ORIGINAL

Commissioner	Yes	No	Not Participating
Huston	√		
Freeman	√		
Krevda	√		
Ober	√		
Ziegner	√		

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** **APPROVED: JUN 29 2020**

ORDER OF THE COMMISSION

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

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INTRODUCTION

On July 2, 2019, Duke Energy Indiana, LLC ("Petitioner," "Company," or "DEI") filed a Verified Petition with the Indiana Utility Regulatory Commission ("Commission") seeking authority to increase its retail rates and charges for electric utility service and associated relief as discussed below. Also on July 2, 2019, DEI filed its case-in-chief and information required by the minimum standard filing requirements ("MSFRs") set forth at 170 IAC 1-5-1, as well as a motion for administrative notice that would be granted on July 18, 2019. DEI submitted public workpapers associated with its case-in-chief on July 10, 2019. DEI filed corrections to the direct testimony of witness Mosley on January 15, 2020, and to the direct testimony of witness Sieferman on January 21, 2020.

Petitions to Intervene were filed by Citizens Action Coalition of Indiana, Inc. ("CAC"), Nucor Steel-Indiana ("Nucor"), Steel Dynamics, Inc. ("SDI"), Duke Industrial Group ("Industrial Group" or "IG"), the Kroger Co. ("Kroger"), Sierra Club, Wabash Valley Power Association, Inc.

d/b/a Wabash Valley Power Alliance ("Wabash Valley"), Walmart Inc. ("Walmart"), the Indiana Community Action Association ("INCAA"), Environmental Working Group ("EWG"), The Department of the Navy, on behalf of the Federal Executive Agencies ("FEA"), Indiana Coal Council, Inc. ("ICC"), ChargePoint, Inc. ("ChargePoint"), Hoosier Energy Rural Electric Cooperative, Inc. ("Hoosier Energy"), Indiana Laborers District Council ("ILDC"), and Zeco Systems, Inc. d/b/a Greenlots ("Greenlots") (collectively, "Intervenors"). The Presiding Officers granted the petitions, and the Intervenors were made parties to this Cause.

On July 12, 2019, the Indiana Office of Utility Consumer Counselor ("OUCC") filed a motion for public field hearings in four cities, which the CAC joined. DEI filed a response on July 22, 2019, and the OUCC and CAC replied on July 26, 2019. The Presiding Officers issued a Docket Entry dated August 21, 2019, granting the motion and setting three field hearings. Pursuant to Indiana Code § 8-1-2-61(b), public hearings were held in Carmel on September 9, 2019, Terre Haute on September 23, 2019, and New Albany on October 1, 2019. At the field hearings, members of the public were afforded the opportunity to make statements to the Commission. The OUCC filed additional written consumer comments on October 30, 2019 and November 15, 2019.

On July 23, 2019, DEI, on behalf of itself and the OUCC, CAC, Industrial Group, Nucor, SDI and Kroger filed a Motion for Approval of Agreed Procedural Schedule in Lieu of Prehearing Conference. The motion provided that, at the request of the parties for more time to conduct discovery and to prepare their testimony and in recognition of holiday breaks, DEI consented to a schedule that goes beyond the 300-day schedule as specified in Indiana Code ch. 8-1-42.7, but DEI did not waive its right and ability to implement temporary rates and charges if the Order is not issued by July 1, 2020. On July 31, 2019, the Presiding Officers issued a Docket Entry that established a procedural schedule for this Cause consistent with the Motion for Approval of Agreed Procedural Schedule in Lieu of Prehearing Conference.

On September 9, 2019, DEI filed a Motion to Amend Verified Petition and submitted certain revisions to its case-in-chief testimony, exhibits, and workpapers. Also on September 9, 2019, DEI submitted revised MSFRs, and it subsequently submitted corrected revised MSFRs on September 26, 2019. On September 20, 2019, after receiving a two day extension of time in order to respond to DEI's Motion to Amend Verified Petition, CAC filed a Notice of Intent Not to Respond to Duke Energy's Motion to Amend Verified Petition. No party objected to DEI's Motion to Amend Verified Petition, and on September 26, 2019, the Presiding Officers issued a Docket Entry granting the Motion to Amend Verified Petition. DEI filed corrections to the revised testimony of witness Flick on January 15, 2020, and to the revised testimony of witnesses Pinegar and Douglas on January 21, 2020.

On October 11, 2019, DEI filed a Notice of Submission of Confidential Excel Spreadsheets in Native Format Replicating Petitioner's Cost of Service Studies. On October 15, 2019, the OUCC, CAC, EWG, INCAA, ILDC, Kroger, Sierra Club and Walmart ("Joint Movants") filed a Joint Motion to Amend Procedural Schedule and for Expedited Briefing, requesting, among other things, the Commission order DEI to refile its MSFRs, workpapers, exhibits and discovery responses, and extend the prefiling date of the OUCC and Intervenors by three weeks after DEI makes such prefilings. On October 16, 2019, Nucor and the Industrial Group filed joinders in support of the Joint Motion to Amend Procedural Schedule. The Presiding Officers issued an

October 18, 2019 Docket Entry granting the request to expedite the period for responding to the Joint Motion to Amend Procedural Schedule. On October 22, 2019, DEI filed its Response to the Joint Motion to Amend Procedural Schedule. On October 24, 2019, Joint Movants filed their joint reply in support of the Joint Motion to Amend Procedural Schedule.

The Presiding Officers denied the Joint Motion to Amend Procedural Schedule by Docket Entry dated October 28, 2019. The Presiding Officers reasoned that because the parties agreed to, and the Commission approved, a procedural schedule with a 360-day timeline, the Commission's General Administrative Order ("GAO") Guidance and MSFR rules basis for facilitating a 300 day schedule became moot. Additionally, although no party objected to DEI's Motion to Amend Verified Petition, over a month later and three months after DEI filed its case-in-chief, Joint Movants filed a delayed objection that did not comport with the additional time afforded on the front end of the agreed-upon procedural schedule. The Docket Entry also stated that although DEI made the Cost of Service Study Model available to the parties at its Plainfield office, it did not appear that any of the parties availed themselves of such opportunity.

On October 30, 2019, the OUCC, Industrial Group, Greenlots, FEA, Kroger, Walmart, Wabash Valley, CAC, EWG, INCAA (CAC, EWG and the INCAA are collectively referred to as the "Joint Intervenors"), Sierra Club, ChargePoint, and ILDC prefiled testimony consisting of their respective cases-in-chief. The OUCC filed workpapers on October 31, 2019; Walmart, Joint Intervenors, and Industrial Group filed workpapers on November 1, 2019; and Kroger filed workpapers on November 4, 2019. The OUCC filed revised direct testimony of witness Aguilar on January 3, 2020. The Industrial Group filed revised direct testimony of witness Gorman on November 4, 2019, and submitted corrections to the testimony of witnesses Gorman and Andrews, as well as corrected workpapers, on January 27, 2020 and January 28, 2020. Joint Intervenors submitted corrections on November 7, 2019, November 22, 2019, and December 11, 2019, while Sierra Club submitted corrections on November 8, 2019. Joint Intervenors submitted additional workpapers on November 12, 2019. FEA submitted workpapers on November 15, 2019.

On November 6, 2019, OUCC, CAC, EWG, INCAA, ILDC, Kroger, and Sierra Club, with the support of the Industrial Group, Nucor, and Walmart, filed a Verified Motion for Clarification and Appeal to the Full Commission of the Presiding Officers' October 28, 2019 Docket Entry Denying Motion to Amend Procedural Schedule. On November 12, 2019, DEI filed its Response to Joint Movants' Appeal to the Full Commission. Joint Movants filed their Joint Reply on November 18, 2019. On November 27, 2019, the Presiding Officers stated in a Docket Entry that the Commission, at its November 27, 2019 Conference, considered the Appeal to the Full Commission, and that the Commissioners approved the decision reached by the Presiding Officers.

On November 7, 2019, DEI filed a Motion to Prohibit Filing of Supplemental Testimony and to Strike Portions of Joint Intervenors' Testimony. Joint Intervenors filed their Response in Opposition to the Motion to Prohibit on November 18, 2019. DEI filed its Reply on November 25, 2019. The Presiding Officers, in a December 3, 2019 Docket Entry, denied DEI's motion.

On November 14, 2019, the Presiding Officers issued a Docket Entry that provided that DEI elected to file its case in accordance with the Commission's MSFRs, and that pursuant to 170 IAC 1-5-15(f), "the electing utility shall make available to the commission during normal business hours, on the electing utility's premises, a computer and all software used to create and store the information." The November 14, 2019 Docket Entry notified the parties the Commission's Advisory Staff would visit DEI's Plainfield offices for the purpose of utilizing the model on November 21, 2019. The OUCC and Joint Intervenors filed a Joint Notice to Attend on November 18, 2019. On November 21, 2019, Commission Advisory Staff and representatives for the OUCC and Joint Intervenors met with DEI representatives at DEI's Plainfield offices to review and utilize the model. Also, some parties joined by telephone.

On December 4, 2019, DEI filed its rebuttal testimony. Also on December 4, 2019, Joint Intervenors, Greenlots, ChargePoint, Industrial Group, and Kroger filed their respective cross-answering testimony.

On December 5, 2019, the Presiding Officers issued a Docket Entry removing two issues from the main proceeding pursuant to 170 IAC 1-1.1-21, and established subdocket proceedings in which to address the issues. Subdocket S1 was opened to address DEI's request for a certificate of public convenience and necessity ("CPCN") for estimated future federally mandated ash pond closure costs. Subdocket S2 was established to consider DEI's requested authority for an electric transportation pilot program.

On December 18, 2019, the Presiding Officers issued a Docket Entry requesting DEI respond to questions. DEI filed its responses thereto on December 31, 2019.

On December 18, 2019, DEI filed a Motion to Strike Certain Pre-Filed Cross Answering Testimony proffered by Joint Intervenors. Joint Intervenors filed their response on December 30, 2019, and DEI filed its reply on January 6, 2020. On January 13, 2020, the Presiding Officers issued a Docket Entry denying the Motion to Strike.

On December 27, 2019, Joint Intervenors filed a Motion to Certify for Interlocutory Appeal the Presiding Officers' October 28, 2019 Docket Entry and the Full Commission's related November 27, 2019 Order. On January 13, 2020, DEI filed its Response to the Motion to Certify for Interlocutory Appeal. On January 17, 2020, the Presiding Officers issued a Docket Entry denying the Motion to Certify for Interlocutory Appeal.

On January 15, 2020, the Presiding Officers issued a Docket Entry requesting DEI respond to certain questions. DEI provided its written responses on January 21, 2020. The Industrial Group filed a Response on January 28, 2020. DEI filed a Supplemental Response to the Commission's January 15, 2020 Docket Entry on January 28, 2020. The Industrial Group filed a Revised Response on February 6, 2020.

Pursuant to notice given and published as required by law, proof of which was incorporated into the record by reference and placed in the official files of the Commission, the Commission conducted an evidentiary hearing in this Cause from January 22, 2020 through January 24, 2020, and from January 29, 2020 through February 7, 2020. During the evidentiary hearing, DEI presented its case-in chief, the OUCC and Intervenors presented their respective cases-in-chief and cross-answering testimony, and DEI presented its rebuttal evidence.

The following witnesses provided testimony in this Cause:

For Petitioner:

- Stan C. Pinegar, President, DEI (revised direct and rebuttal);
- Brian P. Davey, Vice President, Rates and Regulatory Strategy, DEI (revised direct and rebuttal);
- Christopher M. Jacobi, Director, Regional Financial Forecasting, Duke Energy Business Services, LLC ("DEBS") (direct and rebuttal);
- Diana L. Douglas, Director, Rates and Regulatory Planning, DEI (revised direct and rebuttal);
- Suzanne E. Sieferman, Director, Rates and Regulatory Planning, DEI (direct and rebuttal);
- Christa L. Graft, Lead Rates & Regulatory Strategy Analyst, DEI (revised direct and rebuttal);
- Maria T. Diaz, Director, Rates and Regulatory Planning, DEI (revised direct and rebuttal);
- Jeffrey R. Bailey, Consultant (revised direct and rebuttal);
- Roger A. Flick, II, Rates and Regulatory Strategy Manager, DEI (revised direct and rebuttal);
- Daniel G. Hansen, Vice President, Christensen Associates Energy Consulting, LLC (direct and rebuttal);
- Robert B. Hevert, Partner, ScottMadden, Inc. (direct and rebuttal);
- John L. Sullivan, III, Director Corporate Finance and Assistant Treasurer, DEBS (revised direct and rebuttal);
- Jeffrey T. Kopp, Managing Director of the Utility Consulting Department, Burns & McDonnell Engineering Company, Inc. (direct and rebuttal);
- John J. Spanos, President, Gannett Fleming Valuation and Rate Consultants, LLC (direct and rebuttal);
- Keith B. Pike, Strategic Analytics Director – FHO, Duke Energy Carolinas, LLC (direct and rebuttal);
- Jeffrey R. Setser, Director of Allocations and Reporting, DEBS (direct and rebuttal);
- John R. Panizza, Director, Tax Operations, DEBS (direct);
- Renee H. Metzler, Managing Director, Total Rewards, DEBS (direct and rebuttal);
- James Michael Mosley, Vice President of Midwest Generation, DEBS (direct and rebuttal);
- Cecil T. Gurganus, Vice President for Edwardsport Generating Station, DEBS (direct and rebuttal);
- Timothy J. Thiemann, General Manager of Coal Combustion Products, DEBS (direct and rebuttal);
- Brett J. Phipps, Managing Director, Fuel Procurement, Duke Energy Progress, LLC (direct);
- John D. Swez, Managing Director, Trading and Dispatch, Duke Energy Carolinas, LLC (direct and rebuttal);
- Jonathan A. Landy, Director, Renewable Business Development, DEBS (direct and rebuttal);
- Timothy A. Abbott, Director of System Operations, DEBS (direct);
- Cicely M. Hart, Vice President – Customer Delivery Engineering, DEBS (direct and rebuttal);
- TK Christie, Director Distribution Vegetation Management, DEBS (direct and rebuttal);
- Donald L. Schneider, Jr., General Manager, Advanced Metering Infrastructure, DEBS (direct);
- Lesley G. Quick, Vice President Revenue Services, Duke Energy Carolinas, LLC (direct and rebuttal);
- Retha I. Hunsicker, Vice President Customer Connect-Solutions, DEBS (direct);
- Scott Park, Director IRP Analytics-Midwest, DEBS (rebuttal);
- Phillip O. Stillman, Director Load Forecast and Fundamentals, DEBS (rebuttal);

- Melissa B. Abernathy, Accounting Manager II, DEBS (rebuttal); and
- Owen R. Schwartz, Lead Environmental Specialist, DEBS (rebuttal).

For the OUCC:
- Michael D. Eckert, Assistant Director – Electric Division, OUCC (direct);
- Lane Kollen, Vice President and Principal, J. Kennedy and Associates, Inc. (direct);
- Cynthia M. Armstrong, Senior Utility Analyst – Electric Division, OUCC (direct);
- Wes R. Blakley, Senior Utility Analyst – Electric Division, OUCC (direct);
- Anthony A. Alvarez, Utility Analyst – Electric Division, OUCC (direct);
- Eric M. Hand, Utility Analyst – Electric Division, OUCC (direct);
- John E. Haselden, Senior Utility Analyst – Electric Division, OUCC (direct);
- Lauren M. Aguilar, Utility Analyst – Electric Division, OUCC (direct);
- Peter M. Boerger, PhD, Senior Utility Analyst – Electric Division, OUCC (direct);
- David E. Dismukes, PhD, Consulting Economist, Acadian Consulting Group, LLC (direct);
- David J. Garrett, Managing Member, Resolve Utility Consulting, PLLC (direct); and
- Glenn A. Watkins, President and Senior Economist, Technical Associates, Inc. (direct).

For the Industrial Group:
- Brian C. Andrews, Senior Consultant, Brubaker & Associates, Inc. (direct);
- James R. Dauphinais, Consultant/Managing Principal, Brubaker & Associates, Inc. (direct);
- Michael P. Gorman, Consultant/Managing Principal, Brubaker & Associates, Inc. (direct); and
- Nicholas Phillips, Jr., Consultant/Managing Principal, Brubaker & Associates, Inc. (direct and cross answering).

For the Joint Intervenors:
- Jonathan Wallach, Vice President, Resource Insight, Inc. (direct and cross-answering);
- David A. Schlissel, Schlissel Technical Consulting, Inc. (direct and cross-answering);
- John Howat, Senior Policy Analyst, National Consumer Law Center (direct); and
- Anna Sommer, Principal, Energy Futures Group (direct).

For FEA:
- Kevin W. O'Donnell, CFA, President, Nova Energy Consultants (direct).

For ILDC:
- David Frye, Business Manager, Indiana Laborers District Council (direct).

For Kroger:
- Justin Bieber, Senior Consultant, Energy Strategies, LLC (direct and cross-answering).

For Sierra Club:
- Tyler Comings, Senior Researcher, Applied Economics Clinic (direct).

For Wabash Valley:
- Frank J. Smardo, Executive Vice President-Energy Solutions, Wabash Valley (direct); and
- Lee R. Wilmes, Executive Vice President-Resource Portfolio and Risk, Wabash Valley (direct).

For Walmart:

- Steve W. Chriss, Director, Energy Services, Walmart (direct).

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

1. Notice and Jurisdiction. Due, legal and timely notice of all public hearings in this Cause were given and published as required by law. DEI is a public utility as defined in Indiana Code § 8-1-2-1(a) and is subject to the jurisdiction of the Commission in the manner and to the extent provided by the laws of the State of Indiana. Therefore, this Commission has jurisdiction over DEI and the subject matter of this proceeding.

2. Petitioner's Organization and Business. DEI is an Indiana limited liability corporation with its principal office in the Town of Plainfield, Hendricks County, Indiana. DEI is engaged in the business of generating and supplying electric utility service to approximately 840,000 customers located in 69 counties in the central, north central and southern parts of the State of Indiana. DEI is a second tier wholly-owned subsidiary of Duke Energy Corporation.

DEI provides electric utility service to the public by means of electric utility plant, properties, equipment and facilities owned, operated, managed and controlled by it, which are used and useful for the convenience of the public in the production, transmission, distribution and furnishing of electric utility service to the public in the State of Indiana. DEI supplies steam service to one customer from its Cayuga Generating Station. DEI also sells electric energy for resale to municipal utilities, Wabash Valley, Indiana Municipal Power Agency ("IMPA"), Hoosier Energy, and to other public utilities that in turn supply electric utility service to numerous customers in areas not served directly by DEI.

3. Existing Rates. DEI's existing retail base rates were established pursuant to the Commission's May 18, 2004 Order in Cause No. 42359. Those base rates and charges remain in effect today, as modified for the Commission's August 22, 2018 Order in Cause No. 45032 S2 to reduce the federal income tax rate included in base rates to reflect lower tax rates resulting from the 2017 Tax Cuts and Jobs Act, and as modified by various riders approved by the Commission from time to time. Therefore, in accordance with Indiana Code § 8-1-2-42(a), more than fifteen months have passed since the filing of its last base rate case to the filing of this base rate case. Additionally, in accordance with Indiana Code § 8-1-39-9, DEI initiated this proceeding for a change in its basic rates and charges prior to the expiration of its currently approved Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") Plan under Commission Cause No. 44720, which ends December 31, 2022.

4. Test Year and DEI Forecast. As authorized by Indiana Code § 8-1-2-42.7(d), DEI proposed a forward-looking test period using projected data. Consistent with the Prehearing Conference Order, the test year to be used for determining DEI's projected operating revenues, expenses and operating income is the 12-month period ending December 31, 2020 ("Test Year"). The historical base period is the 12-month period ended December 31, 2018.

5. **Petitioner's Rate Base.** DEI's proposed forecasted jurisdictional net original cost rate base, with the Company's rebuttal testimony adjustments, as $10.195 billion at December 31, 2020. The Company's proposed rate base includes utility plant-in-service, materials and supplies ("M&S"), fuel and emission allowance inventories, regulatory assets and liabilities, and a prepaid pension asset.

Aspects of the Company's rate base were challenged in this proceeding by the OUCC and certain intervenors, relating to the Company's solar and battery storage projects; the Gallagher Station units to be retired in a few years; the Company's capital-related vegetation management investments; the Company's levels of fuel inventory and M&S inventory balances; the prepaid pension asset; regulatory assets related to the prior retirement of other Gallagher Station units and certain Wabash River Station generating units; and regulatory assets related to the Company's coal ash basin closure and remediation activities. In addition, while no party specifically proposed that the Edwardsport IGCC Plant be excluded from the Company's rate base, certain parties made proposals related to the Edwardsport IGCC Plant that have rate base implications, and those rate base implications are discussed in this section of the Order. Other issues raised about the ongoing operation of the Edwardsport IGCC Plant are addressed later in this Order.

With regard to the undisputed rate base items, we find the Company has adequately demonstrated that its forecasted end of test period utility plant in service is or will be in service and used and useful in providing utility service to retail customers, and other items of rate base are reasonable. Accordingly, we find such undisputed rate base items should be reflected in retail rates approved in this proceeding, subject to the removal of capital costs related to the Company's proposed electric vehicle pilot which is now being addressed separately in Cause No. 45253 S2 established pursuant to our December 5, 2019, docket entry and subject to the Company's post-Order demonstration that all applicable utility plant is actually in service prior to being included in Step 1 or Step 2 rates.

a. **Utility Plant in Service – Edwardsport IGCC Plant.** DEI witnesses Gurganus and Douglas testified the Edwardsport plant went into service in June 2013 and has been and continues to be in service and used and useful in providing service to the Company's customers. Company witness Douglas testified the Company has included $2.651 billion of total company original cost investment for the IGCC facility at Edwardsport, less the forecasted accumulated depreciation reserve as of December 31, 2020. She explained the Commission's December 27, 2012 Order in Cause No. 43114 IGCC 4S1 ("IGCC 4S1") established the estimated $2.595 billion Hard Cost Cap amount at June 30, 2012, and the parameters for determining the additional allowance for funds used during construction ("AFUDC") that could be added to the actual amount as of June 30, 2012, until the facility was in-service. The final Hard Cost Cap amount of $2.651 billion was approved in the Commission's August 24, 2016 Order in Consolidated Cause No. 43114 IGCC 15 ("IGCC 15"). In addition, DEI made a *pro forma* adjustment to remove the net book value of the Ongoing Capital investment from April 2015 through December 2017 that exceeded the Ongoing Capital cap amounts approved in the Commission's IGCC 15 Order.

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 the return 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. The basis for his recommendation is the "declining IGCC cost curve" and the magnitude of the IGCC plant amount included in rate base.

Company witness Davey disagreed with Mr. Kollen's recommendation that Edwardsport essentially continue to be included in a rider, rather than included in base rates. Mr. Davey emphasized that while the legislature provided for the ability to recover costs associated with gasification projects in rates through a rider mechanism, the Company and the settling parties agreed in both the original IGCC settlement agreement approved in IGCC 4S1 and the terms of a settlement agreement approved by the Commission's June 5, 2019 final Order in Cause No. 43114 IGCC-17 ("IGCC-17") that when the Company had a base rate case, Edwardsport would be included in base rates, which is what the Company has proposed and is consistent with how other capital riders have been treated in the past during a base rate case. Mr. Davey also voiced concern with Mr. Kollen's recommendation that the only portion of Edwardsport that should be included in the rider is the declining balance of rate base, and crediting of tax credits, but no other costs such as O&M and new additional capital needed to operate the plant. Mr. Davey concluded that the costs associated with Edwardsport should be included in base rates and in rate base, as proposed by the Company.

Company witness Douglas also testified in rebuttal to Mr. Kollen's proposal. She noted that under the Company's proposal, the Company continues to receive the revenue requirement built into base rates for return, depreciation, and O&M, including items like property tax and property insurance. The fixed return level, along with any growth in sales, serves to help fund any increases in O&M costs due to external influences like inflation, labor shortages, and commodity price increases, as well as additional capital additions or capital maintenance required between rate cases. In contrast, she stated Mr. Kollen's proposal would give customers the benefit of declining rate base without having to fund additional capital additions, which are meant to be offsetting. She noted the customers would be protected from price increases due to cost increases until the next base rate case under either the Company's proposal or Mr. Kollen's proposal, but the Company's ability to manage cost increases and earn a fair return until then would be impaired under Mr. Kollen's proposal. She concluded the OUCC has not put forth a compelling reason to deviate from standard ratemaking practice for Edwardsport and instead the OUCC proposes continued one-way (downward only) tracking for return while continuing to leave other cost recovery at the flat level of amounts embedded in base rates. She opined the more reasonable, fair and balanced approach is the traditional handling of previously tracked plant that has been used historically in Indiana for DEI and other utilities.

She also noted the Company committed in Settlement Agreements in IGCC 4S1 and IGCC 17 that in the next rate case, DEI would propose to eliminate the tracking of plant via the IGCC Rider and include the plant in rate base, while ensuring customers receive the full benefit of related tax benefits.

i. **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.

Indiana Code § 8-1-8.5-6.5 provides that a utility with a certificated plant is entitled to recover in rate base the approved costs of plant absent any showing of fraud, concealment, or gross mismanagement. The Commission considered this later aspect of the statute in Cause No. 43114-IGCC 4S1 and found the burden of proof with regard to these elements had not been met (at p. 115 of that order).

Indiana Code § 8-1-8.5-6.5 allows a utility with a CPCN to recover a "return of" and a "return on" its plant investment, up to the approved cost estimate. DEI's proposal is consistent with this statute. The OUCC's proposal, by periodically adjusting rates to eliminate a portion of the return on the plant from rate recovery, is not. Therefore, we reject the OUCC's proposal to track and periodically adjust rates for only one aspect of the Edwardsport Plant's costs, the return on the Plant's declining balance. We find that the proposal set forth by DEI is reasonable, consistent with Indiana law and the IGCC 4S1 and IGCC 17 Settlement Agreements, and supported by the evidence, and we approve it.

b. **Utility Plant in Service – Solar and Battery Storage Projects.** DEI witness Landy testified with respect to the Company's solar generation assets, battery storage projects, and microgrid projects, as well as new generation resources capital expenditure changes from 2018-2020. Specifically, Mr. Landy's testimony discussed the Crane Solar Project, the Crane Battery Storage Project, the Camp Atterbury Microgrid, the Nabb Battery Storage Projects, the Tippecanoe Solar Power Plant, and the B-Line Heights Solar Power Plant.

He explained that the Crane Solar Project, which was granted a CPCN in Cause No. 44734, is a 17.25 MW AC solar generation plant located at the NSA Crane base near Bloomington, Indiana. He testified the Crane facility was placed into service in late January 2017 and is generating power to the grid. He stated the facility interconnects to DEI's 69 kV transmission line and is bid into MISO in the same way as other DEI-owned generation. He noted the facility is commercially operational and is performing as DEI anticipated, providing clean energy to the Company's customers.

He explained that in lieu of a cash payment for the site lease, DEI agreed to study the feasibility of incorporating future grid-tied energy storage technologies for the purpose of maintaining electric services for critical loads. He stated this feasibility study was completed in August 2018. He testified that the Feasibility Study serves as a guide for DEI and the Department of the Navy to develop a project plan to support additional energy infrastructure at NSA Crane, which will provide both bulk system and local reliability benefits. He stated the Feasibility Study identified new load shedding infrastructure, generation and storage assets, and control and communications infrastructure required to meet the study team's goals and objectives. He noted 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 MW Crane Solar Facility owned by DEI, discussed above; (2) a new battery energy storage system ("BESS"); and (3) new diesel generators.

Mr. Landy explained that through coordination with Crane and the U.S. Navy, DEI plans to install a 5 MW BESS on-base that will support the bulk power system and enable microgrid capabilities, thus enhancing energy resiliency for Crane. He testified the BESS will be a regulated grid-asset owned and operated by DEI, similar to the 17 MW solar facility on-base. He stated the BESS will be located within the existing solar lease footprint, thus reducing project costs. He noted this project will enhance reliability of service for customers and provide ancillary services, such as Regulating Reserves, to MISO. In return for the lease with the Navy for the land necessary to construct the project, he stated the Navy will be able to access the existing solar facility and new battery (Microgrid) during a catastrophic, regional grid event. He testified that during an event in which energy produced by the solar array and the battery services cannot be transmitted to the commercial grid, the Microgrid can provide backup power to critical customer loads on the base. He stated that Crane will continue to pay for service through its standard tariff rate whether the assets are grid-tied or in island-mode. He testified that revenues realized by DEI for providing such ancillary services to MISO will benefit DEI customers; like other Company-owned generation and battery storage, revenues received from MISO for the Crane Battery, net of any related MISO costs or energy purchases, would flow back to customers through an appropriate rate adjustment mechanism. Further, he stated any Investment Tax Credit ("ITC") value that DEI receives from its investment in the project will benefit customers by reducing revenue requirements over the depreciable life of the property. He testified DEI expects construction of the Crane BESS to begin in June 2020 and the Crane BESS to be placed in service in December 2020 at an overall estimated cost of $10 million.

Mr. Landy next addressed the Camp Atterbury Microgrid and the Nabb Battery Storage Projects. He testified that, in Cause No. 45002, the Commission approved both the Camp Atterbury Microgrid and Nabb Battery Storage Projects ("Projects") as clean energy projects eligible for incentives under Indiana Code § 8-1-8.8-11. As such, the Commission approved, among other things: (1) timely recovery of construction and operating expenses via Rider 73; (2) deferral of costs associated with the Projects until such costs are reflected in Petitioner's retail rates and charges; and (3) approval of depreciation rates for the Projects until such time as a new depreciation rate supported by a depreciation study is approved by the Commission. He further stated the Commission found that any future REC proceeds and ITCs should be used to reduce the total Rider 73 revenue requirements.

With regard to the Camp Atterbury Microgrid Project, Mr. Landy testified that after a request for proposal ("RFP") process, DEI began construction of the Camp Atterbury Microgrid in March 2019. He testified DEI expected the Camp Atterbury Microgrid to be placed-in-service in October 2019. With regard to the Nabb Battery Storage Project, Mr. Landy testified that DEI began construction in June 2019, after an RFP process. The Company expected the Nabb Battery Storage Project to be placed in service in November 2019.

Mr. Landy also testified about DEI's plans to construct a 1.6 MW-AC solar plant at Purdue Research Foundation's Discovery Park District in West Lafayette. He stated this Tippecanoe Solar Power Plant distributed energy project will provide DEI customers clean, renewable energy while supporting the economic development and sustainability goals of the Discovery Park. He added that this solar project will set the stage for sustainable land use developments at Discovery Park while diversifying DEI's fuel mix with an emission-free, 100% renewable energy generation resource. He testified the plant will interconnect to a 12.47 kV distribution line. He testified that DEI expected construction of the Tippecanoe Solar Power Plant to begin in July 2019 and expected it to be placed in service by December 31, 2019. Currently, the overall estimate is approximately $3.5 million (exclusive of AFUDC).

Mr. Landy also discussed DEI's plans to construct a 112 kW-AC solar canopy at the B-Line Heights Apartments, an affordable housing complex in Bloomington; the distributed energy project will provide DEI customers with clean, renewable energy. He testified that DEI began construction of the B-Line Heights Solar Power Plant in June 2019, and expected the B-Line Heights Solar Power Plant to be placed-in-service by October 2019. He stated the project's location in Bloomington, Indiana helps demonstrate DEI's commitment to identifying innovative ways to support renewable energy generation in more densely populated urban areas and supports Bloomington's renewable and affordable housing goals. He testified the current cost estimate for this project is approximately $470,000 (exclusive of AFUDC).

No party objected to the Crane Solar Project, the Camp Atterbury Microgrid Project, or the Nabb Battery Storage Project. OUCC witnesses Alvarez and Haselden, however, testified in opposition to inclusion of the Crane 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 he believes that: (1) the Crane Microgrid 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. 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 DEI.

Mr. Landy testified in rebuttal to the OUCC about these projects. With respect to the Crane BESS Project, Mr. Landy first explained that the Company is only seeking to recover the proposed BESS - as recommended in the Feasibility Study - during this proceeding. Any additional investments recommended in the study will be funded separately and are not included in the project cost estimate provided in the Company's direct testimony. With regard to Mr. Alvarez's contention that the Crane Microgrid is not a "real" microgrid, Mr. Landy agreed that there are various definitions that can create confusion, but he emphasized the common theme and most important characteristic for microgrids is their ability regardless of level of automation, to intentionally disconnect from and reconnect to the bulk electric system while still maintaining a specified level of electric service to the targeted area. He noted this is also referred to as "islanding" from the grid. He stated that the Crane Microgrid includes all of these components, including: a group of interconnected loads, multiple distributed energy resources, a well-defined boundary, multiple types of distributed energy resources and loads that can act as a single controllable entity with respect to the grid when coordinated properly by multiple asset owners, and the ability to island from the bulk electric system. He stated that DEI will own, control, and operate the existing solar array and the energy storage assets, as well as all transmission-level delivery and protection and control equipment required – all significant components of the Crane Microgrid – while NSA Crane owns the distribution system. He noted that having multiple owners is common throughout the industry; for example, the Camp Atterbury Microgrid, currently under construction and approved in Cause No. 45002, includes multiple owners.

Mr. Landy disputed Mr. Alvarez's contention that the project will not enhance reliability of service to the Company's customers, testifying that, along with maintaining electrical service to NSA Crane's critical loads during a regional outage event, the battery will also enable DEI to intentionally island the Naval base's load, thus reducing the base's reliance on the bulk electric system to prevent customer outages during emergency situations when there are capacity issues. Mr. Landy also disputed Mr. Alvarez's claim that the battery portion of the project will not be dispatched by MISO. He testified that the battery will be qualified as a MISO resource just like the Company's other generation and storage assets, such as the batteries at Camp Atterbury and Nabb. Further, Mr. Landy stated that the battery will provide ancillary services and be compensated by MISO for those services. More specifically, he explained that it is anticipated the project will be classified as a Stored Energy Resource, capable of supplying regulating reserves in the MISO Energy and Operating Reserve markets. He added that experience with projects like this one will help the industry better understand the opportunities and challenges of including battery storage devices in the MISO transmission planning processes. Mr. Landy next addressed Mr. Alvarez's argument that the battery project will not benefit Crane when it is operated in grid-tied mode. Mr. Landy responded that this is incorrect; benefits from the battery, including MISO revenues, will flow to retail customers including Crane through the Company's Fuel Adjustment Clause ("FAC") and Regional Transmission Organization ("RTO") riders when grid-tied, similar to other generation and storage assets.

With respect to Mr. Alvarez's claim that there will be no "lessons learned" from this project, Mr. Landy testified that lessons learned from this project will be unique given the interconnection to the transmission system, the MISO generation interconnection application process, multiple owners of the infrastructure within the microgrid, and coupling with existing solar versus new solar facilities. He noted that the Nabb and Camp Atterbury projects are different, in that they are interconnected with the distribution system. He further noted that siting this project allows the Company to leverage existing interconnection capacity and land availability to deploy a transmission-tied battery at a relatively low cost and impact to customers.

With regard to Mr. Alvarez's concern that the battery might explode, Mr. Landy responded that the Company is well-aware of the inherent risks associated with delivering energy to its customers and communities; this is why modest investments in alternative technologies are critical for continuing to provide service that is not only safe but also affordable, reliable, and increasingly clean. He pointed out that worldwide manufacturing capacity for lithium-ion batteries now stands at 302.2 gigawatt-hours ("GWh"), plants with another 603.8 GWh are planned to open within the next five years, and stationary storage investments in the United States continue to grow. He emphasized that market participants continue to develop and implement best-in-class safety standards to support growing customer demands. Further, Mr. Landy noted the battery energy storage system referenced by Mr. Alvarez in Paradise, Arizona is a battery system that utilizes different manufacturers and integration methods than what DEI uses at its batteries currently under construction and will use at Crane. He stated that all DEI BESS installations will be equipped with both fire prevention and detection equipment as well as physical barriers where needed, going above and beyond the basic safety requirements. Further, he testified the Company continues to engage with fire safety experts and utility peers to be certain the equipment used in its battery energy storage systems is the safest commercially available in the market today.

Mr. Landy next addressed Mr. Alvarez's statement that DEI had not secured corporate management approval for the project. He explained the Company decided to request corporate funding approval for the BESS project after receiving MISO feedback about grid interconnection feasibility. Those MISO study results were not available at the time of the rate case filing, but Mr. Landy testified that recent preliminary results suggest the project can interconnect as planned. He explained that, as a result, DEI plans to request corporate funding approval by early 2020 in support of a 4th quarter 2020 in-service date. He further noted the BESS project is included in the Company's capital plan and highlighted in other key corporate planning documents, including the Company's recent integrated resource plan ("IRP"); the project was included in multiple IRP scenarios and is aligned with the feedback received during several stakeholder workshops; and the Company's plan to deploy a 5 MW battery in 2020 is clear.

Mr. Landy also addressed Mr. Alvarez's allegation that the proposed Crane Microgrid is "faced with no actual quantifiable operational benefits or prospective revenues to offset costs" and is a "bad deal" for customers. He reiterated there are both operational benefits and prospective revenues associated with the proposed project. He noted that lessons learned from this moderate investment will prove valuable as the Company considers much larger transmission-tied battery projects in the future, where costs are significantly increased for projects that may approach several hundred megawatts. He also stated that it should not be overlooked that enhancing the reliability of service to NSA Crane also enhances national security, benefiting all DEI customers.

With regard to Mr. Haselden's testimony that the Tippecanoe and B-Line projects are small, expensive projects that primarily benefit specific localized customers, Mr. Landy responded first by noting these projects will be connected to the Company's distribution system and will reduce the amount of DEI load, directly serving a portion of customer demand. By doing so, the additional solar generation will offset other sources of energy that would have been allocated to serve native load, either generation operated by the Company or energy purchased to meet native load requirements. Further, he stated any Solar Renewable Energy Credits ("RECs") created by the projects will be sold in the market and any net proceeds received will be flowed back to customers. Additionally, he noted these investments are quite small, with a modest rate impact to customers. He pointed out Mr. Haselden chose to look at these projects only on a levelized cost of energy basis, which makes them look less cost-effective than a larger, utility scale solar project that would encumber a significant amount of rural land or a natural gas combined cycle project. He stated that, as with the proposed Crane Battery, these are modest investments made with an eye toward partnering with customers, diversifying the Company's generation portfolio, and increasing investment in distributed generation. He noted that the B-Line Solar project is the Company's first distributed energy project investment on a customer site that creatively utilizes a parking lot to generate energy in an urban location.

Mr. Landy next addressed Mr. Haselden's contention that these two projects do little to help the Company take incremental steps toward providing customers with clean renewable energy and diversifying its generation portfolio – no more than would a single solar panel. Mr. Landy stated that, with these two projects, DEI is proposing to build more than one megawatt of solar and will be able to power more than 180 homes with its Tippecanoe and B-Line solar projects. Further, he testified that investments such as the Tippecanoe and B-Line solar projects are exactly the type of smaller steps that are appreciated by the majority of customers as the Company plans to transition Indiana's generation mix steadily over time to rely less on coal, and more on cleaner means of producing electricity. He noted that DEI in recent years has invested in its first utility scale solar project at NSA Crane, refurbished its Markland Hydroelectric Facility, making it more efficient and allowing it to run another 60 years, and proposed three new battery energy storage systems. He noted that, as the Company's older coal-fired assets begin to retire over the next twenty years, the Company will be faced with decisions on how to replace those assets. He stated that smaller investments in batteries and solar now will help the Company and its stakeholders make those larger decisions in the near future.

With respect to Mr. Haselden's argument that these investments were only done for "image building purposes," Mr. Landy responded that working with customers on these types of projects and developing generating assets that provide capacity and energy to the grid to benefit all Indiana customers (even if small distributed renewable assets) are far from image building – they are the core of the Company's business.

Mr. Landy next responded to Mr. Haselden's complaint that DEI cannot yet take advantage of the federal ITC for solar projects due to its current tax position. He explained that while DEI is not currently able to utilize ITCs on these renewable projects, the Company forecasts it will be in a tax position to begin utilizing the credits as early as 2025. He explained that solar ITCs have a 20-year carryforward, which means the Company has 20 years from the initial year the ITC is earned to be able to utilize it. Further, he stated the Company will share the full ITC benefits with customers over the lives of the associated renewable projects, as soon as the Company can utilize the ITCs. He explained the delay essentially results in customers receiving the same amount of benefit but over a shorter period of time beginning when the Company can first utilize the ITC and stopping at the end of the useful life of the asset.

With regard to Mr. Haselden's comparison of the levelized cost of energy of these two projects to utility scale solar projects, Mr. Landy noted that levelized cost of ownership excludes any comparison to the specific generation resource's benefits, size, or operational characteristics. He stated that utility-scale solar projects are simply different types of projects than the Tippecanoe or B-Line solar projects; the projects with those lower levelized cost of energy numbers are much larger in scale, transmission connected, and typically sited in more rural areas that encompass large tracts of land (often hundreds of acres). In contrast, he stated that the Tippecanoe and B-Line solar projects are examples of distributed energy projects that are tied to distribution lines in more developed, suburban/urban locations. He testified that these facilities, while smaller in scale, utilize less land, are sited closer to customer load, and assist in providing all DEI customers clean, renewable energy.

Mr. Landy next addressed Mr. Haselden's complaint that the Tippecanoe Solar Plant Project does not have the most efficient panel design. He testified that all solar projects are designed based on site characteristics, production assumptions, and financial cost. He explained that, for the Tippecanoe Solar Project, a fixed tilt solar array was selected in the design primarily due to site characteristics and cost. Furthermore, the site is relatively small and has a triangular shape with curved sides. He noted that tracking systems, in contrast, require more rectangular shaped areas to be constructed and operated efficiently. He also noted that the construction costs of tracking systems increase significantly for smaller capacity systems while fixed tilt systems tend to scale more effectively – and tracking systems are complex and require more frequent maintenance and additional training for personnel. He stated that given these conditions, this project would not see a significant net benefit from a tracking system.

Mr. Landy also addressed Mr. Haselden's contention that the land lease for the Tippecanoe Solar Project was for undevelopable land, making this lease a poor deal for customers and a good deal for the Purdue Research Foundation. Mr. Landy explained this site is suitable for a small solar site as it does not require parking, permanent access roads, or other infrastructure. Further, it is flat, was relatively easy to interconnect, was free of significant vegetation, had minimal environmental constraints, and has limited public access that makes it suitable for solar development. He stated that whether the site is "non-developable" from a commercial real estate perspective is of no consequence; the site is ideally suited for small scale solar development. He rejected the notion that the Purdue Research Foundation is receiving a windfall for this site, stating that similar to the B-Line project, this project is a true public/private partnership that supports the Foundation's mission of supporting discovery and learning at Purdue University, benefits all of DEI's customers in advancing green, sustainable energy on an underutilized property, and provides access to data from an active, local solar generation facility for research purposes. Finally, he noted the annual lease payment for this site is nominal.

Regarding Mr. Haselden's argument that there is nothing innovative about the proposed B-Line Project, Mr. Landy testified that while the technology of a solar canopy is not innovative on its own merit in terms of it being considered an emerging technology, the innovation is in the collaborative working environment and public/private partnership between the City, Pedcor (the affordable housing developer), and DEI to find creative ways to add solar in an urban area by utilizing an affordable housing location for solar with grid benefits.

i. <u>Commission Discussion and Findings</u>. The evidence of record demonstrates that these projects are reasonable investments in clean energy resources that will provide benefits to the DEI system and customers with modest rate impacts. Further, we find that these projects will provide the Company and customers with valuable information and experience, as the Company begins to transition its resource portfolio to the use of more renewable energy and storage resources, many of which will likely be sited on or adjacent to customer sites.

Additionally, these projects will 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, a portfolio that currently contains relatively minimal amounts of solar 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: "[t]he 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: "[i]t 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, and to earn financial incentives if the utility meets its portfolio goals. The projects proposed by the Company are consistent with these state policies as pronounced by the General Assembly.

In addition to these statutory provisions, we previously have recognized the importance of fuel diversity generally, with respect to generation portfolios, and recognized the benefits of local renewable resources, in particular. Recently, in *Verified Petition of Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc*., Cause No. 45086 (IURC; March 20, 2019), we stated:

> We continue to believe fuel diversity and the addition of local renewable resources is important to protect electric utilities and their customers from contingencies such as fuel price fluctuations, and changes in regulatory practices that can drive up the cost of a particular fuel (e.g., environmental regulations). Fuel diversity also can help ensure stability and reliability of electricity supply and can strengthen national security. We would note that in 2011, the Indiana General Assembly created a voluntary clean energy portfolio standard that set a target of producing 7% of the state utilities' electricity supply from clean energy sources by 2019, with the share increasing to 10% by 2025. Approval of the Solar Project allows Petitioner to get closer to the foregoing targets.

Therefore, based on the evidence presented, we find these solar and battery energy storage projects (Crane Solar, Crane BESS, Camp Atterbury Microgrid, Nabb Battery, Tippecanoe Solar and B-Line Heights Solar) will provide operational, reliability, revenue, and experiential benefits to the DEI system and customers, and will further diversify the Company's resource portfolio. Accordingly, we conclude that these projects are reasonable, qualify as clean energy projects, and will be used and useful in providing electric utility service to customers. As such, the investment in these projects should be recoverable through Petitioner's rates. We note that these projects are reasonable and necessary and therefore also eligible for incentives under Indiana Code 8-1-8.8-11, and as such, in the event the projects are not placed in service and included in rate base by the end of the forecasted test period of 2020, such projects are approved for recovery in the Company's Renewable Rider pursuant to Indiana Code 8-1-8.8-11(a)(1) provisions allowing timely recovery of renewable projects.

c. <u>Utility Plant in Service – Gallagher Units 2 and 4</u>. Company witness Douglas testified that the Company has included in its proposed rate base the forecasted balance of the net book value of the utility plant for the two remaining Gallagher Station Units 2 and 4, which the Company is committed either to retire or cease burning coal by December 31, 2022, pursuant to the settlement agreement approved by Commission's IGCC 15 Order. She noted the IGCC 15 Order specified that ratemaking for the retirement of Gallagher Station Units 2 and 4 will be consistent with normal retirement accounting. She explained that, under generally accepted accounting principles ("GAAP"), retirements of equipment that are considered "normal" retirements are accounted for by crediting plant accounts and debiting accumulated depreciation for the original cost of the equipment. In other words, the values of both the investment and its related accumulated depreciation are reduced by the original cost of the equipment that has been retired. If costs are required to dismantle, decommission, or otherwise remove the plant and equipment upon retirement ("cost of removal"), these costs are debited to accumulated depreciation. She stated that it is standard practice for Indiana electric utilities to include an estimate for the cost of removal in depreciation studies, so that by the time the asset is retired, both the cost of the asset and estimated cost of removal have been recovered from customers who have benefitted from the service of that asset.

OUCC witness Kollen recommends the Commission require the Company to reclassify the net book value of Gallagher Units 2 and 4 to a regulatory asset at June 30, 2020, rather than leaving the asset in net plant and depreciating it over the remaining life of the units using traditional Indiana ratemaking for plant assets. Further, he recommends that when the amortization is over, both the recovery of and return on the asset that is included in the 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.

