maintain a set state of charge level and DEI may charge, discharge, play or simulate operational scenarios with it, but the battery would not provide any utility service to NSA Crane. Mr. Alvarez testified that at present, BESS would not provide any grid service to dispatch by the Midcontinent Independent System Operator ("MISO"). He explained that MISO would not "see" BESS in its network topology or dispatch it, nor would it allow BESS to participate in its markets to provide revenue-generating services at an economical scale sufficient to justify ratepayers paying for the battery.

Mr. Alvarez pointed out that there were little to no quantifiable operational benefits that would flow to ratepayers from DEI's proposed solar and battery interconnection projects. He testified that not until after the Camp Atterbury Microgrid and Nabb Battery projects were operational and functional would DEI gain any meaningful operational data, insight, education, or experience to analyze and better understand the deployment of such technologies here in Indiana. However, he pointed out, until DEI completed this process, there is absolutely no need to spend another $10 million on battery research with BESS. He testified given the exceptionally low probability NSA Crane would require and call upon the solar and BESS to serve, DEI would learn little from the project, not gain any material insight into microgrid operations, and offer no benefits to the ratepayers from potential MISO participation.

Mr. Alvarez testified the results of his evaluation show the battery project provided no benefits to DEI ratepayers. He explained the BESS project only benefits NSA Crane and would not provide enhanced reliability of service to customers or provide ancillary services such as Regulating Reserves to MISO. He stated BESS could suffer the same fate as the battery storage that exploded in Arizona on April 19, 2019. Mr. Alvarez testified there are few multiple market services and opportunities at MISO and other grid efficiency benefits for generation resources. He noted DEI's statement that it would be a viable option for BESS to become a market participant and offer reserve services at MISO. However, Mr. Alvarez stated that if this was the only revenue-generating benefit DEI could find for BESS, then it would be a bad deal for ratepayers because DEI has not shown such benefits could economically justify the investment it asked of ratepayers. He further explained, DEI has not shown that all revenues generated from BESS, if any, could pay for the O&M and capital maintenance expenditures it would incur. He discussed how DEI was seeking regulatory pre-approval for the solar and battery interconnection projects without first securing its own corporate management approval for these projects or for project funding, which must still compete with all other Duke capital project for approval, as contained in OUCC Attachment AAA-6 – DEI's Response to OUCC DR Set 14.6. 14.8 and 14.9.

Mr. Alvarez described the OUCC's concerns regarding DEI including $10 million in base rates for its proposed solar and battery interconnection projects, noting DEI would not own, control, or operate the NSA Crane planned microgrid. He testified his first concern was finding out, as discussed earlier, that DEI's proposed BESS / solar project was not actually a true microgrid project; rather, DEI's proposed projects would entail interconnecting the existing Duke Energy solar facility and the proposed BESS with the Navy's planned microgrid at NSA Crane. He testified his second concern was neither DEI's existing solar nor its proposed BESS were primary or critical power sources for the planned NSA Crane microgrid. In an event of the a major grid outage when primary and backup services to NSA Crane were out, the microgrid operators at NSA Crane would require DEI operators to ask permission, receive clearance and approval, and follow necessary switching protocols before NSA Crane would allow DEI's solar and BESS to interconnect and interface with the microgrid, which could be a long process. By then, he stated, the NSA Crane diesel generators would be providing power to the microgrid without any need for support from either DEI solar or battery, which leaves BESS with a limited operational functionality at best.

Mr. Alvarez further described his third concern that DEI's solar-and-battery-only combination would not have sufficient capacity to power the microgrid critical loads for a duration and at a level that would provide a sense of security to Crane. The fourth concern, he testified, is that BESS would be a dedicated resource to NSA Crane during outages and would not provide any benefits to ratepayers during normal operations. In addition, the revenues generated from NSA Crane could not justify the cost of BESS, and should DEI qualify BESS to offer services to the MISO markets, the revenues generated could not compensate for the O&M and capital expenditures BESS would incur throughout its useful life. Faced with no actual quantifiable operational benefits or prospective revenues to offset costs, Mr. Alvarez said the solar and BESS interconnection projects were not beneficial to the ratepayers who would shoulder the initial \$10 million project costs and then every penny of O&M and capital expenditures once embedded in future rates.

Mr. Alvarez recommended a \$10 million adjustment (including AFUDC) to remove the capital expenditures found in Mr. Ritch's Direct Testimony, p. 12, lines 1 – 2, including all O&M expenditures associated with and related to the DEI's solar and BESS interconnection projects, from the 2020 forecasted Test Year.

With respect to the Tippecanoe Solar Power Plant and the B-Line Heights Solar Power Plant, OUCC witness Haselden testified that cost recovery should be denied for these two projects because they are small, expensive solar projects that primarily benefit localized customers and are being developed for image building purposes for Duke Energy Indiana. Mr. Haselden pointed out recovery of such costs are prohibited by I.C. § 8-1-2-6(c). Mr. Haselden listed specific concerns with the inability of Duke Energy Indiana to monetize solar investment tax credits until after 2025 during which time customers will pay a return of and a return on an additional 30% of the projects' costs. In addition, Mr. Haselden noted the Tippecanoe project will have a levelized cost, estimated by Duke Energy Indiana, of \$135.04/MWh which is approximately four times the cost of other utility-scale solar projects. Mr. Haselden explained the OUCC is not necessarily opposed to small solar projects, but if utility investments in such projects are to be in the best interests of ratepayers, those investments should be at a reasonably competitive cost. Mr. Haselden noted Mr. Landy's claims that the project will support Purdue Research Foundation's Discovery Park District's ("Discovery Park") economic development and sustainability goals by being located in a highly visible but otherwise "non-developable" location. The escalating lease provides income to Discovery Park, further examples of image-building at the expense of ratepayers. Mr. Haselden went on to discuss the B-Line Solar Plant project in Bloomington, Indiana. He identified Duke's estimate of the levelized cost of the project is \$356.91/MWh, or approximately ten times the cost of competitively priced utility-scale solar projects. Mr. Haselden referred to Mr. Landy's testimony that this project "…demonstrates DEI's commitment to identifying innovative ways to support renewable energy generation in more densely populated urban areas and supports the City of Bloomington's renewable and affordable housing goals." Mr. Haselden noted the project is connected to DEI's distribution system and not to the host building, which begs the question how the project relates to affordable housing goals and what might be innovative about solar panels on a parking canopy. Mr. Haselden noted implementing such a project is unreasonably expensive and not possible without requiring the subsidization of DEI ratepayers to underwrite this decision by DEI. Mr. Haselden also expressed the OUCC's concerns with DEI's request for lost revenue recovery for DSM programs delivered in 2020. Mr. Haselden recommended this issue be addressed in the pending Cause No. 43955 DSM 8 proceeding.

iii. **Petitioner's Rebuttal Evidence**. The OUCC does not have any objections to Petitioner's recitation of its evidence.

iv. **Commission Discussion and Findings**. The evidence established Petitioner cannot adequately respond to the OUCC's objections to the Crane BESS Project and the Tippecanoe and B-Line Solar Projects. With respect to the Crane BESS Project, Mr. Alvarez demonstrated that while the infrastructure within the Crane property can operate within the U.S. Department of Energy definition of a microgrid ("interconnected loads and distributed energy resources within clearly defined electrical boundaries that act as a single controllable entity," the inarguable fact is that the BESS itself is not interconnected to the NSA Crane load, nor does the BESS have operational control of the NSA Crane load. The BESS is a stand-alone, solar & storage project. It may be called upon by Crane and permitted, at Crane's discretion, to provide some energy to the property. If Crane does not provide its ultimate approval, and activate the switch connecting the BESS, Duke Energy Indiana cannot send power to the Crane microgrid. The microgrid will operate as a self-contained network without connection to the BESS. It is not the primary backup energy source, and during normal operations the BESS will provide no support to Crane. Mr. Landy testified how experience with the BESS Project will help the industry better understand how to integrate battery storage devices. Duke Energy Indiana is already involved in other microgrid and storage projects with the Camp Atterbury microgrid and Nabb battery projects. Once these already-authorized projects become operational, Duke Energy Indiana can utilize them for operational education, and share that data / experience with the industry regarding battery storage and microgrids. At a cost of $10 million, the BESS has not been shown to provide additional ratepayer benefits. Given the exceptionally low probability that it will ever be called upon to serve the Crane microgrid, Duke Energy Indiana is not likely to gain meaningful operational education, and has not demonstrated anything learned would be materially different than information that may derive from the Atterbury / Nabb projects.

With regard to the Tippecanoe and B-Line Solar Projects, Mr. Landy essentially agreed with the facts presented by Mr. Haselden that the projects are much more expensive than competitively priced utility-scale projects. He explained the innovative aspect of the B-Line Project is found in the collaborative working environment and public/private partnership between the City, the developer, and Duke Energy Indiana to find creative ways to add solar in an urban area by using other ratepayer's money, but offered no evidence how such projects relate to affordable housing or what grid benefits are generated. He did not dispute Mr. Haselden's contention that the Projects will primarily benefit specific local customers, noting the projects provided image-building benefits to other entities and few benefits to ratepayers in the form of small reductions in the amount of Duke Energy Indiana load served by other sources of energy. Finally, he acknowledged Mr. Haselden's complaints about the design of the Tippecanoe Project, explaining why the less-efficient fixed tilt solar array design was necessary. He explained that the land lease for the Tippecanoe Project was nominal.

We recognize these projects may serve to help diversify the Company's resource portfolio, through the addition of local renewable resources, while at the same time meeting customer desires with respect to the manner in which they want to be served. The evidence is undisputed that the Crane BESS and the Tippecanoe and B-Line Heights Solar Projects will add diversity to Petitioner's resource portfolio, and storage resources. Notably, the Indiana General Assembly recognizes that the addition of renewable energy resources in the State is both beneficial and necessary. For example, Indiana Code § 8-1-8.8-11(a) states: "The commission shall encourage clean energy projects . . . if the projects are found to be reasonable and necessary." Additionally, Indiana Code § 8-1-2.4-1 provides: "It is the policy of this state to encourage the development of alternate energy production facilities . . . in order to conserve our finite and expensive energy resources and to provide for their most efficient utilization." Further, Indiana Code ch. 8-1-37 allows a utility to develop a clean energy resource portfolio, with the possibility of earning additional financial incentives under Indiana's current clean energy statute. However, it would be unreasonable & imprudent to award any financial reward to Duke Energy Indiana with the cost of the additional generation as high as in this proceeding. In short, the nature of the Company's proposed projects might be consistent with the goals of adding "green" or "clean" generation to its resource portfolio, but not at the existing, significant price premium Duke proposed in this case compared to current average prices for such generation. In balancing conflicting interests of different stakeholders, the Commission's statutory duty requires it to safeguard consumer interests not just in the source of generation, but also in terms of the cost and rate impact on end users, especially when the utility has voluntarily selected a generation project that costs significantly more than the average cost of other available alternatives, including other clean generation projects. However, the cost of the renewable energy project Duke Energy Indiana selected and proposed for approval in this case does not meet the customer's request, because the cost is unreasonable when it so unfavorably compares to other available alternatives.

Although we have previously acknowledged the benefit of diversifying sources of energy used to generate electricity, we must consider the full impact on ratepayers and what arguments utilities could make in future cases if the Commission accepts such an excessive cost, when compared to other alternatives. If other states have found ways to make renewable generation cost-competitive with other sources, it would not be prudent for this Commission to approve projects designed without regard to the additional cost imposed on ratepayers. Although we have approved settlements in other renewable generation cases, those cases were fact-specific, not binding in any subsequent case.

Therefore, based on the evidence presented, we find the Crane Solar, Crane BESS, Tippecanoe Solar and B-Line Heights projects are not reasonable and necessary expenditures of ratepayer dollars. The benefits to ratepayers and the Company do not exceed the cost. Accordingly, we conclude that these projects are not approved, and the amounts associated with these projects ($10 million, including AFUDC for the Crane BESS and solar project, $4 million for the Tippecanoe and B-Line Solar Projects) are denied and are removed from Duke Energy Indiana's requested relief.

c. Utility Plant in Service – Gallagher Units 2 and 4.

i. Petitioner's Evidence. The OUCC does not have any objections to Petitioner's recitation of its evidence.

ii. <u>OUCC's Evidence</u>. OUCC witness Kollen discussed how the Company plans to retire Gallagher 2 and 4, including the baghouses on or about December 31, 2022. Mr. Kollen noted the Company will retain the non-fuel O&M expense savings and the return on the Gallagher 2 and 4 included in rate base. Mr. Kollen recommended the Commission address these issues to ensure that the Company recovers its actual reasonable costs and also to ensure that its ratepayers are not harmed through front-loaded and excessive recovery. Mr. Kollen recommended the Company reclassify the net book value of Gallagher Units 2 and 4 to a regulatory asset at June 30, 2020. He also recommended the Commission levelized the recovery of the return on and of over the minimum ten years he recommended for all regulatory assets. Further, he recommended that when the amortization is over, both the recovery of and return on the asset that is included in his levelized amortization amount be included as a credit in Rider 67, along with the non-fuel O&M included in the test year for these units.

iii. <u>Petitioner's Rebuttal Evidence</u>. The OUCC does not have any objections to Petitioner's recitation of its evidence.

iv. <u>Commission Discussion and Findings</u>. The evidence demonstrates that although Gallagher Units 2 and 4 are expected to remain in service and be used and useful during the test period, they are expected to retire shortly after the end of the test period. The evidence demonstrates that the Company has reclassified the net book value of other retired plants as regulatory assets, e.g., Wabash 6 and Gallagher Units 1 and 3. The Company does not dispute that the Commission has the authority to require that the net book value of Gallagher Units 2 and 4 be reclassified to regulatory assets now or at the date of retirement. The evidence further demonstrates that there will be reductions in non-fuel O&M expense after the retirements. No party disagrees with these facts. In addition, the Company acknowledges that it will not record depreciation expense after the retirement of Gallagher Units 2 and 4 and agrees that it will reflect the savings from the avoided depreciation expense in the Credits Rider 67. That is appropriate. However, the OUCC raises legitimate concerns that the Company's proposal does not address the entirety of the reductions in the Gallagher Units 2 and 4 costs, and thus, the revenue requirement, after the Units are retired, most notably, the return on rate base and the non-fuel O&M expense. On the other hand, the OUCC recommendation does so and provides an equitable and reasonable resolution of the entirety of the cost reductions while ensuring that the Company fully recovers its costs.

d. <u>Utility Plant in Service – Capital-Related Vegetation Management Investments</u>.

i. <u>Petitioner's Evidence</u>. The OUCC does not have any objections to Petitioner's recitation of its evidence.

ii. <u>OUCC's Evidence.</u> The OUCC disagreed with the level of Hazard Tree Removal Program (HTRP) spending DEI proposed to include in its rate base at the end of the test year. The OUCC's witness Mr. Hand recommended the Commission authorize DEI to capitalize only $5 million for its distribution system at the end of the test year. Mr. Hand testified DEI's HTRP revenue requirement should be set at a level based on DEI's actual history of addressing hazard trees. He explained that DEI's actual average (2011-2018) spending on its distribution system HTRP has only been $4.96 million per year.

Mr. Hand noted DEI's proposal represents an unprecedented spending level on a program that did not exist before 2010, and only reached $11 million in the base year (2018). Mr. Hand explained that while DEI says it plans to spend $30 million at the end of 2020, DEI failed to justify its proposal with a cost benefit analysis. (OUCC DR 34.19 (OUCC Attachment EMH-1)). He added that DEI only included two pages of testimony about its HTRP in Mr. Christie's testimony (Christie, page 9, line 13 – page 11, line 6). Mr. Hand argued DEI will expend additional time and money to secure required owner permission for tree removals, a program for which DEI did not establish a substantial benefit. Mr. Hand testified DEI should focus its attention on routine vegetation management of its distribution system.

Mr. Hand also recommended the Commission deny the Company's test year capitalized transmission system HTRP costs that are attributable to the EAB Program. Mr. Hand noted that DEI does not disclose how much of its forecasted distribution system HTRP costs are due to EAB. Mr. Hand stated the Company has not demonstrated its HTRP, including its EAB Program, will be more effective at reducing outages than more traditional and well accepted routine vegetation management practices.

Mr. Hand disagreed with the premise that an ash tree infected by the EAB is a sudden threat to DEI's system. Mr. Hand explained that ash tree death by EAB kills is a multiyear process, and DEI should be able to handle ash tree removals through a seven-year vegetation management cycle without requiring expensive accelerated campaigns. Ash trees (alive, dying, or dead from the EAB) do not pose an immediate threat to utility power lines. Mr. Hand explained that the dying process is slow at approximately five to seven years preceded by visual detection (leaf loss in upper half of tree) in years two or three. Mr. Hand noted that even after death by the EAB, the ash tree remains more structurally sound, often 5-10 more years, than other species of dead trees and may not fall over for 10-20 years. Mr. Hand explained that after death by the EAB, the ash tree remains structurally sound for longer than other dead trees due to specifics unique to ash trees killed by the EAB. The core of the trunk and the roots are not attacked by the EAB; therefore, the tree remains structurally strong for several years, thereby posing less risk to utility lines than other dead trees.

Mr. Hand further explained that as an ash tree dies from the EAB, it dies from the top downward, losing leaves, twigs and eventually branches. He added that the loss of leaves reduces wind resistance, thereby reducing the risk of the tree being blown over in storms. As twigs and branches fall during the extended dying process, the tree becomes shorter, less top-heavy, and less likely to fall. As the tree becomes shorter, it becomes less likely to contact the power lines when it eventually does fall many years later. As such, Mr. Hand concluded that there is no need for an aggressive and costly utility project to seek out and remove living, dying or dead ash trees. Mr. Hand advised that if a utility maintains a normal vegetation management trim cycle of four to seven years, the utility has two or more trim cycles in which to remove the dead tree during its normal vegetation management practices. Mr. Hand testified that here is no need for an urgent ash tree removal project, which unnecessarily increases costs.

iii. <u>Petitioner's Rebuttal Evidence</u>. The OUCC does not have any objections to Petitioner's recitation of its evidence.

iv. <u>Commission Discussion and Findings</u>. For purposes of updating its rate base through the end of the test period, DEI forecasts spending $30 million to remove hazardous trees located outside its easements in its distribution system. DEI proposes an unprecedented level of spending on a program that did not exist before 2010. DEI has never spent more than $11 million on its HTRP, which it did in the 2018 base year, and it has spent only an average of $4.96 million per year in the eight full years for which we had data in this rate case (2011-2018).

For 2020, DEI forecasted spending nearly three times its highest level of spending and six times its average annual spend on removing trees from outside the easements in its distribution system. DEI's description of its HTRP for its distribution system in its case-in-chief consisted of only 34 lines of testimony in Mr. Christie's testimony. (Petitioner's Exhibit 27, p. 9.) Within these 34 lines, Mr. Christie testified that DEI is targeting over 20,000 trees each year in 2019 and 2020 that are outside of DEI's right of way.

Mr. Christie indicated that because a quarter of outages were due to vegetative interference in 2018, DEI has begun an aggressive program to remove all hazard trees that are likely to cause a problem with DEI's distribution system from outside the company's right of way. DEI began the HTRP in 2010, after Petitioner's last rate order, and it is clear that DEI intends to ramp up a practice that DEI has not adequately disclosed. Nothing in DEI's brief description of its program gives any detail of its criteria for selecting hazard trees for removal or explains why addressing a tree that presents a danger to DEI's distribution system should not be addressed by the owner of that tree, as it presumably was before 2010.

DEI's HTRP has never been evaluated by this Commission. Unlike DEI's routine maintenance of its distribution system through vegetation management, which is an operations and maintenance expense, DEI's HTRP is a capital program and therefore presents an opportunity for DEI to earn a return on what it spends addressing issues on land in which it has no property interest. DEI's HTRP did not exist when DEI was last in for rates more than 15 years ago. Therefore, we have not evaluated DEI's practice of investing its capital to remove trees from property owned by others. The OUCC acknowledged there may be instances when it is appropriate for a utility to remove or trim trees outside its easement with landowner permission, or as allowed under emergency conditions. But we have not had an opportunity in this case to evaluate when such unusual actions are appropriate. DEI has not presented a sufficiently detailed program for us to evaluate whether the cost it says it will incur removing danger from another person's or entity's property should be borne DEI's ratepayers. For instance, should DEI's ratepayers pay a return on a cost that could have been addressed through a nuisance claim?

Mr. Christie's rebuttal testimony devoted 76 lines of testimony responding to Mr. Hand's testimony about DEI's HTRP and EAB program in its distribution system. In its proposed order, DEI asserted that Mr. Christie's rebuttal described the benefits of both the HTRP and the EAB programs on system reliability. The OUCC's witness contended that DEI has not demonstrated that its HTRP, including its plan to remove all trees infested with the EAB, will be as effective at reducing outages as more traditional routine vegetation management practices. DEI responded by asserting that the Company has identified approximately 45,000 hazard trees that are outside of its maintained right of way from late 2018 through 2019. This factual assertion does not support an aggressive ramp up of DEI's new HTRP. Mr. Christie asserted in his rebuttal case that the Company's 2018 follow up investigation of distribution outages in Indiana in 2018 revealed that 71.4% of the vegetation outages reviewed in Indiana were caused by tree failures from outside the right of way. That study was not included in Mr. Christie's testimony, so the quality, scope and specific findings of that investigation is not in evidence to be scrutinized. For instance, there is no information that permits a conclusion as to whether the number of outages reviewed represents a statically significant sample. If two thirds of vegetation outages were caused by "tree failures from outside the right of way," DEI has still not supported its program with a cost benefit analysis or even sufficient description of how its program really operates. The only plan DEI has presented is spending three times more a year than it ever has removing trees from someone else's property.

Incorporated in DEI's HTRP is its EAB program, though DEI does not disclose how much of its forecasted distribution system HTRP costs are due to EAB. Accordingly, DEI's forecasted HTRP rate base requires consideration of DEI's EAB program. The OUCC's Mr. Hand asserted the Company has not demonstrated its HTRP, including its EAB Program, will be more effective at reducing outages than more traditional and well accepted routine vegetation management practices. Moreover, the OUCC's witness Mr. Hand disagreed with the premise that an ash tree infected by the EAB is a sudden threat to DEI's system. Mr. Hand explained that ash tree death by EAB kills is a multiyear process, and DEI should be able to handle ash tree removals through a seven-year vegetation management cycle without requiring expensive accelerated campaigns. Mr. Hand concluded that there is no need for an aggressive and costly utility project to seek out and remove living, dying or dead ash trees.

This is not the first time we have evaluated for rate making purposes the potential effect of the EAB on an electric utility system. In Cause No. 43839, we disallowed Vectren South Electric's entire EAB revenue requirements request, which similarly depended on an aggressive removal of ash trees:

> While Vectren South presented some evidence in support of its request, there is significant evidence that the Company failed to put forth for our consideration. There is no evidence before us that there is any federal, state, or local requirement that mandates the removal of ash trees. There is no evidence demonstrating that ash trees affected by EAB have caused any actual increased system reliability risk for any electric utility, located in Indiana or elsewhere. <u>There was no explanation as to why dead ash trees outside the right-of-way but within striking distance of utility lines pose any greater risk to Vectren South's system than similarly situated dead trees of another species.</u>
>
> In addition, we are not persuaded by the Company's claim that without these additional funds, its existing Vegetation Management budget would be insufficient. It is less expensive for Vectren South to remove a tree than to trim it, and once removed, the Company will not incur additional trimming costs. Regarding the trees themselves, Mr. Hand's testimony explains that since EAB does not affect the roots or trunk of the tree, affected ash are less susceptible to falling than other infected trees suffering from root deterioration or trunk hollowing/rot. Further, because the EAB ash trees suffer first from leaf loss, they are less susceptible to being blown over. Further, as water and nutrients are less able to reach the treetop and limbs, EAB affected ash will grow at a slower than normal rate, posing even less of a risk of horizontal encroachment from the side or vertical encroachment from below.

> Having considered all of the evidence, we find that Vectren South has failed to demonstrate that it requires additional funds for an EAB infestation program beyond its regular appropriate vegetation management practices. We find further that there is insufficient evidence to support Vectren South's claim that EAB will pose a significant increased risk to system reliability. As such, Vectren South's proposed EAB adjustment is disallowed.
>
> (Cause No. 43839, Final Order Apr. 27, 2011 at 54) (emphasis added.)

As in the Vectren case, Mr. Hand noted specific aspects of the EAB and its effects on ash trees that mitigate against the notion that the EAB requires significant and urgent expenditures. DEI's rebuttal case neither refuted nor addressed Mr. Hand's specific arguments. Mr. Christie merely made a general assertion about how long it takes ash trees to die and repeated the vague platitude that "it is good utility practice to efficiently and effectively remove these ash trees." (Petitioner's Exhibit 54, p. 14.) Mr. Hand explained why addressing ash trees as part of routine maintenance of the distribution system is effective and efficient.

What the Commission recognized for Vectren South Electric has not changed. The EAB kills ash trees; however, living, dying or dead ash trees pose no more threat to utility lines than other living, dying or dead trees. The EAB has been in the Midwest since 2002. DEI has not provided a study or any other evidence in this case to contradict our finding in that case. We agree that DEI should be able to handle the EAB as part of its routine vegetation management of its distribution system.

DEI asserted that is presented substantial evidence supporting the benefits of the HTRP and EAB Program. In order to be included in rate base, a public utility must show that its investment is reasonable and prudent and that the plant created is both used and useful in the provision of utility service. We find that DEI's HTRP program is not well defined. DEI's request for an additional $30 million of rate base at the end of the forecasted test year was not accompanied by any study, any cost benefit analysis, or any meaningful plan as to how it would spend $30 million to remove trees from property it which it has no ownership interest. We agree with the OUCC that DEI should be permitted to increase its rate base for HTRP associated with its distribution system for up to $5 million.

e. Fuel Inventory.

i. Petitioner's Evidence. The OUCC does not have any objections to Petitioner's recitation of its evidence.

ii. OUCC's Evidence. OUCC witness Kollen recommended that the Commission reduce the fuel inventories to the target number of day's burn. Mr. Kollen explained the fuel inventories the Company is seeking to include are forecasts of the quantity and cost of these inventories at December 31, 2020 and it is not reasonable for the Company to forecast more than the target number of days burn. The Company's forecast coal inventories at Cayuga and Edwardsport are greater than the target number of day's burn at those generating stations. He stated that the Company's target day's burn for both stations is 45 days; however, the Company included 47 days burn for Cayuga and 46 days burn for Edwardsport. He explained the forecast inventory quantities and costs, by definition, are based on assumptions. He further stated that it is reasonable for the Commission to assume that the Company will manage its fuel inventories to the target number of day's burn, and it is not reasonable for the Company or the Commission to assume that the Company will intentionally stockpile inventory quantities greater than the target number of day's burn.

iii. **<u>Petitioner's Rebuttal Evidence</u>**. The OUCC does not have any objections to Petitioner's recitation of its evidence.

iv. **<u>Commission Discussion and Findings</u>**. A utility's rate base should include prudent and reasonable levels of fuel inventory. In this case, the evidence shows that Duke Energy Indiana's target level of coal inventory at each of its coal-fired generating stations is a 45-day supply of coal. It is also reasonable given the projected nature of a future test period that the Company will manage its full inventory to align with its projected day's burn. It is unreasonable to include a projection greater than the stated target level of coal inventory. The OUCC compared projected test period levels to the Company's target inventory levels, and proposed to exclude from ratemaking forecasted inventory levels at the Company's Edwardsport and Cayuga Stations that exceed the Company's target inventory levels. The Company has chosen to include forecasted levels of coal inventories at Edwardsport and Cayuga that are above the Company's target inventory levels. Including a projection that is higher than the Company's stated fuel inventory target is unreasonable and imprudent absent justification. The Company provided no justification in this case. Allowing this would incent the Company to have excessive amounts of coal on hand. We do not require perfection from the Company in forecasting coal inventory levels, but projecting above target levels is not reasonable. This standard does not require a determination of prudence or imprudence or a determination of error in the Company's calculations. Rather, it is a simple application of an assumption that is reflected in a forecast. Further, we note that at the end of the historic base period in this case (December 31, 2018), the Company's coal inventory levels were higher than the forecasted end of test period levels, which demonstrates that the Company has a history of having surplus coal levels and including more that the target inventory levels would be a detriment to its customers. Accordingly, we accept the OUCC's proposed adjustment and find that the Company's forecasted coal inventory levels should be set at its target level or 45 days and that amount should be included in the calculation of its rate base.

f. **<u>Financing of Fuel Inventory and Materials and Supplies Inventory.</u>**

i. **<u>Petitioner's Evidence</u>**. The OUCC does not have any objections to Petitioner's recitation of its evidence.

ii. **<u>OUCC's Evidence</u>**. OUCC witness Kollen recommends the Commission subtract the accounts payable for the fuel and M&S inventories from rate base. His reasoning for this recommendation is that this will ensure the Company recovers a return on only the portions of these inventories financed by its investors. He stated the Company's equity and debt investors finance only the portions of the fuel and M&S inventories that are not financed by its vendors; the Company records its vendor financing in accounts payable until the vendors are paid pursuant to the terms of the contracts and purchase orders between the Company and its vendors. He testified that ratemaking should reflect the reality that the portions of the fuel and M&S inventories financed by its vendors are cost-free capital. He stated that the Company should not earn a rate of return on the fuel and M&S inventories that are not financed by its investors because they do not incur that cost. He testified that the Commission can remedy this through either a reduction to rate base for the inventories accounts payable or an adjustment to the capitalization and cost of capital for the cost-free capital; either approach ensures that the Company does not improperly recover a return on the fuel and M&S inventories that are financed by its vendors, not its investors. Mr. Kollen testified that the Company's forecasts for accounts payable amounts at December 31, 2020 are unreasonably low and do not correlate to actual historic payable amounts. In fact, he mentioned that the Company has a negative payable forecast, which would imply a prepayment by the Company. Mr. Kollen recommends the Commission use the average actual coal inventories accounts payable and the average actual M&S inventories accounts payable from January 2018 through August 2019.

iii. <u>Petitioner's Rebuttal Evidence</u>. The OUCC does not have any objections to Petitioner's recitation of its evidence.

iv. <u>Commission Discussion and Findings</u>. A utility is allowed to earn a return on investments it has made. If a utility has not made an investment, it should not be unjustly enriched by having the ratepayers pay a return on that plant. As part of rate base a utility may properly include fuel and materials and supplies inventories, but only for the amounts actually financed by the utility. We are not persuaded by the Company's rebuttal suggesting this is part of working capital that was not requested. Whether the Company chose not to seek a working capital allowance has no bearing on whether or not ratepayers should be responsible for paying a return on part of rate base that the Company has not financed. Duke Energy Indiana should not recover financing costs it does not incur. The Company suggests that Mr. Kollen focuses on one aspect of working capital. We note that Mr. Kollen is not discussing working capital. His recommendation is only that the Company not be allowed to earn a return on an investment it has not made. Ms. Douglas points out that past Commission decisions dealing with items treated as cost-free capital have been customer-supplied funds, not "vendor-supplied" funds. While this may be accurate, it is not controlling and does not prevent us from investigating further. No matter who is supplying the capital, it is cost-free to the utility and makes little sense to have a divergence drawn between what is customer-supplied cost-free capital and what is vendor-supplied cost-free capital in this case. The rationale is the same: the Company did not supply the funds used so it should not be awarded a return on that investment. If the working capital assets such as inventory are included in rate base, then the portion of the inventory financed by vendors and represented by the related accounts payable also should be subtracted from rate base. Accordingly, we adopt Mr. Kollen's recommendation to treat "vendor financing" as cost-free capital and reduce rate base by the accounts payable for fuel and materials and supplies. We find that Duke Energy Indiana's rate base should be reduced by the average fuel and material and supplies inventories accounts payable from January 2018 through August 2019, or $29.463 million dollars.

g. <u>Prepaid Pension Asset.</u>

i. <u>Petitioner's Evidence</u>. The OUCC does not have any objections to Petitioner's recitation of its evidence.

ii. <u>OUCC's Evidence</u>. The OUCC objected to the inclusion of the prepaid pension asset in rate base. OUCC witness Kollen recommended that the Commission exclude the entirety of the prepaid pension asset from rate base.

Mr. Kollen testified that Duke did not seek Commission approval of a "prepaid" pension regulatory asset; it is the result of an accounting requirement that was adopted in 2006, after the Company's last base rate case. He testified that the pension asset is a non-cash regulatory asset and accounting placeholder. This placeholder is the difference between the pension trust fund assets and the accumulated pension benefit obligation that initially was recorded by Duke in response to changes in pension accounting requirements pursuant to generally accepted accounting principles ("GAAP") adopted in 2006 (SFAS 158, now codified in ASC 715). In accordance with the requirements of SFAS 158, Mr. Kollen stated that Duke recorded the initial net funded status (the difference between the fair value of pension trust fund assets and the projected benefit obligation) of its pension and OPEB funds on its general ledger and reported it on its balance sheet in 2006. At that time, Duke's qualified pension plan was underfunded and the Company recorded a net pension liability.

Mr. Kollen testified that the FERC Office of Enforcement issued accounting and reporting guidance (OE Docket No. AI07-1-000, "Commission Accounting and Reporting Guidance to Recognize the Funded Status of Defined Benefit Postretirement Plans"), which directed jurisdictional utilities to record a regulatory asset if it had a net pension liability, or regulatory liability if it had a net pension asset. This FERC accounting guidance noted that the regulatory asset was simply the difference between the fair value of the pension trust fund assets and pension liability at each measurement date and that it was not amortized to pension (expense or capital). He explained that consistent with SFAS 158, Duke recorded the cumulative effect of the unrealized gains and losses in accumulated other comprehensive income ("AOCI"), a component of common equity. In effect, Mr. Kollen stated, the entry to AOCI offset the fair value of the pension trust fund assets with the amount of the unrealized gains or losses that had not yet been realized or recorded to pension cost. Finally, he stated that as a regulated utility, Duke reclassified the unrealized gains and losses from AOCI to a regulatory asset because the unrealized gains or losses ultimately will be realized and included in the pension costs reflected in regulated rates.

Mr. Kollen explained that adoption of SFAS 158 and the FERC's guidance did not require Duke to fund a prepaid pension regulatory asset or obtain investor financing to do so. He testified that the prepaid pension asset is a non-cash regulatory asset, similar to other non-cash regulatory assets and liabilities that are not included in rate base or as a zero-cost component of capitalization because Duke has not incurred and will not incur the cash cost until some future date. Mr. Kollen stated that when Duke adopted SFAS 158, it had no effect on the pension trust fund assets, no effect on the pension liability, no effect on pension funding requirements, and no effect on capitalization or financing. He pointed out that when Duke adopted SFAS 158, it did not issue common equity or debt to finance the underfunded pension liability. Rather, in accordance with the FERC guidance, Duke simply recorded the required regulatory asset for the net underfunded liability and, in accordance with SFAS 158, it also recorded a regulatory asset for the unrealized gains and losses.

Mr. Kollen testified that the prepaid pension asset is similar to other non-cash balance sheet amounts not included in rate base or capitalization for ratemaking purposes. For example, he stated

Duke does not include any so-called asset retirement obligations ("AROs") assets or liabilities as additions to or subtractions from rate base because these amounts do not represent cash payments or receipts. Mr. Kollen explained that similarly, Duke does not include any SFAS 109 regulatory assets or liabilities or additions to or subtractions from rate base or in the zero-cost ADIT component of capitalization because they do not represent cash payments or receipts.

Mr. Kollen pointed out that if Duke had financed the prepaid pension asset, its capitalization necessarily would be greater to reflect this fact. Yet, Duke's capitalization is not greater and does not reflect the issuance of equity and debt to finance the prepaid pension asset. He stated that, in discovery, Duke was asked to provide a reconciliation between rate base and capitalization similar to a reconciliation that Duke Energy Kentucky ("DEK") recently filed in its pending rate base before the Kentucky Public Service Commission ("KPSC"). Mr. Kollen testified that this reconciliation is not a difficult task, yet Duke objected to the OUCC's request and refused to provide the reconciliation. Based on DEK's reconciliation, Duke's reconciliation would have demonstrated that the prepaid pension asset should not be included in rate base because it would have shown that Duke did not finance the prepaid pension asset. He testified that unlike Duke Energy Indiana, DEK did not include a prepaid pension asset in rate base in the Kentucky proceeding. Mr. Kollen explained that DEK correctly recognized that it actually had not financed the prepaid pension asset. He testified that in this proceeding, Duke requested to include a prepaid pension asset in rate base yet it failed to provide any proof for its claim that it financed the regulatory asset, and it refused to provide a reconciliation of rate base to capitalization, which would either prove or disprove that claim. In the Kentucky proceeding, DEK decided not to include its prepaid pension asset in rate base and its reconciliation of rate base to capitalization proves conclusively that DEK did not finance its prepaid pension asset.

He explained that the correct approach is to exclude any prepaid pension asset from rate base. Duke does not incur a carrying cost on the prepaid pension asset because it has not funded or financed the asset it recorded. Mr. Kollen stated that at best, the prepaid pension asset is comparable to a regulatory asset in the sense that it ultimately has the right to recover the underfunded accumulated pension benefit obligation through pension "cost." However, he testified that this right to recovery is merely an accounting "placeholder" that will reverse as the pension cost is calculated and recovered in future years, including the return on the actual plan assets and the interest expense on the actual accumulated pension benefit obligation.

Mr. Kollen testified that if the Commission includes a prepaid pension asset in Duke's rate base, Duke has not correctly calculated the asset amount. He explained that Duke made various assumptions that do not reflect the difference between Duke's contributions to the pension trust fund and the costs recovered from customers. He stated Duke has not tracked the costs recovered from customers through rates. Mr. Kollen testified that rather, Duke tracks only the actuarially calculated costs each year, and has done so only since 2009. He pointed out Duke's base rates have been in effect since 2004 and have not changed to reflect the actuarially calculated costs each year. Further, Mr. Kollen stated that Duke's prepaid pension asset does not reflect the fact that a portion of the actuarially calculated costs has been capitalized and is already included in rate base in the plant in service amounts. He testified that a portion of pension costs is capitalized to construction work in progress ("CWIP"), then closed to plant in service when the asset is placed into service. The capitalized portion of the pension costs is included in rate base as well as the return on; therefore, this portion of pension costs is included separately in the revenue requirement.

Consequently, Mr. Kollen stated, a portion of the prepaid pension regulatory asset accounting placeholder is due to the plant in service included in rate base and a portion is due to the pension expense included in the revenue requirement. He explained that on average, Duke capitalized 27.2% of its actuarially calculated pension costs to CWIP/plant in service and expensed the remaining 72.8% over the last ten years.

Mr. Kollen recommended the Commission exclude the entirety of the prepaid pension asset from rate base. He calculated that the effect of excluding the prepaid pension asset is a reduction in total Company rate base of $150.74 million and a reduction in the retail revenue requirement of $10.883 million. In the alternative, and at minimum, Mr. Kollen recommended the Commission reduce the prepaid pension asset to remove the portion of the asset due to the contributions and pension costs that have been capitalized to plant and not expensed. He explained that Duke should not be allowed to earn a return on both the prepaid pension asset and the capitalized portion already included in the plant in service rate base amounts. He calculated the effect of reducing the prepaid pension asset to exclude the capitalized portion is a reduction in total Company rate base of $41.001 million and a reduction in the retail revenue requirement of $2.960 million.

iii. **Industrial Group's Evidence**. The OUCC accepts the Industrial Group's recitation of its evidence.

iv. **Petitioner's Rebuttal Evidence**. The OUCC does not have any objections to Petitioner's recitation of its evidence.

v. **Commission Discussion and Findings**. In litigated rate cases, we have approved requests for inclusion of a prepaid pension asset in a utility's rate base for two utilities, Indiana Michigan Power Company (Cause Nos. 44075 and 45235) and Indianapolis Power and Light Company (Cause No. 44576).

In a case of first impression, *Indiana Michigan Power Co*., Cause No. 44075, we approved rate base recovery of I&M's prepaid pension asset based on our understanding that the asset represented prepayments that reduced I&M's revenue requirement:

> The record reflects that the prepaid pension asset was recorded on the Company's books in accordance with governing accounting standards. The record also reflects that the prepaid pension asset has reduced the pension cost reflected in the revenue requirement in this case and preserves the integrity of the pension fund. Petitioner made a discretionary management decision to make use of available cash to secure its pension funds and reduce the liquidity risk of future payments. In addition, the prepayment benefits ratepayers by reducing total pension costs in the Company's revenue requirement. Therefore, we find that the prepaid pension asset should be included in Petitioner's rate base.
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> *In re. Ind-Mich. Power Co.,* Cause No. 44075, p. 10, 2013 WL 1180842 (Ind. Util. Regulatory Comm'n Feb. 13, 2013), *aff'd mem.* (Ind. Ct. App. 2014), *trans. denied.*

In *Indianapolis Power & Light Co*., Cause No. 44576, we approved rate base recovery of IPL's prepaid pension asset by concluding that it represented a component of working capital. Our order also reduced the amount of the asset:

> As for the amount to be recognized, while we agree with IPL that the prepaid pension asset represents a component of working capital, we disagree that the entire $ 138.5 million should be recognized as investor-supplied capital and included in rate base. As noted above, working capital represents an amount of investor-supplied capital. However, funds held by the utility are only available to investors to the extent that the utility has already met its existing obligations. The evidence establishes that ERISA minimum funding is not discretionary and we view non-discretionary funding as an obligation of IPL in its role as an electric service provider. Further, to the extent revenues collected from customers are used for the provision of electric service to fund IPL's obligations, those funds are not available to be used at IPL's discretion. In this case, Mr. Felsenthal testified that $73.6 million would represent the pension asset if IPL only contributed the ERISA minimum contributions from 2000-2014. Because ERISA requirements mandated a level of minimum funding of its pension asset, the $73.6 million was not available to shareholders to use for other purposes. We find that customers have effectively supplied this minimum amount of the prepaid pension asset and therefore do not owe IPL a return on this portion of the asset, or the accompanying impact on deferred taxes. However, the remaining $ 64.9 million of the net prepaid pension asset was a discretionary choice to provide additional funding to the pension asset. . . . Accordingly, we find that $ 64.9 million of the net prepaid asset (the sum of the prepaid pension asset, supplemental pension asset, and other post-retirement positions) shall be included in rate base.

In re Indianapolis Power & Light Co., Cause No. 44576, 2016 WL 1118795 *23, 329 P.U.R.4th 486 (Ind. Util. Regulatory Comm'n Mar. 16, 2016), *aff'd, Citizens Action Comm. v. Indianapolis Power & Light*, 74 N.E.3d 554 (Ind. Ct. App. 2017).

In the same *Indianapolis Power & Light* order, we further found that our conclusion "should not be read to foreclose alternative proposals to address prepaid pension assets." *Id*., fn. 5. In Cause No. 45235, I&M's most recent rate case, we again approved I&M's request for rate base recovery of its prepaid pension asset based on the same rationale articulated in these prior decisions, finding that "no alternative proposal or changed circumstances were presented in this matter that cause us to change our treatment of I&M's prepaid pension asset." *I&M*, Cause No. 45235, Final Order at 27 (March 11, 2020).

