

ORIGINAL

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

APPROVED: MAR 11 2020

ORDER OF THE COMMISSION

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

Handwritten signatures and initials: JH, [unclear], DO, SMC

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On May 14, 2019, Indiana Michigan Power Company (“I&M,” “Petitioner,” or “Company”) 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.<sup>1</sup> 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 (“IAC”) 1-5-1 *et seq.* I&M’s case-in-chief filing on May 14, 2019, included testimony and exhibits from the following witnesses:

- 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 at the Donald C. Cook Nuclear Plant for I&M
- Timothy C. Kerns, Managing Director – Generating Assets for I&M
- Kamran Ali, Managing Director of Transmission Planning for AEPSC
- Jason A. Cash, Senior Staff Accountant in Accounting Policy and Research for AEPSC
- Aaron L. Hill, Director of Trusts and Investments for AEPSC
- Roderick W. Knight, Decommissioning Manager for TLG Services, Inc.
- Michael N. Kelly, Manager of Taxes – Tax Accounting and Regulatory Support for AEPSC
- Robert B. Hevert, Partner at 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
- Daniel E. High, Staff Regulatory Consultant in the Regulatory Pricing and Analysis Department for AEPSC<sup>2</sup>
- Matthew W. Nollenberger, Manager, Regulated Pricing and Analysis for AEPSC
- Kurt C. Cooper, Regulatory Consultant Principal in the Regulatory Services Department for I&M.

On June 26, 2019, the Commission issued a Prehearing Conference Order establishing a procedural schedule and related requirements.

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<sup>1</sup> On April 10, 2019, I&M provided its notice of intent to file a rate case consistent with the Commission’s General Administrative Order 2013-5.

<sup>2</sup> On August 8, 2019, I&M filed a notice that Michael M. Spaeth, Regulatory Consultant Senior in the Regulated Pricing and Analysis Department for AEPSC, was being substituted for Mr. High and adopting Mr. High’s prefiled testimony.

Petitions to Intervene were filed by I&M Industrial Group, an ad hoc group of industrial customers located in I&M's service territory, that ultimately included the following customers: Air Products, General Motors LLC, I/N Tek L.P., Marathon Petroleum Company LP,<sup>3</sup> Messer LLC, Praxair, Inc., and University of Notre Dame du Lac ("IG" or "Industrial Group"); The Kroger Company ("Kroger"); Steel Dynamics, Inc. ("SDI"); Walmart, Inc. ("Walmart"); Citizens Action Coalition of Indiana, Inc. ("CAC") and 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. d/b/a Wabash Valley Power Alliance; and City of Auburn Electric Department ("Auburn").<sup>4</sup> These petitions were granted without objection.

Alliance Coal, LLC ("Alliance") and the Indiana Coal Council, Inc. ("ICC") also filed Petitions to Intervene, which were granted over I&M's objection. The Indiana Office of Utility Consumer Counselor ("OUCC") also participated as a party.

Public field hearings were held on July 11, 2019, in South Bend, Indiana; on July 15, 2019, in Muncie, Indiana; and on July 16, 2019, in Fort Wayne, Indiana, the largest municipality in I&M's Indiana service area. At the field hearings, members of the public were afforded the opportunity to provide oral and/or written submissions to the Commission.

On August 20, 2019, the OUCC and certain Intervenors filed their respective cases-in-chief. For purposes of its case-in-chief, the OUCC prefiled multiple volumes of consumer comments and testimony and exhibits from the following witnesses:

- Lauren M. Aguilar, Utility Analyst in the OUCC's Electric Division
- Anthony A. Alvarez, Utility Analyst in the OUCC's Electric Division
- Cynthia M. Armstrong, Senior Utility Analyst in the OUCC's Electric Division
- Wes R. Blakley, Senior Utility Analyst in the OUCC's Electric Division
- Michael D. Eckert, Assistant Director of the OUCC's Electric Division
- Michael Gahimer, Senior Utility Analyst in the OUCC's Federal Division
- 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 in the OUCC's Electric Division
- Kaleb G. Lantrip, Utility Analyst in the OUCC's Electric Division
- Margaret A. Stull, Chief Technical Advisor in the OUCC's Water/Wastewater Division
- Glenn A. Watkins, President and Senior Economist of Technical Associates, Inc.

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

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<sup>3</sup> Marathon Petroleum Company LP was added to I&M Industrial Group on August 20, 2019, and the University of Notre Dame du Lac was added on September 16, 2019.

<sup>4</sup> The International Brotherhood of Electrical Workers by and through its Local 1392 representatives ("IBEW Local 1392") was granted intervention on July 25, 2019. IBEW Local 1392 subsequently petitioned to withdraw its intervention on August 6, 2019, which petition was granted in a Docket Entry issued on August 19, 2019.

- 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 Justin Bieber, Senior Consultant for Energy Strategies, LLC, as well as workpapers.

Walmart provided the testimony and exhibits of Steve W. Chriss, Director, Energy Services for Walmart.

Intervenors CAC-INCAA provided testimony and exhibits from Kerwin L. Olson, CAC’s Executive Director, and Jonathan F. Wallach, Vice President of Resource Insight, Inc.

The Joint Municipal Group provided testimony and exhibits from the following witnesses:<sup>5</sup>

- 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 of the City of Fort Wayne, Indiana
- Joseph A. Mancinelli, President and Chief Executive Officer of NewGen Strategies and Solutions, LLC.