Ms. Douglas responded to Mr. Kollen's recommendation. She testified that the Company's proposed rate base treatment for Gallagher Units 2 and 4 is consistent with traditional Indiana ratemaking for other used and useful plant providing service to customers during the test year and should be approved. She stated there is no reason to deviate from standard ratemaking practice and require the use of a regulatory asset for the Gallagher Units 2 and 4 currently included in the Company's plant accounts because they are currently used and useful plant and will remain so during the test period. She noted their retirement can be accounted for as a normal retirement, with the remaining net book value at time of retirement left in net plant, under the Company's proposed ratemaking treatment (including the December 31, 2022 retirement dates for the units when developing depreciation rates). However, she also stated that, given the unusual circumstances of knowing at the time of the rate case that Gallagher Units 2 and 4 will be retiring by the end of 2022, the Company commits to credit customers for the depreciation expense associated with the Units via Rider 67 beginning January 1, 2023.

Ms. Douglas also addressed Mr. Kollen's proposal to credit customers with non-fuel O&M savings once Gallagher Units 2 and 4 are retired. She testified that this proposal is inconsistent with traditional ratemaking, which recognizes that many cost items change between rate cases. She stated that it would be inappropriate to effectively track this one downward change in one plant's O&M costs, while ignoring other potential O&M and capital cost increases, which are not taken into account in rates between rate cases.

i. Commission Discussion and Findings. The evidence demonstrates that Gallagher Units 2 and 4 remain in service and used and useful, and are expected to remain in service and used and useful throughout the forecasted test period. The evidence further demonstrates that for accounting purposes, the retirement of Gallagher Units 2 and 4 will be treated as a normal, not an accelerated, retirement. For these reasons, we agree with the Company that Gallagher Units 2 and 4 should remain in rate base, and no regulatory asset should be created as proposed by the OUCC. We also agree with the Company that rates should not be adjusted, in the absence of another base rate case, to reflect a reduction in O&M costs once the Units are retired. The Company is correct that under traditional ratemaking for plant retirements, such adjustments are not made. Rather, traditional ratemaking assumes that the utility must manage many cost increases and capital additions between rate cases that cannot be recovered through rate adjustment mechanisms, and cost reductions that may occur between rate cases are used to fund such cost increases and capital additions. We do, however, accept the Company's proposal to credit customers with the depreciation expense built into base rates for these Units, via Rider 67, once the Units are retired.

d. Utility Plant in Service – Capital-Related Vegetation Management Investments. Mr. Christie described the Company is engaged in a Hazard Tree Removal Program ("HTRP") that will remove trees that pose a potential danger to DEI's distribution system and provided the associated forecasted 2020 capital costs in the amount of $30 million for the HTRP. Mr. Abbott further testified that the Emerald Ash Borer ("EAB") had killed millions of ash trees in North America and was now present in all 92 Indiana counties. Mr. Abbott discussed that in 2018 the Company had created the Indiana EAB Program to focus on ash trees along the 69 kV and 138 kV transmission lines and stated the Company forecasted $6.7 million in 2020 capital expenditures associated with its EAB Program. Messrs. Christie and Abbott discussed the importance of both the HTRP and EAB programs that address damaged and dying trees to system reliability.

OUCC witness Mr. Hand recommended the Commission set the Company's capitalization of the HTRP for its distribution system at $5 million for the test year. Mr. Hand further recommended the Commission deny the Company's test year capitalized transmission system HTRP costs that are attributable to the EAB Program. 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. Christie described the benefits of both the HTRP and the EAB programs on system reliability. Mr. Christie also responded to Mr. Hand's contention that the Company has not demonstrated that its HTRP, including the removal of all trees infested with the EAB, will be as effective at reducing outages as more traditional routine vegetation management practices. Mr. Christie stated that the Company has identified approximately 45,000 hazard trees that are outside of its maintained right of way from late 2018 through 2019. He stated that reducing the capital costs associated with HTRP to Mr. Hand's recommendation of $5 million/year is unacceptable given the number of dead, dying, and diseased trees requiring removal within striking distance of the Company's electric facilities. Mr. Christie stated it would be short-sighted for the Company to not remove trees identified as being infested with the emerald ash borer before they become a problem to the system.

Ms. Graft testified that the capital expenditures included in the forecasted test period are appropriate for recovery in rate base under traditional ratemaking concepts and that it is unreasonable to arbitrarily remove capital expenditures from rate base when such expenditures provide clear benefits to customers. DEI presented evidence supporting the benefits of the HTRP and EAB Program. Mr. Christie further testified that the Company performed an outage system follow up investigation of distribution outages in Indiana in 2018, which revealed that that 71.4% of the vegetation outages reviewed in Indiana were caused by tree failures from outside the right of way. Trees that are dead, dying or diseased are at increased risk of making contact with distribution and transmission lines.

i. Commission Discussion and Findings. We find that Petitioner has demonstrated the value of its HTRP and EAB programs on system reliability. Further, because they are capital expenditures their inclusion in rate base will be dependent upon timely execution by the conclusion of the test year, providing both near term and ongoing reliability improvement. Accordingly, we find that the Company's HTRP and EAB Program capital expenditures represent a reasonable proactive approach to reducing outages caused by trees and if undertaken in the test year as proposed by Petitioner should be included in rate base. If the cost is not incurred in the test year, then the capital cost is not included in the rate base for this case.

e. Fuel Inventory. Mr. Phipps testified concerning DEI's fuel procurement strategy for its generating units. Among other things, Mr. Phipps testified concerning the Company's coal inventory. He stated that DEI manages to a target inventory of approximately 45 days of coal at full load burn ("FLB"). He noted, however, that actual inventory levels fluctuate due to changes from, but not limited to, the following factors: (1) weather driven demand; (2) plant availability; and (3) commodity price fluctuations. He testified that the forecasted coal inventories for the end of 2020 (the end of the test period) and reflected in the Company's proposed rates were as follows:

Station	**Days Full Load Burn (As of 12/31/2020)**
Cayuga	47
Edwardsport IGCC	46
Gallagher	31
Gibson	47
Total	**46**

Mr. Phipps testified that this forecasted coal inventory level is reasonable and consistent with the Company's fuel inventory strategy, and he noted that an approximate average of 45 to 46 days of coal burn for the forecasted 2020 period is reasonable and consistent with recent experience. He further testified that the Company's fuel inventory strategy is designed to balance the costs associated with maintaining coal inventory with the need to provide a reliable inventory level, so that when needed – especially during periods of high demand, extreme weather, fuel transportation or mine production problems – DEI will have adequate fuel supplies to operate its generating units. He explained that the Company continues to evaluate a host of options to effectively manage inventory levels – for example, the Company actively manages its portfolio and has been utilizing increased amounts of spot coal to enable its purchases to be more responsive to current actual burns and projected future burns that have become more volatile. However, he stated, in cases where actual burns unexpectedly drop below projections and the Company's inventory levels are above target, as inventory levels dictate, the Company explores options to store or defer contract coal or resell surplus coal into the market. Due to continued weak coal market conditions, resale opportunities will continue to be extremely difficult in the near term. The Company will continue to closely monitor its anticipated coal requirements and inventories and take every action available to effectively control coal inventories in the least cost-impact manner for customers including the use of a coal price decrement on an as needed basis.

OUCC witness Kollen recommended that the Commission reduce the fuel inventories to the target number of days of burn. He opined that this is the maximum amount that should be included in rate base, especially for a forecast test year. He testified that the Company's forecast coal inventories at Cayuga and Edwardsport are greater than the target number of days of burn at those generating stations. He stated that the Company's target days of burn for both stations is 45 days; however, the Company included 47 days of burn for Cayuga and 46 days of burn for Edwardsport. He stated that 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 days of 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 days of burn.

In rebuttal, Company witness Sieferman explained that the forecasted coal inventory amounts were developed starting with the actual coal inventory balances by station (in tons and dollars) at December 31, 2018 and building up the inventories assuming the monthly purchases (tons and dollars) per the forward plan and the monthly consumption amounts based on the burn projections and associated per ton pricing. Ms. Sieferman testified that the forecasted coal inventory levels at the end of the 2020 test period for Cayuga, Edwardsport, and Gibson generating stations were 47, 46 and 43 FLB days, respectively. She reiterated that, while the day-to-day inventory levels will fluctuate, the Company manages to an overall target inventory level of 45 FLB days for each of these stations. She disagreed with Mr. Kollen's recommendation, stating that the Company's forecasted coal inventory levels are reasonable in light of the way in which the forecasted inventory levels were developed and how close those forecasted levels are to the 45-day target levels.

i. Commission Discussion and Findings. A utility's rate base should include prudent and reasonable levels of fuel inventory. In this case, the evidence shows that DEI's target level of coal inventory at each of its coal-fired generating stations is an approximately 45-day supply of coal. The evidence also shows that DEI forecasted its end of test period coal inventory for each station starting with actual end of 2018 inventory levels, building up to end of test period levels using typical burn, consumption, and pricing assumptions. No party took issue with the Company's target inventory levels, the manner in which the Company projected its end of test period coal inventory levels, or the reasonableness of the forecast of the coal inventory levels. Rather, the OUCC focused on the end of test period levels as compared 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. We are not persuaded that these forecasted levels of coal inventories at Edwardsport and Cayuga that very slightly, totaling less than 30 thousand tons, above the Company's target inventory levels are unreasonable or imprudent. As Company witness Phipps pointed out, inventory levels can and do fluctuate based on circumstances that are largely outside the control of the Company, such as weather driven demand, plant availability, and commodity price fluctuations. Accordingly, we reject the OUCC's proposed adjustment and find that the Company's forecasted coal inventory levels are reasonable and should be included in the calculation of its rate base.

f. <u>Financing of Fuel Inventory and Materials and Supplies Inventory</u>. Petitioner's evidence indicates that it has forecasted fuel inventory and M&S inventory balances of $125.1 million and $307.6 million, respectively, on a total company basis, at the end of the test period. The retail jurisdictional amounts proposed to be included in rate base are $114.7 million for fuel inventory and $286.9 million for M&S inventory.

OUCC witness Kollen recommends that 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 that the Company recovers a return on only the portions of inventories financed by its investors. He stated that 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. 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.

DEI witness Douglas responded to Mr. Kollen's testimony. She recommended that the Commission reject Mr. Kollen's argument to selectively offset fuel and material and supplies inventories with accounts payable values of any amount. She testified that accounts payable amounts are working capital items. She noted that the Company has not requested a working capital allowance be included in rate base, nor has it prepared a lead/lag study as would be necessary if the Company were to request a working capital allowance be included in rate base. She testified that Mr. Kollen selectively recommends this one item of working capital be included as an offset to the inventory amounts included in rate base because he characterizes these amounts as vendor-financed. Ms. Douglas testified that the cost-free capital items in rate base or capital structure have traditionally been determined to be customer-financed items in Indiana ratemaking, such as deferred income tax balances and customer deposit amounts. She stated that because the Company makes use of vendor financing as part of reasonable and cost-effective cash management practices does not equate to selectively considering such financing as customer-provided financing. She noted that other than providing a return on the Company's inventories to cover financing costs, customers only pay for fuel and M&S as they are used. Consequently, there is definitely no prepayment by customers – nor is there currently a regulatory mechanism for customers to ever pay for any M&S inventory remaining at a generating station at the end of its life, even though the inventory was reasonably maintained throughout the plant's life to ensure reliable service to customers.

i. Commission Discussion and Findings. We agree with DEI that accounts payable are but one portion of a utility's working capital. The Company does not seek a working capital allowance in this case, and neither the Company nor any party presented the Commission with a lead/lag study to support a working capital allowance. A well-developed lead/lag study would include a more holistic review of financing activity and any vendor supportive features of it. We also note that contracts for goods and services typically contain payment terms that do not require immediate payment, and the payment terms of contracts may be negotiated, with trade-offs in other contract terms. Accordingly, we decline to adopt the OUCC recommendation. We find that DEI's forecasted fuel inventory and M&S should be reflected in the Company's rate base, as proposed by the Company.

g. Prepaid Pension Asset. Ms. Douglas testified that DEI has included the forecasted end of test period prepaid pension asset of approximately $151 million (total company) in rate base. The amount included in retail jurisdictional rate base is $142.8 million, as included on Petitioner's Exhibit 4-F (DLD), Schedule RB1. She testified that the prepaid pension asset is the cumulative amount of cash contributions to the pension trust fund in excess of the cumulative amount of accrued pension cost. She stated that the prepaid pension asset presented in the case is calculated consistent with GAAP under Accounting Standards Codification ("ASC") 715, (formerly Statement of Financial Accounting Standards ("SFAS") No. 87). She stated that the test year ending balance is based on the actual balances as of December 31, 2018, and the change associated with accrued pension cost for 2019 and 2020. She further testified that DEI's management has made use of available cash to fund the pension plan with investor capital in excess of required funding amounts to reduce the liquidity risk of future payments. Ms. Douglas explained that customers benefit from the prepaid pension asset because the additional pension contributions to the trust fund result in additional trust fund investment income that directly reduces annual ASC 715 pension expense. She stated that the test year pension expense included in the cost of service for customers is therefore lower than it otherwise would have been without these additional pension contributions represented in the prepaid pension asset.

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. Alternatively, Mr. Kollen recommended that if the Commission included a prepaid pension asset in rate base, it should exclude the portion of the prepaid pension asset that is reflected in capitalized rate base. Mr. Kollen stated that the effect of excluding the prepaid pension asset is a reduction in the retail revenue requirement of $10.8 million, and the effect of his alternative of reducing the prepaid pension asset to exclude the capitalized portion is a reduction in the retail revenue requirement of $2.9 million.

The Industrial Group also opposed inclusion of the prepaid pension asset in rate base. Industrial Group witness Gorman recommended removing DEI's retail jurisdictional $142.8 million prepaid pension asset from rate base, reducing the Company's revenue requirements by approximately $9.7 million. He claimed that DEI has fully recovered from customers all contributions it makes to its prepaid pension trust. As such, he stated, the prepaid pension asset was not funded by investor capital because all contributions were fully recovered from customers in rates. Therefore, Mr. Gorman testified, DEI is not entitled to a rate of return on its prepaid pension asset because it was not funded by investor capital.

DEI witness Mr. Setser rebutted the OUCC's and Industrial Group's arguments on the prepaid pension asset issue, testifying that the prepaid pension balance has been funded by the Company's investors. He explained that the Company accounts for its pension plans in accordance with GAAP and that the primary authoritative GAAP guidance is ASC Topic 715 (which codifies SFAS 158).

i. **Commission Discussion and Findings.** The inclusion of a prepaid pension asset in either the utility's rate base or capital structure has been previously addressed in other Indiana utility rate cases. In those cases, we have determined the following:

In an *Indiana Michigan Power Co*. ("I&M") case, Cause No. 44075, we found that:

> 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." These findings were upheld on appeal. *See Ind. Office of Util. Consumer Counselor v. Ind. Mich. Power Co.*, 7 N.E.3d 1025 (Ind. Ct. App. 2014).

In an *Indianapolis Power & Light Co*. case, Cause No. 44576, we found that:

> A prepaid pension asset may . . . be categorized as a component of working capital. 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 [Employee Retirement Income Security Act of 1971] 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 this case, Petitioner has demonstrated that a prepaid pension asset of $142.8 million on a jurisdictional basis exists, and that prepaid pension asset has been recorded on the Company's books in accordance with applicable 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 the asset serves to preserve the integrity of the pension fund. Further, the record demonstrates that on numerous occasions, Petitioner made discretionary management decisions to make use of available cash to secure its pension funds and reduce the liquidity risk of future payments, through numerous contributions to its pension fund in excess of actuarially determined GAAP pension costs. It is undisputed that the prepayment benefits ratepayers by reducing total pension costs in the Company's revenue requirement. Additionally, unlike the IPL case cited above, Petitioner's witness Setser testified that no additional minimum ERISA contributions have been required on the Duke Energy plans since 2010; therefore, we find that because no non-discretionary funding has been required, all the Company's contributions can be considered to be discretionary for purposes of calculating the amount of prepaid pension asset to be included in rate base. Therefore no additional reductions to remove such minimum ERISA contribution requirements are required in this case. Moreover, we reject Mr. Kollen's argument that the asset should be adjusted to reflect the capitalized portion of the prepaid pension asset, as Mr. Setser's rebuttal testimony demonstrated that it is irrelevant whether those costs flow through expense or are ultimately capitalized to plant. Therefore, we find that the prepaid pension asset should be included in Petitioner's rate base as proposed by the Company.

h. <u>Regulatory Assets</u>. DEI'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, DEI 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, DEI 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 regulatory assets in the total amount of $182.8 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.

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.

Ms. Douglas testified that Gallagher Station Units 1 and 3 retired on January 31, 2012 pursuant to a New Source Review litigation settlement agreement with the Environmental Protection Agency. She explained that, under the settlement, DEI had the option of converting Gallagher Units 1 and 3 to natural gas fuel or retiring the units. She testified that in Cause No. 43956, the Company proposed to retire the units and replace their capacity with the acquisition of a portion of the existing Vermillion CT Peaking Station ("Vermillion"), and the Commission found this proposal to be prudent. Further, she noted that in its Order in Cause No. 43956, the Commission authorized the deferral of the remaining net book value of the Gallagher Units 1 and 3 as a regulatory asset, with amortization and recovery over 14 years. According to Ms. Douglas, that Order also authorized the Company to account for dismantling costs through normal cost of removal accounting and to defer for subsequent recovery the retail jurisdictional portion of the costs associated with the gas conversion "Plan B" preservation option (converting Gallagher Units 1 and 3 to natural gas fuel) through year-end 2011. Accordingly, Ms. Douglas testified, the Company has included both the remaining net book value of the Gallagher Station Units 1 and 3 and the gas conversion preservation costs in rate base in this proceeding as a regulatory asset, proposed to be amortized over the remainder of the original 14-year remaining life period approved in Cause No. 43956.

OUCC witness Kollen proposed that the Commission direct the Company to create a regulatory liability account comprised of the non-fuel O&M savings realized since the 2012 retirement of the Gallagher Units 1 and 3. He further proposed that such regulatory liability account 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. Effectively, Mr. Kollen's proposal subtracted the non-fuel O&M savings from the Company's rate base in this proceeding.

Mr. Davey and Ms. Douglas responded to the OUCC's proposal to retroactively create a regulatory liability and reduce rate base in this case by the amount of non-fuel O&M savings resulting from the retirement of the Gallagher Units 1 and 3. Ms. Douglas responded that this issue should have been raised in 2011 in Cause No. 43956, where the Commission approved the establishment of this regulatory asset, providing for ongoing amortization that approximated the depreciation cost that was being recovered in rates. She further testified that the balance of the regulatory asset included in the test period by the Company has been properly calculated in accordance with the Cause No. 43956 Order and should not be further adjusted, and neither should a regulatory liability and customer refund be required retroactively. Ms. Douglas noted the Company's agreement to use 10-year amortization periods for regulatory assets, discussed below and in her rebuttal testimony, specifically requested Commission approval to deviate from the amortization period contemplated in the Gallagher Order and instead use the longer 10-year period for the amortization of the Gallagher 1 and 3 regulatory asset.

Company witness Douglas explained that the Company is seeking to recover as a regulatory asset to be included in rate base the remaining net book value of Wabash River Station Unit 6 that was retired in 2016 due to economics related to costs of complying with several federally mandated environmental rules after 48 years of service. Ms. Douglas testified that Wabash River Unit 6 had an expected retirement date of 2028 in the last approved depreciation study. The early retirement (change in retirement date from 2028 to 2016) and the remaining net book value of the unit factored into the Accounting Department's decision that normal retirement accounting could not be used for Wabash River Unit 6. The Company determined that because Wabash River Unit 6 was used and useful plant that was included in base rates at the time of its retirement, the Company moved the remaining net book value of the unit from plant-in-service and accumulated depreciation accounts to a regulatory asset account. Ms. Douglas testified the Company continued to reduce the regulatory asset with amortization in the amount of the depreciation included in base rates for the unit. Ms. Douglas explained that the requested accounting and ratemaking treatment is no different than what would have occurred for Wabash River Unit 6 if the unit had been closer to its retirement date at the time it was retired – it's just that the costs are included in a regulatory asset account rather than a plant account.

Similar to his recommendation concerning Gallagher Units 1 and 3, OUCC witness Kollen recommended 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 avoided non-fuel O&M expense by retroactively setting up a regulatory liability to offset the regulatory asset from the date of retirement. Industrial Group witness Gorman similarly recommended the regulatory asset be completely offset by avoided fixed O&M expense for Wabash River Units 2-6 and excluded from rate base. Both Messrs. Kollen and Gorman took issue with the Company's decision to create a regulatory asset for the net book value of Wabash River Unit 6 without Commission approval.

Ms. Douglas testified in rebuttal to the proposals of Messrs. Kollen and Gorman. First, she clarified that both recommendations refer to the same annual O&M savings level, although they each characterize them differently. Second, she disagreed with both recommendations.

i. <u>Commission Discussion and Findings</u>. With regard to these undisputed regulatory assets, 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.

As we found in Cause No. 43956, the Company reasonably and prudently decided to settle its New Source Review litigation with the EPA, and further, the Company reasonably and prudently decided to retire, rather than repower, its Gallagher Units 1 and 3. Additionally, consistent with our Order in Cause No. 43956, the Company established a regulatory asset for the remaining net book value of those Units. Regulatory accounting use, whether to establish assets or liabilities, provides the regulating authority a vehicle to balance stakeholder interests when certain circumstances arise. In general, the optimum time to balance such interests occurs at common points in time. As such, the offsetting of a previous balance inherently requires sufficiently changed circumstances. We do not find the offsetting of the previously approved regulatory asset in the manner proposed by the OUCC is reasonable given the time that has passed since the original regulatory accounting was approved. Accordingly, we find reasonable the Company's proposed Gallagher Units 1 & 3 regulatory asset and its recovery.

The evidence presented demonstrates that upon the retirement of Wabash River Unit 6 due to economic reasons, the Company created a regulatory asset consisting of the net book value of the Unit, after reaching a determination that recovery of such was probable based upon the prior regulatory asset treatment for the retired Gallagher Units 1 and 3. The evidence also demonstrates that the Company's creation of this regulatory asset was consistent with applicable accounting standards, which do not require an order from regulators in order to conclude that recovery is probable. There is no evidence suggesting that the retirement of Wabash River Unit 6 was in any way imprudent or unreasonable. Rather, the evidence indicates that the Unit provided service to customers for almost 50 years. The evidence also shows that, under normal retirements, where the creation of a regulatory asset is not required by the accounting rules, the utility recovers the full net book value of its investment after retirement, through depreciation. Thus, the creation of a regulatory asset in this situation is necessary in order for the utility to recover its full plant investment, as it does with normal plant retirements.

The remaining disputed issue: Should the O&M Savings offset the Wabash River Unit 6 regulatory asset as O&M expenses were built into the Company's base rates in its last base rate case but were no longer incurred once the Unit was retired. This issue is distinguishable from the Gallagher Units 1 and 3 case, because the OUCC and intervenors did not have the opportunity to propose such an O&M offset in a deferred accounting authorization case. However, we reach a similar conclusion and find that the offsetting proposal should be rejected. DEI's regulatory accounting treatment at the retirement of Wabash River Unit 6 is consistent with historical precedent and the retroactive requirement of offsetting O&M between rate cases in such circumstances is not. Accordingly, we find reasonable the Company's creation of a regulatory asset for the net book value of Wabash River Unit 6, and we approve recovery of such regulatory asset in this case, over a period of 10 years.

Finally, at the evidentiary hearing in the proceeding, Commissioner Freeman asked Mr. Davey questions regarding a regulatory asset for the Dynegy buyout that was fully amortized in May of 2017. She questioned whether the Company had plans to return any over-recovery related to the regulatory asset. Mr. Davey explained that for the regulatory assets proposed in this proceeding, the Company has proposed to stop such recovery once the regulatory assets are fully amortized and change rates using the Company's Credit Rider. However, at the time of the prior rate case when the Dynegy asset was last addressed, there was no such provision in the order requiring a rate change outside of a base rate case when regulatory assets were fully amortized. Mr. Davey indicated that was not the practice at that time and most costs go up in between rate cases and some costs go down and in between rate cases rates are not changed. This particular cost went down and was material, but there was no provision requiring a rate change. Tr. B 85-88.

We understand that there was no prior requirement for DEI to credit customers when the amortization was fully realized, and, as such, DEI was not required to credit rates at that time. However, as we have been ordering in recent rate cases the better practice for regulatory asset recovery is to change rates once such regulatory assets or regulatory liabilities are fully recovered or fully refunded, and, as such, we are requiring this in this proceeding.

j. <u>Coal Ash Basin Closure and Remediation</u>. DEI 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, DEI 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 collectively as "Coal Ash" costs. The Commission opened a subdocket (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.

Company witness Douglas discussed the Company's accounting for its incurred CCR Project and IDEM Projects costs and described the ratemaking treatment used for the coal ash costs in developing the proposed rates in this case.

First, Ms. Douglas noted that if these costs were not considered a legal obligation under ARO accounting, they would have been accounted for as a cost of removal that would be charged to a FERC 108 account to make up the final costs for a generating plant in its plant accounts. She testified that depreciation rates are traditionally set for regulated utilities such that they are intended to cover the cost of the plant, plus any cost of removal less salvage value remaining at the end of the life of the plant. She stated that the coal ash remediation and closure costs are properly considered cost of removal, dismantling and decommissioning of utility electric plant, and had the current environmental rules been foreseen and the current closure plans been developed at the time of the last depreciation study, the costs could have been estimated as a part of the decommissioning study and included in the depreciation rates, as some other Indiana utilities have done. However, she stated they were not, and the depreciation study included a much lower level of coal ash costs in the cost of removal than what the Company has incurred to date and is forecasting to incur in the future under the current environmental rules governing the remediation and closure.

Further, Ms. Douglas testified, because the coal ash costs that have been incurred by the Company are required due to the federal or state rules and meet the requirements for ARO Accounting under GAAP and FERC Accounting Guidance under Rule 631, the Company has separated out the costs from the Accumulated Depreciation Reserve FERC account 108 and instead accumulated the costs in a regulatory asset, net of the amounts customers have paid via depreciation rates for the coal ash portion of the estimated cost of removal that was included in current depreciation rates via a transfer from the 108 account where it was initially recorded. She stated that the Company believes this regulatory asset accounting treatment is appropriate and supported by the past practice in Indiana of recovery of both plant costs and cost of removal costs via depreciation rates.

Ms. Douglas explained that the Company has included in a separate Coal Ash ARO Regulatory Asset Account (account number 182471) ("Coal Ash Regulatory Asset") the retail jurisdictional coal ash costs incurred from April 2015 when the CCR rule was promulgated through December 2018 for both CCR Projects and IDEM Projects, net of accumulated amounts that were recovered in depreciation rates for coal ash up through December 2018. She noted that the Coal Ash Regulatory Asset amount included in base rates excludes any costs that were charged to the same regulatory asset accounting related to the Company's Phase 1 CCR projects that were approved under the Federal Mandate Statute for timely cost recovery in the Company's ECR Riders in Cause No. 44765. She emphasized, as she noted before, but for the Company's ARO accounting, the costs the Company included in base rates in the Coal Ash Regulatory Asset would have been included as a cost of the plant assets included in base rates which are being depreciated. She stated that the Company's ARO accounting treatment for these costs and its proposed ratemaking for the costs has not increased nor decreased the amount that would have been included in base rates in this proceeding.

Ms. Douglas also explained that the Company also included in the Coal Ash Regulatory Asset proposed to be included in rate base the retail jurisdictional coal ash costs forecasted to be incurred in 2019 and 2020, but only costs associated with the IDEM Projects that have approved closure plans (Gibson East Ash Pond and Dresser Station.)

Ms. Douglas provided an overview of cost recovery for federally mandated costs under the Federal Mandate Statute. She explained that, pursuant to the statute, federally mandated costs include capital, operating, maintenance, depreciation, tax or financing costs. She explained that the Company is also requesting the financing costs it has incurred or is forecasted to incur in relation to the December 2018 balance of costs for the CCR projects.

Ms. Douglas explained that the Company has included in the regulatory asset to be included in base rates in this proceeding financing costs computed at its applicable weighted average cost of capital associated with the cost of the CCR projects included in the regulatory asset and also forecasted the amount of 2019 and 2020 financing costs on both the projects and the accrued financing costs through December 31, 2020.

Ms. Douglas stated that the Company is proposing amortization of the coal ash costs included in the regulatory asset over 18 years, consistent with the remaining life of the last operating coal unit at Gibson Station. The amount included in the regulatory asset balance forecasted as of December 31, 2020 which is being requested for recovery via amortization under either traditional ratemaking treatment or under the Federal Mandate Statute is $186.7 million of costs other than financing costs plus $25 million of financing costs for a total of $211.7 million, as shown in Petitioner's Exhibit 4-F (DLD), Schedule RB4.

Ms. Douglas concluded her testimony by emphasizing that the requested base rate cost recovery, with both return on and of the costs, is the same ratemaking treatment the costs would have received if they had been treated as a normal retirement and is consistent with historical Indiana practice for regulated utilities of cost recovery for reasonable and necessary generating station costs of removal such as these. In addition, she noted, it is consistent with cost recovery for Federally Mandated projects.

The OUCC opposes recovery of Petitioner's coal ash basin closure and remediation expenses. Ms. Armstrong testified that the OUCC recommends the Commission deny DEI's proposed recovery of $211.7 million in regulatory assets. Issuance of a federally mandated CPCN for ash pond closure costs incurred from 2015 through 2018 should be denied, as DEI failed to seek approval of these costs prior to incurring them and has not met the requirements under Indiana Code ch. 8-1-8.4. In the alternative, Ms. Armstrong testified, should the Commission decide to issue a federally mandated CPCN for past ash pond closure costs, the OUCC recommends federally mandated costs only be approved for $117.3 million (the retail portion of the total company amount of $127.7 million) to exclude $73.9 million of the IDEM-related costs. Ash pond closure costs related to Agreed Orders entered into with IDEM should not be recovered from ratepayers, as they result from the Company's failure to prevent its CCR wastes from creating a pollution hazard. Finally, any cost recovery methodology approved 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. The Company 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.

The Industrial Group also opposed recovery of Petitioner's coal ash basin closure and remediation expenses. Industrial Group witness Gorman testified that DEI's proposal to defer costs without prior approval from the Commission is contrary to typical ratemaking principles. Additionally, he stated that the language of Indiana Code ch. 8-1-8.4 appears to be forward looking, in that the Commission must approve a federally mandated project before the utility incurs the expense and can seek to recover the cost. He noted that this issue was addressed in the Commission's September 18, 2019 Order in Cause No. 44367 FMCA 4, in which it denied DEI's request to recover historic costs under the statute.

Referencing his Attachment MPG-17, Mr. Gorman stated that a majority of these costs were deferred from the period 2010 through 2018, and the annual level of deferred costs averaged approximately $22 million per year. He testified that the annual average expense incurred over this time period was less than the savings created through full recovery of regulatory assets that are being amortized which it concluded around 2015 ($10.5 million per year) and a reduction in interest expense of approximately $23.5 million per year. As such, he testified that he believed the Company failed to provide any evidence that the revenue it collected during this time period was not more than adequate to fully recover these deferred coal ash closure expenses. Additionally, he testified that approximately $19 million relates to employee and contract services. He stated it is not appropriate to include these costs in deferrals because these costs are traditionally recovered in DEI's base rates; specifically, DEI's base rates provide full recovery of its employee costs and contract labor costs. As such, he testified, if the Commission allows for some amount of coal ash deferred costs, it should not allow for the inclusion of employee and contract labor costs. In conclusion, Mr. Gorman recommended that the Commission deny DEI's request in this case for a CPCN under Indiana Code ch. 8-1-8.4.

Joint Intervenor witness Schlissel also testified on these issues. Mr. Schlissel stated that to his knowledge, IDEM only approved the closure plans submitted by Duke for three coal ash impoundments at Duke's Wabash River plant. He stated that closure plans for coal ash sites at Duke's Cayuga, Gibson, and Gallagher plants, as well as for other coal ash impoundments at the Wabash River plant, remain pending before IDEM and have not been approved. Yet, he stated, as Mr. Thiemann notes in his testimony, "[t]he Company has begun to execute on certain portions of its proposed closure plans," apparently based in part on the assumption that the coal ash closure plans that it has submitted to IDEM will be approved. Mr. Schlissel opined that this is not a safe assumption. He testified that IDEM has repeatedly noted to Duke that it has concerns about whether Duke's proposed closure plans comply with the federal CCR Rule. Specifically, he testified, IDEM has expressed a concern to Duke that certain portions of its sites for which the Company has proposed to cap ash in place instead of removing have not demonstrated compliance with federal CCR Rule requirements that coal ash sites be closed in a manner that "controls, minimizes or eliminates, to the maximum extent feasible, post-closure infiltration of liquids into the waste and releases of CCR, leachate, or contaminated run-off to the ground or surface waters or to the atmosphere." He testified that if IDEM ultimately does not approve any portions of Duke's closure plans as proposed, Duke may be required to modify its proposed plans, including by proposing to excavate coal ash from certain portions of its sites that it is currently proposing to cap in place. Additionally, Mr. Schlissel stated that Duke's case-in-chief does not provide sufficient information and explanation regarding the prudence of the CCR compliance expenditures for which it is now seeking recovery. In the absence of such sufficient information and explanation, it is his opinion that those expenditures could be considered reasonable or prudent by the Commission only after IDEM has approved the closure plans as proposed by Duke, without any modifications. Magnifying this concern, he stated that Duke recently wrote to IDEM that it is currently engaging in additional CCR activities at its Cayuga and Gibson Stations "in anticipation of approval of the closure plan[s] previously submitted to IDEM." In Mr. Schlissel's view, the lack of sufficiently specific information provided with Duke's case-in-chief, and Duke's apparent willingness to move forward with coal ash closure activities without waiting for necessary approvals from IDEM, raises serious concerns that it is asking the Commission for recovery of CCR compliance costs in this proceeding that were not reasonably or prudently incurred.

Ms. Abernathy testified regarding the propriety of the Company's establishment of a regulatory asset for its coal ash basin closure and remediation expenses. She testified that ASC 980 applies to regulated entities that charge rates at levels designed to recover the entity's costs of providing regulated services. ASC 980 provides that a utility should capitalize a cost, as a regulatory asset, if it is probable that, through the ratemaking process, there will be a corresponding increase in future revenues. Under ASC 980, a regulated entity should capitalize incurred costs that would otherwise be charged to expense if both of the following criteria are met: (1) it is probable (i.e., likely to occur) that future revenues in an amount at least equal to that capitalized cost will result from inclusion of that cost in allowable costs for ratemaking purposes; and (2) based on available evidence, the future revenue will be provided to permit recovery of the incurred cost rather than to provide for expected levels of similar future costs. The determination whether recovery is probable is a matter of professional judgment, based upon specific facts and circumstances, but the following evidence can support a conclusion that recovery is probable: (1) a rate order from regulators specifically authorizing recovery; (2) previous rate orders from the regulators allowing recovery for substantially similar costs; (3) written approval from the regulators approving recovery; and (4) analysis of recoverability from internal or external legal counsel.

Ms. Abernathy testified that the accounting rules do not require that a regulated utility obtain a deferred accounting authorization order from its regulators prior to creating a regulatory asset. Rather, ASC 980 requires that the utility conclude that cost recovery is probable, and while a deferred accounting authorization from regulators is one way to determine probability, there are other ways that do not involve obtaining a deferred accounting authorization order – such as reliance on previous orders from the regulators approving recovery for substantially similar costs and analysis of recoverability from internal or external legal counsel. She testified that the guidance in ASC 980 is applicable for all costs where the above criteria is met, including AROs.

She confirmed that, as discussed in both the initial and rebuttal testimony of Company witness Ms. Douglas, prior to the coal ash remediation and pond closure costs becoming legal obligations under the enacted EPA and IDEM requirements described above, these types of costs were properly considered a cost of removal. As such, the costs were estimated as part of the cost of decommissioning the coal plants in prior decommissioning studies and included in depreciation rates to be charged to customers over the life of the plants. Accordingly, the Company accumulated a balance in its accumulated depreciation reserve for the amounts that customers have paid via depreciation rates for the coal ash portion of the estimated cost of removal. However, as noted in the testimony of Ms. Douglas, the historical estimates for cost of removal were much lower than the costs of complying with the newly enacted EPA and IDEM requirements.

Further, she explained that, in accordance with GAAP as prescribed in ASC 410-20, as well as FERC rules as prescribed in Order No. 631, the Company records an ARO liability when it has a legal obligation associated with the retirement of a long-lived asset and the obligation can be reasonably estimated. The Company evaluated these GAAP and FERC rules in light of the legal obligations imposed upon it by the EPA and IDEM compliance requirements regarding coal ash as described above. The Company determined that the coal ash basins it operated at its coal-fired generating facilities needed to be closed as a result of these compliance requirements, and this closure obligation triggered a requirement for the Company to record an ARO liability under the accounting rules. When the ARO liability was recorded, a corresponding equivalent ARO asset was recorded on the books as part of the cost of the associated asset in the property, plant and equipment accounts. This ARO asset will be depreciated over the remaining estimated plant life, and the depreciation expense associated with the ARO is being deferred into a regulatory asset account because the Company believes the costs meet the requirements for capitalization under ASC 980, as described above.

Ms. Abernathy also testified that as actual costs are incurred to comply with the federal and state regulations that gave rise to the AROs, the Company reduces the ARO liability to reflect cash spent to satisfy those legal obligations. Simultaneously, the Company records an entry to reduce the regulatory asset described above and increase a separate regulatory asset that was created for the purpose of tracking the amount of actual cash expenditures incurred. In addition, the Company transferred the cumulative balance of coal ash related cost of removal amounts collected from customers from the accumulated depreciation reserve to this regulatory asset, so that customers receive credit for the coal ash remediation costs they have already paid.

Ms. Abernathy explained that the Company's determination that recovery was probable was based upon the cost recovery framework in place in Indiana, and the history of authorizing recovery for environmental remediation costs as well as for federally-mandated costs. Additionally, she noted that the Commission has authorized cost recovery for substantially similar costs for several utilities, including for DEI in 2017. In that 2017 Order, the Commission approved a settlement which allowed recovery of various environmental compliance projects, including coal ash remediation projects, and carrying costs, the capital costs of which were incurred from approximately 2015 through early 2019. In that case, the costs at issue were for, among other things, coal ash management equipment and processes at the Gibson and Cayuga Stations for purposes of complying with the U.S. EPA Coal Combustion Residuals ("CCR") Rule. *See In re DEI, LLC*, Cause No. 44765 (IURC; May 24, 2017). Ms. Abernathy also cited IURC Orders issued for other utilities, allowing recovery of coal ash-related remediation expenses.

Ms. Abernathy stated that the Company continues to believe recovery is probable. The costs relate to federal and state legal mandates and activities that the Company is required to perform and are incremental to the current costs being recovered from customers in base rates. Without the creation of a regulatory asset and the associated deferral of these costs, the Company would be in a position of prudently incurring required costs with no opportunity to recover such costs.

She explained that if the Company was not legally obligated to incur these costs, they would have been recorded as costs of removal. Ms. Abernathy stated that, as Ms. Douglas explains in both her direct and rebuttal testimony, cost recovery treatment would be substantially similar whether accounted for as an ARO or cost of removal.

Ms. Douglas testified that both Ms. Armstrong and Mr. Gorman ignore the fact that, with some exceptions, the activities Mr. Thiemann described that comprise the coal ash costs being requested would have been properly accounted for as a capital project in plant account 101, preliminary engineering costs in a 183 account, or as cost of removal charges to plant account 108, absent the Company's ARO accounting arising from the CCR Rule or IDEM closure plans. She testified that costs are accumulated in these accounts – that is, they build up over time. She explained that they are balance sheet accounts and do not influence the net operating income like current year expense items do, unless and until certain events happen, such as putting the capital project in-service, at which time depreciation begins. She noted that, consistent with traditional regulatory practice, the net book value of other production plant costs charged to accounts 101 and 108 was included in rate base for purposes of return calculation, and both values were factored into the depreciation rates proposed in the case, which were used to develop the depreciation expense included in revenue requirements. In other words, in the absence of required ARO accounting, both a "return on" and a "return of" these costs would have been built into rate base. Further, Ms. Douglas testified that the costs that accumulated in these balance sheet accounts for in-service plant would have properly had the same ratemaking treatment regardless whether, for example, interest costs had decreased over time.

Ms. Douglas rejected Mr. Gorman's argument that the Company should require evidence that the revenue it collected during this time period was not more than adequate to fully recover these costs. She stated that she was not aware of any MSFR requirement or GAO best practice or Commission rule that requires such a back-looking net operating income test be met in order to recover costs deferred in a regulatory asset account in a base rate case. Moreover, she pointed out that the Commission had recently rejected a similar back-looking expense reduction argument, relative to recovery of federally mandated project costs. Specifically, in the Commission's Order in Cause No. 45052 (a Vectren case), the Commission stated:

> Eligibility for recovery through Ind. Code § Ch. 8-1-8.4 is not contingent on whether other costs have declined to offset the new federally mandated costs. Once we have made the required findings, 80% of the federally mandated costs "shall be recovered by the energy utility through a periodic retail rate adjustment mechanism." Indiana Code § 8-l-8.4-7(c)(l). (45052 Order at 35)

Ms. Douglas also corrected Mr. Gorman's erroneous assumption that, if recovery of the Company's coal ash costs is allowed, employee and contract labor costs should be removed because of "full recovery" of such costs in the Company's base rates. She testified that the Company's practice for engineering and support groups, such as those who work for and with Mr. Thiemann on the various coal ash projects he discussed in his direct testimony, was, at the time of the last rate case, and still is, to track employee and contractor time to the projects they are working on to the extent possible, to allocate costs between capital overhead pools and O&M, or to charge a pool that will allocate their time based on the direct charging of others in the group. She stated that costs are budgeted similarly. She explained that this results in employee labor and contractor charges to capital, retirement, and various deferred FERC accounts during the test period, as well as O&M expense accounts. She noted that DEI did not have a *pro forma* adjustment in its last base rate case to adjust test period O&M upward to make sure 100% of the base employee salaries and wages and contractor labor costs were classified as O&M expense and included in revenue requirements, and the Company did not make such an adjustment in this case either. Therefore, she concluded, as with other utility plant included in rate base, Mr. Gorman's recommendation to remove employee and contract labor costs from the Company's coal ash regulatory asset should be rejected.

Ms. Douglas agreed with OUCC witness Armstrong that the coal ash regulatory asset should be credited with any coal-ash related insurance recoveries and offset with amounts included in rates due to estimates included in prior decommissioning studies used to set rates. She stated that the Company has reflected the insurance proceeds amount that the Company received related to Dresser Station in the coal ash regulatory asset account in November accounting business and will similarly credit any such future amounts received. Further, she stated that the Company has also included a credit of approximately $5 million for amounts collected in depreciation rates. She added that, as part of the Company's compliance filings for Step 1 and Step 2 rates, the Company will provide actual amounts for the coal ash regulatory asset as of December 31, 2019, and December 31, 2020 and provide additional support for the calculation of the actual cost of removal credits as of those periods.

With regard to the OUCC's recommendation that the Company amortize the regulatory asset using Mr. Kollen's proposed "levelized" methodology, Ms. Douglas reiterated that the Company disagrees with the use of Mr. Kollen's proposed levelized methodology for the same reasons articulated previously in her testimony. (A summary of that section of her testimony is included in a later section of the Order covering amortization periods for regulatory assets in general.)

Additionally, Ms. Douglas noted that traditional Indiana ratemaking practice has allowed the recovery of reasonable and necessary costs of operating generating stations, including costs to decommission, demolish, and dismantle the site. She stated that it is her understanding that both Indianapolis Power & Light Company ("IPL") and I&M have been authorized to recover coal ash related costs in recent base rate cases, IPL through depreciation rates as a traditional cost of removal would be recovered, and I&M through the inclusion of accretion and depreciation of ARO accounting in revenue requirements. This ratemaking treatment for coal ash related costs was approved by the Commission, but not under the federal mandate statute. Accordingly, she testified that approval under the federal mandate statute is not necessary for the Commission to authorize recovery of these reasonable and necessary costs. She stated that if the Commission should agree with the OUCC and Industrial Group that the Company did not satisfactorily meet the requirements for CPCN approval under the federal mandate statute for either the costs the Company has already incurred or future costs, the Company believes the nature of the deferred past costs qualify for the cost recovery proposed by the Company in this case under traditional ratemaking practice.

In his rebuttal testimony, Mr. Thiemann addressed the federal mandate nature of the CCR Rule, the activities the Company has taken and continues to take to ensure compliance with the CCR Rule even in the absence of IDEM approval of proposed closure plans, and how the Company has met the requirements of the federal mandate statute.

Mr. Thiemann emphasized that the CCR Rule is a federal mandate, as it was issued by the EPA (as well as adopted into the Indiana Solid Waste Management Plan). The Company must comply with this federal CCR Rule and its compliance deadlines. DEI's activities with respect to CCR work to date and as projected into the future are all in support of compliance with the CCR Rule. He opined that DEI continues to use good judgment in the use of resources related to its CCR compliance activities. He noted that expenses that are represented in his testimony are directly related to support the Company's compliance with the requirements of the CCR Rule. He stated that the Company has conducted ground water assessment, and monitoring and implemented necessary corrective actions when warranted.

He explained that the Company's work has also supported the need to remove ash from specific ash basins to allow the construction of non-CCR lined retention basins, two of which were approved in Cause No. 44765. These lined retention basins were required in order to remove all ash and water flows from ash basins by the dates specified in the CCR Rule. He stated that the Company has undertaken ash movement from ash basins to support the need to conduct work to address structural stability issues also as defined in the CCR Rule. Further, he stated the Company has performed engineering for the development and support of the closure plans submitted to IDEM in late 2016. He testified that the Company has continued to work with IDEM since then on finalizing closure plans and providing the agency with additional information. He noted that IDEM has been kept abreast of the activities performed while the closure plans have been pending. He stated that any activity performed to date has been necessary for the Company to complete in order to remain on track to comply with the CCR Rule deadlines, necessary for the Company to complete whether or not IDEM makes changes to the proposed closure plans, and discussed with IDEM. Contrary to Mr. Schlissel's contention, Mr. Thiemann emphasized that the Company has not been proceeding with execution of its proposed closure plans, ignoring IDEM and the possibility that it could require new or different closure-related activities. Rather, he testified, the Company has been prudent in proceeding with closure activities necessary to ensure compliance with the CCR Rule deadlines (and trying to avoid a citizen suit for non-compliance), but also not proceeding where the timing has allowed.

He testified that continued operation of the generating assets produces ash that must be placed in a landfill or beneficially used as structural fill for closure as permitted by IDEM. He stated that the Company continues to beneficially place fixated material (production ash mixed with FGD gypsum and lime) as structural fill to achieve sub grades for the basins being closed in place. He noted that, consistent with a primary goal of the Resource Conservation and Recovery Act, beneficially using the material as structural fill avoided the use of virgin material, thereby conserving natural resources that the Company would otherwise have had to obtain through extraction.

Mr. Thiemann's testimony provided specifics on a basin by basin view related to the actions described above. He testified that the Company's actions were all required by law in order to achieve and maintain compliance with federal regulations.

He also reviewed the conditions and factors that the Commission must consider to issue a federal mandate CPCN. He stated that the first factor the Commission must consider is a "description of the federally mandated requirements." He noted that his direct testimony on pages two through seven describes the CCR Rule and how it applies to DEI's generating units.

The next factor for the Commission to consider is a "description of the projected federally mandated costs associated with the proposed compliance project." He stated that his direct testimony on pages 11- 18, as well as in several of his exhibits, describe the activities performed at each generating station for CCR Rule compliance. He noted that Petitioner's Exhibits 21-E, 21-F and 21-G, in particular, describes the projected federally mandated costs.