The record evidence in this case shows there is no requirement in GAAP, SFAS 158, or FERC accounting and reporting guidance that requires Duke to fund a prepaid pension asset or to obtain investor financing to do so. Duke admits there is no authoritative accounting guidance that supports its description and claims regarding the prepaid pension asset. (OUCC CX-17, DR 17.32.) The pension trust fund assets reflect the present funding and the pension liability reflects the present value of the future obligation. In its simplest form, the prepaid pension asset is simply the *unfunded* difference between these two amounts, meaning that the pension liability is greater than the pension trust fund assets, not less. Accounting standards require Duke to record a regulatory asset for its net underfunded pension liability and for unrealized gains and losses. While these entries are associated with accounting standards, the requirement to make these entries has no effect on the pension trust fund assets or on the underfunded pension liability. Rather, these entries reflect that Duke has a right to recover the underfunded accumulated pension benefit obligation through pension cost, and that right to recover will reverse as the pension cost is calculated and recovered in future years, including the return on the actual plan assets and the interest expense on the actual accumulated pension benefit obligation. The regulatory asset changes each year as the result of changes in the pension trust fund asset and the pension obligation.

Duke claims the prepaid pension asset is the difference between the amount of pension cost incurred by Duke Energy, Inc. and allocated to Duke Energy Indiana compared to amounts recovered from customers. However, this claim is unsupported by the record evidence. Specifically, the pension plans are not Duke Energy Indiana plans; they are Duke Energy, Inc. plans. These plans have been merged and modified as Duke Energy, Inc. has made acquisitions and restructured its businesses and pension plans. In fact, the costs charged by Duke Energy, Inc. to Duke Energy Indiana are based on the number of plan participants, not on any historical or actuarial differences among Duke Energy, Inc.'s affiliates and each affiliate's plan participants. (OUCC CX-17, DR 17.18.) Therefore, the Company cannot and did not track or calculate the pension cost actually incurred by Duke Energy Indiana; it cannot and did not track or calculate the pension contributions made by Duke Energy Indiana, especially prior to 2006, when it adopted SFAS No. 158, and even prior to 2010 (OUCC CX-17, DR 17.34 and 33.6); it cannot and did not track or calculate the ERISA minimum funding requirements (OUCC CX-17, DR 17.30); and it cannot and did not track or calculate the pension cost, either pension expense or pension cost capitalized by Duke Energy Indiana, reflected in the ratemaking process, either prior to the date when it adopted SFAS 158 or in any other year since its base rates were reset in 2004. (OUCC CX-17, DR 17.) The Company confirmed these facts with its response to OUCC DR 33.1 (OUCC CX-17):

> Duke Energy Indiana participates with other Duke Energy affiliate companies in Duke Energy pension plans, which are evaluated for ERISA minimum funding requirements and Plan Accounting (ASC960) in total, and not for each participating affiliate company. In addition, there is not a methodology in place to allocate the ERISA minimum funding requirements or ASC960 by participating affiliate company.

In prior findings, we have concluded that prepaid pension assets serve to reduce pension expense included in base rates, which we have found to be a benefit to customers. However, the evidence in this proceeding does not support that conclusion. While we recognize that, according to GAAP, the return on pension trust fund assets reduces pension costs, we must also recognize that pension costs under GAAP do not include a return on a prepaid pension asset. Therefore, as a factual matter, there is no reduction in pension cost from the prepaid pension asset. Moreover, we cannot ignore that the Company recovered the same amount of pension expense each year from its customers since base rates were reset in 2004, despite the fact that pension cost and pension expense declined significantly over that same fifteen year period. (Tr. at S-15 – 16.) By understating this contribution from customers, we agree with OUCC witness Kollen that Duke's calculation of its prepaid pension asset is excessive and that any return on this amount included in the revenue requirement would be excessive. (Tr. at S-16.) Even if we were to assume that Duke's pension expense in this case is reduced by the contributions in excess of recoveries allegedly reflected in the prepaid pension asset, Duke has overstated its prepaid pension asset to such an extent that the increase in the revenue requirement caused by the return on the prepaid pension asset would exceed any purported pension expense savings. We decline to artificially isolate one component of Duke's pension proposal and ignore the broader ratepayer impact. Moreover, without evidence showing the amount of customer contributions towards Duke's pension cost since 2004, the Commission cannot credibly conclude that any discretionary pension trust fund contributions were funded by Duke's investors, and not its ratepayers. Duke admitted in response to OUCC discovery that it did not finance the prepaid pension asset when it adopted SFAS 158 in 2006 and that the changes in the prepaid pension asset each year are not the result of any changes in investor financing: "There was no effect on investor financing resulting from the implementation of SFAS No. 158. . . The remeasurement of pension plan assets and pension plan liabilities results in neither a reduction nor an increase in investor financing." (OUCC CX-17, DR 43.7)

Accordingly, based on our findings above, we deny Duke's request for inclusion of a $150.75 million prepaid pension asset in its rate base.

The OUCC also raised concerns about Duke's calculation of prepaid pension asset on the basis that it includes pension costs already part of capitalized labor expenses. Duke's response is that even though some pension costs are capitalized, no adjustment is required because the prepaid pension asset is reduced over time by recognition of GAAP pension costs. We find this response unconvincing. The issue is whether the prepaid pension asset arose due to the amounts expensed and the amounts capitalized or only the amounts expensed. Perhaps rather obviously, it arose due to both the amounts expensed and the amounts capitalized. To the extent the amounts were capitalized, then they already are included in the plant in service in rate base. Had we opted to include any part of Duke's proposed prepaid pension asset in rate base, we would have accepted OUCC witness Kollen's adjustment to remove the portion of the asset that has already been capitalized, leaving $109.74 million in rate base.

h. Regulatory Assets Previously Approved. Duke Energy Indiana's proposed revenue requirements include continued inclusion in rate base and recovery of several previously-approved regulatory assets, as well as additional amounts deferred after the cut-off used in the last rate case for such regulatory assets. In addition, Duke Energy Indiana proposed recovery of several regulatory assets not yet included in rate base, including regulatory assets related to: previously-approved TDSIC investments; previously-approved federal mandate investments; previously-approved deferred amounts for Gallagher Station baghouses in excess of amounts allowed to be included for rider recovery; previously-approved environmental compliance investments; previously-approved utility-owned renewable generation investments; and coal ash basin closure and remediation expenses. Additionally, Duke Energy Indiana proposed inclusion in rate base and recovery of several items that were included in rate base previously as inventory or plant rate base, rather than as regulatory assets - SO_2 emission allowances, the net book value of Gallagher Units 1 and 3, and the net book value of Wabash River Unit 6.

Inclusion in rate base and recovery of the following regulatory assets in the total amount of $182.885 million, after reflecting the Company's rebuttal adjustments increasing the length of amortization life (discussed later in this Order), was not challenged by any party (amounts in table are stated in thousands as shown in Petitioner's Exhibit 35-B (DLD), Rebuttal Schedule RB4):

In thousands:

Undisputed Regulatory Assets to be Included in Rate Base	Rebuttal Dec. 31, 2020 Adjusted Balance
182140-Noblesville Carrying Costs - Retail	1,777
182150-Noblesville Deferred Depreciation - Retail	734
182141-Noblesville Carrying Costs - Retail	8,497
182151-Noblesville Deferred Depreciation - Retail	4,527
182113-Post in Service Carrying Costs-NOX	493
182222-Madison and Henry County Carrying Costs - Retail	6,994
182232-Madison & Henry County Deferred Depreciation - Retail	3,406
182221-Madison and Henry Carrying Costs - Retail	16,587
182231-Madison & Henry Deferred Depreciation - Retail	6,994
182570-Other Production Plant AFUDC Continuation - Retail	268
182580-Other Production Plant Depreciation Deferral - Retail	2,104
182670-Other Production Plant AFUDC Continuation - Retail	2,386
182680-Other Production Plant Depreciation Deferral - Retail	5,186
182365-Deferred Depreciation Gallagher Baghouses Units 2 & 4	3,488
182114-Post in Service Carrying Costs-Environmental Phase I	21,376
182602-Post in Service Carrying Costs-CCR 40%	16,732
182608-CCR - Deferred Depreciation - 40%	11,374
182611-CCR Plan Development - 20%	2,484
182609-CCR Deferred O&M - 20%	5,960
TBD- Retail Native SO_2 EA	9,520
182916-Post in Service Carrying Costs - Crane Solar	2,190
182475-Post in Service Carrying Costs-Federal Mandate - 20%	820
182643-Federal Mandate - Deferred Depreciation - 20%	276
182640-Federal Mandate - Deferred O&M Costs - 20%	2,428
182641-Federal Mandate - Carrying Costs on Def O&M - 20%	471
182913-Post in Service Carrying Costs-TDSIC Rider 65 - 20%	19,206

182656-TDSIC - Deferred Depreciation - 20%	8,820
182650-TDSIC - Deferred O&M Costs - 20%	15,914
182651-Post in Service Carrying Costs-TDSIC Deferred O&M - 20%	1,873
Total	$182,885

Among the undisputed rate base regulatory assets is the regulatory asset resulting from the Company's request herein to transfer the remaining balance of native load SO_2 emission allowance inventory to a regulatory asset, rather than including it as part of the emission allowance inventory in rate base, as supported in testimony by Company witnesses Sieferman and Douglas, supported by OUCC witness Ms. Armstrong and unopposed by other parties. This issue is also addressed later in this order when addressing emission allowance tracking via the riders and the accounting deferral request for the SO_2 regulatory asset.

With regard to these undisputed regulatory assets, including the regulatory asset related to the SO_2 emission allowance balance transfer, we find that the Company has adequately demonstrated that recovery of such assets is reasonable and should be approved. Accordingly, we find that such undisputed recovery of regulatory assets should be reflected in retail rates approved in this proceeding and recovered pursuant to the amortization periods proposed by Petitioner in the Rebuttal Testimony of Ms. Douglas.

The OUCC and certain intervenors challenged the recovery of the regulatory assets related to the Gallagher Station Units 1 and 3 net book value, the Wabash River Unit 6 net book value, and the coal ash basin closure and remediation expenses. The OUCC also took issue with the Company's proposed amortization periods for these regulatory assets, and the OUCC proposed an alternative amortization methodology.

i. Gallagher Station Retired Units 1 and 3.

(A) Petitioner's Evidence. The OUCC does not have any objections to Petitioner's recitation of its evidence.

(B) OUCC's Evidence. OUCC witness Kollen proposed that the Commission direct the Company to create a regulatory liability account for the non-fuel O&M expense savings realized since the 2012 retirement of the Gallagher Units 1 and 3. He also proposed that this regulatory liability be amortized over ten years or, alternatively, the same period of time that is used to amortize the Gallagher Units 1 and 3 regulatory asset. He also proposes that the regulatory liability be subtracted from rate base using a June 30, 2020 date for this purpose, the same date used by the Company for the Gallagher Units 1 and 3 regulatory asset. In addition, he proposed that the regulatory liability and return on the regulatory liability be levelized (annuitized) over the ten year amortization period in the same manner that he proposed for the Gallagher Units 1 and 3 regulatory assets and other regulatory assets that are included in rate base. Mr. Kollen noted that the Company did not seek and did not obtain authorization from the Commission to retain the non-fuel O&M expense savings after the retirement of the Gallagher Units 1 and 3 and that it did so unilaterally. Mr. Kollen also discussed that if the Company is allowed to recover the costs related to Gallagher Units 1 and 3, then those costs should be offset by the O&M expense savings as a matter of equity and fairness.

(C) Petitioner's Rebuttal Evidence. The OUCC does not have any objections to Petitioner's recitation of its evidence.

(D) Commission Discussion and Findings. We found in Cause No. 43956 that the Company reasonably and prudently settled its New Source Review litigation with the EPA, and that the Company reasonably and prudently decided to retire, rather than repower, its Gallagher Units 1 and 3. In addition, we authorized the Company to establish a regulatory asset for the remaining net book value of those Units as well as the related study costs. The Company did not seek a regulatory liability for the O&M expense savings and we did not address the savings in Cause No. 43956. This is the Company's first rate case since the retirement of Gallagher units 1 & 3 and we will now address the O&M expense savings associated with these retired units. This issue should have been raised in Cause No. 43956, not this case. We disagree with the Company that the only time the O&M savings associated with these two units could be addressed was when the company sought a regulatory liability. The savings are due to a specific retirement of an asset and was not due to the normal variations in O&M expense that occur between rate cases, where the utility is expected to manage those expenses. We would note that in its proposed order the Company mentions the Indiana FAC expense and earnings tests serve to protect customers in the unlikely event that, overall, expense reductions exceed expense increases and lead to overearnings, this is true but does not address the issue at hand and the Company provided no evidence as to the effect on the FAC earnings test in this proceeding. Accordingly, we find the Company shall recognize a regulatory liability for the non-fuel O&M expense savings and subtract these amounts from rate base with an amortization period at 10 years. The Company shall also reflect the return on and return of theses liabilities on a levelized basis.

ii. Wabash River Retired Unit 6.

(A) Petitioner's Evidence. The OUCC does not have any objections to Petitioner's recitation of its evidence.

(B) OUCC and Industrial Group's Evidence. Similar to the OUCC's recommendation concerning Gallagher Units 1 and 3, OUCC witness Kollen recommended that the regulatory asset the Company included in rate base for the remaining net book value of its retired Wabash River Unit 6 be reduced by a regulatory liability for the non-fuel O&M expense savings after the retirement of the unit 6. Industrial Group witness Gorman recommended the Wabash River Unit 6 regulatory asset be reduced to $0 and excluded from rate base to reflect the fixed (non-fuel) O&M expense savings for Wabash River Units 2-6. Similar to his recommendation for the regulatory asset and regulatory liability for Gallagher Units 1 and 3, Mr. Kollen recommended that the net regulatory liability for Wabash River Unit 6 at June 30, 2020 be recovered (refunded) over ten years on a levelized basis and that the reductions in the revenue requirement as the return on rate base declines and the amortization ceases, if the Company's position is approved, or the increase in the revenue requirement as the levelized recovery is completed and ceases, if the OUCC recommendation is approved, be reflected in the Credits Rider 67. Mr. Kollen stated the Company neither sought nor obtained Commission authorization to prematurely retire Wabash River 6 and create a regulatory asset for the net book value of Wabash River Unit 6.

(C) Petitioner's Rebuttal Evidence. The OUCC does not have any objections to Petitioner's recitation of its evidence.

(D) Commission Discussion and Findings. The Company may have correctly created a regulatory asset for the remaining net book value of Wabash River Unit 6 for accounting purposes, but the evidence is clear that the Company did not have Commission approval to create the regulatory asset. The Company failed to seek and did not obtain authorization for this regulatory asset. As the Company never sought permission to create the regulatory asset we have made no ruling on what should be done with the O&M expense savings associated with the retirement. The Company sought authorization to create a regulatory asset for Gallagher Units 1 and 3, but chose not to seek approval for Wabash River Unit 6. The accounting requirements did not change between the retirement of Gallagher Units 1 and 3 in 2012 and the retirement of Wabash River Unit 6 in 2016. Regardless of the accounting requirements, there is no dispute that the O&M expense savings that were retained by the Company after the retirement in 2016 exceed the remaining net book value of Wabash River Unit 6 at June 30, 2020. The OUCC recommends that the Commission reflect both the regulatory asset and the regulatory liability in rate base and essentially refund the net regulatory liability on a levelized (annuitized) basis over ten years. The Industrial Group simply recommends no net recovery or refund and that the regulatory asset be excluded from rate base. We agree with Mr. Kollen's recommendation and find the Company shall create a regulatory liability for the non-fuel O&M expense savings for Wabash River Unit 6 and subtract this from rate base. The Company shall amortize this liability over 10 years.

iii. Dynegy Regulatory Asset Commission Discussion and Findings. The OUCC does not have any exceptions to this section.

i. Coal Ash Basin Closure and Remediation

Duke Energy Indiana seeks recovery of its past expenses associated with activities taken to comply with federally mandated and state requirements applicable to coal ash surface impoundments and other ash management areas. Specifically, Duke Energy Indiana seeks to include in rate base a regulatory asset consisting of the retail jurisdictional portion of its past coal ash basin planning, closure and related expenses, and to recover the costs over 18 years (which coincides with the estimated retirement date of the last operating Gibson Generating Station unit). These costs will be referred to herein collectively as "Coal Ash" costs. The Commission opened a sub-docket (Cause No. 45253-S1) to review the Company's future Coal Ash costs not included in the regulatory asset. Those expenses will, therefore, not be addressed in this Order.

The Company has included in the regulatory asset the retail jurisdictional portion of past expenses incurred through 2018 to comply with the federal Coal Combustion Residuals ("CCR") Rule – referred to herein as the "CCR Projects." These projects are also governed by the Indiana Department of Environmental Management ("IDEM") solid waste management rules.

Also included in the above-mentioned regulatory asset is the retail jurisdictional portion of past costs incurred through 2018 for projects at Dresser Station, Noblesville Station, retired

Edwardsport Station, and for the Gibson East Ash Pond under the IDEM solid waste management rules – referred to herein as the "IDEM Projects." In addition, the Company seeks to include in the same regulatory asset the additional IDEM Project costs to be incurred in 2019 and through the end of 2020 test period for the same rate base and amortization recovery of the costs – but only for the Dresser and Gibson East Ash Pond projects.

The Company grounded its requests for recovery of costs associated with the CCR Projects and the IDEM projects on two bases: first, traditional rate case recovery of previously-deferred, prudent and reasonable costs associated with providing utility service; and second, the Indiana "Federal Mandate" Statute, Indiana Code ch. 8-1-8.4. Company witnesses Thiemann, Schwartz, Abernathy and Douglas supported the Company's requests for ratemaking and accounting relief.

i. **<u>Petitioner's Evidence</u>.** The OUCC does not have any objections to Petitioner's recitation of its evidence.

ii. **<u>OUCC's and Intervenors' Evidence</u>.** Ms. Cynthia Armstrong, Senior Utility Analyst for the OUCC, addressed DEI's requests to recover past coal ash closure expenditures (incurred from 2015-2018) and future costs, which Duke Energy Indiana defined as costs incurred after 2018. She explained that DEI requested the creation of a regulatory asset for past costs in the amount of $211.716 million to include in rate base.

Ms. Armstrong explained that under the CCR Rule, utilities must meet multiple requirements and standards to operate and manage CCR disposal units. The CCR Rule also will require closure in forthcoming years for surface impoundments that fail structural stability requirements or locational requirements, or demonstrate they impact groundwater. She testified that very few existing ash ponds meet or will meet these standards. She noted that although the EPA is revising the CCR Rule and the Water Infrastructure Improvements for the Nation ("WIIN Act") requires the EPA to develop a federal permitting program for CCR units, the requirements that trigger closure under the original CCR Rule still apply during the permitting program development and approval process.

Ms. Armstrong stated that because Duke's ash ponds do not meet the requirements for existing surface impoundments under the CCR Rule, they must close. She noted DEI has already transitioned to dry bottom and fly ash handling systems for Cayuga and Gibson to allow both of these facilities to continue operating in compliance with the CCR Rule.

Ms. Armstrong stated that while the majority of the past closure costs meet the definition of "federally mandated" costs, the OUCC believes the CCR closure and remediation costs related to IDEM Agreed Orders should not be considered a federally mandated cost.

She recommended the IDEM-related costs be denied, regardless of any other past costs that may be approved. This results in removal of $73.931 million, which is the retail portion of the total company amount of $80.544 of IDEM-related remediation costs, from the overall requested regulatory asset of $211.716 million. Ms. Armstrong stated that these costs are as result of state enforcement actions, not as a result of the federal CCR Rule, due to DEI's previously closed ash storage sites leaching hazardous constituents into the ground. OUCC Attachment CMA-2 provided copies of the Agreed Orders for the Dresser, Legacy Edwardsport, and Noblesville Stations. She noted that the Dresser Station closed in 1975, well before the CCR Rule was in place. Ms. Armstrong testified that these costs would not have been imposed on DEI if DEI had not violated state waste rules. While no state or federal regulations for CCR disposal applied to these legacy sites at the time of operation, there were state regulations prohibiting the deposit of any waste that would present a pollution hazard. She asserted that DEI was obligated to manage its CCR waste in a manner that would not result in a release to groundwater, surrounding properties, surface waters or present a danger to human health or the environment. She maintained that these costs are due to DEI's past management decisions for its CCR waste, and it should not be permitted to recover them under the Federally Mandated Requirements statute.

Ms. Armstrong testified that the question of whether DEI should recover these costs through future rates is not clear-cut. With the exception of the Gibson East Ash Pond, the coal units generating the waste streams targeted by the IDEM Agreed Orders are no longer in service. She further pointed out at least two rate cases have occurred since DEI removed the Dresser Station from service. She cited to Cause No. 39353 Phase II, where the Commission denied Indiana Gas's recovery of remediation costs related to old manufactured gas plant ("MGP") sites. She noted that in its ruling, the Commission acknowledged that ratepayers had not only paid these costs directly through insurance premiums included in operation and maintenance costs, but also indirectly as a component of its authorized rate of return, which reflected Indiana Gas's environmental risk.

She compared the Indiana Gas case to DEI's ash pond closure costs because it involves the remediation of an asset that is no longer providing service to customers. She asserted that DEI's legacy coal ash costs have been recognized in past rates through the past rate of return the Commission authorized for DEI. She testified that it is difficult to separate how these costs were accounted for in the rate of return allowed in past rates.

With regard to the other past closure costs, Ms. Armstrong testified that DEI did not meet the requirements to receive a CPCN under the Federally Mandated Requirements Statute, or I.C. § 8-1-8.4-7, because DEI failed to obtain a federally mandated CPCN before it incurred these costs. She pointed to the Commission's ruling in Cause No. 44367 FMCA-4, where the Commission rejected DEI's request to collect costs related to a vegetation management project to comply with federal transmission requirements that were incurred prior to it seeking a CPCN for these costs.

Ms. Armstrong also asserted that DEI did not adequately address the factors it must include in its application under I.C. § 8-1-8.4-6(b). She noted that while DEI provided the required estimates for the past coal ash closure costs pursuant to I.C. § 8-1-8.4-6(b)(1)(B), it did not provide the level of support for these estimates normally required in a federally mandated CPCN proceeding. She stated that DEI's estimates provided in Petitioner's Exhibits 21-E and 21-F differed significantly from the ash pond closure purchase and change orders included in Mr. Thiemann's workpapers. She further pointed out that none of the engineering studies DEI provided in supporting its proposed closure plans included cost estimates for the work to be performed. She noted that although these studies acknowledged alternatives for closure, they did not explain why each closure option was selected for each pond, nor do they provide cost estimates for alternatives. Without this information, she stated that DEI has not met the requirements for a CPCN application for federally mandated project costs under I.C. § 8-1-8.4-6(b)(1)(B), or the alternative plans justifying the proposed compliance project under I.C. § 8-1-8.4-6(b)(1)(D).

Ms. Armstrong also disagreed with DEI's claim that the projects in this Cause for which it seeks a CPCN will extend the useful life of the existing energy utility facilities, one of the factors the Commission must consider in determining whether a project is worth granting cost recovery incentives under the Federally Mandated Requirements statute. Ms. Armstrong provided a DEI response to a data request in which DEI admitted the closure costs do not extend the useful life of the generating facilities. While Ms. Armstrong stated that DEI needs to undertake these projects regardless of whether the generating facility continues to operate, the OUCC questions whether coal ash closure costs are eligible for recovery under I.C. ch. 8-1-8.4.

Ms. Armstrong testified that while coal ash closure is mandated by a federal rule, the costs for CCR closure are unique among other federally mandated costs because, unlike compliance with other environmental laws in I.C. § 8-1-8.4-5, the costs cannot be avoided through retiring or shutting down a generating facility. She added that coal ash closure costs represent an asset that is being removed from service with no new piece of equipment or value being added to the facility to serve ratepayers into the future. She re-iterated that these costs were likely reflected in previous rates through O&M expenses for insurance premiums and DEI's authorized return, which already considers DEI's environmental risk. She stated that it may be difficult to quantify these items in order to credit ratepayers with the costs they already paid through approved rates in order to offset the substantial costs of closure now. She also argued that allowing cost recovery in the manner DEI proposes may not provide DEI with the incentive to pursue as much reimbursement as possible from current and past insurance policies. (Armstrong Direct at p. 11-13) Ms. Armstrong noted that DEI had received a partial payment from an insurance claim related to the Dresser Station, but had yet to apply this amount to the CCR costs in this case. She also indicated that DEI had provided other historic liability insurers a notice of circumstances that may give rise to a claim in the future regarding DEI's potential CCR liabilities, which preserves its rights to file more claims in the future.

Ms. Armstrong also pointed out that the demolition cost estimates used for determining depreciation rates in Cause No. 42359, PSI/Cinergy/DEI's last general rate case, included pond closure costs. She noted that PSI's witness testifying to the demolition studies admitted that if PSI were required to remove and dispose of all stored ash from the existing ash pond at Cayuga, it would add more than $100 million to the cost of demolishing the facility, and the witness used this as support for allowing PSI to include a 25% contingency cost in the dismantling costs used for determining depreciation rates. (Armstrong Direct at p. 13) Ms. Armstrong acknowledged that DEI includes costs it has recovered through depreciation associated with ash pond closure costs, but noted that it is unclear if DEI's reported amounts include the 10% of indirect costs, 25% contingency costs, or the inflation of these costs reflected in DEI's previous demolition cost and depreciation studies.

Finally, Ms. Armstrong reasoned that while costs for closing ash ponds have increased since DEI's last rate case, DEI may also have experienced significant reductions in other costs occurring outside of the test year that could offset – completely or partially – the increased closure costs. She stated that the previous Edwardsport generating units, Gallagher Units 1 and 3, and the Wabash River Generating Station have all retired since the last rate case, but DEI continues to recover in its current rates the costs for operating these facilities. She stated that it is problematic to focus on one specific cost DEI incurred outside of the test year without also recognizing any cost savings occurring since the previous rate case, and that DEI's request to recover past ash pond closures would constitute retroactive ratemaking.

Ms. Armstrong acknowledged that the Commission has approved recovery of coal ash closure costs through I.C. ch. 8-1-8.4 in Cause No. 45052, where the Commission approved Vectren South Electric's costs to close the Culley East Ash Pond. However, she distinguished the Vectren case from this case by noting that there was not enough space at Culley to install equipment to comply with the CCR requirements, which would have prevented Culley Unit 3 from continuing to operate. She noted the Commission's approval of this project stated there were no alternatives to continue operating Culley Unit 3 without closing the ash pond, so the ash pond closure would extend the useful life of Culley Unit 3.

Ms. Armstrong also denied that the Settlement Agreement approved in Cause No. 44872 for NIPSCO's CCR Compliance Plan indicated that the OUCC agreed that ash pond closure costs could be recovered as federally mandated costs. She testified in support of the settlement in Cause No. 44872 and was heavily involved in settlement discussions. She explained that the OUCC agreed to the "incremental" cost to construct a new landfill cell related to continuing operation of NIPSCO's coal units, which included both the incremental cost to construct a new landfill cell under the federal CCR Rule and the portion of the project associated with the disposal of ash generated by the continued operation of NIPSCO's coal units. She indicated that the costs allowed for the "incremental" costs of the "Landfill/Pond Closure" project was reduced from $18.285 million to approximately $4.261 million, but the title of the project did not change. She explained that while the project name gives the appearance the OUCC agreed to the cost recovery of a Pond Closure project under the Federally Mandated Requirements statute, the OUCC agreed only to the disposal costs associated with continuing to operate NIPSCO's coal units.

Ms. Armstrong recommended denial of DEI's federally mandated CPCN for ash pond closure costs incurred from 2015 through 2018 and associated recovery of $211.716 million in regulatory assets, as Duke failed to seek approval of these costs prior to incurring them and has not met the requirements under I.C. ch. 8-1-8.4. If the Commission issued a federally mandated CPCN for past ash pond closure costs, she alternatively recommended that DEI's request be reduced to $117.304 million (the retail portion of the total company amount of $127.796 million) to exclude $73.931 million of the IDEM-related costs. If the Commission were to approve DEI's request for past ash closure costs, Ms. Armstrong also indicated her support for OUCC Witness Kollen's levelized-cost method for recovering regulatory assets sought in this proceeding, stating that Mr. Kollen's method would mitigate the impact these substantial closure costs will have on ratepayers. She further recommended that any cost recovery methodology approved by the Commission should require DEI to offset the overall closure costs with the proceeds from any insurance settlements it receives for ash pond remediation and ash pond demolition costs previously recovered through depreciation. She stated that DEI should clearly show how it calculated ash pond closure costs recovered through previous rates, and include any indirect costs, contingency costs, and escalation applied to the demolition costs approved in previous rate cases.

Ms. Armstrong also opposed recovery of the Company's future IDEM Project and CCR Project costs, which will be addressed fully in Cause No. 45253-S1.[5] Ms. Armstrong testified that it is premature to approve the future ash pond closure costs, as DEI did not provide sufficient support for these estimates as is required in a CPCN proceeding. She explained that a utility normally provides a detailed engineering study with its application, which outlines the preferred compliance project and alternatives, the preferred and alternative projects' costs, and the technical and economic reasoning for selecting the preferred project. She further noted that the utility provides information regarding the utility's confidence in the estimate, such as the classification and range of certainty of the estimate pursuant to ACEEE standards. She stated DEI did not provide these estimates in its application in this Cause.

Ms. Armstrong stressed that this information is crucial for the Commission as part of its analysis to determine if the costs are prudent and warrant approval of a CPCN, as I.C. § 8-1-8.4-7(a) requires the utility to support its application with technical information in as much detail as the Commission requires in order to receive a CPCN under I.C. § 8-1-8.4-6. She referenced that in previous Commission decisions regarding other types of CPCNs the initial cost estimates are a significant factor in the Commission's decision-making process. She provided examples where the Commission encouraged utilities to improve the accuracy of their initial cost estimates, citing Cause Nos. 42170 ECR 16-S1 (Final Order at p. 7) and 44012 Phase I (Final Order at pp. 19-20). Since DEI did not provide this information with its application, she recommended denial of DEI's request for a federally mandated CPCN under I.C. § 8-1-8.4-7(b) for estimated future ash pond closure costs as DEI failed to meet the requirements for federally mandated project costs under I.C. § 8-1-8.4-6(b)(1)(B), or the alternative plans justifying the proposed compliance project under I.C. § 8-1-8.4-6(b)(1)(D).

Ms. Armstrong also stated that IDEM has not yet issued closure plans for the pond closures and reasoned that the plans could change based on what IDEM determines is reasonable to safely close the ponds. She provided IDEM's recently issued requests for information regarding DEI's closure plans and indicated that the agency is concerned DEI's plans do not prevent the lateral movement of groundwater through the ash closed in place (*See* OUCC Attachment CMA-7). She concluded that DEI's current estimates could vary based on IDEM's judgment of the plans.

She also advocated against Duke providing this information in rebuttal, as it will foreclose the OUCC's and intervenors' opportunity to adequately respond to DEI's compliance plans in testimony. She noted the Commission has admonished utilities that wait until rebuttal to support its case as a needless burden on the parties' time and resources (See Cause No. 45142, Final Order at p. 2).

She concluded by recommending the Commission deny DEI's request for estimated future ash pond closure costs at this time. She also recommended that once DEI receives approval for its closure plans and has more firm cost estimates, that it file a new request in a separate proceeding. If the Commission approved the future closure costs, she recommended that the costs be approved for only $443 million and exclude $60 million in IDEM-related CCR remediation activities. She also recommended that future costs be recovered according to OUCC Witness Kollen's levelized-

[5] Despite the establishment of a sub-docket, for completeness of the record we are including the recitation of Ms. Armstrong's argument regarding future CCR costs.

cost method for regulatory assets. Finally, she argued that any cost recovery method approved should require DEI to offset the overall closure costs with the proceeds from insurance settlements it receives for ash pond remediation and ash pond demolition costs previously recovered via depreciation, and she recommended DEI clearly show how it calculated ash pond closure costs recovered through previous rates.

[The OUCC accepts the Industrial Groups recitation of its evidence.]

[The OUCC accepts the Joint Intervenor's recitation of its evidence.]

iii. <u>Petitioner's Rebuttal Evidence</u>. The OUCC does not have any objections to Petitioner's recitation of its evidence.

iv. <u>Commission Discussion and Findings</u>. Regarding recovery of CCR costs, DEI has already agreed to (1) offset estimated amounts included in rates in prior decommissioning studies used to set rates; (2) include a credit of approximately $5 million for amounts collected in depreciation rates; (3) as part of its compliance filings for Step 1 and Step 2 rates to provide actual amounts for the coal ash regulatory asset as of December 31, 2019, and December 31, 2020; and (4) provide additional support for the calculation of the actual cost of removal credits as of those periods. These amounts reflect what DEI has already booked or accounted for that go to defray the costs that DEI seeks for the CCR and IDEM projects.

While no party disputed that the CCR Rule meets the definition of a federal mandate, or that DEI is required to comply with IDEM mandates, the question is whether DEI's previously-incurred coal ash-related expenses and forecasted 2019-2020 expenses should be recoverable through the rates sought here. We will discuss the various arguments of the parties.

We will address some of the other arguments as to why we should disallow recovery of the Company's coal ash basin closure and remediation expenses: (1) DEI should not be allowed to recover costs because it did not seek prior Commission approval to defer the costs; (2) allowing recovery of past costs would constitute retroactive ratemaking; (3) approximately $19 million of the costs relates to employee and contract services, which costs are traditionally recovered in DEI's base rates; (4) the IDEM Project costs are not "federally mandated" costs;[6] (5) DEI has not adequately addressed the factors it must include under the federal mandate statute; (6) the projects will not extend the useful life of a generating facility; and (7) past costs are not recoverable under the federal mandate statute. To the extent we do not address every argument in detail, we note that our findings below make some of the arguments moot, and therefore unnecessary to discuss.

Multiple parties argue that DEI should not be allowed to recover costs because it did not seek prior Commission approval to defer the costs. We must first note that DEI has shown itself able to ask for deferred accounting treatment in the past.[7] While we have in the past ruled that a

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[6] A "federally mandated requirement" by its very nature, and as elucidated in I.C. § 8-1-8.4-5, means something imposed by the *federal*, not state government. Therefore DEI's argument that IDEM costs qualify for inclusion in a "federal mandate" fails.

[7] *Petition of Duke Energy Indiana,* Cause No. 43743, 294 P.U.R.4th 156, 2011 WL 5088653 (IURC Oct. 19, 2011), *aff'd* 983 N.E.2d 160 (Ind. Ct. App. 2012); *Petition of Duke Energy Indiana LLC,* Cause No. 44734, 2016 WL 3667121 (IURC Jul. 6, 2016).

Commission order authorizing deferral is not a prerequisite to either deferring or recovering reasonable costs, specific facts dictate the outcome. If a utility defers a cost on the grounds that recovery is "probable", who or what determines the probability? Precedent can be a guide, but it is not determinative. DEI cites to *In Re Petition of South Haven Sewer Works, Inc.*, Cause No. 41903, 2002 Ind. PUC LEXIS 221 (IURC June 5, 2002) as support for its proposition that the Commission has previously allowed recovery of costs that were deferred before the Commission gave approval.[8] However, *South Haven* does not provide the support DEI argues, as it analyzed costs incurred under the Uniform System of Accounts for Class A Wastewater Utilities pursuant to 170 I.A.C. 8-2-1.

> To the extent South Haven is unclear about the 'probability' this Commission will approve a particular deferred debit, the Commission clarifies that deferred debits have traditionally been approved in very limited circumstances. Two kinds of deferred debits that are routinely approved are rate case expenses and tank painting expenses. Treating those costs as deferred debits *is explicitly contemplated in the instructions for Account 186*. As pointed out by Petitioner, the Commission also allowed the recovery of a deferred debit for construction interest expense by Hoosier Energy Rural Electric Cooperative in Cause No. 37294-E2. In those cases where the Commission has allowed the recovery of a deferred debit, the common traits are that the costs being amortized as deferred debits are infrequently incurred, involve assets with significant and long-lasting benefits, and involve significant cost, to the point that it is prudent to smooth the cost over a period of years. Often this 'smoothing' is used to lower the revenue requirement when that revenue requirement is based on a test year that includes certain irregularly incurred expenses, for example, rate case expenses and tank painting.
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> *South Haven*, Final Order at 16 (emphasis added).

The Commission's findings in South Haven did not uniformly approve the inclusion of deferred costs in rates. Instead, it found that certain deferred costs contemplated by utility-industry-specific rules (in South Haven's case, a privately-owned water/sewer utility) *could* be included in rates. A thorough reading of *South Haven* shows that the Commission considered a wide range of deferred expenses and disallowed most of them. South Haven's citation to 170 I.A.C. 8-2-1, which authorizes the USOA for Class A wastewater utilities, refers specifically to the instructions for Account 186.

> 186. Miscellaneous Deferred Debits
> A. This account shall include all debits not elsewhere provided for, such as miscellaneous work in progress, losses on disposition of property, net of income taxes, deferred by authorization of the Commission, and unusual or extraordinary expenses, not included in other accounts, which are in process of amortization, and items the proper final disposition of which is uncertain.
> B. The records supporting the entries to this account shall be so kept that the utility can furnish full information as to each deferred debit.

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[8] DEI's citation to *In re Amended Petition of Northern Indiana Public Service Co.,* Cause No. 43396-S1, 2009 Ind. PUC LEXIS 59 (IURC Feb. 18, 2009) is inappropriate, as the case was a settlement and is not to be used as precedent.

> C. The following subaccounts shall be maintained as a minimum unless otherwise authorized by the Commission. The utility may add additional subaccounts, if desired (such as deferred tank painting expenses).
> 186.1 Deferred Rate Case Expense
> 186.2 Other Deferred Debits

South Haven, pp. 16-17.

The Commission went on to note that the descriptions in the instructions for Account 186:

> all lead to the conclusion that this is a catch-all account for items that are unusual in nature or do not clearly fit into other accounts. Of particular note is Part B, which unlike other provisions of the Uniform System of Accounts, places a burden on the utility to justify the inclusion of items under this account.
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> Petitioner's "deferred debit accounting system" turns the unusual and catch-all nature of Account 186 on its head. Under Petitioner's proposal, the expenditure for any non-capital asset with a useful life in excess of one year could be treated as a deferred debit. Such an approach would create an entire microcosm of sub-accounts within what is essentially a miscellaneous account.
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> *South Haven*, p. 17.

As a consequence, DEI's citation to *South Haven* does not provide support for deferred accounting of CCR costs. Further, our decision regarding CCR remediation in *In re Vectren*, Cause No. 45052, dealt with a request for prospective recovery of such costs under I.C. ch. 8-1-8.4, the federal mandate statute. "While the utility may incur any amount of operating expense it chooses, the Commission is invested with broad discretion to disallow for rate-making purposes any excessive or imprudent expenditures." *City of Evansville v. S. Ind. Gas & Elec. Co.*, 339 N.E.2d 562, 569 (Ind. Ct. App. 1976) (hereafter *"City of Evansville")*. This has generally been expressed as a cautionary warning to utilities that preapproval of expenses will provide prospective rate recovery; utilities who seek approval after the fact face the prospect of denial. We reject DEI's attempted recovery of deferred expenses without prior authorization.

As to DEI's argument that there is no violation of the prohibition on retroactive ratemaking, we disagree. DEI's citation to *Indiana Tel. Corp. v. Public Serv. Comm'n of Indiana*, 171 N.E.2d 111, 124 (Ind. Ct. App. 1960) makes the very point that DEI itself is trying to avoid – the Commission does not have "the power to cancel, or to fix, rates retroactively. The statute provides the Commission with the power to fix rates for the future if it finds the rates in effect to be unreasonable or unjust; but we look in vain to find statutory authority for the Commission to fix rates for the past. The Commission has no powers except those conferred by statute." *Id.*, 171 N.E.2d at 124. DEI seeks to recover past losses, which "cannot be recovered from consumers nor can consumers claim a return of profits and earnings which may appear excessive." *Indiana Bell Tel. Co., Inc. v. Office of Util. Consumer Counselor*, 717 N.E.2d 613, 625 (Ind. Ct. App. 1999), *mod. on reh'g on other grounds*, 725 N.E.2d 432 (Ind. Ct. App. 2000). This is also implied in the test year construct. Traditionally historic in nature, Indiana utilities are now free to use a future test year, or a hybrid historic/future approach. Therefore, "the initial determination that the Commission must make concerns the future revenue requirement of the utility." *City of Evansville* at 568; *see also* I.C. § 8-1-2-42.7. The historic CCR/IDEM costs are not recurring expenses, as contemplated in the calculation of revenue requirements. Instead, the costs DEI seeks to (retroactively) recover are part of decommissioning, closure and retirement obligations already contemplated by DEI's current rates. DEI acknowledges as much in its agreement to calculate decommissioning and depreciation amounts in its future filings.

Long-standing precedent is clear: the Commission may not fix rates for the past, but only the future. "[T]he Commission does not have the statutory authority to set rates retroactively." *Airco Indus. Gases v. Indiana Michigan Power Co.*, 614 N.E.2d 951, 953 (Ind. Ct. App. 1993). Instead, the Commission has only "the power to fix rates for the future, not for the past." *Id.* Indeed, "[w]e find nothing in the statute giving the Commission the power to cancel, or to fix, rates retroactively. The statute provides the Commission with the power to fix rates *for the future* if it finds the rates in effect to be unreasonable or unjust; but we look in vain to find statutory authority for the Commission to fix rates *for the past*. The Commission has no powers except those conferred by statute." *Indiana Tel. Corp. v. Pub. Serv. Comm'n of Ind.*, 131 Ind. App. 314, 340, 171 N.E.2d 111, 124 (1960) (emphasis in original).

DEI's request to include its past CCR and IDEM costs in prospective rates is retroactive ratemaking: DEI seeks to recover costs it incurred in the past that were not otherwise authorized to recover. We reject this attempt at retroactive ratemaking.

In addition, whether DEI may have collected enough revenue during the time period of the deferrals to fully recover coal ash-related costs cannot be resolved by reference to DEI's FAC orders. FAC orders showing that DEI has not been overearning its authorized return on a sustained basis during the period the costs were incurred are not by themselves dispositive. The FAC "earnings test" is a simple calculation that compares the current earnings of the company as filed in the FAC to what the utility was previously authorized to recover in base rates. *See*, I.C. § 8-1-2-42(d)(3). The earnings test does not show, nor is it intended to, how the internal workings of the utility may have changed to modify factors previously established in rates. This is especially true in light of the long period between DEI's last and current rate cases. The Commission's findings that DEI did or did not over-recover in a given FAC period should not be construed as a determination that DEI had enough revenue to recover coal ash related costs. We therefore reject DEI's arguments on this point.

As to the approximately $19 million of the costs related to employee and contract services traditionally recovered in DEI's base rates, we refer to our findings above regarding deferred expenses. The fact that DEI tracked employee and contractor time to the projects they were working on does not change the fact that employee salaries are already a part of DEI's existing rates and do not qualify for double recovery. Further, DEI deferred the contractor costs without approval. We therefore support the recommendation, already implicit in our decision regarding deferrals above, to deny recovery of employee and contract labor costs included in DEI's coal ash regulatory "asset."

