FILED
December 3, 2019
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF INDIANA MICHIGAN POWER COMPANY, AN INDIANA CORPORATION, FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN RATE ADJUSTMENT; AND FOR APPROVAL OF RELATED RELIEF INCLUDING: (1) REVISED DEPRECIATION RATES; (2) ACCOUNTING RELIEF; (3) INCLUSION IN RATE BASE OF QUALIFIED POLLUTION CONTROL PROPERTY AND CLEAN ENERGY PROJECT; (4) ENHANCEMENTS TO THE DRY SORBENT INJECTION SYSTEM; (5) ADVANCED METERING INFRASTRUCTURE; (6) RATE ADJUSTMENT MECHANISM PROPOSALS; AND (7) NEW SCHEDULES OF RATES, RULES AND REGULATIONS.	)	**CAUSE NO. 45235**

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR'S PROPOSED ORDER

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

Respectfully submitted,

Tiffany T. Murray
Attorney No. 28916-49
Deputy Consumer Counselor

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ORDER OF THE COMMISSION

Presiding Officers:
David L. Ober, Commissioner
Carol Sparks Drake, Senior Administrative Law Judge

On May 14, 2019, Indiana Michigan Power Company ("Petitioner," "Company" or "I&M") filed a Petition with the Indiana Utility Regulatory Commission ("IURC" or "Commission") seeking authority to increase its rates and charges for electric utility service and associated relief as discussed below.[1] The Petition included a request for administrative notice. On May 14, 2019, Petitioner also filed its Case-in-Chief, workpapers and information required by the minimum standard filing requirements ("MSFRs") set forth at 170 Ind. Admin. Code ("I.A.C.") 1-5-1 *et seq.* The following witnesses filed testimony and exhibits:

- Toby L. Thomas, President and Chief Operating Officer for I&M
- Andrew J. Williamson, Director of Regulatory Services for I&M
- David A. Lucas, Vice President Finance and Customer Experience for I&M
- Nancy A. Heimberger, Financial Analyst Senior Staff in Corporate Planning and Budgeting for American Electric Power Service Corporation ("AEPSC")
- David S. Isaacson, Vice President of Distribution Operations for I&M
- Q. Shane Lies, Site Vice President of the Donald C. Cook Nuclear Plant for I&M

[1] On April 10, 2019, I&M provided its notice of intent to file a rate case in accordance with the Commission's General Administrative Order 2013-5.

- Timothy C. Kerns, Managing Director – Generating Assets for I&M
- Kamran Ali, Managing Director of Transmission Planning for AEPSC
- Jason A. Cash, Accounting Senior Manager in Corporate Accounting for AEPSC
- Aaron L. Hill, Director of Trusts and Investments for AEPSC
- Roderick Knight, Decommissioning Manager for TLG Services, Inc.
- Michael N. Kelly, Manager – Taxes of Tax Accounting and Regulatory Support for AEPSC
- Robert B. Hevert, Partner of ScottMadden, Inc.
- Franz D. Messner, Managing Director of Corporate Finance for AEPSC
- Jeffrey W. Lehman, Electric Transportation Program Manager for AEPSC
- Chad M. Burnett, Director of Economic Forecasting for AEPSC
- Tyler H. Ross, Director of Regulatory Accounting Services for AEPSC
- Jennifer C. Duncan, Regulatory Consultant Principal in the Regulated Pricing and Analysis Department for AEPSC
- Michael M. Spaeth, Senior Regulatory Consultant in the Regulated Services Department for AEPSC
- Matthew W. Nollenberger, Manager, Regulated Pricing and Analysis for AEPSC
- Kurt C. Cooper, Regulatory Consultant Principal for I&M

On June 26, 2019, the Commission issued a Prehearing Conference Order, which established a procedural schedule and other requirements for this Cause.

Petitions to Intervene were filed by I&M Industrial Group, an ad hoc group of the following customers: Air Products, General Motors LLC, I/N Tek L.P., Marathon Petroleum Company LP, Messer LLC, Praxair, Inc., and University of Notre Dame du Lac ("IG" or "Industrial Group"); the Kroger Company ("Kroger"); Steel Dynamics, Inc. ("SDI"); Wal-Mart, Inc. ("Walmart"); Citizens Action Coalition of Indiana, Inc. ("CAC"), Indiana Community Action Association ("INCAA"), (collectively "CAC-INCAA"); City of Fort Wayne, Indiana, City of Marion, Indiana and Marion Municipal Utilities (collectively, "Marion" and, with Fort Wayne, collectively the "Joint Municipal Group"); City of South Bend, Indiana ("South Bend"); 39 North Conservancy District ("39 North"); Wabash Valley Power Association, Inc.; and City of Auburn Electric Department ("Auburn").

These petitions were granted without objection. Alliance Coal, LLC ("Alliance") and the Indiana Coal Council, Inc. ("ICC") also filed Petitions to Intervene, which petitions were subsequently granted over I&M's objection. The Indiana Office of Utility Consumer Counselor ("OUCC") also participated as a party.[2]

Public field hearings were held on July 11, 2019 in the City of South Bend, on July 15, 2019 in the City of Muncie, and on July 16, 2019 in the City of Fort Wayne, the largest municipality in Petitioner's Indiana service area. At the field hearings, members of the public were afforded the opportunity to make statements to the Commission.

[2] While the International Brotherhood of Electrical Workers Local 1392 ("IBEW") was granted leave to intervene, the IBEW subsequently sought leave to withdraw from this proceeding, which request was granted by Docket Entry dated August 19, 2019.

On August 20, 2019, the OUCC and certain Intervenors filed their respective cases-in-chief. The OUCC provided testimony and exhibits from the following witnesses:

- Lauren M. Aguilar, Utility Analyst
- Anthony A Alvarez, Utility Analyst
- Cynthia M. Armstrong, Senior Utility Analyst
- Wes R. Blakley, Senior Utility Analyst
- Michael D. Eckert, Assistant Director of the OUCC Electric Division
- Michael Gahimer, Senior Utility Analyst
- David J. Garrett, Managing Member of Resolve Utility Consulting, PLLC
- Mark E. Garrett, President of Garrett Group Consulting, Inc.
- John E. Haselden, Senior Utility Analyst
- Kaleb G. Lantrip, Utility Analyst
- Margaret A. Stull, Chief Technical Advisor in the Water/Wastewater Division
- Glenn A. Watkins, President and Senior Economist of Technical Associates, Inc.

The I&M Industrial Group provided testimony and exhibits from the following witnesses:

- Brian C. Andrews, Senior Consultant with Brubaker & Associates, Inc. ("Brubaker")
- James R. Dauphinais, Consultant and a Managing Principal with Brubaker
- Michael P. Gorman, Consultant and a Managing Principal with Brubaker
- Nicholas Phillips, Jr., Consultant and a Managing Principal with Brubaker

Kroger provided testimony and exhibits from the following witness:

- Justin Bieber, Senior Consultant for Energy Strategies, LLC

Walmart provided testimony and exhibits from the following witness:

- Steve W. Chriss, Director, Energy Services for Walmart

The CAC-INCAA provided testimony and exhibits from the following witnesses:

- Kerwin L. Olson, Executive Director of CAC
- Jonathan F. Wallach, Vice President of Resource Insight, Inc.

The Joint Municipal Group provided testimony and exhibits from the following witnesses:[3]

- Constance T. Cannady, Executive Consultant at NewGen Strategies and Solutions, LLC.
- Douglas J. Fasick, Senior Program Manager, Utilities Energy Engineering and Sustainability Services for the City Utilities Division for City of Fort Wayne, Indiana
- Joseph A. Mancinelli, President and Chief Executive Officer of NewGen Strategies

[3] The Joint Municipal Group also submitted a Motion for Administrative Notice with its case-in-chief.

and Solutions, LLC.

South Bend provided testimony from the following witnesses:

- Therese Dorau, Director of Sustainability for the City of South Bend
- Theodore Sommer, Partner with LWG CPAs and Advisors
- William Steven Seelye, managing partner for The Prime Group, LLC

39 North provided testimony from the following witness:

- Reed W. Cearley, special utility consultant for 39 North

Auburn provide testimony from the following witness:

- Edward T. Rutter, Manager with LWG CPAs and Advisors

ICC provided testimony from the following witness:

- Emily S. Medine, Principal for Energy Ventures Analysis, Inc.

On September 17, 2019, the OUCC and Intervenors filed their respective cross-answering testimony. The OUCC provided cross-answering testimony and exhibits from the following witness:

- Glenn A. Watkins

The I&M Industrial Group provided cross-answering testimony and exhibits from the following witness:

- Nicholas Phillips, Jr.

Kroger provided cross-answering testimony and exhibits from the following witness:

- Justin Bieber

CAC-INCAA provided cross-answering testimony and exhibits from the following witness:

- Jonathan F. Wallach

South Bend provided cross-answering testimony from the following witnesses:

- Therese Dorau
- William Steven Seelye

Alliance provided testimony from the following witness:

- Stephen Norfleet, Principle and Senior Project Manager with RMB Consulting and Research, Inc.

I&M subsequently moved to strike the Alliance testimony on the grounds that such testimony was not proper cross-answering testimony and the filing thereof violated the requirements governing the Alliance intervention. I&M's motion was subsequently granted in part by Docket Entry dated September 27, 2019.

On September 17, 2019, I&M filed rebuttal testimony, exhibits and workpapers for the following witnesses:

- Kamran Ali
- Chad M. Burnett
- Andrew R. Carlin, Director of Executive Compensation & Benefits for AEPSC
- Jason A. Cash
- Kurt C. Cooper
- Jennifer C. Duncan
- Robert B. Hevert
- Aaron L. Hill
- David S. Isaacson
- Timothy C. Kerns
- Jeffrey W. Lehman
- Q. Shane Lies
- David A. Lucas
- Matthew W. Nollenberger
- Tyler H. Ross
- Michael M. Spaeth
- Toby L. Thomas
- Andrew J. Williamson

Requests for Administrative Notice filed by I&M and the Joint Municipal Group were granted.

Pursuant to the notice of hearing given as provided by law, proof of which was incorporated into the record by reference and placed in the official files of the Commission, a public evidentiary hearing in this Cause commenced on October 7, 2019 and continued on October 10, 11, 15, 16, 17, 21, 22, 23 and 24, 2019. At the evidentiary hearing, the direct, cross-answering, rebuttal and administrative notice materials were offered and admitted into the record. Thereafter, the parties submitted their proposed orders and post-hearing filings in accordance with the post-hearing briefing schedule.

The Commission, based upon the applicable law, the evidence herein, and being duly advised, now finds as follows:

1. <u>Notice and Jurisdiction.</u> Due, legal and timely notice of all public hearings in this Cause were given and published as required by law. I&M is a public utility as defined in Ind.

Code § 8-1-2-1(a). Pursuant to Ind. Code §§ 8-1-2-23, 42 and 42.7 the Commission has jurisdiction over I&M's additions and improvements to plant and its rates and charges for retail utility service. Therefore, the Commission has jurisdiction over Petitioner and the subject matter of this proceeding.

2. Petitioner's Organization and Business. I&M, a wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP"), is a corporation organized and existing under the laws of the State of Indiana, with its principal offices at Indiana Michigan Power Center, Fort Wayne, Indiana. I&M is engaged in, among other things, rendering electric service in the States of Indiana and Michigan. I&M owns and operates plant and equipment within the States of Indiana and Michigan that are in service and used and useful in the generation, transmission, distribution and furnishing of such service to the public. Petition, ¶¶ 1-2.

I&M provides electric service to approximately 468,000 retail customers in the following northern and east-central Indiana counties: Adams, Allen, Blackford, DeKalb, Delaware, Elkhart, Grant, Hamilton, Henry, Howard, Huntington, Jay, LaPorte, Madison, Marshall, Miami, Noble, Randolph, St. Joseph, Steuben, Tipton, Wabash, Wells and Whitley. In Michigan, I&M currently provides retail electric service to approximately 129,000 customers. In addition, I&M serves customers at wholesale in the States of Indiana and Michigan. I&M's electric system is an integrated and interconnected entity that is operated within Indiana and Michigan as a single utility. I&M's transmission system is under the functional control of PJM Interconnection, L.L.C. ("PJM"), a Federal Energy Regulatory Commission ("FERC") approved regional transmission organization ("RTO"), and is used for the provision of open access non-discriminatory transmission service pursuant to PJM's Open Access Transmission Tariff ("OATT") on file with the FERC. As a member of PJM, charges and credits are billed to AEP and allocated to I&M for functional operation of the transmission system, management of the PJM markets including the assurance of a reliable system, and general administration of the RTO. As a PJM member, I&M must also adhere to the federal reliability standards developed and enforced by the North American Electric Reliability Corporation ("NERC"), which is the electric reliability organization certified by the FERC to establish and enforce reliability standards for the bulk power system. ReliabilityFirst ("RF") is one of eight NERC Regional Entities and is responsible for overseeing regional reliability standard development and enforcing compliance. I&M's transmission facilities are wholly located with the RF region. Petition, ¶¶ 3-6.

I&M renders electric service by means of electric production, transmission and distribution plant, as well as general property, equipment and related facilities, including office buildings, service buildings and other property, all of which is used and useful in the generation, purchase, transmission, distribution and furnishing of electric energy for the convenience of the public. I&M's property is classified in accordance with the Uniform System of Accounts ("USOA") as prescribed by FERC and adopted by this Commission. Petition, ¶¶ 7-8.

3. Existing Rates. I&M's existing retail rates in Indiana were established pursuant to the Commission's May 30, 2018 order in Cause No. 44967 based upon test year operating results for the twelve months ended December 31, 2018. The petition initiating Cause No. 44967 was filed with the Commission on July 26, 2017. Therefore, in accordance with Ind. Code § 8-1-

2-42(a), more than fifteen months has passed between the filing of I&M's Petition in this Cause and I&M's most recent request for a general increase in its basic rates and charges.

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

5. **I&M's Requested Relief.** In its case-in-chief, I&M requested the Commission to approve an overall annual increase in revenues from its base rates and charges, including rate adjustment mechanisms, in the total amount of approximately $172 million. I&M proposed to implement the requested revenue increase in three phases: Phase I would increase revenue by approximately $82.5 million; Phase II would reflect a revenue increase of approximately $129 million; and Phase III (which would be effective January 1, 2021) would reflect the final revenue increase of approximately $172 million. As detailed in the Petition and Company's case-in-chief I&M also requested Commission approval of specific accounting and ratemaking relief, including updated depreciation accrual rates and a new rate adjustment mechanism to track advanced metering infrastructure ("AMI") investment. Petition, ¶¶ 21-24.

6. **Opposition, Cross-Answering and Rebuttal.** OUCC and Intervenors presented numerous challenges to the Company's filing, including challenges to rate base, depreciation rates, rate of return, operating and maintenance ("O&M") expenses, rider proposals, cost of service allocation, rate design, and tariffed terms and conditions. The extent to which these parties disagreed with each other was addressed in their respective cross-answering testimony. The Company's disagreement with the OUCC and Intervenors was addressed in I&M's rebuttal evidence.

OUCC witness Michael Eckert provided testimony regarding the OUCC's overarching concerns about I&M's rate request in this proceeding. He stated the OUCC and the hundreds of ratepayers who submitted comments are gravely concerned about the immediate financial impacts of I&M's requests. Eckert, 4. Mr. Eckert noted that the Indiana General Assembly has declared a policy that specifically recognizes affordability of utility services for present and future generations of Indiana citizens, under Ind. Code § 8-1-2-.05. *Id.*

Mr. Eckert stated the Commission is charged with the task of balancing the interests of the utilities and ratepayer interests. *Id.*, 4-5. He pointed out the magnitude of this case combined with the last rate case order in 2018. *Id.*, 5. Mr. Eckert requested the Commission examine the various components of I&M's requests and determine if they are really necessary and prudent at this point in time, or if some of these expenditures should be implemented more gradually.

He testified that the OUCC urges the Commission to maintain its flexibility as stated in the Vectren Order (*In re S. Ind. Gas & Elec. Co.*, Cause No. 45052, Final Order, p. 26 (Ind. Util. Regulatory Comm'n Apr. 24, 2019)) and its ability to require sufficient evidence, especially in light of Indiana's new focus on its emerging energy policy and that the Commission should only approve requests that are necessary and reasonable. *Id.*, 6.

7. Petitioner's Rate Base. I&M's proposed Indiana jurisdictional net original cost rate base at December 31, 2020, is approximately $4.95 billion.[4] This proposed rate base includes materials and supplies, fuel stock and allowance inventory, deferred gain on the Rockport Unit 2 sale, certain deferred income taxes, regulatory assets and liabilities, and a prepaid pension asset.[5]

As discussed below, the OUCC and/or certain intervenors challenged the continued inclusion of the prepaid pension asset in rate base, the proposed AMI deployment, distribution investment, the enhancement of the Rockport Dry Sorbent Injection ("DSI") system, the Rockport Coal Combustion Residuals ("CCR") Compliance Project, the replacement of the High Pressure Turbine at Rockport Unit 2, the South Bend Solar Project, and the nuclear decommissioning study/rate case expense regulatory asset. We discuss these contested issues below.

A. Advanced Metering Infrastructure ("AMI").

1. I&M. Mr. Thomas and Mr. Isaacson explained the Test Year infrastructure investment includes the Company's initial phase of the AMI deployment, which will continue through 2022. Thomas Direct, 19; Isaacson Direct, 28. Mr. Thomas stated the estimated capital cost of the total AMI Project over the three-year period is approximately $93.6 million. Thomas Direct, 19; see also Williamson Direct, 36.

As discussed by Mr. Thomas, AMI is also referred to as "smart grid" or "smart metering" because it enables two-way communication between the meter and the utility's central systems. Thomas Direct, 20. He stated this enables the utility to have more accurate information about system operating conditions for operation and planning purposes as well as electricity usage to provide timely information to customers. *Id.* Mr. Thomas added the AMI infrastructure comes with a customer engagement platform that enables the consumer to have better insight into the consumer's electricity usage and cost. *Id.* Mr. Thomas explained AMI deployment is consistent with the industry and the transition to "smart" technologies enables a fundamental change in the way the Company operates, serving as the necessary foundation upon which the Company will provide more reliable service, improved customer experience and greater efficiency opportunities for I&M's customers in the future. Thomas Direct, 21-38. Mr. Isaacson elaborated on the operational, reliability and customer benefits of AMI and the Company's deployment plans. Isaacson, 23, 25, 28-33. Mr. Lucas described how AMI technology will provide access to data that I&M will use to inform and empower customers to make better decisions about their electric consumption habits and manage their monthly budgets and explained the Company's plan for customer notification and education. Lucas Direct, 17, 38-48.

Mr. Thomas testified the Company's existing AMR meters are at the point where they are in need of replacing. He said given the age of the existing meters, I&M considered whether to continue to replace failing meters with AMR or move to the next generation of technology. Thomas Direct, 22-23. Mr. Thomas stated in making the decision to move to AMI, the Company

[4] I&M Ex. A-1, 1; Ex. A-6, 1.

[5] In rebuttal, Mr. Kerns testified the $159.190 million (including allowance for funds used during construction ("AFUDC")) forecasted cost for the Rockport Unit 2 SCR should be adjusted to $122.676 million (including AFUDC) based on a revised cost estimate presented in Cause No. 44871 ECR-3. Kerns Rebuttal, 9.

recognized that over the past decade AMI technology has matured, its pricing has stabilized and its importance to system reliability has increased. *Id.*, 23. Mr. Thomas stated three years is the period reasonably necessary to efficiently and cost-effectively obtain the necessary resources for the project, install the technology and IT systems and implement the associated consumer education and functionality. *Id.*, 23-24.

2. OUCC. Mr. Alvarez reviewed the Company's AMI proposal and recommended the capital ($14.167 million) and O&M ($2.410 million) associated with I&M's AMI deployment be removed from the Test Year and that the Commission require I&M to study and quantify AMI's operational benefits and use this to perform a cost-benefit analysis prior to granting approval for full deployment. Alvarez, 2, 4-28, 38. His analysis showed that I&M's proposed AMI deployment lacks the basic financial justification that would allow the Commission, the OUCC, and other interested parties the opportunity to review and evaluate its reasonableness. *Id*. 2, 5-8. He testified I&M did not complete a cost-benefit analysis for its proposed AMI deployment; rather, I&M provided an analysis it characterized as generic and using generic template and inputs. *Id*., 5. Mr. Alvarez discussed I&M's AMI deployment plan for Michigan and expressed concern about using that plan as a basis for the Indiana deployment. *Id.*, 5-8, 16-17. He testified I&M provided a partial AMI deployment plan for its Michigan territory as a substitute plan for its proposed AMI deployment in Indiana. *Id*., 5-8. The results of his review of I&M's Michigan Plan showed it did not quantify the operational benefits including the financial and rate impact, and it also failed to articulate and describe the goals and objectives including the success criterion of the plan. *Id*., 7-8, 16-17. Mr. Alvarez concluded the Michigan Plan contained insufficient information to evaluate and inappropriate data to support whether ratepayers should fund any AMI deployment project in Indiana. *Id*., 7-8. He stated that using a rough sketch project template designed for another jurisdiction to implement in Indiana is inadequate without offering a plan identifying and quantifying benefits specific for Indiana. *Id*. He explained that using the Michigan Plan could set the Indiana AMI deployment on a path towards project cost escalations due to poor project scope definition and a general lack of understanding of location-specific nuances. *Id.*, 8. This is because it lacks defined ratepayer and operational benefits, success criteria, articulated objectives, quantified cost and benefits, and definitive project milestones, and therefore, it should not be used. *Id*. Mr. Alvarez described the magnitude of the proposed AMI meter deployment in Indiana would be much larger and more complex than in Michigan, and merely attempting to implement a scaled-up version of the Michigan Plan can lead to unintended consequences for Indiana because any oversight or defect in the Michigan Plan would tend to be magnified in a larger and more complex deployment in Indiana. *Id*. With such a poorly defined plan, he stated, it would be difficult for regulators to determine if the implementation is appropriate and decide which policy and operational changes are most beneficial and important to ratepayers, and it would be difficult for the Commission to establish equitable future looking regulations with such a defective plan.

Mr. Alvarez testified I&M previously deployed AMI in its Indiana service territory through its Smart Meter Pilot Project ("SMPP") conducted in 2009, and issued a final report "SMPP: Process and Impact Evaluation Report" ("SMPP Report") in 2011. *Id.*, 8-14. He discussed the primary objectives of the SMPP to gain operational experience with various smart grid technologies, including AMI, and evaluate any effect on reliability, distribution grid management, and customer service operations, and I&M's aim to define the effects of consumer programs on energy consumption and customer access to their own usage data. *Id*. He pointed to the SMPP report findings that any future deployment should use the existing SMPP installation to determine how to increase customer participation; otherwise, without substantial customer interest and participation, the benefits of the deployment would not outweigh the costs. *Id*., 12. Mr. Alvarez explained the SMPP Report recommended that, before expansion of the SMPP or other AMI projects could be considered, I&M confirm customers were interested in and supported AMI programs to the point that the program is cost justifiable. *Id*. He stated the SMPP Report recommended commercial and industrial customers engage, participate, and understand the energy cost benefits from a smart grid application, and identified a need to develop a business case for any AMI deployment in the future that encompassed all aspects of the deployment. *Id.*, 9-13. He explained that I&M's prior business modeling of the SMPP overestimated (25%) its customers' interests versus the actual program participation rate (2.2%) and the report concluded that, absent compelling reasons to believe I&M customers would embrace the benefits of AMI and smart grid technology, the deployment benefits would not outweigh the costs. *Id.*, 12. Mr. Alvarez proposed if the Commission approves I&M's proposed deployment over the OUCC's objections, the Commission should approve only the proposed 2020 deployment as a pilot program to be evaluated within the context of a collaborative involving Commission technical staff, the OUCC and interested parties. *Id.*, 17-18.

3. Intervenors. The Joint Municipal Group, South Bend and CAC-INCAA also recommended the Commission disallow the Test Year AMI capital and operating expenses and contended that AMI deployment should not be approved without a detailed cost/benefit analysis. In the alternative, the Joint Municipal Group recommended that the AMI costs be deferred until the actual detailed costs can be evaluated. Cannady Direct, 4, 29-32; Sommer, 5, 33-36; Wallach, 4, 7-10. Mr. Sommer stated he had seen nothing that proves to him that AMR meters are unreliable or will soon fail at an unreasonable rate. Sommer, 34. South Bend's witnesses contended the proposed costly upgrade to AMI readers is not a prerequisite for successful implementation of the PEV tariff as I&M's current AMR meters will support the PEV off peak tariff. Dorau, 17; Sommer, 35. Mr. Wallach testified I&M has not provided any evidence in this Cause that the proposed AMI investments are expected to be cost-effective over the life of the investments. Wallach, 8-9.

Walmart witness Chriss testified Walmart generally supports the deployment of "smart" metering and appreciated the Company's efforts in this regard. Chriss, 29. He recommended the Commission make transitioning away from hours-use rates a near-term priority and include a stakeholder process to explore this transition as part of the conditions of approval of AMI deployment in this Cause. Chriss, 5, 29-30.

4. Rebuttal. Mr. Thomas explained why he disagreed that the used and useful standard Indiana uses in a general basic rate case should be replaced with a formulaic assessment of whether the benefits of an infrastructure project exceed the cost thereof. Thomas Rebuttal, 12-13. He also explained why it is difficult to quantify the economic value of the incremental benefits and undertake a meaningful cost-benefit analysis of infrastructure investments such as AMI, particularly where the benefits of moving from manual to automated operations have already been achieved, as is the case for I&M. *Id.*, 13-15. Mr. Thomas testified the 2012 Ameren Illinois and Duke Energy Indiana AMI projects involved a transition from manual to automated options and these proceedings were not general rate cases. *Id.*, 15-18. Mr. Thomas discussed the robust "societal" cost beneficial test imposed in Illinois and stated that the

OUCC has not identified a sound reason for supplanting the used and useful standard with the Illinois approach. *Id.*, 16. Mr. Thomas stated the Duke Energy Indiana analysis was limited to the "hard" operational savings benefits I&M had already achieved for the benefit of I&M's customers. *Id.*, 17-18. He also disagreed with the implication that once I&M moved from manual to automated operations, the Company should discontinue its efforts to maintain its system consistent with ongoing development of technology and progress of the industry. *Id.*, 17. Messrs. Thomas and Isaacson explained the 2011 SMPP report was not a credible basis for rejecting I&M's AMI project now because circumstances have changed since the 2011 SMPP Report discussed by Mr. Alvarez, including the maturation of AMI technology to a point where this more advanced technology has supplanted AMR. Thomas Rebuttal, 18-19; Isaacson Rebuttal, 22-23. Mr. Lucas explained I&M has incorporated lessons learned from the SMPP report, while also taking into consideration more recent advances in technology and customer expectations in designing the programs proposed in this case. Lucas Rebuttal, 3-7.

Mr. Lucas also responded to the criticism of I&M's customer engagement strategy and customer experience benefit. Lucas Rebuttal, 3-5. He showed that a 2018 J.D. Power Survey found that utility customers that are aware they have a smart meter have a higher level of satisfaction and also stated that in March 2019, the U.S. Department of Energy Office of Electricity recognized key benefits of AMI. *Id.*, 5.

Mr. Thomas explained the generic draft analysis identified by the OUCC and CAC-INCAA did not consider a systematic transition from AMR to AMI deployment (the infrastructure investment issue here) and was not completed, vetted or used by I&M. Thomas Rebuttal, 19. He added this draft analysis shows what he already knew and had taken into consideration – the readily quantifiable "hard" benefits such as labor savings are relatively small given the existing AMR technology – and the qualitative benefits are substantial. *Id.*, 19-20. Finally, Mr. Thomas explained why he disagreed the AMI proposal in this general rate case should be addressed under the standards applicable to TDSIC plans and explained why he disagreed with the OUCC's characterization of the TDSIC standard and decisions. *Id.*, 20-21.

Mr. Isaacson explained why it would be unreasonable and impractical to replace I&M's existing AMR meters with something other than AMI meters. Isaacson Rebuttal, 18-19. He said with the emergence of AMI, AMR is a declining technology and is being phased-out industry wide. He noted nearly all vendors have stopped manufacturing and supporting AMR meters; currently there remains only one vendor that supplies I&M's type of AMR meters, and the vast majority of this vendor's business is AMI. He stated it is not reasonable to rely on a single vendor to provide AMR replacements for all of I&M's AMR meters reaching the end of their service life, especially when it is not known how much longer this vendor will continue to manufacture and support this equipment. He clarified that during I&M's proposed AMI deployment, approximately 35% of the existing AMR meters will reach the end design life of 15 years. Isaacson Rebuttal, 18. He said replacing AMR meters with AMR meters would put an outdated technology in service for possibly another 15 years and would deny any realized customer benefits that he discussed in his direct testimony. He concluded that as I&M's existing AMR meters begin to reach the end of their service lives, replacing them with AMI meters is the most reasonable action. Isaacson Rebuttal, 18.

Mr. Isaacson stated that the only question is whether I&M should replace AMR meters with AMI meters in a random, reactive way, which would be much more costly and inefficient and explained why the Company's proposed systematic, proactive deployment will minimize costs and maximize benefits for customers. Isaacson Rebuttal, 18-21. Mr. Isaacson explained why waiting to deploy AMI technology while another pilot program is conducted would only serve to delay the numerous operational and customer benefits associated with AMI technology. *Id.*, 19-20. Mr. Lucas also disagreed that a collaborative pilot is necessary but offered to engage with the OUCC on the design of programs such as time of use rates, peak load management, and pre-pay, prior to I&M's next base rate case. Lucas Rebuttal, 6-7. Mr. Isaacson disagreed with Mr. Alvarez' contention regarding the AMI Michigan project and Mr. Alvarez' assertion that I&M had not considered Indiana specific issues, explaining that in identifying the Michigan template, I&M was pointing out what was being done in Michigan because I&M will be able to leverage this experience to generate efficiencies, such as taking advantage of trained, contracted work force. Isaacson Rebuttal, 21-22. Mr. Isaacson also explained why simply replacing these AMR meters upon failure with AMI technology would not be efficient and would not allow either customers or the Company to fully realize the benefits of this new technology. Isaacson Rebuttal, 23.

5. Discussion and Finding. I&M proposes to upgrade its current AMR meters to more technologically capable AMI meters. This substantial investment also includes the associated communication infrastructure to enable the collection of meter usage data, back-end system upgrades, and provide education to customers on the information that AMI produces. I&M presents this deployment as inevitable and a "not if, but when" situation. Isaacson Rebuttal, 18-19. We disagree that AMI is a foregone conclusion at this time as presented by I&M. I&M provides a generic description of the AMI benefits, insisting that approving an organized deployment is the only path forward. *Id*. I&M has not provided a sufficient basis to support this investment.

Indiana applies a used and useful test to a utility's property including requests for approval of additions or improvements to its plant and equipment. Ind. Code §§ 8-1-2-6; 8-1-2-23. "The Commission's 'used and useful' standard requires: (1) that the utility plant be actually devoted to providing utility service, and (2) that the plant's utilization be reasonably necessary to the provision of utility service." *City of Evansville v. S. Ind. Gas & Elec. Co*., 339 N.E.2d 562, 589 (Ind. Ct. App. 1975) (citations omitted).

In this case, based on the information provided, we cannot conclude that the AMI deployment is reasonably necessary.

Notably, I&M failed to provide information that the costs of deployment outweigh the benefits of the project. Reciting the generic benefits of AMI does not provide sufficient basis to authorize AMI deployment. Isaacson Direct, 29-32, Isaacson Rebuttal, 23. Based on the magnitude and assumed impact of this project, we need a more robust record upon which to approve a project of this nature.

Additionally, I&M has already conducted a pilot and has failed to leverage its previous experience and recommendations from the SMPP Report. The SMPP report noted the difficulty of achieving significant levels of customer engagement in AMI-enabled programs. The customer engagement plan described by Mr. Lucas does not address how this significant level of customer participation will be achieved. Rather, he provides only a description of the information provided to customers before deployment and a high-level overview of the information provided on the platform. Lucas Direct, 39-42. I&M is proposing a significant change to its metering technology, with a significant capital outlay. However, I&M failed to adequately support this proposal, only providing generic descriptions of the AMI benefits, without a specific quantification of how this will impact customers in its Indiana service area. Without better information upon which to base our decision, we find the proposed AMI infrastructure investment is not reasonably necessary and decline to approve I&M's proposal.

In order for I&M to quantify the customer benefits, we direct I&M to conduct a pilot program as proposed by the OUCC. Moreover, this pilot would also function to allow I&M to develop its customer engagement to achieve higher levels of customer participation, which would improve the benefits of any AMI deployment. The pilot would build on the previous deployment, and would form the basis for any future AMI deployment.

B. Distribution System Asset Renewal, Reliability Improvements and Major Projects.

1. I&M. Company witness Isaacson presented an overview of the Company's distribution system, its condition, and the metrics the Company uses to measure the reliability of its facilities. Mr. Isaacson discussed the Company's distribution planning and presented the Company's Distribution Management Plan, which is a comprehensive, forward-looking capital and operations plan under which the Company is making significant investments to maintain and improve the reliability of its distribution system, to enhance public safety, and to leverage technology to benefit the grid. Isaacson Direct, 2, 3-27, 34-37. Mr. Isaacson explained that much of I&M's system was built in the 1960s and 1970s, when I&M's territory experienced growth. He said an increasing portion of assets are now reaching the end of their expected design lives. Mr. Isaacson testified although age alone does not determine when assets fail, assets are more likely to fail when they reach the end of their design life, and older assets can be harder to replace when they fail because it is often difficult to obtain available parts for aging equipment. He said older assets also pose safety risks from failures during operation. *Id.*, 4. Mr. Lucas also supported the distribution components of the Company's capital investment. Lucas Direct, 17.

2. OUCC. Mr. Alvarez recommended the Commission reject over $75.12 million in 2019 and 2020 distribution system asset renewal and reliability capital projects from rate base (and exclude associated O&M) until I&M provides adequate documentation and support for its proposed 2019 - 2020 Distribution Management Plan, Asset Renewal and Reliability Program. Alvarez, 3. He recommended I&M provide basic project information so the Commission, the OUCC, and other interested parties could evaluate the reasonableness or necessity of these projects. He also recommended the Commission reject $32.57 million in 2019 and 2020 distribution system major projects (and associated O&M) and require I&M to provide detailed project cost estimates with the corresponding approved Capital Improvement Requisition for each Major Project prior to approval. *Id.*

Mr. Alvarez reviewed the support I&M provided for its asset renewal and reliability programs. He testified I&M's Distribution Management Plan is set to be constructed in 2019 and

2020, but the reasonableness of the programs and projects cannot be credibly assessed because I&M did not provide detailed project scope information. He stated the cost estimate I&M provided was at high program level and not project level, which did not provide any further details or insights into the cost structure of these programs. *Id*., 21-23. Mr. Alvarez was concerned I&M merely provided brief descriptions of a program or individual project and the total project cost amount or total program expenditure per year, which were inadequate to determine the reasonableness of affording I&M cost recovery for these projects. He explained that I&M is seeking cost recovery of these proposed projects in a forward-looking test year therefore, is also seeking pre-approval for these projects. *Id*., 23-24. He stated the Commission, the OUCC, and other interested parties must have the ability to review the detail underlying this forecast to ensure ratepayers' interests were served by those investments and costs. Mr. Alvarez testified the OUCC solicited additional details through discovery and also met with I&M in Fort Wayne, Indiana to allow I&M the opportunity to provide adequate support for its projects. However, he explained, I&M's response indicated that the request was unduly burdensome and the meeting at I&M's offices in Fort Wayne, Indiana, on July 19, 2019 yielded no additional information adequate to support I&M's request. *Id*., 24-25. He stated the few project cost estimates I&M provided during the meeting appeared unreasonable because the indirect costs range from 55% to 62% of the total project costs. *Id*., 25-26. He concluded the cost estimates of these projects were excessive and unreasonable.

Mr. Alvarez reviewed I&M's Distribution Management Plan - Major Project Summary and found it impossible to determine the reasonableness of these projects because each scope of work was not well-defined and the distribution and transmission functions not clearly distinguished. *Id*., 30-33. He testified several of the projects do not have an approved internal Investment Requisition ("IR") from I&M management to indicate its management independently determined the scope and cost of the project and endorsed fund allocation to its construction; instead, it appeared that I&M is waiting for regulatory approval before it will authorize the allocation of funds. *Id*.

3. <u>Rebuttal</u>. Messrs. Thomas and Williamson explained the Company's case-in-chief and workpapers included the information required by the governing statute and MSFRs. Thomas Rebuttal, 3-4; Williamson Rebuttal, 40-51. Mr. Isaacson detailed the considerable support and documentation provided in the Company's case-in-chief and workpapers showing the reasonableness of I&M's Distribution Management Plan. Isaacson Rebuttal, 3-4, 8. Mr. Williamson and Mr. Isaacson also discussed the Company's meeting with the OUCC and other information provided to the OUCC through the discovery process. Williamson Rebuttal, 49-50; Isaacson Rebuttal, 4-8. Mr. Isaacson explained it is appropriate to use parametric estimates for the projects in the Asset Renewal and Reliability program (*e.g.*, poles, cross-arms, porcelain cutouts, cable) because the work has been performed repeatedly over many years. Isaacson Rebuttal, 7. He added that providing Class 2 cost estimates for projects two years out is unnecessary and would add costs needlessly. *Id.* Mr. Isaacson explained Mr. Alvarez' criticism of the distribution "indirect costs" appear to reflect a misunderstanding of the Company's definition of "indirect costs" and also fails to recognize the difference in how indirect costs are treated in contract labor costs compared to Company labor costs. *Id.*, 10. Mr. Isaacson clarified the major projects are more complex projects that I&M has identified as necessary to improve the reliability of the system, to improve the ability to serve increased load, and to promote safety and enhance the technological capabilities of I&M's system. *Id.*, 10-11. He

referred to the definition, documentation and other details provided in his direct testimony and in the Company's discovery responses. *Id.*, 10-11. He said the details included project justification, benefits, project start and end dates, total cost, material cost, internal and contractor labor cost, and total indirect cost and were consistent with the information provided in the Company's direct testimony in Cause No. 44967. *Id.*, 11. He explained while a Major Project can have a transmission component, all projects and costs in the Distribution Management Plan are distribution projects and do not include any transmission investment. *Id.*, 12.

4. Discussion and Finding. The OUCC presented evidence of its concerns that I&M did not provide sufficient information to evaluate the reasonableness of its proposed distribution projects. In a recent proceeding, we noted that "[the Petitioner] is reminded that it bears the burden of proof in demonstrating it is entitled to its requested relief." *Petition of City of Evansville,* Cause No. 45073, 2018 WL 6791622 *10 (Ind. Util. Regulatory Comm'n Dec. 19, 2018). I&M points to Ind. Code § 8-1-2-42.7 or the MSFR Rules as support for the information it filed. However, we note that Ind. Code § 8-1-2-42.7 does not provide a measure for the specificity of information provided in a proceeding. Rather, it provides general descriptions of the information to be provided in a utility's case-in-chief filing. Ind. Code § 8-1-2-42.7(b). Similarly, the MSFR rules, specifically 170 I.A.C. 1-5-9 and 1-5-10, provide a description of the type of information that a utility should provide in its rate case filings. It is the utility's burden to ensure that the information provided is sufficient to support its request, and parties can reasonably argue that a petitioning utility's evidence is not sufficient. In this instance, we find that the information is not sufficient.