The next factor for the Commission to consider is a description of how the proposed compliance project allows the energy utility to comply with the federally mandated requirements.

He stated that pages six through nine of his direct testimony describes what DEI needs to do to comply with the CCR Rule. In addition, he stated, on pages eight through fifteen, his testimony describes the specific plans the Company is undertaking to comply with the CCR Rule.

The next factor for the Commission to consider are alternative plans that demonstrate that the proposed compliance project is reasonable and necessary. He stated that on pages ten and eleven of his direct testimony, he discusses how the Company considered alternative ways to comply with the CCR Rule before settling on its final proposed closure plans. He pointed out that the closure plan exhibits (Petitioner's Exhibits 21-A, 21-B, 21-C, 21-D) attached to his testimony also describe the alternative closure options reviewed to achieve compliance, and the means of compliance selected by the Company for each generating station. He noted that those closure plans also provide detail regarding the selected compliance option for each surface impoundment at its generating stations.

The fifth factor to be considered is "information as to whether the proposed compliance project will extend the useful life of an existing energy utility facility and, if so, the value of that extension." He stated that his direct testimony on page eleven explained certain compliance projects are required for continued operation, such as the loading, hauling, and placement of ash and fixated material in operating landfills. He also stated that closure of a surface impoundment does not necessarily extend the useful life of the generating facility where it is located.

The last factor is simply "any other factors the Commission considers relevant." He testified that in his direct testimony, he tried to explain why the Company must comply with the CCR Rule, why it has performed or will perform the closure-related activities at each station, and how those activities will ensure compliance with the CCR Rule. In addition, he noted that he attached the closure plans the Company submitted to IDEM for its consideration.

The federal mandate statute also states that an energy utility must provide the information discussed above "supported with technical information in as much detail as the commission requires." Mr. Thiemann stated that he provided exhibits that included the estimated costs for the coal ash basin closures and the closure plan summaries, which include technical information about the Company's plans.

He reiterated that DEI knows that it must close its surface impoundments in compliance with the CCR Rule. There remains uncertainty with the exact timing of related expenditures, as well as some uncertainty with whether IDEM may require changes to the closure plans the Company submitted in December 2016.

He emphasized that requirements and deadlines to comply with the CCR Rule have not stopped because IDEM has taken close to three years to review the Company's proposed closure plans. During this period, he testified, Company has attempted to proceed with the compliance-related activities that are prudent and reasonable and would need to take place whether the surface impoundment in question is closed in place or closed by removal, or any variation in between.

Mr. Thiemann summarized the activities that DEI has been performing to date, including beneficially placing structural fill as part of IDEM-approved closure plans, dewatering of surface impoundments (which needs to be completed whether closed in place or closure by removal), removal of ash in order to support construction of lined retention basins mandated by the CCR Rule, and removal of ash where the Company's proposed closure plan involved closure by removal.

He summarized that, as for DEI, the closure plans can be broken down into two options: (1) close a basin by removing all ash (closure by removal); or (2) close a basin by installing an impermeable cap over the material in place (closure in place). He stated that because of the issuance of the CCR Rule and its compliance requirements, DEI has chosen to take action on certain ash basin closures to avoid the potential of not meeting the closure dates imposed by the CCR Rule while its proposed closure plans are pending at IDEM.

He stated that DEI's actions to date, and that will be taken in the future, are taken to satisfy the requirements of state and federal law and that the Company continues to work with IDEM to ensure the Company's plans satisfy the State, and perform some work in parallel to ensure DEI will meet the CCR rule compliance dates.

He testified that the Company does not have numerous alternatives to closing its surface impoundments as mandated by the CCR Rule. Essentially, DEI can close its surface impoundments by closure by removal or by closure in place but in the end will have to use the alternative that IDEM approves.

Mr. Thiemann emphasized that DEI takes seriously its compliance obligations, whether safety, reliability or environmental in nature. He stated that the OUCC's suggestion that the Company be penalized for its actions for the variety of reasons it suggested should be disregarded as bad policy for the state of Indiana. He stated that both the CCR Rule and IDEM require electric utilities to close existing ash ponds, to remediate existing ash management areas and to comply with all post-closure monitoring and compliance activities; there are no alternatives to these requirements. Utilities cannot shut down their coal fired generators to avoid the compliance requirements. Not allowing utilities to recover their reasonable and prudent costs does nothing but penalize those utilities for many years of providing customers with electricity created by burning coal. DEI's activities to comply with the CCR Rule and IDEM regulations are a reasonable part of the provision of service to its customers – all of whom will also benefit from the Company's compliance with environmental standards. Mr. Thiemann urged the Commission to reject the OUCC's argument and allow the Company to recover its coal ash remediation expenses whether they were spent in the recent past few years to help plan and engineer the closures or whether they will be spent in the upcoming years to finalize those closures and as part of post-closure maintenance.

Mr. Schwartz's rebuttal testimony responded to Ms. Armstrong's assertion that all costs associated with IDEM Agreed Orders should be disallowed. He also addressed Ms. Armstrong's comparison of coal ash closure expenses to an old Indiana Gas case regarding manufactured gas plant ("MGP") remediation. Finally, in response to Ms. Armstrong's and Mr. Schlissel's testimony that the Company's request should be denied because IDEM has not yet approved the Company's CCR closure plans proposed in December 2016, he discussed the current status of those closure plans and how the Company continues to cooperatively work with IDEM to address its questions and concerns.

Mr. Schwartz reiterated that, in addition to federal CCR Rule requirements, the Company also has coal ash closure and compliance obligations under Indiana's Solid Waste Regulations. For example, for coal ash surface impoundments that are not subject to the CCR Rule, IDEM reviews and approves closure plans pursuant to Indiana's solid waste disposal regulations and IDEM's "Surface Impoundment Closure Guidance." He stated that Gibson Station's East Ash Pond system is being closed pursuant to these regulations. With respect to coal ash that has been historically managed via the placement of the ash on the ground in designated areas before modern landfill regulations were enacted (called "historic ash management areas"), Indiana's solid waste rules, which are required by federal law, govern closure. The Company is closing historic ash management areas at the former Dresser Station, the Noblesville Generating Station and the repurposed Edwardsport Station pursuant to these regulations. Notably, all these closure activities have been or are proceeding under approved closure plans with IDEM, and will be similar to the CCR Rule compliance activities.

Mr. Schwartz testified that there is a connection between these IDEM compliance activities and federal law. The Indiana solid waste management laws are part of a federally mandated and federally approved "solid waste management plan" that was required pursuant to a U.S. Congressional Act—the Federal Resource Conservation and Recovery Act ("RCRA"). Mr. Schwartz testified that DEI's actions to address the final closure of historic ash management areas at the former Dresser Station, the Noblesville Generation Station, and the repurposed Edwardsport Station are being conducted in compliance with the state law and accompanying regulations, which are in turn required by federal law and were explicitly reviewed and approved by U.S. EPA. Similarly, Mr. Schwartz testified, when DEI implemented its approved closure plan for Gibson Station's East Ash Pond, the purpose of the closure plan was to comply with state regulations that are required by federal law and were explicitly reviewed and approved by U.S. EPA.

Mr. Schwartz next testified as to what triggered the Company's decision to further investigate and determine whether any closure actions were needed at these historic ash management areas. He stated that the Company regularly performs inspections of its ash ponds and other ash management areas at all its facilities, in all jurisdictions. As a next phase of this process, he testified, the Company also conducted environmental audits related to, among other items, the historic ash management areas at the former Dresser Station, Noblesville Station, and Repurposed Edwardsport Station pursuant to Indiana's Environmental Audit Program.

With regard to IDEM's Environmental Audit Program, Mr. Schwartz explained that Indiana law and IDEM's policies strongly encourage environmental compliance audits. For example, State law creates a general statutory privilege over environmental audit reports. Further, as a supplement to this State law, IDEM has issued an agency "nonrule policy document," to encourage self-disclosures of issues identified in environmental audits. Among other things, the IDEM policy "[s]tates the parameters wherein IDEM shall exercise its enforcement discretion to either eliminate or reduce assessed gravity-based civil penalties through environmental auditing and self-disclosure." This potential for penalty reductions is a significant inducement for companies such as DEI to engage in voluntary environmental audits like the ones discussed below. He added that several years ago, Duke Energy implemented a fleet-wide voluntary program to monitor potential groundwater impacts associated with its ash pond surface impoundments. As a result, Duke Energy installed monitor wells to assess whether there were groundwater impacts from Gibson Station's East Ash Pond. Duke Energy also conducted linear transport groundwater modeling that predicted potential impact to offsite residential wells.

Mr. Schwartz next discussed what the environmental audit information revealed with respect to these historic ash management areas. He stated that the information indicated that there were some on-site and off-site impacts to groundwater near the historic ash management areas referenced above. Specific to Noblesville Station, there were a small number of off-site drinking water wells that had elevated levels of boron, a constituent often associated with coal ash. With respect to the Gibson Station East Pond, he testified that the information from the voluntary investigation indicated that there were some on-site and off-site impacts to groundwater due to the East Ash Pond. For example, there were a small number of off-site drinking water wells that had elevated levels of boron, a constituent often associated with coal ash. Mr. Schwartz explained that DEI voluntarily disclosed the results of its above-referenced environmental investigations. As noted above, IDEM strongly encourages this type of proactive and voluntary disclosure, and IDEM has been willing, and continues, to cooperatively work with DEI on closure activities to manage ash management areas in a manner protective of health and the environment.

Mr. Schwartz testified that Duke Energy subsequently submitted a Proposed Closure and Post-Closure Plan for the Gibson East Ash Pond System on August 4, 2008. IDEM approved the plan on March 11, 2009. A Proposed Modification to the Existing Closure and Post-Closure Plan to include the East Settling Basin was submitted to IDEM on March 21, 2016 and approved by IDEM on October 25, 2016. He testified that Duke Energy has completed most of the closure work and has submitted multiple Construction Quality Assurance Reports documenting construction of completed areas of the final cover system, which IDEM has approved. He stated that the final closure work will be completed within the next few months, at which time the 30-year post-closure period will begin.

With regard to the historic ash management areas at the former Dresser Station, Noblesville Station, and repurposed Edwardsport Station, Mr. Schwartz testified that representatives of DEI and IDEM engaged in conversations about the best way to facilitate the successful closure of the historic ash management areas such that: (a) DEI would have clearly defined expectations and timelines for the closure work to be done; and (b) IDEM has the authority to review and approve of DEI's plans, as well as supervise the work. As a result of these discussions, DEI and IDEM agreed that having the parties execute an administrative "Agreed Order" would accomplish the objectives identified above. He explained that, in cases where parties may have differing interpretations of the facts and/or law related to a site (such as a coal ash management area) or the parties simply want to identify a defined path forward to address environmental issues, an IDEM Agreed Order is often utilized. An Agreed Order is essentially a settlement agreement between the agency and a business entity/person that sets forth the actions (and often the timing for such actions) to address a particular environmental compliance matter. Notably, no party admits in an Agreed Order that any alleged legal violation occurred. To the contrary, all the parties acknowledge that their respective factual and legal positions may be different. Nevertheless, the parties agree to a series of settlement terms and actions to allow the environmental matter at issue to be resolved. Mr. Schwartz testified that it is quite common to enter into an Agreed Order, because Agreed Orders provide a very good vehicle for allowing utilities and IDEM to establish settlement terms on various issues, avoid litigation, and identify actions to resolve environmental issues in a manner to protect human health and the environment. By way of example, he attached as Petitioner's Exhibit 60-B(ORS) another utility's Agreed Order with IDEM related to the resolution of alleged compliance issues involving one of its ash ponds. He pointed out that the costs associated with the Agreed Order compliance were recovered in Cause No. 45029 and was unopposed by the OUCC.

With respect to the former Dresser Station, the Noblesville Station, and the repurposed Edwardsport Station, Mr. Schwartz testified that the Agreed Orders set forth what actions DEI agreed to take in order to close and be deemed in compliance with all legal requirements related to the historic ash management areas at those sites. The Agreed Orders also allow IDEM to review, approve, and set completion schedules for Duke Energy's proposed closure actions. The Agreed Orders also contain small administrative penalties. These administrative penalties are often unrelated to the conduct that originally led to the placement of the coal ash in the first place. He reiterated that the original conduct regarding the placement of the coal ash was lawful at the time. In contrast, the Agreed Order civil penalties often relate IDEM's view regarding the current state of the site – for example, a situation where coal ash legally placed over time is now having some adverse impacts to groundwater.

Mr. Schwartz next discussed the proposed Closure Plans submitted by DEI to IDEM under Agreed Orders for these sites. He stated that a Proposed Closure and Post-Closure Plan to address the historic ash management areas at the former Dresser Station on December 7, 2016, which IDEM approved on January 2, 2018. He stated that work is underway to consolidate coal ash and install final cover, and a Construction Quality Assurance Report will be submitted to IDEM to document construction of the final cover system. Further, groundwater monitoring is ongoing and will continue throughout the 10-year post closure period. He also testified that a Proposed Closure and Post-Closure plan for the historic ash management areas at Noblesville Station was submitted to IDEM on July 18, 2018 and approved on October 17, 2019. He stated that closure work has begun to consolidate coal ash and install the final cover system, and a Construction Quality Assurance Report will be submitted to IDEM to document construction of the final cover system. He noted that an interceptor well system is in use to prevent impacted groundwater from moving off site. Once closure is complete, he testified, a 30-year post-closure period will begin during which DEI will be required to maintain the cover system, submit groundwater monitoring reports to IDEM, and document compliance with financial assurance obligations. He also testified that a Proposed Closure and Post-Closure Plan for the historic ash management areas at the repurposed Edwardsport Station was submitted to IDEM on September 4, 2019 and is currently under review.

Mr. Schwartz opined that the Commission should allow DEI to recover its coal ash closure expenses because managing and disposing of coal ash in compliance with the state and federal law is part of providing electric service to customers. He emphasized that an Agreed Order is basically an Indiana state version of consent decree, which is explicitly discussed under Indiana Code 8-1-8.4 as a potential federally mandated requirement (seeking the utility provide a "description of the federally mandated requirements, including any consent decrees related to the federally mandated requirements"). Indiana Code § 8-1-8.4-6(b)(1)(A). He noted that the federal mandate statute also helps make clear that while expenses related to compliance with a consent decree would be recoverable, the definition of federally mandated costs explicitly excludes "fines or penalties assessed against or imposed on an energy utility for violating laws, regulations, or consent decrees related to a federally mandated requirement." Indiana Code § 8-1-8.4-4(b). He offered that a reasonable read of this statute is that fines or penalties imposed on an energy utility for violating a consent decree would not be recoverable, but compliance with a consent decree would be recoverable. He stated, the Commission has previously held that other expenses DEI has incurred to comply with consent decrees are recoverable; for example, in Cause No. 43873, the Commission held that DEI would be granted a CPCN to install and operate a new dry sorbent injection ("DSI") system (and approved the estimated costs for the DSI system), which was required as part of a Consent Decree with the U.S. Department of Justice, related to litigation involving the Clean Air Act's New Source Review ("NSR") program. DEI submits that the same treatment should be afforded to Agreed Orders as has been the case in the past as well.

Mr. Schwartz next discussed Ms. Armstrong's testimony concerning a 1990s case involving recovery of manufactured gas plant remediation costs. He explained his understanding of the factual differences between the Indiana Gas case and DEI's ash management areas, as follows. Based on his reading of the 1995 case, although operations at Indiana Gas's MGP sites had ceased decades ago, then-current environmental laws and regulations required additional remediation and decommissioning activities at those sites. He analogized this to some of DEI's historic ash management areas (those other than Gibson East Ash Pond) in that current law requires additional remediation activities that were not necessary at the time these facilities were operating. However, he emphasized that, critically, Edwardsport, Dresser and Noblesville sites all continue to support ongoing electric utility operations of DEI. Edwardsport now hosts the IGCC facility, Dresser is the location of a substation, and Noblesville is a natural gas fired generating station. He noted that this is significantly different than the MGP sites at issue in the *Indiana Gas* case. In that case, the Commission's Order stated that Indiana Gas did not incur "environmental liability because it is a public utility, it is incurring liability because it owns the land. In that connection, a business which purchases similarly contaminated land, constructs a parking lot for the purpose of selling automobiles, and subsequently discovers the contamination would incur the same liability as [Indiana Gas] is incurring today." Mr. Schwartz stated that DEI did not incur liability simply for owning the land under the historic ash management areas, but as part of its years of burning coal to provide service to customers.

In addition, Mr. Schwartz noted that the Commission stated that "the record . . . indicates that [Indiana Gas] knew of the environmental liability associated with the MGP sites, knew there were three MGP sites associated with its acquisition of Richmond and Terre Haute Gas, knew that the owners of Richmond and Terre Haute Gas refused to indemnify [Indiana Gas] for the environmental risk associated with those three MGP sites and knew that recovery of MGP costs from the ratepayers as well as from other parties is uncertain." Unlike Indiana Gas, however, Mr. Schwartz testified that DEI did not knowingly acquire contaminated property and unsuccessfully attempt to obtain indemnification from the seller associated with that contamination. Further, Indiana Gas had acquired all but one of the MGP sites after they had already ceased operations and had been partially decommissioned.

Mr. Schwartz also pointed out that the Indiana Gas Commission Order was appealed, and the Court upheld the Commission's order because the MGP plants in question were not used by Indiana Gas to provide service. Of particular relevance, Mr. Schwartz stated, the Court stated that out of twenty-six MGP plants, only one manufactured gas after Indiana Gas acquired it. The other twenty-five MGP plants were already out of business when Indiana Gas acquired them. Because of this, the Court found no connection between the costs incurred to manufacture gas and the provision of service to Indiana Gas customers. Mr. Schwartz noted that this is clearly different to DEI's historic ash management areas. DEI owned these facilities at the time they were generating electricity and continues to own them today. In addition, he testified, each location continues to be involved with the provision of service to Indiana customers and is used and useful.

Similarly, Mr. Schwartz pointed out that the Court stated that "Indiana Gas is entitled to recover only costs related to the provision of service. . . . Environmental cleanup costs, on the contrary, relate to a past use of the property which occurred prior to Indiana Gas's ownership of the land. Thus, the connection is too tenuous to meet the standard established in NIPSCO. To allow recovery of costs related only to the ownership of the land, with no connection to the provision of service, would put the ratepayers in the position of being insurers of any purchase made by Indiana Gas. Such a result is untenable."

Mr. Schwartz argued that, for the Indiana Gas precedent to be applicable to the Company's efforts to remediate its historic ash management areas, DEI would have had to have purchased other utilities and along with those purchases, acquired some retired, yet contaminated generating stations. Then DEI would have to have sought the costs of environmental remediation for activities that do not now and never were involved in the provision of service to the Company's customers.

Mr. Schwartz concluded that the Indiana Gas MGP case is not similar to DEI's historic ash management areas.

In response to Mr. Schlissel's argument that the Commission should not approve DEI's request in this proceeding until IDEM approves the closure plans, Mr. Schwartz provided an update on the status of the IDEM approvals. He stated that DEI submitted ash basin closure plans to IDEM in December 2016. DEI, along with IDEM, held closure open house meetings near each of the generating stations to engage the public. These closure plans included ash ponds regulated by the federal CCR Rule and those regulated only by state implemented (but federally required) solid waste regulations. He stated that the Company has received and responded to several

Requests for Additional Information ("RAIs") for these plans, providing technical detail and addressing questions from IDEM technical staff. IDEM has indicated that the agency is prepared to approve the closure plans for the majority of the sixteen impoundments at four generating stations and recently approved the closure plan for ash ponds at Wabash River Station, except for Ash Pond B. IDEM has communicated to DEI that the closure plan for this ash pond, and three other ash ponds at Gibson, Cayuga, and Wabash River Stations, will need to be modified to meet the IDEM interpretation of CCR Rule in-place closure requirements. IDEM's position has been that because Indiana has adopted the CCR Rule by reference, closure plans regulated by the CCR Rule should be approved based on compliance with the federal CCR Rule and IDEM's interpretation of the rule. DEI recently submitted closure plan modifications to IDEM for three of the four ponds for which IDEM rejected closure as proposed in the original closure plan.

Further, he explained that ash basins that are regulated by the federal CCR Rule have requirements to stop inputs and initiate closure under the CCR Rule and DEI is required to comply with federal CCR Rule deadlines. DEI is also required to comply with Indiana solid waste regulations and close ash ponds in compliance with IDEM approved closure plans. Because the closure plans submitted to IDEM in December 2016 are either not approved, or recently approved, Mr. Schwartz testified that DEI has made a good faith effort to proceed with work necessary to remain in compliance with environmental regulations and be in position to complete closure within the time limits required by the federal CCR Rule.

Mr. Schwartz emphasized that, regardless of when IDEM approves the Company's closure plans, the Company must continue to proceed with complying with the CCR Rule. He reiterated that the CCR Rule is "self-implementing," meaning that there is no federal permit program for CCR units. However, if DEI fails to comply with the requirements and deadlines in that Rule, it may potentially be subject to enforcement pursuant to RCRA's citizen suit provisions. Although IDEM's position has been that because Indiana adopted the CCR Rule by reference, it may review and approve closure plans, IDEM has not yet created a state CCR Rule permit program. Until such time as IDEM does create such a state permit program and receive federal approval of that permit program, DEI must continue to follow the federal CCR Rule requirements and incur costs as necessary to ensure compliance with that Rule.

In conclusion, Mr. Schwartz testified that DEI has acted prudently and reasonably regarding the submission of coal ash closure plans to IDEM for its review and approval. He stated that when the CCR Rule was promulgated, all utilities were put on notice that they would need to assess their existing surface impoundments for compliance with the CCR Rule's new location restrictions, and when those surface impoundments do not meet those requirements, be prepared to close them in compliance with the new requirements. He stated that following IDEM's adoption of the CCR Rule, in December 2016, the Company submitted proposed closure plans to IDEM for its review and consideration. Further, as described above, DEI has continuously worked in cooperation with IDEM on its proposed closure plans, providing additional information and holding public meetings. Mr. Schwartz opined that DEI has acted reasonably and prudently in how it has proceeded with submitting closure plans to IDEM for its review and approval and in its development of those closure plans. He noted that even through this IDEM process, however, the CCR Rule deadlines continue to apply. And as Mr. Thiemann's testimony explains, DEI's activities to date have largely included activities that must be done whether or not IDEM makes changes to the Company's proposed closure plans. He testified that DEI's compliance activities have been managed reasonably and in a manner designed to ensure the Company's continued compliance with applicable rules and standards, and he urged the Commission to approve the Company's request to recover its associated expenses.

i. <u>Commission Discussion and Findings</u>. No party disputed that the CCR Rule is a federal mandate with which the Company must comply, nor did any party dispute that the Company must comply with the IDEM solid waste management rules. Additionally, no party provided evidence of any imprudence on the part of DEI with respect to its coal ash basin closure and remediation activities to date. However, the OUCC and certain intervenors contend that the Commission should disallow both the Company's previously-incurred coal ash-related expenses and the forecasted 2019-2020 expenses presented in this case, related to both the CCR Projects and the IDEM Projects. In considering these arguments, the Commission cannot ignore that coal generating stations have historically supplied most of the energy to Indiana's retail customers and that ongoing environmental regulations drive costs associated with that history, and we make the following findings.

We find that the CCR Project costs and the IDEM Project costs were properly deferred and preserved for recovery consideration in this proceeding. We further find that such costs are recoverable under traditional ratemaking: the costs at issue are significant and infrequent (stemming from federal and state mandated requirements) and will provide longstanding benefits, in terms of compliance with such federal and state mandates, improved environmental footprints, and the ability to continue to use utility properties. Further, important to our decision is that we have consistently allowed recovery of environmental compliance costs generally and coal ash-related compliance costs in particular. See for example, our Orders in Cause Nos. 44765, 44794, 45052, and 44872. Also important to our decision is the fact that, as the Company pointed out, these costs have been deemed to be AROs, such costs would be reflected in costs of removal and depreciation rates and recoverable in that manner. In other words, in the absence of required ARO accounting, both a "return on" and a "return of" these costs would have been built into rate base. Although we base our decision to allow recovery in this case on traditional ratemaking, we nonetheless note that the federal mandate statute analytical framework and specific considerations can reasonably be understood to be a means of evaluation that provides collateral support of our decision to allow recovery of such costs in this manner. Absent the timing of the request these costs would have been the type of costs that are recoverable under the federal mandate statute. Accordingly, applying the statutory considerations of the federal mandate statute was helpful to our conclusion. Significantly, DEI presented detailed testimony supporting the reasonableness of its actions to date, and no party disputed the reasonableness or prudence of the Company's activities and costs incurred to date, with respect to either the CCR Projects or the IDEM Projects. Accordingly, we authorize Petitioner to recover its previously-incurred and deferred CCR Project costs including financing costs and IDEM Project costs including financing costs as a regulatory asset to be included in rate base to be amortized over an eighteen-year period, as proposed by the Company. Additionally, we authorize Petitioner to recover in base rates in this proceeding the IDEM Project costs forecasted to be incurred in 2019 through the end of 2020 test period, for IDEM Projects with approved closure plans. We also authorize Petitioner to recover the financing costs forecasted to be incurred in 2019 through the end of the 2020 test period associated with the coal ash costs authorized for recovery. We also note that we will consider the future coal ash expenditures in the pending S1 subdocket.

k. Amortization Periods and Amortization Methodology. DEI 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.

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 – in other words, a methodology for calculating an amortization amount that effectively factors in the decrease in return due to declining rate base, using Rider 67 to credit customers with the difference between the return on the rate base reflected in base rates and the return on the declining balance of rate base.

Company witnesses Davey and Douglas testified in rebuttal that, in an effort to help mitigate the rate impact of the Company's proposal in this proceeding, the Company was agreeable to using ten years to amortize any of the regulatory assets in rate base that used a shorter amortization period than ten years in the Company's case-in-chief filing. The regulatory assets affected by this agreement include:

Table 3

Regulatory Asset	Case-in-Chief Amortization Period	Rebuttal Testimony Amortization Period
PISCC-NOX	3 years	10 years
NBV-Gallagher 1&3 and Gas Conversion	5 years, 6 months	10 years
Def. Depr. Gallagher Baghouses 2&4	3 years	10 years
NBV-Wabash River 6	8 years	10 years
CCR-Plan Development-20%	3 years	10 years
CCR-Def. O&M-20%	3 years	10 years
PISCC-Fed. Mandate-20%	3 years	10 years
Fed. Mandate-Def. Depr.-20%	3 years	10 years
Fed. Mandate-Def. O&M-20%	3 years	10 years
Fed. Mandate-Carry Costs on Def. O&M-20%	3 years	10 years
PISCC-TDSIC-20%	7 years	10 years
TDSIC-Def. Depr.-20%	7 years	10 years
TDSIC-Def. O&M-20%	7 years	10 years
PISCC-TDSIC-Def. O&M 20%	7 years	10 years

Both Mr. Davey and Ms. Douglas opposed Mr. Kollen's proposed levelized methodology for amortizing regulatory assets. They characterized his proposal as a departure from traditional ratemaking and an asymmetrical approach to amortization of regulatory assets, in that customers would receive the benefit of declining asset base in between base rate cases, but would not bear increased costs between base rate cases. Ms. Douglas testified that traditional ratemaking practice sets the value of rate base as of the end of the test period and includes an allowed rate of return on that value in its revenue requirement and base rates, until the next time base rates are reset. She stated this practice is reasonable as rate base and operating costs, such as amortization of regulatory assets, don't just go down between rate cases – they also go up. She noted that the Commission has historically recognized that, although a certain fair return on assets is granted in a base rate case, that return is not guaranteed, and it is up to the utility to manage all costs between rate cases to have the opportunity to earn that return. She argued that changing this practice, as the OUCC has proposed, for rate base items such as regulatory assets (and other rate base assets addressed later in other sections of her testimony) limits the return the Company has to offset other changes in costs or additions to plant after the rate case, thus impairing the Company's opportunity and ability to earn a fair return between rate cases. She cautioned that if the OUCC's proposal became precedent it would potentially result in more frequent base rate cases by all utilities. The main problem with Mr. Kollen's approach, according to Mr. Davey, is that he picks which cost items are trued up annually so that only items that provide reductions in customer costs are included. Mr. Davey also noted that, generally speaking, costs increase over time, and Mr. Kollen makes no recommendations to adjust for future cost increases. Mr. Davey noted that DEI has already agreed in its case-in-chief to remove amortizations from rates once regulatory assets are fully amortized, and has agreed to stretch out recovery of such regulatory assets over a minimum of ten years.

i. Commission Discussion and Findings. 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, as it reasonably provides a measure of rate impact mitigation.

With regard to the OUCC's proposal to use a non-traditional "levelized" amortization methodology, and given its asymmetrical nature as DEI witnesses pointed out, we are not persuaded that this departure from traditional ratemaking is necessary or desirable as a reasonable rate mitigation measure when coupled with the agreement to extend the amortization period. Accordingly, we decline to order the OUCC proposed levilization.

6. Original Cost of DEI'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 DEI's rate base used and useful for the benefit of the public is forecasted to be $9,928,872,000 at December 31, 2019, comprised of the following elements:

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	152,452,000
Regulatory Assets	425,633,000
NET UTILITY RATE BASE	$9,928,872,000

Further, we find that the jurisdictional net original cost of DEI's rate base used and useful for the benefit of the public is forecasted to be $10,195,192,000 at December 31, 2020, comprised of the following elements:

Net Electric Utility Plant in Service	$9,214,171,000
Fuel Inventory	114,710,000
Emission Allowance Inventory	86,000
Materials and Supplies	286,925,000
Prepaid Pension Asset	142,803,000
Regulatory Assets	436,497,000
NET UTILITY RATE BASE	$10,195,192,000

7. Fair Value of DEI'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 ($10,195,192,000), and that this fair value rate base should be used for purposes of Indiana Code § 8-1-2-6.

8. Fair Rate of Return.

a. Capital Structure. Mr. Sullivan testified that, as of May 31, 2019, DEI's financial capital structure is 46.2% long-term debt and 53.8% equity. He further testified that DEI's capital structure is forecasted to be 47% long-term debt and 53% equity at the end of 2020 (the end of the test period). He stated that this forecasted capital structure is consistent with the target capital structure of 47% long-term debt and 53% equity for DEI, as it introduces an appropriate amount of risk due to leverage while minimizing the weighted average cost of capital to customers. He stated that use of the forecasted capital structure in setting DEI's rates will help DEI maintain its credit quality, and would also be consistent with the Company's target credit metrics needed to support its current credit ratings. Ms. Douglas testified and supported the Company's regulatory capital structure, incorporating Mr. Sullivan's forecasted financial capital structure, as shown in Petitioner's Exhibit 4-G.

Ms. Douglas explained that both the historical reference period and forecasted test period capital structure and cost of capital had been calculated using the same expanded regulatory presentation and the same methodology as has been used in recent years for all the Company's rate adjustment riders that include return on investment as part of the calculation. She stated that the forecasted financial capital structure had been expanded to include traditional Indiana regulatory components including accumulated deferred income taxes, unamortized ITCs, and customer deposits. The components of the Company's regulatory capital structure included cost rates computed in accordance with traditional Indiana regulatory practice (the embedded cost of long-term debt, average financial rates for ITC and zero cost of capital for deferred income taxes). She explained the Company is proposing the Commission approve the Company's request to allow it to use a 2% interest rate on customer deposits included for the test period, rather than the 6% currently effective rate. She stated that use of this lower rate on the customer supplied funds in the capital structure will benefit all customers by lowering the rate of return, resulting in lower revenue requirements of approximately $1 million.

Ms. Douglas also explained that the Company removed a long-term financing issuance specifically related to the liability assumed by the Company to pay the Rural Utility Service ("RUS") resulting from the settlement of litigation with Wabash Valley as well as removing the Gas Pipeline Lease Liability recorded as a capital lease for payments under a Gas Services Agreement with Southern Indiana Gas and Electric Company, to provide gas to the Edwardsport IGCC plant via a gas pipeline which Vectren constructed and owns. This was removed for ratemaking due to the treatment of the payments under the lease for both ratemaking and income tax purposes as a "pay-as-you-go" operating lease. In addition, adjustments were made to eliminate certain deferred income taxes recorded on the Company's books for financial statement reporting purposes in accordance with the provision of Statement of Financial Accounting Standards No. 109, but which have historically been excluded from the capital structure for ratemaking purposes, as well as to remove the deferred income taxes related to the Gas Pipeline Lease. Ms. Douglas explained that the Company made certain other adjustments to the accumulated deferred income tax balances to remove deferred taxes associated with impairments taken by the Company for accounting books purposes but which are not used for tax purposes. As approved by the Commission in its IGCC-4S1 Order, the Company excluded deferred income taxes associated with the amount of the IGCC capital investment in excess of the agree-upon Hard Cost Cap, including Additional AFUDC. The Company similarly removed the deferred taxes associated with the non-AMI legacy meter impairments taken by the Company, so that customers will neither be harmed by nor benefit from the inclusion of related deferred taxes in the capital structure for the portions of the IGCC plant and non-AMI legacy meters that shareholders are paying for, not customers. Ms. Douglas explained an adjustment to remove the deferred income tax asset balances related to the Company's deferred utilization of ITCs and to include the unamortized balance of the regulatory liability for the EDIT amounts resulting from the 2017 Tax Cuts and Jobs Act and from other previous state and federal tax changes as an additional zero cost source of capital component in the calculation. Finally, she explained that short-term debt has been excluded from the capital structure, consistent with previous Commission orders. However, the Company has included $150,000,000 inter-company notes payable for Commercial Paper issued by Duke Energy Corporation on behalf of the Company that is part of the Company's permanent long- term financing.

OUCC Witness Kollen testified that the Company understated the Accumulated Deferred Income Taxes included in capitalization as cost-free capital. He proposed adjustments to ADIT to reflect the rate base adjustments proposed by the OUCC as well as a number of adjustments to ADIT for what he characterized as the Company's failure to remove certain per books ADIT amounts through *pro forma* adjustments for ratemaking purposes. As a general ratemaking principle, he said 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. In Mr. Kollen's opinion, if the underlying temporary difference is not reflected as an addition to or subtraction from rate base, then the related liability or asset ADIT should not be added to or subtracted from the ADIT included in capitalization. Mr. Kollen indicated the ADIT amounts that incorrectly reduce (on a net basis) the ADIT included in capitalization were shown in a table set forth in his testimony, along with the reason why it should not be included in rate base. 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 $10.5 million reduction in the retail revenue requirement due to the increase in ADIT included in capitalization as cost-free capital.

FEA witness O'Donnell recommends the Commission reduce the common equity ratio to reflect a capital structure of 50% common equity and 50% long-term debt. He testified that the basis for his recommendation are the equity ratio requested by the Company, compared to the equity ratio of the proxy group, the average allowed equity ratio by state regulators across the country in 2018, and the equity ratio of Duke Energy Corp., the parent company of DEI.

Ms. Douglas took issue with Mr. Kollen's recommendation for certain additional adjustments to the Company's zero cost ADIT balance included in capital structure. She pointed out that there is no Indiana statutory or regulatory requirement to exclude from the capital structure all deferred income tax balances that are associated with working capital or other items not included in rate base or operating income for retail jurisdictional purposes. She noted that the Commission previously approved DEI's capital structure that included deferred income tax balances with only the FAS109 adjustment in in Cause No. 42359, approved May 18, 2004. Since then, she stated, the Commission has approved the use of the same capital structure components and methodology in many rate adjustment rider filings, most recently in Cause No. 44720 - TDSIC 6 approved on October 10, 2019. The capital structure used in these rider filings included deferred income tax balances with the limited adjustments she supported in her direct testimony. Furthermore, she testified, the Company does not maintain its capital structure for the retail jurisdictional business separate from the rest of its business. Rather, it manages one DEI capital structure, and it is assumed all parts of the business benefit.

After reviewing Mr. Kollen's recommendations, Ms. Douglas stated the following three items (MGP Sites, Charitable Contribution Carryover and RUS Obligation—Contract Reserve) appeared to be related solely to non-jurisdictional expense activity and may be appropriate to exclude from the regulatory capital structure.

i. <u>Commission Discussion and Findings</u>. Addressing Mr. Kollen's ADIT issues first, we find that his proposed adjustments that flow from rate base adjustments need not be made, as we are not accepting the OUCC's rate base adjustments. His additional proposed ADIT adjustments are neither required nor supported by Indiana precedent. Given DEI's agreement as to ADIT adjustments for MGP, RUS, and charitable contributions, which we accept, we reject the remainder of the OUCC's proposed ADIT adjustments.

Turning now to the appropriate equity component to use in the capital structure for setting rates for Petitioner, we find that Mr. O'Donnell's recommendation should be rejected. Longstanding Indiana precedent requires the use of a utility's actual, not hypothetical, capital structure when setting rates. Hypothetical capital structures are contrary to Indiana law. *See Public Service Comm'n of Ind. v. Ind. Bell Tel. Co.*, 235 Ind. 1, 130, N.E.2d 467 (Ind. 1955). Although we are dealing with a future test period in this case, and are using forecasted capital structures at this point in the process, the Company's proposal will incorporate its actual capital structure, not a forecasted capital structure, when implementing its Step 1 and Step 2 rate increases. Accordingly, we accept Petitioner's proposed capital structure in this case.

b. <u>Cost of Debt</u>. Ms. Douglas explained the calculation of the cost rate assigned to long-term debt in the forecasted test period capital structure. She explained that the summation of the annual interest requirements and amortization of costs related to the issuance of long-term debt, including costs of interest rate hedges, were divided by the net proceeds received from the issuance of the debt. The net proceeds are defined to include unamortized debt premium, discount, issuance expense and unamortized gain or loss on reacquired debt. She stated that for ratemaking purposes, it is appropriate to use net proceeds (i.e., the net investible proceeds from the debt) as the denominator in this equation to recognize that the cost rate will be applied to rate base, ensuring that all debt-related costs associated with rate base are covered in the Revenue Requirements calculation.

Mr. Sullivan testified that, as of March 31, 2019, DEI's weighted average cost of long-term debt is 4.94%. He further testified that DEI's weighted average cost of long-term debt is forecasted to be 4.88% at the end of 2020 (the end of the test period). He noted that, over the past decade, DEI has been taking advantage of low interest rates, decreasing its weighted average cost of long-term debt as older bonds are replaced with lower cost debt. Ms. Douglas testified that the Company's proposed 2-step rate increase should reflect the Company's actual cost of debt as of December 31, 2019, for its Step 1 rate increase, and should reflect the actual cost of debt as of December 31, 2020 for its Step 2 rate increase.

OUCC witness Garrett testified that the Commission should approve a cost of debt of 4.66% for the Company, based on the Company's approach to estimating the rate on upcoming long-term debt issuances, but with considering the reduction in 30-year Treasury bond yields since the Company conducted its analysis. Industrial Group witness Gorman proposed an adjustment to embedded cost of debt for repricing certain new debt issues to 4.62%.

In its rebuttal testimony, DEI agreed to update its forecasted cost of debt. Mr. Sullivan testified that in September 2019, DEI issued $500,000,000 of 30-year First Mortgage Bonds at a coupon of 3.25%, originally estimated at 4.25%. He stated that the expected transaction size was originally $400,000,000 but was upsized to take advantage of the continued low interest rate environment. He further testified that the additional $100,000,000 was issued to refinance two existing callable bonds with a weighted average cost of debt of 4.73%. He observed that this refinancing is an example of how DEI continues to opportunistically lower the overall cost of debt being charged to customers. He testified that, factoring in the actual 2019 debt replacement activity and the current view of variable and fixed interest rates for 2019 and 2020, the Company's updated forecasted cost of debt for December 31, 2020 is reduced from 4.88% to 4.50% (and Ms. Douglas testified that the current forecasted end of year 2019 debt rate is forecasted to be 4.65%.). Mr. Sullivan and Ms. Douglas both reiterated that rates will ultimately be set to the actual cost of debt as of 12/31/2019 for Step 1 and 12/31/2020 for Step 2.

i. <u>Commission Discussion and Findings</u>. The evidence reveals no dispute at this point that the Company's forecast of debt for the end of the test period should be updated to 4.50%. However, consistent with our approval of the Company's 2-step rate increase proposal, the Company's proposed 2-step rate increase should reflect the Company's actual cost of debt as of December 31, 2019, for its Step 1 rate increase, and should reflect the actual cost of debt as of December 31, 2020 for its Step 2 rate increase.

c. <u>Cost of Equity</u>. Robert Hevert testified on behalf of the Company with respect to cost of equity. Mr. Hevert stated that, based on longstanding precedent, the return on equity ("ROE") authorized in this proceeding should provide the Company with the opportunity to earn a return on equity that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks. He explained that, to the extent DEI is provided a reasonable opportunity to earn its market-based cost of equity, neither customers nor shareholders should be disadvantaged. He states that a return adequate to attract capital at reasonable terms enables DEI to provide safe, reliable electric utility service while maintaining its financial integrity, all to the benefit of both investors and customers.

Mr. Hevert testified that, based on the quantitative and qualitative analyses he performed and discussed in his direct testimony, and considering the Commission's orders in prior rate proceedings, he believes a return on equity ("ROE") in the range of 10.00% to 11.00% represents the range of equity investors' required ROE for investment in electric utilities like DEI in the current capital market environment. Within that range, he testified that an ROE of 10.40% is reasonable and appropriate. He stated that his recommendation is based on the use of several widely accepted methods and reflects the results of several analyses regarding the effect of DEI's business risks on its cost of equity.

Mr. Hevert explained that, because all financial models are subject to various assumptions and constraints, equity analysts and investors tend to use multiple methods to develop their return requirements. Therefore, he relied on three widely accepted approaches to develop his ROE determination: (1) the Constant Growth of the Discounted Cash Flow ("DCF") model; (2) the traditional and Empirical forms of the Capital Asset Pricing Model ("CAPM"); and (3) the Bond Yield Plus Risk Premium approach. According to Mr. Hevert, those analyses indicate the Company's Cost of Equity currently to be in the range of 10.00% to 11.00%. He further testified that range is corroborated by the Expected Earnings, which results in an average ROE estimate of 10.50% and a median ROE estimate of 10.53%. Mr. Hevert stated that his analyses recognize that estimating the cost of equity is an empirical, but not entirely mathematical exercise; it relies on both quantitative and qualitative data and analyses, all of which are used to inform the judgment that inevitably must be applied. He emphasized that no single model is more reliable than all others under all market conditions, and all require the use of reasoned judgment in their application, and in interpreting their results.

Mr. Hevert testified that a balanced approach to estimating a utility's cost of equity is to consider the relative strengths and weaknesses of multiple methods, and give the appropriate weight to their results. Based on his analysis and utilizing that approach, Mr. Hevert reiterated his view that an ROE in the range of 10.00% to 11.00% represents the range of equity investors' required ROE for investment in integrated electric utilities in the current market environment; and an ROE of 10.40% represents the cost of equity for DEI.

OUCC witness 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 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. 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%.

Mr. Gorman testified on behalf of the Industrial Group with respect to cost of equity. Mr. Gorman recommended DEI's current market cost of equity to be no higher than 9.0%. He stated that a return on common equity of 9.0% is the midpoint of his estimated range of 8.50% to 9.30%. His recommended ROE range was based on the following analytical models: Constant Growth DCF, Multi-Stage Growth DCF, CAPM. With one exception, Mr. Gorman utilized the same proxy group as did Mr. Hevert. Mr. Gorman further testified that his recommended return on equity estimates reflect observable market evidence, 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, and a general assessment of the current investment risk characteristics of the electric utility industry and the market's demand for utility securities.

Mr. O'Donnell testified that Mr. Hevert's recommended ROR is unreasonable, unnecessary, and excessive, and that the Company's allowed ROE should be set at 9.0%. He also critiqued Mr. Hevert's analyses. His recommendation in this case is for the Commission to grant DEI a ROE of 9.0%. He stated that this 9.0% ROE is slightly above the midpoint of the DCF results for the proxy group, well above the CAPM results, and is slightly below the low end of the Comparable Earnings results.

Mr. Chriss recommended that the Commission closely examine the Company's proposed ROE, especially in light of the customer impact of the resulting revenue requirement increases, the use of a future test year, which reduces regulatory lag, recent ROEs approved by the Commission, recent rate case ROEs approved by other state regulatory commissions for other Duke Energy subsidiaries, and recent rate case ROES approved by other state regulatory commissions nationwide. Mr. Chriss stated that the average Commission-approved ROE since 2016 is 9.94%. He also testified that the South Carolina Commission authorized ROEs of 10.1% and 9.5% for Duke Energy Progress in 2016 and 2019, respectively; the North Carolina Commission approved ROEs of 9.9% for Duke Energy Carolinas and Duke Energy Progress in 2018; and the Ohio Commission approved an ROE of 9.84% for Duke Energy Ohio in 2018. Additionally, he testified that according to S&P Global Market Intelligence, the average of the 128 reported electric utility rate case ROEs authorized by state regulatory commissions to investor-owned utilities (including distribution-only utilities) in 2016 to 2019 (to date) is 9.6%; the range of reported authorized ROEs for the period is 8.4% to 11.95%, and the median authorized ROE was 9.6%, well below the Company's proposed ROE of 10.4%. Mr. Chriss noted that the average ROE for vertically integrated utilities over the same period was 9.73%. Mr. Chriss concluded his testimony by commenting that decisions of other state regulatory commissions are not binding on this Commission -- rather, each commission considers the specific circumstances in each case in its determination of the proper ROE. He stated that Walmart is providing this information on industry trends on ROE from its perspective as a customer with operations that are nationwide as it believes that recently authorized ROEs in other jurisdiction provide a general gauge of reasonableness for the various cost of equity analyses presented in this case. Moreover, Walmart believes that it is appropriate for the Commission to consider how any ROE authorized in this case impacts existing and prospective customers relative to other jurisdictions.

Mr. Hevert indicated that he continues to believe an ROE in the range of 10.00% to 11.00% represents the range of equity investors' required ROE for investment in electric utilities like DEI in the current capital market environment. Within that range, he indicated he continues to believe an ROE of 10.40% is reasonable and appropriate.

i. Commission Discussion and Findings. In setting the rate of return for DEI, 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).[1] 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.

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. 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

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

appropriate and reasonable inputs, models such as the DCF and other methods 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, DEI's authorized return on equity should be reasonable given the totality of the circumstances.

To meet the requirements set forth in *Bluefield* and *Hope,* the parties proposed various returns using the DCF model and other methods as bases for their positions. Mr. Hevert's analysis produced a range of 10.0% to 11.0%. He recommended the Commission adopt a COE of 10.40%. Mr. D. Garrett recommended a COE of 9.0% based on a range of 8.75% to 9.25%. Mr. Gorman's analysis produced a range of 8.50% to 9.30%. He recommended a COE of 9.00%. Mr. O'Donnell recommended a COE of 9.0%. In light of the discussion below on recent COE authorizations in Indiana, as well as the evidence submitted by Mr. Chriss on the recent COE authorizations by other state commissioners, we find it is reasonable to narrow this range around its center, such that a range of 9.25% to 10.25% will frame an outer bound for our award determination.

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 DEI) 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); Indianapolis Power and Light Company 9.85% in Cause No. 44576 (2016), Northern Indiana Public Service Company LLC 9.75% in Cause No. 45159 (2019), and with the most recent COE award for such an electric utility being 9.70% approved on March 11, 2020, for Indiana Michigan Power in Cause No. 45235.