Now we consider whether the Federal Mandate Statute applies to DEI's CCR costs. The CCR Rule qualifies as a federal mandate under I.C. § 8-1-8.4-5, and DEI must also comply with the IDEM solid waste management rules. This does not resolve the issue of whether DEI can collect CCR costs absent more. Indiana Code ch. 8-1-8.4 establishes a process by which energy utilities may request recovery of costs prospectively. Such future recovery is implicit in the requirement that the utility request a CPCN *before* acquiring the right to collect any qualifying costs from ratepayers. And it is explicit in the language of I.C. § 8-1-8.4-6(a), which states that "an energy utility that *seeks* to recover federally mandated costs under section 7(c) of this chapter must obtain from the commission a certificate that states that public convenience and necessity *will be served* by a compliance project proposed by the energy utility." Emphasis added. The statute clearly establishes that the right to cost recovery is prospective: the Commission must find that the compliance project will serve the public convenience and necessity *in the future*. Allowing the recovery of costs incurred before the Commission has authorized the utility to do so undoes the very purpose of Commission oversight. The point of a CPCN proceeding is to determine whether the project and its attendant costs are prudent *before* the utility passes such costs to consumers. A utility may incur any cost that it chooses, but the Commission is free to disallow costs it deems excessive or imprudent. *L.S. Ayres & Co. v Indianapolis Pwr. & Light Co.,* 351 N.E.2d 814, 820 (Ind. Ct. App. 1976).

We reject DEI's request to retroactively collect costs absent prior authorization. To interpret the statute as DEI suggests would produce an absurd result, one we choose to reject. *Appolon v. Faught,* 796 N.E.2d 297, 300 (Ind. Ct. App. 2003). Had the legislature intended utilities to be able to retroactively recover federally mandated costs, it would have said so. There is no such language in I.C. ch. 8-1-8.4. We therefore decline to authorize retroactive ratemaking treatment for costs incurred absent prior authorization.

This finding should not be a surprise to DEI, as we rejected DEI's request for retroactive application of I.C. ch. 8-1-8.4 in its most recent FMCA proceeding.

> We note that Ind. Code ch. 8-1-8.4 establishes a process by which energy utilities may request recovery of costs prospectively. Such future recovery is implicit in the requirement that the utility request a CPCN *before* acquiring the right to collect any qualifying costs from ratepayers. And it is explicit in the language of Ind. Code § 8-1-8.4-6(a), which states that "an energy utility that *seeks* to recover federally mandated costs under section 7(c) of this chapter *must* obtain from the commission a certificate that states that public convenience and necessity *will be served* by a compliance project *proposed* by the energy utility." The statute establishes that the right to cost recovery is prospective: the Commission must find that the compliance project will serve the public convenience and necessity *in the future.* Ind. Code § 8-1-8.4-6(b) is clear that the intent of a CPCN is to obtain a certificate of public convenience for a *proposed* compliance project, and Ind. Code § 8-1-8.4-6(b) requires the Commission to examine a description of the *projected* federally mandated costs associated with the *proposed* compliance project. As noted above, we are presented in this Cause with alternatives that are no longer ripe for prospective consideration. Allowing the recovery of costs incurred before the Commission has authorized the utility to do so undoes the purpose of Commission oversight. The point of a CPCN proceeding is to determine whether the project and its attendant costs are prudent *before* the utility passes such costs to consumers.

Petition of Duke Energy Indiana, LLC, Cause No. 44367 FMCA 4, 2019 WL 4600201 at *28-29 (IURC Sep. 18, 2019), *aff'd on reconsideration,* 2019 WL 6683737 (IURC Dec. 4, 2019)

DEI sought reconsideration of our decision in the FMCA case, seeking clarification that our decision would not be applied retroactively. While we made it clear that "the Commission's decision in this Cause is limited to DEI and the facts and circumstances of [44367 FMCA 4][,]" 2019 WL 6683737 at *4, our statutory analysis does not change.

> [T]he Commission performed a thorough statutory construction analysis of the applicable statutes in Ind. Code ch. 8-1-8.4 in its Final Order at pages 28-29. Ind. Code § 8-1-8.4-1 and -7 state that: (1) a CPCN is required before recovery can be granted; and (2) a utility must (a) receive approval of proposed compliance projects, and (b) the Commission must find that the public convenience and necessity will be served before rate recovery is allowed. The point of a CPCN proceeding is to determine whether the proposed compliance project and its attendant costs are prudent before the utility passes such costs to consumers….
>
> We recognize that federally mandated requirements rarely establish a prescribed project, but instead generally set a standard that can be met through a variety of alternative actions. Consequently, we fully expect a utility will incur costs related to its compliance with a federal mandate before it determines what compliance project should be undertaken. However, once the utility determines what compliance project is necessary, it is incumbent upon a utility that wants timely cost recovery of those related costs to file its request for approval within a reasonable time to afford meaningful Commission review. In this instance, because DEI failed to timely seek approval of its costs in a manner that afforded the Commission timely consideration of any alternatives for the years prior to its petition, we found it reasonable to award recovery only back to the time of the filing of its petition.

Id. at *3.

The statute has not changed since the entry of the Order on Reconsideration, and our analysis also remains the same. DEI failed to seek authority to incur the CCR or IDEM costs despite knowing years ago that it needed to do so. And while DEI notified the Commission in Cause No. 44765 that it would be undertaking further CCR and IDEM compliance activities and would ultimately bring its proposed plans to the Commission for approval under the federal mandate statute, it did not do so.[9] This is yet another reason why we decline to allow DEI to recover costs retroactively. We will fully address future CCR expenses in Cause No. 45253 S1.

j. <u>Amortization Periods and Amortization Methodology</u>.

i. <u>Petitioner's Evidence</u>. Duke Energy Indiana proposed various amortization periods for regulatory assets proposed to be included in rate base, ranging from three years to seven years, using a traditional straight-line amortization methodology.

[9] *See Petition of Duke Energy Ind.*, Cause No. 44765 at 7 (IURC May 24, 2017).

ii. **<u>OUCC's Evidence</u>**. OUCC witness Kollen recommended the use of an amortization period of at least ten years for regulatory assets included in rate base. Mr. Kollen also recommended the use of a "levelized" amortization methodology to amortize these regulatory assets. Mr. Kollen's levelization methodology calculates an annual annuity payment, similar to a home mortgage. He explained the calculation factors in the principal, in this case, the regulatory asset balance at June 30, 2020, the amortization period, in this case, ten years, and the return on the regulatory asset, in this case, the authorized rate of return. In addition, Mr. Kollen recommended that, regardless of whether or not the Commission adopts the levelization methodology, the reduction in the Company's costs (elimination of the amortization expense when the regulatory asset is fully recovered plus the reduction in the return on the unamortized balance as it is amortized under the Company's proposal, or the elimination of the levelized payments when the regulatory asset is fully recovered under Mr. Kollen's recommendation) be reflected in the Credits Rider 67. Mr. Kollen stated that including the levelized cost in the base revenue requirement and the reduction in the cost curve regardless of the methodology in the Credits Rider 67 is fair and reasonable because it provides the Company recovery of its regulatory assets with a return while balancing impact on ratepayers. Mr. Kollen explained the Company's proposal guarantees over recovery because the Company will continue to recover the return on the regulatory asset at June 30, 2020 until base rates are reset even though it incurs a reduced cost as the regulatory asset is amortized or no cost at all once it is fully amortized and recovered. Mr. Kollen noted that the regulatory asset amounts at June 30, 2020 are fixed, the amortization period is fixed, and the rate of return is fixed until the base rates are reset in a future proceeding.

iii. **<u>Petitioner's Rebuttal Evidence</u>**. The OUCC does not have any objections to Petitioner's recitation of its evidence.

iv. **<u>Commission Discussion and Findings</u>**. We find the Company's acceptance of Mr. Kollen's proposal of at least 10-year amortization periods for recovery of its regulatory assets to be reasonable, and we approve such, including approval of a 10-year amortization period for the Gallagher Units 1 and 3 regulatory asset. We also find that the OUCC recommendation to use a levelized methodology to calculate the revenue requirement is reasonable. Contrary to the Company's arguments, the levelization does not reduce the Company's opportunity to earn its authorized return on the regulatory assets as of the midpoint of the test year, in this case, June 30, 2020, the date utilized by the Company for the rate base amounts of the regulatory assets. Rather, the levelization *guarantees* that the Company will earn its rate of return on these regulatory assets. Also, contrary to the Company's arguments, the Company is allowed to defer a return on many of its regulatory assets; thus, we do not agree with the Company and its "compensating errors" arguments. Instead, we view the recovery of the return on existing regulatory assets separately from the return on new regulatory assets, with our concern focused on over recovering the return on the existing regulatory assets and under recovering the return on new regulatory assets where a return on those assets is authorized. Finally, we agree with the OUCC that the reductions in cost due to recoveries of the regulatory assets through base rates should be reflected in the Credits Rider 67. The Company agrees with the OUCC with respect to the amortization expense, but inexplicably disagrees with the OUCC with respect to the return on the regulatory assets, instead arguing that it should be allowed to retain these savings as the regulatory assets are amortized. This is a matter of principle. It is important to ensure that the Company recovers the principal and a rate of return on the regulatory assets included in rate base.

8. Original Cost of Duke Energy Indiana's Rate Base. Based upon the evidence presented in this case, and the findings discussed above, we find that the jurisdictional net original cost of Duke Energy Indiana's rate base used and useful for the benefit of the public is forecasted to be $9,928,875,000 at December 31, 2019, comprised of the following elements (which have not been updated or revised to reflect adoption of the OUCC's recommendations):

Net Electric Utility Plant in Service	$8,944,707,000
Fuel Inventory	116,322,000
Emission Allowance Inventory	86,000
Materials and Supplies	289,672,000
Prepaid Pension Asset	152,454,000
Regulatory Assets	425,634,000
NET UTILITY RATE BASE	$9,928,875,000

Further, we find that the jurisdictional net original cost of Duke Energy Indiana's rate base used and useful for the benefit of the public is forecasted to be $9,578,724,201 at December 31, 2020, comprised of the following elements:

Net Electric Utility Plant in Service	$9,201,378,959
Fuel Inventory	86,356,241
Emission Allowance Inventory	86,000
Materials and Supplies	286,925,000
Prepaid Pension Asset	0
Regulatory Assets	3,978,000
NET UTILITY RATE BASE	$9,578,724,201

9. Fair Value of Duke Energy Indiana's Rate Base. Petitioner presented a reproduction cost new less depreciation valuation study of its utility plant in service, but proposed that a fair return for purposes of this case be based on its weighted cost of capital times its original cost rate base. No party disputed that net original cost should be used as the fair value of Petitioner's utility plant in service in this case, or that a fair return for Petitioner should be based on its weighted cost of capital. Accordingly, we find that for purposes of this proceeding, Petitioner's fair value rate base is the same as its original cost rate base ($9,578,724,201), and that this fair value rate base should be used for purposes of Indiana Code § 8-1-2-6.

10. Fair Rate of Return.

a. Capital Structure.

i. Petitioner's Evidence. The OUCC does not have any objections to Petitioner's recitation of its evidence.

<u>OUCC's and Intervenors' Evidence</u>. OUCC Witness Kollen testified that the Company understated the Accumulated Deferred Income Taxes ("ADIT") included in capitalization as cost-free capital and thus, overstated the rate of return and revenue requirement. These errors affect the base revenue requirement and all riders that rely on the rate of return set in the base rate case for the rate of return used in those riders. First, as a matter of consistency between the rate base components and the related ADIT reflected in capitalization, Mr. Kollen recommended proposed adjustments to ADIT that directly correspond to and match the rate base adjustments proposed by the OUCC. Next, he proposed a number of adjustments to ADIT to remove certain per books ADIT amounts from capitalization not related to the costs included in rate base. As a general ratemaking principle, Mr. Kollen explained the ADIT reflected in capitalization as cost-free capital should match the rate base or other ratemaking treatment for the underlying temporary difference that gave rise to the ADIT. Mr. Kollen discussed if the underlying temporary difference is not reflected as an addition to or subtraction from rate base or otherwise reflected in other ratemaking revenues or costs, then the related liability or asset ADIT should not be added to or subtracted from the ADIT included in capitalization. Mr. Kollen listed the ADIT amounts that incorrectly reduce (on a net basis) the ADIT included in capitalization on a table set forth in his testimony, along with the reason why it should not have been included the ADIT reflected in the capitalization used to calculate the rate of return.

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Duke Energy Indiana, LLC
OUCC Recommended ADIT Adjustments
$

	Federal ADIT	State ADIT	Total ADIT	Reason*
FIT Gross-Up on Excess Federal Tax	5,130,584	-	5,130,584	3
FIT Gross-Up on Excess Federal Tax	1,576,799	-	1,576,799	3
Bad Debts - Tax over Book	431,923	105,975	537,898	2
Surplus Materials Write-off Liab	5,036	1,236	6,272	2
Surplus Materials Write-Off Asset	71,942	17,651	89,593	2
LT Cap Lease Oblig-Tax Oper	1,934,889	474,736	2,409,625	2
Mark to Market - LT	4,192,548	1,028,666	5,221,214	2
Accrued Vacation	3,586,550	879,981	4,466,531	2
Property Tax Reserves	3,690,477	905,480	4,595,957	2
Severence Reserve - LT	495,709	121,625	617,334	2
MGP Sites	768,883	188,650	957,533	2
Deferred Revenue	508,123	124,671	632,794	2
Miscellaneous NC Taxable Income Adj - DTA	2,667,840	654,570	3,322,410	2
Reserve for Claims	813,818	199,675	1,013,493	2
Lawsuit Contingency	841,006	206,346	1,047,352	2
Rate Refunds	(218,931)	(53,716)	(272,647)	2
Demand Side Management (DSM) Defer	1,538,861	377,568	1,916,429	2
Charitable Contribution Carryover	43,683	10,718	54,401	1
Retirement Plan Expense - Underfunded	7,793,009	1,912,059	9,705,068	2
Non-qualified Pension - Accrual	637,311	156,368	793,679	2
RUS Obligation - Contract Reserve	10,407,789	2,553,611	12,961,400	3
Annual Incentive Plan Comp	1,445,266	354,604	1,799,870	1
OPEB Expense Accrual	11,407,830	2,798,977	14,206,807	1,2
FAS 112 Medical Expenses Accrual	1,058,173	259,629	1,317,802	1,2
OPEB Admin Fees	(1,094,679)	(268,586)	(1,363,265)	2
Deferral Comp - Emp Director	665,412	163,263	828,675	1
FERC - FIT Adj Offset to Regulatory Liability (182320)	59,002,419	-	59,002,419	2
FERC - SIT Adj Offset to Regulatory Liability (182320)	-	29,034,613	29,034,613	2
Reg Liability - Overcollection of Revenue Refund Adj	(3,530,980)	(866,346)	(4,397,326)	2
Vacation Carryover - Reg Asset	(2,205,370)	(541,100)	(2,746,470)	2
Deferred Fuel Asset - LT	(2,864,025)	(702,705)	(3,566,730)	2
Rate Case - Deferred Costs	(83,007)	(20,366)	(103,373)	2
Federal Excess DIT Adjustment-254036	27,121,792	-	27,121,792	3
Total	137,840,680	40,077,853	177,918,533	

* 1: Expense not included in revenue requirement
2: Temporary difference not added to or subtracted from rate base
3: Temporary difference not included in cost of capital

The positive amounts shown on the table are asset ADIT that incorrectly reduced the ADIT included in capitalization and the negative amounts are the liability ADIT that incorrectly increased the ADIT included in capitalization. Mr. Kollen then summed the effects on the retail revenue requirement of removing these ADIT amounts from the ADIT included in capitalization and showed the effect on a single line item on the table in the Summary section of his testimony. The effect of Mr. Kollen’s adjustments is a $10.559 million reduction in the retail revenue requirement due to the increase in ADIT included in capitalization as cost-free capital.

[The OUCC accepts the FEA recitation of its evidence.]

ii. **Petitioner's Rebuttal Evidence.** The OUCC does not have any objections to Petitioner's recitation of its evidence.

iv. **Commission Discussion and Findings**. We will first address the ADIT included as cost-free capital in the capital structure used for the rate of return. We agree with Mr. Kollen's adjustments based on the general matching principle. We agree the ADIT included in the calculation of capitalization should be *consistent* with and *match* the costs (underlying temporary differences that gave rise to the ADIT) included in rate base and other revenues and costs reflected in the revenue requirement. The Company appears to partially agree with Mr. Kollen when it agreed in its rebuttal case to remove the non-utility and certain other ADIT items from capitalization where it had excluded the temporary differences that gave rise to the ADIT items from rate base. We find that this matching should also apply for the other ADIT amounts identified by Mr. Kollen. We see no difference between excluding an ADIT that is "non-utility" and excluding any other ADIT that is related to any other revenue or cost that is not included in the revenue requirement. Fundamentally, each ADIT amount results from a temporary difference. If the temporary difference is the result of a rate base cost or a revenue or expense that is included in operating income, then the ADIT should be reflected in the capitalization. If not, then the ADIT should not be reflected in the capitalization.

b. **Cost of Debt.**

i. The OUCC has no exceptions to this section.

c. **Cost of Equity.**

i. **Petitioner's Evidence.** The OUCC does not have any objections to Petitioner's recitation of its evidence.

ii. **OUCC's Evidence.** Mr. Garrett testified that, pursuant to the legal and technical standards, the awarded ROE should be based on, or reflective of, the utility's cost of equity. He testified that the Company's estimated cost of equity is approximately 6.3%, based on his analyses using the DCF and CAPM methodologies. He noted, however, these legal standards do not mandate the awarded ROE be set exactly equal to the cost of equity. Rather, he stated, in *Federal Power Commission v. Hope Natural Gas Co*., the U.S. Supreme Court found that, although the awarded return should be based on a utility's cost of capital, it is also indicated that the "end result" should be just and reasonable. Mr. Garrett testified that if the Commission were to award a return equal to the Company's estimated cost of equity of 6.3%, it would be accurate from a technical standpoint. He recommended, however, the Commission authorize an ROE that is remarkably higher than the Company's actual cost of equity in this case. Specifically, he recommends an authorized ROE of 9.0%, which he stated is within a reasonable range of 8.75% – 9.25%. He noted that the ratemaking concept of "gradualism," though usually applied from the customer's standpoint to minimize rate shock, could also be applied to shareholders. He further noted that an authorized return as low as 6.3% in any current rate proceeding would represent a substantial change from the "status quo." He testified that if the Commission were to make a significant, sudden change in the authorized ROE anticipated by regulatory stakeholders, it could have the undesirable effect of notably increasing the Company's risk profile and would arguably be at odds with the *Hope* Court's "end result" doctrine. He opined that an authorized ROE of 9.0%

represents a good balance between the Supreme Court's indications that awarded ROEs should be based on cost, while also recognizing that the end result must be reasonable under the circumstances. He further opined that an authorized ROE of 9.0% also represents a gradual move toward the Company's market-based cost of equity, and it would be fair to the Company's shareholders because 9.0% is over 250 basis points above the Company's market-based cost of equity.

Mr. Garrett testified that he chose to use the same proxy group used by Mr. Hevert. He stated that there could be reasonable arguments made for the inclusion or exclusion of a particular company in a proxy group; however, he noted the cost of equity results are influenced far more by the underlying assumptions and inputs to the various financial models than the composition of the proxy groups.

Mr. Garrett chose to use the Quarterly Approximation DCF Model to estimate the Company's cost of equity capital. To determine the stock price input to the DCF Model, he used a 30-day average of stock prices for each company in the proxy group, under the rationale that using a short-term average of stock prices for the current stock price input adheres to market efficient principles while avoiding any irregularities that may arise from using a single current stock price. The stock prices he used were based on 30-day averages of adjusted closing stock prices for each company in the proxy group. The dividend term in the Quarterly Approximation DCF Model is the current quarterly dividend per share. Mr. Garrett testified that the Quarterly Approximation DCF Model results in the highest cost of equity relative to other DCF Models, all else held constant, due to the quarterly compounding of dividends inherent in the model. Mr. Garrett stated that the differences between his DCF Model and Mr. Hevert's DCF Model are primarily driven by differences in growth rate estimates, rather than by stock price and dividend inputs for each proxy company.

Mr. Garrett stated that the most critical input in the DCF Model is the growth rate, and unlike the stock price and dividend inputs, the growth rate input must be estimated. The DCF model he used in this case is based on the constant growth valuation model. Under this model, a stock is valued by the present value of its future cash flows in the form of dividends. Before future cash flows are discounted by the cost of equity, however, they must be "grown" into the future by a long-term growth rate. Thus, as stated above, one of the inherent assumptions of this model is that these cash flows in the form of dividends grow at a constant rate forever. Mr. Garrett stated that once a firm is in the maturity stage, it is not necessary to consider higher short-term growth metrics in multi-stage DCF Models; rather, it is sufficient to analyze the cost of equity using a stable growth DCF Model with one terminal, long-term growth rate. He testified that because utilities are in their maturity stage, their real growth opportunities are primarily limited to the population growth within their defined service territories, which is usually less than 2%. He noted that in Duke Energy Indiana's 2018 IRP, the Company acknowledged a very low load growth projection of 0.5% over the 20-year planning period. He noted that this figure is starkly at odds with Mr. Hevert's annual earnings growth projections for the proxy group, which are as high as 10% per year over the long term.

Additionally, Mr. Garrett stated, a fundamental concept in finance is that no firm can grow forever at a rate higher than the growth rate of the economy in which it operates. Thus, the terminal growth rate used in the DCF Model should not exceed the aggregate economic growth rate. This is especially true, he stated, when the DCF Model is conducted on public utilities because these firms have defined service territories. In fact, he offered, it is reasonable to assume that a regulated utility would grow at a rate that is less than the U.S. economic growth rate. He testified that according to the Congressional Budget Office's Budget Outlook, the long-term forecast for nominal U.S. GDP growth is 3.9%, which includes an inflation rate of 2%. For mature companies in mature industries, such as utility companies, he opined, the terminal growth rate will likely fall between the expected rate of inflation and the expected rate of nominal GDP growth. Thus, he concluded that the Company's terminal growth rate is realistically between 2% and 4%.

He added that any thorough assessment of company growth should be based upon a "qualitative" analysis. Such an analysis would consider specific strategies that company management will implement to achieve a sustainable growth in earnings. While qualitative growth analysis is important regardless of the entity being analyzed, it is especially important in the context of utility ratemaking. This is because the rate base rate of return model inherently possesses two factors that can contribute to distorted views of utility growth when considered exclusively from a quantitative perspective: (1) rate base and (2) the awarded ROE.

Mr. Garrett stated that he considered various qualitative determinants of growth for the Company, along with the maximum allowed growth rate under basic principles of finance and economics. For the long-term growth rate in his DCF model, he selected 3.90%, which means his model assumes that the Company's qualitative growth in earnings will match the nominal growth rate of the entire U.S. economy over the long run.

Based on Mr. Garrett's inputs to the Quarterly Approximation DCF Model discussed, he estimated a DCF cost of equity estimate for the Company of 6.9%, which he characterized as likely being at the higher end of the reasonable range due to his relatively high estimate for the long-term growth rate.

Mr. Garrett also offered several critiques of Mr. Hevert's DCF analyses, summarized as follows:

- The results of Mr. Hevert's DCF Model are overstated primarily because of a fundamental error regarding his growth rate inputs. Mr. Hevert used long-term growth rates in his proxy group as high as 10%, which is about three times as high as projected, long-term nominal U.S. GDP growth (about 4.0%). This means Mr. Hevert's growth rate assumption violates the basic principle that no company can grow at a greater rate than the economy in which it operates over the long-term, especially a regulated utility company with a defined service territory. Further, Mr. Hevert used short-term, quantitative growth estimates published by analysts. These analysts' estimates are inappropriate to use in the DCF Model as long-term growth rates because they are estimates for shorter-term growth.

- Mr. Hevert inappropriately considered flotation costs when making his awarded return recommendation. Flotation costs are not actual "out-of-pocket" costs; the Company has not experienced any out-of-pocket costs for flotation. Instead, underwriters are compensated through an "underwriting spread "-- the difference between the price at which the underwriter purchases the shares from the firm, and

> the price at which the underwriter sells the shares to investors. Furthermore, Duke Energy Indiana is not a publicly traded company, which means it does not issue securities to the public and thus would have no need to retain an underwriter. Accordingly, the Company has not experienced any out-of-pocket flotation costs. Moreover, the market already accounts for flotation costs.

Mr. Garrett next discussed his CAPM analysis. He testified that he considered a 30-day average of daily Treasury yield curve rates on 30-year Treasury bonds in his risk-free rate estimate, which resulted in a risk-free rate of 2.18%. Further, he testified that he used betas recently published by Value Line Investment Survey. He noted that the beta for each proxy company is less than 1.0, and the average beta for the proxy group is only 0.57.

Next, Mr. Garrett testified about the Equity Risk Premium ("ERP"). He testified that he relied primarily on the ERP reported in expert surveys and the implied ERP method rather than the calculation of a historical average. He stated that, after collecting data for the index value, operating earnings, dividends, and buybacks for the S&P 500 over the past six years, he calculated the dividend yield, buyback yield, and gross cash yield for each year. He also calculated the compound annual growth rate (g) from operating earnings. He used these inputs, along with the risk-free rate and current value of the index to calculate a current expected return on the entire market of 8.19%. He then subtracted the risk-free rate to arrive at the implied equity risk premium of 6.0%. For the final ERP estimate he used in his CAPM analysis, he considered the results of the ERP surveys, the implied ERP calculations discussed above, and the estimated ERP reported by Duff & Phelps. Mr. Garrett stated that he conservatively selected the highest ERP estimate of 6.0% to use in his CAPM analysis. Using the inputs for the risk-free rate, beta coefficient, and equity risk premium discussed above, he estimated that the Company's CAPM cost of equity is 5.6%.

Mr. Garrett also critiqued certain aspects of Mr. Hevert's CAPM analysis. He stated that the primary problem with Mr. Hevert's CAPM cost of equity result stems primarily from his estimate of the ERP, which he estimates as high as 12%. Mr. Garrett stated that the highest ERP found from my research and analysis is only 6.0%.

Regarding Mr. Hevert's other Risk Premium analyses, Mr. Garrett testified that he disagreed with the premise of Mr. Hevert's "bond yield plus risk premium" analysis, because Mr. Hevert looked at awarded ROEs dating back to 1980. He stated that not only is this contra to Mr. Hevert's claim that the cost of equity is a "forward-looking" concept, but it also suffers from the fact that awarded ROEs are consistently higher than market-based cost of equity. Further, he stated that the risk premium analysis offered by Mr. Hevert is completely unnecessary when we already have a real risk premium model to use: the CAPM. The CAPM itself is a "risk premium" model; it takes the bare minimum return any investor would require for buying a stock (the risk-free rate), then adds a premium to compensate the investor for the extra risk he or she assumes by buying a stock rather than a riskless U.S. Treasury security.

Mr. Garrett also took issue with Mr. Hevert's consideration of various firm-specific risk factors. He stated that the Commission should not consider these firm-specific business risk factors in making their decision on a fair awarded ROE in this case, because they are not unique to Duke Energy Indiana. He argued that that market risk, or "systematic risk," is the only type of risk for which investors expect a return for bearing, and investors do not require additional compensation for assuming these firm-specific business risk.

He concluded that the cost of equity indicated by the results of the DCF Model and the CAPM is about 6.3%. He added that the average market cost of equity from sources such as consulting expert surveys, etc., is only 7.5%, which he stated supports his estimated 6.3% ROE. He recommended the IURC award the Company with a 9.0% ROE, which is the midpoint in a reasonable range of 8.75% – 9.25%. He stated that although Duke Energy Indiana's cost of equity is much lower than 9.0% by any objective measure, the Commission should gradually reduce the Company's awarded return towards market-based levels, consistent with the *Hope* Court's end result doctrine

iii. <u>Industrial Group's Evidence</u>. The OUCC accepts the Industrial Group's recitation of its evidence.

iv. <u>FEA's Evidence</u>. The OUCC accepts FEA's recitation of its evidence.

v. <u>Walmart's Evidence</u>. The OUCC accepts Walmart's recitation of its evidence.

vi. <u>Petitioner's Rebuttal Evidence</u>. The OUCC does not have any objections to Petitioner's recitation of its evidence.

vii. <u>Commission Discussion and Findings</u>. In setting the rate of return for Duke Energy Indiana, the Commission's decision must be framed by *Bluefield Waterworks & Improvements Co. v. Pub. Serv. Comm'n,* 262 U.S. 679, 43 S.Ct. 675 (1923) and *Federal Power Comm'n v. Hope Natural Gas, Co.,* 320 U.S. 591, 64 S. Ct. 281 (1944).[10] The general standards these cases established require a cost of common equity set by the Commission be sufficient to establish a rate of return that will maintain the utility's financial integrity, attract capital under reasonable terms, and be commensurate with the returns that could be earned in investments in other enterprises of comparable risk.

More recently, we stated

> The Commission is also mindful that 'the cost of common equity cannot be precisely calculated and estimating it requires the use of judgment.' *Indiana-American Water Co.,* Cause No. 44022, p. 35 (June 6, 2012). Due to this lack of precision, the use of multiple methods is desirable, in part, because no one method will produce reasonable results under all conditions and in all circumstances.

In re *Petition of Indiana Michigan Power Co*., Cause No. 45235, at p. 40 (IURC March 11, 2020).

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[10] *See also Re Indianapolis Power & Light Co.,* Cause No. 44576, p. 41, 2016 WL 1118795 *43 (IURC March 16, 2016).

The Commission is also mindful of the strengths and weaknesses of the various models typically used to estimate a utility's cost of common equity, and we find that with appropriate and reasonable inputs, models such as the DCF and CAPM can produce reasonable estimates of a utility's cost of common equity. Consistent with the standards in *Hope* and *Bluefield,* as well as under Indiana law, Duke Energy Indiana's authorized return on equity should be reasonable given the totality of the circumstances.

Many of the witnesses testifying concerning Petitioner's cost of capital used similar approaches – various types of DCF studies, the CAPM model, Risk Premium approaches, and Comparable Earnings analyses. Mr. Hevert's recommended range of reasonable ROEs for Petitioner is 10.00% to 11.00%, with a point recommendation of 10.40%. In contrast, three non-Duke witnesses testified with a specific recommendation for ROE: OUCC witness Mr. Garrett, Industrial Group witness Mr. Gorman, and FEA witness Mr. O'Donnell. Though these witnesses included different ranges in their testimony, all three ultimately recommended an ROE of 9.00%.[11] In addition, Walmart witness provided information about ROEs in other jurisdictions, and did not specifically recommend an ROE.

In addition to the recommendations of these experts, while not determinative of the COE the Commission approves in this Cause, we note the COE awarded Indiana's vertically integrated electric utilities outside of settled cases has been trending lower over time. *See, e.g.,* PSI Energy, Inc. (now Duke Energy Indiana) 10.5% in Cause No. 42359 (2005); Southern Indiana Gas and Electric Company 10.4% in Cause No. 43839 (2011); Indiana Michigan Power 10.2% in Cause No. 44075 (2013); and Indianapolis Power and Light Company 9.85% in Cause No. 44576 (2016). Most recently, the COE awards for such an electric utility were 9.75% (approved on December 4, 2019, for Northern Indiana Public Service Company LLC in Cause No. 45159) and 9.70% (approved on March 11, 2020, for Indiana Michigan Power Company in Cause No. 45235).

We find the evidence shows Mr. Hevert's recommended COE of 10.40% exceeds a reasonable estimate of Duke Energy Indiana's COE given current market conditions and recent COE decisions approved by the Commission and approved nationwide for investor-owned electric utilities. More specifically, the record reflects Mr. Hevert's constant growth DCF analysis relies on unsustainably high growth rates the Commission finds are unrealistic. Mr. Hevert's CAPM utilizes inflated market risk premiums, his ECAPM is based on flawed methodology, and that his Bond Yield Plus Risk premium studies are based on inflated utility equity risk premiums.

The evidence also shows Mr. Hevert's cost of common equity reflects consideration of a "flotation cost" adder that, while not directly included in his DCF, CAPM, or RP models, nevertheless was considered in developing his recommendations. With respect to flotation costs, we have previously stated that the "Commission will only allow such an adjustment when it is based on verifiable actual costs so that the reasonableness and appropriateness of the costs may be examined." *Indiana-American*, Cause 44022 at 35.

[11] With respect to Mr. Garrett's 6.30% "true" cost of equity, we note his distinction (direct at pp. 26-31) between that number and his recommended *authorized* return on equity. The former is based on financial and mathematical models using historical data & forward-looking projections. The latter is the ultimate decision of the regulator, based on "fairness" and "reasonableness," which are necessarily subjective elements, informed further by the entirety of the evidence presented.

We are not persuaded Mr. Hevert appropriately considered the mitigation of risk associated with various regulatory mechanisms, including Duke Energy Indiana's use of a future test year in this proceeding and the riders and/or trackers approved for Duke Energy Indiana. His recommendations are also inconsistent with recent COE decisions approved nationwide for investor-owned electric utilities, based on intervenor Walmart's evidence, and with the lower trend, generally, by the Commission. While the Commission does not base its COE conclusion on national averages, the evidence presented demonstrates the trend in approved COEs for vertically-integrated utilities, both in Indiana and nationwide, is lower than Duke Energy Indiana requests. We recognize financial strength is important for a utility to attract capital at a reasonable cost in order to make the investment necessary to fulfill its service obligations, but the evidence demonstrates investor-owned utilities similar to Duke Energy Indiana and located in similar regulatory jurisdictions have been awarded reasonable and fair COEs that are below Duke Energy Indiana's requested range.

The evidence presented in this case demonstrates that the current market cost of equity for both debt and equity securities for utility companies was very low in the current market environment at the time of the hearing. Tr. at P24. Moreover, though the authorized returns on equity in Indiana and nationwide are trending downward, they are still above the current market cost of equity. *Id*. at P24-P25. The evidence also demonstrates that authorizing a 9.00% return as recommended by the non-Duke parties will maintain Duke's financial stability and credit rating. We base our findings of cost of equity on the evidence presented. A lower cost of equity, if justified by the evidence and market conditions, will reassure the markets that Indiana regulatory policy is consistent far more than adoption of an artificially high return on equity done without regard to the evidence of market conditions.

The Commission has considered the analytical results based on a proxy group of electric utilities, as well as the risk factors associated with: Duke Energy Indiana's generation portfolio and environmental regulations; Duke Energy Indiana's planned capital expenditures, and the costs of issuing common stock. We find these risk factors are, however, lessened by the future test year Duke Energy Indiana used, and the trackers Duke Energy Indiana is requesting and/or has in place, which serve to reduce risks of uncertainty Duke Energy Indiana would otherwise face. Having recognized the risk factors, we find it is important the Commission also recognize factors mitigating these risks. As the Commission stated in *Indianapolis Power & Light Co.,* Cause No. 44576, p. 42 (IURC March 16, 2016):

> Trackers that adjust rates for incremental investments or for costs that are nearly certain to be increasing serve to adjust the base line earnings for post rate case changes and address issues primarily associated with regulatory lag. Trackers that adjust rates for cost changes that are more unknown and that are equally likely to decrease or increase address the rise of volatile earnings results. The general effect of these trackers reduces the uncertainty of earnings that an investor can expect.

Mr. Eckert's Table 1 helps quantify the impact of the Company's trackers. It demonstrates how nearly 40% of an average (1,000 kWh per month) residential customer's $119.94 bill is attributable to current trackers. This sizeable portion of tracked revenue provides additional security to the Company by reducing volatility in monthly cash flows. The Company's EE and

DSM programs further reduce risk. 100% of all program costs, including evaluation, measurement and verification, are paid by ratepayers and recovered through the DSM tracker. Duke Energy is further insulated from risk by the DSM program's associated lost revenues and shareholder incentives, which are also tracked.

Having taken into consideration the foregoing factors and observable market data reflected in the record, including the impact of Federal Reserve policies on current and expected long-term capital market costs, an assessment of the current risk premium built into current market securities, expected inflation rates, and a general assessment of the current investment risk characteristics of the electric utility industry, combined with a thorough understanding of the Indiana jurisdiction and its risk mitigation ratemaking mechanisms, and Duke Energy Indiana in particular, the Commission finds a reasonable range for Petitioner's COE is 8.75% to 9.25%. Taking into consideration all the evidence presented, the Commission finds and concludes a 9.00% COE is fair and reasonable under the totality of the circumstances.

Accordingly, for purposes of this Cause, we find that Petitioner's overall cost of capital is 5.40%, computed as follows:

Description	Capitalization (in thousands)	Ratio	Cost	Weighted Cost
Common Equity	$ 4,770,344	40.89%	9.00%	3.68%
Long Term Debt (estimated)	4,224,223	36.21%	4.50%	1.63%
Deferred Income Taxes	2,447,974	21.25%	0.00%	0.00%
Unamortized ITC – Crane Solar	10,999	0.09%	6.88%	0.01%
Unamortized ITC -- 1971 & Later	1,955	0.02%	6.88%	0.00%
Unamortized ITC – Advanced Coal (IGCC)	133,500	1.14%	6.88%	0.08%
Customer Deposits	47,056	0.40%	2.00%	0.01%
Total	$ 11,669,051	100.00%		5.40%

11. **Forecasted Operating Income at Present Rates and *Pro Forma* Adjustments**.

a. General. For the forecasted test period ending December 31, 2020, Duke Energy Indiana's Jurisdictional operating income from its electric utility operations on an ongoing level basis, is as follows:

$ in Millions under current rates	2020
Total Operating Revenues	2,517.952
Operating Expenses	
Operation and Maintenance, Incl. Fuel and Purchased Power	1,355.783
Depreciation and Amortization	693.925
Property and other Taxes	68.569
Income Taxes	57.316
Total Operating Expenses	2,175.593
Operating Income	342.359

b. Undisputed *Pro Forma* Adjustments. Petitioner proposed a number of undisputed *pro forma* adjustments to its operating income in its forecasted test period results. It proposed other adjustments that, though disputed at some point in the process of this rate case, were compromised or were no longer in dispute at the conclusion of the evidentiary hearing in this Cause. All such undisputed *pro forma* adjustments proposed by Petitioner, either as originally proposed and undisputed, or as compromised with the compromised positions having been fully identified by the parties, are hereby accepted even though they may not be specifically discussed in this Order. Note that these undisputed *pro forma* adjustments we are approving include the agreement reflected in Mr. Jacobi's and Ms. Sieferman's rebuttal testimony to reduce Account 575 expense by $2.0 million. We note also that Petitioner proposed, and no party disputed, that its base cost of fuel should be 26.955 mills per kWh.

c. Disputed *Pro Forma* Adjustments. In making our determinations regarding an appropriate level of forecasted operating expenses to be used in setting Petitioner's rates, we are guided by our overall objective of achieving a level of expenses which are representative of probable future experience. The Indiana courts have emphasized the importance of viewing test year results and *pro forma* adjustments in the context of estimating a representative ongoing level of utility expenses. *See, e.g., City of Evansville v. Southern Indiana Gas & Electric Co.*, 167 Ind. App. 472, 339 N.E.2d 562, 575 (Ind. Ct. App. 1976), in which the Court stated that: "The theory underlying the use of any test year and of any adjustment method in the rate-making process demands that the data used provide an accurate picture of the utility's operations during the period in which the proposed rates will be in effect." With this guidance in mind, we turn to an examination of the disputed *pro forma* revenue and expense adjustments at issue in this case.

i. Load Forecast and Unbilled Revenues.

(A) Petitioner's Evidence. The OUCC does not have any objections to Petitioner's recitation of its evidence.

(B) OUCC's Evidence. The OUCC raised two load forecast-related issues, relating to: (1) unbilled revenues; and (2) the residential energy use forecast. With regard to unbilled revenues, OUCC witness Kollen recommends that the Commission reject the Company's *pro forma* adjustment removing its unbilled revenues. Mr. Kollen testified the Company records and reports revenues using the unbilled revenue methodology whereby it calculates revenues based on its actual sales each month even if a portion of those sales have not yet been billed. Mr. Kollen explains the unbilled revenues methodology results in revenue accruals that accurately reflect the Company's actual or forecast sales in the month at its authorized billing rates. The billed revenues in a month primarily reflect sales in the prior month due to billing lag. He testified that the billed revenue methodology results in revenue accruals that do not accurately reflect the Company's actual or forecast sales in the month. He stated that the Company's revenues should reflect the forecast sales in the year, not the billed sales, which lag the actual sales each month and should reflect the same unbilled revenues methodology that the Company uses for financial reporting. He noted that it would be inappropriate to understate revenues to reflect an outdated billed revenues accrual methodology that is not used by DEI or other utilities subject to generally accepted accounting principles or the FERC Uniform System of Accounts. He added that the billed revenues methodology understates the sales and revenues in the test year and creates a fundamental mismatch between the test year for revenues (approximately mid-December 2019 through mid-December 2020) compared to the approved 2020 calendar year test year used for the Company's costs (rate base, expenses, and capitalization). Further, he testified that it is inappropriate to restate revenues to reflect sales in a period other than the test year.

With regard to the Petitioner's sales forecast, OUCC witness Watkins explained that deficiencies in the Petitioner's case-in-chief has made the investigation difficult. However, given the limitations in the filing, Mr. Watkins was able to investigate the reasonableness of forecasted residential customers, KWH sales and resulting revenues, although he was not able to investigate the forecasted amounts for other classes. Mr. Watkins determined that the Company's forecasted KWH sales and attendant revenues for residential customers used for ratemaking purposes (both for class cost of service purposes as well as actual rate design purposes) are significantly understated. Mr. Watkins testified that the forecasted number of residential customers is within the range of reasonableness.

Mr. Watkins testified that the Company based its 2020 energy sales forecast on a Fall 2018 load forecast, as opposed to an updated Spring 2019 load forecast. He noted that the Company's Fall 2018 forecast is significantly lower than other forecasted amounts for 2020, either in prior forecasts (Fall 2017 and 2016 forecasts), or in the more recent Spring 2019 forecast (conducted after Petitioner's filing in this case). He also stated on a weather-normalized basis, historical residential sales during the period 2016 through 2018 have been significantly higher than the Company's forecasted residential energy sales used for ratemaking purposes in this case. Mr. Watkins proposed an adjustment to the forecasted residential energy sales based upon an average weather-normalized usage from 2016-2018, because of the reasonably consistent usage over this three-year period. Mr. Watkins applied the current customer growth rate to the August 2019 actual customer number, resulting in an August 2020 forecast of 741,733. In order to be conservative, Mr. Watkins accepted the Spring 2019 forecasted number of customers during 2020 of 738,993. Mr. Watkins multiplied the average weather normalized usage per customer by the forecasted average year 2020 number of customers to obtain a residential sales forecast of 9,235,500 MWH. He then allocated his adjusted forecast of residential energy sales to individual rate schedules using the same allocation as used by Mr. Bailey, also including the riders that are proposed to move into base rates and converted his adjusted forecast to residential revenues at current rates. Finally, Mr.

Watkins adjusted for additional fuel costs, producing a before-tax margin adjustment of $42,266,005.