South Bend provided testimony and exhibits from the following witnesses:

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

39 North provided testimony and exhibits from Reed W. Cearley, an independent contractor 39 North retained as a special utility consultant for this proceeding.

Auburn provided testimony from Edward T. Rutter, Manager with LWG CPAs and Advisors.

ICC provided testimony and exhibits from Emily S. Medine, Principal in the consulting firm of Energy Ventures Analysis, Inc.

On September 17, 2019, the OUCC and Intervenors prefiled their respective cross-answering testimony. This included cross-answering testimony and exhibits from Glenn A. Watkins on behalf of the OUCC. Cross-answering testimony and exhibits from Nicholas Phillips, Jr. for the Industrial Group, and cross-answering testimony and exhibits from Justin Bieber on behalf of Kroger. CAC-INCAA also prefiled cross-answering testimony and exhibits from

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<sup>5</sup> The Joint Municipal Group also submitted a Motion for Administrative Notice with its case-in-chief.

Jonathan F. Wallach, while South Bend prefiled cross-answering testimony from Therese Dorau and William Steven Seelye

Alliance prefiled testimony from Stephen Norfleet, a Principle and Senior Project Manager with RMB Consulting and Research, Inc. I&M subsequently moved to strike this testimony on the grounds that it was not proper cross-answering testimony and the filing thereof violated the requirements associated with Alliance's intervention. I&M's motion was granted in part in a Docket Entry dated September 27, 2019.

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

- Kamran Ali
- Chad M. Burnett
- Andrew R. Carlin, Director of Executive Compensation and 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 by Docket Entries issued on May 31, 2019, and September 16, 2019, respectively. Multiple requests for administrative notice were also ruled upon during the evidentiary hearing.

Pursuant to the notice of hearing, the Commission held an evidentiary hearing in this Cause commencing on October 7, 2019, and continuing thereafter on October 10, 11, 15, 16, 17, 21, 22, 23, and 24, 2019. At the evidentiary hearing, direct, cross-answering, rebuttal, and administrative notice materials were offered and admitted into the record and/or excluded consistent with rulings upon objections.

Based upon the applicable law and the evidence presented, the Commission now finds as follows:

1. **Notice and Jurisdiction.** Due, legal, and timely notice of the public hearings in this Cause was given and published as required by law. I&M is a public utility as defined in Ind.



Code § 8-1-2-1(a). Under 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. The Commission, therefore, has jurisdiction over I&M and the subject matter of this proceeding.

**2. Petitioner's Organization and Business.** I&M is a wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP") and is a corporation organized 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 Indiana and Michigan. I&M owns and operates plant and equipment within Indiana and Michigan that are used and useful in the generation, transmission, distribution, and furnishing of electric service to the public.

I&M provides electric service to approximately 468,000 retail customers in the following 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. I&M also provides electric service in Michigan to approximately 129,000 retail customers. In addition, I&M serves customers at wholesale rates in Indiana and Michigan. I&M's electric system is integrated and interconnected and operates 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 under 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, and general administration of the RTO. As a PJM member, I&M also adheres 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 within the RF region.

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. I&M's property is classified in accordance with the Uniform System of Accounts ("USOA") as prescribed by the FERC and adopted by the Commission.

**3. Existing Rates.** I&M's existing retail rates in Indiana were established pursuant to the Commission's order in Cause No. 44967 based upon test year operating results for the 12 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 15 months have 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, with the test year used for determining Petitioner’s projected operating revenues, expenses, and net operating income being 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 Commission approval of 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. As proposed, Phase I will increase revenue by approximately \$82.5 million; Phase II will reflect a cumulative revenue increase of approximately \$129 million; and Phase III (to be effective January 1, 2021) will reflect a final cumulative revenue increase of approximately \$172 million. As detailed in the Petition and I&M’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 metering infrastructure investment.

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

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.<sup>6</sup> 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.<sup>7</sup>

As discussed below, the OUCC and/or certain intervenors challenged the continued inclusion of the prepaid pension asset in rate base, Petitioner’s 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 rate case expense regulatory asset. These contested issues are discussed below.

#### A. **Advanced Metering Infrastructure (“AMI”).**

1. **I&M.** Mr. Thomas and Mr. Isaacson testified that Petitioner’s test year infrastructure investment includes I&M’s initial phase of AMI deployment across its Indiana service territory, with the proposed three-year AMI deployment to continue through 2022. Petitioner’s Ex. 1 at p. 19; Petitioner’s Ex. 37 at p. 28. Mr. Thomas stated the estimated

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<sup>6</sup> Petitioner’s Ex. 41, Ex. A-1 at p. 1 and Ex. A-6 at p. 1.

<sup>7</sup> 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. Petitioner’s Ex. 15 at p. 9.

capital cost of the total AMI Project over this three-year period is approximately \$93.6 million. Petitioner's Ex. 1 at p. 19; *see also* Petitioner's Ex. 24 at p. 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. Petitioner's Ex. 1 at p. 20. He stated smart meters can record consumption of electric energy and demand and system parameters such as voltage at intervals of an hour or less and can digitally communicate this information to the utility, enabling the utility to have more accurate information about system operating conditions as well as electricity usage. *Id.* Mr. Thomas testified the AMI infrastructure comes with a customer engagement platform that enables consumers to have better insight into their electricity usage and cost. *Id.* He explained that as technology advances, the electric utility industry must enhance the way it does business to achieve system and customer benefits. I&M's plan is to provide a robust energy delivery system that is reliable and efficient and, ultimately, provide a platform that enables universal access to all customers to be served the way they want to be served – all at a reasonable cost. Petitioner's Ex. 1 at p. 21. Mr. Thomas testified that AMI technology has matured, and customers have become accustomed to digital technology and real time access to data. He stated I&M's service will improve by modernizing the grid and enhancing customers' use of Petitioner's service. *Id.* at p. 22.