Our determination should appropriately consider the mitigation of risk associated with various regulatory mechanisms, including DEI's use of a forecasted test year in this proceeding and the riders and/or trackers approved for DEI. *In Re Psi Energy, Inc.*, 234 P.U.R.4th 1 (IURC May 18, 2004). Additionally, in this case DEI is proposing to move the Edwardsport IGCC from a tracker into base rates, which removes even more risk from the Company

Having taken into consideration the observable market data reflected in the record, and a general assessment of the investment risk characteristics of the electric utility industry, combined with a thorough understanding of the Indiana jurisdiction and its risk mitigation ratemaking mechanisms, and DEI in particular, and our narrowed expert witness recommended range identified above, the Commission finds a reasonable range for Petitioner's COE is 9.50% to 10.0%. Taking into consideration all the evidence presented, the Commission finds that an unadjusted 9.75% COE, the mid-point of this range, would represent a fair and reasonable rate.

However, as we noted in Cause No. 43526,

> a utility's operational and financial performance were appropriate considerations in determining a utility's cost of equity .... The Commission has a unique role in regulating its jurisdictional utilities, which at times requires us to send a clear and direct message to utility management concerning the need for

> improvement in the provision of its utility service. Our determination of the authorized cost of common equity capital can be a very direct means to incent improved service.

NIPSCO, Cause No. 43526, at 32 (IURC Aug. 25, 2010).[2] We are troubled by the under spending on vegetation management. To illustrate, in the present case, DEI proposed a five-year trim cycle. However, as Witness Christie pointed out, DEI's trim cycle has been closer to 16 years for the past two years. We will discuss this issue further below, and therefore, find that a downward adjustment is necessary to address DEI's deficiencies in regard to vegetation management. Thus, we are approving a 9.70% COE.

Accordingly, for purposes of this Cause, we find that Petitioner's overall cost of capital is 5.71%, computed as follows:

Description	Capitalization (in thousands)	Ratio	Cost	Weighted Cost
Common Equity	$ 4,770,344	40.98%	9.70%	3.98%
Long Term Debt (estimated)	4,228,373	36.33%	4.50%	1.63%
Deferred Income Taxes	2,447,756	21.03%	0.00%	0.00%
Unamortized ITC – Crane Solar	10,999	0.09%	7.25%	0.01%
Unamortized ITC -- 1971 & Later	1,955	0.02%	7.25%	0.00%
Unamortized ITC – Advanced Coal (IGCC)	133,500	1.15%	7.25%	0.08%
Customer Deposits	47,056	0.40%	2.00%	0.01%
Total	$ 11,639,983	100.00%		5.71%

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

a. 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 *pro forma* adjustments proposed by Petitioner, either as originally proposed and undisputed, or as adjusted 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 that 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.

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[2] This principle was also applied in Cause No. 44576. *See IPL*, 329 P.U.R.4th 486 (IURC Mar. 16, 2016).

b. <u>Disputed *Pro Forma* Adjustments</u>. 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, 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. <u>Load Forecast and Unbilled Revenues</u>. Mr. Jacobi testified in his direct testimony how he used the Company's load forecast in the development of its financial forecast for 2020, which in turn forms the basis for the Company's requested revenue requirement in this case. Ms. Graft testified concerning a *pro forma* adjustment that removes $28.8 million from test period revenues for unbilled revenues that are excluded from the development of new base rates. She stated that unbilled revenues represent the estimated amount of revenues associated with electric utility service the Company has provided but not yet billed to customers. She further stated that the Company bases the calculation of its revenue deficiency in a rate case on billed revenues only.

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. 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 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 residential sales forecast, OUCC witness Watkins testified 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 Company based its 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 forecasted amounts for 2020, either in prior forecasts (Fall 2017 and 2016 forecasts), or in the more recent Spring 2019 forecast. 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 and based upon the Spring 2019 forecasted number of customers. He then allocated his adjusted forecast of residential energy sales to individual rate schedules using the same allocation as used by Mr. Bailey, and converted his adjusted forecast to residential revenues at current rates.

Ms. Graft and Mr. Bailey responded to the OUCC's position on unbilled revenues. Ms. Graft reiterated that the Company bases the calculation of the revenue deficiency in a rate case using a forecasted test period on billed revenues only. She stated that this ensures alignment with the sales volumes used in rate design, which are also on a billed basis. Additionally, she stated, proposed revenues (which are the basis for proposed rates) are equal to the sum of proposed net operating income (return on investment) plus proposed operating expenses. In other words, she emphasized, unbilled revenues do not impact the calculation of proposed revenues. Mr. Bailey similarly testified that the rate design process utilized a historical billing period predicated on billing cycle data. He stated that this data was then used to apportion the forecast to rate schedules, as well as the blocking for applicable rates, then used to compute present revenue. He testified that the forecast is computed based on a billing cycle basis as well. Finally, he testified, the total proposed revenue requirement was developed without unbilled revenue. Thus, he summarized, while unbilled revenue may have some relevance to certain accounting computations, it has no bearing on the final revenue requirement, nor the computation of the Company's final rate designs. Accordingly, he concluded excluding unbilled revenue from the revenue requirements and rate design is proper ratemaking.

In a docket entry question from the Commission, the Company was asked to explain the substantially higher level of the unbilled revenues at issue, compared to a year earlier. The Company's docket entry response summarized the volatility in unbilled revenues and the drivers of unbilled revenues, and explained that while unbilled sales were likely overstated slightly, this was the result of a very minor growth rate assumption. The Company's response concluded that a more reasonable estimate of unbilled revenues would range from about a negative $5 million to positive $12 million instead of $28 million. As a final point, the Company's response to our docket entry question emphasized that the forecasted $28 million in unbilled revenues has no effect on the Company's revenue requirement: "The Company identified a level of revenues required to cover its costs identified in the cost of service. In the event unbilled revenues were to be included, it would only impact the identified level of present revenues and should not be included in rate design as indicated in Mr. Bailey's rebuttal testimony."

Company witness Stillman responded to Mr. Watkins' concerns that the Company's forecasted kWh sales and therefore revenues for residential customers are understated. Mr. Stillman testified that the Company has updated the forecast twice since the Fall 2018 forecast, and the most current forecast shows that expected 2020 retail billed sales come in slightly below what was originally assumed in the Fall 2018 forecast. His testimony showed actual billed sales for 2014 through 2019, which demonstrated that 2018 billed sales, which influenced the Company's Spring 2019 forecast, was an outlier, growing by almost 33 GWh whereas the Company had experienced sales declines in previous periods. Mr. Stillman stated that the unusual growth experienced in 2018 is thought to be the result of the fiscal stimulus, brought on largely by the 2017 Tax Cut and Jobs Act. Mr. Stillman stated that this provided a short-term stimulus, prompting business investment and growth across most classes. However, he testified, that stimulus was short lived, and sales going forward are more likely to follow the trend in sales seen since 2014.

Mr. Stillman also showed that the residential use per customer used in this proceeding is relatively close to what is expected in the Company's most recent forecasted results. He testified that the unusual 2018 results impact Mr. Watkins' calculations and cause him to overstate both his assumed 2020 use per customer, as well as his estimated 2020 MWH sales. Mr. Stillman concluded his testimony by stating that in his experienced opinion, the forecast used by the Company in this proceeding is still reasonable in terms of kWh sales.

(A) **<u>Commission Discussion and Findings</u>.** Unbilled revenues represent the estimated amount of revenues associated with electric utility service provided but not yet billed to customers. DEI adjusted its 2020 forecasted test year downward by $28.8 million ("Adjustment REV3") to reflect a revenue amount for unbilled sales. DEI stated that the revenue requirement in the rate case is based on billed revenues only and the total proposed revenue requirement was developed without unbilled revenue.

Because the proposed net revenue adjustment is higher than expected, we issued several docket entries to try and understand the magnitude of the adjustment. On January 21, 2020, DEI filed its Docket Entry response and noted:

> [U]nbilled sales were likely overstated slightly, this is the result of a very minor growth rate assumption. Rather than $28 million referenced, a better updated estimate would be to look at the range history provides. Using similar pricing that was used to estimate the $28 million, a more reasonable estimate would range from about a negative $5 million to positive $12 million.

While the responses to the Presiding Officer's docket entries and the live testimony responses to bench questions identified that the Adjustment REV3 does not alter the determined revenue requirement, it would alter the rate increase percentage as it changes the current revenue deficiency amount. Based on the evidence presented, there is a significant amount of uncertainty as to the proper adjustment amount, thus, we are denying Adjustment REV3.

With regard to the issue of forecasted residential sales, the balance of the evidence shows that the residential sales forecast used by the Company in this case is reasonable. The Company's forecast used to develop rates for this case is supported by its most recent updated load forecast (circa Fall 2019). Additionally, the evidence shows that the residential sales forecast relied upon by the OUCC to support its proposed adjustment is an outlier. Accordingly, we reject the OUCC's proposed adjustment to the residential sales forecast numbers.

ii. **<u>Depreciation</u>.** The Parties debated several aspects that determine the depreciation rates. Our presentation of the arguments and discussion and findings are as follows:

(A) **<u>Estimated Useful Lives of Mass Property</u>.** OUCC witness Garrett took issue with certain portions 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 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 are relatively minor, for some accounts he has proposed significant increases when compared to the current estimates. For example, he proposes 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.

(1) Commission Discussion and Findings. We recognize that while the past can help in predicting the future, the future is not exactly a repeat of the past. Informed judgment must be utilized in conjunction with a study of the past. We agree with Mr. Spanos that it is appropriate for judgment to factor into the estimate of service lives; estimation of service lives should not be solely a mathematical and mechanistic exercise.

We note that authorities on the topic of depreciation, such as NARUC, are clear that estimating service lives must include a subjective component. For example, in Chapter XIII of NARUC's *Public Utility Depreciation Practices*, entitled "Actuarial Life Analysis," NARUC discusses and emphasizes the subjective nature of the process of estimating service lives. NARUC starts this chapter by explaining that the analysis of historical data is only one part of the process of estimating service lives:

> Actuarial analysis objectively measures how the company has retired its investment. The analyst must then judge whether this historical view depicts the future life of the property in service. The analyst takes into consideration various factors, such as changes in technology, services provided, or capital budgets.[26]

NARUC further explains that the process of estimating service lives must go beyond any objective measurement of the past. In describing the determination of a survivor curve estimate (referred to as the "projection life" in this passage), NARUC states:

> The projection life is a projection, or forecast, of the future of the property. Historical indications may be useful in estimating a projection life curve. Certainly the observations based on the property's history are a starting point. Trends in life or retirement dispersion can often be expected to continue. Likewise, unless there is some reason to expect otherwise, stability in life or retirement dispersion can be expected to continue, at least in the near term. Depreciation analysts should avoid becoming ensnared in the mechanics of the historical life study and relying solely on mathematical solutions. The reason for making an historical life analysis is to develop a sufficient understanding of history in order to evaluate whether it is a reasonable predictor of the future. The importance of being aware of circumstances having direct bearing on the reason for making an historical life analysis cannot be understated. These circumstances, when factored into the analysis, determine the application and limitations of an historical life analysis.[3]

Thus, NARUC strongly advises against the approach used by Mr. Garrett, stating clearly that "relying solely on mathematical solutions" should be avoided. NARUC further elaborates on the need for a subjective component to forecasting service lives:

> A depreciation study is commonly described as having three periods of analysis: the past, present, and future. The past and present can usually be analyzed with great accuracy using many currently available analytical tools. The future still must be predicted and must largely include some subjective analysis. Informed judgment is a term used to define the subjective portion of the depreciation study process. It is based on a combination of general experience,

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[3] National Association of Regulatory Utility Commissioners, *Public Utility Depreciation Practices*, 1996, p. 126.

> knowledge of the properties and a physical inspection, information gathered throughout the industry, and other factors which assist the analyst in making a knowledgeable estimate.[4]

Accordingly, we find that Mr. Spanos' estimated mass property service lives should be adopted, and Mr. Garrett's differing estimated lives should be rejected.

(B) Estimated Useful Lives of Generating Units and IRP Issues. DEI witnesses Pinegar and Pike testified regarding the useful lives of the Company's generating stations. Mr. Pinegar indicated that one of the rate increase drivers included transitioning to a cleaner generation portfolio in a reasoned and moderated fashion. The moderate transition plan the Company included in its depreciation rate request does increase costs to customers now, but in the long run this transition plan will be lower cost to customers given how heavily dependent on coal the Company's existing generating fleet is today and given the risk associated with likely future federal greenhouse gas regulation. Mr. Pinegar opined that it was becoming clear that greenhouse gas emissions, like carbon dioxide, are the next emission to be regulated, and that there is no proven economically feasible technology today to significantly reduce carbon dioxide emissions from coal-fired power plants. As such, the useful lives of coal-fired assets are declining in relation to what we may have thought they would be 15 or even 5 years ago. Mr. Pinegar explained DEI is not proposing to retire any coal-fired generation prematurely – these assets have already outlived their initial intended useful lives. Rather, DEI is proposing to shorten the estimated useful lives of its Gallagher, Cayuga and Gibson Generating Stations' coal-fired units from an average of 65 years to an average of 58 years. He indicated that this proposed orderly transition plan increases costs gradually over time in recognition that a transition to cleaner energy is taking place and likely to accelerate in the not too distant future.

Company witness Pike explained what impacts the useful life of coal generating assets, including technical and economic factors. Key technical factors include the initial robustness of the design and construction of the unit; what environmental controls are original versus what environmental control retrofits or replacements occur in the life of a unit; the operational duty of a unit; the type and quality of the coal burned; and how well maintained the unit is. Key economic factors include fuel costs and unit efficiency; incremental environmental regulations' investment requirements; the evolution of competing technologies providing lower cost capacity and energy options; and the evolution of the regional transmission operator market, which provides potential short-term options for the management of energy and capacity needs.

Mr. Pike explained that relatively new units are being proposed for retirement in the industry primarily because their environmental controls are either original equipment or were early retrofits and are at the end of their useful lives. Whereas older boilers and turbines with newer environmental control retrofits may have life left to give. Mr. Pike indicated that other high-profile developments in the industry are climate change and carbon emission risk.

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[4] Id. at 128.

Mr. Pike compared the Company's existing retirement dates from its last depreciation study completed in 2011 to the updated retirement dates DEI has included in its new depreciation study filed in this proceeding based on the moderate transition plan included in its IRP. On average, the expected life in the last depreciation study of the coal units (excluding Edwardsport) was approximately 65 years, whereas the updated retirement dates in the depreciation study for this proceeding, the average life of the coal units decreases to approximately 58 years, ranging from 47 years to 64 years on individual units. He concluded that overall, the updates to the average lives, and the range of lives for individual units proposed by the Company are directionally consistent with industry trends.

Mr. Pike then testified that DEI filed its 2018 IRP with the Commission on July 1, 2019, and over the twenty-year planning horizon of the IRP, the updated depreciation retirement dates proposed in this proceeding are aligned with the Company's preferred portfolio. Mr. Pike next opined that from a technical perspective, the Company's preferred portfolio is an ordered and logical management of the end of life of the Company's generation assets, considering individual unit circumstances and reasonable practical constraints.

Mr. Pike testified that DEI's 2018 IRP preferred portfolio is a thoughtful first step towards meeting the changing expectations of our stakeholders and reducing our CO_2 emissions in the state. DEI believes it would be risky for it and its customers to simply wait for carbon policy to happen. Making moderate shifts in the expected remaining lives of our coal-fired assets is a reasonable action to take now, while the Company continues to monitor the changing industry landscape and impacts of market forces.

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.

Of the intervening parties, the Sierra Club, Joint Intervenors, and Wabash Valley provided testimony related to the retirement dates of coal units and the Company's IRP.

Sierra Club's witness Comings concluded that the Edwardsport IGCC plant is uneconomic and should be retired as soon as possible. DEI is seeking to include $300 million in costs for Edwardsport in 2020 alone. This includes $146 million in O&M, $103 million in fuel costs, and $51 million in capital costs. He testified that the plant is clearly uneconomic as it loses money on the energy market and has more expensive fixed costs than those from replacing it—much higher fixed costs than a typical coal unit. He claimed there is no economic justification for continuing to operate this plant, yet the IRP does not consider its retirement before 2045—twenty six years from now. He concluded that Edwardsport costs should be denied and the Company should develop a plan for retiring the plant. Once the Company develops such a plan, then the Company may recover prudently incurred costs prior to retirement.

Next, Mr. Comings indicated the Company's recent IRP does not justify the Company's fixed retirement dates because it fails to consider near-term economic retirement for most of its units. Without such an analysis, it is unclear if DEI and its ratepayers should continue to invest in these units. Mr. Comings believed the Cayuga and Gibson units should be evaluated for retirement prior to 2024. The Company should consider robust retirement options for all its remaining coal units as soon as possible in order to assess whether these units have going-forward value for customers. The Company should also conduct an all-resource RFP and evaluate replacement options for these units.

Mr. Comings testified the Company's IRP analysis was severely limited in its economic evaluation and erred on the side of keeping older coal units operating. If the IRP analysis had concluded that some units should retire in the near-term then, in anticipation, the Company could ramp down spending on capital and operating costs in this rate case. Because of the connection between the IRP and the rate case, and because the Commission does not hold an evidentiary hearing and typically does not approve or deny the IRP around the time it is filed, this rate case affords the opportunity to rule on long-term planning issues.

Mr. Comings believes the IRP analysis that led to the Company's proposed retirement dates was flawed. First, the IRP failed to even consider retirement of Edwardsport within the 20-year analysis period, even though the plant is costing ratepayers a significant amount of money. The Company also did not consider retirement of Cayuga or Gibson units prior to 2024. Second, the IRP also fails to consider competitive bidding for new resources that could compete with existing resources, as Northern Indiana Public Service Company (NIPSCO) did in its most recent IRP. As such, regarding Cayuga and Gibson, Mr. Comings concluded the Company should be compelled to evaluate all reasonable options for retiring these units, including allowing for retirement prior to 2024 and pursuing lower-cost replacement options—such as through an all-resource RFP.

Joint Intervenor witness Sommer provided testimony specific to the Company's 2018 IRP and included a draft report as Exhibit ALS-2. She concluded that DEI's 2018 IRP was irredeemably flawed in a number of respects including but not limited to: 1. DEI applies its reserve margin requirement to all months of the year rather than just the MISO coincident peak; 2. DEI requires the model to self-supply capacity in all months of the year rather than purchasing from other utilities; 3. The Company tries to solve the problem of unrealistic market purchases by imposing a hurdle rate on purchases, but this is a "band-aid" solution and an imperfect and inadequate one at that; 4. Coal unit retirements are unnecessarily limited to 2024 or later and only to the Company's existing pulverized coal units; 5. DEI's energy efficiency bundles are unreasonably high in cost and suffer from other flaws that prevent the selection of the optimal portfolio of energy efficiency measures; 6. Capital costs for renewables are higher than is justifiable; 7. Capital costs for combined cycles is lower than is justifiable; 8. Wind and battery storage is limited to 250 MW per year without basis; 9. A $5/MWh adder for new solar resources is based on a study for Duke Energy's Carolina service territory that has no relevance to Indiana and was rejected by the North Carolina Utilities Commission; 10. DEI refused to provide copies of the System Optimizer and Planning and Risk model manuals except in person despite having done so in its prior IRP; 11. The Company did not deliver the modeling files required for the Technical Appendix in Indiana's IRP rule; and 12. DEI's pre-IRP stakeholder process was frustrating in a number of respects including the tendency to push stakeholder recommendations off to the next IRP filing.

Ms. Sommer concluded the 2018 IRP as filed and relied upon by the Company in preparing its case-in-chief in this docket is significantly deficient and, therefore, is not a reasonable basis upon which the Commission should rely for decisions.

Joint Intervenor witness Schlissel testified that as a result of his review of the Company's IRP as filed, the numerous Company responses to CAC's informal and formal discovery responses regarding the IRP in the IRP process and in this base rates case, and the preliminary Energy Futures Group report critiquing the IRP and the modeling process utilized by the Company in preparing it, he has concluded as follows: 1. The 2018 IRP as filed and relied upon by the Company in preparing its case-in-chief in this docket is significantly deficient and, therefore, is not a reasonable basis on which the Commission should rely for the appropriate, economics-based retirement date for Edwardsport being 2045. For this reason, the Commission should not rely on a retirement date of 2045 in setting a depreciation schedule for Edwardsport for ratemaking purposes in this proceeding.

Wabash Valley witness Wilmes testified that DEI, Wabash Valley and IMPA jointly own Unit 5 of the Gibson Generating Station with the following ownership interests: DEI 50.05%, Wabash Valley 25%, and IMPA 24.95%. As joint owners, these parties all should have input into any decisions regarding the retirement of Gibson Unit 5. Mr. Wilmes disagreed with Company witness Pike's assertions regarding the retirement date of Gibson Unit 5. Rather, Wabash Valley supported retiring Gibson Unit 5 in the 2026 timeframe because it would be consistent with the power supply goals of Wabash Valley and would also avoid the expense of re-routing the flue gas from Gibson Unit 5 to Gibson Unit 4's newer scrubber. He further indicated that Wabash Valley will fully cooperate with DEI and IMPA in the procedures necessary to retire Gibson Unit 5 in the 2026 timeframe. Mr. Wilmes also testified Wabash Valley supports the Commission's approval of the accelerated depreciation on Gibson Unit 5 as may be necessary to retire that unit. To the extent that Petitioner has requested accelerated depreciation of Gibson Unit 4, in accordance with Table 2 provided on page 12 of witness Pike's testimony, Wabash Valley would support a comparable accelerated depreciation timeline for Gibson Unit 5. Mr. Wilmes indicated that Wabash Valley has a diverse power supply portfolio and is constantly replacing and adding additional resources to its supply. In recent years Wabash Valley has added over 200 MW of Wind generation and 400 MW of Solar generation. Finally, he indicated that he had communicated Wabash Valley's position on the retirement of Gibson Unit 5 to IMPA, and IMPA has represented that its position is the same.

Wabash Valley witness Smardo, Executive Vice President of Energy Solutions for IMPA, provided testimony substantially similar to Mr. Wilmes, indicating that IMPA supports retirement of the jointly owned Gibson 5 Unit in the 2026 timeframe because it would be consistent with the power supply goals of IMPA and would also avoid the expense of rerouting the flue gas from Gibson Unit 5 to Gibson Unit 4's newer scrubber.

Mr. Andrews also indicated that DEI did not consider the accelerated depreciation expense associated with the early retirement of its coal plants in the IRP analysis because it used a metric called the Net Present Value Revenue Requirement ("NPVRR"). He stated that if a portfolio requires the early retirement of any plant and the models do not account for the increased depreciation expense, then the NPVRR coming out of those models does not allow for an accurate comparison of portfolios.

The Company provided the rebuttal testimony of Messrs. Pinegar, Pike, Gurganus, and Park regarding the coal unit retirement and IRP issues. Mr. Spanos also commented on the issue, noting that the Company's estimated retirement dates were consistent with the industry. Mr. Pinegar explained the Company took a moderate transition approach to its coal retirements included in the 2018 IRP and in depreciation rates proposed in this proceeding. He indicated that there are many good reasons for a moderate transition, not least of all being the impact to local communities where these coal plants have been located. The community impacts range from property taxes, coal mining jobs, generating plant jobs, and other related industries in the locale. Mr. Pinegar expressed the Company's belief that its balanced approach allows communities time to transition and prepare for a future without the coal plants operating.

Mr. Pike responded to the recommendation by Wabash Valley and IMPA to retire jointly owned Gibson 5 by 2026. He indicated the Gibson Unit 5 Joint Ownership Agreement requires unanimous agreement among the owners in order to retire the unit, and that achieving a consensus on the retirement date is a capital opportunity for DEI that should not be dismissed. To the extent there is no material difference in the cost or performance of Gibson Unit 4 and Gibson Unit 5 (other than the Unit 5 scrubber), and the proposed scrubber flue gas crossover duct would be eliminated, Mr. Pike indicated the Company can fully support Wabash Valley's and IMPA's recommendation. As such, Mr. Pike indicated that the Company would be amenable to a simple swapping of the retirement dates of Gibson Units 4 and 5. So, Gibson Unit 5 would retire in 2026, and Gibson Unit 4 would retire in 2034 along with Gibson Unit 3 and Noblesville. Accelerating Gibson Unit 5's retirement date without also deferring Gibson Unit 4's retirement date would result in a further increase in depreciation expense in this proceeding, which would be undesirable for customers, and is unnecessary at this time. DEI witnesses Mr. John Spanos and Ms. Diana Douglas present the impact of this change on depreciation rates and expenses in their rebuttal testimonies.

Mr. Pike explained that because DEI only owns about half of Gibson Unit 5, swapping the retirement dates of Gibson Units 4 and 5 will reduce the Company's capacity need by 2026 in half, slowing the pace of diversification, and decreasing Company carbon emission reductions. However, the opportunity to capitalize on unanimous agreement with the Gibson Unit 5 Joint Owners has more immediate value to customers. Absent this agreement now, there would be uncertainty even in the original proposed retirement date of 2034. Further, if DEI objected now and held out its option to continue to operate the unit, the long-standing productive relationship we have had with the Joint Owners could become stressed, impacting other business relationships, such as wholesale, that are beneficial for retail customers. Additionally, the change is not expected to materially impact the Company's carbon emission reduction goals.

Mr. Pike concluded this issue by indicating that the swapped retirement dates for Gibson Units 4 and 5 result in lives of 55 years for Gibson Unit 4 and 44 years for Gibson Unit 5, and that both lives are reasonable, and are in line with the range seen in industry based on unit-specific circumstances.

Mr. Pike next addressed concerns expressed by the Sierra Club and Joint Intervenors regarding the Company's IRP and coal retirements. He indicated the fundamental purpose of the IRP in this proceeding is to support reasonable depreciation rates for the Company's generation assets. DEI is not requesting any type of formal approval of future generating unit retirements, nor pre-approval of future new generation resources in this proceeding. There are no notable resource actions planned between now and the time the Company will file its next IRP in 2021, when the system will be re-evaluated again. Mr. Pike believed the shutting down coal-fired generating units as fast as possible would only go to dramatically raising depreciation expense and is unnecessary at this time. Mr. Pike noted that Sierra Club and Joint Intervenors are the only parties that seem to protest the IRP preferred portfolio as unreasonable. Other interests, such as the witness for the Indiana Laborers District Council, Mr. Frye, espouse the negative impacts on the workforce and the economies of local communities from accelerated plant shutdowns. And, other intervenors, such as the OUCC and Industrial Group, generally do not take issue with the planned retirement dates. The Company's goal is to find a balance that takes measure of all of the implications of our proposed resource plan, and the Company's preferred portfolio does that. The goal of resource planning is not merely to find the lowest cost system, but rather to find the lowest cost system that can actually succeed in serving customers reliably.

Next, Mr. Pike addressed Ms. Sommer's complaint that DEI included a limitation in its IRP of 2024 for the earliest coal unit retirements relying in part on the need for potential transmission investment. It is true that DEI established assumptions regarding coal unit retirement transmission constraints for 2018 IRP modeling purposes based on a vintage 2016 internal retirement transmission impact analysis, which was the information available at the time. And it is also true that the Company updated this study in 2019, but that it was too late to be taken into consideration in the 2018 IRP. It is further true that the 2019 study revealed fewer transmission constraints to coal unit retirements than the 2016 study. However, such transmission impacts are constantly changing as various generation and transmission projects enter and leave the MISO planning queue. The internal studies that DEI performs are informal, directional, and at a point in time. Mr. Pike explained, MISO performs the actual formal transmission impact study once an entity actually files for a unit retirement, at which point such retirement becomes a non-rescindable commitment. Since it would be imprudent to commit to a unit retirement a long time in advance, the Company must rely on the internal studies as directional only, at whatever point in time they are available.

Further, Mr. Pike noted that 2024 is still a reasonable date for early coal unit retirements for IRP modeling purposes. He explained that there is much more to it than just remedying any transmission system impact. Other practical constraints and considerations include a smooth and thoughtful transition of the labor force; managing local community impacts; allowing sufficient lead-time to manage the roll-off of long-term coal contracts; allowing sufficient minimum lead-time for the construction of new dispatchable resources; managing the rate impacts to customers of dramatically accelerated depreciation; and also giving due consideration to corporate cash flow and credit constraints for funding what would be a large replacement build in a short timeframe. The DEI 2018 IRP preferred portfolio, as modified with the Gibson Unit 4-5 retirement date swap, spreads out the coal unit retirements in a prudent and reasonable way so as to enable effective management of these challenges.

Mr. Pike next responded to Mr. Comings' contention that DEI should have a resource plan more like NIPSCO's. Mr. Pike indicated that no two utilities, let alone any two coal units, are situated exactly alike. There are very notable structural and cost differences between NIPSCO and DEI that help explain why the NIPSCO coal units may be more economic to retire than the DEI coal units in an IRP. Four important differences are the existing fleet makeup, degree of environmental compliance, coal supply and cost, and O&M cost rates. Mr. Pike concluded that there are clearly material differences in the structural and cost circumstances between NIPSCO and DEI that make any assignment of NIPSCO's resource planning strategy to DEI inappropriate and uninformative.

Mr. Pike concluded that Sierra Club and Joint Intervenors make no compelling arguments that DEI's 2018 IRP preferred portfolio, as used for depreciation rate purposes in this proceeding, should not be considered reasonable by the Commission. Despite their complaints regarding DEI's IRP process and assumptions, models only inform us; models do not make reasoned recommendations or decisions. The preferred portfolio is not necessarily intended to be optimized to a specific future, but rather designed to perform robustly across a potential range of futures, and take into consideration reasonable and realistic constraints, and impacts beyond raw economics.

Mr. Gurganus responded to allegations by Sierra Club and Joint Intervenors that Edwardsport IGCC should be considered for retirement. He explained the benefits to customers of Edwardsport's generation and the benefits of it operating on both syngas and natural gas. He also explained how it would not be strategic to immediately shut down a new diverse asset that will be providing energy to customers for another twenty-five plus years after running it only six years. He explained that every year, the Plant has improved the planning and execution of its maintenance and maintenance outages, settling most recently on a modular approach, which ensures the station continues to provide net positive generation to customers while other components of the station are being maintained.

Further, he explained that the station's unique ability to run on both natural gas and coal provides diversity and reliability. Edwardsport was built to be a long-term asset for DEI's customers and the Company believes it will continue to be a valued asset – shutting the station down or even just shutting down or "mothballing" the gasification island, as the Industrial Group suggests, would both result in the underutilization of a significant investment. In fact, Edwardsport has not yet completed its full maintenance cycle yet – its final outage in the first maintenance cycle will be executed in 2020 – that outage will also be the first time the steam turbine has had major scheduled maintenance. As such, the plant remains early in its useful life.

Mr. Gurganus explained why diversity of generation supply is important and how Edwardsport provides such. Today, the risks of single-fuel-source energy reliance are increasing, and it is in customers' best interests to diversify. However, diversity does not mean retire all coal and build all natural gas plants; or retire all coal and build all renewables. Rather, true diversity means an "all of the above" approach. Therefore, as the Company moves to retire its older coal-fired units, there is value in maintaining its youngest coal-fired unit – particularly one with advanced emission controls – Edwardsport IGCC, so that coal can continue to be a meaningful contributor to diversity for customers' benefit for years to come.

Mr. Gurganus explained that the Station's coal is supplied by a local Indiana mine, limiting transportation costs, and providing jobs and economic value to the local community and the state. The Company also shares in coal supply contracts with Cayuga and Gibson stations, giving the Company more flexibility in coal procurement and pricing. Procuring coal from a local mine also limits the impact from natural disasters and other political events on the price and availability of our coal, even when natural gas prices and availability can experience swings. Coal also provides a reliability and resiliency value of fuel inventory maintained at coal plants, relative to natural gas. Edwardsport's fuel diversity is not subject to the same ambient condition design limitations (wind speed, clouds, temperature, etc.) as renewable generating resources.

Finally, Mr. Gurganus opined, since 2005, the Commission has been presented with a variety of arguments regarding nearly all aspects of the station's construction and operation. While DEI has reached settlement agreements resolving some of the more major disagreements between the parties over the years, the Company has not wavered in its support for Edwardsport and its commitment to customers and to the state of Indiana and its other stakeholders to prudently and reasonably operate Edwardsport, improving first its safety and reliability and second, its efficiency. DEI will continue its efforts to maintain safety and reliability, while working every day to operate the station more efficiently from a cost perspective.

Mr. Gurganus explained that the past six years of operations have led to improvements in managing Edwardsport's operations, predicting maintenance needs and avoiding forced outage events. Edwardsport has been an important investment in a technology that allows for the cleaner utilization of coal. The station is an industry benchmark both domestically and internationally for those using and interested in using the gasification technology to reduce emissions in their own processes. DEI has been a great corporate partner living up to and exceeding its commitments regarding investment in the station and its communities, employment and usage of coal. Customers continue to benefit from the tax incentives provided at the inception of Edwardsport to encourage the Company to make this investment.

Company witness Mr. Park next addressed the criticism of the Company's IRP process and results, both generally and in particular in relation to generating units' lives. Mr. Park began by indicating that Ms. Sommer's IRP report mischaracterizes, is misleading, and contradicts itself. As to complaints regarding reserve margins, Mr. Park indicated Ms. Sommer's report argues that having a monthly reserve margin is not realistic. However, she confuses the short-term resource adequacy view of MISO with the long-term resource adequacy that needs to be considered in the IRP, wherein the reserves must be available in every month. Further, Ms. Sommer's report fails to consider that if the economics of the industry drive more coal retirements and solar additions, the rest of MISO will also become winter peaking for planning purposes which means that the winter peak now becomes the primary reserve margin constraint.

Regarding Ms. Sommer's criticisms related to generating unit retirements, Mr. Park indicated that the report uses historical data to address unit retirements where retirement analysis should be based on prospective data and the report uses a monthly average price which completely ignores the dispatchability of the units. Dispatchable units will operate when economic and those periods will have higher average prices than the average of all hours. The report only values the capacity that these units provide at the MISO auction clearing price – a short term market price. The auction clearing price is typically very erratic and tends to be quite low and does not reflect the true value of capacity in the market and is not close to the value for capacity in the bilateral market. Further, he opined the report is also missing the cost of the other generation that would be required to maintain resource adequacy.

Mr. Park next addressed the report's claims that that there are four portfolios that are lower cost than the Moderate Transition portfolio that was selected as the preferred portfolio in the IRP. What the report fails to mention is that this only true in some of the scenarios that the IRP considered. For example, the Current Conditions, Slower Innovation and Reference, No Carbon portfolios are all more expensive than the Moderate Transition portfolio in the scenarios that include carbon regulation. The report then undermines itself by criticizing the preferred portfolio in the next paragraph for not moving fast enough with regard to carbon reduction, but then goes on to criticize the preferred portfolio based on cost in scenarios without a carbon tax. Since greater carbon reductions and costs are positively correlated, it is disingenuous to criticize the preferred portfolio for its carbon reduction in one scenario and its costs in materially different scenarios. Mr. Park indicated that the preferred portfolio accelerates coal retirements and renewable additions in an unprecedented fashion for the utility despite the current absence of meaningful carbon regulation.

In response to Mr. Andrew's criticism that the remaining net book value of existing assets in an IRP was not included, Mr. Park indicated that this is standard practice and does not dissuade from the robustness of the preferred portfolio in any way. While Mr. Andrews is correct that accelerating generating unit retirements increases the present value of revenue requirements ("PVRR") of depreciation, he failed to consider the fact that at the same time, the PVRR of the return components (equity, debt, and tax gross up) are decreasing for every year the rate base is brought forward and reduced. These affects are largely offsetting, so that the total PVRR of existing net book value (of and on) is relatively insensitive to remaining asset life. Therefore, exclusion of it from an IRP has no material impact on portfolio PVRR, nor the selection of the preferred portfolio.

Finally, Mr. Park addressed retirement of generating assets in the IRP, finding the measured retirement schedule in the preferred portfolio as very reasonable for customers. Furthermore, when measured across five different scenarios on the basis of cost, CO2 emissions and market exposure, the Moderate Transition portfolio was selected as the preferred portfolio. This portfolio is the most aggressive in terms of coal retirements and renewable additions than any previous IRP. He also indicated that after the IRP had been developed, the Joint Owners of Gibson 5 Unit approached the Company about the possibility of retiring Gibson 5 sooner, as discussed in Mr. Pike's rebuttal testimony. The Company looked into the possibility of moving the retirement of Gibson 5 to 2026 and delaying the retirement of Gibson 4 to 2034. This change has minimal impact on the PVRR of the portfolio and results in a slight rate reduction to customers. Offsetting this benefit is that it does slow down carbon reductions of the portfolio as well as renewable additions.

Mr. Park concluded his rebuttal indicating that the IRP process and results remain reasonable and most importantly a robust choice given the potential for many different future scenarios.

(1) Commission Discussion and Findings. The estimated life of generating units does significantly impact the depreciation rates in this proceeding. DEI's proposed depreciation rates use the retirement dates from the moderate transition portfolio, which was its resulting preferred portfolio coming out of the IRP stakeholder process. Sierra Club and Joint Intervenors took issue with the retirement dates of Edwardsport IGCC and other coal units, finding that DEI should consider an earlier retirement of these units. In considering Edwardsport first, we find Mr. Gurganus' testimony persuasive. Edwardsport is the newest coal unit on the DEI system and continues to be a valuable asset for the Company's generating system, especially as the Company moves, as many utilities are, to retire older and less efficient coal plants. We also understand the many complexities and issues associated with primarily operating the plant on natural gas pointed out by Mr. Gurganus, not least of which is the requirement for new air permitting, elimination of tax incentives, and losing the optionality and diversity that operation primarily on coal provides. In contrast to the cross answering testimony of Mr. Schlissel, and based on the testimony provided by Mr. Gurganus, we find that Edwardsport has showed steadily increasing gasifier availability and capacity factor in line with expectations, and we note that the Company has invested in improvements at the plant, often at shareholder expense, to achieve these improvements, which Mr. Gurganus expects to continue.

As to the Company's other coal units, Sierra Club and Joint Intervenors criticize the Company's modeling that does not allow these units to retire prior to 2024. However, we find Mr. Pike's testimony on this point persuasive. There are clearly practical constraints and considerations to retiring units that should not be ignored by IRP modeling, such as labor force, community impacts, transmission constraints, and not least of all rate impact to customers. We also agree with Mr. Pike and Wabash Valley witnesses that it is reasonable to swap the retirement dates of Gibson Units 4 and 5, to accommodate the wishes of the joint owners of Gibson 5 and save the expense associated with the planned flue gas work for the units. Overall, we find that this moderate transition approach is reasonable and results in reasonable depreciation rates that, while increased compared to previous depreciation studies, are moderated to that which would accompany a more expedited transition.

Regarding the other Joint Intervenors' criticism of the IRP process, we find that the IRP is at issue in this proceeding only to the extent it helps support the proposed depreciation rates. We find Mr. Park's response to the various IRP issues reasonable and thorough. Further, we agree with Mr. Pike that models only inform us and do not themselves make reasoned recommendations or decisions. Rather, the Company does that through a review of various scenarios, sensitivities, and portfolios.

In sum, we find that DEI's proposed retirement dates, as revised in its rebuttal testimony for the Gibson 4/5 retirement date switch, are reasonable and prudent and will result in fair and reasonable rates for customers who benefit from the Company's rate base.

(C) <u>Depreciation Rates and Expense</u>. Mr. Spanos presented and supported a depreciation study related to DEI's electric plant as of December 31, 2018, as well as a fair value study. He testified that depreciation refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation, against which the Company is not protected by insurance. He stated that among the causes to be given consideration are wear and tear, decay, action of the elements, obsolescence, changes in the art, changes in demand and the requirements of public authorities. He testified that in preparation of his study, he followed generally accepted practices in the field of depreciation and valuation. He testified that his recommended depreciation rates appropriately reflect the rates at which the costs of DEI's assets are being consumed over their useful lives, and that the rates are an appropriate basis for setting electric rates in this matter and for the Company to use for booking depreciation and amortization expense going forward.

He testified the purpose of the depreciation study was to estimate the annual depreciation accruals related to electric plant in service for ratemaking purposes and determine appropriate average service lives and net salvage percentages for each plant account. He stated that in preparing his study, he used the straight line remaining life method of depreciation, with the equal life group procedure for all plant assets except some general plant accounts. He stated the annual depreciation is based on a method of depreciation accounting that seeks to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of each unit, or group of assets, in a systematic and rational manner. He testified that for certain General Plant Accounts, he used the straight line remaining life method of amortization. He explained that the annual amortization is based on amortization accounting that distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account and vintage.

To determine his recommended annual depreciation accrual rates, in the first phase of his study, he estimated the service life and net salvage characteristics for each depreciable group -- each plant account or subaccount identified as having similar characteristics. Then in the second phase of his study, he calculated the composite remaining lives and annual depreciation accrual rates based on the service life and net salvage estimates determined in the first phase.

He explained that in the first phase of the study he compiled historic data through 2018 from records related to DEI's plant; analyzed these data to obtain historic trends of survivor and net salvage characteristics; obtained supplementary information from DEI's management, and operating personnel concerning practices and plans as they relate to plant operations; and interpreted the above data and the estimates used by other electric utilities to form judgments regarding average service life and net salvage characteristics. To analyze the service life data, he used the retirement rate method and applied the retirement rate method to each different group of property in the study. He explained that the retirement rate method produces an original survivor curve for that property group, and that interpretation of the original survivor curves is required in order to use them as valid considerations in estimating service life. He explained that widely used Iowa-type survivor curves were used to perform the interpretations. He further testified that he used the life span technique, which has been used previously for DEI, to estimate the lives of significant facilities for which concurrent retirement of the entire facility is anticipated.

He testified that DEI provided the production facility life span estimates based on informed judgment that incorporates factors for each facility such as the age, use, size, nature of construction, and technology of the facility; management plans and outlook for the facility; the estimates for similar facilities for other utilities; and the results of the Company's 2018 IRP. DEI witness Mr. Keith Pike discusses the life span estimates in detail, as is discussed below. Mr. Spanos also stated that he made a field review of DEI's property during November 2018 to observe representative portions of plant and that he also made field visits during prior studies since 1999. He explained that field reviews are conducted to become familiar with Company operations and obtain an understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements.

He next discussed net salvage -- a component of the service value of capital assets that is recovered through depreciation rates. He explained that the service value of an asset is its original cost less its net salvage, and net salvage is the salvage value received for the asset upon retirement less the cost to retire the asset. He stated that when the cost to retire exceeds the salvage value, the result is negative net salvage.

He testified that inasmuch as depreciation expense is the loss in service value of an asset during a defined period, (*e.g*. one year), it must include a ratable portion of both the original cost and the net salvage. That is, he stated, the net salvage related to an asset should be incorporated in the cost of service during the same period as its original cost so that customers receiving service from the asset pay rates that include a portion of both elements of the asset's service value, the original cost and the net salvage value.

He testified that the net salvage percentages estimated in the depreciation study were based on informed judgment that incorporated factors such as the statistical analyses of historical net salvage data; information provided by the Company's operating personnel; general knowledge and experience of industry practices; and trends in the industry in general. He stated that the statistical net salvage analyses incorporate the Company's actual historical data for the period 1989 through 2018 and consider the cost of removal and gross salvage ratios to the associated retirements during the 30-year period. He explained that the net salvage percentages for generating facilities were based on two components: the interim net salvage percentage, and the final net salvage percentage. He stated that the interim net salvage percentage was determined based on the historical indications from the period 1989 to 2018 of the cost of removal and gross salvage amounts as a percentage of the associated plant retired. He stated that the final net salvage, or decommissioning and dismantlement component, was determined based on the retirement activities associated with the assets anticipated to be retired at the concurrent date of final retirement. He testified that the decommissioning or dismantlement component has been included in the net salvage percentage for steam, hydro and other production facilities; the decommissioning and dismantlement component is part of the overall net salvage for each location within the production assets. He stated that based on studies for other utilities and the cost estimates of DEI, it was determined that the decommissioning or dismantlement component for steam, hydro, and other production facilities is best calculated by dividing the decommissioning or dismantlement cost by the surviving plant at final retirement. He explained that these amounts at a location basis are added to the interim net salvage percentage of the assets anticipated to be retired on an interim basis to produce the weighted net salvage percentage for each location.

He testified that the decommissioning or dismantlement cost estimates are based on the decommissioning study of each generating site performed by Burns and McDonnell (discussed below). He explained that these estimates are based on the current cost (year 2018 dollars) to decommission the facilities. He noted, however, that the costs to decommission power plants have tended to increase over time (as have construction costs in general). For this reason, he testified, in order to recover the full decommissioning costs for each site, these costs need to be escalated to the time of retirement.

After Mr. Spanos estimated the service life and net salvage characteristics for each depreciable property group, he then calculated the annual depreciation accrual rates for each depreciable group based on the straight line remaining life method, using remaining lives weighted consistent with the equal life group procedure. He stated that the calculations of annual depreciation accrual rates were developed as of December 31, 2018. He explained that the straight line remaining life method of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage, in equal amounts to each year of remaining service life.

He testified that in the equal life group procedure, the property group is subdivided according to service life -- that is, each equal life group includes that portion of the property which experiences the life of that specific group. He stated that the relative size of each equal life group is determined from the property's life dispersion curve. He explained that this procedure eliminates the need to base depreciation on average lives, inasmuch as each group is equivalent to a unit having a single life. The full costs of short-lived units are accrued during their lives, he stated, leaving no deferral of accruals required to be added to the annual costs associated with long-lived units. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life group, according to Mr. Spanos.

Mr. Spanos testified that the equal life group procedure allocates the capital cost of a group property to annual expense in accordance with the consumption of the service value of the group.

He added that the more timely return of plant investment accomplished by fully accruing each item's cost during its service life not only reduces the risk of incomplete capital recovery, but also results in less investment-related cost over the life span of a depreciable group. He explained that under the equal life group procedure, the future book accruals (original cost less book reserve) for each vintage are divided by the composite remaining life for the surviving original cost of that vintage, and the vintage composite remaining life is derived by summing the original cost less the calculated reserve for each equal life group and dividing by the sum of the whole life annual accruals.

Mr. Spanos stated that amortization accounting is used for accounts with a large number of units, but small asset values. In amortization accounting, he explained, units of property are capitalized in the same manner as they are in depreciation accounting; however, depreciation accounting is difficult for these assets because periodic inventories are required to properly reflect plant in service. Consequently, he stated, retirements are recorded when a vintage is fully amortized rather than as the units are removed from service -- that is, there is no dispersion of retirement; all units are retired for depreciation purposes when the age of the vintage reaches the amortization period. He emphasized that amortization accounting is only appropriate for certain Common and General Plant accounts – in this case, for plant accounts which represent approximately one percent of depreciable plant.

Mr. Spanos testified that the development of the book reserve for each location has been established based on a composite rate for a group of locations within an account; thus, the actual book reserve at the location level was determined by applying a composite rate to the plant balance.

He explained that when dealing with group depreciation there are multiple parameters that affect the rate, such as interim survivor curve, probable retirement date and net salvage percent among the key factors. He further explained that in conducting a depreciation study, a more defined manner of determining the individual location rates should be established. He testified that these key factors or parameters establish the theoretical reserve which is utilized to appropriately assign the book reserve at the location and vintage level. He noted that updating retirement dates adjusts the weighting between the locations; therefore, a changed retirement date, survivor curve or net salvage percent for one location affects all the locations in the account.

Mr. Spanos next addressed depreciation rates for DEI's new solar generation assets planned by year-end 2019. He explained that the rates for these assets will be based on interim survivor curves for each account, a negative net salvage percent for some of the accounts, and a 25- year life span for all assets at the location. He stated that an estimated rate for new battery storage assets in Account 363 was also prepared.