(C) <u>Petitioner's Rebuttal Evidence</u>. The OUCC does not have any objections to Petitioner's recitation of its evidence.

(D) <u>Commission Discussion and Findings</u>. Addressing the unbilled revenues issue first, we agree with Mr. Kollen the Company's proposed pro forma adjustment removing its unbilled revenues should be rejected. The billed revenues accrual is outdated and not used by the Company or other utilities for financial reporting and should not apply in this case. If the Company was to use billed revenues this would overstate its required rate increase and result in a fundamental mismatch between the effective twelve months used to determine the revenues and the test year requested in this proceeding. If present revenues are understated based on a different and earlier test year, as is the case with the billed revenues methodology, then the rate increase necessarily is overstated. We also note that if the billing determinants are understated, this not only overstates the revenue deficiency, but also overstates the proposed tariff rates because the billing determinants used in the denominator for the rate calculations are understated for this purpose as well. In other words, the use of billed revenues overstates the revenue deficiency and then compounds this problem even further by overstating the tariff rates necessary to collect the overstated revenue deficiency.

We agree with Mr. Kollen's argument that the forecast of revenues for the test year should be based on the forecast of the billing determinants and revenues for the test year itself, not an earlier test year. This is necessary to ensure that all components of the revenue requirement and deficiency are forecast and calculated for the defined test year and that they are consistent with and match all other components. To ensure they match requires the use of unbilled revenues methodology which matches the revenues to the test year and is consistent with and matches the revenue accounting required for financial reporting purposes. We also agree that the billing determinants used in the calculation of the present revenues and the billing determinants used for the calculation of tariff rates should be consistent and match. However, having the billing determinants match does not justify the use either the billed revenues methodology or the unbilled revenues methodology. The matching simply addresses the need to ensure that the billing determinants used are consistent. As such, we not only will require that the present revenues used to calculate revenue deficiency be calculated using the unbilled revenues methodology, but we also will require that all tariff rates be calculated using the same billing. In its proposed order the Company cited to Cause No. 43090 where we allowed Lawrenceburg Gas Co to use the billed revenue methodology. While we have allowed the use of billed revenue methodology in the past we decline to allow Petitioner to use the billed revenue methodology in this case as the Company provided no compelling evidence demonstrating a need for it and the Company uses unbilled revenue methodology for financial reporting purposes.

With regard to the issue of forecasted residential sales, the balance of the evidence shows that the residential sales forecasted used by the Company in this case is understated. Based on the evidence presented, Mr. Watkins calculated a reasonable adjustment to the forecasted residential sales for the future test year. Mr. Stillman argues that Mr. Watkins should not use 2018 residential sales in his calculations because the total company sale results for 2018 were unusual based on the 2017 Tax Cut and Jobs Act. However, this argument is flawed for several reasons. First, this claim in Mr. Stillman's rebuttal testimony is unsupported, with his testimony merely stating that "[i]t is thought" that this is the case, but Mr. Stillman provides no further evidence to support the assertion. Second, in responding to Mr. Watkins' analysis, Mr. Stillman presents an analysis of total company sales in his rebuttal testimony (page 4 of Petitioner's Exhibit 58), which does not address Mr. Watkins' analysis of residential sales. Third, Mr. Stillman's written testimony is contradicted by his hearing testimony, in which he stated that Duke has seen "very strong residential customer growth over the last two years." (Tr. at C-36, l. 22 – C-37, l. 1) This increased customer growth is not accounted for in the forecast of 2020 sales relied upon by Duke in this proceeding, as the most recent (November 2019) actual number of residential customers was shown to be already higher than the forecasted number of customers used by Duke in this case. Finally, it is noteworthy that Duke's direct testimony in this case did not rely upon the more recent forecast from Spring 2019, which showed higher forecasted residential customer energy usage than the previous forecast, Fall 2018, used as the basis for this proceeding, and the Fall 2018 forecast was the lowest forecasted residential customer energy usage of all the test year forecasts provided. Based upon all of the evidence, we must conclude that the Fall 2018 forecast of residential sales was a clear aberration from forecasts of the test year made both before and after the Fall 2018 forecast that was used by DEI in preparing its case and cannot be relied upon as the basis for determining residential rates in this Cause. DEI should have recognized this aberration prior from the forecasts developed after its filing and did not. Further, the Company's rebuttal of these clear facts addresses total test year sales, not residential test year sales, and as such are irrelevant to the issue before us. Accordingly, we find that Petitioner's forecasted residential sales were understated and Mr. Watkins' adjustment to the residential energy sales is appropriate and should be used as the basis for determining test year residential revenue.

ii. <u>Depreciation.</u>

(A) <u>Depreciation Rates and Expense.</u>

(I) <u>Petitioner's Evidence</u>. The OUCC does not have any objections to Petitioner's recitation of its evidence.

(II) <u>OUCC's Evidence</u>. OUCC witness Garrett testified that he employed a depreciation system using actuarial plant analysis to statistically analyze the Company's depreciable assets and develop reasonable depreciation rates and annual accruals. In contrast to Mr. Spanos' use of the Equal Life Group ("ELG") procedure, Mr. Garrett recommends the calculation of depreciation rates under the Average Life Group ("ALG") procedure. He also proposed adjustments to the Company's proposed terminal net salvage rates. More specifically, Mr. Garrett testified that the OUCC's proposed depreciation adjustments comprise several key issues: (1) calculating rates under the ALG method; (2) removing contingency costs from Duke Energy Indiana's decommissioning cost estimates; (3) removing inventory costs from Duke Energy Indiana's decommissioning cost estimates; (4) removing escalation factors from Duke Energy Indiana's terminal net salvage calculations; and (5) adjusting the Company's proposed service lives for several of its transmission and distribution accounts.

Mr. Garrett testified that depreciation rates calculated under the ELG procedure for a particular vintage group of property will be higher in earlier years relative to later years, citing to [Wolf] and the National Association of Regulatory Utility Commissions ("NARUC") as support for his testimony. In contrast, he stated, depreciation rates calculated under the ALG procedure for a particular vintage group of property will be the same each year. Further, he testified that in order for depreciation rates calculated under the ELG procedure to be accurately applied, a utility's depreciation rates would need to be adjusted each year to reflect the decreasing depreciation rates for applicable account. He stated that under the ELG procedure, as proposed by Duke Energy Indiana, the Company's accelerated depreciation rates would simply be applied each year until the next depreciation study is filed, regardless of the fact that depreciation rates should decrease annually during that time under the ELG procedure. He testified that this arrangement does not result in a systematic and rational cost recovery mechanism, and, by proposing depreciation rates under this scheme, Duke Energy Indiana has failed to meet its burden to make a convincing showing that its proposed depreciation rates are not excessive.

He stated that, in theory, the ELG could be part of a systematic and rational cost recovery system. In practice, however, it would be difficult to come to the same conclusion, because in order for the ELG procedure to be properly applied, a utility would need to revise depreciation each year. However, he stated, given the logistical realities involved with prosecuting rate cases, this would be impractical and inefficient. He further testified that when a utility has made substantial, recent capital investments, depreciation expense calculated under the ELG method will always be higher than the expense calculated under the ALG method; the larger the amount of the investments, the larger the discrepancy will be between the two procedures. He attributed utilities' use of the ELG method to a desire by utility finance managers to increase cash flow and a desire by utility investors to reduce risk through accelerated capital recovery. He emphasized that the rules and standards governing capital recovery through depreciation require that public utilities recover their capital investments in a systematic and rational manner, accomplished by estimating service life through actuarial analysis and other objective techniques.

He noted that in the pending Indiana Michigan Power Company rate case, the utility proposed depreciation rates using the ALG procedure; no party opposed the utility's use of the ALG procedure and no party proposed using the ELG procedure. He stated that, in his experience, the ALG procedure is the most commonly used procedure by analysts in depreciation proceedings. Thus, he concluded, the majority of depreciation rates approved by regulators around the country are calculated under the ALG procedure. During redirect examination Mr. Garrett testified Indiana and the Texas Railroad Commission are the only two commissions he is aware of that use the ELG methodology.

Mr. Garrett stated that if the IURC approves the ELG procedure in this case, ratepayers will not only pay excessive rates next year, but will continue to pay excessive rates each year until the next depreciation study. He claimed that under these circumstances, it may actually be inaccurate to refer to what Duke Energy Indiana is doing as the "ELG procedure"; he stated for that description to be accurate, depreciation rates must be adjusted each year. Rather, he claimed, it would be more accurate to describe Duke Energy Indiana's "scheme" as the "Accelerated Cash Flow" procedure. He testified that if the IURC accepted all of Duke Energy Indiana's substantive depreciation positions, but simply adopted the ALG procedure, it would result in depreciation rates that are much more fair and reasonable than those proposed by the Company. He further testified that it could be reasonable to use the ELG procedure if Duke Energy Indiana was also proposing to have its depreciation rates adjusted every year in order to reflect a mathematically proper application of the ELG procedure, but that was not a part of the Company's filing. Instead, he claimed, to the extent the Company's ELG-derived rates are adopted, the Company will receive arbitrarily higher cash flows for its investors each subsequent year after this proceeding until its next depreciation study is filed. Under these circumstances, he concluded, the Company has not made a convincing showing that its proposed rates are not excessive.

Mr. Garrett offered an alternative ELG proposal, stating that if the IURC is inclined to adopt the ELG procedure as proposed by the Company, he has also presented his depreciation parameter adjustments under the ELG method. He emphasized these adjustments do not represent the OUCC's primary recommendation, which are the ALG depreciation rates outlined in his testimony.

Mr. Garrett next addressed the issue of contingency costs. He testified that the Company's terminal net salvage costs are estimated through demolition studies for most of its generating units. He stated that the demolition studies include contingency costs that purportedly reflect uncertainties in future demolition estimates. However, he claimed that contingency costs are unknown by definition, and therefore are not known and measurable. He stated that charging current ratepayers for speculative costs that may not even occur up to decades in the future is inherently problematic from a ratemaking perspective. Mr. Garrett stated that Duke identified no legal obligation in its testimony that requires it to demolish its power plants consistent with the activities described in the decommissioning cost estimates. He opined that in the absence of such a legal requirement being imposed in the foreseeable future, actually incurring these costs is speculative. He also suggested that if and when Duke actually demolishes the power plants and requires more funding to do so, it can request additional funds from ratepayers when actual costs are known.

With regard to the issue of inventory costs, Mr. Garrett noted that Duke Energy Indiana included $185 million of inventory costs as part of its decommissioning cost estimates. However, he stated, inventory costs are not typically included as part of decommissioning cost estimates, and he testified that he could not recall ever seeing such costs proposed in a decommissioning study, including those filed by Burns & McDonnell in prior cases. He noted that decommissioning studies estimate the terminal salvage and cost of removal of generating facilities, and he testified that Duke Energy Indiana has not shown how the inclusion of inventory relates to that process. Furthermore, he stated that Burns & McDonnell has not conducted an analysis supporting the level of inventory included in the decommissioning costs.

Mr. Garrett next addressed the Company's use of escalation factors to escalate its demolition cost estimates from present-day dollars to the future retirement date of each generating unit by applying an annual cost inflation factor. According to Mr. Garrett, the problem with this approach is that current ratepayers are forced to pay for a future-value cost with present-day dollars. He claims that this "scheme" violates basic time-value-of-money principles. He testified that if future, escalated costs are allowed, they should then be discounted back to present-day dollars by the Company's weighted average cost of capital, noting that a similar approach is used to account for asset retirement obligations. He concluded, however, that it would be more straight-forward and reasonable to simply disallow the escalation factors and base the Company's decommissioning costs on present value.

(III) **<u>Industrial Group's Evidence</u>.** The OUCC accepts the Industrial Group's recitation of its evidence.

(IV) **<u>Petitioner's Rebuttal Evidence</u>.** The OUCC does not have any objections to Petitioner's recitation of its evidence.

(V) **<u>Commission Discussion and Findings</u>.** The depreciation-related issues in this case relate to: (1) the ELG versus ALG methodology; (2) the appropriate calculation of terminal net salvage estimates; and (3) estimated useful lives for certain mass property accounts and coal generating units, including IRP issues. We address each of these issues in turn.

First, with respect to the question of whether the ELG or ALG method should be used, we find the evidence presented by OUCC witness Mr. Garrett and Industrial Group witness Mr. Andrews persuasive, as both witnesses showed that the ELG method results in unreasonably high depreciation rates. Use of the ELG procedure would require annual updates to depreciation rates, which is not practical. On the other hand, ALG depreciation rates result in systematical and rational cost recovery without the need for annual updates. While we have determined that the ELG methodology is appropriate in the past we evaluate each case as it comes before us and do not need to approve the same methodology based on prior decisions. We are compelled by Mr. Garrett's testimony that a vast majority of other jurisdictions approve the use of the ALG methodology. The Company argues that the ELG methodology produces more accurate depreciation rates; we do not need to rule on if this is true or not, because to use the ELG methodology correctly the Company would need to update its deprecation rates every year, which is not practical.

With regard to the issues surrounding the calculation of terminal net salvage estimates, we note that no party has proposed depreciation rates without terminal net salvage estimates, and, accordingly, no party appears to disagree with the concept of including terminal net salvage in depreciation rates. Instead, the differences are related to components of the estimated costs that are included.

Regarding the issue of whether decommissioning costs should be escalated, we find that it is unfair to current ratepayers that they pay for escalated future costs with present-value dollars. Approving DEI's proposed escalation rates would require customers to pay millions of additional dollars per year for speculative future costs.

Next we address the parties' contention that contingency be removed from the decommissioning study. We agree with the parties that the circumstances here warrant such removal. Contingency costs are unknown by definition. We cannot think of any other cost issue in a rate case where we take an unknown future cost, then increase that cost by 20% due to uncertainty. For the same reasons DEI asserts in favor of a positive 20% contingency factor, one could assert in favor of a negative 20% factor. That is, if a future cost estimate is uncertain, one could argue that such estimate should be decreased by 20% in the interest of being conservative. Rather, we find the most fair and reasonable approach is to disallow any positive or negative contingency factor. Thus, the Company's request for a 20% contingency markup is denied, and the 0% contingency factor recommended by OUCC witness Mr. Garrett is approved. Regarding the parties' arguments that inclusion of the cost to address end-of-life inventory at retired generating plants as part of the decommissioning of a generation site, we are persuaded that these costs are not true costs associated with decommissioning a generation site and should not, therefore, be included in the Company's estimate of decommissioning its generation. These type of inventory costs are not typically included as part of decommissioning cost estimates, and they do not relate to the demolition of a power plant. The fact that this inventory was not used during the life of the power plant to provide utility service indicates that it was not a used or useful utility investment. Thus, we are denying recovery of these inventory costs

(B) Estimated Useful Lives of Mass Property. OUCC witness Garrett took issue with certain of Mr. Spanos' recommended mass property service lives. OUCC witness Garrett proposed changes to the service lives of four transmission and distribution plant accounts, specifically: Account 353, Station Equipment; Account 356, Overhead Conductors and Devices; Account 367, Underground Conductors and Devices; and Account 369, Services.

Mr. Garrett addressed his proposed longer service lives for mass property accounts. He explained that the term "mass property" refers to the Company's grouped assets, such as those in its transmission and distribution accounts. He stated that through depreciation expense, a utility recovers the original cost of its plant assets over the average service life of those assets. He stated that when service life estimates are extended or reduced, depreciation rates decrease or increase accordingly. He testified that several of the average service lives proposed by Mr. Spanos for the Company's mass property accounts were shorter than what was otherwise indicated by the historical retirement data for these assets as provided by the Company, which would result in depreciation rates that are unnecessarily high. Accordingly, he proposed longer average service life estimates for these accounts (Accounts 353, 356, 367, and 369).

Mr. Spanos testified in rebuttal to Mr. Garrett's proposals to increase the service lives further for these four mass property accounts. For three of the four accounts listed above, Mr. Spanos had recommended an increase or no change to the average service life from the current estimate. While some of Mr. Garrett's adjustments were relatively minor, for some accounts he proposed significant increases when compared to the current estimates. For example, he proposed a 19-year increase in average service life for Account 369. In rebuttal testimony, Mr. Spanos testified that, for many of these accounts, the recommendations made by Mr. Garrett are not reasonable. Mr. Spanos stated that his recommendations result from the approach Mr. Garrett has used to develop his estimates, which is based primarily on mathematical curve fitting. This approach does not give the appropriate consideration to the mortality characteristics of the assets studied or to other factors that should be considered. Additionally, Mr. Spanos testified that Mr. Garrett's statistical analysis did not properly incorporate relevant historical data that is supportive of Mr. Spanos' estimates. Mr. Spanos explained that while both Mr. Garrett and he used Iowa type survivor curves to calculate depreciation expense and used the retirement rate method to analyze historical data, Mr. Garrett's overall approach differs. Mr. Spanos testified that his approach also differs from the correct and proper approach to estimating service lives that is set forth in depreciation textbooks such as NARUC's *Public Utility Depreciation Practices*. Specifically, Mr. Spanos testified that Mr. Garrett's testimony indicates that he believes estimating service lives is primarily a mathematical exercise in which little more than mathematical computations of historical accounting data will result in reasonable estimates. Mr. Spanos emphasized that this overall approach is incorrect; depreciation, and particularly estimating service lives, is a forecast of the future rather than a calculation of what has happened in the past.

We agree with OUCC witness Mr. Garrett's positions regarding his proposed service life adjustments on these accounts. The Iowa curves selected by Mr. Garrett are based on objective analysis, and the evidence shows that the Iowa curves he selected for these accounts result in better mathematical fits to the historical retirement patterns in these accounts.

(C) Estimated Useful Lives of Generating Units and IRP Issues.

(I) Petitioner's Evidence. The OUCC does not have any objections to Petitioner's recitation of its evidence.

(II) OUCC Evidence. The OUCC did not take issue with the retirement dates of coal generating units included in the development of the Company's proposed depreciation rates or the Company's IRP.

(III) Intervenors' Evidence. The OUCC accepts the recitation of each intervening party's evidence.

(IV) Petitioner's Rebuttal Testimony. The OUCC does not have any objections to Petitioner's recitation of its evidence.

(V) Cross Answer Testimony. The OUCC accepts Joint Intervenor's recitation of its cross answering testimony.

(VI) Commission Discussion and Findings. The OUCC did not take a position on this issue.

iii. O&M Expenses (Other than Depreciation and Taxes).

(A) Production O&M Expense.

(I) Petitioner's Evidence. The OUCC does not have any objections to Petitioner's recitation of its evidence.

(II) OUCC's Evidence. OUCC witness Alvarez disagreed with the Company's proposal to include $229 million of power production O&M expenditures in the 2020 Test Year for generating facilities other than Edwardsport. Mr. Alvarez recommended normalizing O&M expenditures for DEI's generating facilities, including the cyclical maintenance outages. Using a seven-year average methodology to normalize the O&M expenses, including the associated major outage costs, he recommended an $80 million adjustment, reducing DEI's generating facilities' forecasted Test Year O&M expenses to $149 million.

Mr. Alvarez testified he reviewed power production O&M expenditures associated with DEI's generating facilities: Cayuga, Gallagher, Gibson, Henry County, Madison, Markland Hydro, Noblesville, Vermillion, and Wheatland, including non-fuel O&M expenses and O&M expenses related to these generators' outages ("outage expense"). He stated the base cost of power production O&M expenses included reagents and chemicals necessary to operate these generators in compliance with environmental regulations. Mr. Alvarez discussed the total power production O&M expenditures DEI proposed to include in the 2020 forecasted Test Year. He testified DEI proposed to include $229 million of power production O&M expenditures in the 2020 forecasted Test Year, for the nine generating facilities identified above, and DEI's 2020 forecasted Test Year O&M expenses included $197 million of non-outage and $32 million outage-related O&M expenses. He stated a generating unit's non-outage O&M expenses were typically flat year-to-year and periodically punctuated with outage-related expenses, based on the maintenance cycle of the generating unit. He identified the primary driver of planned major outages, and associated outage-related expenses, was the major turbine inspection, which normally occurs about every seven years, based on actual hours of operation. He stated that DEI performed (or plans to perform) major outage work on all nine of the above-named generating units during 2018 – 2020. Mr. Alvarez stated the total cost in outage-related O&M expenses for all nine generating units was $70 million, based on $11 million actual (2018), $27 million budgeted (2019), and $32 million forecasted (2020). He testified that if the Commission approved embedding $32 million for outage-related O&M expenses in base rates, DEI would continue to collect $32 million in four of the seven years where there are no scheduled major outages, which was essentially over-collecting $128 million over the seven year period 2018-2024. Further, he testified, if DEI performed scheduled major outage repairs on all nine facilities within a three-year period (2025–2027) following the seven-year cycle (2018-2024), DEI's proposal to embed $32 million in annual outage-related O&M expenses would result in DEI recovering $96 million over that three-year period, which was $26 million more than the $70 million DEI spent (or plans to spend) on major outage-related O&M expenses for the three-year period 2018–2020.

Mr. Alvarez discussed the OUCC's recommendation regarding DEI's generating total power production O&M expenditures (outage and non-outage) for the 2020 forecasted Test Year. Mr. Alvarez recommended normalizing power production O&M expenses associated with DEI's generating facilities and adopting a seven-year average methodology to reflect both non-outage and cyclical outage O&M expenses in the 2020 forecasted Test Year, including using the power production O&M cost data found in DEI's 2018 IRP, because it is part of the current information DEI relied upon to keep its "long-term plan updated." He testified DEI stated in its 2018 IRP Summary, "[w]hen it is time to make a near-term decision, we gather the best available information to analyze for that specific decision in detail at that time." He explained because DEI gathered "the best available information to analyze," it is also the best available data and information to use in analyzing the cost of operating DEI's generation assets on a going-forward basis. DEI's 2018 IRP Summary stated, "[a]fter comparing the expected cost of each portfolio under a variety of scenario assumptions, we [DEI] selected the Moderate Transition portfolio for the 2018 IRP." Mr. Alvarez testified he used the same cost data DEI provided in its 2018 IRP Moderate Transition Portfolio to normalize power production O&M expenses for DEI's generating assets. He pointed out DEI also stated, "This portfolio benefits from a diverse generation mix as well as the ability to respond to emerging regulations." Therefore, he concluded, it is reasonable to expect the same benefits from his analysis.

Mr. Alvarez recommended DEI embed $149 million of power production O&M expenses in base rates, which was an $80 million reduction to DEI's proposed 2020 forecasted Test Year power production O&M expenses of $229 million. This amount reflected a reduction in DEI's proposed annual non-outage O&M expenses from $197 million to $129 million and a reduction in DEI's proposed annual outage-related O&M expenses from $32 million to $20 million. He explained he derived his recommended non-outage O&M expenses from DEI's IRP assumptions and was conservative in that the fixed operation and maintenance ("FOM") considered both non-outage and outage O&M expenditures. Mr. Alvarez's recommended $149 million seven-year average outage-related O&M expenses will allow DEI to sustain normal cyclic maintenance outages plus recover an additional amount to insure against unanticipated major outage expense. He testified any amount above $149 million per year was unnecessary and unreasonable. Mr. Alvarez described DEI's IRP reference to its generating asset's FOM, which was essentially the combined outage and non-outage O&M expense. He explained DEI used FOM data to develop the preferred portfolio in its 2018 IRP reference case scenario and he focused his analysis on the cost data for the period 2018 through 2026, which included the cost data from forward-looking years prior to DEI's next major outage in 2027. Alvarez at 8, lines 6 – 10. He calculated his $149 million seven-year average FOM, using FOM for forecasted years 2020-2026 and adjusting these annual amounts to reflect the seven-year amortization of major outage costs. Mr. Alvarez testified since DEI performed, or plans to perform, its major outage work over a three-year period, he normalized the three-year outage O&M costs shown in Table 10 of Mr. Mosley's testimony by adding the costs in years 2018-2020 ($70 million) to represent the cyclic maintenance outage over seven years; and applied a factor of two ($70 million x 2 = $140 million) to cover the costs of any unexpected events similar to the turbine failure at Cayuga in Oct. 22, 2014, or major turbine overhauls needed sooner due to higher operating hours that could happen within a seven-year period. He then amortized the resulting total over the seven-year period 2020-2026 ($140 million ÷ 7 years = $20 million per year).

To derive the Total FOM per year, he added the seven-year amortization major outage expense of $20 million per year to the FOM cost for each year of the 2020-2026 period, then summed the Total FOM costs of each year for 2020-2026. Mr. Alvarez then divided the total sum by seven to determine the seven-year average FOM costs to produce his recommended $149 million level of total power production O&M expenses to include in DEI's 2020 forecasted Test Year. His Table 1 summarized the power production O&M expenses cost data he used. Mr. Alvarez testified the FOM cost data found in his Table 1 was the total annual FOM cost of the nine DEI generating facilities he identified earlier as reflected in the 2018 IRP. He explained by taking into consideration DEI's seven-year cyclical maintenance schedule, it would be appropriate to use a seven-year average methodology to normalize the generating facilities' power production O&M expenses.

Mr. Alvarez recommended the Commission normalize, over seven years, Edwardsport's overall O&M Expenditures, Major Outage Expenses, and Miscellaneous Administrative and General Benefits ("Misc. A&G") costs in 2020. He also recommended reducing DEI's requested Edwardsport O&M, Major Outage and Misc. A&G expenses for the forecasted 2020 Test Year from $112.7 million to an overall total of $61.87 million.

Mr. Alvarez discussed how DEI reduced its 2020 forecasted Test Year O&M expense of $145.8 million by $46.4 million associated with a major outage planned for 2020, added the seven-year amortization of the major outage cost to reflect the 7-year cyclical major outage schedule of Edwardsport, and included miscellaneous administrative and general expenses to derive the embedded test year amount. His Table 4 summarized DEI's $112.7 million as proposed by Mr. Gurganus. Mr. Alvarez testified at this level of expense, Edwardsport's ongoing maintenance cost was excessive and unreasonable for 618 MW of capacity. He testified DEI's Gibson generating station, which was four-and-a-half times larger at 2,845 MW, has comparable O&M costs, and all else equal, Edwardsport could not operate economically using coal when its O&M costs were four-plus times greater than DEI's other coal plants. Alvarez, at 11, lines 1 – 6. Based on his review of DEI's historical actual amounts and IRP cost data, he recommended $61.87 million in Edwardsport O&M expenditures be embedded in base rates, which was an approximate $50.83 million reduction to DEI's proposed $112.7 million.

Mr. Alvarez testified he reviewed actual Edwardsport O&M expenditures for 2013 through 2018, and projected amounts for 2019 and 2020; the 2016 Edwardsport Settlement Agreement ("2016 IGCC Settlement") approved by the Commission in Cause No. 43114 IGCC-15, dated August 24, 2016; and the 2018 Edwardsport Settlement Agreement ("2018 IGCC Settlement") approved by the Commission in Cause No. 43114 IGCC-17, dated June 5, 2019. He stated in the 2016 IGCC Settlement, the O&M Expenditure Caps ("O&M Caps") were $73.3 million in 2016 and $76.8 million in 2017; in the 2018 IGCC Settlement, the O&M Caps were $97.6 million in 2018 and $96.0 million in 2019; and in the 2016 IGCC Settlement, the Edwardsport Capital Expenditure Caps were $36.1 million in 2016 and $16.9 million in 2017. He added he also reviewed Edwardsport's confidential fixed and variable O&M data found in DEI's 2018 IRP dated July 1, 2019, and publicly available data and statistics for Edwardsport found in DEI's FERC Form 1 and EIA-923 reports and filings.

Discussing his review of Edwardsport's actual, projected and forecasted O&M expenditures for 2013 through 2020 relative to the IGCC Settlement O&M Caps, Mr. Alvarez testified DEI recovered Edwardsport's actual O&M expenditures incurred in 2013, 2014 and 2015 through rates, albeit subject to the provisions of the 2012 IGCC Settlement Agreement. He noted DEI's recovery of Edwardsport's O&M expenses during the period 2016 through 2018 and projected in 2019, were subject to O&M Caps under the provisions of the 2016 and 2018 IGCC Settlements. His Table 2 summarized Edwardsport's actual O&M expenditures from 2013 through 2018, projected in 2019, and forecasted in 2020, including the cost of the major outage in 2020. He testified due to the O&M Caps in the 2016 and 2018 IGCC Settlements, DEI could not recover from ratepayers the Edwardsport actual O&M expenditures in excess of the O&M Caps in 2016, 2017, 2018 and projected for 2019. His Table 3 compared Edwardsport's actual and projected O&M expenditures and O&M Cap amounts for the period 2016 through 2019. He showed DEI incurred disallowances, absorbed by shareholders, for each year with a cap - $59 million (2016), $33.3 million (2017), $5.5 million (2018), and $10.4 million (2019). He testified in 2018, when the O&M Cap increased by 27.1% from the previous year, Edwardsport operations still exceeded the cap, projected an increase to its operational expenses the following year (2019), and expected to incur a higher disallowance in 2019.

Mr. Alvarez disagreed with Mr. Gurganus's Table 1 (Direct at 17), which showed the 2019 Budget for Edwardsport O&M expense decreased and saved ratepayers $3 million as compared to the $99 million actual expense in 2018. Alvarez, Footnote #30, p. 14. Mr. Alvarez testified based on his analysis, Edwardsport O&M expenses did not decrease when comparing 2018 actual to 2019 budgeted. He explained, as shown in his Table 3, actual and projected O&M expenses of Edwardsport operations did not decrease in 2019 and without the O&M Cap in place would not provide any savings to ratepayers. He testified Mr. Gurganus' analysis reflected the IGCC Settlement O&M Cap for 2019 and compared it with an understated actual 2018 expense to show a decrease in 2019 Edwardsport O&M expense and savings of $3 million. Without the O&M Cap in place for 2019, ratepayers would be responsible for an additional $9 million in 2019 as compared to 2018 ($106.4 in 2019 less $97.6 million in 2018). His Table 3 showed, since 2015, the actual O&M expenses of Edwardsport operations have not fallen below $100 million.

Mr. Alvarez testified, contrary to Mr. Gurganus' claims, there was no "declining trend" in the Edwardsport operation's O&M expenses, and any cost decrease afforded to ratepayers resulted from O&M Caps imposed by previous IGCC Settlement Agreements, and not from Edwardsport operations. Despite the incentive signals from O&M Caps embedded in previous IGCC Settlement Agreements, Edwardsport operations continue to run the facility at a high level of operating costs—in excess of $100 million annually. Mr. Alvarez likewise disputed Mr. Gurganus's claim that absent the major outage cost in 2020, Edwardsport operations have "keenly focused on reducing O&M." Gurganus Direct at 18, lines 6 – 9. Mr. Alvarez testified Edwardsport operations have not achieved any significant expense reductions, again citing the 2016 – 2019 uncollectable O&M amounts. Mr. Alvarez testified by the end of 2019, O&M Caps for the period 2016-2019 would have saved ratepayers $108.2 million. Mr. Alvarez explained despite the O&M Caps and the almost-certain internal pressure from DEI shareholders to stop the losses they had absorbed, Edwardsport operating costs remained excessive, especially when compared to the operating costs DEI projected when they sought approval to build this plant.

Mr. Alvarez testified DEI and its IRP did not consider Edwardsport for retirement because it "is the newest on our [DEI] system," it "has the longest estimated life (2045)," "successfully improved operations in the past several years," was focused "on reducing its ongoing maintenance costs," and contributes "to the fleet's diversity." He stated aside from the estimated life of Edwardsport lasting beyond the 2018 IRP planning horizon, the IRP took into account a realistic forecast of the IGCC's expense. Mr. Alvarez highlighted how the IRP crucially assumed Edwardsport "*going forward will be focused on reducing its ongoing maintenance costs*." Thus, DEI's IRP forecasted the fixed and variable O&M expense of Edwardsport at an optimal level based on the belief that "[t]he plant has successfully improved operations over the past several years." Mr. Alvarez noted the IRP provided DEI with a guide for making business decisions, one of which was a realistic insight of Edwardsport's overall future operations and performance. Mr. Alvarez testified DEI selected the Moderate Transition Portfolio as its 2018 IRP preferred resource plan "[b]ased on its superior performance in scenario and sensitivity analyses," and embedded in that preferred resource plan was Edwardsport's cost forecast for the review period of the 2018 IRP. He noted that DEI filed its case-in-chief on July 2, 2019, one day after submitting its 2018 IRP with the Commission, which reflected the 2018 IRP Edwardsport cost forecast and DEI's latest cost data and management insights of the generating plant's current and future operational performances.

Mr. Alvarez described how he focused his cost review on the period 2018 through 2026. That period included historic test period costs from 2018, projected 2019 costs, forecasted Test Year 2020, and the forward-looking years prior to the next major outage in 2027 ("forecast years"). He made adjustments to incorporate the major outage cost seven-year amortization in the cost data of his analysis and modeled both nine-year average and seven-year average costs to determine the reasonable level of FOM (non-fuel) expenses of Edwardsport to include in the future Test Year. He compared the results of his analysis with "Edwardsport IGCC Unit Specification Summary" document provided by DEI in its response to IG DR Set 8.3(b), Confidential Attachment IG, and presented his Table 5 to summarize Edwardsport FOM cost data used in his analysis. Mr. Alvarez testified the cost data sets (A), (B) and (C), in his Table 5 incorporated the Edwardsport major outage cost in 2020, and it showed the nine-year cost average was higher than the seven-year cost average because it included two additional years of historical costs (2018 and 2019) and overstates the 2020 forecasted Test Year, which already considered such costs. Likewise, he stated, embedding a single-year expense forecast in future rates would be counter-productive in the case of Edwardsport, because it would only perpetuate unreasonable and excessive operating costs going forward, provide operations with no incentive to improve future operating performance, and dissuade management from reducing its ongoing maintenance costs. He explained that taking into consideration its seven year cyclical maintenance schedule, it would be appropriate to use a seven-year average methodology to normalize the Edwardsport IGCC fixed O&M and major outage expenses. Mr. Alvarez recommended embedding $61.87 million of Edwardsport O&M expenditures in base rates, and to achieve this, he also recommended the Commission adopt a seven-year average methodology to normalize Edwardsport overall O&M Expenses, Major Outage Expenses, and Misc. A&G costs (forecasted and attributed to Edwardsport by other corporate groups) in 2020 as shown in his Table 5, Section B.

(III) **Industrial Group's Evidence**. The OUCC accepts the Industrial Group's recitation of its evidence.

(IV) **Sierra Club's Evidence**. The OUCC accepts Sierra Club's recitation of its evidence.

(V) **Petitioner's Rebuttal Evidence**. The OUCC does not have any objections to Petitioner's recitation of its evidence.

(VI) **Commission Discussion and Findings**. The parties dispute Petitioner's power production O&M costs. The issues of contention are: (i) whether the Edwardsport plant should be shut down completely, run as a gas plant or continue to operate as an IGCC plant; (ii) the appropriate amount of O&M expenses for plants other than the Edwardsport station; and (iii) the appropriate amount of non-outage related O&M cost for the Edwardsport station. We examine each of these issues in turn below. We address Joint Intervenors' arguments for disallowance of past dispatch related costs for the past three years in the section on FAC issues later in this order.

(a) **Continued Operation of the Edwardsport Plant**. The OUCC did not take a position on closing Edwardsport, modifying its fuel source or continuing to operate as a dual-fuel unit. Therefore, the OUCC offers no proposed language for this portion of the Order.

(b) **Non-Edwardsport O&M Cost**. The OUCC recommended using a seven-year average methodology to normalize O&M expenses for plants other than the Edwardsport station, resulting in a proposed $80 million reduction in O&M costs. Duke Energy's rebuttal testimony from witness Pike demonstrated certain flaws with Mr. Alvarez's analysis, including that the OUCC's seven-year average analysis only included the fixed component of O&M cost in the derivation of the $80 million adjustment. In excluding non-fuel variable O&M costs, the OUCC inadvertently omitted costs including: emission control reagents, coal and waste handling, and other outage and non-outage variable maintenance expenses.

However, during cross examination, neither witness Pike nor witness Mosley could clearly delineate the differences (or overlap) between the outage and non-outage non-fuel O&M expenses requested by Duke Energy (Mosely rebuttal at page 29, Table 10), and the variable O&M Mr. Pike calculated Mr. Alvarez had inadvertently excluded (Pike Rebuttal at 11, Table 2).

Mr. Pike further testified that the OUCC's analysis also was in constant year 2017 dollars and thus did not include any inflation of costs to the appropriate year nominal dollars. Mr. Pike claimed that if these issues were corrected, the resulting 2020-2024 average of the total O&M cost as-modeled in the IRP would be $258 million, which is higher than the $229 million proposed by Petitioner. But that analysis was also flawed. During cross examination, the OUCC demonstrated that Mr. Pike's analysis included excessive inflation by including years beyond 2023.

Mr. Alvarez's 7-year normalized O&M plan is grounded in the idea that major outages, associated with turbine inspections, occur every 7-10 years. His use of Duke Energy's most recent IRP data to estimate fixed operations and maintenance, which combines outage and non-outage O&M expense, is a reasonable starting point, given Duke Energy's testimony regarding the importance and sophistication of the IRP. The IRP data cannot be dismissed as "still just from a model" as witness Pike would have us do. Pike Rebuttal at 12. By using the fixed operations and maintenance costs for 2020 – 2026 (Alvarez CONFIDENTIAL direct at 9, Table 1), his analysis captures a seven-year cycle in line with the expected life cycle of major turbine inspections. Mr. Alvarez's recommended $20 million annual Major Outage amount is based directly on Duke Energy's 2018 – 2020 Outage O&M data (Mosley rebuttal at 29, Table 10) and combines actual 2018 amounts, budgeted 2019 dollars and Duke Energy's 2020 forecasted figures. Mr. Alvarez's process is not diminished because he incorporates some historical spending context to calculate his estimate. Rather than recommend $10 million / year for Major Outage expense that would be a straight average of those three years from Mr. Mosley's Table 10, Mr. Alvarez recommended doubling that amount to $20 million annually "to cover the costs of any unexpected events similar to the turbine failure at Cayuga in Oct. 22, 2014." Thus, his recommended $149 million annual total for fixed O&M for the non-Edwardsport fleet is also reasonable.

But consideration must be given to reflect variable non-fuel O&M included in the IRP but inadvertently excluded by Mr. Alvarez, and to recognize that inflation should also be applied to IRP cost estimates through 2023. Without evidence that specifically identifies the "non-outage" and "outage" O&M amounts discussed by Mr. Mosley intersect / overlap / exclude the non-fuel 'fixed" and "variable" O&M amounts in the IRP, we are unable to conclude that Petitioner's proposed O&M expense of $229 million is reflective of its ongoing needs for O&M expense for its generation units. Based on the totality of record evidence, we find $189 million annually to be a reasonable amount to meet the O&M needs of the Company's production facilities, aside from Edwardsport.

(c) <u>Edwardsport O&M Cost</u>. Unlike the non-Edwardsport generating units, there was no disagreement between Petitioner and the OUCC regarding outage-related O&M for the Edwardsport Station. The OUCC's proposed $6.63 million per year is equivalent to the Company's requested $46.4 million amount for major planned outage expenses levelized over seven years ($46.4 million/7 years = $6.63 million/year).

For non-outage O&M, the OUCC reduced Duke Energy's proposed $99.4 million per year to $55.24 million per year, a difference of $44.16 million annually. As with the analysis for other generating units, Duke Energy's rebuttal noted the OUCC analysis again inadvertently excluded variable O&M costs and did not factor in inflation. As we found above, while these flaws prevent us from adopting the OUCC's recommendation entirely, we give significant weight to OUCC's use of Duke Energy's IRP cost estimates. DEI filed its case-in-chief on July 2, 2019, just one day after submitting its 2018 IRP with the Commission, which reflected the 2018 IRP Edwardsport cost forecast and DEI's latest cost data and management insights of the generating plant's current and future operational performances. Furthermore, we cannot ignore the 2016 - 2019 data demonstrating the $108.2 million dollars of non-outage O&M costs saved by ratepayers as Duke Energy was unable to manage those costs below settlement agreement O&M caps. With those caps no longer in place, Duke Energy may well have even less incentive to manage towards further reducing O&M non-outage O&M costs. Accordingly, we find $77.32 million dollars per year for non-outage O&M costs for the Edwardsport Station is reasonable for Petitioner's ongoing needs.

We decline Industrial Group's recommendation that only O&M costs associated with hypothetically running Edwardsport as a gas unit should be included in rates. We have found continued operations primarily on coal is reasonable for Edwardsport and as such, we are required to set a level of O&M in base rates based on such operation, which Duke Energy Indiana has adequately supported.

(B) <u>Major Storm Damage Recovery Expenses.</u>

(I) <u>Petitioner's Evidence</u>. The OUCC does not have any objections to Petitioner's recitation of its evidence.

(II) <u>OUCC's Evidence</u>. OUCC witness Alvarez testified that there is no assurance that the utility incurred its historical major storm expenses despite prudent management. For an example, he pointed to the 2018 data in Table 4 in Ms. Hart's direct. 51% of all 2018 outages (excluding planned outages and major event days) were caused by equipment failure or vegetation, compared to only 4.57% attributable to weather. He noted the absence of evidence demonstrating that DEI was acting proactively with respect to storm damage by identifying and targeting vulnerable circuits, lines, equipment and facilities most susceptible to extensive damage and / or prolonged outages during major storms. Based on historical SAIDI and related performance metrics, Mr. Alvarez testified that Duke Energy's distribution reliability metrics continued to deteriorate even after additional vegetation management and capital improvement funds were provided to Duke Energy via its TDSIC. Alvarez direct at 23-24. In another example, Mr. Alvarez testified regarding his review of 2016 storm amounts. He described Table 9 of Ms. Hart's direct which showed a significant *increase* in 2016 storm expenses vs. 2015, and *increased* SAIDI both normal and major event days while the company simultaneously reported the fewest number of major event days for the entire 2014 – 2018 period. Mr. Alvarez also said that the absence of historical context caused him to oppose the Company's proposed five-year average of $12.7M. He noted that while he had supported a five-year average for this purpose for Indiana Michigan Power in Cause 45235, that utility had been through three generations of major storm expense analysis, substantial evidence supported the storm amounts and the mechanism included and over / under collection adjustment.

Mr. Alvarez stated there is a need to create an incentive for the Company to manage its system and major storm expenses with prudence. To do this, he proposed that Petitioner be required to develop an operational plan to manage storm restoration activities that is coordinated with its vegetation management and TDSIC plans. Mr. Alvarez stated that such a plan would not throw off Petitioner's TDSIC schedule or burden its operational management of storm restorations.

Mr. Alvarez stated that if the Company agrees to develop an operational plan based on the goals prescribed, the OUCC does not oppose establishing a Major Storm Reserve in the amount of \$6 million (see discussion on Major Storm Reserve later in the Order). Alternatively, Mr. Alvarez testified that should the Commission deny the Company authority to establish a Major Storm Reserve mechanism, it should approve embedding \$5 million in base rates to represent half of the Company's annual \$10 million O&M budget for major storm expense (a reduction of \$7.7 million from the Company's proposed normalized major storm expense amount).

(III) Petitioner's Rebuttal Evidence. The OUCC does not have any objections to Petitioner's recitation of its evidence.