I&M provided almost no information upon which to evaluate the proposed distribution projects. I&M did identify approximately 670 projects in Attachment DSI-1. However, the only information I&M provided in support were three pieces of information for each of these projects. First is the project description provided in Attachment DSI-1 to Mr. Isaacson's direct testimony. The project descriptions are extremely generic, and provide no support for the necessity of any project. Second is the scope of the project, measured in units, length in feet, or miles. Again, there is no information to show that the scope is necessary or needed. Third is the year in which the project will take place, 2019 or 2020. There is also the total cost for groups of the individual projects. This information is inadequate for any party to determine if the project is necessary or if it is scoped appropriately. The project descriptions are generic, and do not provide adequate information to properly judge the reasonableness of a project, and whether the scope of units or length is necessary. Mr. Isaacson also pointed to Ms. Heimberger and Mr. Lucas as providing additional information on forecasted distribution expenditures. Isaacson Rebuttal, 3-4.

However, I&M did not describe, nor can we determine, how the information presented by Ms. Heimberger and Mr. Lucas tie to the individual distribution projects. Therefore, there is no other information upon which we or any party can assess the projects, not even the cost for each of the individual projects. Likewise, the information presented for I&M's Distribution Management Plan - Major Project Summary was insufficient to determine the reasonableness of these projects. The scopes of work were not well-defined and the distribution and transmission functions not clearly distinguished in the descriptions. I&M notes that it did provide more detailed information on ten asset renewal and reliability distribution projects and seven major projects. Isaacson Rebuttal, 5. However, this information is out of approximately 670 asset renewal and reliability projects and twelve total major projects, providing incomplete support for these projects. Absent sufficient information upon which to make a proper evaluation of I&M's proposal, we cannot approve I&M's request. Accordingly, I&M's request for cost recovery of its proposed distribution system asset renewal, reliability improvements, and major projects is denied.

C. Rockport Enhanced Dry Sorbent Injection ("DSI") System.

1. I&M. Mr. Thomas explained both units of the Rockport Plant are equipped with flue gas scrubbing technology that uses DSI equipment to inject dry sorbent (sodium bicarbonate) into the flue stream to reduce hydrochloric acid ("HCl") and sulfur dioxide ("SO_2") emissions. Thomas Direct, 15. The Commission authorized the use of the DSI system at Rockport in Cause No. 44331. As stated by Mr. Kerns, the Rockport Plant utilizes the DSI system to meet reduced SO_2 emission limits required under the Plant's air permit. Kerns Direct, 24. He said this SO_2 limit becomes more stringent over multiple years, with lower SO_2 emission limit taking effect on January 1, 2018, and January 1, 2020. *Id.* He added that in response to the stepped reduction SO_2 limit, I&M will increase the injection rate of sodium bicarbonate. *Id.*

As discussed by Mr. Kerns, during the Test Year, the Company plans to place certain enhancements to the DSI system into service at an estimated capital cost of approximately $13.3 million, which is significantly less than the cost of the alternative control – a dry scrubber. Kerns Direct, 30; Thomas Direct, 17-18. Mr. Thomas testified this capital investment will enhance the performance of the DSI equipment by moving the injection point of the sodium bicarbonate into the flue gas stream upstream of its current location. Thomas Direct, 15. Mr. Kerns said the DSI enhancements will result in approximately an $8 million incremental increase in O&M expenses that is mostly consumables expense. Kerns Direct, 30-31. Mr. Thomas explained the enhanced DSI is required to comply with the Fifth Modification of the Consent Decree and stated that the project is a reasonable means of maintaining the availability of low cost, coal-fired generation that complies with environmental regulations, allows the plant to continue to serve customer needs provide jobs and taxes to the community, and does so in a manner that mitigates the rate impact on customers. Thomas Direct, 18-19.

2. OUCC. Ms. Armstrong recommended denial of I&M's request to include enhancements to the DSI systems on Rockport Units 1 and 2 in rate base and their associated O&M expenses. Armstrong, 1. Ms. Armstrong described the Consent Decree and explained the events leading up to its Fifth Modification. She explained that the original consent decree emerged to settle claims made by the U.S. EPA and the Department of Justice ("DOJ") that several of AEP's units had violated the New Source Review provisions of the Clean Air Act. *Id.*, 2-5. Although Rockport and several other larger AEP units were not a part of the litigation, she noted the settlement required AEP and its subsidiaries to undertake major investments in pollution controls on these facilities. *Id.*, 6.

Specific to Rockport, she explained that the original Consent Decree required I&M to install and continuously operate Flue Gas Desulfurization ("FGD") systems and Selective Catalytic Reduction ("SCR") systems on Rockport Unit 1 by December 31, 2017, and on Rockport Unit 2 by December 31, 2019. *Id.*, 3. However, AEP requested the third modification of the Consent Decree, which was approved on May 11, 2013, to delay the required installation of FGD systems for Rockport Units 1 and 2. *Id.*, 4. She testified that under the third modification, AEP was required to install and continuously operate DSI systems on Rockport Units 1 and 2 by April 16, 2015. *Id.* She expounded that the third modification also required one Rockport unit to retrofit with an FGD, re-power to natural gas, or retire by December 31, 2025, and the second unit was also required to retrofit, re-power, or retire by December 31, 2028. *Id.*

She explained that soon after the third modification, the investor group owners of Rockport Unit 2 sued AEP for breaching the lease agreement, and they claimed that AEP imposed an impermissible lien on the Unit and adversely impacted its economic useful life by entering into the modified Consent Decree. *Id*., 5. She noted that while the district court initially dismissed the owners' claims, the appellate court ruled in their favor. *Id.* She concluded that AEP was forced to seek another modification of the Consent Decree as a result of this litigation. She testified that all parties to the Consent Decree agreed to the modifications, and the Fifth Modification to the Consent Decree was approved by the court on July 17, 2019. *Id.* She explained that both units must now install an enhanced DSI systems in 2020 as well as meet more stringent emission rates beginning in 2021. She noted that while Rockport Unit 1 must still retrofit with an FGD, repower, or retire by December 31, 2028, Unit 2 is no longer required to install an FGD to continue operation beyond 2025. *Id.*

Ms. Armstrong contended that the Consent Decree was the only environmentally-related mandate requiring Rockport to install the enhanced DSI Systems. She testified that Rockport meets the Mercury and Air Toxics Standards ("MATS") and current National Ambient Air Quality Standards ("NAAQS") for fine particulate matter ($PM_{2.5}$) and sulfur dioxide with the existing DSI and Activated Carbon Injection ("ACI") systems. *Id*., 6. She also pointed out that I&M did not model the DSI Enhancements in its 2018 Integrated Resource Plan. *Id*., 9. She reasoned that the only manner in which a customer benefit to the DSI enhancement is realized is if the Rockport Unit 2 lease is extended, allowing the Unit to serve ratepayers beyond 2022. *Id*., 7.

Ms. Armstrong asserted that I&M is again asking ratepayers to fund the consequences of AEP's questionable management decisions. *Id*., 7. She stressed that AEP chose how to manage its non-Rockport generating facilities and to enter into the Consent Decree, which weighed down the Rockport Units with unnecessary environmental compliance costs. *Id.* She emphasized that AEP failed to communicate and obtain approval from the Rockport investors prior to signing the Consent Decree. *Id*., 7-8.

She disputed I&M's characterization of the Consent Decree as a beneficial deal for ratepayers in the past by arguing it allowed generating facilities to continue operation while avoiding the continued costs of litigation. *Id*., 7. She reasoned that it was speculative as to whether the Commission would have approved passing those litigation costs onto customers. *Id*., 8. AEP's questionable management decisions were made without input from ratepayers and Unit 2 investors. She stated that ratepayers were never given the opportunity to accept or reject the Consent Decree prior to AEP (and I&M) signing it. *Id.* She argued that AEP offered to construct the pollution control projects on Rockport as a way to reach agreement in the Consent Decree to the benefit of other AEP generating facilities and subsidiaries. She concluded that I&M should bear some of the risk of its management decisions. *Id*., 7-8.

Ms. Armstrong clarified that the OUCC is not recommending I&M terminate the Unit 2 lease early and that I&M should still take action to keep Rockport operational. *Id*., 11. However, for the purposes of the DSI enhancements, these costs should be borne by I&M's shareholders, as they receive the benefits of the Consent Decree modification. *Id.*

Ms. Armstrong also offered an alternative recommendation to deny the DSI enhancement costs for Rockport Unit 2, should the Commission approve the DSI Enhancements for Rockport Unit 1. *Id*., 11. She noted that I&M states the lease for Unit 2 will not be renewed and I&M has not taken steps to renew the lease. *Id.* She reasoned that only a short period of time exists between I&M's proposed schedule for installing the Enhanced DSI equipment and the Unit 2 lease expiration. *Id.* She concluded that I&M failed to establish that investing in Rockport Unit 2 provides a benefit to ratepayers during the short period of time over which these assets would be utilized. *Id.*

She noted that if Unit 2's lease were extended, it may be possible the project could be economical for ratepayers to fund the DSI Enhancements <u>if</u> those assets are necessary for environmental compliance and therefore preserve Unit 2's ability to serve I&M customers' needs for a meaningful period of time beyond 2022. *Id.* However, she re-affirmed that the OUCC stands by its position that I&M ratepayers should not bear the costs of pollution control equipment that are only necessary due to the Consent Decree and not required by any other environmental regulation. *Id.* By I&M's next rate case, Ms. Armstrong reasoned that the Unit 2 lease will have more certainty and I&M should be able to quantify the value of the service customers received from that Unit through 2022 or inform the Commission that the lease has been extended. She concluded that the parties can make an informed judgment about whether cost recovery for the DSI Enhancement is appropriate at that time. *Id.*

3. <u>Intervenors</u>. While the Industrial Group took no position as to the prudence or reasonableness of I&M's proposed installation of the enhancements to the DSI system at Rockport, Mr. Gorman noted a possibility that some portion of the Rockport Unit 1 costs can be recovered from the lessors. Gorman, 40-41. He recommended that if the Commission approves cost recovery for this investment it should require I&M to reimburse customers for any costs recovered pursuant to the terms of the lease. *Id.*

Alliance witness Norfleet argued Ms. Armstrong's analysis does not look at the fuller picture of how AEP's choices may impact the dispatch and retirement of plants ratepayers have funded and does not consider additional ways to mitigate the harm to ratepayers by requiring I&M to look for ways to keep Rockport Unit 2 in operation past the planned retirement date. Norfleet, 3.

4. <u>Rebuttal</u>. Mr. Thomas explained the OUCC recommendations are based on a flawed understanding of the Consent Decree and the manner in which it came about. Thomas Rebuttal, 21-22. He testified the execution of and modifications to the Consent Decree are not the result of "questionable management decisions," as alleged by Ms. Armstrong, but have been a series of actions taken by AEP to comply with evolving environmental requirements in a cost effective manner that have avoided the expenditure of billions of dollars. Mr. Thomas explained that the Rockport Units have gained a significant advantage by participating in the Consent Decree as the Rockport Units have the latest compliance dates of any units in the AEP

system for installing post-combustion SO_2 and NO_x controls and this means I&M customers will benefit from the proven performance of lower-cost DSI technologies that have only recently become available. Thomas Rebuttal, 22. Mr. Thomas testified regardless of whether the lease is renewed or not, the modest adjustment to the DSI system is reasonable because it optimizes the use of the existing equipment, relocates the injection point for the dry sorbent, takes advantage of mixing plates that are included in the SCR design for both units, and thereby significantly increases the achievable SO_2 removal efficiency. Mr. Thomas noted the continued uncertainty about future environmental requirements and said the DSI enhancements provide additional compliance margin for a new standard currently under review by the U.S. EPA. Thomas Rebuttal, 23-24.

Mr. Thomas stated the consequences of non-compliance with the terms of the Consent Decree would be severe because the units cannot comply with the thirty-day average emission rates if the DSI Enhancement Project is not in operation by the end of 2020. Thomas Rebuttal, 24. He said the lease requires I&M to return Rockport Unit 2 to the lessors at the end of the lease term in a condition to comply with all of the applicable environmental requirements. Thomas Rebuttal, 24. He added the lease was approved by the Commission and I&M must continue to comply with the lease through its full term. Thomas Rebuttal, 24. Mr. Thomas stated I&M's customers benefit more from the enhanced DSI system than they would from any alternative means of complying with the terms of the lease. Thomas Rebuttal, 24.

Mr. Thomas stated Ms. Armstrong confused two different versions of the Fifth Modification of the Consent Decree, explaining that Ms. Armstrong discussed a contested motion filed by AEP, not the settlement agreement among all parties that became the Fifth Joint Modification. *Id.*, 24-25.

With respect to the IG recommendation, Mr. Thomas stated that while it may be appropriate to credit I&M's depreciation accounts with amounts receive from the transfer of assets to the Lessors upon the expiration of the Rockport Unit 2 lease, it would be inappropriate to create a refund obligation to customers. Thomas Rebuttal, 25-26. He added that I&M will act in accordance with the requirements of the Lease and good accounting practice to reflect the appropriate amounts in the appropriate accounts.

5. Discussion and Finding. The OUCC has proposed disallowance of the DSI system enhancement costs through base rates, instead placing the cost burden on shareholders. While I&M argues that the Commission authorized the use of the DSI systems at both Rockport Units in its Order dated November 13, 2013, approving the settlement agreement in Cause No. 44331, the issue here is the costs related to the *enhanced* DSI ("EDSI"). While Ms. Armstrong testified in Cause No. 44331 that "[t]he DSI systems are necessary for I&M to comply with, MATS, CAIR, CSAPR, and the NSR Consent Decree," Cause No. 44331, Public's Exhibit No. 2, 16, the EDSI project is solely the product of the 5th Modification to the Consent Decree, which did not exist in 2013.

The OUCC agrees that I&M should take action to keep Rockport operational and not terminate the Unit 2 lease early. The OUCC's recommendation that shareholders bear the expense of the EDSI is based on the reasonable fact that the EDSI may not be installed on Rockport Unit 2 until the lease on that unit is close to termination. Once the lease is terminated, it will not provide electric service for the benefit of I&M's customers. I&M argues that its analysis of plant investments on Rockport Unit 2 demonstrates these investments, including the EDSI project, continue to be more economic than terminating the lease early. That may be true, but it is not the inquiry at hand. The question is rather whether ratepayers should bear the cost of the EDSI projects when those projects (1) are not required by any environmental edict other than I&M's involvement in the Consent Decree and (2) may only be in service for a year before the lease on Unit 2 is terminated. By I&M's next rate case, the OUCC reasoned that the Unit 2 lease will have more certainty and I&M should be able to quantify the value of the service customers received from that Unit through 2022 or inform the Commission that the lease has been extended.

We agree with the OUCC that I&M should bear the EDSI costs. I&M's decision to enter into another modification of Consent Decree did not include the Commission, the OUCC, or other interested intervenors. Instead, I&M entered into another modification to mollify its investors, relying on the argument that it must comply with the dictates of the Consent Decree. We agree – I&M must comply with the terms of the Consent Decree. But we also find that the current likelihood that the lease will be terminated (currently scheduled for 2022) and the fact that the EDSI might only be in service for a year before that occurs lead us to agree that I&M should not recover the cost of the EDSI through customer rates. I&M chose to enter into the Consent Decree to placate its investors. That decision should therefore be supported by those who benefit from that decision – I&M's shareholders.

D. Rockport Coal Combustion Residuals ("CCR") Compliance Project.

1. I&M. Mr. Kerns testified the CCR rule imposes construction and operating obligations, including location restrictions, liner criteria, structural integrity requirements for impoundments, operating criteria, and additional groundwater monitoring requirements to be implemented on a schedule spanning an approximately four-year implementation period. He said Rockport's compliance with the CCR rule – which primarily consists of the discontinued use of the east bottom ash pond and inciting closure – is currently projected to be completed by May 31, 2020 at a total cost of $4.069 million (including AFUDC). Kerns Direct, 14.

2. OUCC. Ms. Aguilar testified that I&M should not earn a return on closure activities as a capital expenditure. I&M's closure of the east bottom ash pond at Rockport does not involve installing new equipment, it is not used and useful, and does not further the generating capabilities of the Rockport units. Aguilar, 23. I&M could not provide assurances that the project would be completed during the test year, as it had not received a closure plan approval from the Indiana Department of Environmental Management. *Id.*, 27. Ms. Aguilar recommended the Commission deny I&M recovery of its requested $4,069,000.

3. Rebuttal. Mr. Kerns testified I&M continues to refine the details of the forecasted CCR project, and said it is possible that some of the forecasted capital costs will be reclassified as fuel or closure costs. Kerns Rebuttal, 8. He said I&M can confirm that at least $798,000 (including AFUDC) of the forecasted $4,069,000 (including AFUDC) are properly classified as capital costs and will not be reclassified. As for the remaining $3,271,000, he said

I&M is amenable to removing this amount from I&M's forecasted rate base in this proceeding and addressing these costs in future I&M regulatory proceedings. Kerns Rebuttal, 8-9.

4. Discussion and Finding. We find I&M's rebuttal position reasonably addresses the OUCC's concerns. Accordingly, we find I&M's rate base should include $798,000 (including AFUDC) associated with the CCR project. I&M may address the remaining CCR project costs in future regulatory proceedings.

E. Rockport Unit 2 High Pressure ("HP") Turbine Replacement Project.

1. I&M. Mr. Kerns explained this project involves rebuilding the Unit 2 HP turbine, including the installation of the system spare turbine rotor and inner shell (inner block) and blade carriers during a scheduled Unit 2 outage in 2020. He said the 1300 Series turbines have a service life of eight to ten years based on good engineering practices. He stated this project is forecasted to be placed in service by June 1, 2020 at a total cost of $1.323 million (including AFUDC). Kerns Direct, 15.

2. OUCC. Mr. Alvarez stated it is unreasonable to ask ratepayers to fund the replacement and/or rebuild of the turbine that will provide I&M's customers with electricity only through 2022. He recommended removal of $1.323 million (including AFUDC) in capital expenditures and all O&M expenditures associated with the HP turbine replacement project. Alvarez, 4, 36-37. He was concerned with I&M embedding the replacement costs for Rockport Unit 2 HP turbine in the forecasted Test Year because I&M already found it inadvisable to extend its lease for Rockport Unit 2 beyond December 2022. *Id.*, 36. He stated that from a ratepayer's perspective, I&M's proposition is a bad deal because, after the lease ends in 2022, I&M will continue collecting (and ratepayers will continue paying) the return on and of its investment far beyond 2022. *Id.*, 37.

3. Rebuttal. Mr. Kerns stated not rebuilding the Unit 2 HP Turbine exposes I&M and its customers to more risk. Kerns Rebuttal, 5. He explained with a turbine rebuild in 2020, the HP turbine will remain below the 80,000 service hour threshold and retain the risk assessment ranking of "Notice" (<10% probability of failure). He said it is prudent utility practice to avoid a turbine failure (which would cause extensive damage and result in a lengthy forced outage) and that the HP turbine rebuild project is the reasonable course of action regardless of whether the Unit 2 lease will expire at the end of 2022. Kerns Rebuttal, 6-7. He added that failure to rebuild or replace the HP turbine subjects I&M to the risk of future litigation should the work not be performed. *Id.*, 8.

4. Discussion and Finding. While I&M argues that the Rockport Unit 2 HP Turbine Replacement Project is consistent with prudent utility practice and avoids increasing the risk assessment ranking for the turbine, we share the OUCC's concern with the proposed cost recovery of the project, rather than the necessity of the turbine replacement itself. The record shows that I&M expects the new turbine to be in service by June 1, 2020 and that the Rockport Unit 2 lease is set to expire at the end of 2022. Therefore, the new turbine will only be in place for 30 months before I&M loses the lease of Rockport Unit 2. Based on this short time frame, we agree with the OUCC that it is unreasonable to allow for recovery of this expense for

such a short time, and allow continued recovery after the lease ends. Accordingly, we deny I&M's request to recover the total cost of this project, estimated to be $1.323 million.

F. South Bend Solar Project ("SBSP").

1. I&M. Mr. Kerns testified that if the SBSP is approved by the Commission in Cause No. 45245, it is forecasted to be placed in service by December 31, 2020 at a total cost of $29.303 million (including AFUDC). Kerns Direct, 13.

2. OUCC. Mr. Blakley recommended that the cost of I&M's SBSP be removed from rate base in this proceeding based on the OUCC's recommendation in Cause No. 45245 that if any recovery is approved for such costs, recovery should be accomplished through a renewable energy rider, which Mr. Blakley testified will provide valuable information and cost data on renewable energy technologies. He stated I&M would receive the benefit of a return "of" and a return "on" through the rider while at the same time ratepayers would benefit from accumulated depreciation applied to lower plant investment and recalculation of earnings. He also testified Indiana law permits a wide variety of different clean energy resources and a renewable rider would make it easier to evaluate and gain a better understanding of costs associated with renewable technologies. Blakley, 11-15.

3. Rebuttal. Mr. Williamson explained that I&M disagrees with the OUCC's proposal to track the SBSP and said he expects the Commission to decide this issue in the separate pending case. He recommended for purposes of this rate case that the SBSP project costs be included in rate base, as proposed by I&M, if the project is approved. Williamson Rebuttal, 68.

4. Discussion and Finding. The record shows that if the SBSP is approved by the Commission in Cause No. 45245, it is forecasted to be placed in service during the Test Year. The issue before us is whether the Commission should decide the accounting and ratemaking for the SBSP in the instant case or in Cause No. 45245. Developments in Cause No. 45245 aid this determination. The Commission takes administrative notice that on October 31, 2019, a docket entry was entered in Cause No 45245 which granted the unopposed joint petition to re-open the record in that proceeding to receive a settlement agreement of all issues among all the parties. Accordingly, we find it reasonable for purposes of this rate case that the accounting and ratemaking for the SBSP project be based on the outcome of Cause No. 45245.

G. Prepaid Pension Asset.

1. I&M. Aaron L. Hill, Director of Trust for AEPSC, testified in support of the continued inclusion in rate base of Petitioner's prepaid pension asset. He noted this treatment is consistent with the Commission's Orders in Cause Nos. 44967 and 44705. He said the prepaid pension asset is defined as the cumulative cash contributions to the pension fund in excess of the cumulative pension cost. Hill Direct, 37. He explained the process for forecasting the prepaid pension asset, including forecasted contributions and costs.

2. OUCC. Margaret A. Stull recommended the Commission reject I&M's proposal to include its $84,244,007 "prepaid pension asset" in rate base. She explained that a "prepaid pension asset" is not a defined term in the Financial Accounting Standards

Board's ("FASB") Accounting Standards Codification ("ASC"). Stull, 3. She testified that the term incorrectly implies the existence of an asset that I&M does not actually record as a separately identified asset on its balance sheet – whether historic or projected. Ms. Stull stated that ASC 715 requires an employer to recognize the "funded status" of its defined benefit pension in its balance sheet; "funded status" is the difference between (1) plan assets at fair value and (2) the benefit obligation. If an employer is funding less than its benefit obligation, the company will record a liability, and if an employer's defined benefit pension plan funding exceeds its obligation, the company will record an asset. *Id.*, 4. Ms. Stull testified that AEP has two defined benefit pension plans – a "qualified" plan and an "unqualified" Supplemental Employee Retirement Plan ("SERP") referred to as the "Excess Benefit Plan" and she described the current status of each as well as quantified I&M's share. She explained that the information I&M provided in its MSFR workpaper 1-5-8(a)(14) varied considerably from the funded status reported in response to OUCC discovery. *Id.*, 5.

Ms. Stull explained that there is no "prepaid pension asset" reflected on I&M's 2018 historical balance sheet as I&M claimed. While I&M reflects an amount for a prepaid pension asset it is offset by another account. Therefore, the total amount of "prepaid pension asset" included in I&M's balance sheet is zero. *Id.*, 7 - 8. She described the difference between the "prepaid pension asset" amounts included I&M's direct testimony and that in discovery. *Id.*, 8 – 9. Ms. Stull testified that I&M provided no calculation or support for how the "prepaid pension asset" was determined, and that there is no mention of a "prepaid pension asset" in AEP's defined benefit pension plan actuarial reports. She reported that I&M was able to provide only a partial calculation of its "prepaid pension asset" from 2006 to 2018 but that I&M should be able to support the entire "prepaid pension asset" as the "asset" is substantial and represents 28.21% of I&M's requested non-utility plant rate base. *Id.*, 11. She further explained that I&M made no effort to identify or support the portion of its "prepaid pension asset" provided by investor-supplied capital, nor has it made any alternative proposals to address "prepaid pension assets" as the Commission stated in Cause No. 44576. Ms. Stull reviewed the previous regulatory treatment for "prepaid pension assets" in Indiana, noting that the Commission approved I&M's request for rate base treatment in Cause No. 44075. She explained that the Commission made no findings expressing how the "prepaid pension asset" qualified to be included in rate base under the strictures of Ind. Code § 8-1-2-6, and that the Indiana Court of Appeals' memorandum opinion affirmed the Commission's decision without addressing how the "asset" qualified to be included in rate base. She testified that the OUCC advocates against including a "prepaid pension asset" in rate base because this "asset" is not used and useful plant under Ind. Code § 8-1-2-6, and it cannot be considered inventory, a prepaid asset, or working capital. *Id.*, 14.

Ms. Stull stated that the OUCC's position in this case is consistent with the idea that some ratemaking treatment may be appropriate regarding pension contributions in excess of pension cost. She explained that this departure from the OUCC's past position is to recognize the disconnect between the amount of pension cost as determined by US GAAP, and the amount of pension contributions required by ERISA. She testified that under current regulation, companies are required to provide pension funding at a faster pace than they are required to recognize pension costs. As a result of this disconnect, Ms. Stull expects that "prepaid pension assets" are likely to grow; continuing to allow rate base treatment for this type of "asset" is not sustainable or realistic. *Id.*, 16. She explained that both rate base and capital structure treatment for a "prepaid pension asset" unnecessarily increases net operating income, operating revenues, and income tax expense to the detriment of ratepayers. To recognize the disconnect between ERISA and US GAAP requirements and make I&M whole without incurring additional cost that ratepayers must bear, Ms. Stull proposed an increase to I&M's proposed pension expense to offset the impact of I&M's excess required pension contributions. She explained that her adjustment is based only on the cumulative amount of ERISA minimum contributions in excess of cumulative pension cost, and not discretionary contributions because if those contributions are related to timing, they will reverse in the near future and if they do not reverse, it is unreasonable to burden ratepayers with higher rates to provide a ratemaking benefit to the utility. Ms. Stull calculated a $1,909,822 increase to pension expense. *Id.*, 19. She also calculated an adjustment to accumulated deferred taxes in I&M's capital structure to recognize the effect of her expense adjustment on I&M's temporary tax liability. *Id.*, 23.

At the close of her testimony, Ms. Stull offered additional considerations regarding whether a fully funded pension plan is necessary or desirable. She testified that 100% pension plan funding is not necessary to have a strong or secure plan, and that there are risks to this funding strategy. She stated that in the event of a market crash, regulated utilities will expect ratepayers to pick up the tab to replace lost pension funds, despite the fact that ratepayers have no say in the utility's pension funding goals. She offered that a better use of funds today might be the investments in utility infrastructure or maintenance costs. Ms. Stull also testified that the difference between pension costs recorded for financial statement purposes and the amount of pension costs included in I&M's revenue requirement makes I&M's US GAAP calculation difficult to rely on and could result in customers paying more than the actual cost of providing I&M's defined benefit pension plan. She recommended that for ratemaking purposes, any "prepaid pension asset" should be based on the accumulated pension costs (both capital and expense) included in I&M's revenue requirement rather than the pension cost included in I&M's financial statements. *Id.*, 25.

3. <u>Intervenors.</u> IG witness Michael Gorman objected to the inclusion of a prepaid pension asset in I&M's rate base. Gorman, 10. Mr. Gorman noted that the Commission, in prior orders, had addressed the appropriateness of including a prepaid pension asset in rate base. Mr. Gorman noted that had permitted certain utilities to include a prepaid pension asset in its rate base, Mr. Gorman testified that I&M has not demonstrated that its prepaid pension asset was funded by investor capital nor justification of why I&M should be allowed to earn a return on the asset. Gorman, 12. He testified to the extent the contributions are funded by ERISA minimum funding requirements, the costs had already been recovered through rates and not supplied by investor contributions. He also testified to the extent the return on pension trust assets was large enough to offset the pension service costs and interest costs, that this also was not funded by investors. *Id*., 13. Mr. Gorman testified that I&M has failed to provide any evidence that the utility investors funded the pension asset that were not fully recovered from customers and thus are entitled to a return on this asset. *Id*., 14.

4. <u>Rebuttal.</u> Petitioner's witness Hill noted that I&M's cumulative pension cost is greater than the cumulative minimum ERISA contributions, and so the minimum required contributions are not included in the prepaid pension asset. Furthermore, he noted that minimum required contributions are a legal obligation and would still need to be included even if they did make up a part of the prepaid pension asset. Hill Rebuttal, 16-17. He further objected to Ms. Stull's alternative calculation of pension expense, which he called a fictitious and

hypothetical cost calculation. *Id*., 19. He described the prepaid pension asset as prepayment of an allowable cost which directly reduces annual pension costs. He said the reduction for 2018 was approximately $5.1 million, and for 2020 was forecasted to be approximately $7.7 million. *Id*., 22. He explained without the prepaid pension asset, 2020 pension costs would instead be projected to total nearly $13 million. He said if the Commission were to exclude from rate base the prepaid pension asset, these savings should be removed from the cost of service as well as the benefits from their compounding effects. *Id*., 23. He also stated the contributions and return result in the avoidance of the variable Pension Benefit Guaranty Corporation premiums. *Id.*, 23.

Tyler H. Ross, Director of Accounting and Regulatory Services for AEPSC, testified the prepaid pension asset does exist on Petitioner's books and records and is consistent with GAAP. Ross Rebuttal, 2. He disagreed that the prepaid pension asset was funded by any source other than investor capital. He said I&M's customers pay rates that reflect the level of GAAP-determined pension costs. He explained I&M does not recover through rates any pension amount above and beyond that level since the prepaid pension asset consists of cumulative contributions to the pension fund less the GAAP-determined cost; it is funded solely by investors. *Id*., 10-11. He testified these contributions earn returns that benefit customers through lower pension costs and that therefore the prepaid pension asset represents a prudent investment made to help meet utility obligations, reduces cost of service for customers, and is therefore used and useful in providing public utility service. *Id*., 11. He described the investment as akin to working capital, fuel inventory, materials and supply, and prepayments. *Id*., 12. He explained the prepaid pension asset has been included in rate base for many years, that it has existed on I&M's books since 2005, was expressly approved for rate base treatment in Cause No. 44075, and most recently again in Cause No. 44967. He noted the level included in I&M's forecast in this rate case is actually less than the level included in rate base in the last rate case. *Id*., 14.

5. <u>Discussion and Finding.</u> Since 2013, the question of what, if any, rate recovery should be approved for a utility "prepaid pension asset" has been litigated before us only twice, by I&M in Cause No. 44075 and by IPL Cause No. 44576. In Cause No. 44075, a case of first impression, we approved rate base recovery of I&M's "prepaid pension asset":

> 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 assets should be included in Petitioner's rate base.

In re. Ind.-Mich. Power Co., Cause No. 44075, p. 10, 2013 WL 1180842 (Ind. Util. Regulatory Comm'n Feb. 13, 2013), *aff'd mem.* (Ind. Ct. App. 2014), *trans. denied*.

In Cause No. 44576, we approved recovery of IPL's "prepaid pension asset" in rate base by concluding that it represents a component of working capital. Our order in that Cause also reduced the amount of the "asset":

> As for the amount to be recognized, while we agree with IPL that the prepaid pension asset represents a component of working capital, we disagree that the entire $138.5 million should be recognized as investor-supplied capital and included in rate base.… 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…. While parties did challenge the inclusion of the prepaid pension asset on other grounds, no party contended that the prepaid asset represented an imprudent investment.

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

In the same Order, we further found that our conclusion "should not be read to foreclose alternative proposals to address prepaid pension assets." *Id.*, fn. 5. Having considered the alternative proposals offered by the OUCC and IG in this Cause, we revisit our prior orders and reach different conclusions today.

We turn first to our finding in Cause No. 44075 that I&M's "prepaid pension asset" was "recorded on the Company's books in accordance with governing accounting standards." *In re. Ind.-Mich. Power Co.*, Cause No. 44075, p. 10, 2013 WL 1180842. We first note that FAS Nos. 87 and 158, as issued, do not represent generally accepted accounting principles ("GAAP") today. Current governing accounting standards are represented by the FASB Accounting Standards Codification ("ASC"). ASC Topic 715 – "Compensation – Retirement Benefits" (formerly FAS No. 158) provides current guidance on the determination of pension costs, recording of pension assets and liabilities, and required financial statement disclosures. ASC 715 requires entities to "[r]ecognize the funded status of a benefit plan – measured as the difference between plan assets at fair value (with limited exceptions) and the benefit obligation – in its statement of financial position." ASC 715 does not acknowledge a "prepaid pension asset" in any manner and contains no "prepaid pension asset" reporting requirements.

I&M's testimony in this Cause references the now outdated FAS Nos. 87 and 158, and I&M did not provide any current governing accounting standards that reference a "prepaid pension asset" or "prepaid pension cost." We note the OUCC's uncontroverted testimony that no company is required to reflect any "prepaid pension asset" as an account or category in its statement of financial position or for purposes of financial disclosures in the notes to its financial statements. There is no "prepaid pension asset" or "prepaid pension cost" account designated under FERC's Uniform System of Accounts, which is the basis for I&M's chart of accounts. AEP's actuarial reports contain no calculation or mention of any "prepaid pension asset" or "prepaid pension cost." Stull, 3, 11. Based on the above, we conclude I&M is imputing the term "prepaid pension asset" to the difference between its cumulative pension cash contributions less cumulative pension costs (as recorded to its annual financial statements) and that such a term or concept is not found in any governing accounting standard.

Not only is I&M's proposed treatment not required by GAAP, we note that the recording of a "prepaid pension asset" actually deviates from GAAP. As we discussed above, there is no GAAP requirement to record a "prepaid pension asset" as that term has been defined by I&M. Therefore, as discussed by both Ms. Stull and Company witness Mr. Ross, I&M's accounting schedules show a reclassification of its "prepaid pension asset" through Account 1650014 (Stull, 8 and Attachment MAS-8; Ross Rebuttal, 9-10) to eliminate the "prepaid pension asset" and comply with GAAP.

Even if GAAP did require some form of recognition of a "prepaid pension asset," this Commission has properly deviated from GAAP on many occasions, particularly when following GAAP would not result in a reasonable ratemaking effect. Specifically, this Commission has authorized divergence from GAAP by approving the continued recording of AFUDC after an asset has been placed in service (post-in-service AFUDC), the deferral of depreciation, and authorization to amortize certain operating expenses such as rate case expense and periodic maintenance expense. Moreover, we see that I&M has ignored GAAP when it found it appropriate to do so. In rebuttal, Mr. Ross testified I&M "… has appropriately ignored the ASC 715 balance sheet reclassifications and properly reflected the pension prepayment…in rate base." Ross Rebuttal, 10.

We turn now to whether a "prepaid pension asset" should be considered working capital, as we previously found in Cause No. 44576. This Commission has historically considered three types of working capital – cash, inventories, and prepayments. Cash working capital is defined for ratemaking purposes as the average amount of capital provided by investors to bridge the gap between the time expenditures are required to provide service and the time collections are received for that service. The most reliable method to calculate working capital is to perform a lead-lag study. We note that I&M did not request working capital nor did it present the results of a lead-lag study in this Cause and, therefore, we do not know what, if any, its working capital needs are. Even if I&M's "prepaid pension asset" could qualify for inclusion in rate base as a prepayment, in Cause No. 44576, we stated "[w]e note that prepayments can fall within the definition of working capital if the prepayments were prudently made for the benefit of customers and were made using investor-supplied funds." *In re Indianapolis Power & Light Co.*, Cause No. 44576, 2016 WL 1118795 *23. For purposes of determining whether I&M's claimed "prepaid pension asset" was made using investor-supplied capital, I&M would need to calculate the difference between cumulative pension contributions and the cumulative amount recovered from ratepayers in I&M's cost of service. I&M did not provide this calculation. If we were predisposed to continue to allow the inclusion of a "prepaid pension asset" in rate base, this is the amount that would be relevant for ratemaking purposes. Moreover, as discussed in more detail below, we conclude that I&M's "prepaid pension asset" has not been prudently made because its benefit obligation is now overfunded and its "prepaid pension asset" is larger than is reasonably necessary to insure the financial integrity of the pension fund.

A critical component of our prior reasoning for including I&M's "prepaid pension asset" in its rate base in Cause No. 44075 was our understanding that the "prepaid pension asset" serves to reduce I&M's total pension cost that is included in its cost of service such that having a "prepaid pension asset" benefits customers by reducing I&M's revenue requirement. However, we cannot ignore the testimony presented in this Cause that demonstrates rate base treatment for a "prepaid pension asset" *more than offsets* the reduction to I&M's pension costs, thereby eliminating any customer benefit. As Ms. Stull explained, "[i]ncluding a 'prepaid pension asset' in rate base…increases operating revenues, which creates a corresponding increase to utility receipts tax and income tax expenses that ratepayers must pay. However, increasing pension expense in a utility's revenue requirement does not create additional revenues or taxes." Stull, 21.

Referring to Ms. Stull's testimony at page 22, including an $89,244,007[6] "prepaid pension asset" in rate base *increases* I&M's annual revenue requirement by $7,170,967. This same "prepaid pension asset" only reduced pension cost by $5,577,750 ($89,244,007 x 6.25%). Even though excess contributions to I&M's defined benefit plan serve to reduce I&M's pension cost, inclusion of a "prepaid pension asset" in rate base increases its total revenue requirement beyond any savings, mainly due to the income tax gross-up. Burdening customers with additional expense to provide I&M with a return on an "asset" that is not used and useful utility property and does not, as discussed in more detail above, properly constitute working capital is not appropriate and does not benefit I&M's customers.

Our Cause No. 44075 order also states that I&M's discretionary excess pension contributions "preserve[s] the integrity of the pension fund," which we now find is no longer the case. *In re. Ind.-Mich. Power Co.*, Cause No. 44075, p. 10, 2013 WL 1180842 (Ind. Util. Regulatory Comm'n Feb. 13, 2013), *aff'd mem.* (Ind. Ct. App. 2014), *trans. denied* (no pin cite available). At the outset, we note that a utility has control over the funding of its pension plan, above and beyond any ERISA minimum funding requirements, and that, in I&M's case, management used its discretion to create or increase a "prepaid pension asset." I&M has a pension funding policy, which is to contribute the greater of the ASC 715 service cost or the minimum required contribution. Stull, Attachment MAS-3, p. 8 of 112 (AEP 2019 Pension Actuarial Report). This policy leads to funding of 100% *or more* of I&M's portion of AEP's projected benefit obligation. As of December 31, 2018, I&M's share of AEP's pension plans was overfunded by $15,977,463. Stull, 7 (revised). In Cause No. 44075, I&M's pension plan was not overfunded. In that case, I&M's allocated share of the AEP pension plan at 12/31/2010 was 80.6% unfunded compared to the current overfunded position. More importantly, we note that I&M's share of the benefit obligation has *decreased* by $885,659 but its share of the fair value of the plan assets has increased by $123,217,443.[7]

Moreover, even though I&M's pension plan is now overfunded, its "prepaid pension asset" amount has remained virtually unchanged since Cause No. 44075. In Cause No. 44075, I&M's jurisdictional "prepaid pension asset" was $61,691,738 compared to a $62,209,785 "prepaid pension asset" in this Cause. Cause No. 44075, Final Order, 6. I&M's management continues to make excess contributions to its pension plan without regard for the fact that its pension plan is overfunded, and the return I&M earns on its "prepaid pension asset" only reinforces that management decision.

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[6] This is the value of the total company "prepaid pension asset" rather than the jurisdictional portion attributable to Indiana. However, the principles are the same regardless whether total company or jurisdictional amounts are used in the calculations.

[7] These amounts represent only the amounts of the AEP qualified pension plan and do not include the unqualified excess benefit plan. The funding percentage of the combined plans does not change materially from that reflected.