Mr. Spanos testified concerning his fair value study. He explained that his study segregated the property by plant account consistent with the depreciation study and Company accounting system. More specifically, he first determined the Reproduction Cost New ("RCN") for the property in service at December 31, 2018, by trending the original cost and then deducting depreciation to arrive at the Reproduction Cost New Less Depreciation ("RCNLD"). He explained that for the property for which he determined the trended original cost, he used cost indexes. He calculated the RCN of the Company's electric plant in service as of December 31, 2018, to be $27,218,507,545; and he calculated the RCNLD of the Company's electric utility plant in service as of December 31, 2018 to be $11,633,493,162, which is 43% of the Reproduction Cost New. Mr. Spanos also provided the same fair value study information using the Company's forecasted electric utility plant in service as of December 31, 2020. He testified that it was calculated using the same methodology as his 2018 study and that the RCN of the Company's electric plant in service as of December 31, 2020, is $28,967,368,703 and the RCNLD is $12,054,723,694.

Company witness Mr. Jeffery Kopp sponsored the decommissioning study prepared by Burns & McDonnell for this proceeding. Mr. Kopp explained why it is necessary to demolish a generating station at the end of useful life, citing reuse of land, public safety, and environmental remediation of potential health hazards. The decommissioning study provided an estimated total cost, in 2018 dollars, of decommissioning and dismantling each Company-owned generation unit at the end of its useful life, as well as the total cost of decommissioning and dismantling the common facilities at these generating plants. The total decommissioning and dismantlement cost as determined by Burns and McDonnell and reflected in the Decommissioning Study, was net of salvage value for scrap materials at each plant. In general, the study assumed that each generating site would be restored to a condition appropriate for industrial use. This means that all sites will have above grade buildings and equipment removed, foundations removed to two feet below grade, be rough graded, and seeded. Sites also will have small diameter underground pipes capped and abandoned in place. Mr. Kopp explained that each of DEI's electric generating plants was evaluated, including steam, hydro and other facilities, including solar and that the Burns & McDonnell team visited all plants for which site-specific decommissioning and dismantlement cost estimates were prepared. Mr. Kopp described the types of costs included in the decommissioning study and how the estimates for the direct costs were developed using a bottomsup cost estimating approach. He explained how scrap values were determined and the necessity of including project indirect costs in the estimate, as well as the determination of the indirect costs included. He further explained that contingency costs had been included in the estimate, and that a contingency cost accounts for unspecified but reasonably expected additional costs to be incurred by the Company during the execution of decommissioning and dismantlement activities and contingency. He explained that these costs are in addition to the direct costs associated with the base decommissioning and dismantlement known scope items and that application of contingency is not only appropriate, but also standard industry practice. He further explained that DEI provided estimated remaining M&S inventory balances for inclusion in the Decommissioning Study, with a portion of the inventory given a salvage credit to reflect potential reuse or resale of remaining M&S. The estimated total net decommissioning and dismantlement cost for DEI's generation facilities included in the study is $420,569,400 in 2018 dollars. Mr. Kopp stated that the estimates used in the study were carefully prepared using standard and accepted estimating techniques and the best information available, and are consistent with Burns & McDonnell's industry experience. He stated that assumptions used were reasonable and that the inclusion of remaining M&S balance in the decommissioning and dismantlement costs is also reasonable, as maintaining an adequate inventory of M&S for the operation and maintenance of the generating units up to their end of life represents a prudently incurred cost for providing service to customers.

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 DEI's decommissioning cost estimates; (3) removing inventory costs from DEI's decommissioning cost estimates; (4) removing escalation factors from DEI's terminal net salvage calculations; and (5) adjusting the Company's proposed service lives for several of its transmission and distribution accounts. During cross-examination, Mr. Garrett testified that he did not make a field visit prior to completing his depreciation recommendations.

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 DEI, the Company's 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, DEI 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 I&M 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.

Mr. Garrett testified that if the IURC accepted all of DEI'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 DEI 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 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 DEI 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 DEI 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.

Brian Andrews testified on behalf of the Industrial Group with respect to depreciation issues. His stated that DEI's proposed depreciation expense increase is excessive and unduly burdens customers.

He testified that DEI's continued reliance on the ELG procedure for calculating depreciation rates is burdensome to customers. He claimed that ELG depreciation rates are front-loaded and must be updated annually for proper implementation. He further claimed that DEI is the only Duke electric company that utilizes the ELG procedure to calculate depreciation rates, and it has the highest depreciation rate of any of the Duke electric companies. He stated that all other Duke electric companies use the ALG procedure, the most commonly utilized procedure for calculating depreciation rates.

He argued that, by rejecting ELG in favor of ALG, the Commission has an excellent opportunity to achieve the following: (1) allow Duke to retire its coal plants early according to its preferred portfolio, helping achieve significant carbon reductions in Indiana, (2) significantly reduce the rate increase while allowing those early retirements and the resources that will eventually replace them, and (3) utilize the depreciation procedure that is most commonly used in the country.

Mr. Andrews also argued that DEI is attempting to recover through depreciation rates an excessive amount of costs for the demolition of its production plants. He noted that in the decommissioning cost estimates, Duke has included net inventory costs, which is the level of inventory that existed at the plants as of June 2018. He took the position that, as Duke knows the precise retirement dates of these facilities, Duke should effectively manage this inventory and strive to eliminate these balances over the remaining life of the plants. He argued that these costs should be removed from the decommissioning costs estimates that are included in the net salvage rate and depreciation rate calculations.

He also noted that, in the decommissioning cost estimates, Duke has included contingency costs. He characterized these costs as simply a 20% adder to the demolition costs and unnecessary depreciation expense. He recommended that these contingency costs be removed from the decommissioning costs estimates that are included in the net salvage rate and depreciation rate calculations.

Mr. Andrews observed that in the net salvage rate calculations, Duke has included cost escalation. He testified that these costs were determined with an excessive and unsupported 2.5% annual inflation rate and burden current customers with unnecessary depreciation expense. He recommended that these escalation costs should be based on 2.0% inflation before being included in the net salvage rate and depreciation rate calculations.

Mr. Andrews stated that the IURC should reject Duke's ELG depreciation rates and approve the depreciation rates presented in his testimony. He testified that this will reduce the test year depreciation expense by $120 million, or by 83% of Duke's proposed increase, while still allowing coal plant retirements at Duke's proposed time schedule.

Mr. Spanos testified in rebuttal, noting that while each party proposes a fairly significant change in depreciation expense compared to the Company's proposal, the vast majority of the dollar impact of their changes is due to their deviation from Commission precedent. That is, most of their proposed reduction in depreciation expense is based on issues that the Commission has already decided. He stated that the issue with the single largest impact is the Company's use of the Equal Life Group ("ELG") procedure instead of the Average Life Group ("ALG") procedure. He noted that the Commission has clearly stated that "[w]e consider the debate between ELG and ALG to have already been resolved. This Commission has frequently and consistently expressed its preference for the use of the ELG procedure."[5] The Commission has similarly ruled that it is appropriate to include contingency in decommissioning estimates and that decommissioning estimates should be escalated to the date of retirement (for example, see NIPSCO Cause No. 43526). Accordingly, the only issues raised by OUCC and IG that have not been resolved by the Commission relate to the inclusion of inventory costs in decommissioning (which is addressed by DEI rebuttal witnesses Kopp and Mosley), Mr. Andrews' use of a lower escalation rate, and Mr. Garrett's life estimates for a few accounts.

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[5] IURC 8/25/2010 Final Order in Cause No. 43526 at 51.

Mr. Spanos stated that the OUCC proposes a reduction in depreciation expense of $107 million, however, $93 million of this amount is due to the use of the ALG procedure, the removal of contingency and the removal of escalation. Similarly, he stated, the Industrial Group proposes a $120 million reduction in depreciation expense, however, $88.7 million of this is due to the use of the ALG procedure. An additional amount is the result of the parties' proposal to remove contingency.

With regard to Mr. Garrett's and Mr. Andrews' argument that ELG depreciation requires annual updates, Mr. Spanos testified the simple examples they provide to support their opinions are not reflective of real-world operations. He stated that this argument is unpersuasive for multiple reasons. First, he noted this Commission has used ELG for many years and has not required companies to update depreciation rates annually. Second, he stated that both Mr. Garrett and Mr. Andrews are incorrect that annual updates would be required. He pointed out that both examples shown to support their opinions are simplistic examples based on only a single vintage of plant. Thus, their examples do not match real-world experience. For most utility plant accounts, he stated, assets are added and retired every year. Due to this continual activity, he testified, ELG depreciation rates do not actually change as much as Mr. Garrett and Mr. Andrews claim. Third, he testified that annual updates are quite common in Pennsylvania. He stated that his firm performs depreciation studies – and annual updates – for most utilities in Pennsylvania. As a result, he has the opportunity to review changes to depreciation rates that occur each year that result from annual updates to depreciation calculations. In actual practice, he testified, ELG depreciation rates are much more stable than Mr. Garrett and Mr. Andrews claim. He stated that in aggregate, the ELG depreciation rates typically do not change dramatically from year to year and would not warrant annual updating as Mr. Garrett and Mr. Andrews assume.[6] Mr. Spanos testified that, in reality, there is little need to update depreciation rates annually when using the ELG procedure. He noted that the Commission has not been concerned enough with this issue to require annual updates in the many decades since the ELG procedure was first adopted. Accordingly, he concluded, Mr. Garrett's and Mr. Andrews' arguments to this effect are not a persuasive reason to abandon its use in Indiana.

Mr. Spanos also testified about the downsides of moving to an ALG methodology. He testified that a switch from ELG to ALG depreciation rates will result in artificially low depreciation rates due to the higher accumulated depreciation currently on the Company's books due to the historical use of ELG depreciation rates. He stated that this in turn will result in a short-term benefit that will be paid for by future customers who will also pay a return on the higher rate

[6] Mr. Spanos noted there are other aspects of depreciation that have the potential to change each year. For example, any additions to life span property result in a change to the depreciation rate (since the new asset will have a shorter life than the existing assets at the life span facility). Remaining life depreciation rates also change each year. He pointed out that Mr. Garrett proposes a change in approach from Commission precedent for terminal net salvage that would require annual updates, proposing to only include decommissioning costs at today's cost levels, which would mean the decommissioning costs would need to change each year due to changes in cost levels that occur from year to year. However, Mr. Spanos stated, for Mr. Garrett's terminal net salvage proposal (as well as other aspects of depreciation that change each year), he appears unconcerned with the potential for annual updates to depreciation rates. This gives less merit to Mr. Garrett's concerns regarding ELG, in Mr. Spanos' view.

base that will result from the proposed ALG depreciation rates. He characterized this approach as inequitable both because it will artificially reduce rates at the expense of future customers and because those customers will have to pay for the costs of generation that replaces the Company's coal-fired generation that will be retired. He concluded that Mr. Andrews' proposal would unfairly shift the costs of power plants that will soon be retired to future customers, who will receive no service from these plants. Additionally, Mr. Spanos noted, the historical use of ELG depreciation rates, as well as the inclusion of contingency and escalation in decommissioning estimates, already provides a benefit to customers as the Company transitions from coal-fired generation. While the retirement of coal-fired generation at earlier ages than previously expected does result in an increase in depreciation expense in this case, he stated that the Company has recovered more depreciation to date due to the historic use of ELG depreciation rates and more adequate levels of decommissioning (due to the inclusion of contingency and escalation) means that accumulated depreciation is higher than had Mr. Andrews' and Mr. Garrett's preferred approaches been adopted. The result, he noted, is that there is less to recover for the plants that will be retired. To put this a different way, he explained, had ALG been used in the past and no contingency or escalation included, the increase in depreciation resulting from earlier coal-fired generation would be higher than it is in the current case.

Mr. Spanos testified that Mr. Garrett is incorrect to argue that "it is preferable for regulators to ensure that assets are not depreciated before the end of their economic useful lives." While the goal is to estimate depreciation as accurately as possible, it is important to remember that depreciation is a forecast of events many years in the future and as a result estimates do not always match the actual experienced lives and net salvage of a Company's assets. Given this reality, Mr. Spanos opined, erring on the higher side for depreciation rates is preferable than the lower side because the likelihood and the risks of adverse effects on both the utility and customers are greater if depreciation is underestimated. He also added that too low of depreciation rates increases rate base, which results in customers paying higher total rates due to the return on rate base.

Mr. Spanos also took issue with Mr. Garrett's and Mr. Andrews' use of the word "accelerated" to describe the ELG methodology. He testified that ELG is a straight line method; ELG recovers costs on a straight line basis over the expected life of each equal life group.

Mr. Spanos reiterated that there are sound reasons to use the ELG procedure. He noted that this Commission has addressed this issue multiple times in the past and ruled in favor of ELG. And he noted that ELG is also discussed and supported in authoritative depreciation texts and academic literature. One such authority – and a very significant one – is Robley Winfrey, who, as a professor at Iowa State University, developed the Iowa survivor curves that are universally used in estimating service lives based on historical retirement data and is generally regarded as the father of utility depreciation practices, referred to the ELG procedure as "the only mathematically correct procedure."[7]

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[7] Robley Winfrey, Depreciation of Group Properties, Bulletin 155 (Ames, IA: Iowa State University Press, 1942, reprinted 1969); p. 71.

Additionally, he emphasized that it is also important to understand that the change in depreciation resulting from the OUCC and Industrial Group's proposed change to ALG rates is not simply due to the difference between the two procedures. Rather, a portion of this change results from the fact that accumulated depreciation is higher today due to the historical use of ELG depreciation rates than it would have been had ALG depreciation rates been used. A change to ALG rates today will, therefore, result in a greater benefit to today's customers than to other generations of customers. This occurs both because depreciation rates are lower due to the historical use of ELG depreciation rates and because rate base is lower due to the higher accumulated depreciation resulting from the historical use of ELG depreciation rates. If Mr. Andrews' proposal were adopted, it will be future customers that pay the cost for this benefit given to current customers. Future customers will have to pay higher ALG depreciation rates than current customers as remaining life depreciation rates result in accumulated depreciation that will eventually revert to a lower level from the use of the ALG procedure. Future customers will also have to pay a return on the higher rate base that results from the lower ALG depreciation rates. In summary, he testified, Mr. Andrews' proposal will result in shifting costs from today's customers to future generations of customers.

Mr. Spanos next addressed the three adjustments proposed by the OUCC and Industrial Group to the decommissioning cost estimates used in the depreciation study. The first type of adjustment is related to the escalation of decommissioning costs to the time of retirement. The OUCC proposes to remove the escalation component entirely. The Industrial Group recommends the escalation of decommissioning costs, but uses a 2.0% escalation rate instead of the 2.5% escalation rate proposed by Mr. Spanos. The second proposed adjustment is that both the OUCC and Industrial Group advocate removing contingency from the decommissioning estimates. Mr. Spanos noted that both of these issues have been previously addressed by the Commission, which has ruled in favor of the Company's proposals to include escalation and contingency. The third proposed adjustment is that both parties propose the removal of inventory costs from the Company's terminal net salvage estimates. Mr. Spanos noted that he does not address this issue, which is instead addressed by rebuttal witnesses Mr. Kopp and Mr. Mosley. He also noted that Mr. Kopp also addresses the contingency issue, although Mr. Spanos briefly discussed Commission precedent regarding this issue.

With regard to the issue of including escalation in the calculation of decommissioning costs, Mr. Spanos stated that escalation is necessary in order to recover the full net salvage costs of these facilities over their service lives and has previously been accepted by the Commission. He noted that Mr. Andrews recognizes that escalation should be included in the terminal net salvage estimates, but proposes a lower escalation rate of 2.0%. Mr. Spanos testified that, in order to equitably recover the full costs of the Company's assets, including net salvage, net salvage must be based on future costs because decommissioning is going to occur in the future. He emphasized that net salvage must include the effects of future increases in costs, as recognized on multiple occasions by this Commission.

Mr. Spanos noted that Mr. Garrett makes one main argument in support of his proposal to eliminate escalation from the terminal net salvage estimates. He states that "[i]t is not proper to charge current ratepayers for a future cost that has not been discounted to present value." He supports this assertion by stating that "[t]he 'time value of money' concept is a cornerstone of finance and valuation." Mr. Spanos testified, his opinion on this concept with regard to depreciation is incorrect. Mr. Spanos reiterated that depreciation is based on the actual cost at the time of installation or retirement. While the "time value of money" may be a cornerstone of finance and valuation, it is not a concept used in depreciation as widely practiced in the industry. Indeed, Mr. Spanos testified, failing to incorporate escalation, as Mr. Garrett proposes, will result in understating future net salvage costs, resulting in intergenerational inequity by forcing future customers to pay too much for the facilities.

Mr. Spanos next noted that, unlike Mr. Garrett, Mr. Andrews includes an escalation component in his terminal net salvage estimates. However, he uses a 2.0% escalation rate instead of the 2.5% escalation rate used by the Company which he says "has no support and is excessive." Mr. Spanos testified that his estimate of 2.5% is reasonable for a long term rate of cost increases for power plant decommissioning. He stated that his estimate is consistent with escalation rates used previously, as well as other sources including long-term averages of Consumer Price Index ("CPI") inflation and long-term inflation forecasts; the latter is compiled by the Federal Reserve in the Livingston Survey. He noted that CPI inflation has typically been lower than long-term construction cost increases and so, if anything, his estimate is conservative.

Mr. Spanos testified that Mr. Andrews only provided an analysis based on comparing the Livingston Survey to actual CPI inflation since 1991. From this analysis, he concludes that the "average forecast error is 0.6 percentage points" for this survey since 1991. Since the current 10-year median forecast is 2.26%, he subtracts 0.6 from 2.26% to get a value a 1.66%. He concludes that 1.66% is a more realistic forecast, although he proposes an escalation rate of 2.0% "to be conservative." Mr. Spanos testified that there are multiple issues with Mr. Andrews' analysis. First, he stated that the Livingston Survey is not the only support for Mr. Spanos' estimate. Second, Mr. Andrews' calculation of the forecast error is entirely the result of two periods of time. The first is from the early 1990s and the second from the late 2000s. The forecast error in the early 1990s resulted because these years followed the high inflation of the 1970s and 1980s. That is, forecasters not unreasonably expected that higher inflation to continue, but it did not. The second period is comprised of years that encompassed the Great Recession. The Great Recession resulted in very low inflation and even deflation, but was an abnormal event. Accordingly, Mr. Spanos testified, the period of time reviewed by Mr. Andrews' likely overstates any forecast error, particularly downside errors. Indeed, the last two decades have experienced low inflation by historical standards. It should be at least as likely that current forecasts would be too low rather than too high. However, he testified, Mr. Andrews only anticipates that forecasters could be estimating too high of inflation.

Mr. Spanos testified that these concepts are illustrated if we look at longer term inflation. He stated that looking at longer term inflation rates shows that there have been many years with higher inflation. As a result, he explained, simply assuming that a 2.0% inflation rate will continue into the future is not necessarily a reasonable assumption. Mr. Spanos provided data going back to 1960 and noted that the inflation that occurred over 10-year periods was greater than 2.5% in many years. Additionally, Mr. Spanos testified that while the CPI provides a good indication of changes in prices in the overall economy, it is not necessarily a good indicator of changes in decommissioning costs. A price index that serves as a better proxy for changes in decommissioning costs is the Handy Whitman construction cost index. Mr. Spanos provided a comparison of the changes in the Handy Whitman Index for Steam Production Plant to CPI over the past 20 years; the data shows that construction costs have increased faster than CPI over this time period. Further, he stated, the data indicates that for every single long-term period ending in 1960 through 2018, the Handy Whitman index increased at an average rate that was greater than the 2.5% escalation rate he proposed. Thus, he concluded, the Handy Whitman index supports a higher escalation rate than he proposed. In summary, he testified that multiple sources support the 2.5% escalation rate he used, and, if anything, his estimate is conservative. He concluded that Mr. Andrews' estimate is, in his judgment, too low and will not fully recover the costs to retire the Company's power plants over their service lives.

Mr. Spanos next discussed the issue of contingency. He stated that Mr. Garrett and Mr. Andrews also both propose the removal of the contingency component from the decommissioning cost estimates. Mr. Spanos noted that the use of contingency has also been previously addressed by the Commission. For example, he noted the following excerpt from a NIPSCO case, in which the Commission held that the inclusion of contingency was appropriate and also noted that Commission precedent supported the inclusion of contingency:

> Mr. Selecky argued either the post-remediation value of the land in industrial condition should be an offset to the dismantlement costs or the contingency should be eliminated as a trade-off for the value of the land. Mr. Selecky did not identify the dollar value of the land after dismantlement. As a result, there is no evidence in the record to guide us in determining whether this would produce a material difference in the depreciation rates or be a reasonable trade-off for the contingency, assuming for the sake of argument it would even be proper to treat a non- depreciable asset like land as salvage. Further, we find it noteworthy that Mr. Selecky is not a licensed real estate appraiser. As a result, the record is devoid of any evidence to judge whether his proposal to equate the value of the land with the contingency is reasonable. (42356 Order at 53-54.) We also give weight to the fact that the 20% contingency factor used in the BMcD demolition cost studies is conservative compared to the 25% contingency factor we accepted in PSI Energy, Inc., Cause No. 42359, at 70-71. Also, the assumption that the sites will be remediated to industrial condition, rather than greenfield condition, is also conservative. Id. at 70. No evidence was presented that this Commission has ever used the value of land as an offset to an asset's cost of removal. In fact, Mr. Selecky did not identify to us any decision of any regulatory commission accepting his position regarding land and the contingency. Petitioner's JJS-R5; Petitioner's Ex. JJS-R6. Given that Mr. Selecky's recommendation would be such a departure from our past practice and that we have scant evidence to guide us in this exercise, we reject Mr. Selecky's proposal.

Mr. Kopp also provided rebuttal testimony regarding the appropriateness of including contingency in the decommissioning study for this proceeding. Specifically, he noted that the application of contingency is a common and prudent practice in the construction industry, and it is included in order to recognize the probability of increases in cost over the base estimated costs due to unknowns. Mr. Kopp explained that some of these costs cannot be determined until the dismantlement process has begun. Therefore, contingency is applied on top of the base estimated cost in order to formulate a reasonable estimate to dismantle the generating facilities.

Mr. Kopp explained that the 20% contingency amount he included in this decommissioning study is the same percentage as the contingencies he has prepared for decommissioning studies for other electric utilities that have been approved by regulatory agencies in other states.

Contingency is added to account for unknown, but reasonably expected to be incurred costs. These costs are related to weather delays, unknown environmental contamination, discovering equipment or materials not shown on drawings, additional dewatering requirements and changes in the manner the work is performed.

Mr. Kopp responded to Mr. Andrews' contention that DEI has no legal obligation to demolish its retired power plants by expanding on the explanation in his direct testimony of the necessity for demolition of power plants. He explained that although there may be no legal obligation to demolish a power plant, there are legal obligations to comply with environmental regulations. He also explained that the alternative to full demolition is to retire a plant in place. He explained that retiring a plant in place requires carrying costs that are necessary to maintain a safe site and be in compliance with applicable regulations. Mr. Kopp stated in his experience he has found that retiring in place is not a cost-effective long-term scenario when the carrying costs are taken into account.

Mr. Kopp concluded by stating that excluding these reasonably expected to be incurred costs by not including contingency costs will not give the full picture of decommissioning costs. If these costs are not accounted for in planning for future decommissioning, the costs will be passed on from the current ratepayers to future ratepayers.

Company witness, Mr. Mosley, provided rebuttal testimony addressing the inclusion of inventory in the decommissioning study. He explained Duke Energy has experience managing generating stations as they near the end of their useful lives and consistently attempts to deplete remaining inventory and/or transfer it to another generating facility where it can still be used. However, there are risks associated with premature depletion of inventory due to limited availability and long lead time of parts required to sustain reliable operation that must be considered.

In addition, Mr. Mosley stated that there are often limitations on the compatibility of inventoried parts that could be transferred from one station to another. For example, most spare parts that fit Gallagher's coal mills do not fit the mills at Gibson or Cayuga. Most steam turbine and generator parts are model specific and cannot be used at other facilities. Combustion turbine and generator parts have some capability with like-in-kind models, but circa-2000 machine parts would rarely be compatible with future gas-fired generators.

Mr. Mosley also explained that as the existing coal and gas-fired generators are retired, there are increasingly less remaining opportunities to transfer useful inventory. Therefore, reflecting leftover inventory in the cost of decommissioning is a reasonable means of addressing a future where increasing numbers of generating units are retired and replaced.

Mr. Kopp also provided rebuttal testimony regarding the inclusion of obsolete inventory remaining at the end of a generating station's useful life in this decommissioning study. He explained that disposing of remaining inventory is just as much a part of decommissioning a station as disposing of other equipment and plant components. It must be safely sold, moved to other locations, or scrapped. In fact, the warehouse or other portions of the plant where the supplies are held cannot be demolished until the inventory is safely removed.

Mr. Kopp then rebutted Mr. Andrews' contention that if this equipment is not placed in service, then it is not used and useful. Mr. Kopp stated that Andrews' argument ignores that inventory is required to be maintained in order to achieve appropriate reliability of the plants and to facilitate routine maintenance on the facilities. Furthermore, Mr. Kopp stated that it is necessary to purchase this inventory before it is needed, in order to reduce outage time, and even if it is not installed, it has still served a useful purpose in maintaining plant reliability.

Mr. Kopp's testimony also stated that the value of this inventory that cannot be reclaimed through sale or scrap of the inventory is directly related to the retirement of the facility. If the facility were to remain in service, this inventory would retain its value to the plant. However, when the plant is retired, the value of this inventory is reduced to the value it has as salvage or scrap. This reduction in value of the inventory is a cost associated with net salvage rates associated with retirement and demolition of the facility. In response to Mr. Garrett's contention that Mr. Kopp had never proposed including inventory in decommissioning studies before, Mr. Kopp also cited to approval of the inclusion of inventory in a decommissioning study prepared for FPL by the Florida Public Service Commission.

Company witness Ms. Douglas also responded to the recommendations of Mr. Garrett and Mr. Andrews regarding the inclusion of end-of-life generating plant M&S inventory costs as a cost of decommissioning and dismantlement. She explained that unlike other plant, property and equipment used at a generating station, which is depreciated over its useful life and the cost of which is recovered from customers served by and benefitting from the electricity generated at the station during its useful life, under the current ratemaking construct, recovery of the cost of M&S maintained in inventory occurs only once the parts and equipment in inventory are installed in the plant. She explained that when base rates are set, under traditional Indiana ratemaking practice, inventory is included in rate base for return purposes, but is not depreciated over its life like plant. Further, the current construct assumes the M&S inventory can be used up before retirement occurs and whatever amount is left can be reused elsewhere or sold, with no current ratemaking means for recovering the cost of the remaining end-of-life inventory from the customers for whose benefit the inventory held for reliability purposes at the station was maintained. As also discussed in the rebuttal testimony of Company witness Ms. Melissa B. Abernathy, without assurance of regulatory recovery of any remaining inventory costs that have now become obsolete due to the retirement, the Company must write the inventory off as an additional, one-time expense. Ms. Douglas further explained that the Company's proposal is reasonable because it enables the forecasted costs of the end-of-life M&S inventory to be recovered in a rational and systematic way over the remaining life of the plant from the customers who are being served by the plant and benefitting from the reliability that the inventory brings to the plant. Ms. Douglas opined that this approach is a fair and balanced way to address this issue to prevent large negative financial impacts at a plant's end of life for companies who have purchased and managed their M&S reasonably for the benefit of customers. Ms. Douglas noted that the rebuttal testimony of Company witness Mr. John Sullivan addresses the negative impacts on credit quality and financing costs that may result from write-offs such as this. Ms. Douglas concluded by noting that an alternative to recovery over the life of the plant via decommissioning costs would be the pre-approval by the Commission of the use of a regulatory asset at the end of the plant's life, with the remaining value to be recovered from customers over time in a future rate case.

(1) <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. 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. ALG depreciation rates result in systematical and rational cost recovery with near term customer rate relief and full cost recovery of utility investments. While we have determined in the past that the ELG methodology was appropriate and acknowledge the weight given to precedent in many prior decisions, we always evaluate each case as it comes before us and do not need to approve the same methodology based on prior decisions, especially in light of a changed landscape. The use of ELG in a higher than average investment cycle has the effect of unnecessarily increasing the near term depreciation expense as compared to the use of ALG. A review and comparison of Mr. Andrew's exhibits reflecting only the ALG verses the ELG modifications applied to Mr. Spanos' results indicate that the impact of the methodology change on a percentage basis is markedly more significant for the distribution and transmission components than the production, or generation, component. This evidence is not surprising given the increased investment cycle in these categories as highlighted by the relatively recent statutory support for such investment codified at Indiana Code ch. 8-1-39. A changed and encouraged investment cycle is a material landscape change through which we consider our previous proclamations on methodology. Furthermore, the consideration of service affordability in the near term provides sufficient weight to temper our historical preference for ELG. Again, a recently enacted statute, Indiana Code § 8-1-2-0.5, directing the commission to consider "all practical means and measures" to balance necessary investment with service affordability enhances the regulatory landscape. In response to a Docket Entry question DEI confirmed that it had not identified investments that would not be recovered with the ALG methodology as described. Therefore, we find that the application of ALG serves as a reasonable regulatory mechanism to provide rate impact moderation while not limiting DEI's reasonable recovery of its investment.

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. Based on the evidence presented in this case, we find that Mr. Spanos' 2.5% inflation estimate is more realistic and should be used. Mr. Spanos supported his estimate with CPI data going back to the 1960s, as well as more relevant Handy-Whitman index data, while Mr. Andrews' supported his inflation estimate with arguably selective time periods that are not representative of future conditions.

Next we address the parties' contention that contingency be removed from the decommissioning study. We disagree with the parties that the circumstances here warrant such removal. Commission precedent supports the inclusion of contingency and we find it reasonable and appropriate again here. Similar to our previous holdings, we give weight to the fact that the 20% contingency factor used in the demolition cost studies is conservative compared to the 25% contingency factor we approved in the Company's most recent rate case. Furthermore, the assumption that the sites will be remediated to industrial condition, rather than greenfield condition, is also conservative. We therefore decline to depart from our previous practice.

Regarding the parties' arguments concerning inclusion of the cost to address end-of-life inventory at retired generating plants, these type of inventory costs are not typically included as part of decommissioning cost estimates. Normally any unrecovered amount would be expensed at the time of retirement. In rebuttal, Ms. Douglas suggested an alternative in which the Commission pre-approves a regulatory asset at end of life rather than a write-off. As presented in the Industrial Group's February 6 filing this alternative would materially lower the impact of Duke Energy Indiana's rate request. In addition, the alternative affords DEI an opportunity to undertake any and all reasonable actions to minimize the end-of-life inventories as any station retirement draws nearer. Thus, we approve the use of a regulatory asset at the end of life with the understanding that any recoverable amount will be subject to a review of actions taken in advance of any associated retirement.

Based on and incorporating the findings above, we approve for use by DEI the depreciation rates presented in the revised attachment to the Industrial Group's February 6 filing.

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

(A) Production O&M Expense. Petitioner's witness Mosley testified that DEI's 2020 power production O&M forecast is $407 million, as follows:

Category	O&M ($ in millions)
Edwardsport IGCC	$139
Coal Combustion Products	$12
New Generation Resources	$0
Power Production	$229
Other Miscellaneous Power Production	$27
Total	**$407**

Mr. Mosley then testified in support of $229 million of the 2020 power production O&M for generating facilities other than Edwardsport. Mr. Mosley stated that power production O&M expense generally includes the cost associated with the operation, maintenance, administration and support of DEI's generating units. Mr. Mosley provided the following table showing the components of the Company's proposed power production O&M for generating facilities other than Edwardsport for the 2020 test period, in addition to showing comparisons to 2018 actual and 2019 budget:

$ in Millions	2018 Actual	2019 Budget	2020 Forecast
Non-Outage O&M	$198	$182	$197
Increase / (Decrease)		($16)	$15
Outage O&M	$11	$27	$32
Increase / (Decrease)		$16	$5
Power Production O&M Total	$209	$209	$229

Mr. Mosley explained that non-outage O&M expenses are generally incurred on an ongoing basis, while outage-related O&M expenses generally are incurred only periodically based the maintenance cycle of the units. Mr. Mosley testified that each of the Company's generating stations has cyclical maintenance, which the Company attempts to schedule during off-peak times of the year with outages staggered to prevent the majority of units from being out for scheduled maintenance at the same time.

Petitioner's witness Gurganus supported the Company's proposed 2020 power production O&M expense of $139 million for the Edwardsport plant. As with Petitioner's other plants, Mr. Gurganus testified that the components of Edwardsport's O&M costs are: (i) basic generating station operations; and (ii) maintenance outages. Planned outage O&M expenses generally are incurred based on the maintenance outage cycle of the Edwardsport plant components. Mr. Gurganus testified that DEI's 2020 Edwardsport O&M test period forecast includes $46.4 million in expenses associated with a major outage that occurs about once every seven years. He provided the following table showing the components of the Company's proposed power production O&M for Edwardsport for the 2020 test period, in addition to showing comparisons to 2018 actual and 2019 budget:

$ in Millions	2018 Actual	2019 Budget	2020 Forecast
Edwardsport O&M	$99	$96	$139
Increase / (Decrease)		($3)	$43
Less 2020 Major outage O&M			$46
Adjusted Increase / (Decrease)			($3)

Petitioner's witness Thiemann testified in support of the Company's proposed 2020 power production O&M expense of $12 million for coal combustion products. He explained these expenses were for the hauling of production ash to onsite landfills.

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 using a seven-year average methodology to normalize O&M expenses, including the associated major outage costs, which he stated resulted in an $80 million reduction to Petitioner's proposed O&M costs. Mr. Alvarez stated that his proposal reduced the Company's generating facilities' forecasted Test Year O&M expenses to $149 million.

Mr. Alvarez explained that Duke Energy's proposed power production O&M cost for generating facilities other than Edwardsport includes $197 million of non-outage expense and $32 million of outage-related O&M expenses. Mr. Alvarez stated that the Company greatly overstated the $32 million annual outage-related O&M expenses requested. Mr. Alvarez stated that $32 million does not represent the typical year of power production and operation with cyclic major maintenance outages. Mr. Alvarez noted that since Duke Energy performed, or plans to perform, major outage work on all nine units in 2018-2020, there should be no scheduled major outages for 2021, 2022, 2023, and 2024 (based on a normal seven year cycle).

Mr. Alvarez recommended that Petitioner embed $149 million power production O&M expenses in base rates. Mr. Alvarez's proposal reflects a reduction in Duke Energy's proposed annual non-outage O&M expenses from $197 million to $129 million and a reduction in the Company's proposed annual outage-related O&M expenses from $32 million to $20 million.

Mr. Alvarez further recommended that the Commission require the Company to adopt a seven-year average methodology to normalize Edwardsport's overall O&M expenditures, major outage expenses, and miscellaneous administrative and general benefits costs. Mr. Alvarez recommended a decrease to the forecasted 2020 Test Year to an overall total of $61.8 million. Mr. Alvarez noted that this is an approximate $50.8 million reduction to the Company's proposal. Mr. Alvarez stated that the Company'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 Settlements in prior proceedings related to the Edwardsport plant. Mr. Alvarez stated that in each year an O&M cap was in place, Edwardsport operations consistently exceeded the cap. Mr. Alvarez stated that Edwardsport operations have not achieved any significant expense reductions. Mr. Alvarez recommended that Duke Energy use an average of the forecasted Test Year 2020, and the forward-looking years through 2027 to determine Edwardsport O&M expenses.

Industrial Group witness Gorman testified that operating Edwardsport on natural gas would allow it to produce electricity at a much lower cost than continuing to operate it as an IGCC. Mr. Gorman testified that if Edwardsport's dispatch costs are lower on natural gas, then all the fixed O&M costs associated with coal handling and operation of the coal to gas conversion facility can be avoided by shutting these facilities down or placing them in cold storage for use at a later time. Mr. Gorman stated that based on a comparison of Edwardsport to other similar vintage combined-cycle gas units ("CCGU"), it looks promising that Duke could avoid significant annual fixed O&M expense if it operated as a natural gas facility. Mr. Gorman testified that the workforce required to run Edwardsport is much larger than what is required to run a comparable-sized natural gas facility. Mr. Gorman estimated that Edwardsport's O&M on natural gas for the forecasted test period is $20.4 million. Mr. Gorman concluded that using natural gas would result in a savings of $81.6 million over Duke's forecasted Edwardsport O&M costs in 2020 of $102 million.

Mr. Gorman concluded that costs that can be avoided by operating Edwardsport as a natural gas facility should not be included in rates in this proceeding. Therefore, Mr. Gorman recommended the Commission remove fixed costs needed for the operation of the coal gasification and coal handling facilities.

Sierra Club witness Comings recommended that Edwardsport costs should be denied and the Company should develop a plan for retiring the plant. Mr. Comings estimated that on a variable basis alone (*i.e.*, excluding fixed costs) the plant has cost ratepayers $93 million from 2016 through 2018. Mr. Comings stated that these losses are caused by: (i) Duke Energy operating most of the plant as "must run" instead of MISO economic dispatch; and (ii) Duke Energy bidding in the plant below its variable costs. Mr. Comings stated that put another way, if the plant had not operated from 2016 through 2018, ratepayers would have saved $93 million in energy costs.

Accordingly, Mr. Comings recommended the Commission deny the Company's request for Test Year capital, fuel, and O&M for Edwardsport because the Company cannot meet its burden to show that those costs are prudently incurred. Mr. Comings stated that the Commission should not allow the Company to charge ratepayers substantial fixed costs for a plant that is nearly always uneconomic to operate on a variable basis and would save ratepayers money if replaced. Mr. Comings stated that once the Company develops a plan for the plant's retirement, Duke Energy should be permitted recovery of fixed costs that have been adjusted to plan for imminent retirement. Mr. Comings testified that at the very least, the Company should be disallowed the $93 million in losses associated with the plant from the past three years because ratepayers were overcharged this amount for energy.

Petitioner's witness Mosley testified that OUCC witness Alvarez misinterpreted his direct testimony related to frequency and O&M costs associated with 2018 through 2020 planned outages for units other than Edwardsport. Mr. Mosley stated outages for these units are scheduled on an ongoing annual basis to help balance resource needs, cost, and optimized reliability. Mr. Mosley stated that the 2018 through 2019 outage expenses were lower than typical due to fewer maintenance outages being performed than normal. Mr. Mosley stated that the Company's $32 million request for 2020 is more representative of a typical year, and consistent with future year-to-year forecasts.

Petitioner's witness Pike testified that there were problems with Mr. Alvarez's seven-year average methodology to normalize O&M expenses based on Petitioner's IRP. Mr. Pike stated that Mr. Alvarez only included the fixed component of O&M cost as modeled in the IRP in his analysis – not variable costs. Mr. Pike testified that omission of the variable O&M component excludes significant real costs from the OUCC's analysis, including emission control reagents, coal and waste handling, and other outage and non-outage variable maintenance expenses as so-modeled. Mr. Pike testified that including variable costs results in a 2020-2024 average of the total O&M cost as-modeled in the IRP is $258 million, which is actually much higher than the $229 million proposed by the Company. Mr. Pike noted that removing property taxes and insurance costs results in an apples-to-apples comparison of $243 million, which is nearer yet still higher than the Company's request. Mr. Pike stated that de-escalating the future costs into constant year 2020 dollars, results in a 2020 to 2024 average of $232 million.

Mr. Pike stated that Mr. Alvarez's analysis and recommendations regarding Edwardsport's costs also is fundamentally flawed. Mr. Pike stated that including the Edwardsport variable O&M rate as well as a deduction for the 2020 planned outage cost, result in a nominal average of about $83 million, which compares to the Company's non-outage request of about $99 million from Mr. Gurganus' direct testimony. Mr. Pike testified that using as-modeled long-run O&M costs from an IRP is not an appropriate substitute for rigorously developed budgets at the functional level.

Petitioner's witness Gurganus testified that DEI has been operating Edwardsport since before June 2013. Mr. Gurganus testified that the Company has improved plant performance every year through preventative maintenance and efficiently responding to emergent items. Mr. Gurganus stated that shutting the station down or even just shutting down or "mothballing" the gasification island, as the Industrial Group suggests, would both result in under-utilization of a significant investment. In Mr. Gurganus' opinion, making such a decision now is not the best course of action for DEI and its customers. Mr. Gurganus stated that as the Company moves to retire its older coal-fired units, there is value in maintaining its youngest coal-fired unit, so that coal can continue to be a meaningful contributor to diversity for customers' benefit for years to come.

Mr. Gurganus further stated it is operationally difficult, time consuming, and costly to switch fuels in response to short-term natural gas price signals. Mr. Gurganus noted that Edwardsport receives coal under contract from a local mine and if it were to switch to natural gas for any significant length of time, the DEI system would be oversupplied with coal. In addition, Mr. Gurganus noted that shutting down the gasifiers would entail loss of a highly trained and qualified workforce.

Mr. Gurganus noted that Mr. Alvarez does not appear to object to the Company's major planned outage expenses for Edwardsport. Mr. Gurganus stated that Mr. Alvarez made critical errors in his analysis of the 2018 IRP as modeled O&M costs for Edwardsport. Mr. Gurganus stated that the Commission should consider the Company's non-outage O&M expense request in this proceeding reasonable, necessary, and prudent for operation of the facility, and not color it with what was modeled in the IRP. Mr. Gurganus testified that he provided an opinion of potential ongoing O&M cost reductions to inform the IRP modeling, which resulted in the differences between the as-modeled IRP O&M costs ($82.8M per year average over twenty years) and the Company's request for the non-outage O&M expenses in this proceeding. Mr. Gurganus testified that he cannot guarantee the degree of savings that may be achieved and the Company's non-outage O&M expense request in this proceeding represents the currently known actual costs for Edwardsport.

(1) <u>Commission Discussion and Findings</u>. 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 solely 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 dispatch-related costs for the past three years in the section on FAC issues later in this Order.

The Sierra Club argues the entire Edwardsport station should be shut down immediately. The Industrial Group recommends the plant should be operated only as a natural gas plant and that O&M costs associated with operating the plant as a coal plant should be disallowed. DEI has been operating Edwardsport since approximately June 2013 (its in-service date), and Mr. Gurganus noted that a full maintenance cycle has yet to be completed. We believe it is premature to make a decision to retire Edwardsport when the asset is relatively early in its life cycle. As Mr. Gurganus noted, the Edwardsport plant will provide diversity in the future as the Company moves to retire its older coal-fired units. We must consider that, as DEI and other Indiana utilities retire thousands of megawatts of coal-fired baseload generation, the remaining baseload units – such as Edwardsport -- may become critical from a grid reliability perspective. The Edwardsport IGCC is the Company's youngest and most advanced coal-fired unit and is equipped with advanced emission controls that will position it for continued operation for years to come. As older coal-fired units reach the end of their useful lives and are largely replaced by non-coal-fired units, Edwardsport will remain in a position to be a meaningful contributor to maintaining a diverse generation portfolio that will benefit customers and the grid as a reliable and non-intermittent energy source.

We have consistently recognized the importance of generation resource diversity. For instance, in *Indiana & Michigan Power Company,* Cause No. 44511 (IURC; February 4, 2015), we noted that "Chapter 8.5 reflects an integrated resource process which seeks to utilize a diversified portfolio of supply side and demand resources (e.g., coal, gas, nuclear, wind, solar, energy efficiency, load management)." We have, in fact, emphasized the importance of fuel diversity in multiple proceedings. *See e.g., Verified Petition of Indianapolis Power & Light Company for Certificates of Public Convenience and Necessity,* Cause No. 44794 (IURC; April 26, 2017)("fleet fuel diversity mitigates risks'); *Joint Petition of PSI Energy, Inc. and CinCap VII for Issuance of Certificates of Public Convenience and Necessity,* Cause No. 42145 (IURC; Dec. 19, 2002)(the addition of gas-fired peaking capacity will benefit the system in terms of fuel diversity and mitigating future environmental regulation risk); *Wabash Valley Power Association for Issuance of* a *Certificate of Public Convenience and Necessity,* Cause No. 42321 (IURC; March 26, 2003) ("Landfill Units are an appropriate choice to meet Petitioner's need for additional generating capacity, which should enhance system integrity and reliability and provide Petitioner with increased fuel diversity.").

We also reject the Industrial Group's proposal to effectively convert the plant to a gas plant. The evidence indicates that such a conversion decision would have permanent repercussions, and would put the future use of the plant as a dual-fueled syngas/natural gas plant at risk. As noted above, we find persuasive Mr. Gurganus' testimony that it would be operationally difficult, time consuming, and costly to switch fuels in response to short-term natural gas price signals in an attempt to capture benefits for customers. Among other things, the Company would lose the highly trained and qualified workforce, which Mr. Gurganus stated would be devastating to the future of restarting the plant on coal. Mr. Gurganus also noted that Edwardsport receives coal under contract from a local mine and the Company would be oversupplied with coal if it were to switch to natural gas for any length of time.

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 witness Pike, however, testified 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 variable O&M costs, the OUCC inadvertently omitted significant costs, including: emission control reagents, coal and waste handling, and other outage and non-outage variable maintenance expenses. 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. Duke Energy witness Pike noted 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.

The OUCC's analysis also was based on a misunderstanding of Petitioner's maintenance schedule. Mr. Mosley testified that DEI operates a fleet of forty-two units, with outages scheduled on an ongoing annual basis to help balance resource needs, cost, and optimized reliability. Mr. Mosley indicated that the Company's $32 million request for outage maintenance costs is representative of a typical year, and consistent with the Company's future year-to-year forecasts.

Because the evidence reflects that $229 million is an accurate reflection of the O&M needs of the Company's production facilities, aside from Edwardsport, we reject the OUCC's recommended adjustment.

The OUCC proposed $6.63 million per year, levelized, for major planned outage expenses at the Edwardsport Station, and $55.24 million per year for the balance of non-outage O&M expenses. The OUCC's $6.6 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 = $6.6 million/year). However, the OUCC's proposed non-outage O&M expense for the Edwardsport facility is significantly less than Petitioner's proposal.

Again, however, in determining the non-outage O&M costs for the Edwardsport plant the OUCC excluded the same variable O&M costs that it omitted with respect to Petitioner's other plants and neglected to factor in inflation. Accordingly, we find that the evidence reflects that Petitioner's proposed non-outage O&M cost of $99.4 million is more reflective of Petitioner's ongoing needs than the OUCC's proposal and approve the inclusion of this amount in base rates.

We also 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 find it reasonable to set a level of O&M in base rates based on such operation.

(B) <u>Major Storm Damage Recovery Expenses</u>. Petitioner's witness Hart testified that the Company's actual major storm costs for 2018 were $21.4 million as compared to the 2020 forecast for major storm expense of $10 million. Ms. Hart provided a table showing that the average amount spent on major storm expenses over the last five years (2014-2018) was $12.7 million. Ms. Hart explained that a storm is classified as a Major Event Day ("MED") when a major reliability event causes a utility to shift into a crisis mode of operation in order to adequately respond. The Company will use MEDs to classify events as major storm events.

Petitioner's witness Sieferman testified that the Company proposed to embed $12.7 million in base rates for major storm expenses based on the five-year average. She indicated *pro forma* adjustments were made to increase O&M and payroll tax expenses in the 2020 forecasted test period to move from $10 million to the $12.7 million level.

OUCC witness Alvarez testified that there is no assurance that the utility incurred its historical major storm expenses from a prudent management of its storm expenses. 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).