(IV) Commission Discussion and Findings. The issue we are faced with here is determining the appropriate amount to be built into the Company's base rates to fund the Major Storm Reserve. In making determinations regarding an appropriate level of operating expenses to be used in setting any component of a utility's rates, we are guided by the overall objective of achieving a level of expense that is representative of probable future experience. Indiana courts have emphasized the importance of viewing test year results and out of period adjustments in the context of estimating a representative ongoing level of utility expenses. *See, e.g.*, *City of Evansville v. Southern Indiana Gas & Electric Co*., 167 Ind. App. 472, 339 N.E.2d 562, 575, in which the Court stated: "The theory underlying the use of any test year and of any adjustment method in the rate-making process demands that the data used provide an accurate picture of the utility's operations during the period in which the proposed rates will be in effect."

Petitioner's proposal to embed \$12.7 million in base rates for major storm expenses is based on a five-year average of the Company's actual major storm expense, but that average is not supported by substantial evidence that DEI has been successfully managing this expense despite additional TDSIC dollars that target the two largest causes of outages, vegetation and distribution system plant. On the other hand, Mr. Alvarez's alternative proposals of \$5 million and \$6 million are lower than the major storm restoration costs experienced in any of the last five years. OUCC witness Alvarez's point that "there is no assurance that the utility incurred its historical storm expenses from a prudent management of its storm expenses" can't be ignored. Petitioner maintains the burden of proof to demonstrate its five year average is reasonable, and we may appropriately weigh the absence of supporting evidence.

Petitioner's witness Hart's rebuttal attempts to address this shortcoming, but ultimately fails. Ms. Hart's testimony states that every employee has responsibilities during major storm events, and that the Company uses an Incident Command System. These facts only address the Company's actions just prior to a storm and its immediate reaction after. OUCC's testimony addresses the absence of information regarding long-range actions, such as targeting vulnerable circuits, lines, equipment and facilities most susceptible to extensive damage and / or prolonged outages during major storms. Duke Energy's team of meteorologists, the ICS and employees with multiple roles during a storm incident, while commendable, are not evidence that explains the Company's ongoing deterioration in outage performance metrics or why historic costs are reasonable. Based on the substantial evidence of record, we reject Duke Energy's request to embed $12.7 million in base rates for a major storm outage expense adjustment. We will address the Storm Damage Reserve account below.

(C) <u>Vegetation Management.</u>

(I) <u>Petitioner's Evidence</u>. Petitioner's witness T.K. Christie testified that the Company is increasing routine distribution vegetation management work over the next three years to move to an average five-year tree trimming cycle with an expected ongoing O&M *cost* of $49.4 million annually. Mr. Christie testified that the forecasted routine maintenance costs for the forward-looking test period (2020) is $39 million. Mr. Christie said he believes $49.4 million is necessary to sustain a five-year maintenance trim cycle while maintaining safe and reliable service to customers. Mr. Christie explained that he believed a five-year trim cycle is appropriate because in 2013 Duke Energy Indiana commissioned Environmental Consultants, Inc. ("ECI") to perform a regrowth analysis of tree-to-conductor contact by cycle length for the DEI service territory. Mr. Christie asserted the study concluded that a five-year routine maintenance cycle (with a minimum 10-foot clearance specification at the time of pruning) is appropriate for the Duke Indiana's distribution system when included as part of the overall IVM (integrated vegetation management) program.

While Mr. Christie testified the forecasted routine maintenance costs for the forward looking test period (2020) is $39 million, DEI's witness Christine Graft sponsored Schedule OM17, which shows a $10,479,000 increase to Test Period operating expenses, so that the *pro forma* amount of distribution vegetation management costs recovered through base rates would be $49.4 million..

Petitioner's witness Abbott testified that the Company's transmission vegetation management plan is designed to eliminate vegetation on right-of-way caused outages on circuits with voltages of 200 kV and above, in compliance with NERC Reliability Standard FAC-003. Mr. Abbott stated that the O&M for transmission vegetation management in 2018 was $5.62 million, the projected 2019 O&M is $7.65 million, and the projected 2020 O&M is $7.61 million.

(II) <u>OUCC's Evidence.</u> The OUCC did not oppose DEI's pro forma revenue requirement for vegetation management routine maintenance of DEI's transmission system of $7.6 million. But the OUCC disagreed with DEI's request of $49 million for routine maintenance of its distribution system, an increase of $36 million over the $13 million revenue requirement DEI established in its last rate case. Mr. Hand noted DEI's proposed revenue requirement is not supported by any study or historical practice. The OUCC's witness, Mr. Hand proposed a *pro forma* revenue requirement for routine vegetation management O&M of the distribution system be set at $32 million and that any amount not spent on such routine maintenance in a given year be returned ratepayers through the utility's credit rider (Rider 67).

Mr. Hand testified that DEI's obligation is to perform routine vegetation management that is consistent with good practice. Mr. Hand noted that despite recognizing the importance of regular routine vegetation management, DEI failed to do so particularly in recent years. Mr. Hand noted that during the past two years, DEI's average trim cycle has been close to 16 years. Mr. Hand noted DEI said this was due to resource issues and an increase in costs. Mr. Hand explained DEI said it intends to ramp up its routine maintenance over the next three years to achieve an average five-year trim cycle. Mr. Hand noted DEI did not explain what it would do over the next three years to achieve an average five-year trim cycle. He added that DEI did not explain how it would achieve such a pace during a period of scarce tree trimming resources. Mr. Hand noted that scarce tree trimming resources was one of the reasons DEI gave for falling to a 16-year trim cycle. Mr. Hand stated there is no evidence DEI has ever achieved a five-year trim cycle or shown in this case that it will even be able to do so.

Mr. Hand also questioned the reliability of DEI's assumptions resulting in its asserted cost per mile of performing routine vegetation management of its distribution system. He noted DEI provided no study to explain the sharp increase in costs or establish that an increasing cost trend will continue. He added DEI made no allowance for the possibility the market will correct itself. He explained, for instance, new vegetation management companies may enter the marketplace or existing ones may ramp-up their operations. Mr. Hand added that DEI's request for money to achieve a five-year trim cycle does not consider that some vegetation management will be completed through TDSIC projects, FMCA projects, and Storm Reserve projects.

Mr. Hand noted DEI proposes annual recovery of $49 million per year without any requirement that DEI actually spend this amount on vegetation management. Mr. Hand observed DEI testimony provided no spending forecast beyond 2021. He noted Mr. Christie indicated that the pace of routine maintenance over the next three years is a temporary and that DEI's routine maintenance costs are based on a three-year ramp up to attain an "acceptable vegetation trimming cycle." Mr. Hand stated the costs thereafter should be lower. He added that, nonetheless, DEI proposes to collect rates based on this temporary ramp up indefinitely. Moreover, Mr. Hand explained that, once embedded in base rates, these projects could be unilaterally cancelled without a reduction in rates, thereby being a financial windfall for DEI until its next rate case.

Mr. Hand declared DEI's failure to perform its routine vegetation management responsibilities at a reasonable pace should not be ignored. Mr. Hand stated that DEI's ratepayers should not be required to fund a program DEI has not proven it is capable of implementing. Mr. Hand also suggested that DEI's not maintaining a reasonable trim cycle in recent years will make maintaining a five-year trim more expensive than it would otherwise be.

Mr. Hand assumed a seven year trim cycle and recommended DEI's vegetation management *pro forma* annual revenue requirement for its distribution system be set at $32 million and subject to a mechanism to return to ratepayers moneys not used for vegetation management in a given year, specifically DEI's Credit Rider (Rider 67). Mr. Hand derived the $32 million *pro forma* amount by multiplying the cost per mile DEI reported for the 2018 base year of $14,178 by one seventh of DEI's 16,000 miles of distribution system.

(III) <u>Petitioner's Rebuttal Evidence</u>. The OUCC does not have any objections to Petitioner's recitation of its evidence.

(IV) Commission Discussion and Findings. Petitioner's proposed $49 million *pro forma* vegetation management revenue requirement for routine maintenance of its distribution system is based on several assumptions. DEI calculated the expense based on it ramping up its routine maintenance to achieve a five-year trim cycle at its forecasted cost per mile. DEI's proposal makes certain assumptions that must be addressed.

First, Petitioner's proposed revenue requirement assumes DEI will achieve a pace of routine maintenance it has not been able to reach in the past several years. Such a finding is not well supported. This is despite DEI's own analysis indicating that a five-year trim cycle is reasonable. In support of its five-year trim cycle, DEI relies on a species tree growth study it procured in 2014. DEI asserts that study established five years as a reasonable trim cycle for it to follow. Yet DEI's own evidence shows that since that study was completed, DEI has never achieved a five-year cycle. Petitioner's Exhibit 27, p. 7. In fact, in the most last two years of actual data in DEI's case in chief, DEI had slipped to a pace of a 16-year trim cycle. DEI's witness Mr. Christie denied that the reason DEI failed to attain a five-year trim cycle was because it didn't have the money in rates to do it. Hr. Tr. L-31, line 12 - L-32, line 8. Mr. Christie explained it failed to do so because of external constraints, more specifically, crews being diverted to other jurisdictions and suppliers having trouble retaining employees. Hr. Tr. L-32, line 6 - L-35, line 11. Although DEI asserted it has taken steps to improve its ability to procure its ability to procure tree trimming resources, these assertions lack specificity. In fact, DEI indicated it expects to continue to experience such constraint. In its rebuttal case, Mr. Christie disagreed that DEI had "failed" to perform regular routine maintenance of its distribution system and noted that the "Company experienced a contractor shortage in a highly competitive market." Petitioner's Exhibit No. 54, p. 5. In response to discovery, Mr. Christie stated that "The Company's experience tells us that we will continue to experience labor market constraints." OUCC CX 22 (OUCC 40.17).

> **Request:**
>
> With respect to the contractor shortage Mr. Christie referenced on page 5 of his testimony, please provide any studies performed by DEI, procured by DEI, or relied upon by DEI to determine whether and to what extent the contractor shortages it experienced will continue.
>
> **Response:**
>
> No official studies were performed or procured. The evidence of shortages has come primarily from contractors not being able to secure enough local resources to complete the annual work plans, or only having travel crews come in from outside the local area to complete the work at a much higher cost. <u>The Company's experience tells us that we will continue to experience labor market constraints</u>.
>
> (emphasis added.)

Second, we must confront the assumption that the high costs caused by the contractor shortages will continue after the labor shortages issues have been resolved. Both Mr. Christie and Ms. Graft acknowledged that DEI's obligation to maintain a reasonable trim cycle was not absolved by rising prices. Hr. Tr. M-27-M-31. Mr. Christie acknowledged that DEI has "an obligation to trim trees" and he added that "So to provide safe and reliable power, you know, there's some thing's necessary from a vegetation standpoint." Hr. Tr. L-33, lines 18 – 21. Importantly, Mr. Christie insisted the only factor keeping DEI from a more reasonable trim cycle was the availability of labor. Hr. Tr. L-32, line 6 - L-35, line 11. But Mr. Christie also insisted that the lack of availability of labor increased the price per mile of tree trimming. Logically, if the contractor shortage is solved, in whole or in part, the price per mile of tree trimming should also be improved. The OUCC's Mr. Hand noted that in forecasting a cost per mile DEI made no allowance for the possibility the market will correct itself through, for instance, new contractors entering the marketplace or existing companied increasing their operations. DEI claimed that its inability to attain a five-year trim cycle was caused by a contractor shortage. DEI claimed that the significant increase in prices was caused by a contractor shortage. DEI's $49 revenue requirement assumes one effect goes away but the other does not. This is an illogical position.

Third, DEI's proposal is inconsistent with state law. DEI has not based its proposed *pro forma* revenue requirement on its test period expense as authorized and required by IC 8-1-2-41.7. DEI's proposed $49.4 million is a forecast of 2021, the year after the test year. DEI's forecasted test year expense is $39 million based on a forecasted 2,569 miles at an estimated $15,181 per mile. The $10.4 million DEI has attempted to tag on to the test period expenses as an adjustment is unprecedented and, more importantly, unauthorized. Table 1 on page 7 of Mr. Christie's testimony is DEI's admission that it has no plan or intention to attain a five-year trim cycle in the 2020 forecasted test year. The 2,569 miles of distribution system DEI has forecasted it will trim is a little more than one seventh of DEI's distribution system. During cross-examination by the OUCC, Ms. Graft acknowledged that the 2020 forecast amount is the equivalent of a seven-year trim cycle. Hr. Tr. M-23. The $10.4 million *adjustment* DEI proposed to make is based on its asserted expenses occurring *after* the test year. It is a well-established practice for this Commission to permit utilities petitioning for rates using an historic test year to make adjustments within 12 months of that historic test period that are fixed in time, known to occur, and measurable in amount. As authorized by state statute, DEI has chosen a forward looking test year – 2020. As such, there is no statutory or logical basis to permit DEI to estimate even further into the future if it could reasonably do so. Even if DEI could as a matter of law attempt such an adjustment, we cannot agree that such an expense would meet the criteria applied to an adjustment following an historic test period, as for the reasons given in this section, the expense can hardly be considered "known to occur."

The OUCC believed DEI's rates should be based on a seven-year trim cycle, which it considered reasonable. Importantly, this trim cycle is roughly consistent with DEI's own projection for miles trimmed during the forward looking 2020 test year DEI chose. Subject to application of DEI's Rider 67, the OUCC proposed a *pro forma* revenue requirement for vegetation management (routine maintenance) of DEI's distribution system is $32 million. The OUCC's Mr. Hand derived the $32 million by multiplying the $14,178 cost per mile DEI reported for the 2018 base year, which is the last year of an actual cost per mile, by one seventh (1/7) of DEI's16,000 miles of distribution system. The OUCC's proposal results in a revenue requirement that is more than two and a half times what DEI has ever spent on routine maintenance tree trimming of its distribution in any of the actual years presented in this case. We agree $32 million is a reasonable revenue requirement for this expense and find that DEI's *pro forma* revenue requirement for routine vegetation management maintenance of DEI's distribution system shall be $32 million.

We next address what mechanism should be used to address the lack of certainty as to DEI's actual distribution system vegetation management routine maintenance expense. We agree and find that there is a great deal of uncertainty about how much DEI should reasonably be expected to spend in routine maintenance of its distribution system. Accordingly, before we establish that level for ratemaking purposes, we agree that amount should be subject to a mechanism to return to ratepayers moneys not used for vegetation management in a given year, specifically DEI's Credit Rider (Rider 67).

DEI proposed its annual *pro forma* revenue requirement of $49 million per year without any requirement that DEI actually spend this amount on routine maintenance of its distribution system. DEI's actions in recent years has shown that it considers maintaining a reasonable trim cycle to be more or less discretionary.

DEI proposes to more than triple the revenue requirement established in its last rate case without any spending forecast beyond 2021. Moreover, Mr. Christie indicated that the pace of routine maintenance over the next three years is temporary and that DEI's routine maintenance costs are based on a three-year ramp up to attain an "acceptable vegetation trimming cycle." Logically this suggests the costs thereafter should be lower. However, without application of Rider 67, once they are embedded in base rates, these projects could be unilaterally cancelled for any reasons without any corresponding reduction in rates. DEI's witnesses acknowledged that its obligation to maintain a reasonable trim cycle was not limited to the $13 million on which its rates were based more than 15 years ago. Ms. Graft expressed her belief that "the company budgets based on its business need, not based on an amount of expense that's in base rates." Hr. Tr. M-28, lines 5-7. Yet in the base year and the year prior, DEI trimmed less than one third of the distribution system it insists it must now attain. Table 1, Petitioner's Exhibit 27, p. 7. DEI's Rider 67 is well suited to address the particular challenges of this revenue requirement. Moreover, it encourages DEI to maintain a regular and reasonable trim cycle.

In its rebuttal testimony, DEI's witness Ms. Graft opposed the OUCC's suggestion to return to customers unspent vegetation management funds in a given year using DEI's Credit Rider. Acknowledging the very real possibility that DEI will not actually spend its requested pro forma revenue requirement, Ms. Graft said there are many reasons why a specific expenditure may not occur in one year, including resource constraints due to major storms. She said having such funds being available for future years enables flexibility. Ms. Graft asserted a better mechanism to ensure DEI spends the $49 million embedded in rates on vegetation management would be to use a cumulative reserve accounting approach by which Duke would record a regulatory liability for unspent moneys. She explained that the regulatory liability would be based on the amount by which its cumulative vegetation management O&M for the time period between base rate cases is less than the amount to be recovered through base rates. Such unspent funds from each year would be set aside in the reserve account for vegetation management O&M costs incurred in the following years and any balance remaining in the reserve account would be addressed in the Company's next retail base rate case. DEI's witness, Ms. Graft explained that "a final ratemaking proposal would not be determined until the time the Company's retail base rate case is filed. Hr. Tr. M-39.

While DEI's proposed mechanism is better than no mechanism, it would require a potentially contentious dispute in the next rate case as to how soon and even whether such funds should be returned to ratepayers. Moreover, because of the amount of time between rate cases, today's ratepayers will not enjoy the benefit of a credit if DEI's revenue requirement is overstated creating an intergenerational inequity. Finally, unlike application of a Rider 67 credit, DEI's proposed mechanism does not encourage adherence to a regular and reasonable trim cycle, as there is no timely consequence to failing to do so.

Mr. Hand declared DEI's failure to perform its routine vegetation management responsibilities at a reasonable pace should not be ignored. We agree. Our acknowledgement of that fact supports the application of DEI's Rider 67. In fact, relying on Rider 67 permits us to set rates based on what DEI *should* do with respect to vegetation management of its distribution system and not what it *has* done in its base period. The pro forma revenue requirement of $32 million is a significant increase over the $13 million embedded in DEI's prior rates. It is also a significant increase of the $12 million average spend in 2017 and 2018. Despite DEI only maintaining 1/16 of its distribution system in 2017 and 2018, we are setting rates based on DEI maintaining 1/7 of its distribution system. Thus, we set rates based on the assumption DEI will be able accomplish what it has not been able to do in recent years, while still using a 2018 cost per mile reflective of a contractor shortage. Being able to rely on Rider 67 permits this Commission to afford most of what asserts it will spend in its forecasted test year while protecting the consumer from what may be an overly optimistic achievement of trim cycle or over estimated costs.

We find that DEI's pro forma revenue requirement shall be subject to its Rider 67, and that any year following a year in which DEI expends less than $32 million on routine maintenance (vegetation management) of its distribution system shall be returned to ratepayers through the credit rider in the subsequent year.

(D) Incentive Compensation.

(I) Petitioner's Evidence. The OUCC does not have any objections to Petitioner's recitation of its evidence.

(II) OUCC's Evidence. OUCC witness Kollen described Duke Energy Indiana's request for recovery of incentive compensation expense tied to financial performance metrics. He indicated the Company included $28.655 million in total incentive compensation expense, consisting of $12.401 million tied to achievement of financial performance metrics by Duke Energy, Inc. and DEBS, and $16.254 million tied to the achievement of other performance metrics. He testified how these amounts include the incentive compensation expense incurred directly by the Company related to its employees and expense incurred indirectly through charges from DEBS related to its employees.

Mr. Kollen discussed how Duke Energy, Inc. maintains three major incentive compensation programs, the Short Term Incentive Plan ("STI"), Union Employee Incentive Plan ("UEIP"), and Long Term Incentive Plan ("LTI"). Each plan is applicable to different defined employee groups, although there is some overlap, meaning that certain employees may participate in more than one plan. In addition, each plan has separate objectives, performance metrics, weightings of the performance metrics, and payout targets.

Mr. Kollen testified the STI is applicable to executives and all other employees of DEI and DEBS; however, some employees participate in the UEIP sub-plan in accordance with their bargaining agreements. For executives, the earnings per share ("EPS") *financial* performance metric is weighted 50% and other performance metrics (O&M expense, *other* operational excellence, customer satisfaction, team goals, individual goals, and safety) are weighted 50% in the aggregate. For non-executive employees, the EPS *financial* performance metric is weighted 35% and *other* performance metrics are weighted 65% in the aggregate. He explained that if EPS is less than the target (100%) EPS *financial* performance metric, then the incentive compensation is reduced. If EPS is more than the target EPS *financial* performance metric, then the incentive compensation is increased. He stated the UEIP is available to union employees of DEI and certain employees of other affiliated companies. Employees who participate in the UEIP are not eligible to participate in the STI otherwise available to executives and other exempt employees. The EPS financial performance metric is the same and is weighted the same as the EPS financial performance metric for the STI applicable to executives and other exempt employees.

Mr. Kollen discussed how Duke Energy has two LTI programs. One is an Executive LTI program called the Executive Incentive Plan ("EIP"). The EIP is reserved for members of the Enterprise Leadership Team ("ELT") and Senior Management Committee ("SMC") "to drive an ownership mindset and ensure accountability for making short- and long-term strategic decisions." The other LTI program is available to other strategic leaders below the ELT level. Mr. Kollen explained how the EIP "continues Duke Energy's focus on increased stock ownership, more direct alignment with shareholders and retention. Specifically, the plan: 1) provides for share ownership by executives; 2) delivers a portion of long-term incentive opportunity when value is delivered to shareholders; 3) provides for increased award value in alignment with increases in shareholder value; and 4) assists in the retention of key executive talent. He testified how the EIP provides an "incentive opportunity" based on a percentage of an executive's base compensation tied to the achievement of financial performance metrics. For example, the Duke Energy CEO has an "incentive opportunity" equivalent to 750% of her base compensation. The EIP incentive compensation is paid out 70% in the form of performance shares and 30% in the form of restricted stock units. The 70% in performance shares is based on EPS (50% weighting) and TSR (25% weighting) financial performance metrics and a total incident (25% weighting) other performance metric. The 30% in restricted stock units vests over a three year period and includes dividends on the restricted stock units. He noted the other LTI program also provides an "incentive opportunity" based on an employee's base compensation and is paid out in the form of restricted stock units and vests over a three-year period and includes dividends on the restricted stock units.

Mr. Kollen recommended incentive compensation expense tied to Duke Energy, Inc.'s financial performance should not be included in the Company's revenue requirement, but he did not address or recommend the disallowance of the incentive compensation expense tied to the achievement of other performance metrics. He testified the fundamental ratemaking issue is not whether Duke Energy Indiana incurs incentive compensation expense tied to its parent company's financial performance, primarily thorough DEBS charges, but whether Duke Energy Indiana's customers should reimburse the Company for this portion of incentive compensation through their rates. He indicated this determination depends on whether the incentive compensation expense ultimately is incurred to incentivize performance that benefits the Company's customers, not harms them, or whether it is incurred to incentivize performance that benefits Duke Energy, Inc.'s shareholders.

Mr. Kollen stated the achievement of Duke Energy, Inc.'s Earnings Per Share ("EPS") and Total Shareholder Return ("TSR") financial performance metrics exclusively benefits Duke Energy, Inc.'s shareholders and not Duke Energy Indiana customers. Mr. Kollen's stated incentive compensation incurred to incentivize Duke Energy financial performance provides the Company's executives, managers, and employees a direct incentive to seek greater rate increases, in order to improve its parent company's EPS and TSR. Mr. Kollen stated that this is, in effect, a "success fee" for the achievement of rate increases, and that this is an inherent conflict of interest between the Duke Energy, Inc. shareholders and the Company's customers, one that they the customers should not be required to pay. Mr. Kollen also argued that if such incentive compensation expense is included in the revenue requirement, then it removes all risk exposure for actually achieving the target financial metrics through management and employee initiatives, in effect, converting such compensation into a certain expense. In addition, Mr. Kollen noted that these financial performance metrics are affected by the contributions toward EPS and TSR from other Duke Energy, Inc. affiliates, over which neither the Commission nor the Company have any control. Further, Mr. Kollen noted that Duke Energy, Inc. has maintained its incentive compensation tied to financial performance regardless of whether it is recovered through rates by other affiliates in other jurisdictions. He said incentive compensation expenses tied to financial performance metrics should be allocated to Duke Energy shareholders, not Duke Energy Indiana's customers.

As a result, Mr. Kollen recommended a $12.309 million reduction in the Company's revenue requirement for incentive compensation.

(III) **<u>Industrial Group's Evidence</u>**. The OUCC accepts the Industrial Group's recitation of its evidence.

(IV) **<u>Petitioner's Rebuttal Evidence</u>**. The OUCC does not have any objections to Petitioner's recitation of its evidence.

(V) **<u>Commission Discussion and Findings</u>**. We agree with the OUCC and IG recommendations to disallow the incentive compensation expenses tied to the achievement of *financial* performance metrics. These costs are appropriately allocated to shareholders, not customers. We also note that no party disputed that the incentive compensation expenses incurred based on the achievement of other *non-financial* performance metrics were properly allocated to customers. In addition, we note that no party disputed that incentive compensation expenses are or may be necessary to attract and retain highly qualified employees. Thus, the only issue in dispute is whether incentive compensation expenses incurred to achieve the Duke Energy, Inc. *financial* performance metrics should be allocated to its shareholders or allocated to Duke Energy Indiana customers. In Duke Energy Indiana's last general rate case (Cause No. 42359, Order dated May 18, 2004), we set forth certain criteria for the recovery of incentive compensation expenses through rates where: (1) the incentive compensation plans are not pure profit-sharing plans, but rather incorporate operational as well as financial performance goals; (2) the incentive compensation plans do not result in excessive pay levels beyond what is reasonably necessary to attract a talented workforce; and (3) shareholders are allocated part of the cost of the incentive compensation programs. Order in Cause No. 42359 at 89.

We find that the evidence in this proceeding indicates that certain of the incentive compensation plans have only financial performance metrics and certain of the plans have both financial and operational and safety performance metrics. The evidence in this proceeding allows us to distinguish and quantify the incentive compensation expense specifically related to the achievement of *financial* performance metrics and the expense tied to the achievement of *non-financial* performance metrics. We agree that the incentive compensation expense related to the achievement of *non-financial* (operational and safety) performance metrics should allocated to and recovered from customers because the achievement of those metrics benefits customers and employees, although they also benefit shareholders to the extent that they constrain cost increases between rate cases. However, the incentive compensation expense related to achievement of the Duke Energy, Inc.'s EPS and TSR is directed toward incentivizing and rewarding the parent company and other affiliate executives and managers for achieving goals that benefit shareholders, not customers and employees. Consequently, that incentive compensation expense tied to EP and TSR should be allocated to shareholders and not recovered from customers. The fact that the Company chose to limit its incentive compensation expense request based on an assumption that it would achieve "only" 100% of the target financial performance metrics does not affect whether this component of the incentive compensation expense should be allocated to customers rather than to Duke Energy, Inc.'s shareholders. .

(E) Fee Free Payment Option.

(I) Petitioner's Evidence. The OUCC does not have any objections to Petitioner's recitation of its evidence.

(II) OUCC's Evidence. Lauren M. Aguilar testified on behalf of the OUCC with regard to the fee-free payment program. Ms. Aguilar noted that Duke Energy Indiana is unable to state with particularity the extent of customer savings related to the fee-free payment program. Ms. Aguilar took issue with Duke Energy Indiana's reference to the fee-free payment program approved by the Commission in Cause No. 44967, stating that the approval was part of a settlement agreement and should not be given precedential value.

Ms. Aguilar stated the OUCC's recommendation that Duke Energy Indiana's proposal to recover credit card fees through inclusion of $4,528,000 in base rates should be denied, because not all of the Company's residential customers should be required to pay for benefits used by a subset of customers. Ms. Aguilar noted that Duke Energy Indiana is free to offer the fee-free payment program, but the costs should not be permitted to be placed into base rates, and that any savings the Company has yet to quantify can cover the costs of the program.

(III) Petitioner's Rebuttal Evidence. The OUCC does not have any objections to Petitioner's recitation of its evidence.

(IV) Commission Discussion and Findings. Duke Energy Indiana is proposing to offer the fee-free payment option, in order to eliminate the $1.50 convenience fee associated with customer payments by credit card, debit card, and electronic checks, and instead to socialize recovery of the underlying costs from all of its residential customers, even those not using those forms of payment, as if it were part of the basic cost of providing residential service. Specifically, the Company proposes adding a *pro forma* adjustment of $4,528,000 to the cost of service to cover fees that are no longer being collected solely from the cost causers using one or more of the above forms of electronic payment. The evidence Duke

Energy Indiana provided to the contrary did not support its assertion that the three forms of electronic payment continue to grow as preferred methods of payment by many customers, and that it is reasonable to spread these costs across its entire residential customer base as if they were general costs of providing service, instead of just recovering those fees from customers making electronic payments that are subject to those additional fees. The case Duke Energy Indiana relied on was a settled rate case initiated by Indiana Michigan Power Company, LLC, several years ago. The Commission's recent approval of a non-precedential settlement in an *Indiana Michigan Power Company* rate case, Cause No. 44967 (2018), where I&M required electronic payments to be made without requiring those customers to pay a separate line-item charge. However, that rate case does not provide sufficient evidentiary support for the proposition put forward by Duke Energy Indiana – i.e., that the Commission should approve the Company's proposed fee-free payment option because of a negotiated settlement the Commission approved in a different rate case, involving a different utility, with a different service offering. However, Duke Energy Indiana cannot rely on a non-precedential settlement to claim legal entitlement to similar relief in this case, because the I&M rate Duke relied on was a negotiated settlement, which contained the following language:

> 1.1 The parties agree that the Settlement Agreement should not be used as precedent in any other proceeding or for any other purpose, except to the extent necessary to implement or enforce its terms. Consequently, with regard to future citation of the Settlement Agreement, we find that our approval herein should be construed in a manner consistent with our finding in *Richmond Power & Light*, Cause No. 40434, 1997 WL 34880849 at *7-8 (IURC March 19, 1997).
>
> 1.2 Neither the making of this Settlement Agreement (nor the execution of any of the other documents or pleadings required to effectuate the provisions of this Settlement Agreement), nor the provisions thereof, nor the entry by the Commission of a Final Order approving this Settlement Agreement, shall establish any principles or legal precedent applicable to Commission proceedings other than those resolved herein.
>
> 1.3 This Settlement Agreement shall not constitute and shall not be used as precedent by any person or entity in any other proceeding or for any other purpose, except to the extent necessary to implement or enforce this Settlement Agreement.
>
> 1.4 This Settlement Agreement is solely the result of compromise in the settlement process and except as provided herein, is without prejudice to and shall not constitute a waiver of any position that any Settling Party may take with respect to any or all of the items resolved here and in any future regulatory or other proceedings.

The OUCC expressed concern with spreading these costs across Duke Energy Indiana's entire residential customer base, including those customers who do not use debit or credit cards or electronic checks to pay their electric bills. Because of that cross-subsidization, we conclude that Duke Energy Indiana's proposed fee-free payment option is unreasonable since it unfairly requires customers who do not use one of those electronic forms of payment to pay a portion of someone else's utility bill – the extra amount Duke is charged for accepting electronic payments. It is that cross-subsidization that causes the OUCC to oppose Duke's "fee free" electronic payment option.

If some customers trigger extra charges when they pay their electric bills, those customers should have to pay the extra amount, instead of expecting other customers to pay part of the cost-causers' bills for them. We therefore deny Duke Energy Indiana's request for approval its proposed fee-free electronic payment program and deny its request for approval of a *pro forma* adjustment to annual revenue from base rates of $4,528,000, which the Company had hoped to recover from its entire residential customer base.

iv. Tax Expenses.

(A) Federal and State Corporate Income Tax

(I) Petitioner's Evidence. The OUCC does not have any objections to Petitioner's recitation of its evidence.

(II) OUCC's Evidence. Witness Lane Kollen testified regarding several of the Company's tax issues. First, he described Duke Energy Indiana's use of the 4.90% income tax rate for the calculation of deferred income tax expense and said it was consistent with the Indiana income tax rate that will go into effect on July 1, 2021. Mr. Kollen indicated he disagreed with the Company's use of the 5.375% income tax rate for the calculation of current income tax expense and the gross revenue conversion factor.

Mr. Kollen testified the Commission could set base rates using an Indiana state income tax rate of 4.90% in this proceeding and in the gross revenue conversion factor, and then allow the Company to temporarily recover the differential as the income tax rate phases down through the Credits Rider (as an offset to the credits in the 1 rider) from the date new base rates go into effect in 2020 through June 30, 2021. He recommended this approach because the 5.375% Indiana state income tax rate is only temporary and the Company's base rates may be in effect for an extended period before they are again reset.

He noted this approach will allow a "permanent" reduction in the base revenue requirement and require only a "temporary" increase in rates through the Credits Rider. Mr. Kollen said the effect of his offset recommendation is a $2.026 million reduction in the retail base revenue requirement, which initially will be offset by an equivalent increase in the Credits Rider revenue requirement. He added that increase in the Credits Rider revenue requirement will phase out completely in July 2021, effectively implementing a $2.026 million rate reduction at that time.

Wes Blakley, Senior Utility Analyst in the OUCC's Electric Division explained in his testimony details of the Settlement Agreement between Duke Energy Indiana and the OUCC relating to the Tax Cuts and Jobs Act of 2017 ("TCJA") Duke Energy Indiana's unprotected Excess Accumulated Deferred Federal Income Tax ("EADFIT") is being passed back to customers using Rider 67 Credits Rider over a ten year period starting in 2022. This includes an annual amortization of $7 million of unprotected EADFIT credited back to customers over the first five years which will the increase to $35 million over the last five years until the amount is fully refunded. Mr. Blakley explained also pursuant to the TCJA Settlement Agreement, DEI will include a one-time credit of $1.9 million in Rider 67 in January 2020. Amortization of protected EADFIT will also begin in January 2020, in which time Rider 67 will include an annual amortization of protected

EADFIT based on the period determined by the Average Rate Assumption Method ("ARAM"), which was estimated in the TCJA Settlement Agreement to be 25.8 years.

OUCC witness Blakley provided the OUCC's recommendations on the appropriate treatment for Duke's 2018 and 2019 deferred regulatory liability for protected EADFIT credit. He noted Duke Energy Indiana proposed to pass back the 2018 and 2019 protected EADFIT deferrals using ARAM, which is estimated to be over twenty years. Mr. Blakley stated there is no requirement that the 2018 and 2019 protected EADFIT amortizations be returned using ARAM. He said that without the TCJA Settlement Agreement, Duke Energy Indiana's customers would have been entitled to receive immediate refunds of the 2018 and 2019 protected EADFIT amortizations. He noted that instead, the TCJA Settlement Agreement states the amortization of Duke Energy Indiana's 2018 and 2019 protected EADFIT will be addressed in its next rate case. Considering the delay that has already occurred, Mr. Blakley argued it would be unreasonable to extend the refund of those monies to Duke Energy Indiana's customers over a period of more than twenty years. As a result, he testified the OUCC recommends the 2018 and 2019 protected EADFIT regulatory liability be passed back to customers over the life of the rates set in this Cause, which is three years. Subject to the final balance, Mr. Blakley stated using a three-year period results in a $10 million refund to customers.

Mr. Blakley also testified regarding Indiana State Excess Accumulated Deferred Income Taxes ("EADIT") and recommended the EADIT refund be passed back to Duke Energy Indiana ratepayers over eight years, which is the period of the current state corporate tax reduction. Since 2012, according to Mr. Blakley, the Indiana corporate income tax rate has been reduced almost every year - from 8.5% in 2012 to 5.25% in 2020.

Mr. Blakley added that even though the Company's actual state income tax expense was reduced during this period, because it has not filed a base rate case in over ten years, Duke Energy Indiana customers have continued to pay utility rates that reflect an outdated 8.5% corporate income tax rate since the May 18, 2004 Final Order in Cause No. 42539.

Mr. Blakley stated Duke Energy Indiana customers are owed a refund based on the difference between the Company's actual corporate income tax expense and the corporate income tax expense revenue requirement included in its base rates during the period between rate cases. Unlike federal excess deferred taxes, which result from a utility's election of accelerated tax depreciation, Mr. Blakley contended the Company's state corporate excess deferred taxes are not related to depreciation and, therefore, are not categorized as either protected or unprotected for purposes of IRS normalization rules. Mr. Blakley said the Company's total accumulated Indiana corporate EADIT as of December 31, 2020, including gross-up, is $38,074,638. Mr. Blakley recommended this amount be passed back to customers, through Duke Energy Indiana's Rider 67 Credits Rider, over the period of the current state corporate income tax reduction of eight years.

OUCC witness Kollen also addressed the amortization of the DEBS EADIT as a one-time credit in the Credits Rider. He testified that DEBS should have refunded the EADIT to the Company and other regulated utility affiliate companies even if it had not charged them for income tax expense at the 35% federal income tax rate. He continued the Company recovers charges from DEBS in the same manner as if the Company had incurred the costs itself. DEBS acquired assets and depreciated those assets for book and income tax purposes. DEBS used bonus and MACRS accelerated depreciation for income tax purposes, which created temporary differences and the resulting ADIT for the bonus and accelerated tax depreciation in excess of straight-line depreciation. DEBS charged the Company and other affiliate companies for the depreciation expense on these assets and is entitled to any tax benefits, including the EADIT. As a result of the foregoing assertions, Mr. Kollen recommended the DEBS EADIT be allocated to the Company in the same manner that DEBS depreciation expense is allocated to the Company and then refunded to the Company's customers as a one-time $2.910 million credit through the Credits Rider.

(III) Industrial Group's Evidence. The OUCC accepts the Industrial Group's recitation of its evidence.

(IV) Petitioner's Rebuttal Evidence. The OUCC does not have any objections to Petitioner's recitation of its evidence.

(V) Commission Discussion and Findings. Duke Energy Indiana provided evidence discussing their calculation of federal and state income taxes used in the calculation of proposed operating income, which included the state and federal income tax rates used for calculation of current and deferred income taxes, the impact of other *pro forma* adjustments on income tax expense, the Company's synchronized interest deduction, the Company's parent interest deduction calculated in accordance with the Muncie Remand, and the removal of certain Investment Tax Credit and Excess Deferred Income Tax amortization credits which have been proposed to be included in the Company's Rider 67. The OUCC took exception with several issues related to income tax expense, including: 1) the state statutory rate used in the current income tax expense calculation; 2) the amount of excess federal ADIT to be allocated to customers, specifically recommending that a portion of excess ADIT from the DEBS affiliate service company should have been allocated to Duke Energy Indiana; 3) the amortization period used for state excess ADIT; and 4) the amortization period used for deferred federal protected excess ADIT. The Industrial Group also took exception to the amortization period used for the amortization period used for state EDIT and for deferred federal protected EDIT. In addition, the Industrial Group took exception with the Company's proposed allocation of federal EDIT to customers in Rider 67. Other than these issues, no party took exception to the Company's calculation of state and federal income taxes, including the *pro forma* adjustments, calculation of synchronized interest and the Company's parent interest deduction. We therefore find that except for the disputed issues, which we will next address, that the Company's income tax calculation is reasonable. We next address each of these disputed issues.

We first address the issue of the state income tax rate used in the current income tax expense calculation. There was no disagreement among the parties regarding Duke Energy Indiana's use of the 4.9% for the deferred income tax expense calculation. Duke Energy Indiana used the annual state statutory blended rate of 5.375% for the 2020 test period to calculate current income tax expense and in its revenue conversion factor calculation, and the final step of state income tax reductions which will become effective July 1, 2021, under current law for calculation of deferred income tax expense. There is no dispute the state income tax rate will decline to 4.9% on July 1, 2021. Because the rate will decline, the blended rate of 5.375% is temporary and if this rate is used then the Company will recover more for state income tax expense in 2021 and beyond than it will actually incur. The OUCC proposed that base rates should be set using the lower 4.9% state income tax rate, but that Rider 67 be used to step into that rate to allow the Company to temporarily recover the differential as the income tax rate phases down. By using this approach, the Company would be compensated for the temporarily higher income tax rate while not locking in a higher tax rate in base rates that Duke will not actually incur going forward. We find this approach fair and reasonable as it addresses the reality of the further reductions in the state income tax rate shortly after the end of the test year. We do not agree with the Company that it is entitled to retain these savings each year until base rates are reset in its next rate case, given that this change in state income tax rates is known and can be addressed in this proceeding.

We next address the issue of DEBS excess ADIT. The OUCC recommended that a portion of the excess ADIT recorded on the books of DEBS, the Company's service company affiliate, be allocated to Duke Energy Indiana based on the percentage allocation of depreciation expense to the Company and refunded to customers as a one-time credit in Rider 67. The Company and Mr. Kollen agree that DEBS incurs current income tax expense and deferred income tax expense and that temporary differences are reflected in both calculations. If the temporary difference is a deduction in the calculation of current income tax expense and thus, the tax effect is a reduction in the current income tax expense, then the tax effect of that temporary difference is an increase of an equivalent amount in deferred income tax expense. In addition, deferred income tax expense is accumulated into the ADIT balance, which reduces the DEBS rate base used to calculate the return charged to Duke Energy Indiana. When the Tax Cuts and Jobs Act of 2017 ("TCJA") was enacted, the temporary differences related to the income tax rate differential became permanent differences and the tax effects were removed from ADIT. Instead of allocating this reduction in ADIT to Duke Energy Indiana and other affiliate companies, DEBS took this EDIT to income, thus permanently increasing the costs charged to Duke Energy Indiana. We recognize that the ADIT has always been maintained at DEBS, as the Company claims; however, the ADIT is a temporary difference and reverses as the underlying temporary differences reverse. In accordance with DEBS' practice, ADIT is used to reduce the DEBS' "rate base costs" used to calculate the return charged to Duke Energy Indiana. In this manner, Duke Energy Indiana and its customers receive the benefit of the return on the ADIT as a reduction in the DEBS charges included in the Company's revenue requirement. However, a portion of that benefit now is lost to Duke Energy Indiana because the DEBS reduced the ADIT when it improperly took it as income for the benefit of the Duke Energy, Inc. shareholders. We conclude that the EDIT belongs to Duke Energy Indiana and its customers as a matter of cost-based ratemaking, not to Duke Energy, Inc.'s shareholders. Neither DEBS nor the Company had the right to increase DEBS affiliate charges to the Company and its customers as a result of the federal income tax rate reduction enacted by the TCJA.

We now address the amortization periods for the federal and state excess ADIT. Regarding state excess ADIT, we note that the Company agreed with the OUCC's recommendation to pass such benefits back to customers over an 8 year period We believe eight years is a reasonable time period as it aligns with the period over which state corporate taxes have been reduced. Further, Ms. Douglas concluded that this pass-back could be included in base rates as proposed by Mr. Gorman. We agree that approach is a reasonable balance of the parties' positions on the issue.

Regarding federal excess ADIT, we note that the Company's initial proposal was to pass back these credits over the life of the assets that gave rise to them. However, because the 2018 and 2019 protected excess ADIT has now become unprotected, there is no requirement under the law to do so. As such, we find persuasive arguments to pass these benefits back to customers earlier. OUCC and Industrial Group both proposed three-year amortization periods. Duke Energy Indiana proposed to pass them back over eight years. The federal excess ADIT was recovered by Duke Energy Indiana over two years; therefore, we find Duke Energy Indiana's proposal to pass back these benefits over an eight-year amortization period is excessively long. We agree with the OUCC and Industrial Group that the three-year amortization is fair and more closely matches the period of collection of the protected 2018 and 2019 excess ADIT.