We cannot conclude that I&M's discretionary excess pension contributions are reasonable and necessary to preserve the integrity of its pension fund when it is now overfunded. Given that its discretionary pension contributions could have been used to fund needed capital improvements, I&M's decision to continue making excess pension contributions to an overfunded plan was not a necessary, reasonable, or prudent method of providing a financially sound pension plan to its employees at a reasonable cost to ratepayers. Customers face constant demands to bear utility costs that are needed to maintain a safe and reliable utility system. We find that customers should not continue to bear the results of discretionary choices that are not necessary to maintain the integrity of I&M's pension plan.

Having found that the circumstances in which we made our prior decisions on "prepaid pension assets" have changed, we conclude that the evidence does not support continuing rate base recovery of I&M's "prepaid pension asset." Instead, we consider the OUCC's alternative proposal below and find that it has merit; therefore, we find below that Ms. Stull's pension adjustment is a reasonable method to address the appropriate ratemaking treatment for I&M's "prepaid pension asset."

To recognize the disconnect between the ERISA minimum pension contributions and the pension cost calculation required by ASC 715, the OUCC proposed increasing I&M's pension expense to offset the impact of I&M's excess minimum required pension contributions. Increasing I&M's pension expense provides the utility with some ratemaking treatment for its excess pension contributions, does not incent I&M to overfund its pension plan, and does not burden ratepayers with the additional costs associated with rate base treatment, primarily additional income taxes and utility receipts taxes. Further, we find Ms. Stull's proposal provides a means of reducing the prepayment on a going forward basis and possibly eliminating any prepaid pension costs sooner than they otherwise would have been. Increasing pension expense recognized for ratemaking purposes will necessarily increase the cumulative pension expense included in the determination of the prepaid pension costs. Given that a "prepaid pension asset" does not properly fit within the strictures of Ind. Code § 8-1-2-6, recovery of pension costs as an expense rather than as a rate base item avoids controversy. We accept Ms. Stull's adjustment to pension expense, and hereby increase I&M's annual revenue requirement by $1,331,289 accordingly.[8]

Additionally, we note Ms. Stull's comment that I&M could not provide the derivation of its proposed "prepaid pension asset" since its inception despite the OUCC's request for such a calculation. I&M's response to the request was that it was "overly broad and unduly burdensome" and that the request sought "an analysis, compilation, calculation or study that I&M has not performed and to which I&M objects to performing." Given the magnitude of the "asset" being requested, this Commission believes the determination of this "asset" to be pertinent to an understanding of the circumstances leading to its creation. Therefore, we require I&M to provide a detailed calculation, by year since inception, of its "prepaid pension asset" as part of its case-in-chief in its next base rate case filing.

[8] The calculation of the increase to pension expense included in Ms. Stull's testimony at page 18 incorrectly used the total company "prepaid pension asset" value rather than the jurisdictional value. The correct calculation is the following - $84,962,833 (total company) x 73.22% (jurisdictional) = $62,209,786 x 34.24% (required contribution %) = $21,300,631 x 6.25% (return on plan assets) = $1,331,289 increase to pension expense.

H. Unamortized Nuclear Decommissioning Study and Rate Case Expense Asset.

1. Petitioner. As will be explained hereinafter, Petitioner is proposing to amortize its deferred rate case expense over a period of two years. The Company is proposing the deferred amount be included in forecasted rate base. Williamson Direct, 30.

2. OUCC. Mr. Eckert testified that it is inappropriate for I&M to include nuclear decommissioning study expenses and rate case expenses in rate base. Eckert, 17. He testified that rate case expense and nuclear decommissioning study expense are cash working capital items, and not rate base items. *Id.* He testified that if these expenses were to be included in rate base they should be reflected as part of a full cash working capital study, where items such as utility expenses and property taxes are considered. Mr. Eckert stated that it is inappropriate to include these expenses as a single issue working capital requirement and recommended the Commission deny I&M's request. *Id.*

3. Petitioner's Rebuttal. Mr. Williamson explained the OUCC's view is too narrow and that rate case expenses are reasonable and necessary costs incurred to provide service to customers. He explained carrying costs are intended to compensate for the time value of money associated with an expenditure that is recovered over a period of time. He said deferring a recovery of these costs creates an asset, and it is reasonable to earn a return on that asset no different than other assets involved in the provision of electric service. Williamson Rebuttal, 39.

4. Commission Findings. I&M's inclusion of rate case expenses and nuclear decommissioning study expense in rate base is inappropriate and we therefore reject it. Neither expense qualifies as something that is "used and useful" in the provision of utility service under the strictures of Ind. Code § 8-1-2-6, and utilities should include such expenses in a cash working capital study, where the appropriateness of such expenses can be fully examined. I&M performed no such study. I&M should not earn a return on rate case or nuclear decommissioning study expenses, and we find that I&M's request should be denied.

I. Conclusion on Rate Base.

Based upon the foregoing findings, the Commission finds that the Test Year End net original cost rate base (Indiana Jurisdictional) for I&M is $4,714,702,350 and is calculated as follows:

Net Plant in Service	$4,560,700,904
Fuel Stock	23,146,671
Other Materials & Supplies	116,811,112
Allowance Inventory	17,043,356
Prepaid Pension Expense	-
Regulatory Assets	50,658,644
Deferred Gain Rockport 2 Sale	(5,061,526)
Regulatory Liabilities	(2,588,975)
Deferred Income Taxes	(46,007,835)

Original Cost Rate Base	$4,714,702,350

8. **Depreciation.** I&M witness Cash performed a depreciation study for I&M's electric plant as of December 31, 2018. Mr. Cash discussed the methods and procedures used in preparing the depreciation study and recommended an overall increase in I&M's depreciation accrual rates. We discuss the challenges to Mr. Cash's proposed depreciation accrual rates below.

A. Accounts 354, 355, 364, 365, 366, 368, 369.

1. OUCC. OUCC Witness David Garrett used the same Simulated Plant Record ("SPR") Method used by Mr. Cash for purposes of evaluating mass property accounts when aged data is not available for certain accounts. D. Garrett (Part 2), 28, 30. He said with aged data, the ages of assets retired is known and an actuarial analysis can be conducted to recommend service lives. But with unaged data, the ages of retired assets must be "simulated." This is the SPR method. *Id.* He said the Conformance Index ("CI") and the Retirement Experience Index ("REI") are the statistics that provide the quality of the fit for the Iowa Survivor Curve. *Id.*, 30-31. He used "scales" set forth in a 1947 paper written by Alex Bauhan, who developed the SPR Method, to assess the CI and REI. *Id.* p. 30, n.26, 31-32. Based on these scales, in addition to a comparable analysis of other utilities, Mr. Garrett testified the Iowa Survivor Curves selected by Mr. Cash are generally too short, and result in unreasonably high depreciation rates. *Id.*, 32-47. Based in part on the approved service lives of his comparable peer group and results of the SPR Method, Mr. Garrett proposed adjustments to the service lives for Accounts 354, 355, 364-366, and 368-69. *Id.*, 34-35.

2. Industrial Group. IG witness Andrews opposed the proposed rate for Accounts 364,365, and 368. He testified that actuarial life analysis, when the required data exists, is the preferred method of determining the life, and thus retirement, characteristics of a group of property. Andrews, 7. In his opinion, I&M's Simulated Plant Record ("SPR") analysis results in service lives for these accounts that are too short, referencing the NARUC Public Utility Depreciation Practices Manual, discussing the analysis of the Bauhan SPR procedure *Id.*, 15-18. Mr. Andrews testified that I&M's SPR analysis for its proposed survivor curves ("CI") are in the poor fitting range on SPR balance Model. *Id.*, 17. Mr. Andrews instead based his recommendation on his informed judgment to select a survivor curve rather than relying on the results of the SPR analysis. He also testified as to the average service lives from other utilities. *Id.*, 18. He recommended average service lives for Account 364 of 47 years; for Account 365 of 48 years; and for Account 368 of 40 years. *Id.*, 20.

3. Rebuttal. Mr. Cash testified he had not relied solely on the CI, and that instead he had also considered a number of other factors, including the retirement experience index as well as the survivor curves and average service lives that were approved in prior depreciation studies. Cash Rebuttal, 24. He explained the Bauhan scale is arbitrary. Cash Rebuttal, 23. Mr. Cash stated he mainly focused his comparison to the results from the last two approved depreciation studies because there was no indication that the Company's historical data, and thus the resulting survivor curve and average service life assigned to each account, should not be used. Cash Rebuttal, 24-25. He explained the results from the Company's analysis must be given primary weight since the factors that affect the retirement of property are typically

different for every company. *Id.* Mr. Cash also compared his proposed Iowa Survivor Curves for these accounts to those proposed by Mr. Garrett and Mr. Andrews as well as to those that had been approved for comparable AEP affiliates. *Id.*, 25; Attachments JAC-R1 and JAC-R2. Mr. Cash explained the comparison to other nearby AEP affiliates validates the results of his analysis and confirming that it is reasonable. *Id.*, 25. He added his comparison also shows that the proposed services lives proposed by witnesses Garrett and Andrews are significantly outside the range of comparable AEP affiliates that have similar operating conditions to I&M. *Id.*

4. Discussion and Finding. The selection of the appropriate survivor curve involves the use of professional judgment. I&M argues that using the SPR Method is necessary because of the lack of aged data, and because the survivor curves poorly fit the simulated data. Alternatively, the OUCC and Industrial Group used data gathered from other utilities to match the appropriate survivor curves. We reject the Company's analysis based on the SPR Method, finding that the use of actual data presented by the OUCC and IG preferable to the use of simulated data. I&M's comparison of the proposed survivor curves to the survivor curves used in I&M's last two depreciation studies is inappropriate, especially as the depreciation in the most recent case, Cause No. 44967, was a settled proceeding and not a litigated decision. The use of comparison data from other utilities by the OUCC and IG provides a credible explanation for their proposal. We reject I&M's analyses and find that the survivor curves recommended by Mr. Garrett should be approved.

B. Account 370 (Meters).

1. I&M. As noted above, the Company is proposing to transition to AMI meters over the next 4 years. Mr. Cash explained that the Company's proposal with respect to Account 370 (Meters) is to recover any undepreciated balance of meters that are retired over the lives of the new AMI meters. He explained that this is consistent with the FERC USOA. Cash Direct, 11-12.

2. OUCC. Mr. David Garrett proposed that the currently approved depreciation rate for meters be kept at 6.78%, based on OUCC's recommendation that the Commission reject the Company's proposal regarding AMI deployment. D. Garrett (Part 2), 47.

3. Industrial Group. Mr. Andrews testified I&M's proposal for Account 370 is inconsistent with what was used for other accounts, resulting in an increase to the depreciation expense of $1.9 million or 37% more than the currently approved rate for meters. Mr. Andrews noted that under FERC Electric Plant Instruction 10, there was no need to treat meters differently for purposes of setting depreciation rates. Andrews, 14. He testified that the average service life be based on the meters that are actually providing utility service. Andrews, 15. Based on that approach, he proposed a depreciation rate of 7.67% for the meter account. *Id.*

4. Rebuttal. Mr. Cash explained neither Mr. Garrett nor Mr. Andrews had considered the retirement of the existing meters in their proposal. He cited to the NARUC Public Utility Depreciation Practices Manual, which states that changes such as the deployment of AMI meters should be considered in setting depreciation rates. Cash Rebuttal, 20. He explained he could have calculated two different depreciation rates – one for the current meters (recovering over average remaining life of 4 years) and one for the new AMI meters (15 years).

He explained that the existing meters also have an expected useful life of 15 years. Using the average age of the existing meters (10.18 years) would produce a remaining life of 4.82 years for the existing meters. *Id.*, 21. He said under his alternative, the rate for existing meters would be 15.66% and for new meters would be 8.13%.

5. Discussion and Finding. Based on our discussion rejecting I&M's proposed AMI deployment, we do not change the depreciation rate for the existing AMR meters.

C. Contingency.

1. OUCC. Mr. David Garrett testified that the Company's demolition studies include contingency factors that increase the base estimated demolition costs by more than 85% for some generating facilities. D. Garrett (Part 2), 22. Mr. Garrett proposed to exclude contingency from demolition costs that are included in terminal net salvage for purposes of depreciation rates. He testified these costs are unknown and should therefore be excluded. *Id.*, 22-23. Mr. Garrett also testified that the same arguments used in support of a contingency cost increase could be used to support a contingency cost decrease. *Id.*, 23.

2. City of Auburn. Auburn witness Rutter also proposed to remove contingency costs from the demolition studies, claiming they were unknown. Rutter, 23.

3. Rebuttal. Mr. Cash testified this Commission has previously approved the inclusion of contingency, specifically the contingency that had been proposed by Sargent & Lundy in Cause No. 44075.

4. Discussion and Finding. While this Commission has recognized the inclusion of a contingency factor in demolition studies for purposes of computing final terminal salvage, we are not bound by our previous decisions. We must examine the reasonableness of the contingency proposed in this proceeding. We agree with Mr. Garrett that contingency costs are, by definition, unknown, and could either serve to increase or decrease the estimated costs. Additionally, I&M's requested contingency amounts of 33% to 85% (as seen in Retirement Option 1 of the demolition cost estimates) are far greater that those previously approved of 20% and 25%, further highlighting the unreasonableness in this specific instance and its unreliability generally. For this reason, we decline to allow the recovery of contingency costs in I&M demolition estimates.

D. Escalation Rates.

1. OUCC. OUCC Witness D. Garrett proposed to remove escalation from demolition cost estimates for purposes of computing terminal net salvage. D. Garrett (Part 2), 8. While the Company had used an escalation factor of 2.23%, the inclusion of inflation is inappropriate in Mr. Garrett's judgment. *Id.*, 23. He cited to the methodology for calculating an asset retirement obligation under Financial Accounting Standard 143 ("SFAS 143"), where the future cost of removal is discounted. *Id.*, 24. He also cited to an Oklahoma decision rejecting the use of contingency. *Id.*, 25.

2. Rebuttal. Mr. Cash testified that for purposes of computing terminal net salvage, it is necessary to estimate the cost of demolition at the time it is expected to

be incurred. Cash Rebuttal, 8. He explained discounting to present value for purposes of setting depreciation rates would be incorrect because insufficient cost would be recovered over the life of the asset. He further explained customers receive a benefit because customers receive a return on the net salvage component of depreciation expense, which increases accumulated depreciation and reduces rate base. *Id.*, 10. With respect to SFAS 143, Mr. Cash testified Mr. Garrett is confusing the purposes of the required accounting standards with the purposes of recovering the full cost of an asset over its life through straight line depreciation. *Id.*, 11. In response to the citation of an Oklahoma decision, Mr. Cash cited to numerous orders from this Commission specifically approving escalation rates in depreciation calculations. *Id.*, 12-13.

3. Discussion and Finding. The use of future estimated demolition costs should not impose unreasonable costs on consumers. The inflation of present day estimates to some future date ignores the time-value of money, which reflects the reality that current dollars are more "valuable" than future dollars. Escalating current estimates due to inflation without taking the time-value into account ignores this. Based on Mr. Garrett's argument, we decline to impose the escalated future cost on ratepayers and reject I&M's proposal to escalate the demolition costs.

E. Interim Retirements.

1. OUCC. OUCC witness David Garrett proposed to disallow the inclusion of interim retirements in the calculation of depreciation rates. He stated that disallowing interim retirements would not preclude I&M from recovering all its prudent plant investments. D. Garrett (Part 2), 19. He testified that he was unaware of any Indiana Commission order specifically addressing the issue of interim retirements. *Id.*, 20. He cited to the rejection of recovery of interim retirements in a Texas case involving an AEP affiliate.

2. Rebuttal. Mr. Cash testified that interim retirements are included in a depreciation study to recognize that some components of a generating unit will retire before the plant itself is retired. Cash Rebuttal at 14. He responded to the citation of the Texas Commission decision and explained that it is unreasonable to exclude interim retirements because otherwise, the retired components would be depreciated beyond their service life, shifting the cost of interim retirements to future customers. *Id.*, 16-17. He cited to an earlier decision of this Commission involving I&M specifically finding that interim retirement should be included in the calculation of depreciation rates. *In re. Ind.-Mich. Power Co.*, Cause No. 44075, p. 10, 2013 WL 1180842.

3. Commission Discussion and Finding. Mr. Garrett's arguments that interim retirements are not known or measurable is persuasive. As shown in his testimony, interim retirements reduce the average life of an asset to less than its anticipated service life, increasing the current depreciation rate and depreciation expense for ratepayers. I&M would still have the ability to recover prudent plant investments even without the inclusion of interim retirements in its depreciation rates. Accordingly, we reject I&M's inclusion of interim retirements in its depreciation rates.

F. Rockport.

1. I&M. Petitioner proposed to change depreciation accrual rates for steam production from 7.52% to 7.77%. The depreciable investment in steam production plant is for the Rockport Generation Plant, as shown in Attachment JAC-1. The estimated retirement date for Rockport Unit 1 is 2028, which is the same retirement date that was assumed for that unit for purposes of the depreciation rates approved in Cause No. 44967. The estimated retirement date for Rockport Unit 2 is 2022, which is the expiration of the lease agreement for that unit. *Id*., 8. The reason for the change in depreciation rates for steam production is the investment of $21.7 million in the Rockport plant since the last depreciation study. *Id*.

2. ICC. ICC witness Medine opposed the change in rates for steam production. Her testimony was based upon her opinion that the retirement dates for the Rockport units are caused by the Fifth Modification to the Consent Decree, which modification was due (in her opinion) to Petitioner's failure to comply with a Third Modification to the Consent Decree. She claimed that absent the Fifth Modification, I&M would be under no obligation to retire Rockport Unit 1 in 2028. Medine, 4-16.

3. Rebuttal. Mr. Cash testified that there was no change in the estimated useful life of the Rockport units in his depreciation study presented in this case. He reiterated that additional investment has been made to both Rockport units since the last depreciation study, and the depreciation rates need to be updated to reflect that additional investment. Cash Rebuttal, 4.

4. Discussion and Finding. *The OUCC takes no position on this issue.*

G. Rockport Enhanced DSI.

1. Joint Municipal Group. Constance T. Cannady testified on behalf of the Joint Municipal Intervenors with respect to the depreciation accrual rate for Petitioner's proposed enhanced DSI project at the Rockport plant. She testified that Petitioner appears to be proposing a 12% depreciation rate for the enhanced DSI system on Unit 1 and a 20% rate for the system on Unit 2. She argued that I&M's proposed depreciation rate which allowed for recovery over a period of less than 10 years is not consistent with the provisions of Indiana Code § 8-1-2-6.7(b) and should be disallowed. Cannady, 3-4, 11-18. Ms. Cannady also noted that a 10 year depreciation period for enhanced DSI is similar to the DSI depreciation period approved for I&M in Cause No. 44871.

2. Rebuttal. Mr. Cash noted that Ms. Cannady is mistaken concerning the Company's proposal. He said she has confused the depreciation rate for the enhanced DSI project with the rate for the selected catalytic reduction system ("SCR"). He explained the 12% and 20% rates are the proposed rates for the SCR. Cash Rebuttal, 4. He testified that no depreciation rate was calculated specifically for the enhanced DSI project. *Id.*, 4-5. Accordingly, he said the general depreciation rates approved for Rockport would apply. *Id.*

3. Discussion and Finding.

The OUCC takes no position on this issue.

9. Fair Rate of Return.

A. <u>I&M.</u> Mr. Hevert said his analyses indicate that I&M's cost of equity ("COE") currently is in the range of 10.00 percent to 10.75 percent. Hevert Direct, 2. He testified based on the quantitative and qualitative analyses discussed throughout his Direct Testimony, 10.50 percent is a reasonable estimate of I&M's cost of equity.

In developing his recommendation Mr. Hevert relied on several widely accepted methods: (1) the Constant Growth 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. Hevert Direct, 3-4. Mr. Hevert testified his analyses recognize that estimating the COE 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 said 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. He stated therefore, that the results of each return on equity ("ROE") model must be assessed in the context of current and expected capital market conditions, and relative to other appropriate benchmarks. Hevert Direct, 4. Mr. Hevert explained that since 2014, the DCF model has produced results consistently and meaningfully below authorized returns and explained that the model's underlying structure and assumptions are not compatible with the recent capital market and economic environment. Hevert Direct, 5, 8. Mr. Hevert testified we should carefully consider the range of results the DCF model produces in arriving at ROE recommendations. *Id.*, 9.

He discussed his proxy group and explained his recommendation takes into consideration the risk factors associated with: (1) the Company's generation portfolio and related environmental regulations; (2) customer concentration; and (3) the Company's planned capital expenditures and the effect, if any, of certain regulatory mechanisms. In addition to the methods noted above, Mr. Hevert calculated the costs of issuing common stock (that is, "flotation" costs), and considered evolving capital market and business conditions, including changes in Federal Reserve monetary policy and increases in current and projected government bond yields. He stated although those factors are very relevant to investors, their effect on the Company's Cost of Equity cannot be directly quantified. Therefore, he said although he did not make explicit adjustments to his ROE estimates, he considered those factors in determining where the Company's cost of equity falls within the range of analytical results. Hevert Direct, 3-4.

As to I&M's proposed capital structure for the test year ending December 31, 2020, which (on the basis of investor-supplied capital) includes 46.80 percent common equity and 53.20 percent long-term debt, Mr. Hevert concluded the Company's proposal is consistent with the capital structures that have been in place over several fiscal quarters at comparable operating utility companies. Hevert Direct, 57. Given the consistency of its proposal with similarly situated utility companies, he concluded the Company's proposed capital structure is reasonable and appropriate. Regarding the cost of debt, Mr. Hevert said he understands that the Company's projected weighted average cost of long-term debt at the end of the test year is 4.54 percent, which he believes is reasonable and appropriate. *Id.*, 3, 56-58.

B. **<u>OUCC.</u>** Mr. David Garrett testified an analysis of an appropriate awarded ROE for a utility should begin with a reasonable estimation of the utility's cost of equity capital. He explained in estimating the Company's cost of equity, he performed a cost of equity analysis on a proxy group of utility companies with relatively similar risk profiles. Based on this proxy group, which is the same proxy group used by Mr. Hevert, he evaluated the results of the two most common financial models for calculating cost of equity in utility rate proceedings: the CAPM and DCF Model. He stated applying his chosen inputs and assumptions to these models indicates that the Company's estimated cost of equity is about 6.5%. D. Garrett (Part 1), 10-11, 29-83. Mr. Garrett testified that although the awarded ROE should be based on cost, the legal standards set forth in *Federal Power Commission v. Hope Natural Gas Co* indicate that the "end result" should be just and reasonable. Applying the concept of gradualism to the Company's shareholders, Mr. Garrett recommended the Commission award an ROE of 9.1%, which he said is within a reasonable range of 9.0% – 9.5%. *Id*., 11. Mr. Garrett testified that an awarded ROE of 9.1% represents a gradual move toward the Company's market-based cost of equity, and it would be fair to the Company's shareholders because 9.1% is nearly 200 basis points above the Company's market-based cost of equity. *Id*., 12.

Mr. Garrett criticized Mr. Hevert's terminal growth rate, equity risk premium, bond yield plus risk premium model, and discussion of capital market environment. *Id*., 14-19. He discussed the legal standards and awarded returns. *Id.*, 20-29. Specifically, Mr. Garrett criticized Mr. Hevert's growth rate input to the DCF Model because Mr. Hevert used short term growth rates when the DCF Model calls for long-term growth rates. In addition, Mr. Garrett states that Mr. Hevert's growth rate inputs exceed projected growth rates for the entire U.S. economy, as measured by GDP. *Id*., 14. Regarding the equity risk premium ("ERP"), Mr. Garrett testified that Mr. Hevert's ERP estimate is more than twice as high as the results estimated and reported by thousands of survey respondents and other experts. *Id*., 15.

C. **<u>Industrial Group.</u>** IG witness Gorman provided extensive testimony regarding I&M's proposed rate of return and requested authorized ROE. Mr. Gorman began his analysis with a review of general market conditions. He presented evidence of observable evidence related to the authorized returns on equity for electric and gas utilities; the ability of utilities to maintain credit ratings during periods of declining returns on equity; and their ability to access external capital to support capital expenditure programs under reasonable returns. Mr. Gorman also testified regarding the market's assessment of the investment risk of I&M and its parent company, AES. Gorman, 43-61.

Mr. Gorman also testified regarding I&M's proposed capital structure which reflected approximately 46.8% common equity in 2020. He found this proposed capital structure weight reasonable. *Id*., 61.

Mr. Gorman then testified regarding his recommendation for I&M's cost of common equity in light of Hope and Bluefield Standard. He explained the methods he used to estimate I&M's cost of common equity including several variations on the Discounted Cash Flow model, the Risk Premium Model, and the CAPM and the inputs he used in applying those models.

Based on the results of his analyses, Mr. Gorman recommended a return on common equity of no higher than 9% with a ratemaking overall rate of return of 5.35%. Gorman, 934. Mr.

Gorman testified that his recommended rate of return would support an investment grade bond rating for I&M. *Id*., 94. He testified a return on common equity of 9.00% is the high-end of his estimated range of 8.50% to 9.00%, which he testified reflects the current low capital market cost for a utility with risks similar to I&M. He noted that his 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. *Id*., 94.

Finally, Mr. Gorman described his disagreements with Mr. Hevert's approach to calculating I&M's ROE. Mr. Gorman testified Mr. Hevert's analyses produce excessive results for various reasons, including the following: 1) his constant growth DCF results are based on unsustainably high growth rates; 2) his CAPM is based on inflated market risk premiums; 3) his empirical CAPM is based on a flawed methodology; and 4) his Bond Yield Plus Risk Premium studies are based on inflated utility equity risk premiums. *Id*., 62-220.

D. <u>Other Intervenors.</u> Walmart witness Chriss provided Walmart's perspective as a nation-wide electricity consumer and recommended the Commission closely examine the ROE in light of customer impact, use of the future test year and recent ROE decisions approved by the Commission and nationwide. Chriss, 4, 7-14. In this regard, Mr. Chriss noted that the Company's requested ROE increase from the current authorized ROE of 9.95% to 10.5%, and using the Company's proposed rate base constant, cost of debt, and capital structure, would result in an impact on customers of approximately $13.8 million, or 8.1% of the Company's claimed revenue deficiency. *Id.,* 9. Furthermore, Mr. Chriss offered evidence that the Company's proposed ROE is significantly higher than ROEs approved by the Commission since 2016, noting that the average of Commission-approved ROEs since 2016 is 9.94%. In comparison with ROEs approved by other regulatory commissions, Mr. Chriss demonstrated that the average and median of 125 electric utility rate case ROEs approved by regulatory commissions since 2016, as reported by S&P Global Market Intelligence ("S&P Global"), was 9.6%, with a range of reported ROEs from that period of 8.4% to 11.95%. *Id.,* 11. Mr. Chriss further explained that for vertically-integrated utilities reported by S&P Global over the same time period, the average reported ROE was 9.73%, which has remained relatively stable over that time. *Id.,* 11-12. Mr. Chriss concluded that the Company's requested ROE and ROE range are therefore contrary to broader electric industry trends. *Id.,* 11. 39 North witness Cearley also did not perform a cost of equity analysis but recommended the Commission recognize I&M's customer satisfaction scores in adopting a return. Cearley, 8-9.

E. <u>Rebuttal.</u> Mr. Hevert explained there are several methodological, theoretical, and practical reasons why the Opposing ROE Witnesses' recommendations are unduly low. He said because the Opposing ROE Witnesses give meaningful weight to their DCF-based results, it is not surprising that their recommendations fall well below currently authorized returns. He added given their common reliance on the DCF method, it also is not surprising that the Opposing ROE Witnesses' recommendations generally fall within a narrow range. Mr. Hevert stated the fact that the Opposing ROE Witness recommendations are similar does not mean their approaches and conclusions are reasonable. Hevert Rebuttal, 4-5.

He stated in some cases, the Opposing ROE Witnesses' recommendations stem from unreasonably low DCF estimates, which themselves are the result of tenuous assumptions. He said there is no reasonable basis to assume the current volatile capital market environment will remain in place in perpetuity. Mr. Hevert testified we cannot conclude the recent levels of utility valuations are due to a fundamental and permanent change in the risk perceptions of utility investors, as the Opposing ROE Witnesses' recommendations assume. He said those valuation levels are more likely related to the "reach for yield" that often occurs during periods of low Treasury yields. Hevert Rebuttal, 3.

Mr. Hevert also explained certain of the Opposing ROE Witnesses' recommendations are fundamentally disconnected from their own analyses and conclusions, and are far removed from observable and relevant data. Hevert Rebuttal, 4. He said although Mr. Gorman suggests the Cost of Equity has fallen to a level that supports his recommendation, observable data does not support this position. Hevert Rebuttal, 5.

Mr. Hevert stated the Opposing ROE witnesses are not consistent with returns authorized by the Commission and elsewhere in the U.S. He explained if the Commission were to authorize a return of 9.10 percent or lower as the Opposing ROE Witnesses recommend, it would represent a significant departure from returns previously authorized by the Commission. Hevert Rebuttal, 5-6; Chart 1.

Mr. Hevert testified the financial community carefully monitors utility companies' financial conditions, both current and expected as well as the regulatory environment in which those companies operate. He said a consequence of an authorized ROE in the range of the Opposing ROE Witnesses' recommendations would be to increase investors' perceptions of regulatory risk. Hevert Rebuttal, 6.

Mr. Hevert also noted the Company expects its Network Integration Transmission Services ("NITS") costs to increase by about $48 million in 2021, just one year beyond the Test Year in this Cause and pointed out Mr. Williamson's statement that absent the ability to recover the increased NITS cost, the Company's earned Return on Common Equity would fall by about 1.90 percentage points (190 basis points). Hevert Rebuttal, 94. Mr. Hevert stated that because operating cash flow is directly related to income, the earnings erosion brought about by the inability to recover increased NITS costs will put downward pressure on I&M's financial profile, increasing the financial community's perceptions of the Company's risk. Mr. Hevert said the combination of the Opposing witnesses' unduly low ROE recommendations and the increased likelihood of under-earning absent the timely recovery of increased NITS costs suggests returns that are far too low to be considered reasonable. *Id.*, 94-95.

Mr. Hevert concluded based on the analyses discussed throughout his direct and rebuttal testimony, the reasonable range of ROE estimates is from 10.00 percent to 10.75 percent, and within that range, 10.50 percent is a reasonable and appropriate estimate of I&M's Cost of Equity. *Id.*, 96.

F. Discussion and Finding. The rate of return for a utility must be comparable to the return on investments in other enterprises having corresponding risks, sufficient to assure confidence in the financial integrity of the utility, maintain support of the utility's credit, and attract capital. *Bluefield Waterworks* & *Improvements Co. v. Pub. Serv. Comm. of W. Virginia*, 262 U.S. 679, 43 S.Ct. 675 (1923); *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 64 S.Ct. 281 (1944), *see also In re Indianapolis Power & Light Co.*, Cause No. 44576, 2016 WL 1118795 *43.

In order 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 10.75%. He recommended the Commission adopt a cost of common equity of 10.50%. Mr. Garrett's estimated cost of equity is about 6.5%. He recommended a return on common equity of 9.10% based on a range of 9.00% to 9.50%. Mr. Gorman's analysis produced a range of 8.50% to 9.00%. He recommended a COE of 9.00%.

The Commission recognizes that the cost of equity cannot be precisely calculated and estimating it requires the use of judgment. Due to this lack of precision, the use of multiple methods is desirable because no single method will produce the most reasonable result under all conditions and circumstances. We find that when using reasonable inputs, both the CAPM and DCF Model can produce reasonable estimates for the cost of equity. We also find that simply basing I&M's authorized ROE on a national average does not promote the idea that cost of equity estimates are forward-looking and that such an approach may prevent the authorized ROE from changing with market indicators that effect equity costs, such as interest rates. We conclude that consistent with *Hope* and *Bluefield*, I&M's authorized ROE should be based on its cost of equity, while also being reasonable given the totality of the circumstances. The cost of equity is estimated through financial models such as the CAPM and DCF Model.

The evidence presented in this case shows that the authorized ROE of 10.5% proposed by I&M exceeds any reasonable estimate for I&M's actual cost of equity in the current market environment. In particular, I&M relied on growth rate inputs in the DCF Model that exceed the growth rate of the U.S. economy, as measured by GDP. D. Garrett Direct (Part 1), 56-57. In addition, I&M relied on an equity risk premium in the CAPM that is more than twice as high as those reported in expert surveys. *Id*., 73-74.

The Commission has considered the analytical results based on a proxy group of electric utilities, as well as the impact that market risk has the Company. Because business risk is diversifiable, and thus investors do not expect a return for such assuming such risk, we primarily focused on market risk when assessing an appropriate cost of equity estimate for I&M. *Id*., 77-78.

Having taken into consideration the foregoing factors and observable market data reflected in the record, including I&M's market-based cost of equity, 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, the Commission finds that an ROE of 9.1% is fair and reasonable.

G. Overall Weighted Cost of Capital. Mr. Hevert's testimony regarding the Company's capital structure was not challenged. Having reviewed his testimony and that of Mr. Gorman we find the Company's Test Year capital structure is consistent with industry practice and supports I&M's financial integrity. Based on these findings and after having given effect to the ROE authorized above, the Commission finds that Petitioner's capital structure and weighted cost of capital is as follows:

Description	Total Company Capitalization	Percent of Total	Cost Rate	Weighted Average Cost of Capital
Long Term Debt	$2,926,531,185	42.78%	4.54%	1.9422%
Common Equity	2,574,496,077	37.63%	9.10%	3.4243%
Customer Deposits	37,972,608	0.56%	2.00%	0.0112%
ACC. DEF. FIT	1,282,863,267	18.75%	0.00%	0.0000%
ACC. DEF. JDITC	18,960,268	0.28%	6.67%	0.0187%
Total	$6,840,823,405	100.00%		5.3964%

The Commission accepts I&M's proposal to establish its authorized net operating income by multiplying the overall weighted average cost by the original cost Test Year rate base.

10. Disputed Test Year Revenue.

A. Customer Count Adjustment.

1. OUCC. Mr. Watkins stated that, based on informal discussions with I&M, it was determined there was an error in developing the forecasted test year billing determinants as it relates to the number of customers and number of bills. Watkins, 49. He explained the Company corrected its forecasted billing determinants by rate schedule, which has the effect of increasing the number of customer bills for most rate schedules, which in turn, increases customer charge revenue at current rates. *Id.*

2. Rebuttal. Mr. Nollenberger stated Mr. Watkins used the updated Test Year number of bills to re-compute forecasted Test Year revenues, resulting in an increase to forecasted Test Year revenues of $3,758,305. He said I&M agreed with this change to Test Year revenues. Nollenberger Rebuttal, 42.

3. Discussion and Finding. We find the use of the updated Test Year number of bills to be appropriate. We note that while this update does not change the Company's overall revenue requirement, it does reduce the revenue deficiency by the amount of the correction.

11. Disputed Test Year Operation and Maintenance ("O&M") Expenses.

A. Cook 316(b).

1. I&M. Messrs. Williamson and Lies supported the Company's proposal with respect to costs incurred to study the Cook Nuclear Plant's cost of compliance with Section 316(b) of the Clean Water Act, which costs the Company has deferred. Through these studies, the Company was able to determine that no additional capital costs are needed to

comply with this federal environmental requirement. Williamson Direct, 29; Lies Direct, 24-25. The Company proposes to include the deferred costs in rate base and amortize them through rates over 15 years, which reasonably approximates the remaining life of the Cook Plant. Williamson Direct, 29.

2. OUCC. OUCC Witness Michael Eckert recommended the Commission deny I&M's request to create a regulatory asset for D.C. Cook Nuclear Plant's Rule 316(b) study expenses, treat it as rate base, and amortize it over 15 years. Eckert, 16. He testified that 316(b) costs did not a constitute a financial impact to the utility, as I&M was incurring these costs during the last two rate cases and did not seek recovery of them earlier. *Id*., 14-15. He stated that I&M had full control over when it started incurring Rule 316(b) study expenses, as well as when it decided to seek recovery of these expenses and that I&M could have budgeted for, and sought recovery of, recurring Rule 316(b) study expenses in its post-2008 rate case proceedings (Cause Nos. 44075 and 44967). *Id*., 17. Further, Mr. Eckert stated this cost is the type of compliance expense the Commission included in base rates (Cause No. 44967) to be replaced by new onetime expenses that will be incurred in the future. *Id.* Therefore, Mr. Eckert concluded I&M's rates already include an embedded level of compliance cost expense, and it would be inappropriate to provide I&M with additional recovery. *Id.*

3. Rebuttal. I&M witness Ross explained the Cook 316(b) costs were properly recorded to Account 107, Construction Work in Progress, in accordance with the FERC USOA and in anticipation of a capital project. He said when it was determined it was uncertain as to whether I&M would be required to construct a property asset, I&M properly reclassified the Cook 316(b) costs to Account 183 for Preliminary Survey and Investigation Charges, which is the account where costs of preliminary studies of the feasibility of capital projects are recorded. Ross Rebuttal, 16. He said, as also supported by Mr. Lies in his direct testimony, I&M does not believe the result will be I&M's construction of a capital asset. Rather than expensing them, Mr. Ross stated the costs should be recorded in accordance with ASC 980, Regulated Operations, to Account 182.3 based upon the prudence of conducting the study and past precedent of recovery of similarly incurred costs related to Cook. *Id.*, 17.

I&M witness Lies responded to Mr. Eckert's testimony that the 316(b) costs were embedded in the calculation of base rates in Cause No. 44075. He said the 316(b) Project costs are not similar to the Fire Suppression System costs that were expensed and approved in Cause No. 44075. He explained the Fire Suppression System costs of about $1.7 million were related to an O&M project, not a capital project. He added I&M expects to regularly incur O&M costs to comply with emerging requirements that are relatively limited in scope. He said the 316(b) Project costs, on the other hand, were incurred cumulatively over the course of ten years in anticipation of a major capital project that itself also would have taken several years to complete, and which would have been necessary to ensure the on-going operation of the Cook Plant. He noted the possible outcome of the 316(b) study could have been the installation of cooling towers costing upwards of $1 billion. Lies Rebuttal, 2-3. He added, as appropriate for any possible capital project of this scope, studies were used to determine the path forward. He said the 316(b) studies allowed I&M to avoid a major capital project and this outcome was a positive outcome for I&M's customers. *Id.*, 3.

4. Discussion and Finding. I&M began incurring 316(b) study expenses in 2008. Since that time, I&M has filed two rate cases and a life cycle management ("LCM") proceeding for recovery of costs related to the D.C. Cook plant. Now I&M seeks rate recovery for the 316(b) study costs, despite never having received approval to recover or defer those costs.

I&M has no plans to construct equipment at the Cook plant for 316(b) compliance. While I&M's ratepayers can be grateful that they will not shoulder such expenses, I&M is not automatically authorized to recover the 316(b) study costs, absent previous authorization. In previous cases, we have rejected deferral of costs without prior approval. The Court of Appeals agreed with our decision. "The Commission rejected such a distinction—and we agree with its determination—that a deferral must be based on a 'reasonable belief' that the costs will eventually be recovered through rates." *N. Ind. Pub. Serv. Co. v. Ind. Ofc. of Util. Consumer Counselor*, 826 N.E.2d 112, 119 (Ind. Ct. App. 2005). Although our procedural rules allow a utility to defer research and development expenses, it must be in the context of qualified pollution control equipment and must be related to construction. *See,* 170 I.A.C. 4-6-16 and 170 I.A.C. 4-6-17. There is no other authority for rate recovery of a deferred expense absent Commission review and oversight.