Petitioner's witness Hart noted that Mr. Alvarez provided no evidence that the Company's storm response expense was imprudent. Ms. Hart testified that she has been involved with the Company's storm response efforts for seven years, and could attest that its efforts are robust, efficient, and proactive. Ms. Hart indicated that the Company uses an Incident Command System ("ICS"), which is utilized by other emergency response organizations such as FEMA, police, and fire departments. Ms. Hart stated that ICS is mandated by the Federal government for the public sector to be used during disasters. Ms. Hart testified that ICS allows for the integration of facilities, equipment, personnel, procedures, and communications operating within a common organizational structure. Ms. Hart stated that forcing the Company to merge major storm response, vegetation management, and TDSIC through a mandated operational plan would lead to inefficiencies, delays in restoration, and confusion.

Ms. Sieferman testified that the $12.7 million level proposed by DEI is based on an average of actual historical costs, while Mr. Alvarez's recommendations appear to be arbitrary and not supported by any evidence. Ms. Sieferman stated that comparing the recommended level to both a three-year average of $16.6 million and a seven-year average of $11.1 million, illustrates that the $12.7 million level proposed is reasonable.

(I) **<u>Commission Discussion and Findings</u>.** The question here is determining the appropriate amount to be built into the Company's base rates to fund the Major Storm Reserve. 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. Ms.

Sieferman noted that the most recent three-year average of Petitioner's major storm restoration cost is $16.6 million, and the most recent seven-year average is $11.1 million. These averages illustrate that the $12.7 million level proposed by the Company is reasonably representative of probable future experience. 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.

In this case, there is no evidence of "inefficiency or improvidence." To the contrary, Petitioner's witness Hart provided substantial evidence that Petitioner's major storm restoration expense has been prudently incurred. Based on the substantial evidence of record, we reject Mr. Alvarez's recommended major storm outage expense adjustment, as well as his recommended changes to the Company's procedures.

(C) Vegetation Management. Petitioner's witness 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 believes $49.4 million is necessary to sustain a five-year maintenance trim cycle while maintaining safe and reliable service to customers. To support Petitioner's request, Mr. Christie stated that DEI commissioned Environmental Consultants, Inc. ("ECI") to perform a regrowth analysis of tree-to-conductor contact by cycle length for the DEI service territory, which found that a five-year trim cycle is appropriate for DEI's distribution system.

Petitioner's witness Graft sponsored Schedule OM17 which shows an increase in Test Period operating expenses of $10,479,000 resulting in the expected, ongoing, annual distribution vegetation management cost recovery through base rates of $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 $5.6 million, the projected 2019 O&M is $7.6 million, and the projected 2020 O&M is $7.6 million.

OUCC witness Hand did not oppose the test period O&M for transmission vegetation management of $7.6 million. However, the OUCC opposed the Company's proposed revenue requirement for vegetation management of its distribution system. Mr. Hand proposed a *pro forma* revenue requirement routine vegetation management for the Company's distribution system O&M of $32 million with unspent funds in a given year returned ratepayers.

Mr. Hand stated that none of Duke Energy's witnesses explained with any degree of specificity why its forecasted test year vegetation management spend (O&M and capital) should be $90 million. Mr. Hand further stated that, Duke Energy's proposed vegetation management initiatives are not well defined or well supported. Moreover, Mr. Hand stated that there is no evidence the Company has ever achieved a five-year trim cycle or that it will be able to do so. Mr. Hand noted that the Company has not explained in its case what it would do over the next three years to achieve an average five-year trim cycle.

Petitioner's witness Christie stated that the Company is well positioned to meet a five-year trim cycle. Mr. Christie also disagreed with Mr. Hand's testimony asserting that the Company will not be able to achieve a five-year trim cycle. Mr. Christie stated that past performance and miles trimmed prior to substantial contractor cost increases demonstrated the Company's ability to prune over 3,000 miles on an annual basis in 2014 and 2015.

Mr. Christie stated that any expectation that the Company will spend the exact amount of vegetation management O&M included in its base rates each and every year fails to recognize the nature of vegetation management. Mr. Christie stated that vegetation management activities are highly sensitive to weather, both on a local and regional basis. Accordingly, Mr. Christie testified that the Company disagreed with Mr. Hand's proposed credit of unspent funds.

Petitioner's witness Graft further addressed Mr. Hand's proposal to credit customers for the unspent portion, if any, of vegetation management O&M in base rates. Ms. Graft stated it is unreasonable and inappropriate to effectively track vegetation management O&M expenses that are lower than the amount in base rates in a given year without giving consideration to other transmission and distribution expenses that may have increased during that same time period. Ms. Graft stated that a more balanced and appropriate alternative to Mr. Hand's proposal would be to utilize a cumulative reserve accounting approach under which the Company would record a regulatory liability for the amount by which its cumulative vegetation management O&M for the time period between base rate cases is less than the amount being recovered through base rates.

(I) Commission Discussion and Findings. The base rate O&M amount for transmission system vegetation management was not opposed. Based on the evidence presented we accept the amount proposed by DEI. However, the O&M amount for distribution system vegetation management DEI sought was adjusted by the OUCC. DEI sought to include $49.4 million, composed of its 2020 budgeted amount of $38.9 million and an upward adjustment of $10.5 million. The OUCC proposed an overall downward adjustment such that base rates would include $32 million.

We begin our discussion by noting the evidence that DEI spent $14.3 million for distribution vegetation management expense in 2018 and budgeted $13.5 million for 2019. Further, DEI Witness Pinegar answered a question from the bench on whether the current DEI vegetation management performance today was unreasonable with, "it is unacceptable". A review of DEI testimony suggests these efforts resulted in a 16 year trim cycle. DEI's effort is troubling to this Commission. Consistent with actions taken in recent rate cases, IPL's rate case Cause No. 44576 and NIPSCO's rate case Cause No. 43526, the Commission has applied a ROE basis point penalty as means to create a management incentive for improvement with respect to distribution vegetation management practices. Given the self-acknowledged unacceptable current performance and the importance of future acceptable performance for reliability, a basis point downward ROE adjustment is appropriate. We believe that a 5 basis point ROE reduction, as applied above, is a reasonable action to encourage DEI to adhere to a regular and reasonable trim cycle because their lack of adherence going forward may have actual negative consequences. We find that addressing the effort in this manner rather than potentially hindering a recovery to an acceptable effort by adjusting the budget will best serve customer reliability expectations.

The test year in the case includes a budget level of $38.9 million. DEI has supported that this is the amount that its vegetation management program requires during the period and has provided sufficient support on a per unit cost basis for the expected work to be completed. We find that based on the specific circumstances, specifically the starting point at which DEI has placed itself, this budgeted amount is a reasonable amount to include in base rates. However, we reject inclusion of DEI's test year adjustment of $10.5 million. Despite this rejection, we nonetheless find it is reasonable to encourage DEI to continue to improve its trim cycle to an industry standard level and thus acknowledge that the $49.4 million amount presented in this proceeding is a budgeted level to accomplish this target. Further, we find that DEI's recent past efforts in distribution vegetation management require a counter balancing protection for customers. DEI's recent spending levels in comparison to its planned levels suggest such a steep change in efforts that could reasonably be a challenge to deliver on. Accordingly, we find that a reserve account should be created to keep track of annual underspending and overspending, with a cap at $49.4 million, with the length of amortization of this reserve to be determined in DEI's next rate case.

(D) <u>Incentive Compensation</u>. DEI's witness Metzler testified the benefits and compensation opportunities provided to DEI's employees are reasonable, customary, prudent and market-competitive. Her testimony illustrated DEI's benefit programs and compensation opportunities, which she said are critical for attracting, engaging, retaining and directing the efforts of employees with the skills and experience necessary to efficiently and effectively provide electric services to customers. Ms. Metzler indicated DEI's compensation, benefits and career development opportunities directly affect its ability to attract and retain qualified employees.

Ms. Metzler explained DEI's compensation philosophy. First, she said compensation should be market-based, meaning competitive to the external market of similar companies, allowing DEI to remain attractive against competition and attract and retain qualified employees.

Second, Ms. Metzler indicated the Company's compensation package links compensation to performance to set high expectations for employees and reward results. Finally, she testified DEI's compensation policies and pay administration guidelines ensure employees are paid consistently and fairly.

OUCC witness Kollen described DEI's request for recovery of incentive compensation expense tied to financial performance metrics. He indicated the Company included $28.6 million in total incentive compensation expense, consisting of $12.4 million tied to achievement of financial performance metrics by Duke Energy, Inc. and DEBS, and $16.2 million tied to the achievement of other performance metrics.

In Mr. Kollen's opinion, incentive compensation expense tied to Duke Energy's financial performance should not be included in the Company's revenue requirement. He testified the fundamental ratemaking issue is not whether DEI incurs incentive compensation expense tied to its parent company's financial performance, but whether DEI'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's shareholders.

Mr. Kollen stated the achievement of Duke Energy Earnings Per Share ("EPS") and Total Shareholder Return ("TSR") financial performance metrics exclusively benefit Duke Energy shareholders and not DEI customers. In Mr. Kollen's view, 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. He said incentive compensation expenses tied to financial performance metrics should be allocated to Duke Energy shareholders, not DEI's customers.

As a result, Mr. Kollen recommended a $12.3 million reduction in the Company's revenue requirement for incentive compensation.

Industrial Group witness Gorman testified DEI included $24.8 million of incentive compensation in its revenue requirement. He acknowledged it is appropriate to include incentive compensation costs in the Company's ratemaking cost of service but noted incentive compensation programs designed to align the interests of executives with shareholders should be paid by shareholders. In Mr. Gorman's opinion, incentive compensation programs that reflect customer direct goals, such as service reliability, can be incurred by ratepayers, depending on whether the performance metrics are met.

Mr. Gorman observed that including incentive compensation related to financial goals in the cost of service exposes customers to the risk of paying incentive compensation costs, without assurance that the financial targets will be achieved or have any benefit to customers. He said this risk would not be faced by investors if the financial compensation rewards are excluded from cost of service because shareholders can pay for the costs out of higher earnings if the financial goals are achieved.

After reviewing the Commission's findings regarding the recovery of incentive compensation in DEI's last rate case, Cause No. 42359, Mr. Gorman concluded the Company has not demonstrated in this case that shareholders are allocated part of the cost of the incentive compensation programs. Mr. Gorman then recommended removal of the portion of the cost of incentive compensation that relates to financial performance, which he determined to be $13.3 million. He stated the cost of incentive compensation designed to align the interests of employees with shareholders should be paid by shareholders and excluded from cost of service. He added that it is inappropriate to include in rates incentive compensation that is tied to financial performance and therefore may or may not be paid out.

Ms. Metzler testified the Commission should reject the proposed adjustments because they are based on a false premise and contrary to long held and well-established Commission determinations that incentive plan costs are recoverable in rates when: (1) the incentive compensation plan is not a pure profit-sharing plan, but rather incorporates operational as well as financial performance goals; (2) the incentive compensation plan does not result in excessive pay levels beyond what is reasonably necessary to attract a talented workforce; and (3) customers and shareholders are allocated part of the cost of the incentive compensation programs. She indicated the Company satisfied each of the foregoing factors by proving that (a) the Company's incentive compensation plans are not pure profit sharing plans but include other metrics; (b) the Company's incentive compensation plans do not result in excessive pay levels beyond what is reasonably necessary for the Company to attract a talented workforce; and (c) the cost of the incentive plans are allocated to both customers and shareholders, as shareholders would cover any amounts above the target levels proposed to be included in the Company's rates.

With respect to Mr. Gorman's contentions regarding the proposed removal of the RSU component of the LTI Plan, Ms. Metzler stated it is factually incorrect to say that the magnitude of the expense for RSU payments is only aligned to shareholder interest simply because the award is in stock and not cash. She added these costs are a defined benefit amount that is primarily tied to the retention of high-performing employees and unlike all other incentives, the expense for RSU payments to eligible employees is unaffected by Company performance. She concluded her rebuttal on the RSU issue by noting the Company has a legitimate interest in attracting and retaining a high-performing leadership team which directly benefits customers through the accumulation of experience and knowledge.

Ms. Metzler recommended the Commission reject the OUCC's and Industrial Group's proposed adjustments to incentive compensation and permit DEI to recover all incentive compensation expense in rates consistent with well-established criteria. She asserted the energy industry is a knowledge-intensive and experience-intensive industry where the tenure of employees matters, which means DEI needs to attract, develop and retain—over the long term—the engineering professionals that design, help build and operate its plants at a reasonable cost. In Ms. Metzler's opinion, incenting a focus on financial performance via EPS and TSR provides a benefit to customers, as a financially strong Company will have greater access to capital at a lower cost, which in turn benefits customers through a lower cost structure. In addition, she observed the introduction of stock as a component of overall compensation ensures the Company's leadership is focused on the long term, and not overly focused on the short term.

(I) <u>Commission Discussion and Findings</u>. In DEI's last general rate case (Cause No. 42359, Order dated May 18, 2004), we noted it is commonly accepted that incentive compensation plans may be necessary in order for utilities to attract and retain highly qualified individuals. Ms. Metzler provided evidence in her direct and rebuttal testimony to support this proposition. In that same Order, we also indicated our approval for the recovery of incentive compensation costs 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 as part of the cost of the incentive compensation programs. Order in Cause No. 42359 at 89.

OUCC witness Kollen and Industrial Group witness Gorman do not dispute the above-stated general proposition that incentive compensation plans may be necessary to attract and retain highly qualified employees. Nor do they dispute DEI's evidence of record showing the Company's incentive compensation plans are not pure profit sharing plans or raise any issues with respect to the levels of DEI's executive pay. Rather, the OUCC and IG contend that incentive compensation tied to Duke Energy's financial performance should not be included in the Company's revenue requirement because shareholders have not been allocated part of the cost of the incentive programs.

Based upon our review of DEI's compensation programs and supporting evidence in this proceeding, we find that DEI has satisfied the first two requirements for the recovery of incentive compensation in its cost of service. We further find from the evidence that shareholders are all allocated part of the cost of the Company's incentive compensation in that the Company only proposed to include its target compensation amount in base rates, whereas the Company's incentive plans regularly pay out at above target amounts. Accordingly, we find that Mr. Kollen's and Mr. Gorman's proposed adjustments to the level of the Company's incentive compensation should be rejected.

(E) **Fee Free Payment Option.** Petitioner's witness Quick provided testimony regarding DEI's proposal to offer a fee-free program option for residential customers who use credit cards, debit cards and electronic checks to pay their electric bills (the "fee-free payment option"). Ms. Quick explained that the Company currently offers residential customers the ability to pay by credit card, debit card or electronic check via the Company's website, mobile site, phone or IVR, and residential customers making payments by those means are subject to a $1.50 convenience fee, the entirety of which is paid directly to a third-party vendor, Speedpay. In order to offer the fee-free payment option, Ms. Quick explained the Company proposes to eliminate the convenience fees associated with these forms of customer payments and instead recover these costs as part of its cost of service.

Ms. Quick testified DEI is proposing the fee-free payment option now because industry studies have demonstrated customers continue to move toward card transactions and away from checks, and that the number of payments made by credit and debit cards continue to grow as a preferred method of payment by many customers. Ms. Quick described that the current requirement to pay a transaction fee when making a payment by credit card, debit card or electronic check is one of the largest frustrations that customers experience, and customers have voiced such frustrations to the Company. Ms. Quick stated the fee-free payment option would lead to greater satisfaction for all customers who primarily pay for goods and services with a credit card, debit card, or electronic check.

Ms. Quick testified it would be reasonable for the Company to include the cost of the fee-free payment option in the cost of service that is paid by all residential customers, similar to how other payment options are handled. Ms. Quick stated the more convenient the Company can make the bill paying process for customers, the more customers will benefit and be satisfied. Ms. Quick pointed out that giving customers options to pay by the method of their choice without incurring additional fees will lead to more satisfied customers and, ultimately, customer savings.

Ms. Quick provided data regarding the 2020 forecasted cost of the fee-free payment program to Company witness Graft for use in calculating a *pro forma* adjustment of $4.5 million to add to the cost of service. Ms. Quick explained that the forecasted amount included a reasonable projection of 34% growth of the use of credit and debit cards in the test period by residential customers. Ms. Quick testified that the growth projections were based on historical and current payment transaction data from 2016 through 2018, as well as benchmarking the growth projections against both industry data and a similarly-situated electric utility that offers fee-free credit card usage. Ms. Quick also stated her understanding that Indiana Michigan Power Company ("I&M") currently has a fee-free credit and debit card program.

Lauren M. Aguilar testified on behalf of the OUCC with regard to the fee-free payment program. Ms. Aguilar noted that DEI is unable to state with particularity the extent of customer savings related to the fee-free payment program. Ms. Aguilar took issue with DEI'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 DEI's proposal to recover credit card fees through inclusion of $4.5 million 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 DEI 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.

Ms. Quick provided rebuttal testimony for the Company. She first explained the OUCC's position that residential customers should not be required to pay for benefits used by a subset of customers is not consistent with many other programs offered by utilities generally and DEI specifically. Ms. Quick testified that the Company currently offers many programs that are used by a subset of customers, but which are paid for by customers generally and recovered in base rates. She stated the costs of billing and payment channels, such as the costs to produce and mail a paper bill, are spread across all residential customers.

Ms. Quick also addressed the OUCC's assertion that customer savings should cover the costs of the fee-free payment program, stating that the proposal conflates two issues. Ms. Quick reiterated that the proposed fee-free payment option is a means to increase customer satisfaction, not to create customer savings, and that it would be inappropriate to evaluate the success of the program on the amount of customer savings. Ms. Quick testified that there will be no direct cost savings associated with the program, as the fees to Speedpay will remain at the current $1.50 per transaction price. Rather, the program is meant to increase customer satisfaction, much like many other customer service programs offered by the Company, and the associated cost of service should be spread over all customers.

Finally, with regard to I&M's similar fee-free program, Ms. Quick acknowledged that the Commission's approval in Cause No. 44967 was in conjunction with a Settlement Agreement.

(I) Commission Discussion and Findings. Through its proposed fee-free payment option, DEI proposes to eliminate the $1.50 convenience fee associated with residential 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 $4.5 million to the cost of service to cover fees that are no longer being collected solely from the cost causers, the program participants. Importantly, the cost of the convenience remains and the program does not purport to provide any savings or system efficiency gains to the non-participants in the program. The OUCC expressed concern with this feature of the proposed program, while acknowledging that a company-funded program would not present this challenge. While it is reasonable to expect that customer satisfaction for program participants who now can avoid paying a previously unavoidable convenience fee will be enhanced, we conclude that DEI's proposed fee-free payment option is unreasonable since it has not been shown to provide any value, including any level of enhanced customer satisfaction, to non-participating customers. We therefore deny DEI's request for approval of 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 $4.5 million.

iv. <u>Tax Expenses</u>.

(A) <u>Federal and State Corporate Income Tax</u>. Mr. Panizza testified that DEI's income tax calculations were made under the provisions of the Internal Revenue Code ("IRC") of 1986, as amended, including for the impacts of the TCJA, which reduced federal income taxes effective January 1, 2018, and the Indiana Administrative Code. He stated that DEI used the statutory federal corporate income tax rate of 21% for both the base period and forecasted period and that DEI used the composite statutory Indiana corporate income tax rate of 5.88% for current tax and 4.9% for deferred tax for the base period. He also explained that DEI used the composite statutory Indiana corporate income tax rate of 5.375% for current tax and 4.9% for deferred tax for the forecast period, 2020, explaining that the Indiana corporate tax rate is being reduced each year until it reaches 4.9% in 2022. Mr. Panizza also discussed the federal tax normalization rules, DEI's tax sharing agreement, DEI's investment tax credits, and explained DEI's calculation of forecasted property tax expense. He explained that DEI's current forecast reflects full usage of the credits associated with the Edwardsport ITC and DEI's renewable projects during tax years 2022 and 2023, but this will depend on the actual taxable income of the Consolidated Duke Corporation tax entity. He also discussed the TCJA Settlement provisions and how DEI complied with them.

Diana L. Douglas, Director Rates and Regulatory Planning for DEI explained and supported several accounting, revenue requirements and ratemaking aspects of DEI's case, including the effective tax rate for the historical reference period and for the test period (Petitioner's Exhibit 4-H (DLD)). Ms. Douglas also supported the adjusted test period income tax expense calculation and *pro forma* adjustments that are attached as supporting schedules to Petitioner's Exhibit 4-H (DLD).

Witness Lane Kollen testified regarding several of the Company's tax issues. First, he described DEI'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 of time 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 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 million rate reduction at that time.

Wes Blakley, Senior Utility Analyst in the OUCC's Electric Division testified regarding the OUCC's proposed alternative treatment for the Company's Excess Accumulated Deferred Federal Income Tax ("EADFIT") credit. He noted DEI 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, DEI'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 DEI'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 DEI'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 DEI 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, DEI 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 DEI 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 million. Mr. Blakley recommended this amount be passed back to customers, through DEI'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 $2.9 million credit through the Credits Rider.

Mr. Gorman provided testimony regarding DEI's proposal for its Indiana EDIT. Mr. Gorman proposed (1) the Indiana EDIT be included in cost of service, (2) the $19.5 million balance for the pre-2011 rate changes be immediately netted against the $48.1 million credit for post-2011 rate to result in a net balance of $28.6 million; and (3) the amortization period be accelerated and the net balance be amortized over a period of three years, or $9.5 million per year. Mr. Gorman indicated that grossing up his EDIT adjustment for income taxes results in a revenue requirement impact of $12.7 million.

Like the Indiana EDIT, Mr. Gorman noted the 2018 and 2019 Federal EDIT amounts can be amortized in accordance with the Commission's discretion. He proposed that the $30.1 million 2018 and 2019 Federal EDIT be amortized over three years, or $10.1 million per year. After grossing up that adjustment for income taxes, Mr. Gorman stated his Federal EDIT adjustment has a revenue requirement impact of $12.5 million.

The next tax topic Mr. Gorman covered was the Rider 67 allocation of TCJA credits. Mr. Gorman stated DEI is using Rider 67 to pass back refunds to customers of protected and unprotected Federal EDIT that were approved in Cause No. 45032 S2 in the same manner in which the rates were collected from customers using a 12 coincident peak ("CP") allocation methodology.

Mr. Gorman indicated that when DEI amended its case on September 9, 2019, it modified the allocation for revenues remaining in riders using the 4-CP methodology, the impact of which change on the HLF class was a loss of $2.1 million in credits. As a result, and to avoid punishing the HLF class, Mr. Gorman recommended that DEI should continue to allocate the TCJA credit using the 12-CP allocation that was used when customers paid for the plant, equipment and property.

DEI witness Jeffrey R. Setser testified in rebuttal to OUCC witness Kollen's proposal to refund the EDIT to the Company and other affiliates. Mr. Setser stated the current income tax expense is a result of the return on DEB's assets for which the jurisdictions have a corresponding current deduction. He stated that deferred income tax assets or liabilities are considered temporary differences and have always been maintained at DEBS and any adjustments to deferred income taxes through the income statement should remain on DEBS. The depreciation for DEBS assets that is charged out to the utilities is based on straight-line book depreciation. Bonus and MACRS depreciation is a tax adjustment resulting in deferred tax liabilities that are not allocated out to the jurisdictions. Prior to the Duke Energy Share Services ("DESS") (Duke Energy entity for the former, Cinergy Services, Inc. service company that supported the DEI predecessor company, PSI Energy, Inc., and other Cinergy companies) being merged with DEBS on July 1, 2008, the DESS service company (and Cinergy Services, Inc. service company before it) did allocate out income tax expense. At the point that DESS merged into DEBS, the DESS company had a deferred tax asset of $109 million. The jurisdictions received the benefit of this, but the reversal of this asset stayed on DEBS. The jurisdictions have not been charged for this tax expense and we currently are not seeking reimbursement. The return on rate base Mr. Kollen refers to is a calculation based on an apportionment of DEBS assets to DEI and the equity return is grossed up for taxes to arrive at a pre-tax amount. This calculation results in a monthly journal entry that creates current taxable income on DEBS and a current deductible expense for the jurisdiction. In 2018 the gross-up was adjusted for the federal change in tax rates from 36% to 21%. Therefore, there is no deferred taxes that need to be adjusted or distributed as part of this process.

Ms. Douglas disagreed with OUCC witness Kollen regarding the use of the state income rate. She stated the test period is calendar year 2020 and 5.375% is the appropriate calculated (blended) Indiana statutory income tax rate for a 2020 calendar year tax payer. She noted that her position was supported by the Commission's approval of a blended state income rate for IPL in Cause No. 45029, and the use of a blended income tax rate by I&M and NIPSCO in their respective recent rate cases (Cause Nos. 45235 and 45159).

Ms. Douglas also disagreed with Witness Kollen's recommendation that DEI track the future reductions in the state income rate down to the final 4.9% rate using Rider 67. She reiterated that the state income tax rate used in the Company's case-in-chief is appropriate given the test period and consistent with other rate cases. She indicated the Company manages tax expense between base rate cases, with earned return and net operating income, subject to check in the FAC return and expense tests. Ms. Douglas said Mr. Kollen's proposal is not consistent with traditional Indiana practice.

The next subject Ms. Douglas addressed in her rebuttal was the amortization of deferred federal protected excess ADIT. She indicated the protected portion of Excess ADIT is required to be returned to customers in a prescribed way using ARAM. Ms. Douglas testified she agreed with OUCC witness Blakley and IG witness Gorman that there is no requirement that the 2018 and 2019 protected Excess ADIT be returned to customers using ARAM because once the protected Excess ADIT is deferred, it takes on the same nature as unprotected Excess ADIT, which can be returned to customers more quickly than under the prescribed ARAM methodology. While she said the Company agrees as a rate mitigation measure to shorten its amortization period, it believes a more appropriate period would be the remaining amortization period for refunding unprotected Excess ADIT to customers under the terms of the TCJA Settlement. She then noted a reasonable compromise position from ARAM to eight years for amortization results in an annual amortization amount on a grossed-up basis of $5.9 million per year and an incremental refund to customers via Rider 67 of approximately $4.9 million per year over the Company's case-in-chief position.

In rebuttal to IG witness Gorman, Ms. Douglas testified there is not a requirement for certain prescribed method for Indiana state Excess ADIT amortization, and the Company agrees to net the pre-2011 regulatory asset and post-2010 regulatory liability and use the same amortization period going forward for both pieces. She stated the Company also agrees to include the netted amortization amount in its cost of service for purposes of setting the rate base in this proceeding.

As an additional rate mitigation measure, Ms. Douglas testified the Company agrees to accelerate the amortization from what was proposed in the case-in-chief to eight years consistent with Mr. Blakley's 8-year recommendation. However, rather than using Rider 67, she stated that the amount would be refunded via base rates as Mr. Gorman proposed.

Ms. Douglas also responded to Mr.Gorman's recommendation regarding the use of the 12-CP allocation to allocate the federal excess ADIT credit from the TCJA in Rider 67. She explained that the Company used the 4-CP allocation consistent with the Company's agreement in the Duke Energy Merger case to fully support the use of the 4-CP method in its next base rate proceeding. The Industrial Group was a party to the Settlement Agreement in that proceeding. In addition, she stated that updating allocation factors in riders upon approval of new base rates is an accepted or expected Indiana precedent. She explained that the TCJA Settlement Agreement in Cause No. 45032 S2 provides that the allocations factors for the excess ADIT credits resulting from the TCJA will use the Retail Original Cost Depreciated Rate Base as updated in the next general base rate case proceeding. For these reasons, Mrs. Douglas stated that the use of Retail Original Cost Depreciated Rate Base developed in the Company's cost of service study in this proceeding using a 4-CP allocation for production plant is the most appropriate allocation to use for Rider 67 TCJA credits considering both Settlement Agreements. Company witness Brian Davey also testified in rebuttal and agreed with the approach set forth in Ms. Douglass' rebuttal testimony regarding the treatment of federal excess ADIT and state excess ADIT. His testimony included Table 1 showing the proposed adjustments to retail revenue as a result of a variety of different rate making issues.

(I) Commission Discussion and Findings. DEI 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 income tax calculation; (2) the amount of excess federal ADIT to be allocated to customers, specifically recommending that a portion of excess ADIT from the Company's DEBS service company should have been allocated to DEI; (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, and based on the evidence presented in this proceeding, that the Company's income tax calculation is reasonable. We next address each of the disputed issues.

We first address the issue of the state income tax rate. DEI used the annual state statutory blended rate of 5.375% for the 2020 test period to calculate current income taxes 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 taxes. The OUCC proposed the 4.9% rate that will go into effect July 1, 2021, would be the more appropriate rate to use for current income tax and the revenue requirement conversion factor because the 5.375% rate is only temporary. They proposed that rates should be set using the lower 4.9% 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. The Company disagreed, noting that this Commission has previously approved use of the annual blended rate appropriate for the test period in other recent rate cases during the period of the stepped reductions in state income tax and that state income tax expense is an operating income item that is generally managed by the Company between rate cases, subject to check in the FAC return and expense. We find that the statutory rate for state income taxes that will be effective in 2020, the test year, as proposed by DEI is the appropriate rate to use for state income taxes. This is consistent with our approvals of state income tax rates used in other recent rate cases for Indiana electrical utilities.

We next address the issue of DEBS excess ADIT. The OUCC recommended that a portion of the excess ADIT recorded on the books of the Company's service company affiliate DEBS should have been allocated to DEI in the same manner that DEBS depreciation expense is allocated and then passed back to customers as a one-time credit in Rider 67. However, the Company provided evidence in rebuttal testimony that income taxes are maintained on the books of DEBS and not allocated out to utilities and that any deferred income taxes on DEBS' books are temporary differences and have always been maintained at DEBS, and any adjustments to deferred income taxes through the income statement, such as occurred for the federal income tax reduction, should remain on DEBS. We are unpersuaded by the OUCC's argument and are not inclined to require the Company to make an adjustment for ratemaking for this excess federal ADIT issue that would result in inconsistency with the Company's accounting for income taxes and service company allocations. Further, the DEBS credits to income tax expense that the OUCC proposes be refunded to DEI customers were incurred in 2018 as a result of the 2017 Federal Tax Cuts and Jobs Act, for which we established a generic proceeding and subdocket for DEI in Cause No. 45032 S2, and we find that this issue would have better been addressed by the OUCC in that proceeding. Therefore we find that no allocation of past DEBS income tax credits resulting from the federal income tax reduction is required by the Company.

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 eight year period. We find 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 find 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 the arguments to pass these benefits back to customers earlier. OUCC and Industrial Group both proposed three-year amortization periods. DEI proposed to pass them back over eight years. We acknowledge that eight years is consistent with the treatment of the unprotected excess ADIT in the Company's federal income tax act settlement. We find synching up the amortization period for unprotected excess ADIT to the eight remaining years is a reasonable and fair outcome.

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-CP allocation methodology, even though he supports moving to a 4-CP allocation method going forward for base rates and riders. DEI 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 Rider 67 be used. We are persuaded and so find 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 complicate the rider filing.

(B) Utility Receipts Tax. Petitioner's witness Graft testified in support of Petitioner's Exhibit 6-E (CLG), Schedule OTX2, which removed all Indiana URT expense from the Company's test period operating expenses. She testified that currently, the 1.4% URT is embedded in base rates or rider rates as part of the revenue conversion factor and is included in the Company's cost of service. Ms. Graft stated the Company is proposing to present URT as a separate line item on customer bills as an addition to the cost of utility services similar to sales tax, which eliminates the need for the Company to include a provision for the URT in the revenue conversion factor and the need for the Company to include URT in its cost of service. In his revised direct testimony, Company witness Mr. Davey discussed that the Company did not initially include URT in its customer bill impact analysis and clarified the impact of URT on the proposed rate increase.

Company witness Mr. Panizza stated that Ms. Graft's proposal to separately state URT as a line item on customer bills comports with Indiana Code 6-2.3-3-4(a), which outlines the requirements for the URT.

With respect to the presentation of the Indiana URT, Mr. Gorman contended the Company's September 9, 2019 testimony only partially resolved the URT issue. He added that continued citation to the base rate increase of 15.43% even after the URT error was caught was misleading, because it is inappropriate to calculate an increase by including taxes in the "before" figure while failing to include taxes in the "after" figure. Mr. Gorman noted that Company witness

Davey identified the correct Company-wide increase of 17% but left out the correct dollar figure for the Company's requested rate increase. Mr. Gorman testified the correct amount of DEI's requested rate increase is $434.3 million, which includes $41.2 million of URT.

Mr. Davey provided testimony in rebuttal to Industrial Group witness Gorman's testimony related to the URT impacts on the Company's rate increase request. In the Company's July 2019 filing, Mr. Davey indicated the proposed rate increase for total retail customers was 15%. The Company's September 9, 2019 filing clarified the proposed rate increase for total retail was 17% and not 15% when the URT is considered. Mr. Davey stated the proposed rate-making change for URT provides the flexibility that if the tax is decreased in the future, customers will receive the benefit immediately without waiting for the next base rate case.

Mr. Davey stated Mr. Gorman agrees the proposed rate increase with URT is 17%, but he claims the Company did not fully correct a perceived problem with the dollar figure for DEI's requested increase. However, the Company's proposed base rate revenue requirement and its proposed base rates in this proceeding are properly reflected without the URT, as the URT will not be included in base rate revenue requirements under the Company's proposal, but rather will be included as a separate line item on the customer's bill. Mr. Davey noted that Tables 1 through 4 in his rebuttal testimony address Mr. Gorman's point of concern.

(I) Commission Discussion and Findings. We find Petitioner's proposal to present URT as a separate line item on customer bills to be reasonable and approve this request. We also find that the Company has adequately addressed the Industrial Group's concern regarding the communication of the impact of URT on a customer bill.

10. Conclusion Regarding Petitioner's *Pro Forma* Jurisdictional Electric Net Operating Income. On the basis of the decisions above and below, 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 $473.5 million, summarized as follows:[8]

$ in Millions	2020
Total Operating Revenues	2,571
Operating Expenses	
Fuel & Purchased Power Expense	791
Operation and Maintenance	561
Depreciation and Amortization	586

[8] This table is intended to reflect the specific changes directed in this order and is subject to refinement pending the energy division reviewed and approved order directed compliance filing. The changes include the application of the directed depreciation expenses and cost of capital, denial of proposed pro forma adjustments REV3, REV5, COGS2, OM17, OM20, and denial of the amortization for incremental vegetation management expense, as well as the related income tax impacts.

Property and other Taxes	69
Income Taxes	91
Total Operating Expenses	2,097
Operating Income	474

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 4.64%, which is outside the range established in our above findings. Accordingly, on the basis of the evidence and the determinations throughout this order, 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 not sufficient to provide Petitioner a fair 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.

11. **Rate Level to be Authorized.** We find that a net jurisdictional operating income, excluding revenue remaining in riders, of $582 million is 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 5.71% which is within the range of reasonableness established in our previous findings. In order to provide such utility operating income, an increase in Petitioner's gross annual retail electric operating revenues to $145.9 million (excluding items remaining in riders and the utility receipts tax) is required, the increase in revenues will give rise to increased tax expense resulting in total operating expenses of $2,134 million. On that basis, we find that Petitioner's *pro forma* operating results will be:[9]

$ in Millions	2020
Total Operating Revenues	2,717
Operating Expenses	
Fuel & Purchased Power Expense	791
Operation and Maintenance	561
Depreciation and Amortization	586
Property and other Taxes	69
Income Taxes	128
Total Operating Expenses	2,134
Operating Income	582

12. **Cost Allocation.**

[9] Id.

a. **<u>Jurisdictional Separation Study</u>.** Company witness Diaz supported and explained the Company's jurisdictional separation study. She explained that the financial forecast was the starting point for the study, followed by the segregation of the Company's customers into three main categories: one high-pressure steam customer, wholesale electric customers that purchase firm power from the Company and resell it, and retail electric customers that purchase power from the Company as ultimate customers.

Ms. Diaz testified that a steam study was performed to allocate Cayuga Station rate base items, O&M expenses, administrative and general expenses, depreciation, amortization, and taxes to the steam customer. Next, she explained, demand and energy allocators were developed for the Company's non-jurisdictional customers, and production costs and related production expenses were allocated to firm native load wholesale customers -- not including the one wholesale 100 MW contract that is considered a short-term bundled non-native contract. The Company developed the system peak demand (and usage) and the applicable wholesale customers' share of the system peak (and usage), with the remainder being the retail portion of DEI's total system demand (and usage), which represents the retail customers' portion of the maximum electricity load and usage imposed on DEI's electric system. She observed that the wholesale demands and usage for the forecasted 2020 period approximated 8%, which approximates the same percentage from the last base rate case.

She stated that forecasted revenues related to local facilities (distribution) and MISO (transmission) were assigned 100% to retail as the forecasted costs to supply the wholesale distribution and transmission services were assigned 100% to retail. She testified that both DEI's forecasted Joint Transmission System costs and revenues were assigned 100% to retail.

She testified that forecasted net plant in-service and associated O&M expenses, as well as revenues, related to Wabash Valley's and IMPA's shares for Gibson Unit 5 and Wabash Valley's share of Vermillion station were excluded from the development of retail rates, as were costs associated with a 50 MW wholesale contract associated with Henry County Generating Station.

She noted that these non-jurisdictional customers (including the steam customer) and associated costs were treated as non-jurisdictional for purposes of this proceeding, while the retail electric customers and other retail assignments are the jurisdictional customers and activity for purposes of this proceeding.

Industrial Group witness Dauphinais contended that the short-term 100 MW bundled capacity and energy contract should be allocated to the wholesale jurisdiction in the jurisdictional separation study, in the same manner as are traditional wholesale firm native load sales contracts. Additionally, Mr. Dauphinais argued that the Commission should impute as long-term wholesale sales for jurisdictional study purposes, the amount of historical long-term wholesale sales that have terminated since 2013 that have not been replaced with new long-term wholesale contracts.

In rebuttal testimony, Company witness Davey testified that the Company disagrees with treating short-term bundled non-native sales as if they are traditional wholesale native-load sales in the jurisdiction separation study. Mr. Davey testified that the Company's net revenue-sharing proposal is much-more reasonable for these types of contracts, recognizing the difference between these short-term contracts and long-term traditional native-load contracts. Further, Mr. Davey testified that imputing a nonexistent wholesale sale in the jurisdiction separation study is unprecedented and would be a clear departure from traditional ratemaking. Further, it would be unreasonable in this instance, he emphasized, as retail customers are already being allocated a lower percentage of the production demand costs than they were at the time of the last base rate case. He also testified that the Company makes no long-term planning decisions based on this contract, further differentiating it from traditional wholesale native load sales.

i. <u>Commission Discussion and Findings</u>. Based on the evidence, we find that DEI's jurisdictional separation study as presented and supported is a reasonable allocation of costs among the various jurisdictions, both its wholesale and retail electric and steam jurisdictions. We decline to accept the Industrial Group's proposal to make adjustments for historical long-term wholesale sales that have terminated in a managed amount in recent years. Ms. Diaz testified that the level of sales allocated to wholesale in the jurisdictional separation study is approximately the same as it was in the Company's last rate case several years ago, and Mr. Davey testified that in this case, retail customers are being allocated a lower percentage of production demand costs than they were in the last base rate case. These facts are persuasive and as such we find that imputing a historical level of sales, for the circumstances in this proceeding, is not needed.

We also reject the Industrial Group's proposal to allocate the one existing short-term bundled sales contract to the wholesale jurisdiction in the separation study. The testimony of Mr. Swez and Mr. Davey make clear that this contract differs markedly from traditional long-term wholesale native load contracts that are allocated to wholesale in the jurisdictional separation study process, and significantly, the evidence shows that the Company does not plan or build for this contract, in contrast to traditional wholesale native load customers. For these reasons, we reject the proposal to allocate costs to this short-term bundled contract in the jurisdictional separation study.

However, the evidence shows this specific contract will continue to exist throughout the test-year of this proceeding and the contracting strategy is an attempt to opportunistically create value for the Company and its retail customers by creating sales revenues that would otherwise not exist in the current power market. Accordingly, while we decline to apply an adjustment to the jurisdictional separation study, we will address this contract through its treatment as a retail rate revenue requirement credit and ongoing Rider 70 tracking from this test-year amount as discussed further below.

b. <u>Class Cost of Service Study</u>. Ms. Diaz presented the Company's class cost-of-service study, which allocates total Indiana retail jurisdictional rate base, revenues and expenses to each rate schedule. She explained that the Company used a 3rd party application, PowerPlan regulatory suite, to support this base rate case proceeding. She further explained that PowerPlan assigned data into function (Production, Transmission, Distribution, and Customer) and sub-functions. The function data then populates the *Separation* step, wherein the data is separated between a Steam Customer and all other Electric customers. The electric data feeds and populates the *Jurisdiction Separation* step, wherein the data is separated between Indiana Retail and Wholesale. Ms. Diaz testified that the Indiana Retail data feeds and populates the *Retail Rate*

Codes, wherein the data is separated by each rate schedule and grouped into customer classes for rate design processing.

Ms. Diaz noted that in its retail cost of service study, the Company performed allocations for production plant using both a 4-CP and 12-CP methodology to its rate schedules based on the Commission's directive that it do so in Cause No. 42873. Ms. Diaz testified that the 4-CP demands used were the average of the maximum retail demands for the historical twelve-month period ended June 30, 2018. The 4-CP peak period average included the months of August 2017, September 2017, January 2018, and June 2018. Ms. Diaz stated that the Company elected to apply 5.1% as the subsidy/excess reduction in lieu of a larger subsidy/excess reduction that would have increased proposed residential rates more but lowered the rate impacts to other classes.

Messrs. Eckert, Watkins, expressed displeasure 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 testified that while it is his opinion that the 4-CP method does not reasonably reflect cost causation, the OUCC previously agreed not to oppose the 4-CP method in Cause No. 42873. Mr. Watkins testified that settlements involve give and take and Mr. Watkins stated that he was not privy to why that was part of the settlement. Nonetheless, 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.

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-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.

Joint Intervenors witness Wallach, Schlissel, and Howat repeated allegations that were included in the Motion to Amend Procedural Schedule regarding Petitioner's Cost of Service Study. Mr. Wallach testified that the Company's cost of service study over-allocates production plant costs to classes with low load factors by inappropriately classifying all such costs as demand-related. Mr. Wallach asserted it would be proper to reclassify the Company's production plant costs using the Equivalent Peaker method. Mr. Wallach testified that the cost of service study compounds this error by allocating demand-related plant costs based on each class's contribution to system peak in the four months of the year with the highest system peak demands ("4-CP allocator"), rather than based on the contribution to system peak throughout the year ("12-CP allocator"). In addition, Mr. Wallach testified that the Company's cost of service study over-allocates distribution plant costs to low-coincidence classes by allocating demand-related distribution plant costs on the basis of customer maximum demand, rather than based on customer demand coincident with class peaks. In cross-answering testimony, Mr. Wallach reiterated his opinion that the 4-CP allocator does not reasonably reflect his assessment that system peak demands in all months of the year contribute to the Company's reserve requirements and need for reserve capacity.

Messrs. Pinegar and Davey addressed concerns with the Cost of Service Study. Mr. Pinegar explained that the Company sought to be transparent in addressing concerns with the Cost of Service Study. He testified that, although Petitioner complied with the rules, Company personnel created an Excel-based replica of its cost of service model for the use of the parties and agreed to run modeling changes at their request. Mr. Davey testified that using the PowerPlan proprietary model for the cost of service study has benefits in terms of accuracy of data, consistency across jurisdictions, and efficiency because it has direct input feeds from the Company's forecasting tool and accounting tools minimize the chance of error.

Ms. Diaz testified that she did not agree with OUCC witness Watkins' testimony that the 4-CP methodology does not reasonably reflect cost causation. Ms. Diaz noted the selection of a 4-CP or 12-CP is at the Commission's discretion. However, Ms. Diaz stated that a company with a relatively flat load profile throughout the year would typically allocate demand costs on a 12-CP basis because a 12-CP methodology allocates demand costs based on an assumption that capacity is built to meet the demand season-to-season, month-to-month and not just the maximum load on the system at any one given time or any one segment of the year. In contrast, Ms. Diaz stated that a peaking utility would allocate demand costs more typically on a multiple-month basis, which assumes that the load profile has a pronounced peak during those peak usage months.

Ms. Diaz stated that if the cost allocation for production plant were allocated 70% energy/30% demand as proposed by Mr. Wallach, it would shift the design of rates by increasing energy charges more than what is already being proposed as part of this proceeding. Ms. Diaz stated that historically, this Commission has not accepted an electric cost of service study that classifies a portion of production plant as energy-related and has consistently rejected the use of this methodology and there is no reason to depart from this practice. Ms. Diaz noted that utilizing a blend of demand and energy to allocate production investment contradicts the argument that there are peaks on the DEI electric system.

Ms. Diaz also disagreed with Mr. Wallach's recommendation that distribution plant costs be allocated based on diversified class demand instead of non-coincident peak and that costs of primary poles and conductors be allocated on diversified class demand exclusively. Ms. Diaz noted that DEI's practice for allocation of secondary poles, conductors, and line transformers, which uses NCP demand that is the average of the 12 individual customer level peaks has been in place since 1994, when it was approved in Cause No. 40003. Ms. Diaz stated there have not been substantive changes in how customers connect to the distribution system from prior retail cases which would warrant a change in cost assignment in this proceeding.

Ms. Diaz stated that the Company elected to apply a modest 5.1% as the subsidy/excess reduction in lieu of a larger subsidy/excess reduction that would have increased proposed residential rates more while lowering the rate impacts to other classes. Ms. Diaz stated the decision as to which subsidy/excess percentage to apply was a result of the overall strategic decision described by DEI to keep residential customers at a proposed increase of lower than 20% (exclusive of taxes separately shown on a customer's bill) while also considering the proposed rate of increase across the rest of the retail classes.

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.

i. <u>Commission Discussion and Findings</u>. Throughout this proceeding, various parties have raised issue regarding DEI's use of a third-party proprietary software model for its cost-of service study. Specifically, 170 IAC 1-5-15(e), (f) and (g), provide with respect to cost of service studies that: (1) such information shall be confidential and protected from disclosure, and (2) if it is impossible or impractical for the electing utility to provide such information electronically, the electing utility shall make such information available to the Commission staff and any other party (subject to a nondisclosure agreement) during normal business hours, on the electing utility's premises, a computer and all software used to create and store such information. On November 21, 2019, Commission staff made an onsite visit to review the software and several intervenors were present or available by telephone. We find that DEI's Cost of Service Study fully complied with the Commission rules.

(A) <u>Allocation of Production Related Costs; 4-CP versus 12-CP</u>. Using the 4-CP methodology represents a change in the manner in which production- related costs have been allocated in the Company's prior rate cases. In *PSI Energy, Inc.*, we held that a change in cost allocation methodology can have significant impacts on customer classes and, thus, such a change should not be lightly undertaken, especially where so much of the plant was in service at the time of the utility's last rate case. Cause No. 42359, p. 102, 2004 WL 1493966 (IURC 5/18/2004).

The evidence of record reflects that significant operational changes have taken place since Petitioner's last rate case. The Company's last rate case filed by PSI was Cause No. 42359, which was filed at the end of 2002 and was decided by Commission Order dated May 18, 2004. While our decision in this proceeding is driven by DEI's specific service characteristics, we note that the circumstances in the wholesale market and the related impact on DEI's operation is one such change. At the time DEI received an order in its last rate case, MISO had only recently been formed and approved by FERC as an RTO. Currently, MISO establishes capacity requirements for its member utilities based on peak demand and reserve criteria. Consequently, DEI's capacity needs are now determined by its contribution to the MISO system's peak, which occurs consistently in the summer period. In addition, the bargain reached in Cause No. 42873 by the settling parties, the OUCC among them, included self-imposed constraints on this topic that we find should be given at least a measure of weight. The evidence in this proceeding does not support a finding that use of a 4-CP methodology is unreasonable or unjust. Accordingly, given the foregoing wholesale market changes, the service characteristics of DEI, and the previous bargains of several of the parties, we find the use of a 4-CP methodology as presented by Petitioner is reflective of cost causation and is approved.