Finally, we address the allocation method to be used for the pass back of the excess federal ADIT using Rider 67. Industrial Group witness Gorman recommended the funds be returned to customers in the same manner in which the rates were collected from customers using a 12 coincident peak ("CP") allocation methodology, even though he supports moving to a 4-CP allocation method going forward for base rates and riders. Duke Energy Indiana disagrees with singling out this one credit item to continue to use the 12-CP allocation factor. Rather, the Company proposes the updated 4-CP allocation factors in Credit Rider 67 be used. We agree that going forward base rates and riders should all be updated to use the same allocation factors approved in this proceeding based on the 4-CP methodology, to do otherwise for one credit item would unnecessarily complicates the rider filing and provide for inconsistency between costs and credit allocations.

(B) Utility Receipts Tax.

(I) The OUCC did not take a position on this issue.

12. Conclusion Regarding Petitioner's *Pro Forma* Jurisdictional Electric Net Operating Income. On the basis of the foregoing, we find that Petitioner's *pro forma* jurisdictional electric net operating income under present rates excluding revenue remaining in riders, adjusted to a level which fairly represents its forecasted operations is $619,045,000, summarized as follows:

$ in Millions under current rates	2020
Total Operating Revenues	2,601.813
Operating Expenses	
Operation and Maintenance, Incl Fuel and Purchased Power Expense	1,232.923
Depreciation and Amortization	535.571
Property and other Taxes	68.048
Income Taxes	146.226
Total Operating Expenses	1,982.768
Operating Income	619.045

When applied to the original cost (also in this case, fair value) rate base determined for Petitioner above, this operating income produces a return of 6.46%, which is above the range established in our above findings. Accordingly, on the basis of the evidence and the foregoing determinations, we find that the electric operating income to Petitioner, under its present rates for the electric utility service rendered and to be rendered by it, is excessive and is providing Petitioner a greater return upon the fair value of its electric properties used and useful for the convenience of the public for the forecasted test period and beyond. Therefore, Petitioner's current rates are unjust and unreasonable.

13. **Rate Level to be Authorized**. We find that a net jurisdictional operating income, excluding revenue remaining in riders, of $517,594,000 is hereby found to be a fair return upon the fair value of Petitioner's electric property used and useful and reasonably necessary for the convenience of the public. This provides a fair rate of return of approximately 5.40% which is within the range of reasonableness established in our previous findings. In order to provide such utility operating income, a reduction in Petitioner's gross annual retail electric operating revenues of $135,591,000 (excluding items remaining in riders and the utility receipts tax) is required. The reduction in revenues will give rise to reduced income tax expense and as a result, total operating expenses will be $1,948,628,000 On that basis, we find that Petitioner's *pro forma* Jurisdictional operating results will be:

$ in Millions under current rates	2020
Total Operating Revenues	2,466.222
Operating Expenses	
Operation and Maintenance, Incl Fuel & Purchased Power	1,232.923
Depreciation and Amortization	535.571
Property and other Taxes	67.493
Income Taxes	112.640
Total Operating Expenses	1,948.628
Operating Income	517.594

14. **Cost Allocation**.

a. **Jurisdictional Separation Study.**

The OUCC did not take a position on this issue.

b. **Class Cost of Service Study.**

i. **Petitioner's Evidence.** The OUCC does not have any objections to Petitioner's recitation of its evidence.

ii. **OUCC's Evidence**. Messrs. Eckert and Watkins expressed concern at the Company's use of third-party software, which required an on-site visit to review the Company's Cost of Service Study. OUCC witness Watkins repeated these concerns, stating that the information contained in Petitioner's filings were inadequate to conduct a proper evaluation of its proposal, especially relating to the cost of service study. Mr. Watkins explained that, in his experience in general rate case applications, he has always been able to review, examine, and evaluate the information the utility relied upon, as well as verify and understand how the data was manipulated, and be able to replicate the utility's results. However, in this proceeding, the Petitioner's cost of service study was not well documented, and did not provide much of the underlying information required to evaluate or fully understand the study, let alone verify the Company's results. Mr. Watkins was also concerned that Petitioner deemed all aspects of the cost of service study as confidential, which he has never seen in his 39 years of experience. Mr. Watkins explained that the cost of service study results are the foundation for its proposed class revenue requirements and rate design, and that the public has a right to know the basis upon which the Company has developed its proposed rates. Mr. Watkins further explained that he has not seen these difficulties in rate cases involving Duke affiliates in other states.

Mr. Watkins described the purpose of a class cost of service study, explaining that to the extent that certain costs can be specifically attributed to a particular customer of group of customers, these costs are directly assigned to the customer or group in a class cost of service study. It is generally accepted that to the greatest extent possible, joint costs should be allocated to the customer classes based on the concept of cost causation. However, some categories of costs, such as corporate overhead costs, cannot be attributed to specific factors, and must be subjectively assigned, in which there are often disagreements on what is an appropriate cost causation measure or factor. Mr. Watkins further testified that because the vast majority of vertically integrated electric utilities' rate base and expense account items are allocated based on some measure of demand, the estimation of class contributions to demand serve as the foundation for any class cost allocation study. Therefore, if there are any deficiencies within the estimation of class contributions to demand, the resulting cost allocation study will have serious deficiencies. Mr. Watkins explains that because there are disagreements on the specific factors that drive individual costs and cost causation factors, two different studies for the same utility can yield different results, and that regulators should consider the class cost of service study as a guide, with the results used as one of many tools to assign class revenue responsibility.

Mr. Watkins explained the strengths and weaknesses of common generation cost allocation methodologies. Mr. Watkins testified that the OUCC, in Cause No. 42873, agreed not to oppose the use of the 4-CP method in the present Cause. However, Mr. Watkins stated that the agreement not to oppose does not change the flaws in the 4-CP methodology. Mr. Watkins stated that cost allocation methods that only consider peak loads (demands) such as the 1-CP and 4-CP do not reasonably reflect cost causation for electric utilities because these methods totally ignore the type and level of investments made to provide generation service. Peak responsibility methods such as 1-CP or 4-CP totally ignore planning criteria used by utilities to minimize the total cost of providing service, do not reflect the utilization of its portfolio or generating assets throughout the year, and therefore, do not reflect in any way how capital costs are incurred; i.e. they do not reflect cost causation. In the Company's situation, base load plants produce about 95% of the Company's total owned generation energy, while peakers produced slightly more than 1% as they were only operated for a few hours during the year in peak load conditions. When Duke's total generation investment is allocated to classes based only on a few hours of peak demand, the implicit assumption is that the Company's entire investment in generation is made to serve peak load requirements. However, this is incorrect as the vast majority of assets of the generation investment was made to serve customer's load and usage throughout the year. Any allocation methodology that only considers a few hours of peak demand presents a significant bias against low-load factor and weather sensitive customers such as the residential class. However, as the OUCC has agreed to not oppose the 4-CP method in this case, Mr. Watkins did not conduct an alternative class cost of service study. Mr. Watkins confirmed that the Company's 4-CP class cost of service study reflects all of the Company's forecasted and proforma rate base and operating income amounts. However, as Mr. Watkins demonstrated that the forecasted revenues for the residential class are understated, he provided a reasonable estimate for the residential class rate of return under the 4-CP method incorporating his revenue and fuel cost adjustment.

iii. Industrial Group's Evidence. Industrial Group witness Phillips recommended that the Company allocate its production plant and transmission plant on a 4-CP method. Mr. Phillips stated that the average of the 12 monthly coincident peak demand method ("12-CP") is no longer reflective of Duke's current or projected loads, or those used by MISO to determine Duke's reserve margin and capacity requirements. Mr. Phillips further testified that Duke's proposed method of distributing its requested rate increase to classes reduces existing interclass subsidies by only 5% and results in rates that continue to contain massive subsidies and are not reflective of cost. Mr. Phillips stated that a much greater level of subsidy reduction is necessary and appropriate. In cross-answering testimony, Mr. Phillips testified that attempting to classify the majority (70%) of Duke's production investment as being energy-related is flawed and inconsistent with prior Commission findings. Also, in his cross-answering testimony, Mr. Phillips contended that the OUCC's argument to not reduce the subsidy is contrary to the policy of the Commission.

iv. Joint Intervenors' Evidence. The OUCC accepts Joint Intervenors recitation of its evidence.

v. Petitioner's Rebuttal. The OUCC does not have any objections to Petitioner's recitation of its evidence.

vi. Kroger's Cross-Answering Testimony. Kroger witness Bieber recommended the Commission reject Mr. Wallach's utilization of the Equivalent Peaker method to classify production costs. He also testified the Commission should accept Mr. Philips' recommendation to use the minimum distribution system method to classify certain distribution plant costs as customer-related.

vii. Commission Discussion and Findings.

The OUCC dos not have any objections to this section.

(A) Allocation of Production Related Costs; 4-CP versus 12-CP. The OUCC dos not have any objections to this section.

(B) Demand/Energy Allocators. The OUCC dos not have any objections to this section.

(C) Allocation of Distribution Plant Costs. The OUCC does not have any objections to this section.

(D) Subsidy/Excess Adjustment. The OUCC does not have any objections to this section.

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15. Rate Design.

a. HLF and LLF.

i. **Petitioner's Evidence.** Petitioner's witness Bailey supported the design of Rate LLF - Schedule for Low Load Factor Service ("Rate LLF"); and Rate HLF - Schedule for High Load Factor Service ("Rate HLF"). Mr. Bailey testified that the Company's rate design objectives for those rate schedules had not changed. Mr. Bailey described the customer charges and rate blocks for both rates. Mr. Bailey explained that the rates are designed to unbundle costs to provide more accurate price signals and reduce the inter-voltage subsidy and excess revenues.

Mr. Bailey testified that there are no proposed structural changes to Rate HLF or Rate LLF. However, the Company proposed changes to the Time of Use ("TOU") Riders, including changing the On-Peak and winter periods and eliminating the Rate Equalization Adjustment. Mr. Bailey stated that to the extent customers reduce their bills under the TOU Riders relative to their former standard bill, Duke Energy Indiana proposes to include the shifts to these rates in a migration adjustment. Mr. Bailey also testified that the Company also was proposing an Experimental Market Pricing Program and an Experimental Demand Management and Stability Program applicable to Rate LLF and Rate HLF.

ii. **OUCC's Evidence**. With respect to the Experimental Market Pricing Program and an Experimental Demand Management and Stability Program, OUCC witness Boerger recommended the Company collect data on customers' behavior and study the effect of any behavioral changes on its costs of providing service, and be required to present this information and analysis at the time a request is made to extend or expand the programs.

iii. **Intervenors' Evidence**. Industrial Group witness Phillips recommended grandfathering customers on the existing TOU rate to avoid harsh impacts associated with the new rate design. Mr. Phillips further recommended expansion of the Market Pricing Program to allow up to 100 MW of load above what is known as the Customer Baseline Load. Mr. Phillips also suggested interruptions under the Demand Management and Stability Program allow for 24-hour notice.

Walmart witness Chriss recommended the Commission require Duke Energy Indiana to recover 100% of demand-related costs on the demand charge for the HLF rate schedules. Mr. Chriss testified that this recommendation is consistent with the stated purpose of HLF to serve high load factor customers and consistent with cost of service-based ratemaking.

Kroger witness Bieber likewise testified that the Company's rate design for Rate HLF secondary understates the demand charge while overstating the energy charge relative to the underlying cost components. Mr. Bieber stated that the Company's proposed Rate HLF secondary rate is designed to only recover 75% of demand-related fixed costs, while the energy charge would recover 155% of energy-related costs. Mr. Bieber recommended a rate design that will increase the demand-related charges while reducing the energy charges by a corresponding amount to recover Duke Energy Indiana's total proposed revenues for the Rate HLF schedule.

Mr. Bieber recommended that the Company's proposed migration adjustment should be allocated to the Rate LLF secondary schedule. Mr. Bieber stated that Rate LLF secondary already is a subsidized rate that shields customers from the impacts of demand charges, while Rate HLF secondary is a large subsidy provider.

iv. <u>Petitioner's Rebuttal Evidence</u>. Mr. Bailey disagreed with the recommendation of witnesses Chriss and Bieber that all demand related charges should be in the demand charge and energy costs in the energy charge. Mr. Bailey stated that rate design is a much more complex process. He stated that both witnesses, while supportive of cost-based rate design, miss an important translation between cost of service and rate design. This occurs, he stated, by failing to recognize that all demands are not created equal. This failure to recognize differences in demand can result in a distortion of prices of a rate schedule. He explained that all demand elements from the cost allocation process are incorporated into rate design on a noncoincident basis. He noted that noncoincident demands for Rate HLF are approximately 25% higher than coincident demand, and about 19% higher than the class diversified demands. Accordingly, using noncoincident demands as a "common denominator" dilutes the other demand elements. He testified that the result of such dilution is that high load factor customers, who have higher coincidence with the system peak as load factor increases, can drive their costs below the actual cost of providing service. Given the practical need to design rates using such a "common denominator," he stated the rate designer's task is to design a rate that best mimics the cost of serving customers across a range of usage without all cost elements strictly defined by the rate structure. He explained that a common method to address the fact that noncoincident demands for HLF are relatively higher is to use what is called "tilting" – including some portion of demand costs in the energy charge. He testified that with this type of design, the higher load factor customers, as coincidence increases, are assigned some additional fixed costs that they are in fact imposing on the system through their consumption of energy. Mr. Bailey provided illustrative examples to demonstrate these concepts, including an illustration of the relationship between load factor and coincidence factor (a "Bary Curve") using actual load research from the Company's secondary Rate HLF customers. This evidence, he stated, shows that as load factor increases, system coincidence increases as well; and further, that if rates are not tilted, all customers would pay the same level of fixed costs irrespective of their coincident peak demands which cause the most expensive part of the system, (i.e., production and transmission). Such a non-tilted rate design, he stated, produces subsidies for the highest load factor customers, while the lowest load factor customers pay more than the cost to serve. He testified that a tilted rate, in contrast, minimizes the subsidies within the class, by shifting some of the demand costs to the energy portion of the rate. He summarized his testimony on this point by concluding that the intervenors' arguments are flawed, and a tilted rate structure is reasonable and appropriate. Mr. Bailey recommended that the Company's proposed structure, as modified by the Commission's final determination of revenue requirement, be approved.

Mr. Bailey did not oppose Mr. Bieber's proposal that the migration adjustment be allocated to the Rate LLF secondary schedule. Mr. Bailey noted that the class impacts of this recommendation are relatively small. Mr. Bailey stated that while Mr. Bieber's recommendation may precipitate additional migrations away from Rate LLF, he would expect this to be relatively small. Therefore, Mr. Bailey stated that the Company has no major objection to Mr. Bieber's recommendation.

Mr. Bailey disagreed with Mr. Phillips proposed expansion of the Market Pricing Program to allow up to 100 MW of load above the Customer Baseline Load, as well as his recommended 24-hour notice for the interruptible provisions of the Demand Management and Stability Program. Mr. Bailey indicated that Petitioner would agree to Dr. Boerger's recommendation that the Company collect data on customers' behavior and study the effect of any behavioral changes on costs of providing service, as well as be required to present this information and analysis at the time a request is made to extend or expand the programs.

Mr. Bailey also agreed with Mr. Phillips' recommendation to grandfather customers on the existing TOU rate. Mr. Bailey stated that Mr. Phillip's recommendation is reasonable. Mr. Bailey stated that these TOU rates are distinct line items in cost of service, and will be allocated their proportionate increase pursuant to final determination of the revenue requirement.

v. Commission Discussion and Findings.

(A) Design of Rates HLF and LLF. No party opposed Petitioner's proposed connection charges for Rates HLF and LLF or the declining block structure. However, both Walmart witness Chriss and Kroger witness Bieber recommended the Commission require Duke Energy Indiana to recover 100% of demand-related costs from the demand charge for the HLF rate schedules.

We are not persuaded that the change in rate design proposed by Walmart and Kroger is in the public interest. In particular, we are concerned about the impact this proposal will have on members of the rate class that have lower load factors. Mr. Bailey testified that making the changes proposed by Walmart and Kroger could actually drive the costs of high load factor customers below the cost of providing service.

Petitioner's proposed methodology for allocating demand avoids the potential for a disproportionate amount of cost being borne by low load factor customers, by taking into account the difference between "coincident" and "noncoincident" peak demand. "Coincident peak demand" is the demand of a customer (or a class of customers) at the time of the supplier's system peak demand. "Noncoincident demands" refers to a customer's (or a class of customers') peak demands regardless of when they occur. Noncoincident demands for Rate HLF are approximately 25% higher than coincident demand, and about 19% higher than the class diversified demands.

Treating coincident and noncoincident demand the same as proposed by Walmart and Kroger would result in more costs being unjustifiably borne by the lower load factor customers in the class. Accordingly, we find that Company's proposed structure for Rates HLF and LLF should be approved.

(B) HLF and LLF Experimental Rates. No parties opposed the experimental programs the Company proposed. However, Mr. Phillips suggested that they be modified. We find that Mr. Phillips' recommendation to modify the programs should be rejected. Mr. Phillips' recommendation that the Market Pricing Program be expanded to allow up to 100 MW of load above the Customer Baseline Load would shift additional financial risk to the Company. Mr. Phillips' recommendation that the Demand Management and Stability Program allow for 24-hour notice would not allow the Company to include load under as a curtailable resource under MISO requirements. Accordingly, we find that the Experimental Market Pricing Program and Experimental Demand Management and Stability Program should be approved as proposed.

Consistent with Dr. Boerger's recommendation and Petitioner's agreement thereto, we further find the Company should collect data on customers' behavior and study the effect of any behavioral changes on its costs of providing service. Petitioner shall present this information and analysis at the time a request is made to extend or expand the programs.

(C) Time of Use Rates. The Company proposed to modify the TOU Riders applicable to Rates HLF and LLF. The Company proposed to: (i) include the month of March in the Winter season because it presents similar characteristics as the traditional Winter month of December; and (ii) change the Winter On-Peak period to 6 a.m. to 2 p.m. and 6 p.m. to 9 p.m. Eastern Standard Time. In response to Industrial Group witness Phillips' concerns about the potential for harsh impacts associated with the new rate design on existing customers, the Company agreed to grandfather customers on the existing TOU rate. Subject to the foregoing agreement regarding existing customers, we find that Petitioner's changes to the TOU Riders applicable to Rates HLF and LLF, including grandfathering of existing TOU customers, should be approved.

(D) Rate Migrations. No party opposed Petitioner's proposed migration adjustment for expected the migration between the Rate HLF and Rate LLF secondary rate schedules. However, Kroger witness Bieber recommended that the migration adjustment be allocated to the Rate LLF secondary schedule. Mr. Bieber noted that Rate LLF secondary is already a subsidized rate that shields customers from the impacts of demand charges, while Rate HLF secondary is a large subsidy provider. Petitioner's witness Bailey agreed to Mr. Bieber's recommendation. Accordingly, we approve the proposed migration adjustment but direct Duke Energy Indiana to allocate the entire migration adjustment to the Rate LLF secondary schedule.

b. RS and CS.

i. Petitioner's Evidence. Petitioner's witness Bailey supported the design of Rate RS - Schedule for Residential and Farm Service ("Rate RS") and Rate CS - Schedule for Commercial Service ("Rate CS"). Mr. Bailey testified that Duke is proposing two rate design options relating to Rate RS and Rate CS. The Company's first, and preferred option, would apply if the Company were allowed to implement decoupling; its second option is without decoupling. Mr. Bailey stated that for the development of the two residential structures, the Connection Charges are $9.80 (with decoupling) and $10.54 (without decoupling), respectively, compared to the current charge of $9.01 per month. Mr. Bailey stated that for Rate CS, the Connection Charges are $9.27 (with decoupling) and $10.70 (without decoupling), respectively, compared to the current charge of $9.01 per month. Mr. Bailey also described the declining block structures for Rate RS and Rate CS. Finally, Mr. Bailey described three dynamic pricing pilot rates for both rate schedules.

ii. <u>OUCC's Evidence</u>. OUCC witness Watkins testified that a direct customer cost analysis approach is the proper methodology to be used to design customer charges. Under this approach, Mr. Watkins stated there is no provision to include corporate overhead expenses or any other indirect costs in the customer charge. Mr. Watkins stated that the Residential direct customer cost is calculated to be between $8.59 and $8.87 per month. Mr. Watkins explained that the lower cost of $8.59 is based on a 9.0% return on equity as recommended by OUCC witness David Garrett, while the higher cost of $8.87 is based on the Company's requested return on equity of 10.40%. Mr. Watkins stated that although his customer cost analysis indicates a customer charge of no more than $8.59 is warranted, he recommended the current Residential monthly customer charges of $9.01 for both Rate RS-General and Rate RS-High Efficiency be maintained.

Mr. Watkins noted that Mr. Bailey recommended reducing the discount in the second and third usage blocks under both of his rate design options (with and without decoupling). Mr. Watkins stated that in his opinion, this is a step in the right direction.

Watkins also explained that the Company's understatement of forecasted kwh sales affects revenues at current rates as well as Residential rate design. Mr. Watkins provided a comparison of Petitioner's and his recommended kwh billing determinants, by residential rate schedule, in his Attachment GAW-2, Page 1.

Mr. Watkins did not object to the proposed pilot rates. However, Mr. Watkins stated that if the pilots were approved, the Company should keep and maintain specific records on a customer by customer basis that compares each customer's actual bills (and billing determinants) to those that would have resulted under Rate RS. Furthermore, Mr. Watkins stated the Company should be required to submit detailed reports, data, and workpapers to the Commission, OUCC, and other interested parties on at least an annual basis concerning customer impacts and changes and in energy usage and peak load as a result of the critical peak pricing structure.

iii. <u>Joint Intervenors' Evidence</u>. The OUCC accepts Joint Intervenors recitation of its evidence.

iv. <u>Petitioner's Rebuttal Evidence</u>. The OUCC does not have any objections to Petitioner's recitation of its evidence.

v. <u>Commission Discussion and Findings</u>.

(A) <u>Residential Connection Charges</u>. Both Joint Intervenors and OUCC opposed Petitioner's proposed increase to the customer charge from $9.01 to $9.80 (with decoupling) and $10.70 (without decoupling). We find, based on the analysis provided by OUCC witness Mr. Watkins, that an increase of the connection charge is not warranted. Customer charges should only include the direct costs that vary per customer, and are appropriately allocated under the principle of direct cost causation. We do not find that other indirect and overhead costs should be allocated to customers through the connection charge. Rather, these costs are more appropriately allocated and recovered from customers through energy charges. Additionally, a comparison of the customer charge and the proposed change to other utilities is not necessary if the requested increase is not justified. Although Mr. Watkins' analysis showed the direct customer cost is below the current customer charge, he recommends that the current customer charge be maintained. Accordingly, we do not approve the proposed revision to the residential customer charge.

(B) Residential Declining Block Rates. OUCC witness Watkins testified that Petitioner's declining block rate structure is a step in the right direction and recommended it be approved. Joint Intervenor witness Wallach, however, testified that Company lacks a reasonable basis for continuing to employ a declining-block rate structure for residential energy rates and supports a flat volumetric energy charge.

The record shows the Company's proposal is more cost-justified than one that collects demand-related costs through a flat volumetric energy charge. Mr. Bailey testified that the design of Rate RS is supported by modeling, which was provided to the parties in this Cause. We further note that in the IPL 2016 Rate Order, we found that replacing declining block energy rates with inclining block rates could result in harm to customers that use an above average amount of energy. *Re Indianapolis Power & Light Co.*, Cause No. 44576, at 72. We find Petitioner's proposed continuation of the declining block rates should be approved.

(C) KWH Billing Determinants. Because we adopt the OUCC's residential sales forecast adjustment, the design of rates must also reflect this level of kwh sales volumes. The Commission adopts the OUCC's recommended KWH sales billing determinants set forth Attachment GAW-2 for purposes of designing rates.

(D) Dynamic Pricing Pilots. The Company proposed three unique rate designs for each of Rates RS and CS: (i) Schedule CPP: Critical Peak Pricing; (ii) Schedule VPP: Variable Peak Pricing; and (iii) Schedule VPP-D: Variable Peak Pricing with Demand. No party opposed any of the three optional rate designs. The OUCC, however, proposed certain reporting and record keeping requirements which the Company agreed to comply with. Based on the evidence presented by Petitioner in support of the dynamic pricing rate designs we find that they should be approved subject to Petitioner's complying with the recordkeeping and reporting requirements in the manner described by Mr. Bailey.

c. Revenue Decoupling Mechanism.

i. Petitioner's Direct Evidence. The OUCC does not have any objections to Petitioner's recitation of its evidence.

ii. OUCC's Evidence. OUCC witness Dr. David E. Dismukes, PhD testified that the Company's RDM proposal should be rejected for a number of reasons. First, Dr. Dismukes stated that the Company's proposed RDM is inconsistent with the Commission's past policies regarding decoupling mechanisms for electric utilities and the Sales Reconciliation Component ("SRC") approved for natural gas utilities.

In addition, Dr. Dismukes testified that the Company did not show that its efficiency activities or proposed rate design changes have, or will have, a negative financial impact on its ability to earn its allowed rate of return. Dr. Dismukes noted that on a historical basis, the Company's past efficiency efforts have not significantly impacted its ability to earn its allowed return on equity ("ROE"), particularly because the Company already has a mechanism in place that allows it to recover lost revenues associated with these activities. Dr. Dismukes stated that the Company has not provided any projections that quantify any specific future earnings challenges, raising questions about its validity and whether or not the Company will, in fact, see financial impacts that differ significantly from those experienced over the past five years.

Lastly, Dr. Dismukes stated that the Indiana Code already provides that lost revenues associated with energy efficiency ("EE") and demand side management ("DSM") activities can be recovered through a lost revenue adjustment mechanism ("LRAM"). Dr. Dismukes testified that the Company has taken advantage of this opportunity and, as a result, does not have any disincentive to promote EE or DSM measures. Dr. Dismukes stated that the Company does not expect revenue losses from its dynamic pricing pilot programs to be significant and, in regard to its volt/VAR optimization program, its cost benefit analysis showed the overall program resulted in a net benefit. Therefore, Dr. Dismukes concluded that the Company's proposed RDM is not needed to address the Company's purported concerns.

iii. <u>Petitioner's Rebuttal Evidence</u>. The OUCC does not have any objections to Petitioner's recitation of its evidence.

iv. <u>Joint Intervenors' Cross-Answering Testimony</u>. The OUCC accepts Joint Intervenors' recitation of its evidence.

v. <u>Commission Discussion and Findings</u>. DEI proposes to be the first vertically integrated electric company in Indiana to implement an electric decoupling mechanism. The Company's proposal includes a revenue decoupling mechanism ("RDM") that will adjust the rates of certain rate classes, generally residential and small commercial, for differences between fixed costs approved for recovery in this proceeding, adjusted for changes in the number of customers, and fixed costs actually recovered by the Company. These differences would be deferred on a monthly basis for subsequent inclusion in an annual RDM tracker filing that would recover from or pass back to customers the accumulated deferred decoupling amounts.

Throughout its testimony, Petitioner contends that its proposed decoupling mechanism is reasonable and necessary because it: (1) removes the Company's disincentive to pursue energy efficiency initiatives by removing the relationship between collecting revenues and making sales; (2) provides appropriate cost recovery for its energy efficiency programs, dynamic pricing proposals and volt/VAR optimization efforts; and (3) aligns the interest of the Company with its ratepayers in attempting to promote conservation of natural resources. After careful review of the evidence outlined herein, we reject DEI's decoupling proposal for the reasons discussed below.

First, traditional regulation in the State of Indiana provides sufficient safeguards and incentives for DEI to advance required demand-side initiatives. It is prudent to start with a discussion of what is called the regulatory "bargain" or regulatory "compact" that exists in this state. DEI is provided a monopoly service area in which retail consumers cannot choose to obtain their electric service from another provider. In turn, DEI must plan for and serve all retail consumers. Thus, the public is provided safe and adequate utility service at reasonable rates and, in exchange, utilities are ensured cost recovery and an opportunity to earn a reasonable return on its investment. We discussed the regulatory compact in some detail in our July 28, 2010 Order in the Demand Response Investigation (Cause No. 43566):

> Indiana law declares this traditional monopoly structure to be 'in the public interest' and unalterable by the authority granted to the Commission in Ind. Code § 8-1-2.5 *et seq.* Ind. Code §§ 8-1-2.3-1; 8-1-2.5-11. The Service Area Act is a cornerstone of Indiana's retail electric utility service framework. Assigned service areas were created to provide for the 'orderly development of coordinated statewide electric service at retail, to eliminate or avoid unnecessary duplication of electric utility facilities, to prevent the waste of material and resources, and to promote economical, efficient, and adequate electric service to the public.' Ind. Code 8-1-2.3-1. *Id.* at 43.

As Dr. Dismukes testified, DEI operates "in the public interest" because it provides basic and necessary customer service but also because it extracts and utilizes valuable natural resources in providing that service. He stated further that intentionally wasting those natural resources is incompatible with this public interest standard. The promotion of inefficient sales for profit is simply inconsistent with an underlying public interest principle of close to 100 years of utility regulation. Whether DEI receives a particular cost recovery mechanism or not, it remains obligated to conserve our natural resources as part of its regulatory bargain.

One of the ways the Commission can ensure utilities are complying with the mandate to prevent waste of material and resources is through the Integrated Resource Plan ("IRP") each utility is obligated to provide. The triennial IRP filing is intended to provide the Commission with the utilities' long-term resource planning. As we stated in our July 28, 2010 Order in Cause No. 43566:

> An integral component of the IRP in Indiana is that the evaluation of supply and demand resources is to be undertaken with cost effectiveness in mind. Specifically, 170 lAC § 4-7-1(s) defines 'integrated resource planning' to be 'a utility's assessment of a variety of demand-side and supply-side resources to cost-effectively meet customer electricity service needs. *Id.* at 44.

DEI, like all other electric utilities in the State, is legally obligated to consider demand side options on a level playing field with supply side options.

Indiana's Strategic Energy Plan, established in 2006, included a directive to support alternative pricing regulatory mechanisms that encourage utilities to promote efficiency and conservation by their customers without incurring negative financial results. The Commission has also considered alternative pricing regulatory mechanisms when they have been brought before us. Notably, Vectren North, Vectren South and several other Indiana gas utilities now use rate decoupling mechanisms. As we evaluate the need for alternative pricing regulatory mechanisms in this case, it is practical to look at what cost recovery mechanisms are currently available to DEI and whether those mechanisms encourage utilities to promote efficiency and conservation by their customers without incurring negative financial results.

Indiana electric utilities, unlike their natural gas counterparts, have specific cost recovery mechanisms in place that provide them the opportunity to not only avoid negative financial results, but to earn incentives on prudent energy efficient measures. Under the Federal Energy Independence and Security Act of 2007 ("EISA"), states were required to consider modification of rate designs to align utility incentives with the promotion and delivery of energy efficiency resources. As we have found in addressing this EISA directive, our review of Indiana law and regulations demonstrate that the Commission presently possesses sufficient authority under existing statutes and regulations to ensure energy efficiency resources are considered, and timely cost recovery provided. *Investigation of the Indiana Utility Regulatory Commission, et al.,* Cause No. 43580, December 16, 2009 at 28.

Title 170 lAC 4-8-1 *et seq.* provides Indiana utilities the opportunity to: (1) recover program costs; (2) recover lost revenue caused by the implementation of those programs; and (3) receive shareholder incentives. One of the stated purposes for the development of this regulatory framework is to allow "a utility an incentive to meet long term resource needs with both supply side and demand-side resource options in a least-cost manner and ensures that the financial incentive offered to a DSM program participant is fair and economically justified. The regulatory framework attempts to eliminate or offset regulatory or financial bias against DSM, or in favor of a supply-side resource, a utility might encounter in procuring least-cost resources." 170 lAC 4-8-3(a).

To balance the interests of both the utilities and their ratepayers, this rule limits a utility's right to seek recovery of lost margins specifically caused by that utility's energy efficiency efforts. In other words, the utility's ratepayers will not be forced to reimburse the utility for revenues lost due to free riders or to reductions in demand caused by factors not associated with the utility's programs. This is particularly relevant at this time due to the local, national, and global emphasis placed on conservation of natural resources. For example, many of DEI’s customers are undoubtedly taking steps, independent of DEI, to reduce their carbon footprint. Another factor that contributes to the reduction in demand is the expected economic slump and the necessity of ratepayers to conserve as much as possible. It would not be equitable to allow Petitioner to recover lost margins from its ratepayers for energy savings caused by its ratepayers' own responsible efforts to conserve.

Petitioner’s decoupling proposal is not in the public interest because it would allow the Company to recover revenues for reductions in energy consumption that were not caused by its conservation efforts. DEI’s proposal is for "full" decoupling, which means that it will recover its lost margin regardless of causation. Dr. Dismukes testified that a reduction in revenue associated with energy efficiency programs is quite small. Other factors namely changes in weather, income, commodity prices or economic conditions, result in greater reductions in sales. Petitioner should not be rewarded for a reduction in sales that occurs due to these other factors.

Additionally, Petitioner is seeking decoupling because it claims it is needed to account for revenue losses associated with its proposed dynamic pricing tariffs and volt/VAR optimization efforts. This is unpersuasive. If these programs are designed and implemented appropriately, these efforts should result in avoided fuel costs, which would offset these purported lost revenues. Further, the Company has admitted that the revenues losses associated with its dynamic pricing tariffs are not expected to be significant. (OUCC CX 15 - Company response to OUCC DR 36.4.)

Further, the Company provided no empirical evidence that there will be any negative financial impacts as a result of these efforts. The Company has had time of use rates for years and its volt/VAR optimization efforts for enough time that if there was a significant negative financial impact, it could have presented that evidence.

Current Indiana regulation obligates Indiana electric utilities to pursue demand-side resources in their long-range resource planning and provides cost recovery mechanisms that will appropriately incent utilities to pursue energy efficiency savings. DEI has already availed itself of these rules in its DSM dockets in which its energy efficiency programs were approved, and it is entitled to pursue program cost recovery and shareholder incentives. Petitioner has a mechanism that recovers the authorized costs associated with its DSM efforts. In this Cause, DEI indicates its desire to pursue more energy efficiency efforts than have been approved by the Commission to date. Although we encourage Petitioner to do so, it does not justify a cost recovery tracking mechanism such as decoupling, that differs from the one already provided for in Indiana law. Indiana law already provides a better, more equitable way to reward conservation efforts.

Moreover, decoupling, in conjunction with other cost recovery mechanisms sought by Petitioner in this case, is inconsistent with the role of regulation to serve as a surrogate for the dynamics of a competitive business environment. Since utilities are monopolies, their activity is not constrained by the forces of competition and the marketplace. Thus, the traditional role of regulation is to replicate the environment that would exist if the utility operated subject to such competition. Utility rates are regulated and are based on utilities' costs plus the opportunity to earn a reasonable return on its shareholders' investment. Regulation replaces the market and while shareholders assume the risk of the initial investment, they receive reasonable returns as long as the investments are reasonable and prudent.

Decoupling removes those safeguards and creates an essentially risk-free business environment. Shareholders are held harmless from all economic risks by the ratepayers, and yet retain the benefit of the regulatory compact through an assured return on their investment. The regulatory replication of the market would thus be eliminated, and utilities would become unique among business entities in that they would reap unregulated private sector profits without any offsetting private sector risks. Their return would be based on the money they spend, not on the service they provide. There is no justification for granting a private business enterprise such a protected status, let alone a regulated public entity.

Petitioner’s proposed revenue decoupling mechanism unreasonably shifts the burden of revenue stability from the utility to the ratepayers. Under traditional regulation, it is the utility and its shareholders that typically bear the risk of revenue and sales differences from those in the test year. This forms the basis of the establishment of the authorized return on equity the Company receives. It is the Company that chooses its test year and recommends pro forma adjustments thereto. However, revenue decoupling isolates a utility's management and equity owners from the normal business risk inherent to the utility industry, notwithstanding the fact that the existence of a return on equity is to reward equity owners with a return on their investment that includes a sizeable risk premium commensurate with the (now non-existent) business risk. Dr. Dismukes identified several jurisdictions that have been critical of the risk shifting nature of revenue decoupling.

Clearly, the very large potential risk of revenue instability is shifted from the Company to customers. The Company's decoupling proposal thrusts customers into the role of insurer without proffering compensation. Combining a variety of proposed complex cost trackers/automatic adjustment mechanisms (as proposed by Petitioner in this case) disincents the Company to be more efficient and to control costs. Instead, such a combination creates a virtual risk-free enterprise for the Company's shareholders. With all of Petitioner's approved and proposed tracking mechanisms, if we were to approve this decoupling request, we would be hard pressed to identify any variable costs that would not be to be tracked by Petitioner. Decoupling would have the effect of tracking 100% of the Company's fixed costs attributable to its residential customers. This would provide little or no incentive for Petitioner to comply with its obligation to provide efficient cost-effective service to its customers.

But the proposed decoupling mechanism goes beyond eliminating risk for the utility. The Company proposes not only that its fixed costs approved in its last rate case be recoverable through the tracker, but also an amount of fixed costs to reflect future customer growth. This provision effectively allows for return on and return of plant that has not been judged to be used and useful in the service of the utility's customers. To allow revenue for costs unconnected to the specific cost of plant for which an opportunity of review has not been afforded runs counter to the basic tenets of the legislative framework of public utility regulation in Indiana. Beyond these concerns about lack of review for used and usefulness of plant and the cost of that plant, the decoupling mechanism effectively provides for tracking of all of DEI's costs and thus largely eliminates the incentive to come to the Commission periodically for review of its costs in a base rate case, which is a vital part of ensuring reasonable costs for the public.

Finally, a decoupling mechanism is not well suited for use by a vertically integrated fully regulated electric utility. As we have previously discussed, several natural gas utilities in Indiana have decoupling programs in place. As we look around the country, we see decoupling mechanisms that have been approved in several jurisdictions. The vast majority were approved for gas distribution companies.

There are considerable differences between decoupling for a gas distribution company as opposed to a vertically integrated electric utility with generation, transmission and distribution assets and functions. First, decoupling became viable when gas prices began rising in the last decade and there was an increase in state-driven energy efficiency requirements. This has resulted in a consistent decrease in average natural gas usage per customer. This has not been the case for electric companies. Second, gas distribution companies' fixed costs are considerably less than electric utilities. Since there is no generation function for a gas company, it simply procures and transports the gas to its end users. At the time decoupling was approved for Natural Gas Companies the commodity component of a typical utility's gas bill was generally 70%-75%. Conversely, the gas utility's fixed cost was approximately 25%. Decoupling the distribution revenues of a gas company from its sales has minimal impact on its customers. It also allows the gas company to aggressively pursue energy efficiency measures. A customer, through its gas company or otherwise, who implements efficiency measures can realize significant savings since 75% of the bill is the commodity the customer is now using more efficiently. In contrast, the commodity cost of a fully integrated electric utility, such as DEI, is approximately 25% of the bill. Therefore, Petitioner is seeking guaranteed cost recovery for all of its fixed costs (and most of its variable costs through trackers) that is roughly 75% of a customer's total bill.

Further, since the commodity costs are such a relatively small portion of the bill, DEI customers will not be able to noticeably reduce their bills no matter how much they reduce their usage. In fact, revenue decoupling sends the opposite price signal from what is needed to encourage participation in energy efficiency programs. Conservation efforts would be rewarded with higher future rates, while excessive consumption paradoxically would produce bill credits. This does not appear to be the optimal way to induce energy conservation. It is counter-intuitive to expect customers to undertake conservation or energy efficiency efforts without being rewarded with lower bills. It is little wonder that fully regulated states with vertically integrated electric utilities have not embraced revenue decoupling.

The evidence presented by the OUCC in this case demonstrates that time and again revenue decoupling has been tried in several states only to be criticized or even suspended because it unduly interferes with the overall regulatory process. Based upon the discussion above, we find DEI's proposed decoupling mechanism is not in the public interest and we therefore reject its proposed RDM.

16. Rate Adjustment Mechanisms.

a. Rider 70. As established in the Company's last base-rate proceeding (Cause No. 42359), $14.7 million is built into base rates to represent profits from non-native sales. Any amount above or below this amount is split evenly between customers and the Company and trued up in annual Rider 70 proceedings. The Company cannot, however, apply a net annual off-system sales profit of less than zero. In this case, the Company proposes to change the amount embedded in base rates and to change certain details about how non-native sales margins are shared. Specifically, the Company proposes to track the entire amount of non-native sales, with zero embedded in base rates. The Company also proposes that customers share in positive as well as potentially negative margins from non-native sales.

i. Petitioner's Evidence. The OUCC does not have any objections to Petitioner's recitation of its evidence.

ii. OUCC's Evidence and Intervenors' Evidence. OUCC's witness Boerger agrees with the Company's proposal to embed zero non-native sales margins in base rates, but only if the Company allocates 100% of such sales margins to customers. In addition, Dr. Boerger recommends that short-term bundled non-native sales be subject to a sharing mechanism wherein $12.7 million be embedded in base rates, with tracking above and below that amount in which the Company would receive 20% of revenues realized above that amount and would be responsible to cover 20% of revenue deficiency below that amount. He explained the $12.7 million is the amount that the Company will collect in margin during its test year from its existing sale, and thus this is the appropriate amount to embed as an offset to base rate revenue requirement. Further, the 80/20 sharing proposal provides a reasonable incentive for the Company to maximize revenue from excess capacity while allowing customers to receive the majority of the benefits from the generating capacity they are funding through base rates. He also recommended the Company be ordered to return the share of net profit realized on the Company's one existing short-term bundled non-native contract to reflect the 50/50 sharing of off-system sales ordered in DEI's last base rate case (Cause No. 42359), which should have been applied to this sale. Such refund should occur in

DEI's next Rider 70 proceeding(s) and cover the period beginning June 1, 2017 (Cause No. 44348 SRA-5) and continuing through the date base rates are changed in this proceeding. Dr. Boerger also testified that the OUCC opposes DEI's request to reverse the prohibition on recovering negative annual sales margins in Rider 70 instituted in the final order in the Company's last base rate case (Cause No. 42359). He explained that the Commission's order in Cause No. 42359 did not prevent recovery of the kind of negative margins illustrated in the Company's testimony—only preventing recovery of such negative margins to the extent that they exceed sales profits over an entire year. Dr. Boerger also expressed skepticism that a utility could incur net losses on sales over any entire year while operating in an economic manner. While Dr. Boerger cannot say accumulating a loss on non-native sales over an entire year can never result from utility operations that are part of a reasonable strategy of committing DEI units, the accumulation of a net loss over a year should, at a minimum, place a high burden on DEI to show the accumulated losses were justified. Unless DEI provides additional evidence of the reasonableness of its units' commitment over the rider period, it should be presumed that accumulated losses are not recoverable. However, the additional evidence and review required to reasonably review operations of the utility that resulting in such annual losses would burden recovery proceedings intended to be expedited in nature. Based upon this analysis, Dr. Boerger concluded that the Commission can reasonably continue its prohibition on recovery of net annual negative margins. Similarly, Industrial Group witness Dauphinais opposed the combination of zero embedded in base rates, sharing of anything other than 100% of non-native margins with customers, and sharing negative margins. Kroger's witness Bieber also recommended 100% of non-native sales margins be provided to customers.

iii. <u>Petitioner's Rebuttal Evidence</u>. The OUCC does not have any objections to Petitioner's recitation of its evidence.

iv. <u>Commission Discussion and Findings</u>. Regarding traditional MISO-derived non-native sales margins through Rider 70, the parties are in agreement that 100% of such margins be credited to retail customers, and we accept that agreement.