Mr. Thomas testified AMI deployment is consistent with the direction the industry is moving, and the transition to "smart" technologies enables a fundamental change in the way I&M operates, serving as the foundation upon which I&M will provide more reliable service, improved customer experience, and greater efficiency opportunities in the future for I&M's customers. Petitioner's Ex. 1 at pp. 21-38. Mr. Isaacson elaborated on the operational, reliability, and customer benefits of AMI as well as I&M's deployment plans. Petitioner's Ex. 37 at pp. 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 he explained I&M's plan for AMI-related customer notification and education. Petitioner's Ex. 18 at pp. 17, 38-48.

Mr. Thomas testified I&M's existing automatic meter reading ("AMR") meters are at the point where replacement is needed. He stated that 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. Petitioner's Ex. 1 at p. 22. Mr. Thomas stated in making the decision to move to AMI, I&M recognized that over the past decade AMI technology has matured, its pricing has stabilized, and its importance to system reliability has increased. *Id.* at p. 23. Mr. Thomas stated three years are reasonably necessary to efficiently and cost-effectively obtain the necessary resources for the proposed AMI deployment project, install the technology and IT systems, and implement the associated consumer education and functionality. *Id.*

2. OUCC. Mr. Alvarez reviewed Petitioner's AMI proposal and recommended the capital (\$14.167 million) and the O&M expenses (\$2.410 million) associated with I&M's AMI deployment proposal be removed from the test year and the Commission, instead, require I&M to study and quantify AMI's operational benefits and use this to perform a cost-benefit analysis before approving full AMI deployment. Public's Ex. 8 at p. 2. He testified I&M's proposed AMI deployment lacks sufficient financial justification for the Commission, the

OUCC, and other interested parties to review and evaluate its reasonableness. *Id.* at pp. 2, 5-8. Mr. Alvarez stated that instead of completing a cost-benefit analysis for its proposed AMI deployment, I&M provided an analysis it characterized as generic, using a generic template and inputs. *Id.* at p. 5. According to Mr. Alvarez, what I&M provided is its AMI deployment plan for Michigan. He stated this contained insufficient information and inappropriate data with which to quantify specific benefits for Indiana's ratepayers or support whether Indiana's ratepayers should fund the proposed AMI deployment. He testified the magnitude of the proposed AMI meter deployment in Indiana will be larger and more complex than in Michigan, and merely attempting to implement a scaled-up version of the Michigan plan may yield unintended consequences in Indiana because any oversight or defect in the Michigan plan will tend to be magnified in a larger, more complex deployment in Indiana. Public's Ex. 8 at p. 8.

Mr. Alvarez stated that I&M does not appear to have incorporated the findings, recommendations, and operational data from its Smart Meter Pilot Project ("SMPP") conducted in 2009. Public's Ex. 8 at pp. 12-14. He viewed AMI as an optional upgrade that is not currently necessary to provide service to I&M's customers. *Id.* at p. 15. Mr. Alvarez testified that aside from the 10,000 smart meters deployed in South Bend, there are more than 400,000 AMR meters currently deployed in I&M's Indiana service territory of which, he noted, I&M witness Isaacson testified, "35% of the AMR meters deployed in I&M's Indiana service territory will reach the end of their design life by the start of the proposed AMI deployment." Public's Ex. 8 at p. 14; Petitioner's Ex. 37 at p. 28.<sup>8</sup> Mr. Alvarez stated that if any of the 35% are tested and proven to be operating satisfactorily, they can be placed back in service which means that more than 65% of I&M's AMR meters remain in good working condition. *Id.* at p. 14.

Mr. Alvarez referenced an Ameren Illinois analysis as the type of robust utility cost-benefit analysis he recommended before approving AMI deployment. Public's Ex. 8 at pp. 15-16. He also referenced a settled Duke Energy Indiana Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") case where AMI deployment savings were quantified. *Id.* at p. 16, n. 42. Mr. Alvarez recommended that if the Commission is inclined to approve I&M's proposed 2020 deployment of approximately 15,000 AMI meters, it should do so as a pilot program to be evaluated within the context of a collaborative. *Id.* at pp. 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 not approve the AMI deployment without a detailed cost-benefit analysis to assure rates reflect a quantification of all cost savings achieved with AMI deployment. In the alternative, the Joint Municipal Group recommended the AMI costs be deferred until the actual detailed costs can be evaluated. Jt. Municipal Ex. 2 at pp. 4, 29-30; South Bend Ex. 2 at pp. 5, 33-36; CAC-INCAA Ex. 2 at pp. 4, 7-10. Ms. Cannady also recommended the Commission disallow the use of an AMI Rider to reconcile estimated AMI costs to those actually incurred. Jt. Municipal Ex. 2 at p. 4.