(B) **Demand/Energy Allocators.** Petitioner proposed to classify electric generation production plant as 100% demand related. The energy-weighted demand allocation methodologies proposed by Joint Intervenors do not recognize that production plant costs are fixed in nature and exist regardless of how much energy customers consume. Because production plant capacity is required to meet peak demand requirements, plant capacity costs are appropriately allocated to customers based on their contribution to peak demands, since there is a direct relationship to the demand that customers place on the system. Based on the evidence in this proceeding we decline to allocate production cost based on energy consumption.

(C) **Allocation of Distribution Plant Costs.** Joint Intervenors proposed an alternative methodology of allocating distribution plant. Joint Intervenors' proposed allocation of distribution plant fails to recognize that DEI's practice for allocation of secondary poles, conductors, and line transformers, which uses NCP demand that is the average of the 12 individual customer level peaks, has been in place since 1994, when it was approved in Cause No. 40003. This standard practice recognizes that as the distribution equipment used to deliver power gets closer in proximity to the customer, the equipment varies based on the size of the customer. As such, the individual customer's load is what gives rise to the amount of costs incurred and determines the cost assignment. Nothing has changed in this regard. Accordingly, we approve the Company's allocation methodology for distribution plant.

(D) **Subsidy/Excess Adjustment.** Guided by the concept of gradualism, the Company has proposed a method of distributing the rate increase approved herein in a manner to reduce current interclass subsidies by 5.1% based on a desire to limit any class specific rate increase to 20%. However, because the authorized revenue increase approved in this order is not the same as that used by the Company to develop the proposed 5.1% subsidy reduction, we find it is reasonable to direct a different reduction that still upholds the Company's goals. Accordingly, we find that a 25% subsidy reduction, constrained such that no specific rate class experiences an increase that is more than 25% higher than the overall increase, is reasonable and shall be reflected in compliance filings submitted in this proceeding.

13. **Rate Design.**

a. **HLF and LLF.** 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, DEI 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.

With respect to the Experimental Market Pricing Program and an Experimental Demand Management and Stability Program, OUCC witness Boerger recommended that 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.

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 DEI 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 DEI'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.

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 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.

i. 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 DEI 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 would 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. The evidence supports that 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. 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 this load as a curtailable resource under MISO requirements. Accordingly, we find that the Experimental Market Pricing Program and Experimental Demand Management and Stability Program as proposed by DEI should be approved.

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 it 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 the expected 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 DEI to allocate the entire migration adjustment to the Rate LLF secondary schedule.

b. **RS and CS.** 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.

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 recommend 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 recommend 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.

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.

Joint Intervenors witness Wallach testified that the Commission should reject the Company's proposal for the residential connection charge. Mr. Wallach stated that a $9.80 residential connection charge would recover $0.76, or about 8%, more than the actual cost to connect a residential customer. Mr. Wallach further testified that by the Company's own admission, a $10.54 residential connection charge would exceed the Company's (overstated) estimate of the cost to serve. Consequently, the Company's proposal for a $10.54 residential connection charge runs contrary to long-standing principles for designing cost based rates since it would inappropriately shift recovery of demand-related costs from the volumetric energy rate to the fixed connection charge. Mr. Wallach stated that a monthly connection charge of $9.01 would provide for the recovery of the cost of meters, service drops, and customer services required to connect a residential customer.

Mr. Wallach further stated that Company lacks a reasonable basis for continuing to employ a declining-block rate structure for residential energy rates. Mr. Wallach stated that the Company's declining-block rate structure would recover demand-related costs at a higher rate in the first energy block than in the second and third blocks, and thereby would further dampen energy price signals and promote inefficient customer behavior. In his cross-answering testimony, Mr. Wallach also recommended the Commission reject the Company's proposed block rate structure in either the with-RDM or without-RDM rate structure.

Mr. Bailey testified that the Company's declining rate block structure, is reasonable, appropriate and supported. Mr. Bailey stated that the design of Rate RS is supported by modeling. Mr. Bailey noted that the Company's proposal, without decoupling, represents an approximate across-the-board increase to the residential rates.

With respect to the dynamic pricing pilot programs, Mr. Bailey agreed Mr. Watkins' recommendation to "keep and maintain records on a customer by customer basis" is reasonable. However, Mr. Bailey noted that the current billing system does not support "shadow billing", which is billing under a rate other than the customer's selected rate. Mr. Bailey indicated that the Company can commit to tracking load impacts during pricing events and filing those with the Commission annually and on a schedule which would allow for the analysis of the data collected for a year of pricing events. Mr. Bailey stated that a three to six-month lag is appropriate to perform this type of analysis.

Petitioner's witness Diaz testified that the Company is also cognizant that retail customers do not want an increased fixed customer charge. Therefore, Ms. Diaz stated that the Company has stayed consistent with its most recent retail rate case of including meters and customer accounts in the fixed connection charge, and not expanding that charge to potentially include every distribution component necessary to provide service such as substations, wires, poles, etc. Ms. Diaz testified that the proposed fixed connection charge is cost-based and reflects fully embedded costs that include direct costs, overheads and uncollectible account costs, which represent the totality of costs to connect our customers to our system as defined by the Company in this proceeding.

i. **Commission Discussion and Findings.**

(A) Residential Connection Charges. Both Joint Intervenors and OUCC opposed Petitioner's proposed increase to the customer charge from \$9.01 to \$9.80 (with decoupling) and \$10.54 (without decoupling). In reviewing the reasonableness of Petitioner's proposed residential connection charge, it is important to examine connection/customer charges approved for other electric utilities in the State. In *Indianapolis Power & Light Co* ("IPL 2016 Rate Order"), we approved increases in IPL's customer charges from \$6.70 to \$11.25 (for less than 325 kWh/month) and \$11.00 to \$17.00 (for greater than 325 kWh/month). Cause No. 44576, 2016 WL 1118795, at *76 (IURC March 16, 2016) *order corrected,* 2016 WL 1179961 (IURC March 23, 2016). In the IPL 2016 Rate Order, we noted the increase in the customer charge was a "move toward a more fixed and variable rate design consistent with traditional cost causation principles," while being "demonstrably short of SFV rates." The Court of Appeals affirmed the IPL 2016 Rate Order in *Citizens Action Coalition of Indiana, Inc. v. Indianapolis Power & Light Company,* 74 N.E.3d 554, 555 (Ind. Ct. App. 2017).

Subsequent to issuing the IPL 2016 Rate Order, we approved a settlement in NIPSCO's base rate case ("NIPSCO 2016 Rate Order") which increased the monthly customer charge from \$11.00 to \$14.00 for NIPSCO's residential customers. In approving the customer charge increase included in the settlement in that case, we again noted "the increase to the customer charge was a move toward a more fixed variable design consistent with traditional cost causation principles, while being demonstrably short of straight fixed variable rates." (NIPSCO 2016 Rate Order at 88). Again, Joint Intervenors appealed the Order and challenged the increase in fixed monthly charges, but the Court of Appeals affirmed the approval of the NIPSCO settlement in all respects. *See Citizens Action Coalition v. Northern Indiana Public Service Co.,* 2017 WL 1399850 (Ind. App. 2017).

Against this backdrop, we decline to find that Petitioner's modest increase in the residential connection charge would inappropriately shift recovery of demand-related costs from the volumetric energy rate to the fixed connection charge as suggested by the Joint Intervenors. To the contrary, the evidence of record reflects that the proposed fixed connection charges are cost-based and reflect embedded costs of connecting customers to Petitioner's system. Accordingly, we approve Petitioner's proposed increase to the fixed charges. Because we are not approving Petitioner's decoupling proposal as discussed below, we find that the fixed connection charges for Rate RS and Rate CS should be \$10.54 and \$10.70, respectively.

(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 the 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) <u>Dynamic Pricing Pilots</u>. 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. <u>Revenue Decoupling Mechanism</u>. Petitioner's witness Hansen supported Petitioner's proposed five-year revenue decoupling mechanism ("RDM") proposal. Mr. Hansen stated that the RDM is intended to complement DEI's proposed dynamic pricing pilots, potential retail rate design changes, energy efficiency programs, the Company's current volt/VAR optimization project, and address other external changes contributing to reductions in electricity usage by residential and small commercial customers. Mr. Hansen stated that for residential and small commercial customers, the RDM would make the Company indifferent to the effects of customer response to dynamic pricing pilots, modifications to the current default rate designs, implementation of volt/VAR optimization, and successful implementation of energy efficiency programs.

Mr. Hansen stated the RDM would include a deferral tracking account in which the difference between allowed and actual revenue toward fixed cost recovery would be recorded. Mr. Hansen stated that over-recovery of allowed fixed-cost revenue (when RDM allowed fixed-cost revenue is lower than actual fixed-cost revenue) would result in a rate decrease in a future period. Conversely, Mr. Hansen testified that under-recovery of allowed fixed-cost revenue (when RDM allowed fixed-cost revenue is higher than actual fixed-cost revenue) would result in a rate increase in a future period. Mr. Hansen noted that the RDM would completely replace the recovery of lost revenues in the Company's EE Rider for residential and small commercial customers.

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.

Mr. Hansen testified that Company's proposed RDM is consistent with decoupling mechanisms the Commission has previously approved. Mr. Hansen stated that the only electric-utility-specific concern expressed by the Commission in its rejection of Vectren South Electric's decoupling mechanism was based on a misunderstanding of how decoupling affects individual customers. In addition, Mr. Hansen noted that the Vectren South Electric Order specifically acknowledged that the introduction of "creative rate designs" (in the manner the Company has proposed) could affect how the Commission views decoupling for an electric utility. Mr. Hansen testified that the RDM is a better and more comprehensive mechanism than the LRAM and will allow the Company to improve its customers' incentives and ability to manage their usage and bills.

Mr. Hansen further testified that implementing the RDM would put the Company in a position to plan more significant changes to rates in the future without factoring lost fixed cost recovery into its policy evaluations. While the dynamic pricing pilot is limited in scope, Mr. Hansen testified it could lead to the Company offering one or more voluntary rates that obtain significant participation in the future. While the cost-benefit analysis reflects overall benefits from implementing the volt/VAR program, Mr. Hansen stated that those benefits do not necessarily represent financial gains that accrue to the Company or its shareholders.

Mr. Hansen noted that he modified the Company's proposal to add a 4% cap on annual RDM rate increases with no floor on rate decreases.

Mr. Wallach agree with Dr. Dismukes' recommendation that the Commission reject the Company's request to implement the proposed RDM.

i. <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 energy 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 provided in this proceeding, 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 in its assigned service area. 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 electric 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 IAC § 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 management 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 IAC 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 IAC 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 to those 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. 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 any lost margin regardless of causation. Dr. Dismukes testified that a reduction in revenue associated with energy efficiency programs is quite small. Other factors including 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. On the other side of the coin, to the extent the risks of these potential load reducing circumstances were to be moved from the Company to its customers, the Company's risk reduction could reasonably be considered in its authorized risk adjusted return. We do not analyze the appropriate increment herein, but would expect it could be potentially material.

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. We find this unpersuasive. The Company has admitted that the revenue 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 had been a significant negative financial impact, it could have presented that evidence. The Commission acknowledged when discussing the decoupling topic in Cause No 43839, and continues to acknowledge today, that creative rate designs may influence the attractiveness of a decoupled rate design. However, as in that case, in this proceeding the exposure to such creativity has not been established. The Company's scale of its creative offerings is very limited, and the promise of greater scale is not sufficiently likely.

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 or electric distribution companies rather than vertically integrated electric 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. Second, gas distribution companies 'fixed costs are considerably less than those of electric utilities. Since there is no generation function for a gas distribution 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, such a mechanism as proposed by Petitioner is seeking to secure cost recovery for a greater portion of its fixed costs and that greater portion of a customer's total bill is no longer avoidable by them. This means, since the commodity costs are such a relatively small portion of the bill, DEI customers will not be able to noticeably reduce their bills as they reduce their usage.

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.

14. Rate Adjustment Mechanisms.

a. Rider 70. As established in the Company's last base-rate proceeding (Cause No. 42359), $14.7 million is currently 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.

Company witness Swez supported the Company's Rider 70 proposals. He explained that zero should be embedded in base rates because of the volatility of non-native sales. He demonstrated that margins from non-native sales have varied considerably since the last rate case, and have rarely come close to the $14.7 million threshold built into base rates. Given the volatility, he stated that the Company believes non- native sales are more appropriately accounted for totally through a tracker rather than through any fixed base rate component. He testified the Company's proposal is reasonable due to the variability of non-native margins, and his assessment that the realization of margins is largely outside of the Company's control.

With regard to the proposal to include negative (net loss) non-native margins in the sharing mechanism, Mr. Swez stated that sharing both opportunities and risks equally is appropriate. He stated that the negative non-native margins are the result of operating a power system for the greater good of native retail customers, and assigning financial responsibility for these losses solely to the Company is a punitive consequence of the current mechanism.

Mr. Swez also testified about the Company's proposal to include a new category of non-native sales in the Rider 70 sharing mechanism. He explained that currently, the Company does not engage in physical energy sales beyond the MISO border. In the RTO construct, non-native energy sales are an accounting concept. He testified that all of the Company's generation is dispatched into the MISO market and is designated as native or non-native after the fact. As a result, he stated, non-native sales are energy sales that take place in the MISO energy markets when dispatched generation exceeds native-load customer requirements. Mr. Swez explained that DEI is changing its non-native sales strategy. Whereas previously the Company pursued energy only and capacity-only sales to MISO, in order to continue to optimize the value of its generating assets and to adapt to a rapidly evolving energy market landscape, the Company is now also pursuing a non-native sales strategy that includes short-term bundled sales of market-priced capacity and energy to wholesale customers. Mr. Swez noted that the sustained low natural gas prices and increasing renewable energy penetration have created an extremely competitive short-term market environment.

For these reasons, going forward the Company proposes to pursue a new category of sales -- short-term bundled non-native sales contracts that can both meet changing wholesale customer needs and compete with current market prices. He explained that these new short-term bundled non-native contracts will allow the Company to more fully maximize the utilization of its generation portfolio and minimize additional cost allocations to retail customers. He stated that contributions to fixed costs captured through these new agreements, even if they do not fully recover embedded costs, will lower the cost that would be re-allocated to retail customers as current agreements expire. He emphasized that these contracts are non-native sales of capacity and energy for a contract term of five years or less. Further, he explained that they will be negotiated and priced competitively with the market, with bundled contract prices expected to cover energy costs and make a contribution to fixed costs. He testified that, faced with a shrinking wholesale portfolio, these contracts will create incremental value for customers while generation-fleet system costs remain above market. He offered that this short-term bundled sales strategy should provide the Company and its retail customers with a premium above day-ahead and real-time MISO prices. He stated that thus far, the Company has entered into one of these new category sales – a 5 year, 100-megawatt contract for capacity and energy, expiring in 2021. The Company proposes that going forward, for new bundled capacity and energy contracts, including this one existing contract, the associated costs and revenues will be shared 50/50 between the Company and its customers through Rider 70.

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 customers receive 80% of the proceeds of such sales and that an amount of $12.7 million be embedded in base rates. He also recommended that the Company be ordered to return the amount of net profit realized on the existing short-term bundled non-native contract 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 sharing negative margins in Rider 70. 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.

In rebuttal testimony, the Company stated that it was agreeable to sharing 100% of traditional non-native sales with customers, including negative margins, with zero embedded in base rates. However, the Company reiterated that, for its new short-term bundled non-native energy and capacity sales, it believed an incentive in the form of 50/50 sharing of margins was appropriate to incentivize pursuit of this new sales strategy. Mr. Davey testified that the Company believes it's important to have an incentive to continue to pursue short-term bundled non-native sales when the Company has surplus capacity. He stated that the Company's proposed 50/50 sharing mechanism provides such an appropriate incentive. However, Mr. Davey and Mr. Swez both emphasized, embedding any amount in base rates associated with these sales does not make sense given their short-term nature. Additionally, both witnesses emphasized that the only existing such contract expires in 2021, and the Company is not making long term capacity planning decisions related to this contract. Therefore, the Company stands by its initial proposal related to short-term bundled non-native sales.

Mr. Davey also testified that the Company does recognize there is a difference between the level of effort required to pursue such bilateral sales and traditional non-native sales, which reflect the difference between native load and generation. As such, the Company is agreeable to crediting retail customers with the net benefits of 100% of traditional, MISO-derived non-native sales margins, through Rider 70. He stated his belief that this compromise proposal recognizes the importance of aligning incentives between customers and shareholders, and results in a reasonable ratemaking proposal.

Company witness Sieferman addressed Dr. Boerger's recommendation that the Company refund net margins realized on the one existing short-term bundled non-native sale. Ms. Sieferman stated that the current base rate case is the appropriate time to address the prospective treatment for the new short-term bundled bilateral contract, which the Company did through its ratemaking proposal in this proceeding. She stated that this new category of sales, the short-term bundled non-native contract, is clearly different from both the Company's long-term native load wholesale contracts and also the non-native sales of excess generation to MISO that were contemplated in the past for inclusion in Rider 70.

i. <u>Commission Discussion and Findings</u>. The evidence is clear that traditional non-native sales margins are quite volatile, and that embedding any level of such sales margins in base rates is unlikely to be fair to one party or the other. Additionally, the evidence shows that Petitioner currently has one bilateral short-term bundled sales contract in place that expires in 2021, which is after the test year in this proceeding. Accordingly, we find that Petitioner's base rates should reflect zero for traditional non-native sales margins and $12.7 million of the short-term bundled sales margins for the existing short-term bundled sales contract.

As for sharing of non-native sales margins, we accept the parties' agreement to credit retail customers with 100% of the traditional, MISO-derived non-native sales margins through Rider 70. However, we continue to deny sharing of the reflection of negative margins in the calculation of Rider 70 margins. We find the Company to be in a position to address this negative risk, a position unavailable to customers, and that the continuation of this feature will provide an available and reasonable incentive to avoid such results. Further, we accept Petitioner's proposal to share, on a 50/50 basis, modified so that the sharing is to be measured above and below the amount embedded in base rates, sales margins from the category of short-term bundled non-native sales. We agree with the Company, and the evidence demonstrates, that there is a difference in effort, creativity, and initiative, between pursuing and achieving such bilateral sales, compared to the traditional non-native sales made through the MISO markets. We find that the directed treatment of the short-term bundled non-native sales will provide incentive for the Company to pursue the developing wholesale market opportunities while reasonably recognizing the test-year conditions. While the Company presents the short-term bundled non-native sales as new for our consideration of the appropriate treatment going forward and we have done so herein, we note that the existing Rider 70 exists to address non-native sales; however the existing short-term bundled non-native sales have not been presented for consideration as non-native sales that may be tracked in the existing Rider 70. The reconciliation mechanism in Rider 70, while limited to the reconciliation period in any future filing, provides all parties the opportunity to consider the reasonableness of how these existing non-native sales should be treated in a reconciliation period. Accordingly, we decline to address historical Rider 70 treatment in this proceeding because a discussion forum already exists.

b. Edwardsport IGCC. Witness Douglas provided testimony regarding changes DEI is proposing to its IGCC Rider. Consistent with the terms of a settlement agreement approved by the Commission's June 5, 2019 final order in IGCC-17 (the "IGCC-17 Order") (the "2018 IGCC Settlement Agreement"), Ms. Douglas explained the Company included Edwardsport plant investment and operating expenses in the proposed base rates. Ms. Douglas stated the Company is proposing to discontinue tracking Edwardsport investment and operating expenses in the IGCC Rider, effective with implementation of new base rates in this proceeding, at which time DEI is proposing to eliminate the IGCC Rider. Ms. Douglas explained the IGCC-17 Order left the issue of base rate treatment for Edwardsport investment and operating expenses for this proceeding, and that the Company is requesting the Commission approve this base rate treatment for Edwardsport and discontinue the IGCC Rider.

Ms. Douglas testified that should the Commission approve this ratemaking proposal, the 2018 IGCC Settlement Agreement provided that a final reconciliation of the IGCC Rider will be made as part of the first practicable Environmental Compliance Cost Recovery ("ECR") rider ("ECR Rider") filing following the issuance of an order in this proceeding. Ms. Douglas stated the reconciliation calculation will incorporate the 2018 IGCC Settlement Agreement O&M Caps from 2018 and 2019 to ensure customers pay only for the lesser of actual O&M costs incurred in 2018 and 2019 and the agreed upon retail jurisdictional caps of $97.6 million for 2018 and $96 million for 2019. The reconciliation will include the other terms set out in the 2018 IGCC Settlement Agreement.

Ms. Douglas explained there are other items included in the IGCC Rider that will be included in the ECR Rider upon implementation of new base rates, including an amount for amortization of retail jurisdictional operating costs incurred in excess of amounts being recovered through IGCC Rider rates from June 7, 2013 through August 2016. Ms. Douglas testified the 2018 IGCC Settlement Agreement required the Company to propose base rates be set using a $20 million annual amortization amount, which is what the Company included in the development of base rate revenue requirements in this Cause. Ms. Douglas explained additionally that a $10 million annual credit would be included in the ECR Rider to offset the $20 million in base rates until a total of $30 million benefit of the 2018 Settlement Agreement reduction was refunded through rates.

Ms. Douglas testified there are three IGCC facility tax incentive credit items currently included in the IGCC Rider that the Company has not included in its development of proposed base rates. These include a credit for the retail jurisdictional portion of the $15 million annual Indiana Coal Gasification Technology Investment Tax Credit, a credit for the retail jurisdictional portion of the ten-year property tax abatement from Knox County, and a credit for the retail jurisdictional portion of the thirty-year reimbursement due to designation of Edwardsport as a Tax Increment Financing ("TIF") District. As explained in the testimony of Company witness Panizza, an additional credit for the retail jurisdictional portion of the annual federal Advanced Coal Investment Tax Credit was planned to be included in the IGCC Rider, but has not been included in the proposed base rates to ensure compliance with the federal income tax normalization requirements. Ms. Douglas explained the Company plans to include these tax incentive benefits as credits to customer rates in its Rider 67 Credits Rider.

Ms. Douglas explained the Company's ratemaking proposals regarding costs and credits currently included in the IGCC Rider are reasonable, as the request is consistent with past practice in Indiana for capital riders to subsequently include in base rates in-service plant receiving CWIP ratemaking treatment via a tracker. Ms. Douglas supported her statement by reference to the Company's last base rate case and the approval of Southern Indiana Gas and Electric's handing of investment and operating expenses related to certain Qualified Pollution Control Equipment in Cause No. 43839. She also stated excluding IGCC Incentive Tax Benefit credits from base rates and moving them to Rider 67 is a transparent way to show parties that customers are indeed continuing to get these credits. Ms. Douglas explained that Rider 67 is an efficient way to pass these credits back to customers, and is currently the case with the amortization of the unprotected EDIT created due to the reduction in federal income taxes resulting from the TCJA.

OUCC witness Kollen explained the effect of terminating the IGCC Rider, as proposed by DEI, 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 revenue requirement 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 again 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 ECR Rider or 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.

Company witness Davey disagreed with Mr. Kollen's recommendation that Edwardsport essentially continue to be included in a rider, rather than included in base rates. Mr. Davey emphasized the legislature provided for the ability to recover costs associated with gasification projects in rates through a rider mechanism. Mr. Davey stated that the Company and the settling parties agreed in both the original IGCC settlement agreement and the 2018 IGCC Settlement Agreement that when the Company had a base rate case, Edwardsport would be included in base rates, which is what the Company has proposed and which is consistent with how other capital riders have been treated in the past during a base rate case. Mr. Davey also voiced concern with Mr. Kollen's recommendation that the only portion of Edwardsport that should be included in the rider is the declining balance of rate base, and credit of tax credits, but no other costs such as O&M and new capital additions needed to operate the plant. Mr. Davey concluded that the costs associated with Edwardsport should be included in base rates and in rate base, as proposed by the Company.

Company witness Douglas also addressed Mr. Kollen's recommendation. Ms. Douglas stated the OUCC's proposal was not traditional Indiana rate recovery for assets that are moved from being tracked in a rider to rate base. For instance, in the Company's last base rate case, DEI rolled NOx environmental plant that had previously been tracked in Rider 62 into base rates, but Mr. Kollen does not put forth a compelling reason to deviate from standard ratemaking practice. The Company is proposing to handle Edwardsport plant similarly to how it handled all other in-service generating plant that was used and useful for providing service to customers during the test year. However, Ms. Douglas pointed out that under Mr. Kollen's proposal, the revenue the Company receives for return on the plant declines, while the costs are still subject to increasing. As such, the Company's ability to manage cost increases and earn a fair return until the next base rate case is impaired. Ms. Douglas testified this one-way tracking proposal is unfair, unreasonable, and unbalanced.

i. <u>Commission Discussion and Findings</u>. In this proceeding, DEI seeks to implement a provision of the 2018 IGCC Settlement Agreement approved in our IGCC-17 Order. In relevant part, it stated: "In addition, the 2018 Settlement Agreement provides that DEI will not file an IGCC Rider proceeding in 2019 or 2020, and that the Settling Parties intend for DEI 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. The OUCC was a party to the 2018 IGCC Settlement Agreement, and it continues to be bound by its agreement.

Even if the OUCC had not already agreed to the rate mechanism procedures in the 2018 IGCC Settlement Agreement, DEI's proposal would still be reasonable and appropriate. The Company's proposal is consistent with traditional Indiana ratemaking, and the proposal to handle Edwardsport is consistent with how the Company handled all other in-service generating plant that was used and useful for providing service to customers during the test year. We find that the proposal set forth by DEI is reasonable, consistent with Indiana law and the 2018 IGCC Settlement Agreement, and supported by the evidence, and we approve it.

c. <u>DSM/EE Rider</u>. Company witness Douglas explained certain changes DEI is proposing to its energy efficiency ("EE") Rider, the nature and extent of which are dependent on whether the RDM is approved. Ms. Douglas explained the proposed RDM would replace the lost revenue recovery mechanism ("LRAM") for recovery of lost revenues resulting from the Company's EE programs for those customers who are a part of the proposed RDM. Ms. Douglas stated that as such, with the approval of the RDM, the items included in the EE Rider for the Residential and Commercial customer groups will exclude lost revenues for energy savings resulting from Company-sponsored EE programs going forward from the time of rate implementation.

Ms. Douglas next discussed some cosmetic changes proposed to its EE Rider, including numbering, and revision of the revenue conversion factors. Ms. Douglas also explained the Company is proposing to remove all EE program costs, including administrative and EM&V costs, and all shareholder incentives from the cost of service and track these costs in the EE Rider from the zero base. Ms. Douglas also described the process of handling lost revenues currently included in the EE Rider upon implementation of new base rates.

Ms. Douglas explained that the Company's ratemaking proposals regarding the EE Rider are reasonable, as keeping all energy efficiency costs in the EE Rider is appropriate given the statutory requirement to propose plans consistent with each IRP. Ms. Douglas described that because plans can and will change, and the level of EE Rider rates may therefore be volatile.

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, while also noting that DEI has not yet filed its next DSM plan for the period beginning 2020.

Mr. Haselden recommended 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 and no implied or explicit approval of any issues will be decided in this case.

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.

i. Commission Discussion and Findings. DEI and the OUCC agreed to defer future DSM costs, lost revenues, and shareholder incentives to the forthcoming DSM plan case with the condition that any issues will be litigated therein. We approve of the handling of these aspects of the EE Rider in such a fashion. With respect to all other aspects of DEI's EE Rider proposals as set forth by Ms. Douglas' revised direct testimony, except those directly implicated by our denial of the RDM, the Commission approves them as proposed.

d. Rider 62.

i. Reagent Costs. Company witness Mr. Mosley explained that reagents are included in the base cost of power production O&M, and he also discussed that reagent expenses necessary to operate the generating stations vary directly with generation output of the units. He testified that reagent consumption rates also vary with coal quality, and commodity and delivery transportation prices of the reagents themselves can show volatility.

Mr. Mosley explained the Company is proposing to build into its base rates a representative level of reagents. Due to the variability of reagent expenses, however, Company witness Graft explained that DEI is proposing to track its reagent expense, both up and down from the level built into rates, through its consolidated Rider 62. Ms. Graft stated this will protect customers to the extent actual reagent costs are less than the amount in base rates but also protects the Company if actual reagent costs exceed the amount in base rates.

OUCC witness Blakley addressed the Company's reagent expense tracker proposal. He stated that DEI indicated the 2020 forecast for reagent expense it is proposing to embed in base rates is $48.5 million, 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 asserted the practice of setting aside and tracking a single O&M expense outside of base rates is "piecemeal ratemaking." Mr. Blakley stated 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 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 recommended the denial of the Company's proposal to track incremental reagent expense. In the event the Commission allows the Company to track incremental reagent expense outside of base rates, Mr. Blakley recommended the Commission require the Company 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.

Ms. Graft addressed Mr. Blakley's citation to the Commission's April 27, 2011 Order in Cause No. 43839 claiming it does not support his position. Ms. Graft pointed out that such Commission Order reflected the uncertainty as to the potential for chemical and catalyst costs to vary going forward. However, Ms. Graft stated that such uncertainty does not exist in this proceeding. She reiterated Mr. Mosley's direct testimony, which established the variability of the Company's reagent expense, and which distinguishes it from the Order in Cause No. 43839.

Ms. Graft stated her disagreement with Mr. Blakley's position. In addition to the variability in reagent expense established by Mr. Mosley, Ms. Graft explained that continued tracking protects customers if the actual costs of reagent expenses are lower than the amount in base rates. She also explained discontinuing the tracking of these costs is inconsistent with the Clean Energy Project Statute, which provides for timely recovery of clean energy project costs incurred during ongoing operation.

Ms. Graft also stated opposition to Mr. Blakley's proposal to use Rider 67 to credit customers for the effect of declining environmental rate base following implementation of new base rates as an offset to tracking reagent expense through Rider 62. She testified the historic practice is for projects included in riders to be rolled into rate base at the time of a subsequent base rate case, which occurred with environmental projects in the Company's last rate case. To the contrary, Ms. Graft pointed out that continuing to provide customers the benefit of declining rate base for these projects in between rate cases is inconsistent with traditional ratemaking. She also asserted it would be one-sided to track declining environmental rate base when the Company will not be tracking future capital maintenance projects associated with the environmental plant being rolled into base rates in this proceeding.

(A) Commission Discussion and Findings. DEI is proposing to build into its base rates a representative level of reagent expense and also track its reagent expense, both up and down from the level built into rates, through its consolidated Rider 62. The evidence presented established that DEI's reagent expense is and will continue to be variable, and there was no evidence offered to rebut that variability. The establishment of reagent expense variability distinguishes this from the rationale in the Commission's April 27, 2011 Order in Cause No. 43839, in which variability was uncertain.

The structure of tracking these types of variable expenses is reasonable and balanced. This is not a one-way ratchet. Instead, it protects customers to the extent actual reagent costs are less than the amount in base rates, and it also protects the Company if actual reagent costs exceed the amount in base rates. Furthermore, continuing the tracking of these costs is consistent with the framework of the Clean Energy Project Statute, which provides for timely recovery of clean energy project costs incurred during ongoing operation. As such, in these circumstances where there is a history and continued likelihood of cost volatility due to multiple factors beyond the Company's control, including the potential for declining use of coal-fired generation, as well as a demonstration of the significant magnitude of these costs, we find that DEI's proposal to track reagent costs should be approved.

Additionally, we find persuasive Ms. Graft's testimony in opposition to Mr. Blakley's proposal to use Rider 67 to credit customers for the effect of declining environmental rate base following implementation of new base rates as an offset to tracking reagent expense through Rider 62. We agree it is historic practice for projects included in riders to be rolled into rate base at the time of a subsequent base rate case, and continuing to provide customers the benefit of declining rate base for these projects in between rate cases is one-sided because the Company will not be tracking future capital maintenance projects associated with the environmental plant being rolled into base rates in this proceeding. The clear distinction between the fixed cost nature of the environmental rate base and the variable cost nature of the reagent expense provide a distinguishing feature between the two items. Therefore, we reject Mr. Blakley's recommendation.

ii. Emission Allowance Costs. DEI 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.

OUCC witness Armstrong testified the public has no objection with DEI'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 DEI's proposal to continue tracking any emission allowance expense via Rider 62. She argued 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. Ms. Armstrong stated that DEI is unlikely to incur volatile or significant emission allowance costs over the next several years, and therefore tracking these costs is no longer necessary. She 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.

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 DEI 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.

(A) Commission Discussion and Findings. With DEI'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 DEI 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 DEI's emission allowance proposals as modified in its rebuttal testimony.

e. Rider 67. Company witness Douglas described the changes the Company is proposing to its Credits Rider. She stated that in addition to the ongoing TCJA credit currently in the Credits Rider, pursuant to the TCJA Settlement Agreement, a one-time $1.9 million credit will be included in the Rider in January 2020 and the ongoing additional credit amortization of protected EDIT will also begin in January 2020. She added the Company is also proposing to include the deferred 2018 and 2019 amounts of protected EDIT amortization in the Credits Rider. Ms. Douglas explained the Company is proposing to include certain IGCC facility tax incentive credits in the Credits Rider, which are currently included or planned to be included in the IGCC Rider. Additionally, the Company plans to include additional credits in this rider as the regulatory assets for which amortization is being included in base rates becomes fully amortized.

Ms. Douglas further described a two-step rate adjustment, such that the Credits Rider is planned to be used during the first step of implementing the new base rates by crediting customers (upon review and Commission approval in a compliance filing) with the difference between what final base rates are using the proposed forecasted Test Period revenue requirements, reflecting used and useful plant in-service as of December 31, 2020, and what they would be using the known actual used and useful plant in-service as of December 31, 2019. Ms. Douglas explained a second step process with the Credit Rider to ensure that customers continue to pay for used and useful plant only as a result of the final base rates approved during this proceeding.

Ms. Douglas said that in addition, the Credits Rider will also be revised to remove the credit to remove the 1994 Cinergy Merger Costs currently in the rider, update allocations to rate classes consistent with this proceeding instead of Cause No. 42359, and include the calculated revenue requirements differential by rate class for the two-step rate adjustment.

Ms. Douglas testified these ratemaking proposals are reasonable, consistent with the requirements of the TCJA Settlement, provide transparency that the credits are being provided to customers, and via the administratively convenience means under the Thirty-Day Filing Rules.

OUCC witness Eckert stated 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 recommend 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.

As discussed in other sections of this Order, OUCC witnesses Kollen, Blakley, and Hand discussed and recommended additional components be added to the proposed Credits Rider.

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.

i. <u>Commission Discussion and Findings</u>. The Commission finds approval of the agreement of DEI and the OUCC regarding the Rider 67 process is reasonable and administratively efficient. Specifically, DEI 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 OUCC a reasonable opportunity to preview all the various items that could be included in a Rider 67 filing. This preview does not in any way impact the objection rights to 30-day filings that exist by rule.

DEI 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. While the merits of these items are discussed elsewhere in this Order, we reiterate here that DEI's proposals for inclusion in Rider 67, to the extent consistent with our findings elsewhere in this order, as well as the proposed allocations, are reasonable, supported by the evidence, and approved. 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. For clarity, to the extent consistent with our findings elsewhere in this order, those proposals are not approved.

f. Discontinued Riders. DEI 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.

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 DEI 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.

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.

i. 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 DEI. 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, but with the one slight change proposed by the Company. Specifically, the Company desires 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, 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. We are persuaded that the flexibility provided by this set up will facilitate appropriate efficiencies in the future, and authorize the Company to retain this ability, subject to the approved 30-day filing rules.

15. Tariff Provisions. DEI 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. Company witness Flick sponsored the proposal to modify Section 4.2 of DEI's tariff, regarding the circumstances around which the Company may seek a new or additional security deposit from existing non-residential customers. The Company's current tariff provides that such a deposit may be required "at the Company's discretion." Company witness Lesley Quick described the Company is proposing to clarify that such deposit may be required based on the customer's overall financial condition or creditworthiness, which may include external information obtained from credit reporting agencies and public records. Ms. Quick explained this improved language is designed to provide customers with additional insight into how the Company may decide to require the deposit.

Industrial Group witness James R. Dauphinais testified that the non-residential customer deposits provisions, claiming they provide DEI with excessive discretion. He argued the provisions give the Company the discretion to require a non-residential customer make a deposit, even if that customer has made satisfactory payment over a reasonable period of time. He also took issue with the proposed provisions claiming they do not explicitly require the Company to provide written notice of the facts upon which it bases its decision to require a non-residential customer make a deposit, and do not provide them an opportunity to rebut those facts.

Mr. Dauphinais alleged the Company's non-residential customer deposit provisions are inconsistent with past Commission orders. Specifically, he cited the Commission's orders in Cause Nos. 43685 and 43526, involving NIPSCO, and stated the commission required creditworthiness be based on objective basis, allow some form of an appeal procedure, and a utility's rules for non-residential customers be fundamentally the same as those for residential customers.

Ms. Quick addressed the allegations made by Mr. Dauphinais. First, Ms. Quick explained that there are rational reasons that a non-residential customer should be treated differently from residential customers, which support the Company having increased discretion with respect to non-residential customers. Ms. Quick explained that non-residential customers can have a history of paying their bills, but a company's finances may deteriorate during this time. Ms. Quick said DEI monitors credit ratings in order to become aware of things like potential insolvency before bankruptcy occurs, in order to protect the Company and its other customers from an uncollectible account. Ms. Quick characterized this as the exercise of prudent discretion.

Ms. Quick, at the evidentiary hearing, explained that DEI's proposed method of handling deposits for non-residential customers is appropriate. She testified DEI employs fair and equitable methods of determining creditworthiness, by reviewing credit ratings. She also testified that the deposits earn similar earnings, and DEI provides the ability to appeal a deposit determination. She stated the Company notifies, by both letter and phone call, the non-residential customer to let them know why a deposit is being assessed, and informs them how they can dispute the deposit determination by phone. Ms. Quick explained that these procedures are consistent with what DEI currently does, and the Company is proposing to continue them in the future. Tr. p. D-78 to 79. Ms. Quick stated that these facets of the program are in accordance with the Commission's Order in the NIPSCO case, Cause No. 43526. Ms. Quick also stated that several other Duke jurisdictions use credit ratings to assess deposits to non-residential customers, including Florida, South Carolina, North Carolina and Kentucky.

i. Commission Discussion and Findings. The evidence revealed that the DEI non-residential customer deposit rule is reasonable, and so is the Company's proposal going forward. Consistent with our determination in Cause No. 43526, DEI uses objective criteria to ascertain creditworthiness, treats residential and non-residential deposits equally in terms of earnings, and provides non-residential customers notice and an avenue to appeal a deposit determination. While the Company's tariff does not spell out all of these procedures, the evidence demonstrated that the Company does these things now. DEI's proposed modification to its tariff is intended to provide clarity and more transparency to customers as to the how the Company may decide to require a deposit. However, we find that a more transparent presentation of the actual procedures by which a customer may challenge the Company's deposit determination also should be included in the tariff. This increased transparency is further needed as the deposit carrying rate is reduced as discussed below. Accordingly, with such modification, we find DEI's proposal reasonable, supported by the evidence, and approved.

b. Meter Tampering Penalties. 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.

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 DEI should seek criminal prosecution because meter tampering is a felony. 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.

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.

i. **<u>Commission Discussion and Findings</u>.** Based on the evidence provided, the Commission finds the meter tampering penalties proposed by DEI are reasonable. Meter tampering is a grave safety concern, for both customers and others, and the proposed meter tampering fees should serve as a deterrent. While the Company, under the appropriate circumstances, could refer meter tampering to local authorities for potential criminal prosecution, it would be costly and time consuming for DEI's sole recourse to be civil collection against offenders, in which the costs are socialized and the chance of collection uncertain. The Company's proposed meter tamper penalty is more direct and recovers the fees from the specific violators. We find the proposed fees of $200 for residential customers and $1,000 for nonresidential customers reasonable to be included in the Company's tariff, and we approve of the *pro forma* credit adjustment of $194,000 built into rates as proposed by the Company.

c. **<u>Backup and Maintenance Provisions</u>.** The tariffs sponsored by Company witness Flick included minor revisions to Standard Contract Rider No. 50, Rate Qualifying Facility ("QF"), Parallel Operation for Qualifying Facility, which addresses backup and maintenance, or standby, service. These minor revisions addressed definitions for contracted capacity and peak periods and, renaming the rider simply as Rate QF.

Industrial Group witness Dauphinais explained the definitions of backup and maintenance power, and stated DEI is required to provide backup and maintenance power to "Qualified Facilities" pursuant to the Public Utility Regulatory Policy Act ("PURPA") and Commission Rule 4.1. Mr. Dauphinais testified the applicable rates and charges for standby service are not specifically stated in Rate QF. Mr. Dauphinais stated that, in the absence of a special contract, the rates, charges and terms of service would be those set forth in the "applicable rate schedules" or "applicable Service Schedules." Mr. Dauphinais concluded that, for a Rate HLF customer, standby service would be provided subject to the rates and terms of Rate HLF, and for a Rate LLF customer standby service would be subject to the rates and terms of Rate LLF. Mr. Dauphinais asserted that this implies the Company's standby service rates are unjust and unreasonable, and contrary to

FERC and Commission regulations. Mr. Dauphinais recommended rate design modifications to bring them into compliance with FERC and Commission rules for standby service.

Company witness Bailey stated he does not agree with Mr. Dauphinais position. Mr. Bailey first noted there are no historical or current complaints before the Commission related to standby service, and Mr. Dauphinais' reading and interpretation of the Company's tariffs and general terms and conditions does not comport with Company practice. Mr. Bailey testified the Company's experience has been that the provision of standby services is highly contingent on the specific circumstances of the customer and the Company. He stated the Company has two major customers with cogeneration facilities, which are served in different ways with different provisions of service. Mr. Bailey disagrees that these complex provisions can be reduced to a simple smorgasbord of rate options, as Mr. Dauphinais seems to suggest.

Mr. Bailey, in the interest of compromise, stated the Company is willing to consider modest changes to its General Terms and Conditions, with Rate QF to provide additional details on the calculation of standby and backup service, while still allowing the specific negotiation required for such agreements. He stated the Company's proposal is to add the following language to Rate QF, the end of Special Terms and Conditions 8, Exhibits A and B, to the end of Section 8 for Parallel Operation for Qualifying Facilities, and to the end Section 13 for Parallel Operation for Qualifying Facilities: "..., and modified, as necessary, to fully comply with all IURC and PURPA requirements."

i. Commission Discussion and Findings. The evidence demonstrates that the provision of standby services is highly contingent on the specific circumstances of the customer and the Company, and often requires careful negotiation based on the specific circumstances of the customer. The Commission continues to observe, as it did in IPL's rate case, Cause No 44576 at page 77, that ''we appreciate that a well-placed cogeneration facility with well-timed maintenance outages can enhance value to both the providing customer-generator and the utility-system customers as a whole, and direct IPL to explore with existing and potential industrial customer-generators how to capture such value." Accordingly, we similarly direct DEI to seek opportunities to work with its customers to identify and capture such opportunities. The Company's proposal to add language to its tariff to affirm that the terms and conditions of backup service may be modified to ensure compliance with all Commission and PURPA requirements is a reasonable adjustment to ensure potential participants of the assurance of compliance. Therefore, we approve of the Company's proposal, as modified by Mr. Bailey's rebuttal testimony and attachments.

d. Deposit Interest Rate. Ms. Quick described the Company's proposal to modify the rate on which customers earn interest on deposits from 6% to 2%. Ms. Quick stated 6% is far above market interest rates, and that 2% is more reasonable given the current interest rate environment. Ms. Quick stated the proposed reduction will benefit all customers, as the use of a 2% interest rate will cause a reduction in the rate associated with customer-provided sources of funds included in the Company's capital structure and weighted average cost of capital calculation used to determine the Company's revenue requirement.

No witness opposed the Company's proposal to move the interest rate on customer deposits from 6% to 2%. However, Industrial Group witness Dauphinais sponsored Attachment JRD-3, Section 4.4 of which proposed to grandfather in existing customer deposits, such that they will continue to earn interest at six percent even after the interest rate is reduced to 2% in this order. Neither Mr. Dauphinais nor any other witness provided testimony to justify this proposal.

On rebuttal, Ms. Quick stated that the Industrial Group does not appear to object to the proposal to earn interest at two percent as opposed to six percent. However, she pointed out the Industrial Group seeks to grandfather in existing customer deposits, such that they will continue to earn interest at six percent after the effective date of this order. Ms. Quick explained that a more equitable and administratively efficient handling of existing deposits is that they would earn six percent interest from the date of deposit until the date of this order, and then reduce to two percent.

i. Commission Discussion and Findings. The Commission's rule governing interest on customer deposits provides that the interest rate will be 6% or such other rate as the Commission may determine following a public hearing. 170 IAC 4-1-15(f). Based on the evidence submitted, the Commission agrees with the Company's proposal that customer deposits should earn interest at 2%. We note that the lower rate could also change the calculus in the determinations of when a deposit might be required, but find that the increased transparency directed above to the tariff regarding the customer challenge process mitigates such concern. We find the 2% interest rate is an equitable balance between providing for a reasonable rate of return to the customer for deposits being held and the cost incurred by all customers for the Company's provision of electric service.

We decline to adopt the Industrial Group's proposal that customer deposits made prior to the effective date of this Order continue to earn 6%, and customer deposits made after the effective date of this Order to earn 2%. The Industrial Group proposal would place an administrative burden on the Company to keep track of the nuances of each customer deposit, which we do not find as justified. We agree with the Company that a more equitable and administratively efficient handling of existing deposits is that they would earn 6% interest from the date of deposit until the date of this Order, and they all reduce to 2% after the effective date of this Order. We approve the Company's proposal for these reasons.

e. Call/Text Disconnection Program. Company witness Quick described the Company's proposal for a waiver from the Commission rule requiring, prior to disconnection of electric service, the Company to make an on-site premises visit. Ms. Quick stated the Company is proposing, instead of a premises visit, to call and/or text notification to such customers both the day before and the day of a prospective disconnection. She stated if the customer is considered a "sensitive" or "essential" customer, or is on the Company's Medical Life Support Program, the Company will still make personal contact on the premises both two days in advance of and on the day of disconnect. Ms. Quick said that because AMI will be fully deployed by the date of this Order, remote disconnections are available for the vast majority of customers. On cross-examination, Ms. Quick described that a customer has the ability to provide a third-party notification on its account, which adds a layer of protection for customers. In response to Commission inquiry, Ms. Quick stated the Company was not opposed to communicating to customers if the Commission were to provide a waiver of the premises visit. Tr., p. D-86.

The Company believes, and the data demonstrates, that enhanced communications such as call or text will result in more customers receiving actual notice of a potential disconnection. Ms. Quick explained that in March 2018, the Company began a policy of calling and texting customers prior to disconnection, and the percent of disconnections cancelled substantially increased, leading to lower disconnections. Ms. Quick added that while there are no costs related to this program, there will be cost savings associated with not having to make the on premises visits. At the evidentiary hearing, Company witness Graft explained that these cost savings have been rolled into the rate case forecast.

i. <u>Commission Discussion and Findings</u>. 170 IAC 4-1-16(f) provides that prior to disconnection of electric service, a Company employee is required to, among other things, make an on-site premises visit. The undisputed evidence presented in this case reflects that notification by call or text decreases disconnections by increasing actual notice to customers of prospective disconnection. The evidence also showed the Company is continuing protections for sensitive or medically essential customers, and allow for third-party notifications for customers. Based on the evidence presented, we approve of the requested waiver of the requirement of an on-site premises visit prior to disconnection. However, as invited by the Company, we do require the Company communicate to all customers regarding the Commission's waiver of the premises visit being approved in this Order.