Regarding what DEI refers to as "Short Term Bundled Non-Native Sales," no party has objected to the use of this mechanism for maximizing the value of excess capacity, and the evidence is clear that DEI has and will continue to have excess capacity available due to the roll-off of native load contracts as they expire. As such it is reasonable to expect that DEI will continue to use this bundled sales mechanism to maximize the value of its regulated production assets going forward. Given such ongoing use of this mechanism, we find embedding the amount of margin in the test year from such sales as an offset to revenue requirement to be a reasonable reflection of expected activity and a reasonable component of a design to incent the Company to maximize these revenues. While we recognize the Company's concern about volatility of these revenues, such concern can be ameliorated through adjusting the 50/50 sharing ratio proposed by DEI. Specifically, using an 80/20 ratio above and below the embedded amount, as proposed by Dr. Boerger, would provide a reasonable incentive to maximize bundled sale revenues while limiting DEI's risk of not replacing its one existing bundled sale to only 20% of the test year amount. Embedding an amount that reflects known test year margin, as is the case here, comports with our longstanding practice in situations where we have provided the utility the opportunity to profit from customer-funded generation assets.

We next address the issue raised by the OUCC regarding DEI's decision to not share margins from its one short-term bundled non-native sale through Rider 70 in past proceedings. DEI's contention that this sale was not subject to the sharing provisions required of off-system sales from its last base rate order cannot be justified. By the testimony of DEI's witnesses, the Company recognized this as a new category of sales, yet made the decision to not share the margin from the sale without even disclosing it in the appropriate Rider 70 proceeding. In that this is the first proceeding in which the existence of the sale was disclosed, it is appropriate that we order here that DEI, in its next Rider 70 proceeding, present in testimony an amount to reflect 50% of the margin from this sale that would have flowed through as a benefit to customers but for the Company's designation of revenues as not eligible for sharing. Such sharing is to occur through the time that Phase 1 rates are changed as a result of DEI's current base rate case.

Regarding recovery of negative margins on off-system sales, we are unconvinced by the Company's evidence regarding the need for relief in this area. We read the Company's testimony explaining situations in which negative margins could occur, but it is clear, as explained by Dr. Boerger, that the Company is able to recover such negative margins under its current regime. The only prohibition occurs when the sum of all sales—both positive and negative--becomes negative over the course of an entire year. We find that our current prohibition on recovery of such annual losses to already reflect a reasonable compromise between recovery of all such losses and recovery of no losses. Accordingly, we deny the Company's request as pertains to recovery of negative off-system sales margins.

b. <u>Edwardsport IGCC.</u>

i. <u>Petitioner's Evidence</u>. The OUCC does not have any objections to Petitioner's recitation of its evidence.

ii. <u>OUCC's Evidence</u>. OUCC witness Kollen explained the effect of terminating the IGCC Rider, as proposed by Duke Energy Indiana, would result in a greater revenue requirement in the test year and in subsequent years. Mr. Kollen asserted that the Company seeks to include costs in the base revenue requirement that it could not include in the IGCC Rider, such as fuel and M&S inventories in rate base. Additionally, Mr. Kollen stated the base revenues will not decline as the IGCC cost curve declines due to additional accumulated depreciation and additional ADIT until the Company's next base rate case and base rates are reset in that proceeding. Mr. Kollen believes the Commission should continue to track the declining IGCC cost curve after December 31, 2020.

Mr. Kollen recommended the Commission reflect the reduction in the IGCC plant-related revenue requirement (grossed-up return on the increase in accumulated depreciation and the reduction in the grossed-up cost of capital due to the increase in ADIT) in either the Credits Rider or the ECR Rider in the same manner that the Company has proposed tracking the IGCC tax benefits and the expiration of those benefits through the Credits Rider. Mr. Kollen claimed this would maintain the existing benefit to customers of the declining IGCC cost curve that otherwise would be lost under the Company's proposal to roll-in and fix the base rate recovery until the Company's next base rate case.

iii. **Petitioner's Rebuttal Evidence**. The OUCC does not have any objections to Petitioner's recitation of its evidence.

iv. **Commission Discussion and Findings**. No party to this preceding disputes that the IGCC costs are to be rolled-in to base rates in this proceeding pursuant to the terms of the 2018 IGCC Settlement Agreement, which we approved in our IGCC-17 Order. In relevant part, it stated: "In addition, the 2018 Settlement Agreement provides that Duke Energy Indiana will not file an IGCC Rider proceeding in 2019 or 2020, and that the Settling Parties intend for Duke Energy Indiana to include the Edwardsport investment and operating expenses in base rates in its next retail base rate case and to discontinue the tracking of Edwardsport via the IGCC Rider." See page 33 of the IGCC-17 Order. Nevertheless, there are certain tax benefits that have not yet been fully realized and that, ultimately, will expire in future years. The Company has proposed that those tax benefits be tracked separately through the Credits Rider and ECR Rider. No party opposed these proposals. In addition to the Company's proposals to track certain costs through the Credits Rider and ECR Rider, the OUCC recommends that the reductions in the IGCC revenue requirement due to the declining cost curve be tracked through the Credits Rider or the ECR Rider. We find that the OUCC recommendation is fair and reasonable and is consistent with the Company's proposed treatment of the IGCC tax benefits and certain other IGCC costs through the Credits Rider and ECR Rider. We are not persuaded by the Company's argument that the OUCC's recommendation is not consistent with "traditional Indiana ratemaking." That is not a specific standard or a standard that we can apply. Nor is it a "standard" the Company itself applied with respect to the IGCC tax benefits and certain other IGCC costs.

c. **DSM/EE Rider.**

i. **Petitioner's Evidence.** The OUCC does not have any objections to Petitioner's recitation of its evidence.

ii. **OUCC's Evidence**. OUCC witness John E. Haselden stated some concerns regarding lost revenue recovery for DSM programs delivered in 2020. Mr. Haselden asserted that the Company has proposed, as an alternative to decoupling, to collect through the EE Rider lost revenues for measures implemented in 2020 over the measure's expected useful life. Mr. Haselden stated the OUCC has concerns about expected useful life assumptions the Company is using for certain measures.

Mr. Haselden recommended the Commission defer future DSM costs, lost revenues, and shareholder incentives to the recently filed DSM plan Cause No. 43955 DSM 8 with the condition any issues will be litigated therein and no implied or explicit approval of any issues will be decided in this case.

iii. **Petitioner's Rebuttal Evidence**. Company witness Davey agreed with Mr. Haselden's recommendation that the Commission defer future DSM costs, lost revenues, and shareholder incentives to the forthcoming DSM plan case with the condition any issues will be litigated therein.

iv. **Commission Discussion and Findings**. Duke Energy Indiana and the OUCC agreed to defer future DSM costs, lost revenues, and shareholder incentives to the

Company's forthcoming DSM plan approval case so that all disputed DSM-related issues will be litigated therein. We find the Parties' agreed approach to be reasonable and hereby approve the OUCC and Duke Energy Indiana's agreement to wait until the Company's next DSM plan approval case to litigate or otherwise resolve any and all DSM rider issues still in dispute at that time.

d. Rider 62.

i. Reagent Costs.

(A) Petitioner's Evidence. The OUCC does not have any objections to Petitioner's recitation of its evidence.

(B) OUCC's Evidence. OUCC witness Blakley addressed the Company's reagent expense tracker proposal. He stated that the Commission's Cause No. 42061 ECR-33 Order, dated August 21, 2019, showed net pollution control investment of approximately $1 billion for DEI, which DEI proposes to place in base rates. He explained that Duke Energy Indiana's pollution control property investment costs are recovered in two Riders. The capital costs recovery of a return "on" the investment is recovered through Rider 62, and the associated O&M expense and depreciation expense through Rider 71. These Riders plus Rider 63, which DEI uses to recover its emission allowance costs, are included in DEI's Environmental Costs Recovery tracker known as the ECR. Mr. Blakley explained that the Company is proposing to roll the Test Period level of depreciation expense associated with the in service ECR plant, reagent O&M, and non-reagent O&M into base rates. Duke Energy Indiana is also proposing to consolidate Rider 63 and Rider 71 into Rider 62 and reconcile all revenue requirement elements within Rider 62 going forward. He stated that with reference to reagents, the Company is proposing to track outside of base rates certain reagent costs, both above and below the amount in base rates, in the consolidated Rider 62.

He stated that Duke Energy Indiana indicated the 2020 forecast for reagent expense it is proposing to embed in base rates is $48,539,000, and the Company is proposing to track up and down from this level based on actual annual expenses, with the variance collected from or refunded to customers through Rider 62. Mr. Blakley argued that Duke Energy Indiana's request is "piecemeal ratemaking" as that term was used by the Commission in its Final Order in Cause No. 40402, which states:

> Piecemeal ratemaking is when discrete components of a utility's operations are treated singularly, rather than as a part of that utility's larger financial picture. Such treatment is disfavored because, while costs may have increased in one aspect of operations, they may be offset by decreased costs elsewhere, or by increased income.[12]

He explained that the Commission denied requests for continued tracking of O&M expenses when associated pollution control equipment is rolled into base rates, including Vectren South's Electric Cause No. 43839. Mr. Blakley stated traditionally O&M expenses related to plant

[12] See Cause No. 40402, Northwest Indiana Water Company, Final Order dated September 19, 1996, Paragraph 8(a).

investment are placed into base rates at the same time the associated plant investment is placed into rate base during a rate case.

Mr. Blakley stated further in his testimony that Indiana's Clean Coal Technology statutes and rules provide electric utilities cost recovery on very expensive pollution control equipment. Based on his experience, Indiana's five large investor-owned electric utilities, including DEI, have benefited from these statutes and rules, through which billions of dollars of investments have been recovered from customers through tracker recovery mechanisms. These mechanisms have provided utilities with an opportunity to timely recover a return "on" and a return "of" in the form of depreciation expense plus associated O&M expenses from customers. These cost recoveries have occurred outside of a base rate case. When a utility requests a base rate increase, the completed pollution control equipment, along with its associated costs, will be included in base rates. He stated it would be inappropriate to permit an individual operating expense to continue to be tracked after the associated plant investment has been rolled into base rates. This proposed process would deviate from long-standing ratemaking principles. Mr. Blakley recommends the appropriate amount of reagent expense determined and approved by the Commission be included in base rates, along with the associated capital project(s), with no tracking of incremental reagent expense.

Mr. Blakley recommended the denial of the Company's proposal to track incremental reagent expense, but should the Commission allow DEI to track incremental reagent expense outside of base rates, the OUCC recommends the Commission require DEI to recalculate its return on its embedded pollution control investment to reflect the depreciated value and use its existing Rider 67 Credits Rider to pass back the difference as a credit to ratepayers. This recommendation would help balance the effect of DEI's proposed "piecemeal ratemaking" by allowing incremental reagent expense to be tracked and recovered through DEI's Rider 62 ECA tracker, while adjusting and crediting ratepayers through DEI's Rider 67 Credits Rider the difference between the return on the pollution control investment included in rate base and the recalculated return on depreciated pollution control investment – the investment of which the reagent expense is associated. It is the OUCC's position that no capital maintenance, repair costs, or special accounting treatment be included in DEI's Rider 67 Credits Rider, nor for investments embedded in base rates be included in its Rider 62.

(C) Petitioner's Rebuttal Evidence. The OUCC does not have any objections to Petitioner's recitation of its evidence.

(D) Commission Discussion and Findings. The Commission recognizes that normal operating expenses such as reagent expense should not be tracked outside of base rates absent specific statutory authority. This would violate general ratemaking principles and discourage Petitioner from managing its O&M expenses. The Commission has permitted individual expenses and investments to be tracked outside of a base rate case but only under statutory authority such as the FAC, TDSIC, and Clean Energy statutes to name a few. The Commission has also permitted the tracking of RTO expenses because of its uncertain and unusual nature. Permitting individual operation and maintenance expenses without statutory authority or even the proof of unusual burden or circumstance is not sound ratemaking policy. It does not take much imagination to come up with dozens of normal operating expenses that vary with production, but we do not track all of these normal expenses unless special circumstance require it or statute permits. Duke Energy Indiana has not provided evidence of the material impact of reagent expense variability and presents only the notion that this individual expense happens to vary with production. We are concerned by the adjustment of reagent expenses up or down in a tracker because it does not provide protection to ratepayers and actually provides substantial reduction of operating risk to Duke Energy Indiana.

It is indisputable that tracking individual expenses outside base rates provides a real benefit to Duke Energy Indiana with little upside for its customers. In this case, the expenses are directly related to pollution control equipment that will be embedded in base rates. We agree with Mr. Blakley's recommendation which would require DEI to recalculate its return on its embedded pollution control investment to reflect the depreciated value and use its existing Rider 67 Credits Rider to pass back the difference as a credit to ratepayers. The Commission is aware of the skewed rate making treatment Duke Energy Indiana is requesting and we believe the Mr. Blakley's proposal would help balance the effect of DEI's proposed "piecemeal ratemaking" by allowing incremental reagent expense to be tracked and recovered through DEI's Rider 62 ECA tracker, while adjusting and crediting ratepayers through DEI's Rider 67 Credits Rider the difference between the return on the pollution control investment included in rate base and the recalculated return on depreciated pollution control investment – the investment of which the reagent expense is associated. With the benefits that tracking an individual operation expense provides, any remedy that would match revenues with the expenses used to generate those revenues is desirable and fair. We also find that no capital maintenance, repair costs, or special accounting treatment be included in DEI's Rider 67 Credits Rider and for investments embedded in base rates nothing shall be tracked in its Rider 62. If Duke is mandated to construct new pollution control equipment through its ECR, it may request Commission approval in a separate proceeding.

ii. Emission Allowance Costs.

(A) Petitioner's Evidence. Duke Energy Indiana witness Graft described the Company's proposal for its current Rider 63 and its consolidation into Rider 62. As Company witness Sieferman discussed, the Company is requesting a regulatory asset for its native SO_2 emission allowance inventory balance. Ms. Graft stated under this proposal, native SO_2 emission allowance costs would no longer be tracked through Rider 63, as the Company does not expect to incur any additional consumption expense for native SO_2 emission allowances. However, Ms. Graft testified there may be future native NOx emission allowance consumption expense, and the Company may also have gains or losses on the sale of native SO_2 or NO_x emission allowances, both of which would be included in the consolidated Rider 62.

(B) OUCC's Evidence. OUCC witness Armstrong testified the public has no objection with Duke Energy Indiana's proposal to transfer the native SO_2 emission allowance inventory balance to a new regulatory asset account, and to decrease the native SO_2 emission allowance expense to zero. Ms. Armstrong stated the proposal benefits both the Company and its ratepayers.

Ms. Armstrong, however, did take issue with Duke Energy Indiana's proposal to continue tracking any emission allowance expense via Rider 62.

She stated the Company's emission allowance costs have been stable over the past several years, and emission allowance costs are not expected to be significant going forward since SO2 inventory costs will be moved into a regulatory asset. Ms. Armstrong reasoned that that Duke Energy Indiana is unlikely to consume more emission allowances than the zero-cost allowances allocated to DEI annually over the next several years, pointing out that DEI generating unit retirements and SO_2 and NO_X pollution controls installed at Cayuga, Gibson, and Gallagher resulted in significantly decreased emissions. She also noted that the volatility of SO_2 and NO_x EA markets has decreased compared to when DEI's EA tracker was originally established. She concluded that tracking these costs is no longer necessary and recommended the Commission deny the Company's proposal.

Ms. Armstrong said the Company should continue to offset the past costs of emission allowances it will recover through the proposed regulatory asset by selling allowances whenever possible, and net proceeds of such sales should be credited to customers through Rider 62 in future ECR filings.

(C) **Petitioner's Rebuttal Evidence**. Ms. Graft, in rebuttal, stated the Company agrees to discontinue tracking native emission allowance consumption expense upon the implementation of new base rates. However, Ms. Graft testified that Duke Energy Indiana reserves the right to seek tracking of emission allowances pursuant to Indiana statutes, rules and regulations in future proceedings, as it is possible new emission allowance regulations will be enacted or existing emission allowance expense may become more volatile in the future. She reiterated that the Company plans to include any gains or losses on the sale of native emission allowances in the consolidated Rider 62.

(D) **Commission Discussion and Findings**. With Duke Energy Indiana's rebuttal modification on the issue of tracking native emission allowance consumption expense upon the implementation of new base rates, there appears to be no dispute among the parties on this topic. We conclude it is reasonable for Duke Energy Indiana to transfer the native SO_2 emission allowance inventory balance to a new regulatory asset account (as we also discussed earlier in this order in the regulatory asset section and also later in this Order in the accounting deferral section), to decrease the native SO_2 emission allowance expense to zero, and to discontinue tracking of native emission allowance consumption expense upon the implementation of new base rates. It is also reasonable for the Company to reserve the right to seek tracking of emission allowances pursuant to Indiana statutes, rules and regulations in future proceedings. Accordingly, we approve Duke Energy Indiana's emission allowance proposals as modified in its rebuttal testimony.

e. Rider 67.

i. Petitioner's Evidence. The OUCC does not have any objections to Petitioner's recitation of its evidence.

ii. OUCC's Evidence. OUCC witness Michael Eckert expressed some concerns with the proposed Credits Rider. He argued that continuing Rider 67 as a 30-Day filing, which would track at least nine items that use three allocation methodologies would not allow the OUCC enough time to review the filing. Thus, if the Commission accepts the 30-Day filing proposal, Mr. Eckert recommended that the Company be required to provide a draft of its filing, as well as workpapers, at least 60 days in advance of the file date, and schedule a technical conference with the OUCC to explain its filing and workpapers prior to filing. Alternatively, Mr. Eckert stated the Commission should deny the request for a 30-Day filing, and instead implement a tracker proceeding.

iii. Petitioner's Rebuttal Evidence. Ms. Douglas stated the Company's agreement that, for ongoing Rider 67 filings, the extended 60-day preview and technical conference outlined by Mr. Eckert is warranted and reasonable. With this, Ms. Douglas believed that continuing to file Rule 67 under the Commission's 30-Day process is reasonable. However, Ms. Douglas pointed out that this agreement did not extend to the timing and process related to the one-time approval of Step 2 rates under the Company's Two-Step Base Rate Implementation Process proposal. This is addressed in the Step 2 Rate Increase Section below.

iv. Commission Discussion and Findings. The Commission approves of the agreement of Duke Energy Indiana and the OUCC regarding the Rider 67 process. Specifically, Duke Energy Indiana shall continue to afford itself of the Commission's 30-Day procedures with regard to Rider 67, but the Company shall provide a draft of its filing, as well as workpapers, to the OUCC at least 60 days in advance of the file date, and schedule a technical conference with the OUCC to explain its filing and workpapers prior to filing. This will provide the public a reasonable opportunity to preview all the various items that could be included in a Rider 67 filing.

Duke Energy Indiana proposed a number of items be included in Rider 67, including items related to the TCJA Settlement Agreement, other tax items, certain Edwardsport IGCC tax incentive credits, and additional credits as regulatory assets for which amortization is being included in base rates become fully amortized. We also approve the removal of the 1994 Cinergy Merger Costs credits, which have been fully accounted for.

The OUCC recommended that additional components be added to Rider 67. The merits of these components are discussed elsewhere in this Order.

f. Discontinued Riders.

i. Petitioner's Evidence. Duke Energy Indiana is proposing to discontinue several currently-existing riders. As discussed above, Ms. Douglas testified the Company is proposing to discontinue the IGCC Rider (Rider 61); Ms. Graft explained the consolidation of the SO_2, NOx, and Hg Emission Allowance Adjustment (Rider 63), as well as the Environmental Compliance Operating Cost Adjustment (Rider 71) into consolidated Rider 62; and Riders 64 and 69 will continue to be vacant.

ii. OUCC's Evidence. Mr. Eckert testified that the OUCC does not oppose keeping these rider/tariff numbers in place, but the OUCC is not in favor of riders not currently in use being "shelved" for future use. He stated that should Duke Energy Indiana propose to utilize these riders/tariffs for future cost recovery, the OUCC recommends the Company make a formal request through a docketed proceeding and receive Commission approval to do so.

iii. Petitioner's Rebuttal Evidence. Company witness Douglas indicated general agreement with Mr. Eckert's proposal that a docketed proceeding be initiated and

Commission approval be received in order to utilize the rate adjustment riders being discontinued in this proceeding. The one slight change Ms. Douglas proposed was to also allow for the use of a 30-Day filing should the Company need to reuse the rider/tariff numbers 61, 63, 64, 69 and 71, as appropriate depending on the nature of the reuse of the vacant numbers. Ms. Douglas explained this is consistent with what the Company has done previously when it requested Commission approval for the use of a new rider, whether when using a new, previously unused rate adjustment rider number or reusing a previously used but currently unused number.

iv. **Commission Discussion and Findings**. The Commission approves of the discontinuation and consolidation of rider/tariff numbers 61, 63, 64, 69 and 71, as proposed by Duke Energy Indiana. We also agree with the concept advanced by the OUCC, and agreed to by the Company, that the Company must make a formal request through a docketed proceeding and receive Commission approval in order to propose to utilize these riders/tariffs for future cost recovery. We deny the change proposed by DEI to be allowed the use of a 30-Day filing should the Company need to reuse the rider/tariff numbers 61, 63, 64, 69 and 71. If DEI needs a new rider, it can receive – or use – a number for the rider at that time.

17. **Tariff Provisions.** Duke Energy Indiana has proposed several modifications, both clerical and substantive, to its retail electric tariff, as discussed in the revised direct testimony of Company witness Flick. Many of the proposed modifications were unopposed by any party. The unopposed modifications in the General Terms and Conditions include changes to various definitions; a clarification to the Pick Your Own Due Date program; adding streamlined pricing to the Energy Profiler Online program; an update to the increased transformer size limit under general standards for three phase-service; updates to the remote and manual reconnection charges; and updating details of the after-hours service rate. Mr. Flick explained the proposed revisions to the Lighting tariffs, including the proposal to adjust both the metered and unmetered lighting tariffs. Mr. Flick also described the proposed changes to the *GoGreen* program, in that the Company is seeking authority to offer the program on a permanent basis in light of customer demand. Mr. Flick also described other proposed revisions that were not opposed. Having reviewed the evidence presented, we approve each of these unopposed proposals as reasonable and in the customers' interests.

Certain of the proposed tariff provision modifications were the subject of challenge by other parties. We consider these below.

a. **Non-Residential Deposit Rules.**

i. The OUCC did not take a position on this issue.

b. **Meter Tampering Penalties.**

i. **Petitioner's Evidence.** Ms. Quick testified regarding the Company's proposal to implement a new penalty for tampering with Company equipment. Ms. Quick stated the fee is intended to deter customers from tampering with electric meters, which creates safety hazards and adds to the Company's costs of doing business. Ms. Quick stated that the proposed fee is $200 for residential customers and $1,000 for nonresidential customers. Ms. Quick testified in 2018, there were 892 cases of residential tampering and 16 instances of non-residential tampering, and the total penalty under the proposed program would have been approximately $194,000, which is the forecasted amount of 2020 revenue to be collected from the tamper penalty program. Company witness Flick sponsored the *pro forma* credit adjustment to test period revenues for the program.

ii. **OUCC Evidence**. OUCC witness Lauren M. Aguilar explained that the OUCC opposes the proposed tamper penalty program. She stated that the Company does not know how many repeat meter tampering offenders it has, and to the extent someone tampers with a meter, Ms. Aguilar believes Duke Energy Indiana should seek criminal prosecution because meter tampering is a felony. Ms. Aguilar explained that Duke Energy Indiana is already made whole if a customer tampers with equipment. The Company charges the responsible customer for previous usage, a field personnel investigation, and equipment damage. Finally, Ms. Aguilar testified that the OUCC recommends denying the Company's proposed meter tampering penalties in any amount and removing the $194,000 revenue adjustment.

iii. **Petitioner's Rebuttal Evidence**. Ms. Quick responded to Ms. Aguilar's testimony by pointing out that the meter tampering fee was not designed solely to deter repeat offenders, but initial offenders as well. Ms. Quick also emphasized that the Company lacks the ability to criminally prosecute those who engage in meter tampering, and seeking civil damages is time consuming, while the costs would be socialized to all customers. She stated the proposed meter tamper penalty is more prudent and recovers the fees from the specific violators. As such, the requested meter tampering penalties, along with recovery of costs in base rates, best accomplishes the goal of preventing customers from putting themselves and others in unsafe situations.

iv. **Commission Discussion and Findings**. Based on the evidence provided, the Commission agrees with Ms. Aguilar's recommendation that Duke seek criminal prosecution of people engaging in meter tampering. We agree with Ms. Aguilar's testimony that meter tampering poses a grave safety concern for Duke Energy Indiana's customers, employees, and others. We agree with Ms. Aguilar that the threat of criminal prosecution for a felony offense would likely be the most effective deterrent. We disagree with CAC's indication that all of its meter tampering fees will be an effective deterrent, preventing future meter tampering by the wrongdoer or anyone else considering similar wrongdoing in the future. We therefore find that a proposed meter tampering fee of any dollar amount should be denied and Duke's proposed $194,000 annual revenue adjustment be removed from Petitioner's pro forma revenue requirement. The Company is able to report meter tampering violations to local authorities for further investigation and possible criminal prosecution. While the Company's proposed meter tampering penalty might be faster and easier to administer, the strongest and most effective deterrent to a future repeat or first-time criminal behavior is the fear of an arrest, a felony conviction, and incarceration. Accordingly, we reject Duke's request for approval of its proposed penalties for meter tampering and approve the OUCC's request to remove the $194,000 *pro forma* credit adjustment from Duke Energy Indiana's *pro forma* revenue requirement and proposed base rates.

c. **Backup and Maintenance Provisions.**

i. The OUCC did not take a position on this issue.

d. Deposit Interest Rate.

The OUCC did not take a position on this issue.

e. Call/Text Disconnection Program.

i. The OUCC did not take a position on this issue.

18. Other Issues.

a. Two-Step Rate Increase.

i. Petitioner's Evidence. The OUCC does not have any objections to Petitioner's recitation of its evidence.

ii. OUCC's Evidence. OUCC witness Blakley addressed the Company's proposed 2-step rate increase procedures. He indicated that the OUCC generally agrees with Duke Energy Indiana's proposed Step 2 methodology, but with the additional requirement that the OUCC and intervenors will have 60 days from the date of verification of actual used and useful property to state objections to Duke Energy Indiana's verified actual test-year end net plant. If there are objections, the Commission should establish a hearing to determine the Company's actual test-year end net-plant. He further recommends that the Step 2 rates be trued-up (with carrying charges) retroactive to January 1, 2021 (regardless of when Step 2 rates go into effect.)

iii. Petitioner's Rebuttal Evidence. The OUCC does not have any objections to Petitioner's recitation of its evidence.

iv. Commission Discussion and Findings. We appreciate both the Company's and the OUCC's proposals designed to ensure that rates are ultimately implemented in a full and timely manner while also ensuring that the base rates only reflect plant and property that is actually in-service and used and useful at the end of Step 1 and at the end of Step 2. We find that the Company should implement its Step 1 and Step 2 rate increases, as outlined in Ms. Douglas' testimony, but with the additional requirement proposed by Mr. Blakley, giving the OUCC and intervenors 60 days from the date of verification of actual used and useful property to state objections to Duke Energy Indiana's verified actual Step 2 test-year end net plant. If there are objections, the Commission can hold a hearing, if necessary, to determine the Company's actual test-year end net-plant. Further, we find that the Step 2 rates shall be trued-up (with carrying charges) retroactive to January 1, 2021, regardless of when Step 2 rates go into effect.

b. Accounting Requests.

i. Edwardsport Outage Deferral Request.

(A) Petitioner's Evidence. The OUCC does not have any objections to Petitioner's recitation of its evidence.

(B) OUCC's Evidence. Mr. Kollen recommended the Commission limit deferrals for the test year Edwardsport Station major maintenance outage expense to the actual expenses incurred or the estimated $46.4 million, whichever is less.

(C) Petitioner's Rebuttal Evidence. Company witness Douglas testified in rebuttal to OUCC witness Kollen's recommendation that the Edwardsport 2020 major outage expense deferrals be limited to the lower of actual costs incurred or the Company's $46.4 million forecasted amount. Ms. Douglas indicated the Company is amenable to limiting the deferrals for the 2020 Edwardsport major outage to the lower of actual costs incurred or the $46.4 million forecasted amount as recommended by the OUCC. She also noted the actual amount of the 2020 Edwardsport outage will be known by the time Step 2 rates are finalized.

(D) Commission Discussion and Findings. We note that the Company agrees with Mr. Kollen's proposal and no party opposes it. The evidence indicates and we find that it is reasonable and appropriate to amortize the Edwardsport 2020 major outage expense over seven years and to limit the resulting deferrals to the lower of the actual costs incurred by Duke Energy Indiana or the $46.4 million forecasted amount.

ii. Customer Connect Deferral Request.

(A) Petitioner's Evidence. The OUCC does not have any objections to Petitioner's recitation of its evidence.

(B) OUCC's Evidence. Mr. Kollen recommends the Commission deny the Company's request to retroactively reverse and then defer Customer Connect costs that it already recorded as O&M expense pursuant to accounting requirements and then recover those historic costs in the future from customers. Mr. Kollen does not oppose deferral of these O&M expenses after the date base rates are reset in this proceeding, but recommends the Commission deny any deferrals after the Customer Connect project is placed in service. Mr. Kollen also recommends denial of the Company's request to defer depreciation expense and post-in-service carrying costs. Mr. Kollen states that this request is inequitable and unreasonable inasmuch as the Company retains the savings from the accumulation of depreciation and ADIT on existing assets after base rates are reset in exchange for the delay in recovering similar costs on new assets after base rates are reset until they again are reset in a subsequent base rate proceeding

(C) Industrial Group's Evidence. The OUCC accepts the Industrial Group's recitation of its evidence.

(D) Petitioner's Rebuttal Evidence. The OUCC does not have any objections to Petitioner's recitation of its evidence.

(E) Commission Discussion and Findings. IG witness Gorman asks the Commission to deny the Company's Customer Connect deferral request in its entirety but in part because he contends the Company has not provided sufficient information to support approval of a CPCN request associated with utility plant not yet in service. In its rebuttal, the Company made clear that it is not requesting a CPCN for the Customer Connect project. Therefore, based upon the foregoing evidence, we find that compliance with the requirements for granting a CPCN is not an issue with respect the Company's Customer Connect deferral request and provides no basis for us to deny the request.

OUCC witness Mr. Kollen recommended denial of the Customer Connect deferral request in part. In rebuttal, Company witness Ms. Graft agrees in concept with his recommendation to only include in the deferral O&M and payroll tax costs on a going forward basis, however, she clarified the Company's position that going forward means 2019 and forward. As a result, Company witness Ms. Graft indicated that Duke Energy Indiana is willing to forgo recovery of its 2018 O&M and payroll tax costs of approximately $2.1 million.

Duke Energy Indiana is still seeking authority from the Commission to defer the carrying costs on the deferred O&M and payroll tax costs as a regulatory asset to be held for recovery in a future rate case, as well as authority to defer depreciation and post-in-service carrying costs as regulatory assets until the related assets are deemed to be used and useful. After considering the respective positions of the parties on this issue as summarized above, the Commission finds that the Company's revised request to defer the Customer Connect O&M expense should be granted, but only prospectively after base rates are reset in this proceeding. The Company already has incurred and expensed or will incur and expense another 18 months of these costs before base rates are reset in this proceeding. We see no merit or need to authorize a deferral retroactive to January 1, 2019. In addition, we deny the Company's request to increase the deferral for depreciation and carrying costs. With respect to depreciation, the deferral is a regulatory asset, not plant in service; thus, we will determine the amortization expense in the Company's next base rate proceeding. Until then, there is no need nor accounting requirement to amortize the regulatory asset. With respect to the return on the deferral, the Company has not sought and is not authorized to defer a return on the Customer Connect cost that is capitalized and closed to plant in service after the end of the test year. The deferral of O&M expense should not be treated differently than the amount that is capitalized and closed to plant in service after the end of the test year.

iii. Major Storm Damage Restoration Reserve.

(A) Petitioner's Evidence. Duke Energy Indiana witness Sieferman testified that the Company proposes to establish a Major Storm Reserve with a base level of $12.7 million, the amount proposed by the Company to be built into base rates. The Company would track differences between the actual operating costs incurred and the amount collected in base rates, with any under- or over-recovery recorded to a Regulatory Asset or Regulatory Liability account, respectively. The regulatory treatment of the net Major Storm Reserve amount would be addressed as part of the Company's next retail base rate case. Ms. Sieferman explained that it was appropriate to establish a Major Storm Reserve as the timing, frequency, and costs for major storms are unpredictable and therefore challenging for the Company to establish a precise amount in base rates. She indicated the Company's proposal is reasonable and balances the interests of both the Company and its customers by smoothing out these costs and providing for the Company to recover no more or less than its actual costs.

Company witness Hart provided testimony related to the Company's major storm expenses over the past five years (2014-2018). She stated that actual expenditures will vary year to year based on the actual number of major storms and the types of restoration required. Based upon the trend in rising storm costs and the variability and unpredictability of annual MED storm level amounts, Ms. Hart testified Duke Energy Indiana believes it is appropriate to establish an MED storm level amount in base rates and then establish a reserve for any amounts below or above that level.

(B) <u>OUCC's Evidence</u>. Mr. Alvarez testified in support of the Major Storm Reserve account and the attendant mechanism for recording over and under revenue collection in the account. He recommended the initial Major Storm Reserve amount be set at $6 million, a $6.7 million decrease to DEI's forecasted Test Year Major Storm Reserve amount. He also asked the Commission to order DEI to develop an operational plan to manage storm restoration activities prudently, with a set goal to decrease the storm reserve to $6 million. He stated DEI should incorporate the developed major storm operational plan within its vegetation management and TDSIC programs to ensure integration of the prescribed goals in these programs.

Mr. Alvarez described his understanding of how the Reserve account would track major storm expenses over and under initial amount, would record any major storm expense under-recovery as Regulatory Asset and any over-recovery as Regulatory Liability; and proposed to address the recovery of any net amount in the Major Storm Reserve in the next retail base rate case. He testified his recommendations were based on his review of the five-year historical average for major storm costs shown in DEI witness Susan E. Sieferman, Workpaper OM3-SES ("OM3-SES"), and her testimony related to Major Event Day ("MED"); the Institute of Electrical and Electronic Engineers ("IEEE") Standard 1366 ("IEEE Std. 1366"), and System Average Interruption Duration Index ("SAIDI") – a distribution performance metric – as related to IEEE Std. 1366-2012, MED Threshold (*TMED*). He also reviewed Petitioner's witness Cicely M. Hart, Table 4, p. 11, showing the outage causes in DEI's distribution system; Table 8, p. 36, summarizing DEI's storm activity since 2014; and her testimony related to TDSIC and Vegetation Management expenditures.

Mr. Alvarez explained that Sieferman's OM3-SES showed $11.2 million (88%) of major storm expenses were distribution operation related, $0.5 million (4%) were transmission related, and $1.0 million (8%) were benefits and taxes, including the relationships between the distribution performance index, SAIDI, and the IEEE Std. 1366, MED and *TMED*. He stated on any day wherein the severity of a storm caused the utility's SAIDI to reach or exceed *TMED*, the utility declares that day a MED and the utility shifts into a crisis mode to respond adequately to the level of storm severity. Mr. Alvarez described Ms. Hart's Table 4 on p. 11, that showed in 2018, vegetation (29%) and equipment failures (22%) were the top two causes of outages and accounted for more than half (51%) of the outages in DEI's distribution system; and Ms. Hart's Table 8 on p. 36, that illustrated the storm level severity effects on the number of Major Event Day ("MED") declared since 2014. He noted Ms. Hart's description of the cost effects of major storm restoration, vegetation management and TDSIC projects on DEI's historical and forecasted O&M costs; and the TDSIC-related distribution capital expenditures of DEI's historical and forecasted capital expenditures that showed DEI's TDSIC expenditures were $142 million (42%) of $342 million total distribution capital in 2018, projected as $116 million (32%) of $363 million in 2019, and forecasted as $100 million (30%) of $332 million in 2020. Mr. Alvarez discussed how the Major Storm Reserve would smooth out the financial impacts of major storm restoration costs to ease the financial consequences of a major storm, and the attendant mechanism to record the over and under collection of revenues in a reserve account provided some security that customers pay the reasonable costs of restoring power after a major storm and the utility recover its costs through rates. He stated interested parties retained the ability to scrutinize, and given the opportunity, to challenge the reasonableness of the storm expenses included in the reserve account in the utility's subsequent basic base rate case. Mr. Alvarez testified that by establishing a storm reserve the Commission could consider and resolve issues, review revenues and expenses, and issues an order within the context of a rate case to adjust basic rates and closely align revenue recovery with the expected major storm expenses. He said challenges remain in establishing the initial amount of major storm expenses, setting the level of major storm reserve and embedding in rates an incentive for the utility to manage prudently its expenses associated with major storms. He explained although the availability of a reserve does not remove or diminish the Company's separate obligation to reasonably establish the level of storm costs and to manage that expense, there was no assurance that the utility incurred its historical storm expenses from a prudent management of its storm expenses.

Mr. Alvarez testified DEI's major storm activities needed to be more proactive nature (identifying and alleviating vulnerable circuits, lines, equipment and facilities most susceptible to extensive damage and prolonged outages during major storms); needed to coordinate complementary programs (like the TDSIC and vegetation management programs), and develop an operational plan with the goal of substantially decreasing the level of storm reserve needed. Mr. Alvarez testified DEI should recognize the benefits of coordinated programs, and aligned objectives and an operational plan. He also stated setting the initial level of major storm reserve was another crucial element, as this provided the incentive needed for DEI to develop an effective operational plan.

Mr. Alvarez pointed out that DEI's case-in-chief showed vegetation and equipment failures as the primary causes of distribution outages, and that its TDSIC program accounted for more than a third of its historical and forecasted capital expenditures (2018-2020). While the TDSIC included programs to address these causes, DEI distribution reliability metrics continued to show a deteriorating trend.

Mr. Alvarez explained that the OUCC proposed operational plan would not divert vegetation management focus and resources from its original purpose. He testified that while initially the location of targeted facilities might be out of rotation with DEI's pre-set vegetation-clearing schedule, this could be quickly remedied. He explained the proposed operational plan would not throw off DEI's TDSIC schedule, as DEI has the freedom to move the timing of TDSIC projects within that Plan. Mr. Alvarez stated the OUCC proposed operational plan might provide faster restoration times, fewer outages and reduced facility damages suffered during storms.

Mr. Alvarez distinguished his support for a 5-year methodology for Indiana Michigan Power in Cause No. 45235 to determine the level of major storm reserve. He testified I&M's major storm reserve in Cause No. 45235 was in its third generation, and was supported by substantial evidence of both actual storm expenses and importantly, the utility's prudent management of those storm expenses. Mr. Alvarez testified neither the $21.7 million (2018) nor the $12.7 million (5-year average) major storm expenses proposed by DEI were supported by evidence that they were incurred despite prudent management. He pointed towards DEI witness Ms. Hart's direct testimony, in Table 9 on p. 37, which showed a significant increase in DEI's major storm expenses in 2016 compared to 2015. Moreover, he stated, the 2018 IURC Electric Utility Reliability Report showed significant increases in DEI's SAIDI during normal days (without MED) and major event days (with MED) of operations in 2016, as compared to 2015. However, he noted, DEI experienced the fewest number of MED in 2016 during the five-year period 2014 through 2018. He testified that as accurately depicted by Ms. Sieferman, an MED signified the utility shifted "into a crisis mode of operation to adequately respond" to a major reliability event, and accordingly, the utility shifts back into normal mode of operations during stable or normal operating days. Mr. Alvarez testified that in 2016, not only did DEI experience fewer MEDs, it also received its 7-Year Plan approval to spend hundreds of millions of dollars to improve its distribution and transmission through a TDSIC program. Despite these favorable operation conditions with ample resource availability, Mr. Alvarez opined that DEI operations performed poorly, marked by significant increases in major storm expense and SAIDI for both normal and crisis modes of operation.

Mr. Alvarez recommended DEI should maintain the same format used in Ms. Hart, Table 9, p. 36, to summarize major storm annual expenses going forward and make it available in its next basic rates case. In conjunction with the proposed operational plan, he recommended the Commission establish a Major Storm Reserve mechanism for DEI, with an initial Major Storm Reserve amount of $6 million.

(C) **<u>Petitioner's Rebuttal Evidence</u>**. The OUCC does not have any objections to Petitioner's recitation of its evidence.

(D) **<u>Commission Discussion and Findings</u>.** The Commission has approved major storm reserve ratemaking concepts like that proposed by Duke Energy Indiana for use by other Indiana electric utilities in recent base rate case proceedings. For instance, we authorized Indiana Michigan Power Company to implement a Major Storm Restoration Reserve in Cause No. 44075 and again in Cause No. 44967. We also approved the creation of a Major Storm Damage Restoration Reserve for Indianapolis Power & Light Company in Cause Nos. 44576 and 45029.

In *Re Indiana Michigan Power Company*, Cause No. 44075 (approved February 13, 2013) at 73, we discussed the benefits of the major storm reserve approach, noting: "the proposed accounting treatment will smooth out the impacts of major storms, thereby mitigating the financial consequences of a major storm." We further noted that if the "amount of imbedded storm damage expense exceeds the actual expense incurred, ratepayers will receive the benefit of the overpayment." *Id.* We continue to find that the use of the major storm reserve concept is an appropriate approach to account for major storm costs.

Duke Energy's $12.7 million initial Major Storm Damage Reserve, while based on a five-year average of actual costs, is unsupported by evidence that the Company was prudently managing its Major Storm expense during that period. With the addition of its TDSIC, including programs targeting primary causes of system outages, equipment failure and vegetation, it is not unreasonable to expect to see a reduction in storm-related outages caused by those two items. Further, OUCC's recommendation of an operational plan that can coordinate storm damage, TDSIC and vegetation management activity could provide substantial support in the next rate case that DEI proactively and effectively managed these budgets and coordinated the activities to minimize storm damage outages. Based upon substantial evidence of record, we direct Petitioner to develop an operational plan as described above and file that plan with the Commission no later than one year after the date of this Order. We find the Company should be authorized to set the base level for the Major Storm Reserve at $6 million as recommended by the OUCC and the Company should track any differences between the operating costs incurred and the amount collected in base rates. Any under- or over-recovery in such costs then would be recorded to a Regulatory Asset or Regulatory Liability account, respectively. Finally, we conclude the regulatory treatment of the net Major Storm Reserve amount should be addressed as part of the Company's next retail base rate case.

iv. Pension Settlement Deferral Request.