Mr. Sommer stated I&M did not show the proposed conversion to AMI will be cost effective or prove the existing AMR meters are unreliable or will soon fail at an unreasonable

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<sup>8</sup> On rebuttal, Mr. Isaacson modified this, testifying that "[d]uring I&M's proposed AMI deployment, approximately 35% of the existing AMR meters will reach the end design life of 15 years." Petitioner's Ex. 38 at p. 18.

rate. South Bend Ex. 2 at p. 34. He testified the ratemaking treatment of the remaining useful life of I&M's AMR meters and the lack of a real, current need for AMI meters are concerns. *Id.* at p. 33. South Bend's witnesses contended the proposed costly conversion to AMI meters, at an estimated total cost of \$93,619,000, when there remains, according to Mr. Sommer, \$41,260,035 of undepreciated AMR as of year-end 2018, should not be approved. *Id.* at pp. 33-35. Mr. Sommer stated the AMI transition is not a prerequisite for successfully implementing a Plug-In Electric Vehicle ("PEV") tariff as I&M's current AMR meters will support the PEV off-peak tariff. South Bend Ex. 2 at p. 35; *see also* South Bend Ex. 1 at 17. Mr. Wallach testified I&M failed to provide evidence showing the proposed AMI investments could reasonably be expected to be cost-effective over the life of the investments. CAC-INCAA Ex. 2 at pp. 8-9.

Walmart witness Chriss testified Walmart generally supports the deployment of "smart" metering and appreciates Petitioner's efforts in this regard; however, he stated rate designs not based on the utility's cost of service, such as those featured in I&M's proposed Large General Service ("LGS") rate design, do not best leverage AMI technology. Walmart Ex. 1 at pp. 29-30. He recommended the Commission make transitioning from hours-use rates a near-term priority and include a stakeholder process to explore this transition as one of the conditions for approval of AMI deployment in this proceeding. *Id.* at pp. 5, 29-30.

4. Rebuttal. Mr. Thomas testified that the used and useful standard Indiana uses in a general basic rate case should not be replaced with a formulaic assessment of whether the benefits of an infrastructure project exceed its cost; consequently, he disagreed with the suggestion that infrastructure investment decisions should depend on a financial justification model. Petitioner's Ex. 2 at pp. 12-13. He stated 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 with AMR automation, as is the case for I&M. *Id.* at pp. 13-15. Mr. Thomas testified the 2012 Ameren Illinois and Duke Energy Indiana AMI projects involved a transition from manual to automated options, noting these proceedings were also not general rate cases. *Id.* at pp. 15-18. He discussed the "societal" cost benefit test imposed in Illinois and stated the OUCC has not identified a sound reason for supplanting the used and useful standard with the Illinois approach. *Id.* at p. 16. Mr. Thomas testified that with AMR, I&M has already achieved many of the "hard" operational benefits quantified in the Duke Energy Indiana analysis. *Id.* at pp. 17-18. He disagreed with the implication that once I&M moved from manual to automated operations via AMR, the Company should discontinue efforts to maintain its system consistent with developing technology and industry progress. *Id.* at p. 17.

Messrs. Thomas and Isaacson testified the 2011 SMPP report is not a credible basis for now rejecting I&M's proposed AMI project because circumstances have changed since the 2011 SMPP Report Mr. Alvarez discussed, including AMI technology maturing to the point where this more advanced technology has supplanted AMR. Petitioner's Ex. 2 at pp. 18-19; Petitioner's Ex. 38 at p. 24. Mr. Lucas stated 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 being proposed. Petitioner's Ex. 19 at pp. 3-4.

In responding to the criticism of I&M's customer engagement strategy and customer experience benefit, Mr. Lucas testified a 2018 J.D. Power Survey found utility customers who

are aware they have a smart meter have a higher level of satisfaction. He also stated that in March 2019, the U.S. Department of Energy Office of Electricity recognized key insights associated with AMI customer benefits. Petitioner's Ex. 19 at p. 5.

Mr. Thomas testified the generic draft analysis the OUCC and CAC-INCAA identified did not consider a systematic transition from AMR to AMI deployment (the infrastructure investment issue here) and was not completed, vetted for accuracy, or used by I&M management in deciding to proceed with AMI. Petitioner's Ex. 2 at p. 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 I&M's existing AMR technology – and qualitative benefits are substantial. *Id.* at pp. 19-20. Mr. Thomas stated he also disagreed with addressing the AMI proposal in this rate case under the standards applicable to TDSIC plans. *Id.* at p. 20.

Mr. Isaacson stated it would be unreasonable and impractical to replace I&M's existing AMR meters with something other than AMI meters. Petitioner's Ex. 38 at p. 18. He testified that with the emergence of AMI, AMR is a declining technology and is being phased-out industry-wide, with nearly all vendors having stopped manufacturing and supporting AMR meters. Mr. Isaacson testified there currently remains only one vendor that supplies I&M's type of AMR meters, and the majority of this vendor's business is AMI. He testified 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 long this vendor will continue to manufacture and support this equipment. *Id.* at p. 18.

As noted above, Mr. Isaacson stated that during I&M's proposed AMI deployment, approximately 35% of the existing AMR meters will reach the end design life of 15 years. Petitioner's Ex. 38 at p. 18. He opined that replacing AMR meters with AMR meters would put an outdated technology in service for possibly another 15 years and deny the realized customer benefits discussed in his direct testimony (Petitioner's Ex. 37). Mr. Isaacson testified 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, Petitioner's Ex. 30 at p. 18; therefore, the only question, per Mr. Isaacson, is whether I&M should randomly replace AMR meters with AMI meters in a reactive way, which will be more costly, or through the proactive deployment I&M proposes. Petitioner's Ex. 38 at pp. 18-19.