"While the utility may incur any amount of operating expense it chooses, the Commission is invested with broad discretion to disallow for rate-making purposes any excessive or imprudent expenditures." *City of Evansville v. S. Ind. Gas & Elec. Co.*, 339 N.E.2d 562, 569 (Ind. Ct. App. 1975). This is one of those situations. I&M has not previously received authority to recover these costs, and we do not grant it after the fact. Long-standing precedent is clear: the Commission may not fix rates for the past, but only the future. "[T]he Commission does not have the statutory authority to set rates retroactively." *Airco Indus. Gases v. Ind. Mich. Pwr. Co.*, 614 N.E.2d 951, 953 (Ind. Ct. App. 1993). Instead, the Commission has only "the power to fix rates for the future, not for the past." *Id.* Indeed, "[w]e find nothing in the statute giving the Commission the power to cancel, or to fix, rates retroactively. The statute provides the Commission with the power to fix rates *for the future* if it finds the rates in effect to be unreasonable or unjust; but we look in vain to find statutory authority for the Commission to fix rates *for the past*. The Commission has no powers except those conferred by statute." *Ind. Tel. Corp. v. Pub. Serv. Comm'n of Ind.*, 131 Ind. App. 314, 340, 171 N.E.2d 111, 124 (1960) (emphasis in original). In effect, I&M seeks to recover past costs in future rates. We find no basis for such treatment, and therefore deny I&M's request.

B. Customer Assistance Programs.

1. I&M. Mr. Lucas testified I&M worked with a number of stakeholders in 2018 to establish four specific customer assistance programs: (1) Energy Share Pilot Program; (2) Low Income Weatherization; (3) Neighbor to Neighbor Pilot Program; and (4) Low Income Arrearage Forgiveness Pilot Program. Lucas, 29. He provided an update on each pilot and explained I&M is proposing to continue each of these programs. In addition, he said I&M is proposing an Income Qualified Safety & Health Pilot Program to address safety and health issues that prevent the completion of an income-qualified energy audit. Lucas, 29-34.

2. OUCC. Mr. Haselden recommended the Commission deny I&M's request to include the costs of the customer assistance programs in the cost of service. He stated these programs exceed the scope of a utility's operational obligation and are not reasonable and necessary. He said there are a number of state and local programs designed to assist low-income customers and I&M presented no compelling evidence as to why it is appropriate to include the expense to offer these programs at a cost to ratepayers. Haselden, 3-7. Mr. Haselden recommended the Low-Income Weatherization Program should be proposed as a part of I&M's DSM Plan and, if approved, costs recovered through the DSM tracker. *Id*., 5-6. He recommended the Income Qualified Safety and Heath Pilot Program be addressed in the DSM Plan and recovery of costs, if approved, be through the DSM tracker. He also noted that programs of this type used to satisfy certain requirements regarding restitution or funds to come into compliance with the law should not be recoverable through rates. *Id*., 6.

3. Intervenors. IG witness Gorman stated that funds for customer assistance pilots should come from shareholders, not ratepayers. Gorman, 39. IG witness Nicholas Phillips, Jr. testified that, while helping low income individuals is laudable, it should be voluntary and not a hidden transfer mechanism. He added that if I&M wants to pursue the programs, it should provide the funding and not force its customers to do so. He explained that requiring customers to fund these programs distorts the ratemaking process by building in subsidies to certain customers. Phillips added that if the IURC decides in favor of ratepayers funding, the assistance programs should be done on a cost of service basis, should be voluntary and funded by the class or classes receiving the benefits. It should also be transparent so that customers are aware of the purpose of the payments. Finally, because the cost is not related to energy consumption, it should be a uniform per customer charge, not a usage charge. Phillips Direct, 26-27. CAC-INCAA witness Olson provided an update on the Low Income Arrearage Forgiveness Pilot Program and said CAC-INCAA is generally pleased with this pilot program with one exception and recommended I&M go back and continue to work with stakeholders to coordinate this program with the Neighbor to Neighbor Pilot Program. Olson, 13-18. Mr. Olson supported I&M's proposal regarding the Energy Share Program, the Low Income Weatherization Program, and the Income Qualified Safety & Health Pilot Program and appreciated the Company's commitment to these programs. Olson, 18-19. South Bend witness Dorau stated South Bend generally supports the expansion of I&M's customer assistance programs and is enthusiastic about I&M's proposed Income Qualified Safety & Health Pilot Program, which she said will make a significant improvement in the long-term stability of customers receiving this investment. Dorau Direct, 10-12. Her cross-answering testimony elaborated on her view as to the benefits of these customer assistance programs. Dorau Cross-Answering, 7-8.

4. Rebuttal. Mr. Lucas explained the proposed initiatives are designed to address and gather additional information as to whether and how customer assistance programs can improve the longer term cost of providing service. Lucas Rebuttal, 19. He explained the connection between these pilot programs and I&M's cost of service and said it would be premature to categorically rule out these programs as Mr. Haselden does. *Id.*, 19-20. He stated I&M conducted the collaborative process for all customer assistance programs in good faith and has incorporated a number of substantive components proposed by the CAC. *Id.*, 20-21.

5. Discussion and Finding. While I&M currently has several customer assistance programs, these programs were agreed to and approved in its last rate case as

part of global settlement, and were not funded by ratepayers. I&M proposes to continue these programs, along with a new program to assist income-qualified customers in addressing safety and health issues that prevent the completion of a home energy audit, and require ratepayers to fund these programs. The OUCC and IG opposition is based on the fact that these programs are not necessary for the provision of utility service.

I&M's proposal for recovery of these costs appears to be based on the argument that these programs are only pilots, and are designed to gather information on expenses that may affect overall cost of service. Lucas Rebuttal, 19. While these pilot programs are designed to gather information as to whether programs such as these can help reduce the long term cost of providing service, I&M currently has three of the four programs in place to gather such information, and is in the process of implementing the Low Income Arrearage Forgiveness Pilot program with funds allocated due to the settlement agreement in Cause No. 44967. Lucas Direct, 32-33. I&M describes the information that it seeks through the pilot program, but does not state whether it is collecting this information from the current pilot programs, why it needs to extend the pilots to collect more information, and why funding should be provided from ratepayers rather than the company. We agree that these programs are not necessary for the provision of electric service, and without more supporting information for the pilots, we do not find that these programs should be continued on a pilot basis. Accordingly, we reject I&M's proposed request of these costs. However, I&M is free to further fund these pilots through company funding.

C. Economic Development.

1. I&M. Mr. Lucas discussed the importance of economic development and the Company's ongoing support of economic development in its service area. Lucas Direct, 18-19. He explained increased load from economic development benefits all I&M customers by spreading the fixed costs that are necessary to maintain the electric system, ultimately lowering customer rates. Lucas Direct, 19. Mr. Lucas described the Economic Impact Grant ("EIG") Program included in the settlement agreement in Cause No. 44967 and the Company's proposal to reflect $137,500 in the Test Year revenue requirement to continue the third component of the EIG after rates go into effect in this case. *Id.* at 21. He identified challenges to include the availability of a skilled workforce and need for an inventory of desirable existing buildings, available for sale or lease, and said these are critical attracting new businesses to the region. Lucas Direct, 21-22. He added the current building inventory in I&M's service territory is critically low and, as a result, the area has been unable to compete for some new investments. *Id.*, 22.

Mr. Lucas discussed two pilots the Company proposes to use to address these challenges. The Apprenticeship and Training pilot program would focus on workforce development over a two-year period at a cost of $350,000 per year. Lucas Direct, 23-27. The Building Development pilot would support the development of "spec" buildings over a two-year period at a cost of $150,000 per year. Lucas Direct, 24-27.

2. OUCC. Mr. Haselden recommended any funds used for economic development activities should not be included in I&M's cost of service. Haselden, 4. He stated these kinds of programs are not necessary for the provision of energy utility service, and relate to issues that state and local economic development agencies are intended to address. *Id.*, 4-5.

3. Intervenors. Industrial Group witness Phillips and Joint Municipal Group witness Mancinelli also recommended any funds used for economic development activities should not be included in I&M's cost of service. Phillips, 27; Mancinelli, 58. South Bend, the Joint Municipal Group and 39 North all suggested modifications to I&M's proposed economic development programs. Dorau Direct, 21-23; Mancinelli, 57-59; Cearley, 11-21. The Joint Municipal Group and 39 North also raised concerns regarding the consistency and prudence with which I&M has managed and administered the EIG program established in the Settlement Agreement, as approved by the Commission, in Cause No. 44967. Fasick, 5-14; Cearley, 12. Specifically, Mr. Fasick expressed frustration that I&M has been creating a moving target for eligibility requirements, resulting in what Fort Wayne contends is unreasonably withholding approval of an eligible application from Fort Wayne for a new water pressure station. Fasick, 9-12. Ms. Dorau's cross-answering testimony reiterated the importance of economic development support to municipalities seeking to maintain and grow their communities and viewed I&M's pilot programs as modest investments in developing I&M's expanded portfolio of economic development efforts. Dorau Cross-Answering, 6-7.

4. Rebuttal. Mr. Lucas explained why he disagreed that I&M's economic development program costs should be removed from the revenue requirement used to establish rates in this proceeding. He testified that customer load continues to be flat to declining and it is becoming exceedingly difficult to manage customer rates by managing costs. Lucas Rebuttal, 8-9. He said economic development is arguably one of the best tools the Company has to manage the cost of electricity for its customers. *Id.*, 8. He reiterated I&M has worked with local partners to bring over 4,500 jobs and nearly $900 million of capital investments to I&M's service area over the past five years. *Id.*, 8-9. He added in many of these opportunities, safe, reliable, and reasonable electric service was a significant consideration in attracting new companies to the area. He said these economic development successes benefit all of I&M's customers by spreading I&M's fixed costs over a broader base of customers. *Id.*, 9.

Mr. Lucas said I&M appreciates the constructive feedback from the City of South Bend on the economic development programs proposed in this case and said I&M is open to including the energy and construction trades into the Workforce Development pilot program. Lucas Rebuttal, 11. He also said I&M would be willing to incorporate modernizing existing commercial buildings or new commercial construction on an infill site as part of the Building Development pilot so long as they meet all of the eligibility requirements. *Id.* Mr. Lucas disagreed with Mr. Mancinelli's proposal to expand the existing EIG grant and have none the costs included in the revenue requirement. He said Mr. Fasick's recommendation is based on a misunderstanding of I&M's proposal and runs counter to the ratemaking principle that reasonable and necessary costs of providing service should be recognized in rates. *Id.*, 12-13. That said, he explained I&M sees value in the EIG program and proposes to continue to make available $137,500 per year of funding for the EIG. *Id.*, 12.

Mr. Lucas also responded to concerns raised by Mr. Fasick regarding I&M's administration of the existing EIG program. He said I&M is managing the program consistent with the eligibility requirements for Qualifying Projects and strongly disagreed with the notion that I&M is not administering the program correctly. Lucas Rebuttal, 14. He testified since the start of this program, I&M has conducted two Economic Development Stakeholder meetings with local economic development organizations and municipal staff responsible for economic development activities. He said in both of these meetings I&M discussed the EIG program, the application process, and encouraged all attending to participate in the program. Additionally, he noted I&M has conducted a number of one-on-one meetings with the Joint Municipals and economic development organizations to discuss the EIG program and issued multiple communications encouraging participation. *Id.*, 14-15. He testified much of the concern raised by Mr. Fasick's testimony regarding Fort Wayne's application for EIG funds appears to be based on a disagreement over the purpose and goal of the EIG program. *Id.*, 17. He said the intent of the EIG program was not for one utility to pay for the infrastructure project of another utility, which is the basis for Fort Wayne's application. He said I&M had multiple conversations with Mr. Fasick regarding this project and attempted to provide guidance on the necessary components of the application for the project to be approved. *Id.* He said I&M looks forward to working with Fort Wayne on any future applications that will benefit all I&M customers by promoting economic development opportunities in the I&M service area. *Id.*, 18.

With respect to Mr. Cearley's concerns, Mr. Lucas testified that 39 North has submitted five applications under the EIG program. *Id.*, 16. He said three applications were approved for funding and the other two applications did not meet the eligibility criteria. He said I&M has provided 39 North feedback on both applications that did not meet the eligibility criteria. He reiterated I&M is committed to managing the EIG program in an objective and reasonable manner consistent with the terms of the Settlement Agreement approved in Cause No. 44967. *Id.*

5. Discussion and Finding.

We have previously recognized the benefits of economic development through the creation of Economic Development Riders, which provides preferential rates for new or expanding businesses that meet certain conditions. In these proceedings, we stated that "[t]he Commission has long recognized the importance of economic development programs and supported efforts by Indiana utilities to attract additional investments within their service territories through economic development rates." *Re Ind. Mich. Power Co.*, Cause No. 43953, 2011 WL 727567 *4 (Ind. Util. Regulatory Comm'n Feb. 23, 2011). The Commission has also stated "it is our intent to foster quality economic development whenever possible." *Id.*, quoting *In re Indiana Michigan Power Co.*, Cause No. 41366, p. 7 (Ind. Util. Regulatory Comm'n Oct. 13, 1999); see also *Re Northern Indiana Pub. Serv. Co.*, Cause No. 42348, pp. 4-5, 2003 WL 21040235 (Ind. Util. Regulatory Comm'n Mar. 26, 2003) (explaining economic development benefits utility customers and the state). However, our support of economic development must be done in the context of our authority.

I&M's current economic development projects were implemented as part of a global settlement agreement in Cause No. 44967, in which I&M agreed to fund these programs with shareholder funds. I&M proposes to continue one component of the Economic Impact Grant ("EIG") program previously implemented. As stated in the settlement agreement in Cause No. 44967, the qualifying projects for the EIG program, include "industrial and headquarter site development due diligence, workforce development initiatives, housing development initiatives, spec building development, and job creation and retention." *In re Ind. Mich. Power Co.*, Cause No. 44967, Settlement Agreement p. 16 (Ind. Util. Regulatory Comm'n May 30, 2018). I&M also proposes two new programs. The first is an Apprenticeship and Training pilot program, which provides direct reimbursement for companies to develop apprentice and employee training programs. The second is a Building Development pilot program, which would assist communities by reimbursing eligible expenses related to the development of available buildings for businesses.

We agree with the OUCC that these programs go far beyond what is reasonably necessary for the provision of electric service. Reimbursement for a jobs training program, a real estate development program, and other local development projects are not related to providing electric service and should not be recoverable from ratepayers. It is not a sufficient reason to allow funding for a program merely because that program may ultimately increase economic development, leading to increased load which could spread fixed costs over more customers. This could lead to a slippery slope where any expenditure could be deemed reasonable if it could ultimately lead to a potential increase of load to spread fixed costs, even if these costs are not related to the provision of electric service. Because the direct benefits of these programs are outside of the reasonable provision of electric service, we deny I&M's request to fund these programs. I&M is free to expend shareholder funds for these programs on its own initiative.

D. Employee Medical and Dental Expenses.

1. OUCC. Mr. Mark Garrett testified the Company's forecasted Test Year includes $27 million for employee medical costs, which he said represents an increase of 30% over the 2018 historical level. M. Garrett, 43. Mr. Garrett explained that Willis Towers Watson's 2018 annual healthcare cost survey reported an increase in healthcare costs in 2019 of about 5%. To be consistent with the market, he recommended an annual 5% increase be applied to medical and dental insurance expenses (total combined increase of 10.25%) as well as a 5% increase to dental costs. *Id.*, 44. Mr. Garrett explained that from a ratemaking perspective, and especially in a situation where a forecasted test year is being used, I&M should be expected to contain future medical costs. *Id.*

2. Rebuttal. Mr. Carlin testified the Company relied on third-party actuarial experts to evaluate and project its future medical costs. He said as a self-insured plan, AEP's medical benefit expense is actuarially determined based on the plan design, past participant medical expenses, healthcare trends (both medical and prescription) and the rates and terms of vendor contracts that are in place. Carlin Rebuttal, 62. In addition, he noted the Company relied on third-party experts to inform the medical expense growth rates used to project 2020 medical expenses. *Id.* He discussed the factors affecting the Company's 2020 medical cost trend and concluded that the Company's use of a 5.5% medical expense escalation rate, when combined with the actuarial analysis, was a reasonable and robust method for making this projection. *Id.*, 63-64.

3. Discussion and Finding. We agree with the OUCC that from a ratemaking perspective, and especially in a situation where a forecasted test year is being used, I&M should be expected to contain its future medical costs to a level that is no greater than cost levels expected in the market. Moreover, the record shows I&M's 2018 employee medical expense was approximately $20.8 million, which it escalated in 2019 to approximately $25.5 million, a 22% increase. Carlin Rebuttal, 63. I&M then took that escalated 2019 medical expense projection and escalated it again when projected 2020 medical expense to approximately $27 million, an increase of 5.5%. *Id*. The escalation of I&M's 2019 medical expense projection is

significantly out of line with I&M's Attachment ARC-6R, which shows annual medical premium rate increases across the energy utility industry from 2001 – 2019. Attachment ARC-6R shows that across the energy utility industry, Willis Towers Watson projected increases to medical premiums from 2018 to 2019 of only 5.0 – 5.5%. While I&M chooses to focus on the reasonableness of its 2020 escalation (5.5%), the OUCC's adjustment addresses the fact that I&M's 2019 expense is overstated. Furthermore, an increase of nearly 30% to medical expense in just two years is unreasonable. As a result, we adopt OUCC's proposed adjustment for medical and dental expense escalations.

E. <u>Employee Adjustment – Full Time Employee.</u>

1. <u>Industrial Group.</u> IG witness Gorman proposed to reduce I&M's projected Full Time Employee ("FTE") level of 2,305 down to 2,199. Mr. Gorman testified that I&M's actual employee headcount has always been substantially less than its budgeted level of FTE. Mr. Gorman recommended an adjustment to the test year budgeted costs of FTEs to recognize that I&M's actual cost of FTEs is expected to be less than its budgeted amount. *Id*. Mr. Gorman recommended an adjustment to I&M's payroll expense to remove annual recurring costs associated with approximately 100 unfilled budgeted FTE positions. Mr. Gorman testified this adjustment results in a decrease in Test Year O&M expense of $4,323,000 and a decrease of $822,000 in capitalized costs. Gorman, 8, 30-32; Attachment MPG-6.

2. <u>Rebuttal.</u> Mr. Lucas stated I&M's actual FTE headcount has been below its budgeted FTE count in recent years due to an increased amount of attrition. Lucas Rebuttal, 25. He said to the extent I&M has unfilled positions in 2020 there are potentially other components of the forecast, such as contract labor, overtime, or outside services that could potentially increase to compensate. He stated I&M has provided a comprehensive O&M forecast to accomplish the work plans presented in this case. He noted the overall forecasted O&M was reviewed by the business units and I&M management at the time the forecast was prepared and reflect what is reasonably necessary to complete the work plans in the Test Year. *Id.*

3. <u>Discussion and Finding.</u> *The OUCC supports the IG's discussion and findings on this issue.*

F. <u>EZ Bill Program.</u>

1. <u>I&M.</u> Mr. Williamson explained the EZ Bill Program was approved in Cause No. 45114 and is a voluntary billing option designed to allow eligible residential and small commercial customers to be charged a fixed amount per month for electric service over a 12-month period. Williamson Direct, 63. He said I&M is proposing that both EZ Bill Program costs and revenues be accounted for above the line as the program is a customer rate offering like any other I&M rate offering.

2. <u>OUCC.</u> Mr. Lantrip recommended the Commission require I&M to treat all EZ Bill Program profits and losses below-the-line. He said treating all such costs above-the-line would socialize costs among all ratepayers, even though not all ratepayers will qualify for or utilize this optional program. Lantrip, 2, 9-12. He suggested in lieu of rendering a decision in this case on whether EZ Bill Program costs should be treated above or below the line, it would

be appropriate to see the EZ Bill Program through to the end of the three-year period, review I&M's data to verify program costs and profitability, as well as customer data and participation, in order to determine whether recovery above-the-line is appropriate in I&M's next rate case. *Id.*, 13.

3. Rebuttal. Mr. Williamson testified it is not reasonable to account for program costs and revenues below-the-line. He said the EZ Bill program is one of several customer programs that I&M provides to its customers, and the costs of offering these programs are part of I&M's overall cost of serving its customers. Williamson Rebuttal, 51. He stated since the program will be offered to a large number of customers, it is reasonable that the program costs be viewed as a cost of providing service for all customers and not just those who participate. *Id.*, 54. He said the status of the program is not cause for disallowance of these program costs and the OUCC's "wait-and-see" approach indicates the OUCC's recommendation is outcome based, not principle based. *Id.*, 55.

4. Discussion and Finding. We first note I&M is not proposing to include any costs or revenues associated with the EZ Bill Program in its revenue requirement in this Cause. Rather, I&M is requesting regulatory accounting treatment to treat the program costs and revenues as a component of I&M's cost of service in subsequent rate proceedings. Mr. Williamson states that I&M currently offers other budget billing programs that are treated as above-the-line costs, as those programs are available for a large number of customers. Williamson Rebuttal 53. We agree with I&M's decision to not include EZ Bill program costs in its cost of service at this point, as Mr. Williamson states that I&M does not know how many customers will choose to participate in the EZ Bill program, and I&M does not yet have any experience with how EZ Bill revenues may differ from revenues under standard tariffs (i.e. I&M does not yet have any actual data on EZ Bill program "profits and losses"). Williamson Direct 65-66.

The evidence shows that the EZ Bill program is but the newest of many budget billing programs I&M provides its customers and therefore might be a superfluous tariff offering unless participation can demonstrate the associated costs and revenues should be properly included in I&M's next base rate case's cost of service. We find that our decision to decline jurisdiction in the EZ Bill Cause No. 45114 should be upheld. EZ Bill should be a separate tariff program offering by I&M under the Alternative Regulatory Plan and will be addressed in the next base rate case which I&M files once it has obtained more relevant data upon which we may rule.

G. Factoring Expense.

1. OUCC. Mr. Mark Garrett explained that I&M and another AEP affiliate, AEP Credit, Inc., have a contractual arrangement whereby AEP Credit purchases, without recourse, certain accounts receivable arising from the sale and delivery of electricity in Indiana. M. Garrett, 54. He testified that the process of one company selling its accounts receivable, usually at a discount, to a third-party purchaser is called factoring, and that this process gives rise to factoring expense. He stated that I&M included $9.701 million in factoring expense in the 2020 Test Year, of which $7.825 million is assigned to Indiana. Mr. Garrett compared I&M's forecast against its actual factoring expense for years 2016 through 2018, and found I&M's three-year average expense is $7.632 million. He concluded that, for

reasonableness and to manage what is an unknown expense, I&M's forecasted factoring expense should be reduced to reflect the most recent three-year average. Mr. Garrett explained that all indications are that interest rates will be *lower* in the rate effective period, as the Federal Reserve recently cut interest rates by 25 basis points on July 31, 2019, and expects further cuts in the future. He testified that the Company's requested level of factoring expense is overstated, and that a three-year average expense is appropriate. *Id*., 54-55. Mr. Garrett recommended that factoring expense be reduced by $1,668,892. *Id*., 55.

2. Rebuttal. Mr. Lucas explained the Test Year factoring expense forecast is based on reasonable assumptions at the point in time the forecast was prepared. Lucas Rebuttal, 23. He said these assumptions take into consideration the best information available at the time and provide a more accurate methodology to develop a forward-looking projection than simply using a 3-year average of historical data as Mr. Garrett proposes. He stated contrary to Mr. Garrett's assumptions, recent trends in I&M's factoring expense show the amount included in the Test Year may be understated and explained this corroborates that the Test Year level is reasonable and no adjustment should be made. *Id*., 24-25.

3. Discussion and Finding. We recognize that I&M's factoring expense includes the four components mentioned by Mr. Lucas. We note, however, that the Bad Debt Expense component represents a very small percentage (less than 1%) of the total factored receivables. *See* WP-Exhibit A-234789_06252+ at tab "Conversion Factor A-8", which shows Uncollectible Accounts Expense as .2126% of Operating Revenues. Interest rates are by far the most significant driver in the factoring expense calculation. *Id*. Mr. Garrett testified that the Company's projection does not sufficiently adjust for the reduction in interest rates that has occurred. M. Garrett, 55. He testified that the Federal Reserve cut interest rates by 25 basis points in July, and that the Federal Reserve further indicated that a series of rate cuts may follow. *Id*.

In its calculations, the Company uses a LIBOR rate of 3.25%. Lucas Rebuttal, 24. Mr. Garrett testified the LIBOR for the rate effective period will be much lower than the Company estimated. Based upon the relative importance of interest rates in this calculation, we are persuaded that the Company's calculations are significantly overstated—the question is, by how much. We find Mr. Garrett's use of a 3-year historical average for these costs to be the best information available to us at this time. This approach is fair to the Company because the interest rates over the past 3-year period used in the average will be much closer to the actual rates in the 2020 rate year than the 3.25% estimate utilized by the Company. We cannot set rates using a projected factoring expense calculation that we know for a fact is materially overstated.

H. I&M *IM Plugged In* Pilot Program.

1. I&M. Mr. Lehman discussed the Company's proposed three-year pilot program to encourage plug-in electric vehicle ("PEV") adoption in a way that optimizes the overall electric system. The program consists of a number of tariffs and incentives targeting residential and small commercial PEV charging; multi-unit dwelling charging; commercial and industrial fleet and workplace charging; and electric vehicle education and technical development. He supported the *IM Plugged In* program costs, which total $700,000 per year.

Lehman Direct, 3. He described the need for the pilot and identified the benefits to participants and all other I&M customers. *Id.*, 4-20.

Mr. Williamson stated because the level at which customers will participate in the *IM Plugged In* program is difficult to predict, I&M has not included any transportation electrification costs in its Test Year cost of service. Williamson Direct, 59. Instead, he said I&M requests deferral accounting authority to defer the actual cost of transportation electrification incentives as a regulatory asset to be recovered in I&M's next base rate case. *Id.* He explained the requested accounting treatment and said that to recognize the time value of money/opportunity cost incurred by the Company, I&M will accrue carrying costs on the deferred unrecovered balance using the pre-tax WACC rate approved by the Commission in this proceeding. *Id.*

2. OUCC. Ms. Aguilar raised concerns with I&M's proposal to use ratepayer funds to provide rebates for electric vehicle owners to purchase 240 volt charging equipment. Aguilar, 16-20. Ms. Aguilar stated I&M witness Mr. Lehman made numerous claims throughout his testimony regarding optimizing unused off-peak system capacity, but I&M has provided no empirical data other than opinions to support the program's benefits. Ms. Aguilar highlighted I&M's discovery responses, which frequently assert benefits are "based on Mr. Lehman's general industry experience and knowledge, and not specific documentation or analysis." *Id*., 17. Ms. Aguilar was also concerned with I&M's lack of a robust cost benefit analysis. To derive the net benefit of $108, I&M made crude assumptions about how many miles would be driven by a customer and how often a customer would utilize off-peak charging and only applied to the residential portion of the program. *Id*., 18. Given the reduced off-peak rate benefit to be offered to electric vehicle owners, Ms. Aguilar is not convinced a rebate for the 240-volt charging equipment is needed. Ms. Aguilar recommended the Commission deny I&M's request to recover the costs of offering a rebate totaling $700,000. *Id*., 21.

3. South Bend. South Bend witness Dorau agreed the *IM Plugged IN* program is sensible and helps overcome barriers to PEV adoption while avoiding potential negative impacts to the shared grid. Dorau Direct, 16.

4. Rebuttal. Mr. Lehman clarified that I&M is not proposing the incentive because 240V charging is a barrier to electric vehicle adoption. *Id.* He explained that many PEV owners can support their daily driving through 120V charging; however, 240V charging is necessary for customers to have the ability to easily shift their entire charging load to off-peak times. Lehman Rebuttal, 5. He said the number of hours necessary to charge a PEV is significantly reduced when using 240V charging as opposed to 120V charging and this is why I&M is proposing to provide an incentive for customers to install 240V charging equipment – so that they can take advantage of the proposed off-peak charging rate and shift all of their PEV charging to off-peak times. *Id.* Mr. Lehman explained that I&M used reasonable projections and data for its estimate that each residential and small commercial participant can be expected, on average, to provide $579 in net benefits to all I&M customers over a 10-year period. Lehman Rebuttal, 2. He said one reason the Company has proposed to implement the PEV program as a pilot is to obtain empirical data, evidence and customer feedback necessary for developing future programs that focus on increased system utilization and downward pressure on customer electric

rates. *Id.* He added that the customer benefits from the residential and small commercial component of I&M's proposed *IM Plugged In* pilot program can be reasonably estimated before the program is implemented and I&M-specific data is available to support these estimated benefits. *Id.*

5. Discussion and Finding. The record shows PEV adoption is accelerating and that it is important that load from electric transportation be integrated into the grid in a manner that minimizes or eliminates additional system costs. Lehman Direct, 4-7. While I&M attempts to show the benefits that off-peak charging will bring to all customers, and the benefits of faster charging at 240V, it fails to specifically show that a subsidy for the installation of 240V charging equipment is necessary to incent the adoption of 240V charging. I&M's attempt to distinguish the subsidy as an incentive fails to address why this additional step is needed as opposed to only implementing the beneficial PEV off-peak rates. Stating that 240V charging would allow for greater off-peak charging does not lead to the necessity of a subsidy, and this is not sufficiently explained by I&M. Lehman Direct, 13-14; Lehman Rebuttal, 5. As stated below, we approve of the incentive rates for electric vehicle charging and find that this is sufficient incentive for customers to adopt 240V charging. Accordingly, we reject I&M's proposal for the rebate associated with the *IM Plugged In* program.

I. Incentive Compensation.

1. OUCC. Mark E. Garrett was retained by the OUCC to offer testimony in this Cause regarding I&M's short-term and long-term incentive compensation plans. Mr. Garrett has testified in numerous regulatory proceedings involving AEP's incentive compensation plans related to I&M's affiliate companies within the AEP system, including Public Service Company of Oklahoma ("PSO") and Southwestern Electric Power Company ("SWEPCO") in Texas and Arkansas. M. Garrett, Appendix MG-1.

Mr. Garrett recommended two adjustments for the ratemaking treatment of the Company's incentive compensation plan costs: (1) the costs should be adjusted to target levels, (which was proposed by the Company) and (2) the target-level costs then should be allocated 50/50 between ratepayers and shareholders. Mr. Garrett testified that this allocation is appropriate because of the specific metrics of I&M's annual short-term plan, which is heavily weighted toward financial performance measures. He testified that the plan has an earnings-per-share (EPS) trigger, (minimum threshold), below which no incentive payments will be made. Second, the plan has EPS funding mechanism, which provides for increased levels of funding for employee incentives based on AEP's achievement of higher earnings levels. *Id.*, 7-8. AEP's funding is tied to EPS (70% weight), safety and compliance (10% weight) and strategic initiatives (20% weight). *Id.*, 11. Mr. Garrett testified that the combination of the EPS trigger and the EPS funding mechanism causes I&M's plan to be more than 70% weighted to financial performance metrics. In addition, he explained that I&M's "strategic initiatives" category contains additional financially-based performance measures. *Id.*, 11. He stated that financial performance metrics benefit shareholders more than they do ratepayers, and that is why it is appropriate for a meaningful portion of the plan costs to be allocated to shareholders, as is the case with AEP's operating companies in other jurisdictions. *Id.*, 17.

Mr. Garrett noted other problems with AEP's plan. As shown in the Company's filed MSFR, the plan is structured to benefit highly-compensated senior level employees more than rank and file employees. Employees in high level positions are afforded disproportionate incentives to maximize shareholder earnings, while employees at lower levels (who often provide customer service and day to day operations) have lower incentive opportunities under a top-heavy, financially-based incentive plan. *Id.*, Table at 10.

Mr. Garrett applied the Commission's standard for recovery of incentive compensation. He pointed out that the Commission has previously limited recovery of incentive compensation in order to allocate an appropriate portion to shareholders. *Id*., 14-15. He testified that his recommendations adhere to the Commission's three-pronged criteria: (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) shareholders are allocated part of the cost of the incentive compensation programs. *Id*.

Mr. Garrett explains that his recommendations with respect to I&M's plan are consistent with the treatment of AEP's incentive plan in other jurisdictions. Specifically, the AEP incentive compensation is: (1) adjusted to target levels (which reflects market); and *<u>then</u>* (2) allocated between ratepayers and shareholders—with approximately 60% of the target-level costs disallowed in Texas, and 50% of the target-level costs disallowed in Oklahoma. *Id*., 17-19.

Mr. Garrett testified regarding an incentive survey of the western states, which shows that 19 of the 24 western states disallow financial-based incentives. Of the other 5 states in the survey of the 24 western states, one state disallows *all* incentives, two states use some other sharing approach and in two states incentive pay is not an issue. *See* summary of survey at Garrett, 20. His testimony showed that a survey of four additional states surrounding Indiana—Illinois, Michigan, Kentucky and Wisconsin—also disallow financially-based incentives. *Id.*, 22-23. He explained that this is important because it means that I&M will not be at a competitive disadvantage when compared to other utilities if 50% of its target level (market level) incentive compensation is allocated to shareholders. *Id.*, 27.

Mr. Garrett provided extensive rationale as to why financial-based incentive compensation is disfavored among a majority of regulators. These rationale include the following: (1) payment is uncertain; (2) many of the factors that significantly impact earnings are outside the control of most company employees and have limited value to customers; (3) earnings-based incentive plans can discourage conservation; (4) the utility and its stockholders assume none of the financial risks associated with incentive payments; (5) incentive payments based on financial performance measures should be made out of increased earnings; and (6) incentive payments embedded in rates shelter the utility against the risk of earnings erosion through attrition. *Id.*, 24-26. Mr. Garrett further testified that when the costs associated with incentive plans are excluded, the *primary* rationale is that financially-based incentives benefit shareholders more than they do ratepayers. *Id.*, 24.

At the evidentiary hearing, Mr. Garrett testified that the Commission can avoid excessive pay levels when it "adjusts down to target levels because target levels are market levels. Anything above target would be excessive pay." Tr. K-62, lines 11-24. He also testified during the evidentiary hearing that the Commission's order in Cause No. 43526 shows "exactly what [the OUCC] recommended here. So the company's already adjusted down to target levels, which you have to do to get to market." *Id.*

In his prefiled testimony, Mr. Garrett also proposed to disallow in its entirety I&M's long-term incentive plan ("LTIP"), which he described as being "for executives and managers." Garrett, 30-32. He cited to the disallowance of LTIP in Indiana American's rate case in Cause No. 44022. He further cited to orders from other states. *Id*., 32-36.

Mr. Garrett testified that long term incentives, especially stock-based incentives such as AEP's, are financial-based incentives and should be disallowed for all of the reasons set forth in the previous section. *Id.*, 31. He explained that incentive compensation payments to officers, executives, and key employees of a utility, such as the long-term incentive payments, are generally excluded for ratemaking purposes. Further, long-term incentive plans are specifically designed to tie compensation to the financial performance of the Company. Mr. Garrett testified that this is done to further align the interest of the employee with those of the shareholder. *Id*. Since the compensation of the employee is tied over a long period of time to the company's stock price, it motivates employees to make business decisions from the perspective of long-term shareholders. He stated that this intentional alignment of employee and shareholder interests means the costs of these plans should be borne solely by the shareholders. *Id*., 32. Mr. Garrett explained it would be inappropriate to require ratepayers to bear the costs of incentive plans designed to encourage employees to put the interests of the shareholders first.

Mr. Garrett also provided the results of an incentive survey of the 24 western states, which shows that 20 of the 24 states tend to exclude all or virtually all long-term stock-based incentive pay, either through an outright ban on stock-based incentives or through applying the *financial performance* rule, which has the effect of excluding long-term earnings-based and stock-based awards. *Id.*, 34. These states include Arizona, Arkansas, California, Colorado, Hawaii, Idaho, Kansas, Louisiana, Minnesota, Missouri, Nevada, New Mexico, North Dakota, Oklahoma, Oregon, South Dakota, Texas, Utah, Washington and Wyoming. In the other four states surveyed, Alaska, Iowa, Montana and Nebraska, the issue just has not been addressed. Mr. Garrett also provided evidence that additional surrounding jurisdictions - Illinois, Kentucky, Michigan and Wisconsin - also follow this approach. *Id*., 22-23. Mr. Garrett recommended adjustments to reduce the short-term incentive plan expenses by $9,022,802 and the long-term incentive plans expenses by $6,980,198.

2. Industrial Group. Mr. Gorman testified on behalf of the Industrial Group, and he argued that the portions of Petitioner's incentive plan tied to financial performance should be disallowed. He proposed removing that portion of Petitioner's short-term incentive plan. He also proposed to disallow the entirety of Petitioner's LTIP because, in Mr. Gorman's opinion, LTIP is purely financial. Gorman, 24-29.

3. Rebuttal. Petitioner's witness Carlin testified in rebuttal to the proposed incentive pay disallowances. He testified Mr. Garrett is disregarding 20 years of IURC precedent concerning the recovery of incentive pay. Carlin Rebuttal, 2. He noted the recovery of incentive pay dates back to *Public Service Indiana*, Cause No. 40003 (IURC 9/27/1996). He testified the presence of a financial metric trigger has previously been rejected by this

Commission as a reason to disallow recovery of incentive pay and cited to *Indiana American Water Company*, Cause No. 42029, (IURC 11/6/2002), where Indiana American had an earnings per share "gatekeeper". *Id*., 8. Mr. Carlin provided the various factors that go into the calculation of incentive pay and noted both Mr. Garrett and Mr. Gorman overstated the portion made up by financial performance. In fact, it is only 40% of the total AIP award that is related to financial performance. *Id*., 10. The primary measures are non-financial operating measures. *Id*. He disputed Mr. Garrett's testimony that operational portions are also tied to financial metrics. He explained the transmission construction measurement is tied to completing approved projects expeditiously and under budget and not to the selection of projects to complete. *Id.*, 24.

Mr. Carlin corrected Mr. Garrett's quote of the Indiana standard. While Mr. Garrett had stated it is whether incentive compensation is reasonably necessary to attract a talented workforce, the actual standard is that incentive pay does not result in excessive pay levels beyond what is reasonably necessary to attract a talented workforce. *Id.*, 11. Mr. Carlin noted the significance of the distinction is that Indiana does not look at incentive pay in isolation but rather looks at total compensation and asks whether total compensation is greater than that reasonably needed to attract a talented workforce. *Id.*, 12. He cited to *Indiana American Water Company*, Cause No. 43680 (IURC 4/30/2010) for this proposition. He then presented an analysis showing how I&M's average target total compensation is within a single digit percentage point of the market median for each type of employee but would fall well below the median if the incentive compensation were not provided. *Id*., 13-14.

Mr. Carlin also responded to Mr. Garrett's citation to the 15% allocation to shareholders with respect to Indiana American. He noted that in this case, the incentive compensation proposed is based upon the target award, and everything above target is allocated to shareholders. He presented an analysis that showed over the past five years the historic payment has been greater than 150% of target and in some years as high as 191% of target. *Id*., 18-19. With respect to the earnings per share trigger, he explained it is set at a low level that is readily achievable and is only intended to protect against particularly difficult financial circumstances. *Id*., 22. He then responded to Mr. Garrett's surveys of other states. *Id*., 25-30.

With respect to Petitioner's LTIP, Mr. Carlin explained LTIP is available to 1,150 employees. Seventy-five percent of the LTIP award is based upon financial performance, but 25% consists of restricted stock units. He said the restricted stock units are provided as a retention goal and that the restricted stock units do not have any metrics, goals, or measures. *Id*., 48-49, 51.

4. <u>Discussion and Finding.</u> This is the first occasion in which I&M's current incentive compensation plan has been both contested by the parties and litigated before this Commission. In I&M's last litigated rate case, Cause No. 44075, incentive compensation was not opposed, and therefore, no specific findings were made regarding I&M's plan metrics, financial trigger, or financially-based funding mechanisms. *In re. Ind.-Mich. Power Co.*, Cause No. 44075, p. 10, 2013 WL 1180842. Petitioner's last rate case, Cause No. 44967, was settled and has no precedential value.