16. <u>Other Issues</u>.

a. <u>Two-Step Rate Increase</u>. Company witness Douglas testified about DEI's proposed two-step base rate increase procedures. She testified that, because base rates in this proceeding are calculated based on forecasted rate base at the end of the test period (December 31, 2020), the Company proposes to implement the requested rate increase in two steps to reflect the utility property that is used and useful at the time rates are placed in effect. Specifically, the Company proposes a two-step adjustment in rates that will utilize the Company's existing Rider 67 (the Credits Rider). As proposed by Ms. Douglas, Step 1 will adjust rates when new base rates are implemented, expected to occur in mid- 2020, the middle of the test period, following the Commission's issuance of its Order in this proceeding. Upon receipt of the Order, the Company proposes to file and implement the base rates supported by DEI witnesses Mr. Jeffrey R. Bailey and Mr. Flick as adjusted by the Commission's Order. These rates will be left in place until new rates are approved in the Company's next retail rate proceeding. These base rates will be based on the forecasted test period 2020, including forecasted plant and property which may not have been completed or be in-service to customers at the time of the Step 1 increase. Accordingly, Ms. Douglas testified, the rates will require an adjustment using the Credits Rider (Rider 67) to be sure that only rate base that is in-service at the end of 2019 will be included in the Step 1 rates. She stated that the Company will implement an adjustment using the Credits Rider to reflect revised revenue requirements using year-end 2019 actual value of net plant and property -- so long as the 2019 actual value of net plant and property does not exceed the forecasted 2020 values that were included in the Commission approved rates. Further, she stated, these adjusted revenue requirements will also adjust the depreciation expense and include the 2019 actual capital structure and cost of capital values in the calculation. In this way, she testified, the combination of the base rates plus the Credits Rider Step 1 rate adjustment will reasonably reflect actual used and useful plant-in-service as of the Step 1 timing of implementation of the base rates, while aligning both the depreciation calculation and the capital structure with the plant-in-service amount included in rate base.

Ms. Douglas testified that the Step 2 rate increase will adjust rates after the end of the test period, *i.e.*, after December 31, 2020, to reflect December 31, 2020 net plant and property amounts in-service at that point and included in the Commission approved base rates. She explained that, so long as the total revenue requirement amounts using actual December 31, 2020 net plant and property, depreciation and capital structure and cost of capital amounts do not exceed the forecasted 2020 values that were included in the Commission approved rates, the Step 1 Credits Rider rate adjustment will be modified to reflect the revenue requirements using the actual December 31, 2020 plant and property values. But, she stated, if the revenue requirements using the actual December 31, 2020 plant and property values are higher than the revenue requirements the Commission approved in base rates, no ongoing credit adjustment to base rates will be required, and the Step 1 Rate Adjustment component of the Credits Rider will be adjusted to zero following a compliance filing. Under either scenario, she explained, the Credits Rider will be adjusted from the amount included in Step 1 rates via a compliance filing as soon as practicable after year-end results become available, expected to be sometime during the first quarter of 2021. In this way, the combination of the base rates plus the Credits Rider Step 2 rate adjustment will reasonably reflect actual used and useful plant-in-service as of the December 31, 2020 test period end date, while aligning the depreciation calculation with the plant-in-service amount included in rate base and keeping the capital structure aligned with the same timing as the rate base, until new base rates are approved in the Company's next retail base rate case.

OUCC witness Blakley addressed the Company's proposed 2-step rate increase procedures. He indicated that the OUCC generally agrees with DEI'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 DEI'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.)

Ms. Douglas responded to Mr. Blakley's proposal to inject additional time into the schedule before the Commission reviews and approves the final rates (particularly if the parties object and a hearing is required to be scheduled, as under the OUCC proposal). She noted that this proposal has the potential to unreasonably delay implementation of final rates to the harm of the customers or the Company, depending on the differential between Step 1 rates and Step 2 rates. She noted, however, that the OUCC's proposal that, in addition to the extra time in the schedule, rates be trued-up with carrying charges back to January 1, 2021, regardless of when the Step 2 rates are approved by the Commission, helps remedy this delay and is something the Company would be amenable to. She concluded that it appears to be good regulatory policy and a fair and reasonable way to ensure that final rates in a proceeding that uses a forecasted test period can be implemented shortly after the close of the test period -- albeit, via a later reconciliation rather than directly -- while providing adequate review time for the final rates.

She concluded that the Company is agreeable to the OUCC's proposed 60-day review period if the Commission approves the OUCC's proposal to make the Step 2 rates effective January 1, 2021 via a true-up with carrying costs. She also offered that, alternatively, the Step 1 credit could be removed from Rider 67 effective January 1, 2021, so that the only true-up needed would relate to the rate differential arising between the actual and forecasted 12/31/2020 plant and capital structure values rather than the difference between the Step 1 and Step 2 rates. The Rider 67 credit would then be replaced if needed with the final approved Step 2 credit, with a subsequent true-up with carrying costs. She testified that under either such alternative (leaving the Step 1 credit in Rider 67 until Step 2 rates are implemented and then trueing up or removing the Step 1 credit effective January 1, 2021, until Step 2 rates are finalized and then trueing up), the Company would propose the true-up and carrying costs be included in Rider 67 in the next subsequent Rider 67 filing to be filed mid-2021.

i. 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 are 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 DEI'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) to January 1, 2021, regardless of when Step 2 rates are implemented.

b. Accounting Requests.

i. Edwardsport Outage Deferral Request. Petitioner's witness Davey indicated the Company is seeking cost deferral for the 2020 Edwardsport IGCC major planned maintenance outage, which outage will occur every seven years at an estimated expense of approximately $46.4 million. The Company proposes to include one-seventh of this expense in rates and defer the remaining expenses until the amount billed in rates cumulatively exceeds $46.4 million. If the amount billed in rates cumulatively exceeds $46 million, Mr. Davey said Petitioner proposes to establish a regulatory liability.

DEI witness Gurganus provided information on the Edwardsport planned major outage in his testimony. He testified the Edwardsport Station's 2020 outage has an O&M budget of $46.4 million. Mr. Gurganus stated the Company would receive operational benefits from the first major outage at Edwardsport, which would allow the Station to identify and correct issues during a planned outage that would necessitate multiple pieces of equipment being offline, improving the Station's reliability. He added the period of gasifier unavailability will allow for a thorough cleaning of the radiant syngas cooler tubes, which will help increase the HP steam flow to the steam turbine.

Mr. Gurganus indicated the Company worked closely with the regional project engineering group and developed a seven-year outage cycle, which he stated would optimize the amount of generation that is being provided to the grid by the fleet while maximizing the output of the Station. According to Mr. Gurganus, the seven-year outage cycle will permit several major components to be tracked and addressed, including the gasifier refractory replacement, combustion turbine inspections and steam turbine inspections.

Mr. Gurganus said DEI understands that building the full amount of the 2020 outage expense into base rates does not make sense given that it will only occur approximately every seven years. That outage timeframe led the Company to propose the inclusion of 1/7th of the planned maintenance cost into base rates—meaning the Company will recover the costs of the 2020 outage over the following seven years.

Petitioner's witness Douglas sponsored Exhibit 4-E (DLD) Schedule OM16, which normalized the Edwardsport planned outage expenses and removed $46.4 million from test period production maintenance costs for the incremental cost of the first major outage planned for the spring of 2020 at the Edwardsport Station. She testified the additional maintenance cost is not representative of an ongoing level of maintenance cost at the station and, therefore, the cost would be deferred in a major planned outage reserve account and amortized over seven years. Ms. Douglas added that while $46.4 million was removed for setting base rates because the costs weren't reflective of an ongoing yearly level of planned outage maintenance expense, they are reflective of the level of reasonable and necessary incremental planned outage maintenance expense that will occur at Edwardsport approximately every seven years.

Ms. Douglas indicated the retail portion of the production maintenance expense that is actually incurred for the 2020 spring major planned outage in excess of the remaining (after the *pro forma* adjustment) $4.7 million amount included in base rates for ongoing Edwardsport planned maintenance expense up to the $46.4 million forecasted amount be deferred in a regulatory asset account for amortization and cost recovery over seven years. In this way she asserted the revenue requirements for customers will be smoothed out, and the Company will be able to recover its reasonable and necessary maintenance costs for serving customers. She added the Company is not requesting carrying costs in rate base, just deferred recovery of the expenses over time. Ms. Douglas noted the Company's proposed base rates include a forecasted amount of amortization ($6.6 million) for the Edwardsport major planned outage reserve. She concluded this portion of her testimony by stating the Company's proposal provides a balanced way to afford the Company the opportunity to recover the reasonable and necessary costs of the 2020 major planned outage, while avoiding customer rate volatility by recovering the costs over time.

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.

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.

(A) <u>Commission Discussion and Findings</u>. We note that no party objected to the Company's request and as such based upon the foregoing evidence on this issue, 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 DEI or the $46.4 million forecasted amount.

ii. <u>Customer Connect Deferral Request</u>. Mr. Davey briefly summarized the Company's proposed cost deferral for Customer Connect, a new DEI customer service platform to be operational in late 2022. He indicated the enterprise-wide estimated cost of Customer Connect is $900 million and the amount allocated to DEI is estimated at $90-95 million, with approximately 50% reflecting the capital investment and the remainder, O&M. Mr. Davey testified the Company's proposal is to defer these costs with carrying costs until the Company's next retail rate case in which they will be recovered.

DEI witness Graft elaborated in her testimony regarding the proposed ratemaking treatment for the Customer Connect project. She said the Company has requested deferral of depreciation expense and post-in-service carrying costs at the weighted average cost of capital rate as regulatory assets until the related assets are deemed to be used and useful in a future rate case. The Company has also requested deferral of O&M and payroll tax costs incurred from 2018 and forward associated with development and implementation of the Customer Connect project, with carrying costs at the weighted average cost of capital rate, as regulatory assets to be held for recovery in a future rate case. The Company removed O&M and payroll taxes from the forecast test period and is instead seeking deferral with carrying costs.

Mr. Kollen recommended the Commission deny deferral of O&M incurred prior to the date new base rates are implemented in this proceeding, but recommended the Commission allow deferral on a going forward basis, without carrying costs, of O&M incurred after the date new base rates are implemented in this proceeding and until the Customer Connect project is placed in service. He also recommended denial of the Company's request to defer depreciation expense and post-in-service carrying costs.

Mr. Kollen argued the Company should not be allowed to defer previously incurred costs for future recovery upon implementation of new base rates in this proceeding because it would have a positive earnings impact in 2020 and in future years when rates are implemented recovering the deferred costs. He asserted that deferred depreciation, carrying costs on deferred O&M, and post-in-service carrying costs are unnecessary given there is no offset for the effect of declining rate base between rate cases.

Mr. Gorman recommended the Commission deny the Company's Customer Connect deferral request in its entirety. He suggested the Company seek rate recovery of the Customer Connect project and associated costs after implementation is complete. He expressed concern the Company has not proposed a cap on the capital portion of the Customer Connect investment and that without ongoing review, customers would ultimately pay more for the project under the

Company's deferral proposal than if the Company sought cost recovery after the project is in service. He asserted the Company did not provide sufficient information to support Commission approval of its CPCN request and in his opinion no legal basis exists to support the creation of regulatory assets associated with utility plant that is not yet in service.

DEI witness Graft testified the Company is not requesting a CPCN for the Customer Connect project, and no statutory authority exists for the Commission to issue a CPCN for these costs. Ms. Graft indicated that is why the Company is requesting deferral accounting authority in the context of this rate case.

Ms. Graft stated the Company agrees in concept with Mr. Kollen's recommendation to only seek deferral of its O&M and payroll tax costs on a going forward basis. However, she stated the Company defines going forward as 2019 and forward, not just from the date of implementation of new base rates in this proceeding and forward as Mr. Kollen proposed. Therefore, Ms. Graft indicated the Company is willing to forego recovery of its 2018 O&M and payroll tax costs of approximately $2.1 million for the Customer Connect project.

Ms. Graft clarified in rebuttal that the Company is still seeking authority to defer 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 in a future rate case. She noted the Company is requesting this accounting treatment in order to be made whole for this important investment that will help it better serve its customers. Ms. Graft added that only approximately $1.1 million of net plant in service (approximately $2.3 million of plant in service net of approximately $1.2 million in accumulated depreciation) has been included in rate base for Customer Connect in the forecast test period.

According to Ms. Graft, Mr. Kollen's argument that Commission approval of the Company's deferral proposal would have a positive earnings impact in 2020 and in future years when rates are implemented recovering the deferred costs ignores the negative impact to earnings in the years the deferred costs were incurred without any associated rate recovery or assurance of future rate recovery. She claimed Mr. Kollen's assertion that deferred depreciation, carrying costs on deferred O&M, and post-in-service carrying costs are unnecessary given there is no offset for the effect of declining rate base between rate cases does not consider that the Company's current customer information system has been fully amortized for some time.

Therefore, Ms. Graft indicated the Company's proposed base rates in this proceeding include very little for a return on and a return of its investment in a customer information system: an annual return on investment of approximately $65 thousand (associated with the approximately $1.1 million of net plant in service in the forecast test period) and an annual return of investment via amortization expense of approximately $0.6 million (associated with the approximately $2.3 million of gross plant in the forecast test period). Ms. Graft contended the Company should not have to absorb the capital and O&M expense associated with a project of this magnitude that is being implemented over several years, which is why it is seeking the requested deferral accounting authority.

Finally, Ms. Graft noted the Commission, OUCC, IG, and all interested parties will have the opportunity in a future base rate case to review the deferred costs to ensure they are reasonable, necessary, and prudently incurred. She concluded it is reasonable for the Company to request and for the Commission to approve deferral treatment associated with the Customer Connect project that will simplify, strengthen, and advance its ability to serve customers, all of which are a priority to the Company and the Commission.

(A) Commission Discussion and Findings. DEI has brought before the Commission in this proceeding its plan to put the Company's Customer Connect customer service platform into operation. Ms. Graft testified the Company has removed O&M and payroll taxes from the forecast test period and that an amount for the net plant in service in the forecasted test period has been included in rate base. DEI requests authority to defer with carrying costs a portion of its past and going forward 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. At the outset, we find that the timing of the request for deferral treatment does not support approval for O&M and payroll taxes incurred in advance of the test period in this proceeding. The evidence in this proceeding is that the Customer Connect platform is a substantial ongoing investment being undertaken that will reasonably enhance the Company's ability to serve its customers. The evidence also establishes that this platform is not expected to be operational until late 2022. Further, the project cost is made up of approximately 50% capital investment and 50% O&M. However, the evidence does not provide sufficient detail so as to identify the extent to which customer benefits will accrue with which components of the phased in project. Accordingly, we find that our support for the project is reasonable and proportionate with the likely customer benefits when we authorize the Company to defer O&M and payroll taxes beginning with those incurred in the test period, authorize the Company to defer depreciation and post-in-service carrying costs after the full project is declared to be operational, and for carrying costs on both deferrals at the Company's weighted average cost of capital. The Company shall make a compliance filing in this docket when the Customer Connect platform is declared operational.

iii. Major Storm Damage Restoration Reserve.

(A) Petitioner's Evidence. DEI 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 DEI 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.

Mr. Alvarez testified for the OUCC and suggested the Commission should deny the Company's request for a Major Storm Reserve unless the Company agrees to develop an operational plan to manage storm restoration activities. Mr. Alvarez recommends this operational plan should be integrated within the vegetation management and TDSIC programs. Assuming the Company agrees to develop the operational plan he suggests, Mr. Alvarez agrees with the Company's proposal to establish a Major Storm Reserve, but suggests the base level should be set at $6.0 million instead of $12.7 million. In the event the Company does not agree to establish Mr. Alvarez's new operational plan, or if the Commission denies the Company the authority to establish a Major Storm Reserve, Mr. Alvarez recommends that $5 million be embedded in base rates to represent an ongoing level for major storm expenses.

Company witness Hart responded in rebuttal to OUCC witness Mr. Alvarez's recommendations. She stated Mr. Alvarez's testimony is incorrect and unreasonable and that Mr. Alvarez claims that DEI's storm response has been imprudent, without any supporting evidence. Ms. Hart stated that she has been involved with the Company's storm response efforts for seven years and can attest that the Company's efforts are robust, efficient, and proactive. She testified that there are many problems with Mr. Alvarez's suggestion that the Company follow his recommended operational plan, including that the Company already has distinct workstreams and teams responsible for major storm response, vegetation management and TDSIC and that these teams collaborate frequently, when appropriate. In conclusion, Ms. Hart said the Company could not give the OUCC's position any consideration because Mr. Alvarez provided nothing but conjecture and insinuation and, therefore, the Commission should reject his proposal.

DEI witness Sieferman also responded in rebuttal to OUCC witness Mr. Alvarez's testimony in this area. She explained Mr. Alvarez's recommended $6 million level for the Major Storm Reserve appeared to be arbitrary and not supported by evidence. She stated the costs to restore service after major storms are both unpredictable and vary significantly year-to-year.

In addition, Ms. Sieferman further testified the Commission has approved similar Major Storm Reserve concepts for use by other Indiana electric utilities in recent base rate case proceedings. She noted Indiana Michigan Power Company was granted approval for a Major Storm Restoration Reserve in Cause No. 44075 and again in Cause No. 44967. She said the Commission also approved the creation of a Major Storm Damage Restoration Reserve for Indianapolis Power & Light Company in Cause No. 44576 and again in Cause No. 45029.

Finally, Ms. Sieferman stated Mr. Alvarez acknowledged the proposed reserve accounting balances customer and utility interests by providing a way for customers to pay no more (or less) than what the Company incurs for such restoration efforts and allows the Company an opportunity to potentially recover prudently incurred costs necessary to timely restore power after significant storms if that level exceeds what is built into base rates. She indicated storm restoration costs are volatile and highly dependent on storm events and therefore largely outside the Company's control. A Major Storm Reserve recognizes the difficulty with estimating this cost item, while assuring recovery of prudent costs.

(B) Commission Discussion and Findings. The Commission has approved major storm reserve ratemaking concepts like that proposed by DEI 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 *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.

Based upon substantial evidence of record provided by the Company and our experience with the regulation of other Indiana electric utilities which have experienced storm damage costs, we find that the Company should be authorized to set the base level for the Major Storm Reserve at the five-year historical average annual amount of $12.7 million 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. 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 probably 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 DEI 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.

Mr. Kollen testified for the OUCC on this issue. He recommended the Commission reject the Company's request to retroactively defer the costs since in 2019 until base rates are reset in this proceeding. Mr. Kollen also argued that a deferral will harm customers and will allow the Company to record a windfall to income in 2020 in exchange for harming customers in the form of increased customer rates when base rates are reset in the next base rate case proceeding.

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 DEI'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.

(A) <u>Commission Discussion and Findings</u>. We find the Company's evidence persuasive that GAAP accounting rules for pensions require the Company to accelerate the recognition of these expenses when a settlement occurs. We agree the Company is being proactive in identifying that these settlement events will reoccur in future years and will result in "lumpy" expense recognition if we do not approve the requested deferral. Accordingly, we find that DEI should continue to defer these costs and recognize them in a manner consistent with how these costs would otherwise be recognized.

v. **Incremental Vegetation Management Deferral Request.** Ms. Graft testified that Petitioner is seeking the deferral and amortization over three years of forecasted distribution vegetation management O&M costs incurred in 2020 in excess of the amount in current base rates for the period before the Company's revised base rates are implemented.

OUCC witness Mr. Kollen testified the Company is seeking to increase its distribution vegetation management O&M in 2020 by $18.4 million annually, calculated by doubling the $9.2 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 $5.2 million, which represents half of the total *pro forma* increase to test period expense Petitioner proposed.

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.

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 $9.2 million divided by the proposed three-year amortization period).

(A) Commission Discussion and Findings. DEI has requested creation of a deferred asset for an expense that it may incur before the rates approved in this order are made effective and that would be in addition to the forecasted test period amount of the same expense because the Company intends to move to a level of activity that reflects the forecasted period before the revenue from the ordered rates is available to provide for such pre-rate order expense. While we have stated elsewhere in this order our understanding of the critical value of vegetation management for service reliability, we have several case specific concerns with this request. Our discussion above regarding vegetation management expressed our concern regarding the historical unacceptable performance of the Company such that we have signaled with our ROE award an incentive to utility management to improve its performance. Absent evidence of such improvement we are not inclined to provide compensation that assumes such improvement. Additionally, above we created a balancing account that in part addresses concerns that planned vegetation management expense levels will not develop as planned. While we recognize that there are many budgetary reasons for not meeting expenditure plans, we are not inclined to unnecessarily expose customers to such adjustments. Finally, at the evidentiary hearing in the proceeding, Commissioner Freeman asked Mr. Davey questions regarding a regulatory asset for the Dynegy buyout that was fully amortized in May of 2017. She questioned whether the Company had plans to return over-recovery related to the regulatory asset. Mr. Davey explained that for the regulatory assets proposed in this proceeding, the Company has proposed to stop such recovery once the regulatory assets are fully amortized and change rates using the Company's Credit Rider. However, at the time of the prior rate case when the Dynegy asset was last addressed, there was no such provision in the order requiring a rate change outside of a base rate case when regulatory assets were fully amortized. Mr. Davey indicated that was not the practice at that time and most costs go up in between rate cases and some costs go down and in between rate cases rates are not changed. This particular cost went down and was material, but there was no provision requiring a rate change. Tr. B 85-88. The counter of Mr. Davey's position can also apply. Accordingly, based on the facts and evidence presented in this case, we deny the Company's request for the creation of a deferred asset for incremental vegetation management expense.

vi. <u>316(a) and 316(b) Deferral Request</u>. Mr. Mosley testified the Company has requested recovery through the ECR Rider of its prior expenses related to 316(a) and 316(b) studies that it previously deferred on its books. He indicated that in the Company's last rate case $30,000 in annual compliance expenses were built into base rates. However, starting in 2018, there have been two demonstration studies required during NPDES permitting. Mr. Mosley's testimony describes the federal mandate, the federally mandated compliance projects, and how the projects will help DEI comply with the federal mandate.

Ms. Graft also testified on this issue. She said the Company is requesting timely recovery of 80% of the retail portion of the 316(a), 316(b), and NPDES program study costs that must be expensed through the consolidated Rider 62. The Company is requesting to defer the 20% of the retail portion of the 316(a), 316(b), and NPDES program study costs that must be expensed as a regulatory asset with carrying costs at the weighted average cost of capital for recovery in a future rate case.

In addition to seeking to recover the costs of these two studies, Mr. Mosley indicated the Company requested the authority to defer its future 316(a), 316(b) and NPDES compliance related expenses for future recovery in its ECR. To the extent that future studies are required by NPDES permits, then the expenses of those studies presumably would be similar to those already seen at Noblesville and Cayuga. Mr. Mosley stated DEI commits to filing a separate proceeding under the Federal Mandate statute should compliance projects be identified as part of the studies being performed for NPDES permit renewals. He added that the Company would also keep the Commission up to date on the 316(a) and 316(b) studies through its semi-annual ECR proceedings.

Ms. Armstrong argues in her testimony that the Commission should not approve DEI's request to defer its 316(a), 316(b) and NPDES-related compliance costs based on the contention that the Company did not comply with the federal mandate statute and get preapproval from the Commission prior to incurring them. She also argues that the future federally mandated 316(a) and 316(b) study costs the Company is seeking preapproval of should be denied as too uncertain. In addition, she asserts that the 316(a) and 316(b) costs are too small to include in future ECR proceedings and that it would be administratively burdensome to review them.

DEI 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 DEI 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 DEI 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").

(A) Commission Discussion and Findings. Based upon the weight of the evidence, we find that it is appropriate to allow the Company to defer its past and future 316(a), 316(b), and NPDES study costs for timely recovery as federally mandated costs in this rate case. We will also review the extent to which those expenses are reasonable and necessary when they are presented in the Company's ECR proceedings.

vii. SO_2 Emission Allowance Deferral Request. DEI 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. DEI 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.

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 DEI 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 DEI 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 DEI 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.

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.

(A) <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. For the reasons stated elsewhere in this Order, however, we reject the OUCC's proposed levelized approach for the recovery of this regulatory asset. Instead, we approve the Company's modified proposal to recovery of the regulatory asset over a twelve-year period.

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

First, Petitioner proposes two changes to the allocation of fuel costs that occurs in its FAC process (and impacts the sharing in the Rider 70 off-system sales process). The changes relate to the allocations the Company performs in after-the-fact post-dispatch analyses. Mr. Swez testified in support of these changes. He explained that currently the Company economically stacks, on an hourly basis, the demand (load) with available supply resources (actual generator production amounts). He stated that the unit stacking is prioritized based on average production costs, ranked lowest cost to highest cost. He explained that the model economically allocates the average production costs for serving native load. DEI proposes to change this stacking logic 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. The Company would continue to allocate costs for short-term commitment units, such as combustion turbines, on the existing average cost basis. According to Company witness Swez, this incremental cost logic proposed by the Company more appropriately recognizes that the cost of incremental non-native sales is related to the cost of incremental changes in generation output and will better align fuel cost allocation with actual dispatch and commitment operations. In other words, he explained, the Company is proposing this change because the current average cost-stacking logic does not comport with MISO's incremental dispatch logic. He emphasized that the Company is proposing this stacking change only for long-term commitment units because they are committed for, and predominantly serve, native-load customer requirements. He stated that the likely result of this change in stacking logic is that the minimum load block of long-term commitment units will be allocated to native load. He testified that it is appropriate to allocate this cost to native load given that native load will be entitled to the first call on all generation resources, and these units are committed for the benefit of native load. However, he noted, during periods of low native-load demand, when all minimum-load blocks exceed native-load demand, minimum-load blocks would be allocated to non-native sales. He concluded that this proposed incremental cost approach will better align post-analysis results to the actual dispatch logic used by MISO and will more equitably and appropriately allocate fuel costs between native and non-native sales.

In addition, Mr. Swez explained that Petitioner proposes to eliminate the two-pass stacking process and perform the stacking process exclusively in the Real-Time market, because long-term commitment units are unlikely to be entirely allocated to non-native when split into incremental cost blocks. Currently, Petitioner performs a two-pass stacking process, day ahead and real time. According to Mr. Swez, this two-pass process unnecessarily complicates cost allocation. He testified that this change improves native-load resource optionality to respond economically to deviations in real-time load or generation and recognizes the shift of additional no load costs that accompany the transition to incremental stacking.

Petitioner also proposes that the generic purchase-power procedures – the purchased power benchmark – established in Cause No. 41363 be permanently waived upon the effective date of the Commission's Order in this proceeding. Mr. Swez explained that the Company is making this proposal because the benchmark procedures established in Cause No. 41363 are outdated. He testified that the procedures were initiated at a time when the MISO energy market did not yet exist, and purchases were executed on a negotiated bilateral basis. Since then, he noted, the Company has become a full participant in the organized MISO energy market, and the Company purchases all of its energy requirements from the MISO. He stated that as a member of MISO, the Company's generation, along with all generation participating in the MISO day ahead and real-time energy markets, is economically dispatched and the Company's customers have access to all generation resources in MISO to meet their needs. He stated that purchases made from MISO are, by definition, the most economic purchase available to meet customer load. In addition, he testified that the impact of low natural gas prices and increasing renewable energy penetration has had a significant downward impact on the average market price of energy. He observed that these factors suggest that the risks the benchmark was intended to address have been heavily mitigated. Mr. Swez emphasized that this proposal in no way prohibits review of the Company's purchase-power transactions; the Company's purchase-power costs and its offers into MISO will continue to remain subject to review and approval in each FAC filings.

Finally, Mr. Swez discusses the Company's proposal that all PJM charges and credits related to its Madison Generating Station be recovered through, as appropriate, either its FAC Rider, its RTO Rider, or Rider 70. Mr. Swez explained that the reason for this proposal is that the Madison Station is physically located and connected to the PJM transmission grid. Energy from the Station is transferred to MISO using firm transmission service through a pseudo-tie. Because of this configuration period, DEI receives a settlement statement from PJM for charges and credits related to the Station's firm transmission, congestion and loss charges or credits, etc. He testified that Madison Generating Station is operated for the benefit of DEI customers, and as such, customers should be appropriately allocated associated revenues and costs. He noted that the unique situation at Madison was simply not envisioned at the time of the Company's last rate case. He stated that the Company's proposed change appropriately modifies cost and revenue tracking. Similarly, Mr. Swez testified, the Company proposes that costs and revenues associated with Madison Station be further modified because of changes to the MISO capacity market. Specifically, he stated that MISO recently received permission from the FERC to modify the way it values capacity resources located outside the MISO footprint. He testified that DEI and its customers could potentially be subject to a separation of zonal prices between the Indiana Zone 6 and the newly created PJM external zone, and this change could result in a mismatch in funds paid for the capacity obligation versus funds received from the Madison Station. Accordingly, the Company proposes that all capacity revenues and payments be allocated to native customers first, up to the level of capacity charges assigned to native load by MISO. Mr. Swez testified that under this proposal, regardless of the location of assets or source of capacity revenues, no capacity revenues would flow through Rider 70 non-native sharing mechanism until the native load charges have been met. Once that revenue requirement has been satisfied, further revenues from capacity sales and payments will be allocated as non-native margins and shared through Rider 70. If capacity charges for native load exceeds all capacity revenues, the differential will be recovered the same as it is today.

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 DEI's generating units, there is no improvement in efficiency resulting from DEI's proposal. Therefore, with no improvement to operational efficiency resulting from DEI 's proposal, Dr. Boerger stated, the evaluation of its stacking proposal must come down to whether it is fairer for more no-load costs to be allocated to native load customers compared to non-native sales. Based upon his review, he testified, 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.

Industrial Group witness Dauphinais recommended that the Commission reject DEI'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 DEI 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 an analysis of the dispatch economics of the Company's largest coal-fired units.

In rebuttal, Mr. Swez stated that the Company disagreed with the OUCC and Industrial Group's recommendation to reject its proposed change in stacking allocation. Mr. Swez reiterated that its incremental stacking proposal more reasonably allocates costs between native and non-native load. Mr. Swez explained that for plants with longer minimum run times, such as coal and combined cycle units, the decision to turn on the unit for an economic commitment is made with the viewpoint of achieving a positive margin over at least the unit's minimum run time, typically at least 3 days for long-term commitment generating units. He noted that it is typical for long-startup time units to return more revenue than cost during some hours of the day when they are "in the money," but return less revenue than costs in other hours, where the unit is "out of the money." He stated that as long as the amount of revenue is expected to be greater than variable costs over the entire commitment period of three days in this example, it is considered "in the money" and economic to turn on or run the unit. Mr. Swez explained that the Company's units with longer startup times, the coal and combined cycle units, have minimum run times that are typically longer than the MISO energy market timeframes of 24 hours for the Day-Ahead market, the market that is most often used to commit these units. Simply said, he stated, longer start-up units are expected to make money in some hours and lose money in other hours, with the overall margin over the entire commitment period summing to a positive amount. Mr. Swez explained why no-load costs generally should be excluded when long start-up time generators are allocated to non-native sales. He stated that no-load cost is a fixed cost of operating a generating unit, and it is not possible to generate net positive power without incurring the cost of fuel needed to keep boilers hot and turbines spinning (no-load costs). He noted that non-native sales occur only when generation in excess of what is required to serve native load is available (*i.e.* native load receives first call on all generation). He further stated that MISO dispatches generation based on incremental variable cost and does not generally consider the fixed no-load cost when calculating the locational marginal prices that determine generation revenue. He explained that under the current average cost stacking method, fixed no-load cost is commingled with variable operating cost when units are allocated to non-native sales -- this fixed/variable commingled cost is then matched with revenue received from MISO that excludes the fixed no-load cost. He testified that this can incorrectly cause the margin on a non-native sale to be negative. Mr. Swez emphasized that the assignment of no-load cost to native load follows principles of cost- causation in that the cost is incurred to provide native load with first call on all generation. Essentially, he concluded, the average production cost approach is asymmetrical and only serves to artificially and inaccurately reduce the fuel costs assigned to native rather than assign the costs appropriately. He added that there would still be situations when no-load costs for some long start-up time generating units would be allocated to non-native generation – for example, in hours where the amount of generation needed to serve native load was less than the sum of the minimum loads of the on-line long start-up time generating units. During these hours, he stated, no-load costs would be allocated to non-native generation. He also added that the proposed change in stacking methodology would not affect the fuel cost allocated to native load in every hour; in fact, for the year 2017, he testified, the proposed change would have affected the allocation of fuel cost only during the 14% of hours where excess generation existed.

Mr. Swez responded to Mr. Dauphinais' testimony concerning the stacking methodology proposal, as well. Specifically, he addressed Mr. Dauphinais' recommendation that the stacking proposal be approved only if the Company also agrees to credit retail customers with 100% of non-native sales margins. He agreed with Mr. Dauphinais, to the extent his recommendation pertained to traditional non-native sales to MISO, and not the new category of short-term bundled capacity and energy sales. He noted that in rebuttal testimony, the Company had revised its Rider 70 proposal to credit 100% of such traditional non-native sales margins to customers, and to continue the 50/50 sharing mechanism only for the new category of short-term bundled capacity and energy sales. He reiterated that changing to incremental cost stacking will more closely align the party that receives the benefit of running a unit with all the costs necessary to run the unit.

With regard to the OUCC's position on the purchased power benchmark, Mr. Swez testified in rebuttal that root cause analyses are extensive, very detailed, time consuming analyses completed only for significant generating unit outages and events. He stated it was unclear whether Mr. Eckert is proposing that the Company perform a root cause analysis on every outage of greater than 72 hours, or if he only wants the Company to submit root cause analyses that it completes. In any event, completing a root cause analysis for forced outages such as boiler leak repair or other repairs that are more routine in nature, unless the cause of the outage is very unusual, is unnecessary and would add an undue burden and undue cost. In sum, DEI does not agree to the OUCC's request to complete a root cause analysis for any forced outage greater than 72 hours in length. Rather, he testified, DEI will commit to continue to do what it does today; that is, DEI will discuss in FAC proceedings major forced outages of units of 100 MW or more lasting more than 100 hours, and will also provide the any root cause analyses that were performed. In addition, DEI will continue to supply the OUCC day-ahead and real-time unit offers and awards for the test days it selects. Mr. Swez stated that this has worked well and provides the OUCC and the Commission relevant information on outages that meet those established thresholds.

With respect to the OUCC's recommendation to continue to allow the OUCC 35 days to complete its FAC review and file FAC testimony, Mr. Swez testified that this schedule has worked well in the past and he has no concerns with this schedule going forward.

Mr. Swez next addressed the Sierra Club's recommendation that all of the Company's generating units should be "dispatched on an economic basis," not self-committed, or if it must self-commit units, then "Duke's own dispatch decision-making process should be readily transparent and justify the frequency of the unit's operation." He also addressed the Sierra Club's recommendation that the Commission open an investigation into the practice of self-commitment. He emphasized that DEI already commits the Company's generating units on an economic basis, except as required for unit testing, operational requirements, or other infrequent reasons. He testified that the process that the Company performs daily to inform the commitment status decision for each unit is designed to minimize the total customer cost by maximizing each unit's economic value. In addition, he stated, for units that are committed by MISO, they are also being committed on an economic basis using MISO's security constrained economic dispatch. Finally, he testified that units are dispatched on an economic basis between their minimum and maximum capability when not required to run at a specific output as would be necessary for unit testing, operation requirement, or other reasons. Mr. Swez testified that by using both "Economic" and "Must Run" commitment status offers for different units on different days and times, the Company is working to minimize the total customer cost by maximizing the generators total margin. He stated that when it is advantageous to do so, utilizing a commitment status offer of Must-Run in the MISO energy markets does not necessarily mean that a generating unit was not economically committed. He emphasized that the MISO Day-Ahead Market construct was never designed to forecast economic commitments beyond the next day. Accordingly, for units with longer or higher start-up costs, the MISO Day-Ahead Market will typically not result in a commitment of these generating units from an off-line state when being offered with a commitment status of Economic, even though they may be the most economic choice over a multi-day period. As a result, he testified, always using an Economic commitment status could at times cause either the lowest cost unit to remain off-line or uneconomic cycling of certain units across multiple days.

Mr. Swez also pointed out that Sierra Club witness Comings' economic dispatch analysis offered to support his testimony failed to take into account the realities of self-scheduling units and contained a number of significant and incorrect assumptions or errors.

Further, Mr. Swez noted that the Company's generating unit offers, including the commitment status offer as well as resulting dispatch of the units, are already the subject of review during the Company's quarterly fuel clause filing. In other words, there already is a process in place for this examination each quarter. In addition, he stated, the Commission has already specifically considered this issue in Cause No. 42685, finding that "for those units that must be committed for several days or even weeks at a time, self-scheduling at minimum load will guarantee reliable and predictable operation of the units. The remainder of energy available from those units between minimum and maximum operating range can be offered in the day-ahead and real-time markets for economic dispatch." Cause No. 42685 at page 9 (IURC; June 1, 2005). In sum, he testified, there is no need for the Commission to embark on another investigation of a practice that is reasonable, common and well understood.

i. <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 explained why 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. The OUCC objected to this proposal on the basis of fairness, because the change appears to be more likely to allocate more no-load costs to retail customers. The Industrial Group objected if the Company continued to retain a share of non-native sales margins, but did not have an objection if the Company credited non-native sales margins 100% to retail customers. Although we appreciate the OUCC's concern with potentially allocating more fuel costs to retail customers, we find that the Company's proposal is consistent with the allocation of costs to the groups of customers that cause such costs. We also note that in its rebuttal testimony, the Company agreed to credit retail customers with 100% of its traditional non-native sales margins. Accordingly, we approve the Company's proposal to change its stacking process to an incremental production cost basis for its long-term commitment generating units. However, in acknowledgment that the impact of this process change is uncertain, we direct the Company to include in its fourth FAC filing after the implementation of this process change an analysis of the impact.

We also approve the Company's proposal to eliminate the purchased power benchmark process directed in Cause No. 41363. No party objected to this proposal, and the Company demonstrated that circumstances have changed since we instituted the benchmark years ago. The creation of the benchmark established a process to allow review in the context of the statutory time constraints of the FAC proceedings. 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 explaination 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. The Company's dispatch decisions are reviewed regularly in FAC proceedings and we find that process affords a reasonable opportunity to review such decisions. We note that since the time of the hearing in this proceeding the Commission has opened a subdocket in the Company's FAC to take a detailed look at the Company's commitment decisions.

d. <u>OUCC Benchmarking Analysis and Performance Metrics Collaborative</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.

Dr. Dismukes included an analysis of the Company's production plant investment trends as compared to that of its peers in his Schedule DED-8. He stated the Company's net transmission plant investment compared to its peers was set forth in Schedule DED-9. 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.

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. 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% 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%; 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 recommending 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.

Mr. Jacobi disagreed with Dr. Dismukes suggestion that the Commission should take an in-depth review of the Company's production and distribution O&M and initiate a collaborative proceeding to discuss benchmarking metrics. He stated that while there can be valid uses for benchmarking against those in the industry, trying to set rates based on average costs or benchmark studies is not appropriate and concluded no separate collaborative regarding benchmarking is needed.

In regard to the Performance Metrics Collaborative, 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.

i. Commission Discussion and Findings. We appreciate that the collaborative envisioned affords a measured opportunity to explore many of the topics raised by the OUCC in a collaborative value-added process. The Commission views the collaborative process as an opportunity for all parties to dialogue on how to review utility operations. We anticipate that the collaborative will allow stakeholder dialogue of similar trend analysis as proposed by Dr. Dismukes. Accordingly, based on our experience with previously approved performance metric efforts, we find the DEI proposed collaborative is an administratively efficient path to accomplish the same effort review proposed by Dr. Dismukes. 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 Company, Commission, and customers. Thus, we find that DEI 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 DEI'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 shall be 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 DEI to make a progress update filing with the Commission within 90 days of the initial meeting of the collaborative. We also direct DEI 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.

e. Waivers of 170 IAC 4-1. 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.

i. Commission Discussion and Findings. The undisputed evidence presented in this case demonstrates that for the Company to successfully implement Customer Connect, the waiver requests outlined by Ms. Hunsicker are necessary, specifically with respect to 170 IAC 4-1-16(c)(2), 170 IAC 4-1-13(a)(1), and 170 IAC 4-1-16(e). Moreover, the Company has demonstrated that the customer protections at the heart of these IAC provisions will not be lost as a result of the waivers and implementation of Customer Connect.

f. <u>Affordability/Low-Income Collaborative</u>. Company witness Pinegar described the Company's current programs designed to help low income customers. These programs include allowing customers to make payment arrangements to spread out past due amounts, defer due dates, sign up for budget bulling payment plans, third party notification of bills and disconnection notices, and several specific low income assistance programs. Mr. Pinegar stated DEI offers three low income energy efficiency programs to help customers save on energy costs, including the Neighborhood Energy Saver Program, Agency Assistance Portal's program, and Low-Income Weatherization Program.

Mr. Pinegar also introduced DEI's Helping Hand program, through which the Company provides emergency energy assistance through the federal government's Low Income Home Energy Assistance Program ("LIHEAP"). Company witness Quick provided additional detail on the Helping Hand program, stating the Company's shareholders historically contribute about $200,000 per year, which in recent years has been augmented by settlement commitments to $700,000 annually from 2013 to 2017 and $600,000 in 2018. On cross-examination, Mr. Pinegar testified the amount of Helping Hand funding has been increased to $750,000. Ms. Quick detailed that the Helping Hand program provides financial assistance to eligible customers through a one-time $300 payment on a customer's account. She stated the Company has partnered with the Indiana Community Action Energy Assistance Program to distribute program funds to customers eligible for LIHEAP.

Mr. Pinegar acknowledged the proposed rate increase will impact low income customers the hardest, and DEI welcomes a collaborative discussion about ways to continue and ramp up energy assistance to low income customers. Mr. Pinegar explained the Company proposes to convene a Low Income Collaborative with interested stakeholders at the conclusion of this rate proceeding with a goal of introducing additional energy assistance for its customers.

Joint Intervenors' witness John Howat provided testimony on low-income affordability issues. Mr. Howat first recommended the Commission direct DEI to implement a comprehensive low-income bill payment assistance program. Mr. Howat asserted there is an electricity service affordability problem among DEI's lower income residential customers, and as a result, recommended DEI develop and make available a low-income rate that reduces low income customers' payments to a more affordable level. He suggested this be done pursuant to a tiered discount rate program. He also recommended the Company implement an arrearage management program that provides LIHEAP-eligible customers who carry an overdue balance with a reasonable opportunity to have those balances written down over time through timely payments on more affordable current bills.

Mr. Howat also recommended that the Company report monthly to the Commission and stakeholders a series of data points. Mr. Howat suggested the following data be filed: general residential and low-income customer accounts, billing, receipts, arrearages, notices of disconnections, bill payment agreements, disconnections of service for nonpayment, reconnections of service after disconnection for nonpayment, accounts written off as uncollectible, and accounts sent to collection agencies.

Ms. Quick stated, with regard to Mr. Howat's proposals about development of a low income rate and an arrearage management program, that the Company is not averse to discussing such issues with a broad set of stakeholders. For this very reason, the Company has proposed to convene a Low Income Collaborative with interested stakeholders at the conclusion of this rate case. Ms. Quick said the Company believes a Low Income Collaborative, occurring separate and apart from all the other issues involved in a rate case, will be the forum most likely to achieve broad consensus on ways to further assist low income customers.

Ms. Quick also addressed Mr. Howat's data collection proposal. She stated the Company already provides a significant amount of these metrics to Joint Intervenors and others pursuant to the IGCC-15 settlement, and all of the data is made public. Ms. Quick stated that the Company does not agree with Mr. Howat's proposal. However, Ms. Quick added the Company is willing to provide its current public report to the Commission going forward. Any further reporting issues are better left for the Low Income Collaborative.

Industrial Group witness Phillips explained his opposition to using a per kWh charge to provide for the recovery of the cost of Mr. Howat's proposed programs.

i. <u>Commission Discussion and Findings</u>. We appreciate the issues raised by Mr. Howat. We also appreciate the efforts DEI has made in the past with regard to low income customers as well as the commitment the Company has made with regard to addressing the issues raised by Mr. Howat, and other issues, in a Low Income Collaborative. We agree that a Low Income Collaborative presents a reasonable opportunity to reach a broad consensus. As such, we decline to direct the adoption of Mr. Howat's proposals. However, we encourage DEI in its efforts to convene a Low Income Collaborative with all interested stakeholders. 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 shall be authorized to participate in the collaborative without being subject to 170 IAC 1-1.5-3 and -4.

g. <u>Contractor Policies</u>. David Frye, Business Manager of the Indiana Laborers District Council ("ILDC") testified regarding changes that he believed would need to occur in DEI'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 DEI 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.

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 DEI 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 DEI 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 DEI 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.

i. <u>Commission Discussion and Findings</u>. We have reviewed and considered the evidence from ILDC witness Mr. Frye and the rebuttal testimony from DEI witnesses Hart and Mosley. That evidence supports our finding that the Company already has in place procurement policies that prioritize contractors with cost effective service, increased productivity and minimized turnover of its work force. Therefore, we conclude that it is not necessary or appropriate for us to mandate that DEI use local residents as contractors or require it to implement a new Responsible Contractor Policy as proposed by ILDC.

17. <u>Confidentiality</u>. DEI 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. DEI is authorized 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 increase to its rates and charges of $145.867 million (excluding changes in items remaining in riders and the utility receipts tax) which represents an increase in operating revenues of 5.7%. Said rates will produce total jurisdictional electric operating revenues of $2,716.648 million and, on the basis of annual jurisdictional electric operating expenses of $2,134.502 million will result in annual jurisdictional electric utility operating income of $582.145 million. DEI is 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.[10]

2. DEI 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, DEI shall file new schedules of rates and charges with the Energy Division of the Commission. For Step 2, DEI 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 60 days following the date of verification of actual used and useful property to state any objections to DEI'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. DEI is authorized to recover in its retail electric rates the following deferred costs, 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, DEI is authorized to defer, for subsequent recovery in its retail electric rates, the following costs: Edwardsport IGCC outage costs; Customer Connect costs; pension settlement costs; and 316(a) and 316(b) compliance-related costs, all as discussed and approved in this Order. In addition, DEI shall establish and maintain a Major Storm Reserve and Vegetation Management Expense Reserve as set forth in this Order.

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

5. DEI 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. DEI is authorized to implement the rate design proposals and tariff changes as approved in this Order.

7. DEI 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.

8. DEI is authorized to utilize a base cost of fuel of 26.955 mills per kWh and a net operating income of $582,145,000 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, DEI is authorized a permanent waiver of the purchased power benchmark requirements. The OUCC is

[10] The numbers are subject to refinement pending the division reviewed and approved order directed compliance filings of Ordering Paragraph 2.

granted a 35-day period to review Petitioner's FAC applications and to file OUCC testimony in such proceedings.

9. DEI is directed to participate in a collaborative process involving Commission Staff and other parties concerning performance as provided in this Order.

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

HUSTON, FREEMAN, KREVDA, OBER, AND ZIEGNER CONCUR:

APPROVED: JUN 29 2020

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

Mary M Becerra

Mary M. Becerra
Secretary of the Commission