Mr. Isaacson testified that waiting to deploy AMI technology while another pilot program is conducted will only serve to delay the operational and customer benefits associated with AMI technology. Petitioner's Ex. 38 at pp. 19-20. Mr. Lucas also disagreed that a collaborative pilot is necessary, but he testified I&M is offering 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. Petitioner's Ex. 17 at pp. 6-7. Mr. Isaacson disagreed with Mr. Alvarez's contention regarding the AMI Michigan project and his 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 regarding AMI because I&M will be able to leverage this experience and the lessons learned to generate efficiencies, such as taking advantage of a trained, contracted work force. Petitioner's Ex. 38 at p. 21. Mr. Isaacson also reviewed the operational benefits from the South Bend AMI deployment and the lessons learned. *Id.* at p. 23.

5. Discussion and Findings. The record shows AMI technology has matured while AMR technology is no longer advancing. Petitioner's Ex. 2 at p. 18; Petitioner's Ex. 1 at p. 22; Petitioner's Ex. 38 at p. 18. While AMI is the "smart" technology for the future, the parties dispute the reasonableness and prudence of I&M's plan to replace all its AMR meters with AMI technology over the next three years, from 2020 to 2022, at a total forecasted capital investment of \$93.6 million. I&M seeks to begin recovering this investment from ratepayers via a new AMI Rider while continuing to recover Petitioner's existing AMR investment from ratepayers. Given the industry advancements in AMI technology, we find the key question is not "whether" AMI technology should be deployed, but rather, "when" it is reasonable to do so and recover these costs from I&M's ratepayers. As discussed specifically in Finding 7.B (Depreciation, Account 370 (Meters)) and Finding 15.C.1 (Riders, AMI Rider) below, the Commission finds a measured, traditional approach to I&M's transition to AMI is reasonable, as supported by our findings below.

The Commission has encouraged electric utilities to examine smart technologies, and we continue to do so. The Commission does not, however, endorse ratepayers financing a rapid, wholesale replacement of Petitioner's AMR technology given I&M's relatively recent deployment of this technology, the remaining operational life of I&M's AMR meters, and I&M's plan to file its next rate case in 2022, absent an associated cost-benefit analysis or other demonstrated benefit for consumers. As Mr. Alvarez testified, "AMI is an optional upgrade to I&M's meters and is not necessary to provide service to its customers." Public's Ex. 8 at p. 15. The Commission finds I&M did not show the costs of I&M's proposed AMI installation are offset by ratepayer benefits associated with such AMI deployment that are at a level meriting the financial recovery or approval in this proceeding that I&M proposes. Instead, we find a traditional test year to test year rate case transition pace more appropriately balances encouragement and financing support with the service enhancement of this technology upgrade.

Ind. Code § 8-1-2-23 allows a utility to obtain Commission approval of expenditures for proposed additions or improvements to the utility's plant and equipment. But, based on the magnitude of I&M's proposed AMI project and the lack of direct presentation on the balancing of benefits and costs in connection with the timing and/or pace of the transition I&M proposes, the Commission finds a more robust record is needed to approve this capital investment under Section 23. Instead, we find the level of AMI capital and expense included in the test year in this case speaks to our measured support for I&M's direction and further find I&M may present such costs in its next base rate case where their prudence and any associated savings can be reviewed and balanced. The Commission will discuss the associated opt-out tariff and AMI Rider below.

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

1. I&M. Mr. Isaacson presented an overview of I&M's distribution system, its condition, and the metrics Petitioner uses to measure the reliability of its facilities. He presented I&M's Distribution Management Plan, which is a comprehensive, forward-looking capital and operations plan under which Petitioner is making significant investments to maintain and improve the reliability of its distribution system, enhance public safety, and leverage technology to benefit the grid. Petitioner's Ex. 37 at p. 2. Mr. Isaacson stated much of I&M's system was built in the 1960s and 1970s when I&M experienced growth. While recognizing that

age alone does not determine when assets fail, he testified an increasing portion of assets are reaching the end of their expected design lives. *Id.* at p. 4. Mr. Isaacson stated 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 stated older assets also pose safety risks from failures during operation. *Id.* I&M witness Lucas also supported the distribution components of I&M's capital investment during the Capital Forecast Period. Petitioner's Ex. 18 at p. 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. Public's Ex. 8 at p. 3. He recommended I&M provide basic project information so the Commission, the OUCC, and other interested parties can 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 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 a high program level, rather than project level, and did not provide detailed breakdowns of the cost structure of the individual programs. Public's Ex. 8 at pp. 21-23. Mr. Alvarez voiced concern regarding whether I&M's descriptions of a program or individual project and the total project cost amount or total program expenditure per year were adequate to determine the reasonableness of approving I&M cost recovery for these projects. He testified that I&M seeks cost recovery of the proposed projects in a forward-looking test year and, therefore, pre-approval for these projects. *Id.* at pp. 23-24. He stated the Commission, the OUCC, and other interested parties must be able to review the detail underlying this forecast to ensure ratepayers' interests are served by the investments and costs. *Id.* at p. 23. Mr. Alvarez testified the OUCC solicited additional details through discovery and was invited to access various systems at I&M's offices in Fort Wayne, Indiana, on July 19, 2019. *Id.* at p. 24. Mr. Alvarez stated the few project cost breakdowns I&M provided during the meeting appeared unreasonable because the indirect costs ranged from 55% to 62% of total project costs. *Id.* at p. 25-26. Given this level of indirect costs, Mr. Alvarez concluded the cost estimates for five projects are excessive and unreasonable. *Id.* at p. 26.