It has been our longstanding practice to conduct a thorough evaluation of the specific metrics of a utility's incentive compensation plan, on a case by case basis, in order to determine the appropriate amount to include in rates, as well as the portion that should be allocated to shareholders. With respect to incentive pay we apply a 3-part test for recovery of incentive costs in rates:

> The criteria for the recovery of incentive compensation payments through rates are well settled in Indiana: (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) shareholders are allocated part of the cost of the incentive compensation programs.

Re S. Ind. Gas & Elec. Co., Cause No. 43839, Final Order p. 50, 2011 WL 1690057, 289 P.U.R.4th 9 (Ind. Util. Regulatory Comm'n Apr. 27, 2011), *citing N. Ind. Pub. Serv. Co.*, Cause No. 43526, 2010 WL 3444546 (Ind. Util. Regulatory Comm'n Aug. 25, 2010).

Although I&M cites the *NIPSCO* case in support of its position that *all* of its target level compensation should be recovered through rates, Mr. Garrett explained at the evidentiary hearing that his recommendations are more in line with our decision in NIPSCO. Tr. K-62, lines 11-24. In *NIPSCO*, the amount we approved for inclusion in rates is 50% of the target level expense, which is precisely what Mr. Garrett recommends here. In NIPSCO, we stated:

> Mr. Campbell explained that NiSource's shareholders are already allocated a portion of the incentive plan costs because NIPSCO's adjustment only includes incentive compensation at the trigger level *which is 50% below the target amount*, leaving *shareholders* to cover the target and stretch levels. Thus, NIPSCO's adjustment reduces electric test year incentive compensation expense by $916,264. Miller Direct at 20. NIPSCO's adjustment is consistent with incentive compensation adjustments that we have previously approved for other utilities.

N. Ind. Pub. Serv. Co., Cause No. 43526, 2010 WL 3444546 (Ind. Util. Regulatory Comm'n Aug. 25, 2010, p. 63 (emphasis added).

Mr. Carlin contends that I&M has satisfied the sharing requirement because the Company adjusted its 2020 test year to target levels, with I&M's shareholders bearing the expense "in excess of the target level." Carlin, 17. The problem with this approach, in I&M's case, is that I&M's target levels are set to reflect a "market median" level of compensation.

This is demonstrated in the testimony of Mr. Carlin, wherein he testifies that under I&M's incentive plans, the Company's target levels are at the "market median" level of compensation. Carlin, 13. Mr. Carlin further provides schedules with his testimony, (ARC-3R, ARC-4R, and ARC-5R) that also demonstrate that I&M's *target* level of incentive compensation is set at the market median for December 31, 2018.

Thus, I&M's adjustment to target levels merely satisfies our second prong, that is, it avoids recovery of excessive pay levels in rates. An adjustment to the market median does not effectively impose any meaningful *sharing* of legitimate, recoverable incentive compensation costs with I&M's shareholders. Ratepayers should only be required to pay compensation equal to market level, regardless of whether the Company's plan has financially-based performance measures. As such, the Company's approach of allocating its above-market pay to shareholders does not satisfy the third prong of our test - because above market costs would be disallowed and allocated to shareholders in any event.

Mr. Garrett recommends a 50/50 sharing of target level compensation, in keeping with our treatment in *NIPSCO*, Cause No. 43526, because this results in a true sharing of legitimate, market-based compensation. A 50/50 sharing of target level costs is appropriate to reflect the specific metrics of I&M's plan, which is heavily weighted toward financial performance measures, and therefore benefits shareholders at least as much, if not more than, ratepayers.

I&M references Indiana-American's incentive compensation plan in Cause No. 42029 as support for our approval of a "gatekeeper" or "trigger" for funding of incentive compensation. However, notable differences between the plans exist. Indiana-American's plan bases funding on *two* triggers that must *both* be met – "[a] minimum earnings per share ("EPS") of American *and* attainment of individual performance expectations of the participating company and employee." *Re. Ind. Amer. Water Co.*, Cause No. 42029, 2002 WL 32091039 (Ind. Util. Regulatory Comm'n Nov. 6, 2002), p. 43 (emphasis added). Indiana-American's plan also has two *equally weighted* categories for financial and operational measures. *Id.* AEP's Annual Incentive Compensation Plan relies solely on earnings as the trigger to dictate the availability of incentives, and then its funding mechanism is also weighted more than 70% towards financial performance to determine the amount of incentive compensation that will be paid.

We find that the OUCC's recommendations best align with this Commission's views on incentive compensation, and that the Commission's three-part test is best satisfied with a 50/50 sharing of the Company's target levels for incentives. AEP's incentive plan is heavily weighted toward financial measures through is EPS trigger and its EPS funding mechanism. Our decision recognizes the fact that incentive compensation benefits both ratepayers and shareholders alike, but financial-based incentive compensation is of a more immediate benefit to shareholders.

With respect to the Company's Long-Term Incentive plan, we find the Company's long-term plan aligns the interests of employees with shareholders. I&M's long-term plan is set forth in MSFR Vol. II, 1-5-8(a)(12), p. 5 of 28. It provides:

> **Section 1.03. Purpose of This Plan.** The purposes of the Plan are to: (a) *strengthen the alignment of interests between those Employees and Directors of the Company* and its Subsidiaries who share responsibility for the success of the business and *those of the Company's shareholders*, (b) facilitate the use of long-term incentive compensation and the provisions of market competitive total compensation to Employees, (c) *increase Employee ownership of shares of the Company's common stock to encourage ownership behaviors*, and (d) encourage Plan Participant retention. (Emphasis added).

The language from the Company's plan speaks for itself. I&M seeks to strengthen the alignment with shareholders and to "encourage ownership behaviors" in employees by making its key employees into shareholders themselves. Because the Company's key employees and directors are shareholders of the Company, this creates a strong incentive to align behaviors and goals with shareholder's interests. The Commission finds that this alignment of interest between shareholder and employees is more of a benefit to shareholders than it is to ratepayers. As a result, we find the costs of the long-term incentive plan should not be included in rates. This is consistent with our treatment of long term incentive compensation that is strongly tied to financial performance. *See Ind. Amer. Water Co.,* Cause No. 44022, p. 66, 2012 WL 2154248 (Ind. Util. Regulatory Comm'n Jun. 6, 2012).

J. Pension Expense

1. OUCC. OUCC witness Mark Garrett testified I&M did not include the return on pension benefit plan assets in its calculation of pension expense for ratemaking purposes. He said that, as a result, Petitioner had included test year employee benefits expense of $39.5 million. M. Garrett, 41-42. He based this on his review of MSFR 1-5-8(a)(13). Mr. Garrett ultimately proposed to reduce Petitioner's Test Year pension expense on a jurisdictional basis by $15,496,003. In the evidentiary hearing, in response to I&M's cross-examination that attempted to show the $39.380 million may not have been the number actually used in I&M's revenue requirement calculations, Mr. Garrett testified that if there was a discrepancy between the Company's filed MSFR: 1-5-8(a)(13) Projected, and the amount actually used to set rates, that difference should have been corrected in the Company's rebuttal testimony, and it was not. Tr. K-36, lines. 10-21; K-59, lines. 19-25. Mr. Garrett testified at the hearing that as a result, there is nothing in the record that shows the Company's projected expense levels in its filed MSFR were not actually used in its requested revenue requirement. *Id*. He explained that his recommendations are based upon the Company's filed MSFR and if the Company's data in its MSFR is incorrect, the Company had the opportunity to file an errata or to provide a correction in its rebuttal testimony, which the Company failed to do. *Id*.

2. Rebuttal. Mr. Ross testified Petitioner's contributions to the pension fund in excess of pension expense lower pension expense and result in lower customer rates. Ross Rebuttal, 11. He was asked on redirect about a cross-examination exhibit and testified that the return on the pension fund is included as an offset to the revenue requirement in the cost of service. He testified on redirect that the confusion is likely due to a recent change in generally accepted accounting principles ("GAAP") which modifies how pension expense is reported for financial reporting purposes. Tr., I-65-66.

3. Discussion and Finding. We agree with Mr. Garrett that I&M should have provided evidence with its rebuttal testimony showing how its actual revenue requirement calculations differ from those shown in MSFR: 1-5-8(a)(13) Projected so that the parties could have an opportunity to audit those schedules. Errors that go uncorrected in MSFRs serve only to create confusion amongst the parties and the Commission. Not only did I&M not revise its MSFR submission or offer revised calculations with its rebuttal testimony, the record shows I&M provided no rebuttal evidence whatsoever in response to Mr. Garrett's adjustment. If I&M claims the OUCC's adjustment is in error, it has the burden to show this with timely evidence. Accordingly, we accept the OUCC's adjustment to pension expense.

In our prior discussion of I&M's "prepaid pension asset," we accepted Ms. Stull's $1,331,289 increase to pension expense, and hereby incorporate that adjustment to I&M's total authorized pension expense discussed herein.

K. Major Storm Expense and Major Storm Reserve.

1. I&M. Mr. Williamson testified I&M requests to continue the Major Storm Damage Restoration Reserve as approved in Cause No. 44075 and 44967. Williamson Direct, 6, 58. Messrs. Williamson and Isaacson explained I&M's Indiana jurisdictional, major storm distribution O&M expense has ranged from as high as $12.5 million to as low as $1.2 million from 2008 to 2018, compared to the baseline of $4,047,529 approved in Cause No. 44967. Williamson Direct, 58; Isaacson Direct, 39-40. I&M proposed to continue the Major Storm Reserve and associated accounting using the current $4,047,529 baseline given the unpredictable and potentially significant nature of these costs. Williamson Direct, 58-59; Isaacson Direct, 41.

2. OUCC. The OUCC did not oppose I&M continuing the Major Storm Reserve but recommended decreasing the Major Storm Reserve baseline to $2,473,000 based on the five-year average major storm expenses for the period 2014-2018. Alvarez, 18-19, 38.

3. Rebuttal. Mr. Williamson said I&M was agreeable to the OUCC's proposal with one modification. He said if historical dollars are used to determine a future cost, inflation must be considered. Williamson Rebuttal, 63. He applied the Gross Domestic Product as a general measure of inflation and determined that the Commission should use $2,675,000 as the distribution major storm reserve baseline. *Id.*, 63-64.

4. Discussion and Finding. The record shows I&M's distribution O&M expenses associated with major storm restoration efforts can be significant, are volatile in nature, and are largely outside the Company's control. Williamson Direct, 58; Isaacson Direct, 39-41. No party opposed the continuation of the Major Storm Reserve and we find it to be a reasonable approach to addressing these significant, variable costs. Accordingly, we approve the continuation of the Major Storm Expense Reserve and find the appropriate baseline to use is $2,473,000, based on the methodology previously approved and using that five-year average for the period of 2014-2018. We do not find it necessary to adjust the baseline for inflation for a cost that is highly variable and where I&M has the ability to adjust accordingly for expenses above and below the baseline. We grant I&M all necessary accounting authority to follow past practices of deferring the actual amount above and below this level

L. Nuclear Decommissioning Funding Expense.

1. I&M. Mr. Hill testified the annual decommissioning funding amount should be increased to $10 million from the current level of $2 million. Hill Direct, 2. He discussed the estimation of future decommissioning costs presented by Mr. Knight, the rules and guidelines for determining adequate funding levels, and his Monte Carle methodology for determining an appropriate funding level. *Id.*, 3-23. He explained his modeling shows that at an annual funding level of $10 million the probability of having sufficient funds is approximately 90%. Hill Direct, 23. He emphasized that it is important to increase the funding level now, when there is time to gradually protect against a future shortfall, rather than suffer one prior to

decommissioning, with little time to recover. He said I&M will continue to report to the Commission every three years on the adequacy of the existing provision, however, and I&M may recommend adjusting the level of decommissioning fund contributions needed in the future. *Id.*, 24-25.

Mr. Hill stated the Spent Nuclear Fuel trust is adequately funded at the present time and said no additional funding is necessary at this time. Hill Direct, 30. He also discussed the investment guidelines for the Spent Nuclear Fuel trust and recommended for the balance of Indiana jurisdictional pre-April 7, 1983 assets that exceed the Indiana jurisdictional liability by a factor of 1.05 or more, those assets should be permitted to be invested pursuant to the investment guidelines currently in place for the Indiana Nuclear Decommissioning Trust. *Id.*, 31-32. He said providing the option to invest the surplus in this manner can provide improved diversification benefits compared to investing under the current guidelines and provides flexibility. *Id.*, 32-36.

2. OUCC. Mr. Eckert recommended the Commission reduce I&M's current annual contribution to the Nuclear Decommissioning Trust Fund ("DTF") to $0 after December 31, 2020 and deny I&M's request to increase the annual contribution by $8 million. Eckert, 13. Mr. Eckert testified that the both the liquidated value of the Indiana portion of the estimated Nuclear DTF at December 31, 2037 and NRC's estimate in its 2017 Decommissioning Funding Status Report show there will be sufficient funds available as of December 31, 2037 to support a discontinuation of Indiana ratepayers' annual contribution to the Nuclear DTF in this case. *Id.*, 12. Mr. Eckert's Attachment MDE-5 details how I&M's Nuclear Decommissioning fund value has increased by at least 7.73% over the last 6.5 years. Eckert, 11 fn. 21. Specifically, since December 31, 2012, I&M's Nuclear DTF has increased by approximately $1 billion and approximately $510 million since December 31, 2016. *Id.*, MDE-5. Mr. Eckert's Attachment MDE-4 is a summary of the NRC's staff's findings of the 2017 decommissioning funding status, in which the staff concluded:

> [T]he staff finds that all licensees are in compliance with the decommissioning funding assurance reporting requirements of 10 CFR 50.75(f)(1) for operating power reactor licensees and 10 CFR 50.82(a)(8)(v)-(vi) for power reactor licensees in decommissioning.

Mr. Eckert therefore recommended that the Commission deny I&M's request for additional DTF funding.

3. Intervenors. IG witness Gorman and Joint Municipal Group witness Cannady both recommended annual funding remain at $2 million. Gorman, 23; Cannady, 4. Mr. Gorman stated the forecasted value of trust fund assets, using the Company's Monte Carlo modeling but assuming more reasonable modeling assumptions, is adequate. He explained that the Company ignored significant contingencies and risk mitigation factors that support the trust fund's ability to fully pay the cost of decommissioning. He stated the Company's decommissioning cost estimate includes a material contingency with the forecasted decommissioning projected cost, so the trust fund is designed to accumulate more money than needed to pay decommissioning. He added that, if actual trust fund earnings are lower than projected, I&M has the ability to adjust its annual decommissioning expense contribution within rate cases. He said this recurring review of the actual performance of the trust fund relative to

projections mitigates the risk that the trust fund will not grow to be adequate to pay decommissioning cost at retirement. He said I&M also has used very conservative assumptions in forming the expected trust fund asset return and the base inflation rate used to project escalation in the cost of decommissioning. Mr. Gorman testified that the Company's projected asset returns are very low compared to historical actual returns on the security investments. Gorman, 22. He explained that if the Company's inflation rate was reduced from 2.25% to 2.1%, which is comparable to the Federal Reserve's long-term target inflation outlook of 2.0% and consensus economists' long term inflation outlook of 2.1%, the Comp[any's statistical model utilizing the Company's other assumptions increases the probability of successfully funding the trust to a 88%. *Id.*, 23. He explained these conservative return projections mitigate the risk that actual returns will be less than projected returns and this risk mitigation reduces the risk that the trust fund will grow to a level that can fully fund the cost of decommissioning. *Id*. at 24. Ms. Cannady noted the current balance meets NRC requirements, the Monte Carlo simulation results from I&M show that scenarios using the $2 million per year provide over 84% probability that the fund will be fully funded by the time decommissioning begins, and questioned the reasonableness of the increased costs components reflected in the decommissioning cost estimate. Cannady, 21-26. She also noted the possibility that the Cook operating licenses could be extended in the future. *Id.*, 28-29.

4. Rebuttal. Mr. Hill stated Mr. Eckert's estimated decommissioning cost incorrectly excludes on-going spent fuel storage costs and explained Mr. Eckert's reference to the NRC minimum value excludes removal and disposal of spent fuel and the removal of clean structures. Hill Rebuttal, 2-3. He disagreed with Mr. Eckert and Ms. Cannady that compliance with NRC minimum funding guarantees I&M will have sufficient funds at the end of Cook Plant's life to successfully decommission the plant. *Id.*, 3-4. Mr. Hill also responded to Mr. Gorman's arguments against increasing nuclear decommissioning contributions and defended the reasonableness of his Monte Carlo modeling. Hill Rebuttal, 8-13.

5. Discussion and Finding. The purpose of funding the nuclear decommissioning trust is to ensure that adequate funds are available to pay for the safe dismantlement of the Cook Plant and related facilities, disposal of the radioactive portions of the plant, storage of spent nuclear fuel as needed, restoration of the plant site, and to comply with certain State and NRC requirements. The nuclear decommissioning expense is included in the revenue requirement to allocate the cost of decommissioning the plant to the customers who are receiving the benefits of its generation during its useful life. If at the time of retirement, there are adequate funds in the decommissioning fund, then the regulatory objective has been accomplished and generational inequity avoided; if funds are inadequate, then tomorrow's customers will pay higher rates to recover costs that should be recovered today. The funds collected must be placed into a trust account which neither I&M nor AEP can access for any purpose other than decommissioning the Cook Plant. Once the decommissioning is complete, any remaining funds will be returned to customers.

The parties disagree over the annual funding level of the Trust, as has been the case in the last several rate cases. I&M is in compliance with the NRC minimum funding requirement, and absent additional investments and assuming even minimal fund growth, the fund will continue to grow to completely meet its projected costs. I&M states that it is only five years away from the point that it plans on de-risking the trust asset investment profile, meaning the window of opportunity to make up for any current funding deficit is getting smaller and smaller. Hill Rebuttal, 13. The OUCC's recommendation is premised on the assumption that the Trust's returns will produce sufficient additional growth over the remaining life of the Cook Plant to provide adequate funds to decommission the Cook Plant. The investment rate of return provided by Mr. Hill of 5.0% can be expected to result in substantial earnings over the long run as applied to the already existing balance. The already healthy state of I&M's Trust gives us some additional reassurance that the Trust is adequately funded at this time.

In sum, we find and conclude that I&M's proposal to continue funding of the Trust at $10 million each year should be rejected. The Commission's decision provides reasonable assurance that funding will be available to fully decommission the Cook Plant at the end of its useful life and appropriately allocates the cost of such decommissioning between present and future customers who benefit from the Cook Plant.

I&M requested that certain language be included in the Commission's Order to assist I&M in obtaining compliance with regulations of the Internal Revenue Service regarding qualified nuclear decommissioning trust funds. Hill Direct, 25. The language requested by I&M updates language incorporated into previous Commission rate orders. No party objected to this request. Accordingly, we incorporate the following disclosures into this Order:

(1) The amount of decommissioning costs to be included in the cost of service for Units No. 1 and No. 2 of the Donald C. Cook Plant is $0 and $0, respectively.

(2) The assumptions used in determining the amount of the decommissioning costs to be included in the cost of service for each of the two Units are as follows:

(a) The after-tax rate of return assumed to be earned by amounts collected for decommissioning is 5.0%.

(b) The proposed method of decommissioning each of the two Units assumed in the Decommissioning Study of the D.C. Cook Nuclear Power prepared by TLG dated January 4, 2019 (the "TLG Study") is immediate decommissioning of the site ("DECON"), on-site storage of spent fuel, and clean removal.

(c) The total estimated cost of decommissioning in 2018 dollars in total for the Donald C. Cook Plant is $2,404,017,000, consisting of $2,032,121,000 in base decommissioning costs per the TLG Study, $335,013,000 of annual post decommissioning spent fuel storage costs through 2098, and $36,883,000 for the eventual decommissioning of the independent spent fuel storage installation. The estimated cost of decommissioning for each unit is $1,165,328,721 for Unit 1 and $1,238,688,279 for Unit 2.

(d) The methodology used to convert the current dollars estimated decommissioning cost to future dollars estimated decommissioning costs is to use the formula prescribed by the Nuclear Regulatory Commission ("NRC") for development of escalation rates for nuclear decommissioning costs. The NRC formula breaks the decommissioning costs into (3) three components: labor, energy, and radioactive waste burial. The weight of each component is based on the detailed estimates in the TLG Study. A base rate of 2.25% was assumed. The escalation rates for labor, energy and radioactive waste burial were assumed to exceed the base rate of inflation by 0.53%, 1.61% and 0.38%, respectively.

(e) The estimated date on which it is projected that the nuclear unit will no longer be included in I&M's rate base is October 31, 2034, for Unit 1 and December 31, 2037, for Unit 2.

Finally, I&M proposed certain changes in the Spent Nuclear Fuel trust investment guidelines. No party challenged these changes and we find them to be reasonable. The record shows the current investment guidelines were established in the 1980s and that circumstances warrant change. Accordingly, we approve I&M's requested change to the investment guidelines for the pre-April 7, 1983 Spent Nuclear Fuel trust.

M. Rate Case and Nuclear Decommissioning Study Expense.

1. I&M. Mr. Williamson supported the adjustment for rate case expense and incremental nuclear decommissioning study expense. He proposed total estimated expense of $1.55 million, which he proposed to amortize over two years. Williamson Direct, 30.

2. OUCC. Mr. Mark Garrett proposed two changes to Petitioner's adjustment. First, Mr. Garrett proposed to amortize rate case expense over three years rather than two. Second, he proposed to limit the recovery of outside counsel fees to $500,000. He viewed the legal fees in the instant case to be high as a percentage of overall rate case expense. M. Garrett, 51. Mr. Garrett testified that his recommendation is consistent with recent rate cases involving other AEP subsidiaries, in states in which Mr. Garrett has participated. In those cases, although some outside legal expense was incurred, the AEP companies relied more heavily on AEP's in-house legal counsel for rate case work. In Mr. Garrett's opinion, to do so is more cost effective for ratepayers. Based on the Bureau of Labor Statistics, the median salary levels for lawyers, and the salary levels for lawyers in Indiana is comparable to the salary levels in the states in his comparison. *Id.*, 52-53. Mr. Garrett's proposed adjustment reduces rate case expenses by $453,980.

3. Rebuttal. Mr. Williamson objected to using rate case expense figures in other jurisdictions because the regulatory requirements will vary from state to state. As an example, he cited rate case expense in a Texas case involving an AEP affiliate, where outside counsel expense was estimated at more than double the amount here. Williamson Rebuttal, 32-33. Mr. Williamson also compared the proposed rate case expense here to rate case expense in other recent Indiana cases. Here, total rate case expense is estimated at $1.55 million. The total rate case expense estimated in the other recent Indiana cases is *Duke Energy Indiana, LLC* (Cause No. 45253) - $2,853,000; *Northern Ind. Pub. Serv. Co., LLC* (Cause No. 45159) - $2,076,000; *Indianapolis Power & Light Co.* (Cause No. 45029) - $3,980,000; *Indiana American Water Co.* (Cause No. 45142) - $2,177,462; *Northern Ind. Pub. Serv. Co., LLC* (Cause No. 44988) - $1,300,000; *I&M* (Cause No. 44967, the last case) - $1,470,000. Williamson Rebuttal, 33-35. He testified the total rate case expense estimated here was lower than the other two major electric cases that were pending in 2019 and was, indeed, the lowest of all of these other cases excluding the *NIPSCO Gas* rate case (involving far fewer intervenors) and I&M's last rate case (filed two years earlier). *Id.*, 35.

4. Discussion and Finding. We review rate case expense for reasonableness to ensure that regulated utilities are diligently controlling costs so that ratepayers are not charged excessive amounts for the prosecution of rate cases. We note that in his testimony, Mr. Garrett did not question the amount of work that is required for a rate case in Indiana, nor did he dispute the reasonableness of the fee that outside counsel is charging for the work. Instead, Mr. Garrett's argument was based upon the relative percentage of overall rate case expense attributable to outside legal fees, and the assertion that in an effort to more diligently control these costs, it would be more cost effective to for AEP to rely on its extensive in-house legal counsel, as he recommends. We agree. I&M has an obligation to incur rate case costs in the most cost-efficient manner possible. This would include using in-house counsel to the extent practicable. Although we decline to make an adjustment to disallow legal fees in this case, we expect I&M to manage its rate case expenditures in the future to achieve the lowest reasonable costs for these fees. This would include using in-house counsel to help facilitate prosecution of the case, as it seems to be able to do in other states. In order to mitigate the rate impact in this case, we accept the OUCC's recommendation to amortize rate case expense over a three year period.

N. Taxes.

1. Excess Accumulated Deferred Federal Income Taxes ("EADFIT").

(a) I&M. Mr. Williamson discussed the amortization of normalized (protected) and non-normalized (unprotected) EADFIT in connection with the Settlement Agreement approved in Cause No. 44967. Williamson Direct, 60. He said in that Cause, I&M agreed to reflect in the revenue requirement a total amortization of $29.9 million for both protected and unprotected EADFIT, with actual amortization of the normalized EADFIT to be based upon the average rate assessment method ("ARAM") and the amortization of the non-normalized EADFIT to be based on a period of six years. He stated the settlement in Cause No. 44967 also provided: "To the extent that the actual annual amortization differs from the estimated amount, the amortization of the non-normalized excess EADFIT will be increased or decreased to ensure that the total amortization of normalized and non-normalized excess EADFIT each year will to be adjusted to "balance" the fluctuations in ARAM and ensure that the combined amortization each year equals $29.9 million. *Id.* Mr. Williamson stated that this "balancing" methodology ensures both (a) that I&M follows ARAM for normalized excess EADFIT and therefore does not commit a normalization violation and (b) that I&M's total amortization each year equals $29.9 million as agreed in the settlement. *Id.*, 61.

Mr. Williamson explained that while the total amortizations levels is the same as the settlement, the normalized EADFIT amortization has been less than estimated in that Cause, resulting in faster amortization of the non-normalized EADFIT than anticipated. Williamson Direct, 61. Mr. Williamson testified that I&M estimates it will run out of the non-normalized EADFIT as early as 2022. *Id.*, 60-61. Mr. Williamson clarified how the Company would continue the "balancing" methodology in the settlement approved in Cause No. 44967. *Id.*, 62.

To address this issue and avoid a normalization violation, he said that once the non-normalized excess EADFIT is fully amortized, I&M is requesting accounting authority to defer and record as a regulatory asset the annual difference between (i) the annual amortization of normalized and non-normalized excess EADFIT reflected in base rates (*i.e.*, $29.9 million in this case) and (ii) the actual annual normalized ADFIT amortization required by ARAM. Williamson Direct, 62. He stated the deferral will begin once the non-normalized EADFIT has been fully amortized. *Id*., 62.

(b) OUCC. Witness Blakley opposed I&M's deferral request as stated and proposed an alternative. He stated I&M's proposal to maintain the $29.9 million EADFIT credit from the Cause No. 44967 Settlement Agreement would result in large deferrals that would be recovered in its next base rate case because the amount of protected EADFIT in the total EADFIT credit as set in the Cause No. 44967 Settlement Agreement is lower than actual protected EADFIT calculated under ARAM. He explained that, in order to maintain the total EADFIT credit, a lower protected EADFIT amortization causes a larger amortization of unprotected EADFIT, which decreases the balance of unprotected EADFIT down to zero faster than expected by the Cause No. 44967 Settlement Agreement. Mr. Blakley pointed out that, essentially, I&M's proposal would result in customers receiving a higher EADFIT credit than they should, which customers would then be required to pay for in I&M's next base rate case. Instead, the OUCC proposed that when the unprotected EADFIT credit has been fully amortized, I&M should make a compliance filing to reduce the total EADFIT credit to reflect only protected EADFIT. Going forward, I&M would defer only the difference between the amount of protected EADFIT embedded in rates and actual protected EADFIT amortization calculated under ARAM for recovery in its next base rate case. Mr. Blakley testified that the OUCC's proposal would result in smaller deferrals and would provide customers with a deferred tax refund in a manner that does not result in tax normalization violations. Blakley, 7-9.

(c) Intervenors. IG witness Gorman explained how the Tax Cut and Jobs Act of 2017 and the settlement in Cause No. 44967 impacted I&M's EADIT. He noted that the Settlement Agreement recognized that the protected and unprotected EADIT were estimates and the final amounts would be determined at a later time. He noted that the Settlement Agreement required I&M to adjust the amount of protected and unprotected EADIT in order to ensure a $29.9 million credit to be embedded in base rates. He testified in opposition to I&M's proposed EADIT treatment in this Cause and opposed the indeterminable amount of the possible regulatory asset given the undefined time during which the deferral could persist. Mr. Gorman provided alternative approaches to I&M's proposed treatment and noted that the Commission could delay addressing the matter in the next base rate case at which time the base rates be adjusted when the unprotected EADIT has been exhausted. Gorman 43-44. Additionally, he testified that an alternative approach would be to adjust the $29.9 million credit currently in rates to reflect the lower amount of protected EADIT embedded in rates and return the amount of unprotected EADIT to the $21.1 million in the settlement agreement. Joint Municipal Group witness Cannady recommended the Company reduce the annual amortization of EADFIT from $29.9 million to $28.8 million. She also objected to the Company's proposal to establish a regulatory asset and associated carrying charges. Cannady, 3, 6-10.

(d) Rebuttal. Mr. Williamson agreed that there is uncertainty as to when non-normalized EADFIT will be fully amortized and explained that the Company's proposed mechanism addresses this uncertainty, while ensuring customers fully benefit from EADFIT going forward and the intent of the settlement agreement in Cause No. 44967 continues to be carried out. To respond to the IG and OUCC testimony, Mr. Williamson proposed a modification to the Company's original proposal. Williamson Rebuttal, 57. Mr. Williamson proposed the Commission approve the following ongoing ratemaking treatment:

(A) Once non-normalized (unprotected) EADFIT is fully amortized, I&M makes a compliance filing to confirm the occurrence.

(B) Establish a rider to recognize the increased cost of service resulting from the removal of the Test Year level of non-normalized EADFIT which would remain in place until I&M's next rate case. The filing would establish a charge that recognizes the impact on non-normalized EADFIT being fully amortized, by utilizing the final Commission approved revenue requirement from the instant proceeding. Holding all other results of the Commission-approved revenue requirement constant and removing the unamortized non-normalized EADFIT balance from rate base and the annual level of non-normalized excess EADFIT amortization, a new revenue requirement will be determined. The difference between the new revenue requirement described above and the Commission-approved revenue requirement in the instant proceeding would be the basis for the change in rates.

(C) Establish rider rates using two-part rates for demand metered customers, and an energy only rate for non-demand metered customers.

(D) Authorize I&M to defer the difference on an ongoing basis between actual EADFIT amortization and the level embedded in base rates once the non-normalized EADFIT balance is fully amortized.

Id., 59-60. Mr. Williamson explained that this proposal ensures that customers continue to receive the benefits of EADFIT going forward, maintains the intent of the settlement agreement in Cause No. 44967 allows the Company to continue to comply with tax normalization rules and addresses the concerns of the IG and OUCC by minimizing the level of deferred costs. *Id.*, 60. He added that the rider mechanism will provide a more efficient way to addressing this singular topic, rather than revise all the applicable rates in I&M's tariff book. *Id.*

As to Ms. Cannady's position, Mr. Williamson responded there is no need to revisit the settlement that was reached in Cause No. 44967, as it can be fully accommodated in this case. He also confirmed that Petitioner is not seeking any carrying charges on the deferred asset. Williamson Rebuttal, 60-63.

(e) Discussion and Finding. At the outset, we note that Mr. Williamson's proposal for a new tracker to address EADFIT was provided for the first time in I&M's rebuttal testimony, which is a generally disfavored and prejudicial approach, as a petitioning party has an obligation to fully present its requests to the Commission in its case-in-chief. When new proposals are made in a rebuttal filing, the other parties are not provided with a fair opportunity to respond.

We understand the problem with I&M's EADFIT credit to be this: the Cause No. 44967 Settlement Agreement includes a term which provides for a total EADFIT credit of $29.9 million, to be comprised of $21.1 million in unprotected EADFIT and $8.8 million in protected EADFIT. However, as I&M has begun amortizing EADFIT back to its customers and the ARAM calculation has been updated, I&M's actual total EADFIT credit has reflected something closer to $25 million of unprotected EADFIT and $4.9 million in protected EADFIT. In order to continue to return the total agreed EADFIT credit of $29.9 million, I&M first proposed to continue amortizing an amount for unprotected EADFIT even after the actual excess balance had been returned, to defer this amount as a regulatory asset, which will then be collected from customers in I&M's next base rate case. In response to objections to this proposal from the OUCC and other intervenors, I&M offered a new proposal in its rebuttal testimony to implement a tracker that would serve to adjust I&M's revenue requirement set in this Cause when its unprotected EADFIT amortization has been fully returned and only protected EADFIT is owed to customers.

While the parties are in agreement that something must be done upon completion of amortization of unprotected EADFIT, we find I&M's rebuttal tracker proposal is needlessly complicated and burdensome. In order to avoid large deferrals of ongoing unprotected EADFIT amortizations made after the actual balance of unprotected EADFIT has been fully returned to customers, and to ensure that I&M does not risk a tax normalization violation, we find that I&M's revenue requirement as set in this Cause will have to be changed at the time its unprotected EADFIT balance has been amortized back to customers. To accomplish this change, we order I&M to make a compliance filing confirming that all unprotected (non-normalized) EADFIT has been amortized and adjusting the revenue requirement set in this Cause as necessary to reflect an annual amortization of protected EADFIT of $8.8 million as agreed to and approved in the Cause No. 44967 Settlement Agreement. Following that change to I&M's base rates, I&M is authorized to defer the difference between the protected EADFIT amortization reflected in base rates and the actual protected EADFIT amortization expense based on ARAM for treatment in its next base rate case.

2. Utility Receipts Tax.

(a) Industrial Group. Industrial Group Witness Gorman testified that I&M includes a Utility Receipts Tax ("URT") of 1.4% in its calculation of the gross revenue conversion factor. Mr. Gorman testifies that other utilities have removed the URT from base rates and included it as an item on customers' bills. This change would also reduce I&M's claimed revenue deficiency by $2.3 million. Additionally, Mr. Gorman recommended that I&M should remove any URT operating expenses from the test year and I&M's cost of serve. Gorman, 9.

(b) Rebuttal. Mr. Williamson did not disagree in theory with Mr. Gorman's proposal, noting that it would only change "how" the cost is recovered and not "if" the cost is recovered. Nevertheless, he stated Petitioner is not prepared to implement this proposal at this time and would need time to determine how this change would be structured and billed. Williamson Rebuttal, 69.

(c) Discussion and Finding. *The OUCC takes no position on this issue.*

O. Vegetation Management.

1. <u>I&M.</u> Mr. Isaacson summarized the Company's vegetation management program reflected in the Capital Forecast Period and Test Year O&M. He explained the program involves ongoing work on moving away from a reactive approach to managing vegetation to a systematic, cycle-based approach to managing vegetation. Isaacson Direct, 13. He said I&M is on schedule to complete the initial four-year period as planned. He summarized results for 2018 and the work plan for 2019-2022. *Id.* at 13-14. He also identified the drivers and benefits of I&M's vegetation management program. *Id.* at 14-15.

2. <u>OUCC.</u> Mr. Mark Garrett stated the Test Year forecast for vegetation management is higher than its actual spending levels for most of the prior five years. He argued the higher level of spending in 2018 did not justify I&M's request for ongoing recovery at an elevated level. M. Garrett, 47. He asserted the higher expenditures are largely related to remedial work that should have been completed in prior years, that I&M has not historically spent the projected amounts it claims are necessary. *Id.*, 48-49. Mr. Garrett pointed out that even after committing to a 4-year cycle in the Company's last rate case, I&M failed to spend the amount it said was required to achieve this necessary cycle, spending only $8.483 million of its forecasted $14.712 million for 2017, and retaining the difference to bolster its bottom line. *Id.*, 49. Mr. Garrett notes the Michigan commission recently expressed similar concerns that "I&M's inconsistent spending demonstrates a lack of commitment to its vegetation management program." *Id.*, 50.

Mr. Garrett testified that the problem with the Company's request is twofold: First, the Company seeks to recover, *in an accelerated manner,* the costs associated with many years of deferred maintenance. A 55% cost increase above the 5-year average places an undue burden on ratepayers. The Company has an obligation to maintain its system on an ongoing basis to provide safe and reliable service. It is inappropriate for the Company to neglect necessary maintenance for several years, while ensuring profitability targets are met, and then seek a large rate increase to recover the inflated costs necessary to perform remedial maintenance. *Id.*, 48.

He pointed out that during the years in question, 2014-2017, AEP met its annual EPS targets, and funded employee incentive compensation plans, but did not always spend the amounts necessary to keep up with its vegetation management obligations, using the money instead to bolster its earnings. *Id.*, 48-49. As a result, Mr. Garrett recommended allowing recovery of a 5-year historical average of actual expenditures, which would reduce requested vegetation management expense by $5,803,400. *Id.*, 50-51.

3. <u>Rebuttal</u>. Mr. Isaacson explained I&M began its cycle-based vegetation management program in 2018 with the first year of the planned four-year period (2018-2021) to establish a regular four-year vegetation management cycle. Isaacson Rebuttal, 13. He said it is unreasonable to compare I&M's forecasted Test Year level of vegetation management expenditures to the five-year historical average because I&M began its new four-year vegetation management cycle in 2018. He testified the significant reduction proposed by Mr. Garrett would hamper the Company's implementation of a proactive vegetation management approach and could eliminate the significant customer reliability benefits that a proactive approach would bring. *Id.* at 14. He disagreed I&M is "catching up" on deferred maintenance as asserted by Mr. Garrett. He also disagreed I&M diverted funds allocated to vegetation management to I&M's bottom line and pointed out I&M's actual vegetation O&M expenditures

in 2018 were actually *greater* than I&M's forecasted amount and *greater* than the Test Year level of O&M reflected in the settlement approved in Cause No. 44967. *Id.*, 15-16. He said Mr. Garrett's reference to a Michigan Order is distinguishable from the present case and raised issues not shown to be applicable to I&M's Indiana jurisdiction. *Id.*, 17.

4. Discussion and Finding.

I&M's requested vegetation management costs represents a steep increase over its actual 5-year average spending levels:

Indiana Jurisdiction Vegetation Management Costs[9]	
2014	$ 10,201
2015	$ 6,223
2016	$ 9,829
2017	$ 8,483
2018	$ 17,452
5-Year Average	$ 10,437

The Company denies it is catching up on deferred maintenance, but describes its cost increases as related to *remedial* costs. Isaacson Direct, 14. Moreover, it is troubling that although I&M "committed to achieving a four-year trim cycle" in its last rate case, *Indiana Michigan Power Co.*, Cause No. 44967, p. 28, I&M did not spend its budgeted amount for vegetation management in 2017. The record shows that I&M's budgeted spend for 2017 was $14.7 million, but the Company actually spent only $8.48 million for that year, a shortfall of $6.2 million. Isaacson Direct, 15 – 16. With regards to its vegetation management spend in 2017, Company witness Isaacson writes that "the allocation of funds in the budgeting process can be adjusted throughout the course of the year … Changes in weather, customer service needs, and other emergent issues can necessitate budget adjustments." *Id.*

During this same period, AEP's operating earnings were sufficient to pay incentive compensation at levels *far above target* in all years except 2017, as shown in the rebuttal testimony of Company witness Andrew R. Carlin, at p. 18:

Figure ARC-2R

Year	AEP Operating Earnings Score (As a Percent of Target)
2014	182.7%
2015	191.0%
2016	170.5%
2017	92.0%
2018	144.9%
5 Year Average	**156.2%**

[9] Sources: For historical cost data 2014-2018, see WP-DAL-1.

Although the Company was able to pay incentive compensation to employees in all years in question, including 2017, its Operating Earnings Score for 2017 was below target in that year, which raises concern that the Company may have elected to defer some of its necessary vegetation management expenditures to bolster earnings in 2017.