(A) Petitioner's Evidence. Ms. Douglas explained that pension settlement accounting, which is prescribed by U.S. GAAP accounting in certain situations, results in an acceleration of recognition of the settled portion of gains or losses currently deferred in a pension regulatory asset on the Company's accounting books. Absent triggering settlement accounting, these gains or losses would be amortized as a portion of net periodic pension cost, over the average remaining service period of active participants. If settlement accounting is triggered for regulated entities, the losses on the settled portion of the net periodic pension obligation must be reflected as an expense immediately, unless it is probable the costs (the amortization of which are currently a portion of pension cost being recovered through rates) will be recovered from customers. Ms. Douglas explained that the Company proposed that the settled portion of the losses be moved to a separate regulatory asset account and continue to be amortized over the average remaining service period of the pension plan participants. She stated that this GAAP required settlement accounting does not increase pension cost to the Company or to customers – it just accelerates the recognition of it on the Company's accounting books, reducing the original cost in the pension asset and future benefit costs from the actuarial study. Under the Company's requested accounting deferral treatment, she explained that annual pension costs would remain basically the same and that without the Commission's approval of this accounting treatment, the Company would incur earnings erosion and volatility, rather than the smoothing of these reasonable and necessary pension costs over time that normal pension accounting treatment affords.

Mr. Setser testified that settlement charges incurred by Duke Energy Indiana because of the triggering of settlement accounting will be deferred as a regulatory asset and amortization expense of the settlement charge will be recognized over the average remaining service life of Duke Energy Retirement Cash Balance Plan participants, currently 9.75 years.

(B) OUCC's Evidence. Mr. Kollen testified for the OUCC on this issue. He recommended the Commission reject the Company's request to retroactively defer the costs expensed since January 1, 2019 through the date that base rates are reset in this proceeding. Mr. Kollen explained the Company has not been subjected to a change in accounting that would merit a deferral of this expense retroactively, nor has it been authorized to track these costs in a prior proceeding. Mr. Kollen states he does not oppose a deferral of such expenses after the date base rates are reset in this proceeding. Mr. Kollen also argued that a deferral will harm customers when the Company seeks to recover the deferred expenses in a future proceeding and will allow the Company to record a windfall to income in 2020 from the reversal of the amounts expensed in 2019 and earlier in 2020.

(C) Petitioners' Rebuttal Evidence. Mr. Setser testified for the Company on rebuttal and clarified that the Company is not asking for retroactive treatment in this proceeding. He stated these costs are already deferred costs following the guidance of SFAS 158, codified in ASC715. He noted that under ASC Topic 715, Duke Energy is required to recognize as a component of other comprehensive income, the net actuarial gains or losses and prior service costs or credits that arise during the year but are not recognized as components of net periodic benefit cost of the period ("Unrecognized Gains or Losses"). Unrecognized Gains or Losses related to the Company's regulated operations are recorded pursuant to ASC Topic 980 and are reflected in regulatory assets or regulatory liabilities, subject to the regulatory treatment of such costs for the regulated jurisdiction. Unrecognized Losses are recorded to FERC account 182.3 (Other regulatory assets) while Unrecognized Gains are recorded to FERC account 254 (Other regulatory liabilities). The Unrecognized Losses recorded to FERC account 182.3 are commonly referred to as the "SFAS 158 Regulatory Assets."

Mr. Setser further stated the recognition of the SFAS 158 Regulatory Asset complies with FERC guidance per Docket No. AI07-1-000 (March 29, 2007). He also said that GAAP accounting rules for pensions require the Company to accelerate the recognition of these expenses when a settlement event occurs. He noted that Duke Energy Indiana's proposal is simply to continue to defer these costs and recognize them in a manner consistent with how these costs would otherwise be recognized. He concluded his rebuttal on this issue by stating the Company is being proactive in identifying that these settlement events will reoccur in future years and will result in "lumpy" expense recognition if the requested deferral is not approved.

(D) Commission Discussion and Findings. The Company's evidence with respect to the costs that were required to be expensed pursuant to the accounting rules in prior periods is not persuasive. The accounting rules do not mandate that the pension settlement costs that were expensed in prior periods be deferred or dictate whether we authorize such deferrals. If that were actually the case, then there would be no need for the Company to seek authorization to retroactively defer these expenses. However, we do find that it is reasonable to authorize the Company to defer these costs after base rates are reset in this proceeding. We agree that when these accounting rules require the Company to accelerate the recognition of these expenses in the future, it is reasonable to defer these potentially "lumpy" expenses to smooth the expenses so that they are amortized in approximately the same pattern as if they had not been accelerated and deferred. Accordingly, we find that Duke Energy Indiana should defer these expenses if and when incurred after the date base rates are set in this proceeding and amortize them in a manner consistent with how these costs would otherwise be recognized if they had not been accelerated.

v. Incremental Vegetation Management Deferral Request.

(A) Petitioner's Evidence. Ms. Graft described Petitioner's request for deferral and recovery of distribution vegetation management. Ms. Graft testified that the Company is requesting deferral of $9,235,000 in forecasted distribution vegetation management O&M in excess of the amount in current base rates for the January to June 2020 period. Ms. Graft noted this period is before base rates proposed in this proceeding will be effective. She further explained DEI is proposing to recover this amount over a three-year period in its proposed base rates. Although she does not explain in her testimony more precisely how she calculated the amount, she noted the Company is increasing routine distribution vegetation management work over the next three years in order to meet a five-year trim cycle with an expected ongoing O&M cost of $49.4 million annually. Ms. Graft concluded her discussion by asserting that it is reasonable to allow the Company to defer and recover these incremental distribution vegetation management costs it is incurring for enhanced safety and reliability of the distribution system.

(B) **OUCC's Evidence**. OUCC witness Mr. Kollen explained that in effect the Company is seeking to increase its distribution vegetation management O&M in 2020 by $18.470 million annually, calculated by doubling the $9.235 million deferral requested by the Company. He suggests the Company can avoid the need to request a deferral by simply waiting to increase its vegetation management activities to align more closely with when it expects base rates proposed in this proceeding to be effective. Mr. Kollen asserts that if the Commission allows a deferral, it should be for $5.240 million, which represents half of the total *pro forma* increase to test period expense Petitioner proposed.

(C) **Industrial Group's Evidence**. Mr. Gorman testified for the IG and also opposed the Company's proposal to defer forecasted distribution vegetation management O&M. He argues that a utility must manage its O&M between rate cases and that the Company could have timed its rate case differently if it wanted to be able to recover its proposed level of distribution vegetation management O&M via new base rates beginning in January 2020.

(D) **Petitioner's Rebuttal Evidence**. Ms. Graft stated in rebuttal that Mr. Kollen's assumption that vegetation management costs are spread evenly over the year is incorrect. The Company's proposed distribution vegetation management O&M is $49 million, comprised of $38.9 million in the test period forecast, plus a $10.5 million *pro forma* adjustment. She said the proposed deferral amount simply represents the difference between forecasted distribution vegetation management O&M in excess of the amounts in current base rates for the January to June 2020 period before base rates proposed in this proceeding will be effective. Finally, she noted an effective vegetation management program is an important initiative to the Company, its customers, and the Commission and, therefore, it is reasonable for the Company to request and for the Commission to approve deferral treatment associated with the incremental costs the Company is incurring by moving to a five-year trim cycle for enhanced safety and reliability of the distribution system.

As an alternative, Ms. Graft suggested should the Commission desire to utilize the cumulative reserve accounting approach, the Company could incorporate its proposed deferral for January through June 2020 within the cumulative reserve and then any balance remaining in the reserve account would be addressed in the Company's next retail base rate case.

If the Commission were to approve this approach, Ms. Graft stated the result would be a reduction in test period amortization expense of approximately $3.1 million (equal to the deferral request of $9.235 million divided by the proposed three-year amortization period).

(E) **Commission Discussion and Findings.** DEI has requested recovery of an operating expense it asserts it will incur before a rate order is issued in this case. DEI's requested deferral of $9,235,000 in forecasted distribution vegetation management O&M expense reflects a misunderstanding of the purpose of test years in regulatory ratemaking. The purpose of a test year is not to recover expenses that occur before new rates go into effect, but to establish rates based on the utility's expenses while the rates are in effect. "The object of the test year is merely to reflect typical operating conditions of a utility and provide a reliable guide in fixing rates for the future by monitoring actual operating results over a representative period of time." *Capital Improvement Bd. of Managers of Marion Cty. (Convention Ctr.) v. Pub. Serv. Comm'n*, 176 Ind. App. 240, 257–58, 375 N.E.2d 616, 630 (1978). And as the Court of Appeals explained, "the theory underlying the use of any test-year and adjustment method in the rate-making process demands that the data used provide an accurate picture of the utility's operations during the period in which the proposed rates will be in effect." *L. S. Ayres & Co. v. Indianapolis Power & Light Co.*, 169 Ind. App. 652, 673, 351 N.E.2d 814, 828 (1976). The Court further described how test years function in ratemaking, making it clear that a test year is to be used prospectively to provide rates for future activities and not as a *recovery* mechanism.

> The test year may be analogized to the technique of stopping a film to examine one isolated frame. By freezing the action of the utility's operations in a convenient time frame, the Commission can observe the inherent interrelationships among rate base, expenses and revenues. This observation is crucial to the concept of the test period because a complete picture of these dynamic interrelationships can only be obtained when the rate base, expense and revenue components are examined in phase. Thus, rate base, expense and revenue data for an historical test year <u>are meaningful for a determination of utility rates only insofar as past operations are representative of probable future experience</u>.
>
> Id. (emphasis added.)

Moreover, DEI's requested recovery of an operating expense that would be incurred before its new rates go into effect is really a request that we engage in impermissible retro-active rate making. We decline to do so. As such, we need not parse the OUCC's position that DEI has overstated its requested deferral. We hereby decline DEI's request for deferral and recovery of its pre-order vegetation management O&M expense.

vi. <u>316(a) and 316(b) Deferral Request</u>.

(A) <u>Petitioner's Evidence</u>. The OUCC does not have any objections to Petitioner's recitation of its evidence.

(B) <u>OUCC's Evidence</u>. OUCC Witness Armstrong recommended denial of DEI's request to track study costs associated with the Clean Water Act sections 316(a) and 316(b) ("316(a) costs" and "316(b) costs"). She stated that the nature of the compliance activities, the amount of the costs DEI is requesting, and the timeframe in which they were incurred is unclear and unsupported by DEI witnesses. She clarified that through the discovery process, DEI indicated that its 316(a) study costs were incurred from 2014 to 2019 and were $171,302. DEI stated that its 316(b) study costs totaled $2,287,623 since 2007, and that it would spend another approximately $200,000 through 2021 to complete the 316(b) studies for all of its plants.

Ms. Armstrong disagreed with DEI Witness Graft's claim that DEI received approval for the 316(a) and 316(b) costs in Cause No. 44418. Ms. Armstrong explained that Cause No. 44418 involved approval of DEI's Phase 3 Environmental Compliance Plan ("Phase 3 Compliance

Plan"), which presented how DEI would comply with the Mercury and Air Toxics Standards ("MATS"). As part of that settlement agreement between DEI and the OUCC, the OUCC agreed to the timely recovery of future compliance plan development, engineering, testing and pre-construction costs related to the Phase 3 Compliance Plan.[13] Ms. Armstrong noted that as part of its Phase 3 Compliance Plan, DEI tested mercury trim controls other than those approved in the Phase 2 Compliance Plan, which may have avoided the need for Activated Carbon Injection ("ACI") systems on many of its generating units. She explained that as a result of this testing, DEI was incurring plan development, engineering, and pre-construction costs related to mercury controls proposed in both the Phase 2 and Phase 3 Compliance Plans and that the OUCC understood that only these costs would be covered by the settlement agreement. She pointed to Ms. Graft's Settlement Exhibits in Cause No. 44418, which showed the anticipated increases due to the plan development, engineering, and pre-construction costs were attributable to Duke's Phase 3 Compliance Plan.[14] Ms. Armstrong stated that the OUCC relied on these estimates in its settlement negotiations with DEI and the OUCC's agreement to the Phase 3 costs should not be construed as automatic approval of any and all environmental compliance study costs remotely related to a federal mandate. She also pointed out that the Commission specifically noted the approval of the timely recovery of future plan development, preliminary engineering, testing, and pre-construction costs via Rider 71 were in connection with DEI's proposed Phase 3 Compliance Plan (Cause No. 44418, Final Order, p. 29).

Ms. Armstrong addressed the multiple issues with DEI's requested treatment of the 316(a) and 316(b) study costs. First, she stated that DEI appears to seek approval of recovering federally mandated costs after it has already incurred them. She referenced the Commission's ruling in Cause No. 44367 FMCA 4, where the Commission indicated that a utility must obtain a CPCN for federally mandated costs before they are incurred in order to receive cost recovery under I.C. ch. 8-1-8.4.

Second, Ms. Armstrong stated that Duke did not address all factors necessary to obtain a federally mandated CPCN for its 316(a) and 316(b) study costs under I.C. § 8-1-8.4-6(b). She noted that as a part of an application to receive approval for federally mandated projects, I.C. § 8-1-8.4-6(b)(1)(B) requires the energy utility to provide a description of the projected federally mandated costs associated with the proposed compliance project. She reasoned that a necessary part of describing a compliance project's federally mandated costs is a reasonable estimate of its costs and maintained that DEI did not provide clear estimates of the costs or a timeline for implementation. She also noted that in the case of the 316(b) study costs, it appears DEI recorded costs as far back as 2007, before the General Assembly passed the Federally Mandated Requirements statute.

Ms. Armstrong stated that DEI also failed to provide adequate information about the activities for the 316(a) and 316(b) compliance projects it seeks recovery for in this Cause as part of its application, which is required by I.C. § 8-1-8.4-7(a). She pointed to responses to discovery by DEI that clarified the costs were for the characterization studies DEI had to perform to determine the best technology available ("BTA") for compliance with both I.C. § 8-1-8.4-6(b)(1)(C) and I.C. § 8-1-8.4-7(a). *See* OUCC Att. CMA-8. However, she maintained the OUCC

[13] Cause No. 44418, Settlement Agreement, p. 3.
[14] Cause No. 44418, Petitioner's Ex. H-1, Line No. 3.

should not have to issue discovery to determine the federally mandated compliance projects for which DEI is seeking recovery, citing the Commission's order in Cause No. 45073. She also advised DEI to not delay providing this information until discovery or rebuttal, as it precludes the OUCC's and intervenors' opportunity to review and adequately respond in testimony, as well as wasting the Commission's and stakeholders' time and resources.

Ms. Armstrong testified that DEI also did not provide alternative plans demonstrating the proposed 316(a) and 316(b) compliance projects are necessary under I.C. § 8-1-8.4-6(b)(1)(D), nor whether they extend the useful life of the existing facility under I.C. § 8-1-8.4-6(b)(1)(E). Finally, she questioned whether the 316(a) costs were substantial enough to track. She stated that DEI has been complying with the requirements of CWA Section 316(a) for more than forty (40) years through its NPDES permits and has been able to reflect and absorb such costs as an operating expense without a tracker. She noted that the entire five-year period cost for the CWA 316(a) demonstration study is less than $200,000 and reasoned that the administrative resources DEI, the Commission, and the OUCC will spend to review these costs every six months until DEI's next rate case are likely more than the costs of the study itself. She cited I.C. § 8-1-8.4-6(b)(2), which allows the Commission to take into account any other factors it considers relevant to the utility's application. She suggested that there is a more administratively efficient way to allow cost recovery if these studies will be repeated every time DEI renews its NPDES permits, such as embedding a five-year amortized annual O&M amount in DEI's revenue requirement. She stated that the OUCC did not reflect an adjustment for 316(a) or 316(b) Rule costs in its recommended revenue requirement in this proceeding, as DEI neither provided adequate cost information in this filing nor indicated these studies would be an ongoing cost.

(C) Petitioner's Rebuttal Evidence. Duke Energy Indiana witness Ms. Graft testified on rebuttal that the Commission did preapprove for timely recovery the 316(a) and 316(b) study costs. In Cause No. 44418, Ms. Graft said the Company specifically requested timely recovery of such future plan development costs "associated with future environmental planning for compliance with air, water, or waste regulations via Rider 71 (or via Rider 62 to the extent such costs are related to a capital project)." Cause No. 44418, Petitioner's Exhibit F at 9-10. Ms. Graft indicated the Order in that proceeding authorized timely recovery of "future plan development, preliminary engineering, testing, and pre-construction costs via Rider 62 and/or 71." 44418 Order at 29.

Subsequently, in Cause No. 44765, she noted Duke Energy Indiana sought and received Commission approval to recover its plan development, preliminary engineering, testing, and pre-construction costs and cited the preapproval from Cause No. 44418 in its testimony in that proceeding. Cause No. 44765, Petitioner's Exhibit 6 at 5-6. She further indicated Duke Energy Indiana also has been recovering those expenses through its ECR rider (Rider 62 and/or 71, as applicable). *See*, *e.g.*, Cause No. 42061 ECR 31 Order at 17 ("Petitioner is also authorized to recover in Rider 71 the amortization of CCR Compliance Plan development costs").

(D) Commission Discussion and Findings. As we found in our extended findings above regarding DEI's request for federal mandate treatment for previously-incurred costs, there is no basis for such treatment in the statute or our precedent. As to DEI's assertion that it received Commission approval for the 316(a) and 316(b) costs in Cause No. 44418, we disagree. The evidence shows that the costs agreed to (as part of a settlement, it must be noted) pertained to the phased projects under consideration. Allowing DEI to use the provision of that settlement as a blank check to complete any environmental request out into the future flies in the face of our process and the statutes that underlie it.

We also note that the CCR Compliance Plan rate recovery in the ECR refers to expenses explicitly approved in Cause No. 44765, which included the installation of dry ash handling and wastewater treatment equipment. Therefore, we reject DEI's argument that it was previously authorized to collect the 316(a) or (b) costs.

vii. <u>SO_2 Emission Allowance Deferral Request.</u>

(A) <u>Petitioner's Evidence</u>. Duke Energy Indiana proposes to transfer the native SO_2 EAs from the EA inventory account to a new regulatory asset account to be amortized over a twelve-year period. This would allow the Company to recover the costs incurred for these allowances over the remaining useful lives of the associated generating plants. Duke Energy Indiana also proposed to discontinue using Rider 63, and instead include any native allowance consumption expense and gains or losses on the sale of native EAs in its consolidated Rider No. 62.

(B) <u>OUCC's Evidence</u>. Ms. Armstrong testified that the OUCC does not take issue with the Company's native SO_2 allowance inventory costs proposal. She indicated she was aware that Duke Energy Indiana has decreased its use of SO_2 allowances and that unit retirements at the Wabash River and Gallagher Generating Stations, coupled with the installation of SO_2 environmental controls at the Gallagher, Cayuga, and Gibson Generating stations have resulted in the Company emitting less SO_2 over the last several years. In addition, Ms. Armstrong testified the zero-cost SO_2 allowances Duke is awarded each year exacerbate this issue because it lowers the weighted average SO_2 inventory cost, which decreases annual consumption expense and the rate at which Duke Energy Indiana recovers the remaining inventory cost.

Ms. Armstrong stated the Company benefits because it is able to fully recover the costs of more expensive allowances procured prior to the major changes in environmental regulations, unit retirements, and pollution controls impacting the consumption of EAs over the past decade. She indicated that ratepayers benefit from an eventual reduction in the remaining inventory balance, which lowers the return on inventory customers must pay in base rates over what they could expect to pay if the inventory balance was slowly reduced over 40 or more years. However, to reduce further impact of the accelerated recovery of native SO_2 inventory costs, the OUCC recommends that the Commission adopt Mr. Kollen's ratemaking treatment for recovering regulatory assets.

Ms. Armstrong recommends the Commission approve moving the native SO_2 allowance inventory costs into a regulatory asset, which she suggested should be recovered using the levelized-cost recovery method Mr. Kollen proposes for all regulatory assets. She added that Duke Energy Indiana should be required to discontinue tracking EA costs while at the same time selling any excess EAs whenever possible, and pass the proceeds of any such allowance sales through Rider No. 62.

(C) <u>Petitioner's Rebuttal Evidence</u>. Per Ms. Graft's rebuttal testimony, the Company agrees to discontinue tracking of native EA consumption expenses upon implementation of new base rates. However, the Company reserves the right to seek EA tracking in future proceedings if new regulations are enacted or EA expenses become more volatile. With regard to the proposal to recover the regulatory asset using the levelized-cost recovery method, Ms. Douglas testified that, as with other regulatory assets, the Company opposes Mr. Kollen's proposed levelized methodology.

(D) <u>Commission Discussion and Findings</u>. We agree with the Company and the OUCC that moving the native SO_2 emission allowance inventory costs into a regulatory asset is reasonable, and we approve such. This will therefore terminate Duke's tracking of the EA costs. We also approve the OUCC's recommendation to use the levelized-cost recovery method Mr. Kollen proposes for all regulatory assets.

c. <u>FAC Issues.</u> Petitioner made several proposals with respect to its FAC processes. Certain intervenors made other FAC-related proposals.

i. <u>Petitioner's Evidence</u>. The OUCC does not have any objections to Petitioner's recitation of its evidence.

ii. <u>OUCC Evidence</u>. OUCC witness Boerger responded to the Company's stacking proposals. He testified that he agrees with the Company's proposal to eliminate its "two-pass" stacking methodology, noting that it would allow native load customers access to the Company's lowest cost fuel resources as they are ultimately realized in MISO's real-time market.

Dr. Boerger, however, disagreed with the Company's proposal to move to an incremental rather than average cost allocation of no-load fuel costs. He testified that MISO dispatches units based on incremental cost, which is appropriate because that approach will lead to a least cost dispatch. He further testified, however, that changing the Company's stacking does not change MISO's dispatch of its generating units; the Company's proposal changes cost allocations only after the fact. Because there is no change to the manner in which MISO dispatches Duke Energy Indiana's generating units, there is no improvement in efficiency resulting from Duke Energy Indiana's proposal. Therefore, with no improvement to operational efficiency resulting from Duke Energy Indiana 's proposal, Dr. Boerger stated, the evaluation of its stacking proposal must come down to whether it is more fair for additional no-load costs to be allocated to native load customers compared to non-native sales. Based upon his review, he concluded there is no improvement in fairness resulting from allocating more "no-load" costs to native load customers. He analogized to the allocation of joint, fixed costs incurred in providing utility service, and observed that standard methodology addresses the difficulty of determining which customers are "marginal" by simply allocating on an "average" basis. He contended that the allocation of no-load cost is similar to the problem of allocating all other costs incurred in a utility's operation and, as such, there is no reason to depart from the standard methodology of allocating costs on an average basis.

OUCC witness Eckert recommended continuation of the current agreement allowing the OUCC 35 days to complete its FAC review and file its FAC testimony. In addition, Mr. Eckert testified that the OUCC recommended approval of the Company's request to waive the purchased power benchmark procedures, conditioned on providing the following in its audit package: (1) root cause analysis for forced outages lasting more than 72 hours, and (2) day-ahead offers and real-awards for test days the OUCC requests.

iii. <u>Intervenor Evidence</u>. Industrial Group witness Dauphinais recommended that the Commission reject Duke Energy Indiana's stacking proposal unless the Commission also requires the Company, through its Rider 70, to pass back to its Indiana retail customers 100% of the Indiana share of Duke's non-native sales margins. He noted that the Company's proposal will likely increase native load fuel costs while equally increasing non-native sales margins. He stated that Duke Energy Indiana passes 100% of its Indiana share of native load fuel costs onto its Indiana retail customers through its FAC, but is permitted to retain 50% of the Indiana share of its non-native sales margins. As a result, he testified, the Company's proposed change to its stacking method is self-serving because it shifts fuel costs from non-native sales to native load sales. However, he stated, the impact on Indiana retail customers of this type of maneuvering can be neutralized by moving to 100% allocation to Indiana retail customers of both native load fuels costs under the FAC and non-native sales margins under Rider 70.

As discussed previously, Sierra Club witness Comings testified that losses associated with uneconomic dispatch of coal units, including Edwardsport, should be disallowed from rates. In addition, he testified that the Commission should open an investigation into the self-commitment practice. As support for his position, he offered a (confidential) analysis of the dispatch economics of the Company's largest coal-fired units.

iv. <u>Petitioner's Rebuttal Evidence</u>. The OUCC does not have any objections to Petitioner's recitation of its evidence.

v. <u>Commission Discussion and Findings</u>. First, we note that no party took issue with the Company's proposal to recover PJM charges and credits related to its Madison Generating Station in either its FAC Rider, its RTO Rider, or Rider 70, as appropriate. Nor did any party take issue with the Company's proposal to eliminate the two-pass stacking process and perform the stacking process exclusively in the real-time market. Petitioner supported both of these proposals and we approve both.

Next, we address Petitioner's proposal to change its stacking process from an 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. Mr. Swez opined that this proposal is reasonable, in terms of allocating no-load costs to the drivers of those costs, which in most cases will be native load generation needs. However, Dr. Boerger explained that DEI's proposal does not change the offers for these units in MISO markets and thus provides no change or improvement to the efficiency of how the Company's units are dispatched. As such, the issue of cost allocation is one of fairness in how costs are allocated between native and non-native load customers. We are persuaded by Dr. Boerger's analogy to how the traditional methodology of cost allocation, which allocates based upon average cost, is reasonable for allocating the no-load costs that are the subject of the Company's request. We see no reason that sales to non-native customers, which are made possible by these no-load costs, should not share proportionately in those costs. Accordingly, we deny DEI's incremental production cost allocation request.

We also approve the Company's proposal to eliminate the purchased power benchmark process. No party objected to this proposal, and the Company demonstrated that circumstances have changed since we instituted the benchmark years ago. Additionally, as Mr. Swez noted, eliminating the benchmark process in no way precludes our ability to scrutinize power purchases in the FAC process, as necessary.

We also approve the continuation of the process whereby the OUCC is given 35 days to review the Company's FAC application and file FAC testimony. No party objected to this, and it has worked in practice.

Additionally, we address the Sierra Club's recommendations that all of the Company's generating units should be "dispatched on an economic basis," not self-committed, and that the Commission open an investigation into the practice of self-commitment. Mr. Swez provided a lengthy explication of the Company's dispatch process, and how it dispatches its units so as to minimize total customer costs by maximizing the generators' total margins. He demonstrated that the MISO 24-hour day ahead market is an imperfect fit with longer term generation commitment decisions particularly for units that have longer start up times. We agree with the Company that committing units on solely a short term "Economic" basis would not be consistent with the objective of minimizing total customer costs. Accordingly, we reject the Sierra Club's recommendation that all units should be so dispatched. Additionally, we will not adopt the Sierra Club's recommendation that we open an investigation into the practice of self-commitment. We have not found any basis in this record to order such an investigation. We also note that the Company's dispatch decisions are reviewed regularly in FAC proceedings. Finally, for the foregoing reasons, we reject the Sierra Club's proposal to reduce the Company's O&M expense levels to reflect what it characterizes as economic dispatch losses. The Company's past dispatch decisions and methodologies have been reviewed by this Commission in prior FAC proceedings and found to be reasonable. It would be impermissible retroactive ratemaking for the Commission to approve any disallowance in this proceeding.

d. <u>OUCC Benchmarking Analysis.</u>

i. <u>OUCC's Evidence</u>. OUCC witness Dismukes, sponsored the OUCC's Benchmarking Analysis. Dr. Dismukes examined the Company's plant investment trends over the past several years. His Schedule DED-7 presents a list of peer utilities used in his benchmarking analysis and their respective descriptive statistics. Using FERC Form 1 information, Dr. Dismukes compared Petitioner's plant investment, costs, and operational efficiencies against other vertically-integrated electric utilities operating in the Midwest, Mid-Continent, and Appalachian regions.

Dr. Dismukes included a benchmarking analysis of the Company's production plant investment trends as compared to that of its peers in his Schedule DED-8. He explained that Duke's net production plant has grown at an average annual rate of 9.2 percent as compared to the peer group average of 8.6 percent. Dr. Dismukes testified that the growth in production plant is driven entirely by the Edwardsport combined cycle plant which began commercial operations in 2013. He stated the Company's net transmission plant investment compared to its peers was set forth in Schedule DED-9. Nominally, the Company ranks 13th, 14th, or 15th in the peer group each year; in terms of growth rate, Duke's average annual growth rate of 10.5 percent is lower than the peer group average of 14.1 percent. He added that the Company's net distribution plant investment compared to that of its peers was set forth in Schedule DED-10, and its net general plant investment comparison was set forth in Schedule DED-11. Dr. Dismukes stated that Duke's net distribution plant investment compares favorably with its peers, showing Duke as ranked 4th in the peer group since 2011. He explained that in 2020, Duke's net distribution plant growth is expected to accelerate to 15.2 percent per year on a per-MWh basis. Dr. Dismukes explained that Duke's net general plant growth has outpaced the peer group considerably; Duke's ten year average annual growth rate is 11.7 percent as compared to the peer group average of 8.2 percent. He pointed out that Duke's net general plant growth is expected to accelerate to 24 percent per year on a per-MWh basis.

The benchmarking comparisons Dr. Dismukes prepared for the Company's O&M expenses were set forth in Schedules DED-12, DED-13 and DED-14, and benchmarking of the Company's Administration and General ("A&G") expenses were set forth in Schedule DED-15. He explained that Duke's production expenses less fuel and purchased power have grown at an annual average growth rate of 4.5 percent, two percent higher than the peer group average. This increase coincides with the start of commercial operations for its IGCC plant. Duke's transmission expenses are far below that of the peer group average; however, Duke's rate of growth has significantly outpaced the peer group, averaging 20.4 percent over the past five years versus only 4.1 percent for the peer group. Dr. Dismukes testified that Duke's per-MWh distribution O&M expenses have generally been below average for the past ten years. However, he pointed out that Duke's growth rate in the past five years has been 10 percent and the peer group's is only 1.2 percent. Dr. Dismukes stated that Duke's A&G expenses have decreased per year over the past five years, and are expected to decrease by 5.8 percent per year through 2020 on a per-MWh basis. As a result of the foregoing benchmarking comparisons between the Company and its peer group, Dr. Dismukes concluded (i) the Company's projected annual growth rate of 10.3 percent in production O&M expenses per MWh far outpaces the peer group five year growth rate of 0.3 percent; (ii) the projected annual growth rate of 15.2 percent in the Company's net distribution plant per MWh far outpaces the Company's five year average of 9.9 percent; and (iii) the Company's net general plant per MWh is projected to grow by 24 percent per year through 2020, which is greater than its five year average growth rate of 15.2 percent.

Dr. Dismukes concluded his benchmarking testimony by stating his analysis shows a number of Duke's forecasted test year plant expenditures are not in line with, and in many instances exceed, historical expenditures. He recommended the Commission require the Company to undertake an in-depth review of its production and distribution O&M expenses. He further suggested the Commission should initiate a collaborative proceeding in which the Company, the Commission and other interested stakeholders can create, analyze and discuss appropriate benchmarking metrics for the Company.

ii. <u>Petitioner's Rebuttal Evidence</u>. The OUCC does not have any objections to Petitioner's recitation of its evidence.

iii. <u>Commission Discussion and Findings</u>. Starting with our Final Order in *Indianapolis Power and Light Company*, Cause No. 44576, the Commission has ordered several of Indiana's largest investor-owned energy utilities to participate in collaborative processes focusing on a variety of operational concerns, including asset management, performance metrics, reliability, and low-income customer programs. *See Indianapolis Power & Light Co.,* Cause No. 44576, 2016 WL 1118795 (IURC March 16, 2016); *Northern Indiana Public Service Company,* Cause No. 44688, 2016 WL 3996436 (IURC July 18, 2016); *Indiana Michigan Power Company*, Cause No. 44967, 2018 WL 2739912 (IURC May 30, 2018).

Our Order in *NIPSCO*, Cause No. 44688, articulated the role of appropriate performance comparisons in fulfilling the Commission's obligation to facilitate effective utility management:

> It is the Commission's obligation to facilitate effective and efficient management of the utility including continuous improvement to the extent it fosters just and reasonable rates. While looking at the performance of an individual utility in isolation in a traditional rate case may, under certain circumstances, be required to accomplish this key regulatory objective, it is more effective and informative if performance can be assessed with appropriate comparisons and data to measure comprehensive performance across a spectrum of activities over time. The level and trend of utility performance as measured against itself and compared to other utilities is a crucial element if the Commission is to optimally understand how well management is performing.

Northern Indiana Public Service Company, Cause No. 44688, 2016 WL 3996436 p. 93.

The OUCC's evidence in this Cause lays useful groundwork for the kind of in-depth analysis and stakeholder dialogue that can be best accomplished within the context of a collaborative process. Dr. Dismukes' benchmarking analysis raises important concerns regarding Duke's projected growth in production O&M and in net general and production plant investment. Performance metrics can be of significant value to the Commission and Duke's ratepayers. Therefore, we find Duke shall facilitate a meeting with interested stakeholders within six weeks of the effective date of the Order in this Cause to collaborate on a path for moving forward with a performance metrics initiative. We anticipate that it will enable comparisons of Duke's performance over time and in comparison to comparably situated utilities. The collaborative process should further develop the performance metrics already being used by Duke. Because the ongoing collaborative effort will not be occurring within the context of an open docket, the Commission's technical staff should actively participate in the process. For purposes of 170 IAC 1-1.5, the Commission's technical staff shall be authorized to participate in the collaborative without being subject to 170 IAC 1-1.5-3 and 4.

e. Waivers of 170 IAC 4-1.

i. Petitioner's Evidence. Company Witness Hunsicker testified that the Company was seeking the following waivers of 170 IAC 4-1 for the implementation of Customer Connect:

> 170 IAC 4-1-16(c)(2) as it relates to the signature requirements for payment agreements.
>
> 170 IAC 4-1-13(a)(1) as it relates to providing the beginning and ending meter readings, specifically for certain interval-billed rates, to allow the Company to provide usage information only on the customer's bill. Ms. Hunsicker testified that the inclusion of meter readings was more meaningful under traditional rate structures; however, with interval usage the beginning and ending meter readings are no longer relevant to the customer.

> 170 IAC 4-1-16(e) is needed to allow the Company to enable all customers' preferred method of communication as it relates to their energy bill. Ms. Hunsicker testified that the Company plans to provide all customer bills in the manner the customer has designated.

ii. **<u>Commission Discussion and Findings</u>.** The OUCC did not take a position on this issue.

f. **<u>Affordability/Low-Income Collaborative</u>**.

i. **<u>Petitioner's Evidence.</u>** The OUCC does not have an objection with Petitioner's recitation of its evidence.

ii. **<u>Intervenor Evidence.</u>** The OUCC accepts Joint Intervenors' recitation of its evidence.

iii. **<u>Petitioner's Rebuttal Evidence.</u>** The OUCC does not have an objection with Petitioner's recitation of its evidence.

iv. **<u>Industrial Group's Cross-Answering Testimony</u>.** The OUCC accepts the Industrial Group's recitation of its evidence.

v. **<u>Commission Discussion and Findings</u>.** The OUCC did not take a position on this issue.

g. **<u>Performance Metrics Collaborative</u>.**

i. **<u>Petitioner's Evidence</u>.** Company Witness Davey testified that it recognized from prior rate case orders for other utilities that the Commission has a keen interest in performance metrics. As such, at the conclusion of this rate case, the Company proposes a collaborative process with interested stakeholders to develop annual reporting for performance metrics. No other party addressed this issue.

ii. **<u>Commission Discussion and Findings</u>.** We appreciate the parties' willingness to consider the value that is added by the collaborative process. The Commission views the collaborative process as an opportunity for all parties to dialogue on how to improve utility operations. Such a process was created coming out of the recent rate cases for NIPSCO, IPL, and I&M. We believe performance metrics can be of significant value to the Commission and customers. Thus, we find that Duke Energy Indiana shall facilitate a meeting with interested stakeholders within 12 weeks of the effective date of the Order in this Cause to collaborate on a path for moving forward with a performance metrics initiative. We anticipate that it will enable comparisons of Duke Energy Indiana's performance over time and in comparison to similarly situated utilities. Because the ongoing collaborative effort will not be occurring in the context of an open docket, the Commission's technical staff should actively participate in the process. For purposes of 170 IAC 1-1.5, Commission's technical staff maybe authorized to participate in the collaborative without being subject to 170 IAC 1-1.5-3 and -4. In order that the Commission and interested stakeholders may stay abreast of the collaborative process, we direct Duke Energy Indiana to make a progress update filing with the Commission within 90 days of the initial meeting of the collaborative. We also direct Duke Energy Indiana to file quarterly reports for the first year and an annual report by October 1, 2021, and for each year thereafter until otherwise indicated by the Presiding Officers.

h. Contractor Policies.

i. Intervenor's Evidence. David Frye, Business Manager of the Indiana Laborers District Council ("ILDC") testified regarding changes that he believed would need to occur in Duke Energy Indiana's rate filing to align with his recommendations on mitigating the workforce impact from the transition away from coal. He also recommended that the Company implement local worker construction job transparency and reporting requirements for future gas and renewable generation projects. Mr. Frye added that Duke Energy Indiana should include new language in future renewable power purchase agreements to give a preference for projects that pay fair wage and benefits and prioritize the use of local residents. Finally, Mr. Frye testified the Company should implement a responsible contractor policy for contracted out services, such as vegetation management, traffic control and distribution construction projects.

ii. Petitioner's Rebuttal Evidence. Ms. Hart testified in rebuttal to Mr. Frye's recommendations that the Company should adopt a responsible contractor policy. She indicated Mr. Frye's concerns are unfounded and that Duke Energy Indiana already has procurement policies in place that prioritize contractors with cost effective service, increased productivity and minimized workforce turnover. Ms. Hart also responded to Mr. Frye's recommendations for the Commission to mandate certain wage and benefits for contractors. She stated that Duke Energy Indiana reasonably manages its contractors today and there is no evidence to the contrary. Accordingly, she contended that the Commission does not need to direct any changes to the Company's existing policies, which provide for reasonable and efficient use of contractors.

Ms. Mosley also testified in rebuttal to Mr. Frye's proposed Responsible Contractor Policy. Mr. Mosley indicated ILDC apparently believes a Responsible Contractor Policy can help identify and reward contractors who provide cost-effective service, while increasing productivity and decreasing turnover of the Company's contracted-out workforce. However, because Duke Energy Indiana already has in place procurement policies that prioritize contractors with cost effective service, increased productivity, and minimized turnover of its workforce, Mr. Mosley asserted the Commission should not mandate wage or benefit levels, require additional reporting, mandate use of local residents, or require implementation of a new Contractor Policy as proposed by ILDC.

iii. Commission Discussion and Findings. The OUCC did not take a position on this issue.

19. **Confidentiality**. Duke Energy Indiana filed five Motions for Protection of Confidential and Proprietary Information on July 2, 2019, July 22, 2019, November 6, 2019, January 21, 2020, and February 2, 2020. The Industrial Group filed a Motion for Confidential Treatment of Certain Testimony of Michael P. Gorman on October 30, 2019. The Motions were supported by affidavits showing documents to be submitted to the Commission were trade secret information within the scope of Indiana Code §§ 5-14-3-4 and 24-2-3-2. The presiding officers issued docket entries and made rulings from the bench finding such information to be preliminarily confidential, after which such information was submitted to the Commission under seal. We find all such information is confidential pursuant to Indiana Code §§ 5-14-3-4 and 24-2-3-2, is exempt from public access and disclosure by Indiana law and shall be held confidential and protected from public access and disclosure by the Commission.

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

1. Duke Energy Indiana shall be, and hereby is, directed to place into effect base rates and charges for retail electric utility service rendered by it in the territories served by it in the State of Indiana in accordance with this Order, including an annual reduction to its rates and charges of $135,591,000. Said rates will produce total jurisdictional electric operating revenues of $2,466,222,000 and, on the basis of annual jurisdictional electric operating expenses of $1,948,628,000, will result in annual jurisdictional electric utility operating income of $517,594,000. Duke Energy Indiana is hereby authorized to file with the Commission a new schedule of rates and charges which will properly reflect, establish and provide the operating revenues herein authorized. Said schedule of rates and charges should be in accordance with this Order, including implementation of this rate increase in two steps as approved herein.

2. Duke Energy Indiana shall file with the Energy Division of this Commission, appropriate tariffs using the rate design criteria specified in this Order, including the rates and charges authorized herein for Step 1 and Step 2. For Step 1, Duke Energy Indiana shall file new schedules of rates and charges with the Energy Division of the Commission. For Step 2, Duke Energy Indiana shall file new schedules of rates and charges with the Energy Division of the Commission; however, for Step 2 Petitioner shall provide the OUCC and intervening parties sixty (60) days following the date of verification of actual used and useful property to state any objections to Duke Energy Indiana's verified actual test-year end net plant. If there are objections, a hearing may be held to determine Petitioner's actual test-year-end net plant in service, and rates will be trued-up (with carrying charges) retroactive to January 1, 2021. The rates and charges for Steps 1 and 2 shall be implemented upon approval of the filed tariffs on a service-rendered basis.

3. Duke Energy Indiana's request to recover in its retail electric rates the following deferred costs, is hereby denied in accordance with this Order: Gallagher Station Unit 1 and 3 deferred costs; SO_2 emission allowance costs; Wabash River Unit 6 deferred costs; and coal ash basin closure and remediation expenses. Further, Duke Energy Indiana's request to defer, for subsequent recovery in its retail electric rates, the following costs is denied: Edwardsport IGCC outage costs; Customer Connect costs; pension settlement costs; incremental vegetation management costs; and 316(a) and 316(b) compliance-related costs, all as discussed and subsequently denied in this Order. In addition, Duke Energy Indiana shall establish and maintain a Major Storm Reserve as set forth in this Order.

4. Commencing with the first of the month following effective date of updated base rates, Duke Energy Indiana is hereby authorized to place into effect the depreciation rates approved in this Order.

5. Duke Energy Indiana shall be, and hereby is, authorized to implement the changes to various Rate Adjustment Riders as approved in this Order, specifically changes to Riders 60, 61, 62, 63, 65, 66, 67, 68, 70, 71, 72 and 73, all as determined in this Order.

6. Duke Energy Indiana's request to implement a decoupling mechanism and a decoupling rider is denied.

7. Duke Energy Indiana shall be, and hereby is, authorized to implement the rate design proposals and tariff changes as modified in this Order

8. Duke Energy Indiana is granted a waiver of 170 IAC 4-1-16(f) as to the disconnection process and the waivers discussed in Waivers section, 18.e of this order.

9. Duke Energy Indiana shall be, and hereby is, authorized to utilize a base cost of fuel of 26.955 mills per kWh and a net operating income of $517,594,000 in its FAC proceedings. For purposes of computing the authorized net operating income for Indiana Code 8-1-2-42(d)(3), the increased return shall be phased-in over the appropriate period of time that Petitioner's net operating income is affected by the earnings modification as a result of the Commission's approval of this Order. In addition, Duke Energy Indiana is authorized a permanent waiver of the purchased power benchmark requirements. The OUCC is granted a 35-day period to review Petitioner's FAC applications and to file OUCC testimony in such proceedings.

10. Duke Energy Indiana shall be, and hereby is, directed to participate in a collaborative process involving Commission Staff and other parties concerning performance metrics and the low-income issues, as provided in this Order.

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

<u>HUSTON, FREEMAN, KREVDA, OBER, AND ZIEGNER CONCUR</u>:

APPROVED:

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

**Mary M. Becerra
Secretary of the Commission**