Mr. Alvarez reviewed I&M's Distribution Management Plan – Major Project Summary and found it impossible to determine the reasonableness of these projects in the absence of a well-defined distribution project scope of work and clear distinction between distribution and transmission functions. Public's Ex. 8 at p. 31. He testified several of the projects lacked an approved internal Investment Requisition ("IR") from I&M management indicating management has independently determined the scope and cost of the project and endorsed fund allocation to its construction. Mr. Alvarez opined that this gives the appearance that I&M is using regulatory



pre-approval (through a future test year) as support for seeking internal corporate approval and budget allocation of funds. *Id.* at p. 33.

3. Rebuttal. Mr. Williamson explained that I&M's case-in-chief and workpapers included the information required by the governing statute and MSFRs. Petitioner's Ex. 25 at pp. 40-44. Mr. Isaacson detailed the considerable support and documentation provided in I&M's case-in-chief and workpapers showing the reasonableness of I&M's Distribution Management Plan. Petitioner's Ex. 38 at pp. 3-4, 8. Mr. Williamson and Mr. Isaacson also discussed I&M's meeting with the OUCC and additional information provided to the OUCC through the discovery process. Petitioner's Ex. 25 at pp. 49-50; Petitioner's Ex. 38 at pp. 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. Petitioner's Ex. 38 at p. 7. He added that providing Class 2 cost estimates for projects two years out is unnecessary and would needlessly add costs. *Id.* Mr. Isaacson stated Mr. Alvarez's criticism of the distribution "indirect costs" appears to reflect a misunderstanding of I&M'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.* at p. 10. Mr. Isaacson clarified that major projects are more complex projects I&M has identified as necessary to improve system reliability, improve the ability to serve increased load, promote safety, and enhance the technological capabilities of I&M's system. Petitioner's Ex. 38 at pp. 10-11. He referred to the definition, documentation, and other details provided in his direct testimony and in I&M's discovery responses. *Id.* Mr. Isaacson stated the details, which included project justification, benefits, project start and end dates, total cost, material cost, internal and contractor labor cost, and total indirect cost, were consistent with the information I&M provided in Cause No. 44967. *Id.* at p. 11. He testified while a major project can have a transmission component, projects and costs in the Distribution Management Plan are distribution projects and do not include any transmission investment. *Id.* at p. 12.

4. Discussion and Findings. The OUCC proposes the Commission disallow millions of dollars of capital investment in 2019 and 2020 on the basis that I&M's case-in-chief was inadequate. The Commission notes at the outset that neither Section 42.7 nor the MSFRs require the level of detail Mr. Alvarez seeks as part of Petitioner's case-in-chief and workpapers. The MSFRs are intended "to assist the commission in thoroughly and expeditiously reviewing a petition for a general rate change ... ; ... provide support for the electing utility's rate petition; and ... reduce or avoid disputes." 170 IAC 1-5-2(a); Petitioner's Ex. 25 at p. 42. In particular, the information related to utility plant and capital projects that a utility must submit is enumerated in 170 IAC 1-5-9 and -10. Here, our review of the record supports that I&M submitted the information 170 IAC 1-5-9 and -10 require with respect to capital projects and rate base additions; therefore, we find I&M reasonably concluded it had submitted a complete case-in-chief, particularly in the absence of procedural challenges asserting otherwise.<sup>9</sup>

Mr. Alvarez presented a list of 19 additional informational requirements that he stated should be required "at a minimum" to support I&M's distribution system investment (and

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<sup>9</sup> Under the MSFRs, direct concerns regarding the sufficiency of a petitioner's case-in-chief may be raised and addressed up front, early in the process. 170 IAC 1-5-4(a); 170 IAC 1-5-2.1(c). The Commission also has a procedure that allows concerns about discovery to be raised and resolved. 170 IAC 1-1.1-16(d). Neither of these procedural avenues was utilized in this proceeding.

associated O&M). Public's Ex. 8 at pp. 28-29. We disagree that the project reference numbers, identifiers, work request numbers, project stop and start dates, and the additional details Mr. Alvarez listed are required for the Commission to assess the used and useful nature and associated cost of I&M's ongoing investment. Accordingly, the Commission declines to adopt Mr. Alvarez's recommendation by announcing a new list of 19 additional "minimum" requirements that must be included in petitioners' cases-in-chief.

This is a forward-looking test year case under Section 42.7(d)(1). This statute requires the Commission's determination to be made "on the basis of projected data." *Id.* For purposes of rate base projections, the Commission is guided by our standard for preapproval of expenditures under Ind. Code § 8-1-2-23. Our established standard for preapproval under that section confirms the Commission is not approving specific items of utility property or projects, but rather, is approving "expenditures" for improvements. As stated in *American Suburban Utils*:

Petitioner has requested relief pursuant to Section 23 in this proceeding. When faced with such a request, the first question we must ask is whether an expenditure of any amount is reasonably necessary to assure reasonable and adequate service. If so, we must proceed to the second question: what amount reasonably needs to be invested? Once we answer the first question affirmatively, we cannot simply deny in its entirety a request for approval of expenditures. If we did, it would mean that we would deny approval for any amount of expenditures even though we have already found that some level of expenditures is necessary for the provision of reasonable and adequate service. Such a result would be counter to our very purpose. See *Indiana-American*, p. 18 ('We simply cannot condone the OUCC's approach, which we find would lead to inferior water quality and customer complaints.')