Because the Company has significant discretion in determining whether, and to what extent, it makes vegetation management expenditures from year to year, we decline to approve the steep cost increase requested by the Company. The Company has enjoyed above target earnings during the same years it elected not to make the proactive expenditures it now claims are necessary. Accordingly, we find that the OUCC's proposed adjustment, which reduces the Company's recovery to the 5-year average expenditure level, should be accepted.

12. Financial Forecast.

1. I&M. Ms. Heimberger presented I&M's 2020 Test Year financial forecast and discussed the forecast process. Heimberger Direct, 2. She explained the forecasting process used in this proceeding is the same that was used in I&M's last basic rate case, Cause No. 44967. *Id.*, 4-5. She discussed the major components of I&M's financial forecast and identified the other I&M witnesses supporting the O&M and capital expenditure work plan activities. *Id.*, 5-10. She also presented and discussed the forecasted operating revenues, generation forecast, O&M, depreciation and amortization, taxes, plant in service, construction work in progress, and accumulated depreciation. *Id.*, 10-23. She said the projected values she provided are reasonable and accurate and reflect the income statement and balance sheet activity likely to occur during the Test Year. *Id.*, 28.

Mr. Burnett testified the Test Year load forecast is reasonable and was derived using widely accepted modeling techniques based on the best information that was available at the time it was completed. Burnett Direct, 18. He described the load forecasting methods used by I&M for short-term and long-term kWh forecasting and explained I&M uses processes that take advantage of the relative strengths of each methodology. *Id.*, 5-8. He said the Test Year forecast assumes normal weather conditions and is adjusted for the impacts of I&M's DSM and EE programs that are approved by the Commission. *Id.*, 9-11. He said I&M's load forecast methodology is proven to produce accurate and reliable projections that are useful for planning and setting rates. *Id.*, 11. He said the average accuracy of the budget load forecasts for I&M since 2008 has been within 0.3% on a weather normalized basis. *Id.*, 11-12; Figure CMB-2. He explained the Test Year forecast incorporates information from Moody's Analytics, which is predicting the end of the current business cycle and the start of the next recession in the year 2020. *Id.*, 13-14.

2. Intervenors. Mr. Mancinelli stated I&M should remove the recession assumption from its 2020 Test Year load forecast because the assumption is not sufficiently fixed, known, or measurable. Mancinelli, 5, 31. He argued I&M has the burden of proof to show its Test Year assumptions are reasonable, and that I&M provided no definitive information as to the timing of the recession. *Id.*, 31-33. He referenced an April 2019 economic outlook prepared for the State of Indiana, which he said does not indicate a recession. *Id.*, 34.

3. Rebuttal. Mr. Burnett stated I&M's load forecast reflects the base economic forecast from Moody's Analytics, a trusted and reputable provider of economic forecast data. He explained no "adjustment" was made to the forecast to account for the economic downturn and that Mr. Mancinelli failed to provide data to support such an adjustment. Burnett Rebuttal, 2-5. He pointed out the economic outlook provided by Mr. Mancinelli supports, rather than contradicts, the general economic assumptions used by I&M in its load forecast. *Id.*, 5-7.

Mr. Burnett said Mr. Mancinelli's testimony erroneously compares annual incremental DSM savings for the historical data to a cumulative number for 2020, undermining his claim that the DSM assumptions in I&M's load forecast are too high. Burnett Rebuttal, 13-15. Finally, Mr. Burnett showed that I&M's updated June 2019 load forecast for 2020 is 1.2% lower than the forecast used in this case, underscoring the reasonableness of the Test Year forecast. *Id.*, 10-12. At the hearing, Mr. Burnett indicated the newest update to the load forecast shows 2020's load projected to be 1.4% below the level used in this proceeding. Tr. G-109-10.

4. Discussion and Finding. *The OUCC takes no position on this issue.*

13. Net Operating Income at Present Rates. Based upon the evidence and the determinations made above, we find I&M Test Year operating results under its present rates are as follows:

Operating Revenues	$ 1,501,500,440
Less: O&M Expenses	$ 882,636,822
Depreciation/Amortization	268,892,017
Other Taxes	83,404,925
State Income Taxes	5,108,425
Federal Income Taxes	5,245,219
Total Operating Expenses	$ 1,245,287,409
Net Operating Income ("NOI")	$ 256,213,031

In summary, we find that I&M's annual net operating income under its present rates for electric utility service would be approximately $256,213,031, which is insufficient to represent a reasonable return. We therefore find that I&M's present rates are unreasonable. Accordingly, it is both reasonable and necessary for new rates and charges to be established.

14. Authorized Revenue Requirement. On the basis of the evidence presented, we find that I&M should be authorized to increase its basic rates and charges to produce additional operating revenue of approximately $1,732,531. This revenue is reasonably estimated to afford I&M the opportunity to earn net operating income of approximately $254,420,374, as follows:

Operating Revenues	$ 1,499,070,228
Less: O&M Expenses	$ 882,633,901
Depreciation/Amortization	268,892,017
Other Taxes	83,370,974
State Income Taxes	4,982,898
Federal Income Taxes	4,770,063
Total Operating Expenses	$ 1,244,649,854
Net Operating Income ("NOI")	$ 254,420,374

Calculation of Authorized Increase in Revenue:

Rate Base	$ 4,714,702,350
Required Rate of Return	5.40%
Allowable Electric Operating Income	$ 254,425,585
Less: Adjusted NOI at Present Rates	256,213,031
Deficiency in Electric Operating Income	$ (1,787,446)
Times: Revenue Conversion Factor	1.3596
Jurisdictional Revenue Deficiency	$ (2,430,212)
Remove Transmission Owner Costs, Revenues[10]	3,909,218
Total Required Rate Relief Before Phase-In Credit	$ 1,479,006
Less: Current Revenue for Ongoing Riders	(221,393,319)
Plus: Proposed Rider Revenue	221,646,844

[10] As-filed amount shown. Final value will change consistent with approved calculation methodology when approved changes are flowed through class cost-of-service. Nollenberger Direct, 5.

Total Rate Change Before Phase-In Credit $1,732,531

We further approve the phase-in of I&M's rates as proposed by I&M, which was not challenged by any party and which we find to be reasonable. More specifically, when I&M's new base rates are first effective, they will include both the "IMMDA Credit" of $46,442,922 identified by Ms. Duncan on page 20 of her direct testimony and a "Forecasted Plant Credit" to reflect forecasted plant additions during the Test Year.[11]

On June 1, 2020, the IMMDA Credit will automatically expire and the full Forecasted Plant Credit will continue. The Forecasted Plant Credit will remain in effect until I&M's final compliance filing is made on or after January 1, 2021. In this way, I&M's rates will not reflect forecasted Test Year plant additions until they are placed in service and are used and useful in the provision of service for customers. Duncan Direct, 21.

We find Phase III rates should utilize the same compliance filing process as "Phase II" rates in Cause No. 44967. I&M shall certify to this Commission its net plant at December 31, 2020 and thereafter calculate the resulting Phase III rates. For purposes of the Phase III certification, I&M shall use the forecasted Test Year end net plant of $4,714,702,350 approved above. The Phase III rates shall go into effect on the date that I&M certifies its Test Year end net plant, or January 1, 2021, whichever is later. The net plant for Phase III rates shall not exceed the lesser of (a) the forecasted Test Year end net plant approved herein or (b) I&M's certified Test Year end net plant. I&M shall serve all parties with its certification. The OUCC and intervenors shall have 60 days from the date of certification to state objections to I&M's certified Test Year end net plant. If there are objections, a hearing shall be held to determine I&M's actual Test Year end net plant, and rates will be trued-up (with carrying charges) retroactive to January 1, 2021 (regardless of when Phase III rates go into effect).

15. Cost of Service and Revenue Allocation.

A. Jurisdiction Separation Study.

1. I&M. Ms. Duncan presented the jurisdictional separation study, which allocates the total Company rate base, revenues, and expenses to the Indiana retail jurisdiction. She said the same overall methods employed to develop the jurisdictional study in Cause No. 44967 were used to develop the jurisdictional study in this case. Duncan Direct, 6-7. She explained adjustments were made to annualize known interruptible customer load changes and the loss of wholesale load associated with the Indiana and Michigan Municipal Distributors Association ("IMMDA") members effective June 1, 2020. *Id.*, 9-10. Mr. Thomas stated all but one of the IMMDA contracts will expire on or before June 1, 2020, with the last contract to expire on or before June 1, 2026. Thomas Direct, 6. Mr. Williamson explained the Company's proposed phase-in of base rates would ensure that these contracts continue to benefit retail customers until the contracts expire. Williamson Direct, 5-6, 19, 24. Ms. Duncan also supported new demand and energy allocation factors required as a result of Michigan's Electric Customer Choice program. Duncan Direct, 10.

[11] While I&M originally calculated a Forecasted Plant Credit of $43,051,354 (Duncan Direct, 20), we note the approved Forecasted Plant Credit will be slightly different as a result of the rate base approved herein.

2. Intervenors. IG witness Gorman testified I&M did not take reasonable steps to retain the IMMDA load or find replacement load. He said the additional capacity allocated to Indiana retail customers is not needed, pointing to I&M's 2018-2019 IRP that shows I&M's capacity resources exceed its load obligations at least through 2022. He added that I&M's use of 312 MW for its off system sales adjustment indicates the IMMDA capacity is not necessary to meet Indiana retail customers' needs in 2020 through 2022. Therefore, Gorman proposed to make permanent $46.44 million in offsets to I&M's cost of service that are currently received by I&M from its expiring IMMDA contracts. Gorman added that if the Commission approves reallocating the IMMDA costs to Indiana retail customers, the proper valuation should be no more than I&M's estimate of the market value of the excess capacity, which is $36.4 million ($25.4 million) Indiana retail. Gorman, 8-9, 34-38. Joint Municipal witness Mancinelli stated fixed costs associated with the IMMDA load loss should be recovered within the wholesale jurisdiction, not shifted to I&M's retail jurisdictions. Mancinelli, 9-11, 59. Mr. Mancinelli noted that under FERC's rules at 18 C.F.R. § 35.26(b)(1), I&M had the right to recover stranded costs in the IMMDA contracts. Mancinelli, 21-26. He reasoned that because those contracts do not include an exit fee or other stranded cost recovery, I&M should not be allowed to recover costs associated with this IMMDA wholesale load loss through retail customers. *Id*. He contended I&M is using retail customers as a hedge against lost load attributable to the wholesale business. He said this practice should not be allowed, as I&M bears no risk and therefore has little motivation to replace lost load. Mancinelli, 19. Mr. Mancinelli stated I&M experienced some load loss and stranded costs in Michigan as a result of the Michigan Electric Customer Choice program, and did not shift the fixed costs associated with Michigan firm load loss to other jurisdictions. Mancinelli, 26. He said he agreed with I&M's treatment of Michigan load loss in the jurisdictional separation study and said this treatment is consistent with his recommendation pertaining to the loss of firm wholesale load, which he said should be borne by wholesale customers. *Id.*, 26-28. Mr. Cearley stated I&M should not be allowed to decrease test year revenues for loss of wholesale load until it has reasonably demonstrated what it has done to either retain or replace this lost load beyond just making claims of supporting economic development. Cearley, 9.

3. I&M Rebuttal. Ms. Duncan explained that the jurisdictional allocation should reflect the load conditions expected during the period the rates established in this Cause will be in effect. She disagreed her jurisdictional separation study is "raising rates" on customers. Duncan Rebuttal, 3. She explained Mr. Mancinelli's and Mr. Gorman's treatment of costs associated with serving the Company's retail and wholesale customers is not consistent with jurisdictional cost allocation principles and deviates from the historical practice. Duncan Rebuttal, 2.

Ms. Duncan disagreed with Mr. Mancinelli's categorization of these costs as being "stranded" because the capital assets related to these costs are still used and useful to I&M customers. Duncan Rebuttal, 9. She also disagreed with Mr. Mancinelli's assertion that I&M's treatment of the IMMDA load is inconsistent with its treatment of the Michigan Choice customers. *Id.* She said all costs that are related to the wholesale jurisdiction have been allocated using the allocation factors proposed in this case, which includes the loss of the IMMDA load. *Id.*, 9-10. Similarly, she said all costs that are affected by Michigan Customer Choice have been allocated using the "excluding shopping" allocation factors proposed in this case. She said the cost allocation method used in both circumstances (*i.e.*, the IMMDA load loss and the Michigan

Choice customers) is in accordance with the cost causation principle, which ensures customers are only paying for the costs they are responsible for incurring and does not leave so-called “stranded costs” for the remaining Michigan retail and wholesale customers to account for. *Id.*, 10-11.

Mr. Thomas testified the Company’s current IRP shows that regardless of when the Rockport Unit 2 lease terminates, I&M will face a capacity gap of approximately 500 MW. Thomas Rebuttal, 28. He stated Mr. Gorman’s contention that the generation that has been used to serve the IMMDA load is not used and useful in the provision of retail service takes an unreasonably shortsighted perspective in that it fails to recognize that capacity additions or subtractions will rarely exactly match changes in load requirements. Thomas Rebuttal, 28.

Mr. Thomas said Mr. Mancinelli’s contention that the Company should have done more to replace the IMMDA wholesale load is not supported by any evidence and is mere conjecture. Thomas Rebuttal, 29. Mr. Thomas explained I&M actively negotiated with the IMMDA members to find creative alternatives that would allow the contracts to be renewed or reformed. He said I&M and the expert and experienced generation marketing team at AEP made best efforts to avoid the termination of the agreements. He stated since receiving the notices that the contracts will be terminated, I&M explored options available in the wholesale market in anticipation of the capacity and energy becoming available. Mr. Thomas stated if additional revenues result from those activities, the Off System Sales tracker will flow the vast majority of the margins back to customers. Thomas Rebuttal, 29. He added the Company has aggressively pursued the development of economic growth in its communities and have had success doing so. Thomas Rebuttal, 29. He therefore disagreed with the implication that I&M was passive in reacting to the termination of the IMMDA contracts.

4. Commission Discussion and Findings. *The OUCC supports the Joint Municipal’s position on this issue; the effect of any approved adjustment to I&M’s IMMDA proposal should be reflected in I&M’s tariff filing made after the issuance of a final order in this Cause.*

B. Class Cost of Service and Revenue Allocation.

1. I&M. Mr. Spaeth, presented Petitioner’s class cost-of-service study at present rates, Attachment DEH-1, which allocates the total Indiana retail jurisdiction rate base, revenues and expenses to each rate schedule. He explained the cost allocation methodology used in the class cost-of-service study assigns costs among the customer classes in a fair and equitable manner based on principles of cost causation. Spaeth Direct, 2-3.

Mr. Spaeth testified the Company is proposing to continue using the 6 coincident peak (“6 CP”) demand allocator, which assigns costs based on each customer classes’ contribution to three summer and three winter months in the Test Year. Spaeth Direct, 12. He stated distribution plant is classified as demand- and customer-related and allocated to the customer classes using factors based on demand levels or number of customers. He explained classifying services and meters as customer-related (and primary and secondary poles, lines, and transformers as demand-related) has been accepted before this and other Commissions and is consistent with cost causation principles. Spaeth Direct, 15-16.

2. OUCC. OUCC witness Watkins opposed the Company's use of a 6 CP demand allocator for production and transmission plant. He proposed the Company allocate production plant on either a Peak & Average, 12 CP, or Base-Intermediate-Peak method and recommended a 12 CP demand allocation for transmission plant. Watkins, 33. Mr. Watkins explained that when generation cost responsibility is assigned to rate classes only on a few hours of peak demand, there is an explicit assumption that there is a direct and proportional correlation between peak load (for a few hours) and the utility's total investment in its portfolio of generation assets. But he pointed out this not the case with utilities such as I&M wherein the portfolio of I&M's generation assets are predominately comprised of nuclear and coal units coupled with run-of-the-river hydro facilities that provide power throughout the year. *Id*., 14.

Mr. Watkins further explained that if a utility were only concerned with being able to meet peak load with no regard to operating costs, it would simply install inexpensive peakers. He stated that under such an unrealistic system design, plant costs would be much lower than in reality but variable operating costs (primarily fuel costs) would be astronomical and would result in a higher overall cost to serve customers. Mr. Watkins testified that peak responsibility methods such as the 1-CP, 4-CP, and 6-CP totally ignore the planning criteria used by utilities to minimize the total cost of providing service, do not reflect the utilization of its portfolio of generating assets throughout the year, and therefore, do not reflect in any way how capital costs are incurred; i.e., do not reflect cost causation. *Id*., 15.

Mr. Watkins explained there are two general philosophies relating to the proper allocation of transmission-related plant. The first is based on the premise that transmission facilities are nothing more than an extension of generation plant as they simply act as a conduit to provide power and energy from distant generating facilities to a utility's service area, and so under this philosophy, transmission costs are allocated using the same method used to allocate generation-related costs. The second philosophy relates to the physical capacity of transmission lines, in that these facilities have a known and measurable load capability such that customer contributions to peak load should serve as the basis for allocating transmission costs. *Id*., 24. Mr. Watkins explained that allocating transmission costs based on the physical capacity of the lines fails to recognize cost causation in three ways: (1) transmission lines are an extension of generation facilities, (2) transmission facilities are used virtually every hour of any entire year and not just during periods of peak load, and (3) it assumes there is a direct and linear relationship between cost and load, which is not the case with the significant economies of scale associated with high voltage transmission lines.

Mr. Watkins' cross-answering testimony opposed the IG, South Bend and Joint Municipals' proposals to use either a 3 CP, 4 CP, or 5 CP demand allocation method and recommended their proposals related to distribution plant be rejected. Watkins Cross-Answering, 9.

3. Intervenors. IG witness Phillips proposed the Company allocate its production plant and transmission plant on either a 5 CP (PJM Peak Load Contribution) or 4 CP summer method. He said if the 6 CP method is retained, the Commission should include a

customer component for the allocation of distribution system costs using the minimum system approach, particularly for accounts 364 through 368. Phillips Direct, 16. In his cross-answering testimony, Mr. Phillips responded to Mr. Wallach's and Mr. Watkins' energy-related cost allocation proposals.

Joint Municipals witness Mancinelli recommended the Company allocate both production and transmission plant on either a 4 CP or 5 CP method based on his belief that I&M is a summer peaking utility. Mancinelli, 38-40.

CAC-INCAA witness Wallach proposed the use of an energy-weighted demand allocation methodology (Equivalent Peaker) for the allocation of production plant. Mr. Wallach's cross-answering testimony opposed the IG and South Bend recommendations that I&M rely on minimum-system methods to classify distribution costs.

South Bend witness Seelye recommended the use of a 3 CP (summer) methodology for allocating production plant, transmission plant, and certain distribution capacity costs. He also proposed to classify a portion of distribution accounts 364 through 368 as customer-related. Seelye, 2-3, 11, 14. In his cross-answering testimony, Mr. Seelye responded to the testimony of Mr. Watkins, Mr. Wallach, and Mr. Phillips.

Kroger witness Bieber's cross-answering testimony recommended the Commission reject the OUCC and CAC's alternative class cost of service studies. He further recommended the use of a minimum distribution system method to classify certain distribution plant costs.

4. Rebuttal. Mr. Spaeth explained an energy-weighted demand allocator should not be used because it does not does not recognize the fixed nature of production plant costs, which do not vary based on the level of energy consumption. Spaeth Rebuttal, 3. With respect to the OUCC's 12 CP proposal and the Intervenors' alternative 3 CP, 4 CP and 5 CP demand allocation methodologies, Mr. Spaeth explained how these approaches fail to recognize that the Company's load profile shows I&M continues to be a summer and winter peaking utility. Spaeth Rebuttal, 4-10.

Mr. Spaeth also responded to the OUCC and Intervenor proposals regarding transmission and distribution plant allocation and explained how I&M's approach reflects the Company's standard engineering practice to plan its distribution facilities to meet the maximum expected demand on each component of the system. Spaeth Rebuttal, 11-14.

5. Commission Discussion and Findings.

(a) Demand Allocation Methodology. I&M proposed to classify electric generation production plant as 100% demand-related and allocate it to the various rate classes based upon the 6 CP monthly loads for the three summer months of June, July, and August and the three winter months of December, January, and February. The OUCC proposed that the Company allocate production plant on either a Peak & Average, 12 CP, or Base-Intermediate-Peak method and that transmission plant be allocated using a 12 CP demand allocator. CAC-INCAA witness Wallach proposed the use of an energy-weighted demand allocation methodology (Equivalent Peaker) for the allocation of production plant. Intervenors proposed alternative 3 CP, 4 CP, and 5 CP demand allocation methodologies.

In opposing the allocation methodologies presented by the OUCC and CAC-INCAA, I&M argues that energy-weighted demand allocation methodologies do not recognize the fact that production plant costs are fixed in nature and exist regardless of how much energy customers consume. As explained in more detail below, we conclude that I&M's assertions and rationale are misplaced. While there is no doubt that the Company's investment and capital costs relating to production plant reflect "sunk" or fixed costs, the paramount objective and goal of proper cost allocations is to reasonably reflect cost causation. As set forth in the direct testimony of OUCC witness Watkins (p. 22), I&M's total "fixed" investment of $3.545 billion in production plant is comprised almost entirely [97.5% = 71.8% (Cook) + 25.7% (Rockport)] of the Cook and Rockport base load units that were designed, built, and are utilized to serve customers' energy loads throughout the year. I&M does not own any "peaker" units such that the Company's remaining 2.5% investment in production plant is comprised of hydro and solar facilities. Watkins, 22. Under I&M's approach, the Company's total investment in production facilities would be allocated only on six hours of system peak demand even though the Company's investment in production plant was almost exclusively made to serve energy needs throughout the year.

I&M also asserts that the various demand allocation methodologies proposed by the OUCC, IG, Joint Municipal Group, and South Bend are not consistent with the Company's load profile during the Test Year. However, while I&M is both a summer and winter peaking utility, this undisputed fact does not relate to "the Company's load profile during the test year." Mr. Watkins' testimony demonstrates that the Company's load profile is such that its total system load is met by the Company's base load nuclear (Cook) and base load coal (Rockport) units for the vast majority of the year; i.e., the investment in its base load units provide capacity and energy throughout the Company's load profile. These base load units therefore serve the Company's load profile throughout the year, as peaking units are only used for a very few hours of the year.

We conclude, based on the evidence presented, that I&M's proposed 6CP allocation methodology does not reasonably reflect the Company's actual load profile during the test year. We find that the OUCC's allocation factors for production plant, calculated as an average of the factors generated by the Peak & Average, Base-Intermediate-Peak and 12 CP methods included in Mr. Watkin's testimony at Table 7 are a more appropriate reflection of I&M's actual load profile, in that I&M's load profile is served by base load generation for the majority of the year. Therefore, the OUCC's allocation factors for production plant as shown in Mr. Watkins' Table 7 are hereby approved.

(b) <u>Transmission and Distribution Plant Allocation Methodology.</u>

I&M's theory that a 12CP methodology does not appropriately consider the two seasonal peaking nature of I&M's system is misguided. As explained by Mr. Watkins, there are two theories and philosophies regarding the cost causation of transmission plant. The first philosophy is that transmission plant simply acts as a conduit to provide power and energy from distant generating facilities to a utility's load center. Under this philosophy, transmission costs should be allocated using the same method as that used to allocate generation-related costs. The second philosophy relates to the physical capacity of transmission lines wherein transmission facilities have a known and measurable load capacity such that customer contributions to peak load should serve as the basis for allocating transmission costs. Watkins, 24-25. Mr. Watkins' recommended 12 CP method to allocate transmission costs strikes a reasonable balance between these two philosophies.

C. Subsidy Reduction.

1. I&M. Mr. Nollenberger explained the revenue allocation is based on the class cost of service study performed by Mr. Spaeth. Nollenberger Direct, 6. He explained the principles and objectives underlying I&M's proposed revenue allocation among the customer classes and stated that the Company's approach reduced the current level of inter-class revenue subsidies by 25%, while also ensuring that no class received a revenue decrease based on cost of service. *Id.*, 7-8.

2. OUCC. Mr. Watkins proposed an alternative class revenue allocation methodology after considering the results of his various recommended class cost of service studies. Watkins Direct, 36-39.

3. Intervenors. Joint Municipal Group witness Mancinelli disagreed with the Company's allocation condition that ensures that no tariff class receives a decrease in total revenues and recommended that street lighting rates be lowered to cost of service because adequate street lighting is provided by local governments and provides many public benefits, with the resulting shortfall prorated across all other rate classes. Mancinelli Direct, 40-43. CAC-INCAA witness Wallach proposed to (1) maintain base revenues at current levels (*i.e.*, no increase or decrease) for those classes where the class cost of service studies show a revenue decrease at an equalized rate of return; and (2) increase base revenues for all other classes by the same percentage in order to recover any authorized revenue deficiency. Wallach Direct, 17. South Bend witness Seelye recommended that 50% of subsidies be eliminated and disagreed with the Company's proposal that no tariff class receive a decrease in total revenues. Seelye Direct, 3, 26. Auburn witness Rutter disagreed that the Company has moved all classes closer to earning the class average rate of return and recommended a rate of return for the SL class of 9.35%. Rutter, 8-10. Walmart witness Chriss noted Walmart's position that rates should be set based on I&M's cost of service for each rate class, which produces rates that reflect cost causation, sends proper price signals, and minimizes price distortions. Chriss, 14. Mr. Chriss also discussed I&M's proposal to eliminate 25 percent of the current inter-class subsidies within the Company's rate schedules. *Id.*, 16 (citing Nollenberger, 7). Mr. Chriss concluded that Walmart did not oppose the Company's proposed revenue allocation at the requested revenue requirement, but recommended that the Commission apply any reduction to the revenue requirement in a manner that further moves customer classes towards their respective costs of service.

4. Rebuttal. In rebuttal, Mr. Nollenberger showed that I&M's revenue allocation proposal makes progress towards reducing current inter-class subsidies, consistent with all parties' general interests. Nollenberger Rebuttal, 5-6. With respect to Mr. Seelye's recommendations, Mr. Nollenberger stated that while other customer classes are experiencing an

average total revenue increase of more than 11%, it is reasonable to expect that no rate class receive a rate reduction. He added I&M's approach strikes a reasonable balance between reducing current subsidies and managing class impacts as compared to South Bend's proposal. *Id.*, 7. He explained Mr. Wallach's approach would make uneven progress towards mitigating the current level of inter-class subsidies. Nollenberger Rebuttal, 8.

5. <u>Discussion and Finding.</u> I&M's proposed method of distributing its requested overall rate increase is a "purely mathematical approach" (Watkins, 34) based entirely upon its 6-CP class cost of service study. As explained by Mr. Watkins, no class cost of service study can be considered surgically precise (Watkins, 5), and this is consistent with the U.S. Supreme Court's statement that "where as here several classes of services have a common use of the same property, difficulties of separation are obvious. Allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science." *Colorado Interstate Gas Co. v. Fed. Power Comm'n*, 324 U.S. 581, 589, 65 S. Ct. 829 (1945).

I&M's method to distribute its requested overall rate increase relies exclusively upon its 6-CP cost allocation study, which as described above we have declined to implement, as if it were "surgically precise" or "an exact science." Mr. Watkins' approach acknowledges there is no absolute correct or surgically precise cost allocation study and he therefore reasonably relied upon multiple class cost of service study results in developing his recommended class revenue distribution. Watkins, 37. We find Mr. Watkins' approach to be even-handed and appropriate, and approve his recommended subsidy reductions as shown in Tables 11 and 12 of Mr. Watkins' testimony at pages 38 and 39.

16. <u>Rate Design</u>. Mr. Nollenberger presented the rate design supporting I&M's proposed tariffs and explained in general, the Company's approach is to design rates and rate components that reflect the underlying costs of the Company. Nollenberger Direct, 9. He said this includes collecting fixed costs through fixed and/or demand charges and variable costs through energy charges whenever practical. *Id.* He also discussed rate design changes proposed for certain of I&M's riders. *Id.*, 28-30. Based on the record presented, we find the Company's undisputed rate design proposals to be reasonable and should be approved. The disputed rate design issues are discussed below.

A. <u>Commercial and Industrial Rates.</u>

1. <u>Tariffs R.S.–PEV and G.S.–PEV.</u>

(a) <u>I&M.</u> Mr. Cooper testified Tariffs R.S.–PEV and G.S.–PEV are being proposed as part of a comprehensive package of tariffs, rebates, and incentives to attract residential, commercial, and industrial customers to the electric vehicle market. Cooper Direct, 16. Both tariffs are designed to encourage customers to charge plug-in electric vehicles ("PEVs") during off-peak hours.

(b) <u>OUCC.</u> Ms. Aguilar is concerned with I&M not proposing a companion on-peak charge, especially given electric vehicle owners access to 240V charging equipment. Aguilar, 20. With 240V charging equipment, users are capable of more system stress during on peak times then if a 120V charger was used. *Id.* Ms. Aguilar recommended the Commission approve I&M's proposed off-peak rate, and impose an on peak rate. *Id.*

(c) South Bend. South Bend witness Seelye said the off-peak energy charge should be lowered to reflect cost of service and to encourage greater utilization of the service. Seelye, 5, 43-46. He further stated there is no basis for prohibiting net metering customers from taking service under Tariff G.S.-PEV and the exclusion is unduly discriminatory. Seelye, 5, 46.

(d) Rebuttal. Mr. Lehman disagreed with Ms. Aguilar that a punitive approach is necessary to accomplish off-peak PEV charging. Lehman Rebuttal, 6. He stated I&M's proposal is designed to maximize enrollment of eligible participants and shift their PEV charging load to off-peak hours. He also disagreed with Mr. Seelye's recommendation to lower the off-peak charging rate and noted Mr. Seelye's proposal would result in no incremental contribution to fixed costs from participants' off-peak PEV charging, and thus no corresponding benefit to all other customers. Lehman Rebuttal, 11.

(e) Discussion and Finding. I&M's proposed rates would incent customers to charge during off-peak hours by providing lower rates. However, as the OUCC notes, there is no disincentive for customers to charge during on-peak times, which would put further strain on the distribution system, especially if 240 volt charging is used. I&M also notes this strain on its system in seeking to align incentives with off-peak charging, stating that the I&M system will see greater peak capacity demands if default charging behavior coincides with existing system peaks, reducing overall system utilization and require additional system investments and maintenance needs. Lehman, 7. To provide further incentive for customers to avoid on-peak charging, and to avoid further strain on system resources during on-peak times, we agree with the OUCC that higher rates during these times is appropriate, corresponding to the on-peak system average. The record further shows that South Bend's recommendation to allow participation by distributed generation customers is incompatible with the per-kWh credit design of the tariff and impractical from a billing standpoint. Lehman Rebuttal, 9. Accordingly, we approve Tariffs R.S.–PEV and G.S.–PEV as proposed by I&M and modified by the OUCC.

2. Tariff IP.

(a) Walmart. Walmart witness Chriss presented evidence that the Company's hours-use Tariff IP, particularly for the IP-Secondary customer class, incorporates rates that improperly collect demand-related charges through the energy charge component of the rate. According to Mr. Chriss, the Company's proposed rate design for Tariff IP is inconsistent with the Company's own statements that rate components should "reflect the underlying costs of the Company" which includes "collecting fixed costs through fixed and/or demand charges and variable costs through energy charges whenever practical." Chriss, 19-22 (quoting Nollenberger, 9), 31. Mr. Chriss recommended that at the Company's requested revenue level: 1) any approved revenue increase to the IP class should be applied to each service level's demand charge; 2) the Company should maintain the first block energy charges at current levels; and 3) the Company should reduce the second block energy charges as proposed by I&M. Chriss, 31-32. In the event that the Commission approves a lower revenue increase than the

Company has requested, Mr. Chriss recommended that the Commission should apply Walmart's proposal but then reflect the reduced revenue increase in the first block energy charges. *Id.*, 32.

(b) <u>Rebuttal.</u> Mr. Nollenberger provided a comparison of estimated total bill impacts between the Company's and Walmart's recommended Tariff IP rate design. Nollenberger Rebuttal, 17; Attachment MWN-R3. He continued to support I&M's proposed Tariff IP rate design, but said Walmart's proposed Tariff IP rate design was not unreasonable.

(c) <u>Discussion and Finding.</u> *The OUCC takes no position on this issue.*

3. <u>Tariff LGS.</u>

(a) <u>Intervenors.</u> Kroger witness Bieber stated I&M's LGS rate design significantly understates demand-related charges while overstating energy charges relative to the underlying cost components. Bieber Direct, 4. He recommended a rate design that would increase demand-related charges to 65% of the demand-related costs while reducing the energy charges by a corresponding amount to recover I&M's total proposed LGS revenues. Bieber Direct, 4, 6-17.

Walmart witness Chriss generally agreed with the position set forth by Kroger, and presented evidence that the Company's hours-use Tariff LGS, particularly for the LGS-Secondary customer class, incorporates rates that improperly collect demand-related charges through the energy charge component of the rate. Chriss, 21-29. According to Mr. Chriss, the Company's proposed rate design for Tariff LGS is inconsistent with the Company's own statements that rate components should "reflect the underlying costs of the Company" which includes "collecting fixed costs through fixed and/or demand charges and variable costs through energy charges whenever practical." *Id.*, 19-22 (quoting Nollenberger, 9). Mr. Chriss recommended that at the Company's requested revenue level: 1) any approved revenue increase to the LGS class should be applied to each service level's demand charge; 2) the Company should maintain the first block energy charges at current levels; and 3) the Company should reduce the second block energy charges as proposed by I&M and increase the demand charge to account for the reduced second block energy charge revenues. *Id.*, 21-30. In the event that the Commission approves a lower revenue increase than the Company has requested, Mr. Chriss recommended that the Commission should apply Walmart's proposal but then reflect the reduced revenue increase in the first block energy charges. *Id.*, 31.

(b) <u>Rebuttal.</u> Mr. Nollenberger disagreed with Mr. Bieber and Mr. Chriss that recovering demand-related costs through energy charges results in subsidies paid by high load factor customers to lower load factor customers within a given class. Nollenberger Rebuttal, 15-16; Attachment MWN-R1. He did not find the rates proposed by Kroger or rate design methodology presented by Walmart to be unreasonable but continued to support I&M's proposed LGS rate design.

(c) <u>Discussion and Finding.</u> *The OUCC takes no position on this issue.*

2. 4. Tariffs Water and Sewage Service (WSS) and Municipal Service (MS).

(a) I&M. Mr. Nollenberger explained the proposed changes to tariff classes MS and WSS, which align with the Company's general rate design objective of recovering proportional amounts of fixed costs through fixed and/or demand charges. Nollenberger Direct, 27-28.

(b) Intervenors. Mr. Mancinelli testified that I&M's implementation of a demand charge when demand charges presently do not apply to the class, meant that some WSS customers jump to a demand charge of zero to as high as $11.369 per kW in a single step. While he agreed that adding a demand charge to the WSS rate structure incentivizes customers to improve load factors, Mr. Mancinelli reasoned that I&M's proposal is overly aggressive and unduly burdens lower load factor customers in the WSS class. Mancinelli, 50-53. He recommended that I&M's proposed WSS rate structure be modified to cap the rate impacts on low load factor customers, or alternatively, that I&M implement an hours-use rate structure for the Tariff WSS demand charge. *Id*. Mr. Mancinelli testified that MS customers are also receiving significant rate increases due to the introduction of demand charges. Mancinelli, 53-54. He recommended a rate structure for Tariff MS that incorporates the demand-related rate elements of the existing Tariff GS instead of I&M's proposed Tariff MS demand charge. Mancinelli, 54-55.

Mr. Seelye recommended a Tariff WSS demand charge that recovers 1) distribution demand-related costs applicable to the customer's maximum demand during any hour of the month, and 2) a demand charge that recovers production and transmission demand-related costs applicable to the customer's maximum demand during the peak hours of the month. Seelye, 41-43.

(c) Rebuttal. Mr. Nollenberger said while there is a conceptual basis for Mr. Seelye's Tariff WSS proposal, a two-part demand charge is more complex than a single demand charge. Nollenberger Rebuttal, 11. Mr. Nollenberger stated Mr. Mancinelli's Tariff MS recommendation is not an unreasonable alternative to the Company's proposed basic rate structure. However, he disagreed with implementing a flat energy charge, which would conflict with the current Tariff GS block energy charge. He said if Mr. Mancinelli's demand charge proposal is adopted, a blocked base rate energy charge comparable to Tariff GS and an energy charge for the PJM/OSS Rider should also be implemented. Nollenberger Rebuttal, 12-13.

(d) Discussion and Finding. *The OUCC takes no position on this issue.*

B. Residential Rates.

1. I&M. Mr. Nollenberger testified I&M proposes two primary changes to its standard residential rate design. First, he said I&M proposes to increase the monthly service charge from $10.50 per month to $15.00 per month. Second, he said I&M is proposing a declining-block volumetric energy rate structure, where energy usage above 900

kWh is charged at a lower cents-per-kWh rate. Nollenberger Direct, 15. Mr. Nollenberger stated I&M is also proposing a new optional residential rate schedule (Tariff RSD) that will be available for up to 4,000 customers. Nollenberger Direct, 25. He said Tariff RSD uses a three-part rate structure which includes a monthly service charge, a kWh energy charge, and an on-peak kW demand charge. Nollenberger Direct, 25-26. He discussed the benefits of this pilot tariff and described how the Company designed the proposed Tariff RSD rates. Nollenberger Direct, 26-27.

2. OUCC. Mr. Watkins offered his response to I&M witness Matthew Nollenberger's proposal to increase the residential customer charge by 43%. He explained that while Mr. Nollenberger alleges that I&M's rate structure poses challenges to the Company, a residential utility rate structure comprised of a relatively low fixed monthly customer charge and a flat usage (energy or KWH) charge has been used successfully for well over 100 years in the industry. He explained that the electric industry has, and continues to, remain profitable under this historically accepted rate structure. Mr. Watkins testified that I&M's forecasted test year incorporates normal weather conditions such that the revenue requirement established in this case is not based upon any abnormal weather or other usage characteristics. He explained that I&M is a business enterprise and should not act as a governmental taxing agency with guaranteed revenue recovery; in fact, regulation should serve as a surrogate for competition for investor-owned utilities to the largest extent practical. Watkins, 40. Mr. Watkins stated that I&M asserts its proposal is cost justified based on I&M's perception that it is entitled to a guaranteed recovery of fixed costs but that I&M's rate design proposals are nothing more than an attempt to further reduce the Company's risk of revenue collection. Mr. Watkins also addressed Mr. Nollenberger's claim regarding intra-class subsidies paid by high energy users to low energy users. He stated that I&M's system is constructed to serve all customers, and when a new customer applies for service, but for the incremental investment required to connect that customer (e.g. service drop and meter), that customer will use the existing system. He explained that an economic subsidy only exists if the customer in question is not contributing at least the short-run marginal cost to serve that customer. Mr. Watkins pointed to I&M's current approved Tariff and stated it contains a provision to prevent inequities that might accrue as a result of low volume customers utilizing the system through the Contribution in Aid of Construction requirement. He explained that Mr. Nollenberger's assertion about intra-class cost incidence is not supported by classical cost curves, which show that as volume increases, the marginal cost per unit of providing service also increases. *Id.*, 43. Mr. Watkins recommended no change in I&M's monthly residential service charge.