Cause No. 41254, p. 14, 1999 WL 397655 (IURC April 14, 1999). For purposes of projecting rate base in a forward-looking test year, the Commission recognizes that for a utility such as I&M, it must continually make expenditures for system improvements to continue providing reasonably adequate service and facilities. A petitioning utility should describe how its projection was arrived at and why the types of improvements forecasted are reasonably needed. The particular need for more significant projects also should be provided, but for project property accounts such as pole replacements that are at least partially driven by inspections or accidents, we find the projection in this Cause based upon historical experience to be adequate, provided that if the overall projected additions are going to differ significantly from historical expenditure levels, Petitioner should explain why.

Here, for the more routine distribution improvements, Petitioner identified approximately 670 projects in Attachment DSI-1, with total costs and number of units. For each major distribution project, I&M included in Attachment DSI-2 a project description, an explanation of the need for the project, and identified the benefits of the project. Mr. Isaacson described how the projections were prepared and how the various projects were identified. Petitioner's Ex. 37 at pp. 7-27. The need for the expenditures for the improvements Mr. Isaacson discussed and identified was not disputed. Instead, the OUCC's objection is that the cost estimates are not sufficiently refined – that the projections are excessive. Under the *American Suburban* standard, the OUCC's objections are not a sufficient reason to reject *in toto* Petitioner's projected expenditures. Since

there is no dispute that some level of expenditure is needed, “we cannot simply deny in its entirety a request for approval of expenditures.” *American Suburban*, p. 14. We find the best evidence of record upon the amount that is reasonably needed is the projection Mr. Isaacson provided.

The record shows, and the Commission finds, that I&M complied with the applicable statute and MSFRs, supplementing this information through the discovery process. In doing so, I&M provided the information necessary for the investments at issue to be reviewed. We reject the premise that the Company’s data and sworn testimony must be independently verified, recognizing that when a given level of revenue, expense, or rate base is supported by the testimony of knowledgeable utility officials or duly qualified expert witnesses, the Commission does not disregard the sworn testimony of such witnesses. *Re Indiana Michigan Power Co.*, Cause No. 39314, p. 5 (IURC November 12, 1993). Substantial record evidence demonstrates I&M exercised appropriate discretion with respect to its business judgment that the infrastructure investment is necessary. Accordingly, we reject the OUCC proposal to disallow I&M’s 2019-2020 distribution capital investment on the grounds that Petitioner failed to provide adequate information in its case-in-chief as the Commission finds I&M provided the information required by statute and the MSFRs, and its presentation was consistent with that in prior rate cases where the level of detail was not challenged as inadequate.

The issue of whether additional evidence is required in a TDSIC filing is a separate matter, controlled by the TDSIC statutory framework, and does not change the requirements applicable to this general rate case where the forward-looking test period I&M selected is allowed by statute to be “determined on the basis of projected data.” Section 42.7(d)(1); *see* Petitioner’s Ex. 25 at pp. 41-42.

### **C. Rockport Enhanced Dry Sorbent Injection (“DSI”) System.**

1. I&M. Mr. Thomas testified 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<sub>2</sub>”) emissions. Petitioner’s Ex. 1 at p. 15. The Commission authorized the use of the DSI system at Rockport in Cause No. 44331. As Mr. Kerns stated, the Rockport Plant utilizes the DSI system to meet reduced SO<sub>2</sub> emission limits required under the Plant’s air permit. Petitioner’s Ex. 14 at p. 24. He testified this SO<sub>2</sub> limit becomes more stringent over multiple years, with lower SO<sub>2</sub> emission limits taking effect on January 1, 2018, and January 1, 2020. *Id.* Mr. Kerns added that in response to the stepped reduction SO<sub>2</sub> limit, I&M will increase the injection rate of sodium bicarbonate. *Id.*

As Mr. Kerns discussed, during the test year, I&M plans to place certain enhancements to the DSI system into service by December 31, 2020, at an estimated capital cost of approximately \$13.3 million, Petitioner’s Ex. 14 at p. 30, which is significantly less than the cost of the alternative control – a dry scrubber. Petitioner’s Ex. 1 at pp. 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. *Id.* at p. 15. Mr. Kerns stated the DSI enhancements will result in approximately an \$8 million incremental increase in O&M expenses that is mostly consumables expense. Petitioner’s Ex. 14

at pp. 30-31. Mr. Thomas testified the enhanced DSI is required to comply with the Fifth Modification of the Consent Decree being filed in Federal Court and stated 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, provides jobs and taxes to the community, and does so in a manner that mitigates the rate impact on customers. Petitioner's Ex. 1 at pp. 18-19.

2. OUCC. Ms. Armstrong recommended denying I&M's request to include enhancements to the DSI systems on Rockport Units 1 and 2 in rate base and the associated O&M expenses. Public's Ex. 9 at p. 1. She described the Consent Decree and explained the events leading to the Fifth Modification. Ms. Armstrong testified the original Consent Decree emerged to settle claims the United States Environmental Protection Agency ("EPA") and the Department of Justice ("DOJ") made that several of AEP's units had violated the New Source Review provisions of the Clean Air Act. Public's Ex. 9 at pp. 2-5. Although Rockport and several other large AEP units were not part of the litigation, Ms. Armstrong stated the settlement required AEP and its subsidiaries to undertake major investments in pollution controls on these facilities. *Id.* at p. 6.