Mr. Watkins compared I&M's proposal to FERC's adoption of a straight-fixed variable ("SFV") pricing method for natural gas, stating that FERC's objective in adopting SFV pricing is meant to promote additional consumption, not reduce consumption. *Id.*, 44. Mr. Watkins stated that one of the most important tools that this Commission has to promote conservation is by developing rates that send proper pricing signals to conserve and utilize resources efficiently. He testified that a pricing structure that is largely fixed, such that customers' effective prices do not properly vary with consumption, promotes the inefficient utilization of resources. Mr. Watkins detailed that a maintaining relatively low fixed monthly customer charges as has been done in Maryland, Washington State, Virginia, Montana, Oregon, and South Carolina, is particularly relevant in Indiana given that I&M is entitled to use a fully projected test year for ratemaking as well as the numerous guaranteed cost recovery riders that in are in place within I&M's tariff. *Id.*,

46. He offered his direct customer cost analysis, included in his Attachment GAW-7, which shows that I&M's Residential direct customer cost is between $8.77 and $9.27, depending on which return on equity (9.10% or 10.50%) is used. *Id.*, 47. Mr. Watkins recommended the rejection of I&M's proposed declining-block rate structure in favor of maintaining the current flat energy charge per KWH. Mr. Watkins did not oppose the pilot Tariff RSD, but, this is a pilot, or experimental program to gather and obtain information, he recommended that I&M be required to keep and maintain specific records on a customer by customer basis that compares each customer's actual RSD bills (and billing determinants) to those that would have resulted under Rate RS and Rate RS-TOD. He recommended I&M should be required to submit detailed reports, data, and workpapers to the Commission, OUCC, and other interested parties on at least an annual basis. *Id.*, 48-49.

3. CAC-INCAA. Mr. Wallach recommended a monthly residential service charge of $10.12 per bill. Wallach Direct, 42-43. He further recommended the Commission reject I&M's proposed declining-block rate structure. With respect to I&M's proposed Tariff RSD, Mr. Wallach expressed concern that the demand charge would dampen signals for conservation and encourage inefficient customer behavior. *Id.,* 43.

4. Rebuttal. In rebuttal, Mr. Nollenberger testified the OUCC and CAC-INCAA recommendations would not provide efficient price signals because they would overstate the variable cost associated with the incremental consumption or conservation of electricity. Nollenberger Rebuttal, 22-23. He explained I&M's proposal to recover a portion of fixed, demand-related distribution costs through a declining block energy rate structure is more cost-justified than one that collects demand-related costs through a flat volumetric energy charge. Nollenberger Rebuttal, 24. He explained I&M's rate design will still recover close to 90% of total residential costs through the volumetric energy charge and thus is not a "high" customer charge or a straight-fixed variable rate structure. Nollenberger Rebuttal, 27-28. Mr. Burnett explained the OUCC and CAC-INCAA's assertions rest on a hypothetical that does not reflect what is actually being proposed in this case. Burnett Rebuttal, 15-17. He testified actual experience following I&M's last rate case demonstrates that increasing the fixed customer charge did not lead to an increase in residential usage. Burnett Rebuttal, 17-19.

Mr. Nollenberger explained Tariff RSD can actually encourage more efficient customer behavior by providing a volumetric rate that more closely aligns with the true variable cost of energy. Nollenberger Rebuttal, 35. He noted this pilot tariff would also provide the customer with a third dimension to control her or his bill as opposed to a two-part rate structure. *Id.* Mr. Cooper explained implementation of Tariff RSD will be similar to that of other new tariff offerings and that I&M will provide customers with information on the tariff. Cooper Rebuttal, 7. He stated the OUCC has not shown why its proposed reporting and recordkeeping requirements related to the pilot are reasonable nor shown that any potential benefits would be greater than the associated administrative costs. *Id.*

5. Discussion and Finding.

(a) Residential Customer Charge and Declining Block Rates.

We find that I&M's proposed rate design change to implement declining block rates and increase its fixed monthly customer charge to be inconsistent with promoting reasonable conservation and energy efficiency in the consumption of electricity. As FERC discussed in its Order 636, the FERC's adoption of SFV rate design for gas pipeline services was designed to promote expanded use of natural gas. FERC's language states that SFV is a promotional rate design:

> Moreover, the Commission's adoption of SFV should maximize pipeline throughput over time by allowing gas to compete with alternate fuels on a timely basis as the prices of alternate fuels change. The Commission believes it is beyond doubt that it is in the national interest to promote the use of clean and abundant gas over alternate fuels such as foreign oil. SFV is the best method for doing that.

Federal Energy Regulatory Commission, Docket Nos. RM91-11-001 and RM87-34-065, Order No. 636 (Apr. 9, 1992), pp. 128 – 129.

We acknowledge that I&M has not proposed SFV rates, and that no party to this proceeding has alleged as much. However, simply because I&M has not proposed SFV rates does not require the Commission to approve its proposed rate design. We must also consider the extent to which rate designs with declining volumetric charges and higher levels of fixed charges undermine customers' ability to make choices to reduce their total bill and serve to promote the additional consumption of a utility's products and services. There is no doubt that the encouragement of additional consumption is contrary to conservation policies.

As support for its requested rate design change, I&M points to our order in Cause No. 44576, in which we approved an increase to IPL's customer charge and the continuation of a declining-block rate structure. *In re Indianapolis Power & Light Co.*, Cause No. 44576, 2016 WL 1118795 *77. Continuing a legacy declining-block rate structure and instituting a new declining-block rate structure are two critically distinct requests. In the present instance, we cannot justify creating a volumetric rate structure designed to encourage more residential electric usage where such a rate structure did not previously exist.

We conclude that I&M's proposed rate design is not supported by fundamental, widely accepted economic price theory. Higher fixed charges that do not properly recognize marginal cost pricing are less related to customers' actual behavior and more related to providing benefit to the utility and its shareholders. Instituting declining block residential rates undermines important conversation goals. We reject I&M's proposed declining block rate structure and order no change to the structure of its current Rate RS and RS-TOD tariffs. We further order no change to I&M's current customer charge.

(b) <u>Optional Residential Demand Metered Tariff.</u> No party directly objected to I&M's proposed Tariff RSD. The record shows Tariff RSD will help customers control their bills by managing their peak demand. Accordingly, we find Tariff RSD is reasonable and should be approved. I&M explained that implementation of this tariff will be similar to that of other new tariff offerings and that I&M would provide customers with information on the tariff and how to best utilize their electric service to provide a least cost, efficient solution to their specific energy needs.

We agree with the OUCC and CAC-INCAA that because the purpose of a pilot program is to gather and obtain information on an experiential basis, requiring I&M to retain and report certain data points as a "proof of concept" is appropriate. I&M is hereby ordered to maintain records on a customer by customer basis that compares each customer's actual RSD bills (and billing determinants) to those that would have resulted under Rate RS and Rate RS-TOD. I&M is further ordered to provide this detail, along with any related workpapers or reports, to the Commission, OUCC, and other interested parties as an annual compliance filing to be made under this Cause.

C. Riders. I&M proposes to retain all existing rate adjustment mechanisms, with certain modifications, and to add one new mechanism – the AMI Rider. We find the unopposed continuation of certain I&M riders to be reasonable and we find they should be approved. We discuss the contested issues below.

1. AMI Rider.

(a) I&M. Mr. Williamson testified I&M is proposing the AMI Rider to track the full costs associated with I&M's AMI deployment until the deployment is completed and the associated costs are reflected in base rates. Williamson Direct, 37. He identified the costs I&M proposed to track incremental to the level included in base rates and explained how the AMI Rider will be implemented and the necessary deferred accounting authority. *Id.*, 37-39.

(b) OUCC. Mr. Blakley testified that if the AMI Rider is accepted, which the OUCC does not recommend, then the retirement of the AMR meters should be recognized as a decrease in depreciation expense in the new rider. Blakley, 1, 9-11, 15.

(c) Intervenors. Kroger witness Bieber opposed the AMI Rider as single-issue ratemaking and said it does not meet the criteria for this type of regulatory treatment. Bieber, 5, 23-24. Joint Municipal Group witness Cannady also opposed the AMI Rider to reconcile estimated AMI costs and said if AMI deployment is approved, the Commission can conduct a prudence review of the costs in I&M's next rate case. Cannady, 4, 32, 36. Auburn witness Rutter recommended the Commission disallow both recovery of and return on the undepreciated book value of the presently in service AMR meters once they are retired and replaced by AMI meters. Rutter, 6.

(d) Rebuttal. Mr. Williamson stated the OUCC's recommendation that the reduction in depreciation expense associated with retired AMR meters be reflected as a reduction to the AMI Rider revenue requirement is consistent with the Company's intent and proposal. Williamson Rebuttal, 26. With respect to the intervenors' testimony, Mr. Williamson explained why the Company's proposed AMI Rider is a better option for I&M's customers. Williamson Rebuttal, 26-27. He said Mr. Rutter's recommendation is troubling in many ways and should not be adopted by the Commission as it would depart from proper accounting and ratemaking for the remaining book value of retired property. *Id.*, 27-30.

(e) Discussion and Finding. As discussed above, we reject I&M's proposed AMI deployment. Accordingly, we deny the AMI Rider and associated deferred accounting authority as proposed by I&M. I&M may seek recovery of its prudently incurred costs related to the approved AMI pilot project that are used and useful in its next rate proceeding.

2. Environmental Cost Recovery ("ECR") Rider.

(a) I&M. Mr. Williamson proposed the ECR be used to track the consumables and net allowances costs I&M incurs in operating its generating assets for the benefit of its customers. Specifically, he proposed to embed the forecasted Test Year level of consumables and allowances costs in base rates of $21,785,467 (Total Company) and track any annual over/under variances in the ECR from the embedded level in base rates.

(b) OUCC. Ms. Aguilar testified that other than the Consent Decree, discussed by OUCC witness Cynthia M. Armstrong, there are no presently known regulations that would lead to an increase in I&M's environmental consumable or emissions allowance costs. Aguilar, 14. Ms. Aguilar testified I&M's own 2020 forecast only included additional sodium bicarbonate use needed to support the proposed Enhanced DSI and the previously approved Unit 2 SCR. *Id.* As for emissions allowances, I&M projected $1,160,001 in the test year, which is a $63,999 decrease from $1,224,000 in 2018 and immaterial difference. *Id.*, 15. The OUCC recommends the enhanced DSI capital expenditure should be denied, and therefore, the Commission should deny any associated O&M for the sodium bicarbonate increases. Therefore, the OUCC is recommending $13,830,135 be embedded in rates. If the Commission rejects Ms. Armstrong's recommended denial of all Enhanced DSI costs for both Rockport Unit 1 and 2, but accepts her alternate position to, at a minimum, deny the Rockport Unit 2 costs, then $17,807,801 should be embedded in base rates. *Id.*, 15-16.

Mr. Blakley opposed continued tracking of I&M's proposed consumable expense, which are the costs of chemicals used in the operation of pollution control equipment, after I&M's pollution control equipment will be in-service and included in base rates. Mr. Blakley pointed out that the Commission has denied requests for continued tracking of O&M expenses when associated pollution control equipment is rolled into base rates in Cause No. 43839. He stated that I&M's proposal would deviate from long-standing principle to include the operating expenses used to operate the plant investment in base rates after the plant investment is complete. Mr. Blakley also stated I&M's request for continued tracking of consumable expense is "piecemeal ratemaking," which is disfavored because it only addresses costs that have increased while ignoring costs that have decreased or increases in income. Blakley, 1, 3-6, 14.

(c) ICC. ICC witness Medine stated that should the Commission approved I&M's request for recovery of costs in the ECR, I&M should not include the costs recovered in base rates in its Rockport wholesale market offer price. Medine, 5, 17.

(d) Rebuttal. Messrs. Williamson and Kerns responded to the OUCC and ICC contentions and identified the numerous factors contributing to the uncertainty and volatility around future consumables and allowances costs. Williamson Rebuttal, 19-21; Kerns Rebuttal, 2-5. Mr. Kerns also responded to Ms. Medine's testimony and said I&M's PJM offer prices for Rockport in the wholesale power market should not be a basis for determining whether a cost reasonably and necessarily incurred to provide retail service is tracked or not through the prices I&M charges for retail services. Kerns Rebuttal, 5. He said the Commission should not pre-define how I&M offers its power into PJM as doing so could increase the cost of generation for I&M's customers by eliminating I&M's ability to manage costs. Kerns Rebuttal, 5.

(e) Discussion and Finding. The "tracking" of consumables must be viewed through the lens of the rules governing the tracking of qualified pollution control property ("QPCP") *under construction* in 170 I.A.C. 4-6, *et seq*. I&M has recovered the costs of consumables (i.e., sorbents used to control noxious emissions) consistently under its ECR proceedings. While I&M argues that consumable costs are potentially variable and volatile, we note that I&M itself admitted that it issues RFPs to control the cost of consumables. Tr. J-36.

The underlying equipment which uses the sorbents is now being put into I&M's rate base, and I&M wants to continue to track the associated consumables. This is contrary to the very rules governing QPCP rate recovery. 170 I.A.C. 4-6-22 states that:

> A utility may continue collecting revenues as a result of ratemaking treatment granted by the commission under this rule for the value of its qualified pollution control property under construction, to the extent that the related qualified pollution control property projects continue to be or are deemed to be under construction, *until the commission determines whether these projects are used and useful in a proceeding that involves the establishment or investigation of the utility's base rates and charges,* [and] the values of these projects do not exceed the construction cost estimates approved by the commission[.]

Emphasis added.

Once the Commission approves the inclusion of I&M's QPCP in rates, the associated consumables cannot continue to be tracked. There are three traditionally cited elements supporting a cost being tracked: potential volatility of the expense, cost being outside the control of the utility, and the magnitude of the expense impacting a utility's bottom line. If an expense is not volatile, then a utility can handle the expense by including a levelized amount in rates. Similarly, if a cost is within the control of a utility - for example, by being able to procure items through competitive bidding - then an amount can be included in rates. While utilities are entitled to earn a return, they are also held to a standard to ensure that rates are just and reasonable.

I&M cited to Vectren's last rate case, Cause No. 43839, for the premise that the Commission might consider the continued tracking of consumables. Mr. Williamson had to admit that the Commission had not in fact done that. Tr. J-85-86, *see also* OUCC CX-13 (pages 1, 94-95 of the Commission's final order in Cause No. 43839). As we set forth in that case:

> In considering whether to approve a new cost tracking mechanism, we not only review whether a specific type of cost qualifies as material, volatile and difficult to control, but also, from a broader perspective, we review the utility's risks related to its operating costs and the other tracking mechanisms it has in place. In

> general, tracking of costs should remain limited in nature so the Company is responsible for managing its overall operating costs. Typically, utilities track operation & maintenance expenses, such as those proposed to be included in the VPC tracker, only while a QPCP construction project is in progress. Once a QPCP project is complete and a rate case is filed, the maintenance and operation expenses are included in base rates along with the capital value of the project. All of the company's pollution control property is operating and in service at this time, and the property and its associated operating expenses have been rolled into Vectren South's rate base in this Cause.
>
> This Commission has previously allowed trackers for several types of expenses. These include the previously mentioned FAC process, environmental cost recovery trackers, demand side management ("DSM") trackers, and MISO cost trackers. Vectren South believes that the chemical and catalyst costs that it has incurred are volatile, substantial, and largely outside of the control of the utility. These three qualities for an expense to be tracked, are basic guidelines to follow, they are not rigid principles requiring the creation of a tracker. We believe the causes for determining if an expense or revenue is appropriate for tracking are often times situational.
>
> While we have approved a number of trackers in the past, we acknowledge Dr. Dismukes's warnings. Revenue or cost trackers tend to make utilities less accountable for their actions because they are less incented to streamline costs or operations. We are also concerned that the proliferation of trackers in the electric industry may result in utilities unreasonably extending the time between rate cases. If they can recover the majority of their variable costs through trackers, they have no incentive to come before the Commission and account for other, non-tracked, decreasing costs or increasing revenues.
>
> Based upon the discussion above, we do not find Vectren South's VPC tracker proposal to be reasonable. While we acknowledge the possibility that chemical and catalyst costs may be volatile in the future, we find it is reasonable to confirm that possibility before moving toward tracking such costs. As Vectren South has embedded an amount for this expense into its base rates it will receive timely recovery of a representative level of costs. We do not foreclose the future consideration of such a tracker should the potential volatility be realized and established with evidence.

Re S. Ind. Gas & Elec. Co., Cause No. 43839, 289 P.U.R.4th 9, 2011 WL 1690057 *98-99 (Ind. Util. Regulatory Comm'n Apr. 27, 2011).

We agree with the OUCC's opposition to the continued tracking of consumables. As with all items added to a utility's rate base, the attendant O&M costs are included and recovered through resulting base rates. It is no different here. I&M's request to continue to track consumables is denied. We therefore accept the OUCC's recommendation and embed $13,830,135 in base rates.

3. Fuel Adjustment Clause ("FAC").

(a) I&M. Ms. Heimberger sponsored I&M's projected Test Year FAC basing point of 12.989 mills per kWh. Heimberger Direct, 27; Attachment NAH-8. Mr. Williamson said the Company is requesting the Commission waive the purchase power benchmark procedures as applied to I&M in Cause No. 43306, both for this case and all future proceedings. He explained circumstances today render it unnecessary for this issue to be revisited in each general rate case. Williamson Direct, 46. He said I&M also proposes to continue crediting customers for revenues associated with participation in I&M's voluntary renewable programs. *Id.*, 7.

(b) OUCC. Mr. Eckert accepted I&M's recommended base cost of fuel and request for a permanent waiver of the purchased power benchmark. He said should the Commission continue to allow I&M to include renewable energy certificate ("REC") revenues in its FAC filings, it should be contingent on I&M's agreement to allow the OUCC a minimum of 35 days to review I&M's FAC proceedings. Eckert, 18-20. Mr. Eckert did not oppose I&M's request that the Commission permanently waive the generic purchased power procedures established in Cause No. 41363 as of the effective date of the Commission's Order in this Cause. *Id.*, 19. Mr. Eckert testified that I&M offers all its generation into the PJM market and controls only the generation availability and the day ahead offer price and that PJM controls the dispatch of I&M's generation. Mr. Eckert did recommend that as a condition of permanently waiving the purchased power over the benchmark that I&M continue to: 1) provide all internal, external, and root cause analyses for any forced outages greater than seventy-two (72) hours as part of its initial FAC audit package; and 2) provide its day ahead offers and the real time awards for the test days, requested by the OUCC, in its initial FAC audit package. *Id.*, 19-20.

Mr. Eckert recommended that the Commission allow the OUCC 35 days to file its testimony after I&M files its case in chief in its FAC proceeding. *Id.*, 18. He testified the OUCC only has twenty (20) days to review the FAC filing, and I&M is the only utility that files semi-annually, which requires the OUCC to review six (6) months of data in twenty (20) days. *Id.*, 18. He also testified that I&M is proposing to continue to include the GPR in the FAC proceeding. He testified that the OUCC has 35 days to file its testimony after Duke Energy, NIPSCO, Indianapolis Power & Light, and Vectren South file their testimony in their FAC proceedings which reviews three months of data. Mr. Eckert concluded and recommended that should the Commission continue to allow I&M to include its GPR in its FAC filing, the OUCC should be allowed a minimum of thirty-five (35) days to review I&M's FAC proceedings. *Id.*, 19.

(c) Rebuttal. Mr. Williamson said the calculation for the sale of RECs is a very simplistic calculation that does not justify the need for additional days to review the FAC filing.

(d) Discussion and Finding. The record shows I&M's proposed base cost of fuel of 12.989 mills per kWh is unopposed and should be approved. Similarly, no party opposed I&M's request for a permanent waiver of the purchased power benchmark. The record shows the factors that led to the development of the benchmark conditions adopted in Cause No. 43306 have been heavily mitigated and a permanent waiver is reasonable.

While the deadline for the OUCC to file its FAC report is set by statute, Ind. Code § 8-1-2-42(b), the other large Indiana investor-owned utilities have accorded the OUCC the courtesy of an additional fifteen (15) days. This leniency is a recognition of the difficulty presented by the need to schedule audits at multiple statewide locations, and the issuance of necessary discovery. I&M argues that the inclusion of REC sales in the FAC proceeding is a "simplistic" calculation with a "minimal" impact on the FAC filing. Williamson Rebuttal, 67. The OUCC performs an interim audit that reviews to some degree the first three months of the semi-annual FAC period. We note with approval that I&M has committed to continuing to provide the OUCC and its consultant an audit package immediately following the filing of the FAC to expedite and facilitate the review process. *Id*. Notwithstanding this agreement, we find it is a reasonable request by the OUCC to review I&M's FAC in a thirty-five (35), rather than twenty (20) day period, and we therefore approve their proposal.

4. *IM Green* Rider.

(a) I&M. Mr. Lucas explained I&M proposes to consolidate its Green Power Rider ("GPR") and Renewable Energy Option ("REO") into a single revised voluntary renewable program called *IM Green* that will offer customers the ability to purchase renewable energy through a combination of wind and solar RECs. Lucas Direct, 35. He discussed the program design and explained the *IM Green* program will allow all customers to purchase RECs as a percentage of their monthly kWh usage. *Id.*, 35. He said large commercial and industrial customers can participate under the basic terms of the *IM Green* program or through a second option which will allow eligible commercial and industrial customers to participate through a written services agreement tailored to their specific business objectives and renewable energy needs. *Id.* Mr. Lucas described how the proposed *IM Green* program will benefit participating and non-participating customers. *Id.*, 37-38. Mr. Cooper discussed the use of the S&P Global Energy Credit Index for the New Jersey Class 1 RECs to calculate the market rate for RECs under the *IM Green* program and discussed I&M's proposed treatment of RECs purchased by customers. Cooper Direct, 17-19.

(b) OUCC. Ms. Aguilar supported I&M's proposal to consolidate the existing GPR and REO into the new IM Green Rider as this proposal provides a lower cost option for I&M customers to obtain RECs than the existing GPR and REO options provide. Aguilar Direct, 7. Ms. Aguilar further encouraged I&M to investigate sourcing RECs from a voluntary market, which is typically cheaper than using I&M's own generated RECs which can be sold on the market and the proceeds passed on to rate payers. *Id.*, 8. Ms. Aguilar expressed concern with I&M's current strategy for unsubscribed RECs. I&M does not sell any of its RECs and holds them until they expire. I&M makes general claims that certain amounts of generation and energy consumption are carbon free or green. However, I&M does not account for how many of the RECs represent these claims. Ms. Aguilar cautioned that I&M's loose strategy for REC management could potentially run afoul to the FTC's green guides. *Id.*, 11. Ms. Aguilar testified the clearest approach is to allow any customer who wishes to purchase RECs to do so through I&M's rider and I&M should monetized any remaining RECs and pass on the proceeds to all ratepayers as a credit in the FAC. *Id.*, 13.

(c) Intervenors. IG witness Dauphinais recommended I&M work with its large customers to provide expanded options for those customers. Dauphinais, 3, 32-33. Specifically, he noted that I&M's proposal is limited to the purchase of RECs and, as a result, I&M's proposal may not be sufficient for some of I&M's large customers who must meet their sustainability goals by acquiring renewable power (bundled RECs and electric power) from an identified source or by meeting other standards. *Id*. Walmart witness Chriss recommended approval of I&M's Custom Agreement option and proposed alternative language related to REC pricing to remove the reference to New Jersey solar RECs as a basis for pricing this option. Chriss, 6-7, 35-37.

(d) Rebuttal. Mr. Lucas said the OUCC recommendation to monetize unsubscribed RECs would not be in the best interest of I&M's customers and is at odds with the OUCC's general support for renewable, green energy. Lucas Rebuttal, 27-29. He said I&M would be interested in engaging with Walmart to explore potential utility partnership opportunities and explained the New Jersey REC price provides a reasonable market-based index to value RECs absent a market in Indiana. *Id.*, 29-30.

(e) Discussion and Finding. The record shows I&M's proposal to consolidate the GPR and REO programs into the single *IM Green* program is reasonable, provides opportunities for all of I&M's customers to participate, and provides I&M flexibility to tailor its offerings to meet the specific interests and needs of its customers. Lucas Direct, 35-36; Cooper Direct, 17-18. I&M claims that the OUCC's recommendation to require I&M to monetize all of its unsubscribed RECs would prevent I&M and its customers from claiming that a part of their generation came from carbon free energy sources. Lucas Rebuttal, 28. However, I&M also provided information contradicting this position, stating that "it would not be appropriate for a customer to claim that they specifically received green energy from I&M's green energy resources without either purchasing the RECs or having the RECs retired on their behalf." CAC Exhibit CX-2, I&M's Response to OUCC DR 40-24. Accordingly, unless an I&M customer does not specifically participate in the I&M Green program, or other arrangement with I&M, to specifically purchase or retire RECs, we find it inappropriate for I&M to claim a general "carbon-free" benefit applies to all customers. We also note that other electric utilities in Indiana sell RECs, and the revenues of these sales offset other expenses. *See* pending FAC filings *In re NIPSCO*, Cause No. 38706 FAC-124; *In re Duke Energy Indiana*, Cause No. 38707 FAC-121; *In re S. Ind. Gas & Elec. Co., (Vectren South)*, Cause No. 38708 FAC-124. To the extent that RECs are not subscribed by customers, i.e. either purchased by customers from I&M or I&M retires the RECs on the customers' behalf, we direct I&M to use all reasonable measures to sell those RECs and refund the revenues to the benefit of I&M's customers.

With respect to Mr. Chriss' concern regarding the price index used in the *IM Green* program, the record shows there is a distinction between New Jersey Class 1 RECs (which trade in the $6-$7 range) and New Jersey Solar RECs (which trade in the $200-$230 range). Tr. I-40. We find the use of the S&P Global Renewable Energy Credit Index for New Jersey Class 1 RECs is a reasonable proxy for Indiana RECs generated by I&M and provides a relatively stable price index. Cooper Direct, 17-18. We further find I&M's proposal to allow for custom written agreements with its large commercial and industrial customers under the *IM Green* to be reasonable. No party opposed having this option, and the record shows it will allow larger customers and I&M flexibility in customizing an offering specific to the customers' needs. *Id.*, 18. Accordingly, we find the *IM Green* Rider should be approved as proposed by I&M.

5. Off-System Sales Margin Sharing.

(a) I&M. I&M proposes to continue sharing of off-system sales ("OSS") margins on a 95/5 basis, meaning that 95% goes to customers and 5% goes to the Company, with zero embedded in base rates. Williamson Direct, 7-8; 48-49. Mr. Williamson said continuing to share OSS margins is reasonable because it provides an incentive for the Company to maximize the benefits of OSS for both the Company and its customers. *Id.*, 49. In addition, he said continued sharing recognizes the value of I&M's Commercial Operations organization, which is responsible for the PJM market bidding and hedging strategy for I&M's generation fleet, providing substantial value to I&M and its customers by optimizing I&M's OSS margins. *Id.*, 49-50. Mr. Williamson explained it is both reasonable and necessary to track OSS margins from $0 (rather than embed a certain level in base rates) as OSS margins are largely contingent on PJM market energy prices which are variable due to a number of factors outside the control of the Company and in total OSS margins are significant and can vary significantly from year to year. *Id.*, 50; Figure AJW-5.

(b) OUCC. Mr. Lantrip recommended continued tracking of OSS margins, but with 100% of all OSS margins greater than zero dollars allocated to ratepayers. Lantrip, 1, 5-8, 13. This revision was driven by multiple reasons. Ratepayers pay I&M's retail rates to support the operations and the return on rate base for the assets that create the opportunity for OSS margins. *Id.*, 7. Secondly, I&M is required as a market participant to offer all its available electricity produced by its generating facilities into the PJM Market, thus PJM plays the primary role in conducting OSS of I&M's excess generation. *Id.*

In addition, I&M's retail ratepayers pay for the PJM administrative fees for I&M's membership as a market participant through the PJM/OSS annual riders I&M files before the Commission for cost recovery. Therefore, if OSS margins depend primarily on PJM's administration of unit dispatch and PJM's energy markets, I&M has a limited role in its control of OSS margin outcomes and should not be entitled to receive OSS margin revenues. Likewise, if the OSS margins are handled through PJM's administration, and I&M passes through these administrative fees to ratepayers, then ratepayers should be the rightful beneficiaries of 100% of the OSS margins as well. *Id.*, 7-8. Finally, although Mr. Williamson indicates I&M's Commercial Operations organization provides substantial value to I&M and its customers by optimizing I&M's OSS margins, maximizing the use of its generation facilities is something I&M should be doing as part of prudent utility business practice. Mitigating the costs to the customers that are paying for those generation facilities does not necessitate an incentive. *Id.*, 8.

(c) Intervenors. The Industrial Group and Joint Municipal Group both proposed that 100% of OSS margins above zero be allocated to I&M's customers. Dauphinais, 3, 30-31, 33; Mancinelli, 3-4, 28-30, 59. IG witness Dauphinais explained that I&M does not need an incentive to make off system sales because it is required to offer all of its generation into the PJM day ahead and real time energy markets. IG witness Dauphinais testified that I&M does not need an incentive to make off-system sales because it is already required to offer all of its generation into the PJM markets on a daily basis. Dauphinais, 30. Furthermore, he said that customers should be entitled to the entirety of a utility's OSS margins because those OSS margins would not be possible but for the fact that the utility's customers are covering the fixed costs of the generating units that make those OSS margins possible. Dauphinais, 30-31. Mr.

Mancinelli testified that I&M's customers should receive 100% of OSS margins for three reasons: (1) cost responsibility for generation is fully borne by retail customers; (2) I&M is already fairly compensated through allowed return on its generation investment; and (3) OSS provides other benefits to the company such as efficient use of generation assets. Kroger recommended the Commission order I&M to include $38.4 million in base rates and allow 95/5 sharing of the incremental OSS margins above or below that amount. Bieber, 5-6, 26. Mr. Bieber stated if the Commission embeds zero dollars in base rates, then customers should receive 100% of the OSS margins.

(d) Rebuttal. Mr. Williamson said I&M's proposal is a very modest and reasonable request that provides a small yet meaningful share to I&M to further incentivize optimizing OSS margin to reduce the cost of providing service to all customers. Williamson Rebuttal, 23-25. He testified completely eliminating this incentive will not properly compensate I&M for its efforts to effectively compete in the market and the risks it is taking to create the value being shared with customers. *Id.*, 23. He objected to Kroger's alternative proposal, stating embedding such a high level of OSS margins shifts a significant amount of risk to the Company's shareholders in exchange for a very small potential benefit of retaining 5% if annual OSS margins exceed the Test Year level. Williamson Rebuttal, 25-26.

(e) Discussion and Finding. I&M proposes to continue its existing OSS margin sharing mechanism. The OUCC and intervenors propose to change the current mechanism so as to provide 100% of OSS margins to customers. We conclude that a continued sharing of OSS margins is not warranted. We find I&M's obligation to adhere to prudent utility management practices to maximize the benefits of OSS for both the Company and its customers should not merit an additional incentive beyond what has already been provided through regulatory approval. Accordingly, we approve the OUCC's and intervenors' proposal to embed zero dollars of OSS margin in base rates, with 100% of OSS margins above zero through the OSS/PJM Rider to benefit ratepayers.

6. PJM Rider and PJM Capacity Performance Insurance.

(a) I&M. Mr. Williamson testified I&M's PJM costs remain significant, variable, and largely outside I&M's control. He explained I&M proposes to continue the OSS/PJM Rider consistent with the structure agreed to in the settlement approved in Cause No. 44967, with the exception of removing the sunset provision and cap on certain PJM NITS charges, and commence tracking the cost of PJM Capacity Performance Insurance. Williamson Direct, 49-54. He said new PJM Capacity Performance rules impose fees on generation facilities that are unable to meet their capacity commitments when PJM determines there is a system emergency and calls a Capacity Performance "event". Williamson Direct, 32. He sponsored Adjustment O&M-6 to increase O&M expense by $1.5 million to include the annual expense to purchase insurance to cover the final risk associated with these PJM rules. *Id.*, 32. Mr. Thomas further supported the reasonableness of the expense of the Capacity Performance Insurance in light of the potential risk it mitigates. Thomas Direct, 33-34.

Mr. Ali described I&M's role as a Generator, Load Serving Entity, and Transmission Owner ("TO") in PJM and the various charges and credits that the Company experiences resulting from each role. Ali Direct, 7-9. He explained NITS charges represent the cost for I&M

and other PJM network customers to integrate, economically dispatch, and regulate their current and planned network resources to service their network load. *Id.*, 9. He discussed the transmission planning process and the forecast of PJM revenues and charges. *Id.*, 9-19. He said the costs to be recovered through the OSS/PJM Rider are significant and the NITS costs in particular are expected to increase. *Id.*, 19-20. He explained NITS costs are potentially variable or volatile and are largely outside of I&M's control. *Id.*, 20-21. He said continued recovery of NITS costs through the OSS/PJM Rider remains a reasonable process. *Id.*, 21-22.

(b) OUCC. Mr. Gahimer addressed Mr. Williamson's and Mr. Ali's claims that NITS charges are outside of I&M's control. Gahimer, 3. He explained that the control Mr. Williamson and Mr. Ali claim I&M lacks over NITS charges was ceded to other AEP-affiliated transmission companies through two of AEP's voluntary corporate decisions. *Id.*, 7. First, AEP established transmission-owning companies ("TransCos"), each of which builds and owns transmission in one of the AEP Operating Company's ("OpCos") service territory. For example, I&M TransCo builds and owns transmission in I&M's service territory. *Id.*, 6-7. To the extent that I&M lacks control over NITS charges resulting from transmission that, but for AEP's creation of I&M TransCo, would have been built and owned by I&M itself, that lack of control resulted from the creation of the TransCo. *Id.* Second, all of the AEP-affiliated transmission-owning entities (all AEP TransCos and OpCos) entered into a Transmission Agreement under which the NITS charges resulting from the aggregate of all those companies' transmission investment are allocated to each OpCo based on something other than that OpCo's investment in transmission.

Mr. Gahimer testified that in essence, I&M pays a share of the NITS charges resulting from transmission built and owned by each TransCo and OpCo. *Id.*, 7-8. Mr. Gahimer testified that I&M should be deemed to have the control that the AEP corporate decisions ceded to TransCos and other OpCos. From this perspective, I&M has control over its NITS charges. Mr. Gahimer further rebutted Mr. Ali's claimed lack of control by pointing out that Mr. Ali conflated a lack of control over the drivers of transmission investment with a lack of control over NITS charges. *Id*., 9-10. Mr. Gahimer testified that even if I&M lacks control over the drivers of transmission investment, it has control over how it responds to those needs. Given all of these factors, Mr. Gahimer concluded that, properly viewed, I&M has control over its NITS charges. *Id.*

Mr. Gahimer also described the various processes under which I&M plans transmission. Two separate processes are relevant: PJM's M-3 process (Gahimer, Appendix B) and FERC's Formula Rate process. *Id*., 19-20. Under the M-3 process, transmission owners must present assumptions, needs and solutions to stakeholders. Transmission owners must allow stakeholders to provide feedback, but the transmission owners are not required to reply or otherwise demonstrate that they have taken the feedback into consideration. Under the Formula Rate Filing process, transmission owners use FERC Form 1 data as inputs to a formula rate. Specific projects for which costs are included in the FERC Form 1 (and, therefore, the formula rate) are not provided. Mr. Gahimer asserted that these two processes provide insufficient oversight of transmission investment and the prudence thereof. *Id*., 18-19. Therefore, Mr. Gahimer recommended that the Commission open a proceeding through which it could explore process options through which the Commission could assess the prudence of transmission investment before that investment is included in a Formula Rate Filing. *Id*., 21. Mr. Gahimer testified that such an examination could shield I&M ratepayers from the cost of transmission built in other OpCos service territories from which I&M customers do not benefit.

Mr. Gahimer responded to Mr. Thomas' request for recovery of the Capacity Insurance Premium. Mr. Gahimer pointed out that Mr. Thomas had addressed neither the risk of penalty assessment nor the potential to financially benefit under PJM's Capacity Performance rules. *Id*., 25. Mr. Gahimer explained the factors that mitigated the risk that I&M would be penalized and described the potential to financially benefit. *Id*., Appendix C. Mr. Gahimer recommended that the Commission deny recovery of the Capacity Insurance Premium because I&M had failed to demonstrate that the premiums were prudently incurred.

Mr. Lantrip testified continued tracking of non-NITS costs seems appropriate at this time, as well I&M's proposal to embed forecasted Test Year level of all non-NITS costs in base rates. Lantrip, 8, 13-14.

(c) <u>Intervenors</u>. IG witness Mr. Dauphinais and Kroger witness Mr. Bieber opposed NITS tracking and said the costs are largely under the control of the Company and not volatile or variable in a manner that warrants a tracker. Mr. Dauphinais stated that the NITS costs are primarily for I&M and I&M's AEP East affiliates' transmission facilities and are different from regionally allocated transmission projects in PJM. As such, the NITS costs are largely within the control of I&M and its affiliates, they should be recovered through base rates. Dauphinais, 15. Mr. Dauphinais added that the NITS costs are not volatile in nature because they are principally related to new capital investment in transmission facilities that is largely predictable in advance and consistently growing – not costs that involve recurring and difficult to predict significant upward and downward swings. He noted the NITS costs have nearly consistently grown since 2012 and are forecasted to continue to consistently grow through at least 2021. He added that the exception to this was in 2018 when I&M's NITS cost decreased due to a settlement agreement related to the AEP NITS rates under the PJM OATT that settled several issues, including the impact of the Federal Tax Cut and Jobs Act, with a one-time lump sum payment.

He stated that due to their consistently upward behavior, these costs also represent the worst type of costs to be allowed to be tracked and recovered through a rate adjustment rider because the recovery through a rate adjustment mechanism of costs that are rising, but predictably so, allows the utility to recover a single known rising cost while avoiding a base rate case in which all its other expenses and revenues, which are changing in the background, will be examined and perhaps used to offset all or part of the rising cost to avoid an unnecessary rate increase.

Mr. Dauphinais added that he disagrees with Mr. Ali's suggestion that the NITS capital projects of I&M and its affiliates are sufficiently reviewed in the PJM stakeholder process and AEP annual transmission formula rate protocols process. He stated at least some of the projected growth may be due to the lack of oversight and review, and I&M's parent company's own strategic plans, not demonstrated need. He noted there is evidence that it is likely a very large portion of the transmission capital expenditures of I&M and its AEP East affiliates that are driving I&M's forecasted large growth in NITS costs between 2019 and 2023 are for Supplemental Projects and Non-topology Projects proposed by I&M and its AEP East affiliates rather than PJM. Such projects are what Mr. Ali collectively refers to as "Owner Projects" on page 11 of his direct testimony.

Mr. Dauphinais explained that supplemental Projects are projects that change the transmission network and are proposed by transmission owners such as I&M and its affiliates, rather than PJM. PJM does not independently verify the need for Supplemental Projects. PJM only performs a no harm analysis to ensure the addition of the Supplemental Project will not adversely affect reliability. Non-topology Projects are projects that do not change the transmission network. PJM neither performs an independent verification of need nor a no harm analysis for Non-topology Projects since they are not included in the PJM Regional Transmission Expansion Plan ("RTEP") process.

Mr. Dauphinais testified that $222.52 million (69%) of the $321.2 million of I&M and I&M Transco NITS capital project costs identified by I&M as being started in 2019 are for Supplemental or Non-Topology capital projects. He added that while I&M did not provide similar detailed information for the other AEP East Operating Companies and AEP East Transcos, there is no reason to believe that a very similar high percentage of the NITS capital project costs for the projects started by those entities in 2019 were also for Supplemental and Non-Topology Projects.

Mr. Dauphinais testified that AEP, as a holding company, has a vested interest in growing the rate base of its Operating Companies and Transcos in order to increase the total return for its shareholders, and as a result, the AEP Service Corporation employees who propose the Supplemental and Non-Topology capital projects that AEP would like to pursue through its Operating Companies and Transcos, including I&M and I&M Transco, inherently have a conflict of interest with respect to simultaneously representing the interests of I&M's Indiana retail customers in the PJM stakeholder process.

In support of his testimony, Mr. Dauphinais provided a copy of an article that was posted on the AEP website as of June 8, 2018, on which date he accessed it, titled "Investing in Transmission". The article notes that Nick Akins, Chairman, President and Chief Executive Officer of AEP, has called AEP Transmission "the flagship" of the organization [AEP and its subsidiaries]. The articles goes on to state that:

Through 2018, AEP Transmission is expected to add an additional billion dollars a year or more to AEP's rate base, growing its contribution from $700,000 in 2012 to between $6.4 billion and $8.2 billion in 2018.

The article also states:

> AEP Transmission's growth strategy involves cultivating a portfolio of business under the AEP Transmission Holding Company, or Holdco, a subsidiary of AEP. Holdco is the parent of several companies and investment vehicles that put investment dollars to work, earn a return, and address the nation's need to improve grid reliability.

The article identifies trends in the market that AEP believes require investment in and expansion of the AEP transmission system to keep reliable, affordable electricity flowing to customers.

Ms. Cannady recommended disallowing recovery of the insurance premiums because ratepayers should not be responsible for covering the cost of insuring a risk of non-performance under the PJM rules without detailed information on the likelihood of non-performance, and whether such non-performance was outside the Company's control. Cannady, 4, 33. In addition, Ms. Cannady noted that under the PJM Capacity Performance Rules, it is possible for I&M to actually receive compensation for the non-performance of other members of PJM. *Id*. At 34-35. Mr. Bieber testified I&M earns a rate of return on its production plant which is intended to provide an appropriate balance between the risks and rewards for I&M's operations. He said if I&M elects to purchase insurance to mitigate its operational risk, that cost should not be passed on to customers. Bieber, 5.

(d) Rebuttal. Mr. Williamson said a review of the historical and future trend demonstrates from year to year NITS costs are subject to change. Williamson Rebuttal, 7. He said NITS costs are rising such that it is not possible to set a test year level in base rates that is reasonably representative of ongoing NITS costs. He disagreed tracking PJM costs reduces or eliminates the Company's incentive to reduce costs, noting the impact of the increasing NITS cost is so large it cannot be reasonably managed by offsetting costs elsewhere. *Id.*, 13. Mr. Williamson reiterated that PJM NITS charges are expected to increase significantly the year following the Test Year and showed that if I&M does not continue to track PJM NITS as proposed by the Company, it would decrease I&M's earned ROE by approximately 1.90% in the first calendar year following this rate case, making I&M's earned ROE less than that recommended by any intervenor in this case. Williamson Rebuttal, 12. He said it is undoubtedly clear that not tracking PJM NITS would eliminate any reasonable opportunity I&M has to earn its authorized return.

Mr. Ali disagreed with Messrs. Dauphinais and Gahimer's contention that I&M has ceded control and said I&M does not have control over costs that other transmission owners in the AEP Zone incur, including AEP affiliates, just as other Transmission Owners and their respective state utility commissions do not have control over I&M's costs. Ali Rebuttal, 6. He explained that projects giving rise to I&M's NITS expenses are outside the control of I&M and its affiliates because Transmission Owners cannot decline to make reasonable and necessary investments in the transmission grid. He said these investments must be made to fulfill I&M's obligation to operate pursuant to Good Utility Practice and none of the transmission projects giving rise to NITS expense have been alleged to be unreasonable or unnecessary. Ali Rebuttal, 5. He said these transmission projects are driven by the underlying need for infrastructure improvements and each RTO member's respective obligation to provide safe, adequate, and reliable transmission service and facilities in accordance with the Good Utility Practice requirements that have long been the foundation for utility planning and operations and continue to be imposed on the RTO Transmission Owners by FERC. *Id.*, 6. He said ultimately, AEP's structure does not supplant the respective obligations of the RTO members to fulfill their respective public utility obligations to serve. *Id.*, 6-7. Rather, he said AEP's structure facilitates the planning process and helps AEP and I&M achieve the joint transmission system benefits the entire RTO system was created to foster. *Id.*, 7.

Mr. Ali explained the transmission projects are subject to a robust PJM and stakeholder process which provide the opportunity for stakeholders to review and provide input regarding Owner Projects. Ali Rebuttal, 7; see also Williamson Rebuttal, 13. He discussed the multiple opportunities for stakeholders to comment, provide input on additional needs, and propose alternative solutions for PJM Transmission Owners to consider. Ali Rebuttal, 8. He said I&M and AEP consider all input provided by stakeholders. *Id.* Additionally, he said I&M and AEPSC Transmission include stakeholders that are directly impacted by a given project in the project's development and prior to its submission as a Solution to PJM stakeholders to ensure that those direct impacts are considered in identifying and evaluating potential Solutions. *Id.*, 8-9. He stated I&M and AEPSC Transmission also go beyond what the M-3 Process requires by annually meeting with customers to discuss transmission needs, which provides an additional opportunity for stakeholder feedback and review of the needs of the system. *Id.*, 9. He responded to Mr. Gahimer's criticism of the FERC Formula Rate Filing process and explained the AEP Operating Companies and Transmission Companies' FERC-approved formula rates include protocols that establish an open and transparent process for any interested party to review the rates and challenge items, including the ability to challenge the prudence of actual costs and expenditures. *Id.*, 9-10. He also refuted Mr. Gahimer's suggestion that Owner Projects are less necessary than Baseline Projects, explaining the designation of a project as a Baseline or Owner Project is not indicative of the level of, or absence of, need for the project. *Id.*, 11. Instead, he said the designations simply reflect that the project addresses different system reliability and resiliency needs. *Id.* Finally, Mr. Ali responded to Mr. Dauphinais' testimony regarding non-topology projects and explained these projects are essential to the larger projects that are submitted to and reviewed by PJM. *Id.*, 12. He explained non-topology projects are required for important operational functions such as protecting against security threats, minimizing equipment damage, reducing outage durations, and improving safety, as well as many others. *Id.*, 13. He said although these projects do not affect any load flow model used by PJM, they are still necessary for the continued safe, efficient, secure, and reliable operation of the transmission grid. *Id.*

Regarding the PJM Capacity Performance insurance, Mr. Thomas explained the question is not whether I&M is required to purchase this insurance, but whether doing so is a reasonable cost of doing business. Thomas Rebuttal, 7. He said I&M considered both the risk of an event occurring and its consequence in making the decision to purchase this insurance and that the cost of the Company's other types of insurance is recognized as a reasonable and necessary cost of service. *Id.*, 7-8. Mr. Hevert responded to Mr. Bieber's testimony and stated if Mr. Bieber's proposal were to be adopted, it would require an increase in the authorized return on equity. Hevert Rebuttal, 95-96.

(e) Discussion and Finding. NITS costs are significant and projected to increase and the OUCC, Industrial Group and Kroger all recommend recovery of I&M's Test Year PJM NITS costs. Thus, the question is whether I&M should continue to track these costs as proposed.

Before the General Assembly authorized the use of a future test year through the passage of Ind. Code § 8-1-2-42.7, the Indiana Court of Appeals addressed the issue of future test evidentiary challenges in a seminal case:

> While under some circumstances historical data may provide a distorted

> approximation of a utility's operations, the reliability of the projected or future test-year method advocated by the City has been widely disputed. Some regulatory commissions have accepted projected data and future estimates in determining the propriety of proposed rates. *But even those commissions utilizing the future test year have expressed concern about the reliability of projected data, and many have limited its use to cases in which unusual circumstances rendered existing historical data clearly inadequate.* The future test year has been most frequently used in rate proceedings involving utilities which have undergone rapid capital expansion or have experienced some substantial shift in operating structure. On the other hand, some regulatory agencies have decided that the data forecasts of the future test-year method are so inherently unreliable that they should never be considered in rate proceedings.

City of Evansville v. S. Ind. Gas & Elec. Co., 339 N.E.2d 562, 576 (Ind. Ct. App. 1975) (citations omitted, emphasis added).

As a consequence of the legislature's approval of future test years, utilities must now show that the projections of future expense are reasonable. Inherent in that showing is the requirement that costs must be used and useful in the provision of utility service by the end of the future test year. I&M remains a member of PJM as authorized by this Commission. *Re Commission's Investigation*, Cause Nos. 42350/42352 (Ind. Util. Regulatory Comm'n Sep. 10, 2003). However, PJM membership is not a free pass to unlimited recovery; like other utilities in RTOs, I&M must submit its cost to us for approval. Non-NITS charges – consisting of administrative expense – are not an issue. Rather, I&M requests 100% recovery through tracking of NITS charges, consisting of costs incurred by I&M and other AEP utilities within the PJM West (also known as the AEP East) Region.

I&M's NITS projects go through the Regional Transmission Expansion Project ("RTEP") process. In particular, projects classified as "supplemental"[12] are those that have not been mandated because of a violation of FERC, NERC or PJM criteria. I&M (or more precisely, AEP corporate) puts suggested projects into the RTEP queue consisting of, for example, replacement of conductors, replacement or upgrades to substations, and replacing transmission poles or wire. Tr. E-37. The RTEP process includes regular PJM-sponsored meetings at which transmission owners ("TOs") present proposed projects to interested stakeholder for feedback. PJM does not do a prudency review of proposed items in the RTEP but performs what is known as a "no-harm" analysis, which reviews whether the proposed project will harm the grid in any way. Tr. E-32. If the project passes the "no harm" test, PJM does not otherwise review or judge the project. *Id.*

While I&M argues that parties can participate in the PJM and FERC processes in order to contest the NITS charges, it is not that simple. While projects go through multiple review

[12] "There are baseline projects that are resolving a criteria -- criterion violation; there are supplemental projects that are pretty much addressing anything else to ensure the system will operate in a reliable and cost effective manner, and then there are network upgrades which are the upgrades needed to interconnect new generation to the grid." Tr. E-13. Baseline projects "are required to not only address NERC criteria violations but also PJM criteria violations as well as the transmission owner criteria violations published in FERC Form 715." Tr. E-15.

meetings with stakeholders in the RTEP process, stakeholders' complaints or concerns may be ignored altogether by a TO. Tr. E-30.[13] If the projects proceed and are included in a TO's formula rate filing at FERC, FERC does not do a prudency review of included projects unless there is a challenge to the filing. Tr. E-10-11. Identification of projects in a FERC formula rate filing is very limited, often consisting only of a project description and price. Tr. E-12.

Once a TO goes through the RTEP process, it can send the list of "completed" projects to PJM. PJM, in turn, bills the TO for those same NITS projects as part of the PJM bill (which also includes administrative costs). I&M's PJM bill includes NITS expenses from other AEP TOs, such that Indiana ratepayers are paying for projects in other states, where this Commission has no jurisdiction. I&M thus argues that it largely has no control over NITS charges because it is paying a bill PJM sends it. That assertion is a shadow of the truth. In essence, I&M – and AEP – have chosen a cost recovery mechanism that sidesteps traditional regulation and oversight. While it may be an authorized process through PJM, it is not transparent, and there is no real opportunity for stakeholders to subject the projects to regulatory scrutiny.

While there is no specific statute addressing NITS recovery, perhaps most analogous to NITS is a proceeding brought under the TDSIC statue. Ind. Code ch. 8-1-39, *et seq*. Before approving a TDSIC, the Commission must make specific findings:

> When determining that a [TDSIC] plan is reasonable, the Commission's order must include (1) [a] finding of the best estimate of the cost of the eligible improvements, (2) [a] determination whether public convenience and necessity require or will require the eligible improvements, and (3) [a] determination whether the estimated costs of the eligible improvements ... are justified by the incremental benefits attributable to the plan.

NIPSCO Ind. Gp. v. NIPSCO, 100 N.E.3d 234, 239 (Ind. 2018), *mod. on reh'g*, *citing* Ind. Code § 8-1-39-10(b) (internal quotations removed).

In contrast to a TDSIC proceeding, I&M's NITS charges are presented for recovery as a *fait accompli* – the Commission has no opportunity to review the proposed projects, has no access to any cost estimates, and no opportunity to determine if the projects are cost effective. Instead, I&M presents the costs for recovery behind the curtain that PJM has "billed" I&M and therefore I&M is beholden to make such payments. But the supplemental NITS project costs are not generated by PJM: they mirror what I&M has presented. And Indiana customers are paying for projects by other AEP entities.

We have previously disallowed I&M's request for costs that do not benefit Indiana customers. In Cause No. 44075, I&M sought to include in rates the cost of a carbon capture and sequestration ("CCS") study for an AEP plant in West Virginia. I&M argued that the "FEED" study could be applicable to its Rockport Units. In rejecting that request, we held as follows:

> [T]he evidence in the record shows that I&M has no intention of adding CCS

[13] Mr. Ali testified that it would be unwise to ignore stakeholder complaints, because AEP could then be challenged at FERC when the resulting project was included in the formula rate filing. Tr. E-31.

> technology to the Rockport facility at the present time. We are unwilling to authorize the recovery of FEED Study expenses that were undertaken without prior submission to the Commission for approval. In the absence of our prior review of the FEED study, we cannot pass judgment on the reasonableness or necessity of the study or costs. Under such circumstances, we are not inclined to impose upon Indiana ratepayers financial responsibility for a project which we have never had an opportunity to consider or authorize, and which is likely to be of limited value to those ratepayers. Accordingly, we deny I&M's request to include recovery of the costs associated with the FEED study in rates and reduce I&M's proposed revenue request in this proceeding by Indiana's jurisdictional share[.]

In re Ind. Mich. Pwr. Co., Cause No. 44075, 2013 WL 653036.

The same set of facts is at play with NITS: I&M presents its ratepayers and the Commission with a bill for projects the Commission has never had the opportunity to review or approve. Our concern is amplified by the need to balance utility and ratepayer interests:

> The ratemaking process involves a balancing of…the owner's or investor's interest with the consumer's interest. On the one side, the rates may not be so low as to confiscate the investor's interest or property; on the other side the rates may not be so high as to injure the consumer by charging an exorbitant price for service and at the same time giving the utility owner an unreasonable or excessive profit.

Pub. Serv. Comm'n of Ind. v. City of Indianapolis, 131 N.E.2d 308, 318 (Ind. 1956).

And as expressed in *NIPSCO Ind. Gp. v. NIPSCO*, 100 N.E.3d 234, 238 (Ind. 2018), *mod. on reh'g*:

> As a quid pro quo for being granted a monopoly in a geographical area for the provision of a particular good or service, the utility is subject to regulation by the state to ensure that it is prudently investing its revenues in order to provide the best and most efficient service possible to the consumer.

Citing U.S. Gypsum, Inc. v. Ind. Gas Co., 735 N.E.2d 790, 797 (Ind. 2000).

In addition, we cannot overlook the fact that I&M's transmission investment carries its own incentives. In particular, AEP's 2019 Annual Incentive Compensation Plan shows a "Transmission Infrastructure Investment" metric upon which employee incentive compensation is based. Achievement of the metric is based upon the following:

<u>Transmission Infrastructure Investment (3% weight)</u>

- Plant in Service (2% weight)
  - Maximum (200% payout) - $3.655B
  - Target (100% payout) - $3.519B

- Threshold (0% payout) - $3.310B

- Capital Investment (2% weight)
  - Maximum (200% payout) - $3.520B
  - Target (100% payout) - $3.314B
  - Threshold (0% payout) - $3.082B

The AEP Annual Incentive Compensation Plan document speaks for itself, and it clearly shows that incentive compensation under this metric is based upon the amount of capital investment and transmission plant in service AEP completes in 2019. The existence of this metric speaks to the degree of control AEP can exercise over when and at what spending level transmission investment on its system is completed. I&M's NITS proposal ties into this incentive compensation by reinforcing I&M's achievement of financial goals. This is a further factor underscoring our decision.

Utilities cannot have it both ways. They cannot use a future test year - which allows them to project expenses - and then complain that their own projected cost will be insufficient. We find that the proper balance in this case is to hold I&M to its projected NITS expense and embed that amount in base rates. This applies a fair standard: I&M is held to its own projections, while ratepayers are not saddled with uncontrolled, unstudied project costs. I&M can take back some control of its rate elements by providing the Commission with information about potential NITS projects *before* those projects end up in a bill from PJM. Fairness demands that customers be protected from costs that are spiraling out of control.

We therefore concur with the OUCC's recommendation to embed NITS in base rates. The tracking of non-NITS expenses is not affected by this decision, and shall continue as previously authorized. We also agree that an investigation into the calculation and identification of transmission projects is appropriate. Commission oversight should cover all aspects of the rate-making process, including issues that eventually end up in RTO trackers.

With respect to the PJM Capacity Performance Insurance premium, we find that I&M has not demonstrated that its purchase is warranted. As noted by OUCC witness Mr. Gahimer, factors exist to mitigate I&M's potential risk of penalties, and I&M may also financially benefit from the Capacity Insurance. Gahimer, Appendix C. At this time, the imposition of capacity performance penalties is speculative and I&M has not shown that the premiums were prudently incurred. We therefore deny I&M's request to recover this expense through consumer rates.

7. Resource Adequacy Rider.

(a) <u>I&M</u>. I&M proposes to embed in base rates its forecasted Test Year level of non-FAC purchased power costs in the amount of $190,132,242 (Total Company), and track incremental annual costs above and below this embedded amount through the RAR. Mr. Williamson said continuing the existing structure without a "cap" or "sunset" is reasonable and ensures rates only reflect the actual cost of purchased power I&M incurs to provide service to customers. Williamson Direct, 54-55.

(b) OUCC. Mr. Lantrip did not oppose I&M's request to continue the RAR and recommended that any excess capacity sales be passed back to customers through the RAR as a means of reducing capacity purchase costs. Lantrip, 2-5.

(c) Intervenors. Messrs. Dauphinais and Bieber opposed the continuation of I&M's RAR, stating these costs are predictable long-term costs that do not satisfy the criteria for tracking. Dauphinais, 3, 31-32; Bieber, 22-23. Mr. Dauphinais specifically stated these costs are not volatile, but rather relatively predictable rising costs. Dauphinais, 32. He also noted that the tracked costs would be for the recovery of costs that are paid to affiliates of I&M. Dauphinais, 32. He testified that affiliated costs should not be tracked as there would be even less incentive than normal for I&M to keep these costs in line. *Id*. Finally, he testified that, with I&M's likely need to purchase and/or build new capacity for 2022 or beyond, to the extent I&M uses purchases, those purchases should be subject to the greater certainty that a base rate proceeding would provide versus Resource Adequacy Rider reconciliation proceedings. *Id*. Mr. Bieber further argued that tracking these costs reduces the inherent incentive for I&M to manage its costs. Bieber, 24.

(d) Rebuttal. Mr. Williamson supported tracking both capacity purchases and sales through the RAR as proposed by the OUCC. He stated the main arguments raised by IG and Kroger to continued tracking is in direct conflict of the point OUCC witness Lantrip makes in his testimony. Mr. Williamson said the ability to forecast significant changes in these costs on a going forward basis shows the Test Year level is not representative going forward and that tracking is appropriate. Williamson Rebuttal, 21-23. He also disagreed that tracking these costs would influence any incentive I&M has to manage the underlying costs. He said since I&M owns and leases 50% of Rockport and does not track the majority of those costs, I&M has every incentive to continue to manage the costs of Rockport regardless of whether I&M tracks the AEP Generating Company portion of these costs. *Id.*, 22.

(e) Discussion and Finding. Both I&M and the OUCC support continued tracking of purchased power costs through the RAR. While the IG and Kroger witnesses suggest these costs are not sufficiently variable to warrant tracking, the evidence presented shows these costs to be significant in amount and variable across years. Pub. Ex. No. 5, 4. We agree with the OUCC's recommendation that any excess capacity sales be passed back to customers through the RAR as a means of reducing capacity purchase costs. We find continued use of the RAR will ensure rates reflect the actual cost of capacity required to comply with PJM's resource adequacy requirements and will provide benefits to customers by tracking capacity sales revenues, which serve to reduce the revenue requirement. Accordingly, we approve I&M's proposal to embed the Test Year level of non-FAC purchased power costs in base rates and track incremental annual costs above and below this amount, along with any future capacity sales revenues.

17. Miscellaneous Issues.

A. ICC Investigation Request.

1. ICC. ICC witness Medine contended the Fifth Modification obligation arose out of AEP's failure to timely install SCR on Rockport Unit 2 and therefore the

requirements of the Fifth Modification are more akin to a fine or penalty than a regulatory requirement. Medine, 4-5, 14. She requested the Commission (1) direct I&M to investigate options for keeping Rockport Unit 2 on line past 2028 when Rockport Unit 1 is required to be closed under the Fifth Modification, (2) direct I&M to calculate the incremental costs of compliance as a result of the Fifth Modification, and (3) the Commission should determine what if any of these incremental costs should be recoverable. Medine, 5.

2. Rebuttal. Mr. Thomas said Ms. Medine's recommendations are based on her findings and statements that are simply wrong. Thomas Rebuttal, 26. He said there is absolutely no truth to Ms. Medine's assertion that "I&M admitted that the Fifth Modification to the Consent Decree was only necessary due to I&M's failure to timely install SCR on Rockport Unit 2." *Id.*, 26-27. He said the installation of the Rockport Unit 2 SCR is proceeding on track and is fully expected to be in operation by the time set forth in the Consent Decree. *Id.*, 27. He said while that deadline was extended by six months by agreement of the parties to allow negotiations to be completed, there has been no failure to timely install the Rockport Unit 2 SCR. Moreover, he said as supported by the testimony of Mr. McManus in Cause No. 43992 S1, the Consent Decree cannot be construed to be a penalty because "[t]he AEP Companies admitted no violations of law and all claims against them were released." Thomas Rebuttal, 27; Attachment TLT-1R. Mr. Thomas stated I&M leases Rockport Unit 2 and a decision to retire Rockport Unit 2 will be made by the owners of the unit, not a leasee. Thomas Rebuttal, 27. He noted the Fifth Joint Modification does provide that optionality for the owners to exercise if they choose. He testified the appropriate forum to consider the resources to serve I&M's customers is through its periodic IRP process, not a general rate case. *Id.* He explained the ICC has participated in I&M's current IRP stakeholder process and may participate going forward as there will likely be three IRPs developed before Rockport Unit 1 will retire. He concluded there is no need for the Commission to order an investigation as part of this proceeding. *Id.*

3. Discussion and Finding. *The OUCC takes no position on this issue.*

B. Streetlighting.

1. South Bend. South Bend witness Dorau stated I&M's rates for LED streetlighting conversions are overstated and unreasonable. Dorau, 19. She said streetlights are an essential public service which promotes public safety and economic development. *Id.*, 20. However, she said every street light fixture installed by I&M at South Bend's request, while adding to safety and quality of life in neighborhoods, is also a permanent increase to South Bend's ongoing operational costs, energy use, and carbon footprint. *Id.* Mr. Seelye testified I&M is proposing streetlighting rates that are excessive. Seelye, 4, 35-37. He said there appears to be an error in the development of I&M's proposed streetlighting rates in that while SL rates were supposed to be allocated a zero increase in revenue, Mr. Nollenberger's workpapers show I&M is proposing to increase the rates of each type of light by 4.37% to 5.14%. *Id.*, 33. He added that because I&M is proposing to reduce its fuel basing point, I&M's lighting rates should also be going down, not up. *Id.*, 33-35. Mr. Seelye also asserted there were flaws in I&M's Public Efficient Streetlight ("PES") program because it fails to capture the significant O&M savings resulting from the replacement of LED lights. *Id.*, 37-40. He also presented revised lighting rates for Tariffs ECLS and SLS. *Id.*, 40-41; Attachment WSS-11.

Mr. Sommer testified I&M should be ordered to revise its LED streetlighting rates to reflect a lower level of maintenance costs and longer fixture lives. Sommer, 5, 12-17. He said I&M should also be required to commit to working with interested municipalities to fashion a mass LED retrofit plan to meet each municipality's needs and results in economy of scale retrofit savings for the municipality. *Id.*, 17-18.

2. Rebuttal. Mr. Nollenberger testified I&M is not proposing new LED-specific basic rates in this proceeding. Nollenberger Rebuttal, 36. He explained on May 31, 2019, the Company filed a 30-Day filing with the Commission requesting LED rates for tariff classes OL, ECLS and SLC. He said the Commission approved I&M's 30-Day filing on July 10, 2019. *Id.* Mr. Nollenberger responded to Mr. Seelye's claim that there are errors in I&M's proposed street lighting rates in this case. He said the proposed rate increases that Mr. Seelye identifies are specific to the basic rate components and ignores the effect of "Fuel + All Riders" that is clearly identified in each of the applicable pages of his workpaper WP-MWN-4. Nollenberger Rebuttal, 36-37. He said page 46 of WP-MWN-4 summarizes the Company's proposed total revenue change across all street lighting tariffs and shows the net effect of proposed basic SL rates, plus proposed SL rider rates equals total present revenues, within rounding, for an effective 0% increase for the overall SL class. *Id.*, 37.

Mr. Nollenberger also responded to Mr. Seelye's discussion of the impact of the change in I&M's fuel basing point on streetlighting rates. He explained in isolation, a reduction in the fuel basing point should result in a net decrease in basic rates. Nollenberger Rebuttal, 37-38. However, he said I&M's case includes the movement of various revenue recoveries from the Company's riders to its basic rates. Therefore, he said it is necessary to account for the net effect of fuel and all other riders when assessing the change in the Company's proposed basic rates. *Id.*, 38. He presented a table showing the net effect of I&M's proposed ECLS rates is an approximately 0% increase. *Id.*; Table MWN-1R.

Mr. Nollenberger disagreed with South Bend's assertion that the O&M costs included in the development of I&M's streetlighting rates are significantly overstated. Nollenberger Rebuttal, 39. He added even if Mr. Seelye was correct that the Company's full cost estimates are flawed, I&M only uses the relative relationship of those full cost estimates for each fixture to establish proposed rates that only collect the fully supported embedded costs from the Company's class cost of service study. *Id.* With respect to the PES Program rates, he explained he updated the PES conversion rates following the same methodology that was agreed upon and established in the settlement in Cause No. 44841. *Id.*, 40. Finally, Mr. Nollenberger disagreed with the recalculated Tariffs ECLS and SLS rates presented by Mr. Seelye. *Id.*, 41.

Mr. Lucas agreed with the general idea that LED street lighting technology can be beneficial. Lucas Rebuttal, 21. He said the issue is how best to implement a mass conversion from existing street lighting technology to new LED technology for those customers seeking to move to LED technology. He explained a mass conversion project requires new capital investment and this cost must be reflected in rates charged to the street lighting customer(s) involved in the mass conversion. *Id.* He said it would not be in the Company's interest or the interest of its customers for the Company to incur volume labor costs and purchase conversion materials in bulk without a commitment from the customer that it can and will accept service and the costs associated with providing that service. *Id.*, 21-22.

Mr. Lucas explained the PES Program approved in Cause No. 44841 reflects the Company's effort to facilitate mass conversion projects. Lucas Rebuttal, 22. He said while witnesses Seelye, Sommer, and Dorau criticized the PES Program, they do not dispute that I&M is offering the program in accordance with the settlement agreement approved in Cause No. 44841. *Id.* He said there are no current or forecasted participants in the PES Program, which expires at the end of 2019. Therefore, he said it is unnecessary for the Commission to address the criticisms of the current PES Program in this general rate case. *Id.*, 22. He said in Cause No. 45285, I&M proposes to continue the PES Program with updated energy savings and incremental measure costs to reflect changes since the program was first designed. He proposed I&M work with South Bend regarding their concerns with the design and implementation of the PES Program in that separate docket and not in this general rate case. *Id.*, 22-23.

3. Discussion and Finding. *The OUCC takes no position on this issue.*

C. Dry Cask Storage Deferral.

1. I&M. Mr. Williamson stated as agreed in Cause No. 44967, I&M currently defers all costs associated with dry cask storage costs that are not reimbursed by the U.S. Department of Energy ("DOE"). Williamson Direct, 56. He said I&M requests to continue this deferral and to continue to accrue carrying costs on the deferred balance using the pre-tax WACC rate approved by the Commission in this proceeding. *Id.* He explained I&M is not seeking recovery of any deferred costs in this proceeding pursuant to the Commission's order in Cause No. 44967 and said I&M will address any related deferral in I&M's next base case proceeding. *Id.*, 57.

2. Commission Discussion and Finding. No party objected to I&M's request to continue deferral accounting for dry cask storage costs and we find it to be reasonable. The record shows I&M entered into a contract with the DOE under which the DOE was required to accept spent nuclear fuel and high-level radioactive waste from the Cook Plant. Williamson Direct, 56; Lies Direct, 19-20. However, the DOE has partially breached this contract and has never accepted this material, requiring Cook to store the material onsite in dry cask storage. *Id.* I&M has entered into settlement agreements with the DOE since October 2011 under which the DOE has, to date, reimbursed I&M for $146.2 million (or 96%) of the cost of dry cask storage at Cook. Williamson Direct, 57. The record shows there are no dry cask storage costs included in the 2020 Test Year because I&M anticipates that the DOE will continue to reimburse I&M for these costs. *Id.* However, if the DOE reimbursements should cease or if ongoing costs should exceed the amount reimbursed, we find that I&M should continue to record the unreimbursed amount as a regulatory asset and accrue carrying charges on the deferred balance using the pre-tax WACC for recovery in subsequent base rate case proceedings. In addition, we find that all deferred costs will be subject to review for reasonableness before they are reflected in rates as set forth in the Commission's Order accepting the Settlement Agreement in Cause No. 44967. Accordingly, we grant I&M's request for deferral and carrying cost authority for dry cask storage costs.

18. Terms and Conditions of Service and Tariffs.

1. I&M. Mr. Cooper described and supported the Company's proposed modifications reflected in the new Tariff Book 18, including adjusting one-time service charge rates, proposing an AMI Opt-out provision, introducing new rate designs for residential customers, introducing several pilot programs and revising demand rates for specific tariffs. Cooper Direct, 3-17. He said all of the proposed changes to the Tariff Book are just and reasonable and should be approved by the Commission. *Id.*, 21.

Mr. Cooper testified the Company is adding tariff language allowing a customer to opt-out, or decline, the use of AMI technology and instead be served through a standard radio frequency meter. Cooper Direct, 7. He said this proposal includes a cost-based monthly charge to customers choosing to opt-out of the AMI meter and a one-time charge for customers that notify the Company of their preference to opt-out after the AMI meter is already installed at their residential location. He said this language recognizes the additional costs associated with the monthly meter reading process required by opting out of AMI technology. He said I&M received approval of a similar opt-out provision in its Michigan jurisdiction. *Id.*, 8.

2. OUCC. Ms. Aguilar testified absent a no-cost option, the monthly fee is in effect a deterrent intended to force I&M customers to convert to AMI. Therefore, Ms. Aguilar recommends I&M should allow a no-cost self-read option. Aguilar, 3. Ms. Aguilar highlighted I&M's discovery response change on allowing self-read. I&M's initial response position was to allow customers to self-read in order to avoid the monthly AMI opt-out service fee. However, I&M later supplemented its discovery response and claimed the previous response referred to a broader AEP process, but I&M would not allow self-read for its customers. *Id.*, 3-4. Ms. Aguilar also testified I&M should include all AMI opt-out information, including the no cost self-read option, on all AMI communications to customers. *Id.*, 5.

3. Intervenors. South Bend witnesses Dorau and Sommer also recommended I&M offer an AMI self-read option. Dorau, 19; Sommer, 34. Auburn witness Rutter recommended the Commission, working with I&M and the intervenors, should adopt policies and procedures to protect customer data gathered from AMI meters. Rutter, 6.

4. Rebuttal. Mr. Cooper testified I&M did not propose a self-read option because this creates a higher likelihood of meter reading errors and risks putting customers in a position that they may not want to be in. Cooper Rebuttal, 2. He discussed the challenges and difficulties associated with self-reading meters and said these issues are avoided by using I&M's meter readers and the communicating radio frequency meters for opt-out customers. *Id.*, 2-4. He stated Ms. Aguilar did not explain why quarterly reporting is necessary and expressed concern about publishing data around specific customers that have chosen to opt-out of an AMI meter. *Id.*, 5. With respect to Mr. Rutter's recommendation regarding data privacy, Mr. Cooper stated I&M has a Data Privacy Policy in place already and has dedicated a portion of its website to describe said policy in detail. *Id.*, 6.

5. Commission Discussion and Finding. Based upon the evidence of record, the uncontested proposals for I&M's tariffs, riders, rules and regulations are approved as proposed by I&M.

While no party objected to I&M's proposed AMI opt-out language, the OUCC and South Bend both proposed I&M create an additional AMI self-read option. I&M claims that a self-read option could cause difficulties for customers, yet I&M also acknowledges that other I&M operating companies allow for a self-read option. Cooper Rebuttal, 4-5. Additionally, while Mr. Cooper noted the prospect of having individual customers take on the responsibility of reading their meters accurately and during specific periods each month presents a number of obstacles and challenges, Mr. Cooper was unable to specify to what extent this is an actual problem, only referring to anecdotal information on self-read issues. Tr., B-131. Because other AEP operating companies allow for a self-read option, and I&M cannot specify to the extend there is an actual problem with self-reads, we approve the OUCC's and South Bend's recommendation to allow customers to have the option to self-read their meters and decline to impose the AMI opt-out fee on these customers. Additionally, should I&M submit AMI opt-out reports as recommended by Ms. Aguilar, any personal identification data should be removed so as to protect individual customers.

19. **<u>Confidentiality.</u>** Petitioner filed motions for protection and nondisclosure of confidential and proprietary information on May 14, 2019, September 3, and September 17, 2019, all of which were supported by affidavits showing certain documents to be submitted to the Commission contain confidential, proprietary, competitively sensitive, and/or trade secrets as defined under Ind. Code §§ 23-2-3-2 and 5-14-3-4. Docket Entries were issued on each of these motions finding such information to be preliminarily confidential, after which the information was submitted under seal. The Commission finds all such information previously granted preliminary confidential treatment is confidential and exempt from public access and disclosure by the Commission under I.C. §§ 5-14-3-4 and 8-1-2-29.

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

1. Petitioner shall be and hereby is authorized to adjust and increase its rates and charges for electric utility service to produce an increase in total operating revenues of approximately 0.16% in accordance with the findings herein which rates and charges shall be designed to produce forecasted total annual operating revenues of approximately $1,499,070,228, which are expected to produce annual net operating income of approximately $254,425,585.

2. Petitioner shall be, and hereby is, authorized to place into effect Phase I rates and charges in accordance with the findings herein for bills rendered for retail electric service on and after the effective date of this order.

3. Petitioner shall be, and hereby is, authorized to place into effect Phase II rates and charges in accordance with the findings herein for retail electric service on and after June 1, 2020.

4. I&M shall certify its net plant at December 31, 2020 and calculate the resulting Phase III rates and charges, which shall be made effective in accordance with the findings herein.

5. Petitioner shall file new schedules of rates and charges along with its revised tariff

under this Cause consistent with the rates and charges approved above. Petitioner's new schedules of rates and charges shall be effective upon approval by the Energy Division.

6. Petitioner's proposed depreciation accrual rates as modified in accordance with Finding 8.A.4 (Accounts 354, 355, 364, 365, 366, 368, 369), Finding 8.B.5 (Account 370 (Meters)), Finding 8.C.4 (Contingency), Finding 8.D.3 (Escalation Rates), Finding 8.E.3 (Interim Retirements), and Petitioner's proposal to place these rates, as modified, into effect for accrual accounting purposes are approved as set forth in this Order.

7. Petitioner's proposed three-year AMI deployment and the expenditures associated therewith are hereby denied. I&M is authorized to conduct an AMI pilot program, within the context of a collaborative process, with cost recovery of prudently incurred expenses associated with used and useful AMI meters to be addressed in its next base rate case.

8. Petitioner shall make a compliance filing as set forth in Finding No. 11.N.1.(e) (Excess ADFIT) and is granted all necessary associated accounting authority.

9. The deferral accounting authority sought by Petitioner is approved in accordance with Finding No. 11.H.5 (*IM Plugged In*), Finding No. 11.K.4 (Major Storm Damage Restoration Reserve), Finding No. 11.N.1.(e) (Excess ADFIT), and Finding No. 17.C.2 (dry cask storage).

10. Petitioner's request for an ongoing waiver of the purchase power benchmark procedures as applied to I&M in Cause No. 43306 is hereby approved.

11. The information filed in this Cause pursuant to Petitioner's motions for protection and nondisclosure of confidential and proprietary information is deemed confidential under Ind. Code § 5-14-3-4, 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.

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

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

APPROVED:

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

____
Mary M. Becerra
Secretary of the Commission

CERTIFICATE OF SERVICE

This is to certify that a copy of the ***Indiana Office of Utility Consumer Counselor's Proposed Order*** has been served upon the following parties of record in the captioned proceeding by electronic service on December 3, 2019.

I&M
Teresa Morton Nyhart
Jeffrey M. Peabody
Nicholas K. Kile
T. Joseph Wendt
BARNES & THORNBURG LLP
tnyhart@btlaw.com
jpeabody@btlaw.com
nike@btlaw.com
jwendt@btlaw.com

Matthew S. McKenzie
AMERICAN ELECTRIC POWER SERVICE CORP.
msmckenzie@aep.com

CAC and INCAA
Jennifer A. Washburn
Margo Tucker
CITIZENS ACTION COALITION
jwashburn@citact.org
mtucker@citact.org

City of Marion
J. Christopher Janak
Kristina Kern Wheeler
BOSE MCKINNEY & EVANS LLP
cjanak@boselaw.com
kwheeler@boselaw.com

SDI
Robert K. Johnson
RK JOHNSON, ATTORNEY-AT-LAW, INC.
rjohnson@utilitylaw.us

WVPA
Randolph G. Holt
Jeremy L. Fetty
Liane K. Steffes
PARR RICHEY
r_holt@wvpa.com
jfetty@parrlaw.com
lsteffes@parrlaw.com

Kroger
Kurt J. Boehm
Jody Kyler Cohn
BOEHM, KURTZ & LOWRY
kboehm@bkllawfirm.com
jkylercohn@bkllawfirm.com

Kevin Higgins
ENERGY STRATEGIES, LLC
khiggins@energystrat.com

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

Industrial Group
Bette J. Dodd
Joseph P. Rompala
Anne E. Becker
Amanda Tyler
Ellen Tenant
LEWIS & KAPPES, P.C.
bdodd@lewis-kappes.com
jrompala@lewis-kappes.com
abecker@lewis-kappes.com
atyler@lewis-kappes.com
etennant@lewis-kappes.com

City of Fort Wayne, Indiana
Brian C. Bosma
Kevin D. Koons
Ted W. Nolting
KROGER GARDIS & REGAS, LLP
bcb@kgrlaw.com
kdk@kgrlaw.com
twn@kgrlaw.com

Walmart, Inc.
Eric E. Kinder
Barry A. Naum
SPILMAN THOMAS & BATTLE, PLLC
ekinder@spilmanlaw.com
bnaum@spilmanlw.com

Alliance Coal, LLC
Nikki G. Shoultz
BOSE MCKINNEY & EVANS LLP
nshoultz@boselaw.com

ICC
Jeffrey Earl
BOSE MCKINNEY & EVANS LLP
jearl@boselaw.com

City of South Bend, Indiana
Robert Glennon
robertglennonlaw@gmail.com

39 North Conservancy District
Shaw Friedman
FRIEDMAN & ASSOCIATES
sfriedman.associates@frontier.com

Keith L. Beall
CLARK, QUINN, MOSES, SCOTT & GRAHN, LLP
kbeall@clarkquinnlaw.com

City of Auburn
W. Erik Weber
MEFFORD WEBER AND BLYTHE ATTORNEY AT LAW
erik@lawmwb.com

Mark W. Cooper
ATTORNEY AT LAW
attymcooper@indy.rr.com

OUCC Consultants

Garrett Group Consulting, Inc.
Heather A. Garrett
garrett@wgokc.com

Edwin Farrar
edfarrarcpa@yahoo.com

Garry Garrett
ggarrett@garrettgroupllc.com

Mark E. Garrett
mgarrett@garrettgroupllc.com

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

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

Tiffany T. Murray
Deputy Consumer Counselor

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