Specific to Rockport, Ms. Armstrong testified 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. Public's Ex. 9 at p. 3. However, she stated AEP requested the Third Modification of the Consent Decree, which was approved on May 11, 2013, delaying the required installation of FGD systems for Rockport Units 1 and 2. *Id.* at p. 4. Ms. Armstrong 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, and 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 to retrofit, re-power, or retire by December 31, 2028. *Id.* at p. 4.

Ms. Armstrong testified that after the Third Modification, the investor group owners of Rockport Unit 2 sued AEP for breaching the lease agreement, claiming that by entering into the modified Consent Decree, AEP imposed an impermissible lien on Unit 2 and adversely impacted its economic useful life. Public's Ex. 9 at p. 5. She stated that while the Federal District Court initially dismissed the owners' claims, the appellate court ruled in their favor. According to Ms. Armstrong, as a result of this litigation, AEP was forced to seek another modification of the Consent Decree. Ms. Armstrong testified that all parties to the Consent Decree agreed to the modifications, and the Fifth Modification to the Consent Decree was approved on July 17, 2019. *Id.* Ms. Armstrong stated both Rockport Units must now install an enhanced DSI system in 2020, as well as meet more stringent emission rates beginning in 2021. Ms. Armstrong stated that while Rockport Unit 1 must still retrofit with an FGD, re-power, or retire by December 31, 2028, Unit 2 is no longer required to install an FGD to continue operation beyond 2025. *Id.*

Ms. Armstrong asserted the Fifth Modification to the Consent Decree is 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 and sulfur

dioxide with the existing DSI and Activated Carbon Injection (“ACI”) systems. Public’s Ex. 9 at p. 6. She pointed out that I&M did not model the DSI Enhancements in its 2018 Integrated Resource Plan (“IRP”), *Id.* at p. 9, and Ms. Armstrong reasoned that the only way a customer benefit is realized from the DSI enhancement is if the Rockport Unit 2 lease is extended, allowing the Unit to serve ratepayers beyond 2022. *Id.* at pp. 6-7.

Ms. Armstrong asserted that I&M is asking ratepayers to fund the consequences of AEP’s questionable management decisions. Public’s Ex. 9 at p. 7. From her perspective, 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.*

Ms. Armstrong disputed I&M’s characterization of the Consent Decree as a beneficial deal for ratepayers that allowed generating facilities to continue operating while avoiding the continued costs of litigation. *Id.* She reasoned it was speculative as to whether the Commission would have approved passing those litigation costs on to customers. Public’s Ex. 9 at p. 8. Ms. Armstrong stated ratepayers were never given the opportunity to accept or reject the Consent Decree prior to AEP (and I&M) signing it and asserted AEP offered to construct the pollution control projects on Rockport to reach agreement in the Consent Decree to the benefit of other AEP generating facilities and subsidiaries. Ms. Armstrong concluded I&M should bear some of the risk of its management decisions. *Id.* at pp. 7-8.

Ms. Armstrong stated that I&M should still take action to keep Rockport operational, and the OUCC is not recommending I&M terminate the Unit 2 lease early. However, because the DSI Enhancement project stems from the Fifth Modification of the Consent Decree and the OUCC opposes burdening ratepayers with those associated costs, Ms. Armstrong testified the DSI Enhancement costs should be borne by I&M’s shareholders, as they receive the benefits of the Consent Decree modification. Alternatively, Ms. Armstrong reasoned that only a short time period exists between I&M’s proposed schedule for installing the Enhanced DSI equipment and the Unit 2 lease expiration, and she concluded I&M failed to establish that investing in Rockport Unit 2 provides a benefit to ratepayers if the Unit 2 lease is not renewed beyond 2022. Public’s Ex. 9 at p. 11. Ms. Armstrong testified if the Unit 2 lease is extended, it may be possible the DSI Enhancement project could be economical for ratepayers to fund if 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.* By I&M’s next rate case, Ms. Armstrong reasoned 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 confirm whether the lease has been extended. She concluded the parties can make an informed judgment at that time about whether the DSI Enhancement cost recovery is appropriate.

3. Intervenors. 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 testified it is problematic that I&M is seeking cost recovery from Indiana retail customers near the 2022 lease termination date. Intervenor IG Ex. 3 at p. 40. He also stated it is his understanding that under the terms of the lease, I&M can recover from the lessors some of the costs associated with improvements made to Rockport Unit 2. *Id.* He recommended that if the Commission approves cost recovery for this investment at Rockport Unit 2 from Indiana retail customers, the Commission require I&M to reimburse those customers

for any costs recovered from the lessors. Intervenor IG Ex. 3 at pp. 40-41. Otherwise, according to Mr. Gorman, “[I]t is simply unfair to allow I&M full recovery of costs associated with capital investment at Rockport Unit 2 when there is a possibility some portion of those costs can be recovered from others.” *Id.* at p. 41.

Alliance witness Norfleet asserted that Ms. Armstrong’s analysis does not look at the full picture of how AEP’s choices may impact the dispatch and retirement of plants ratepayers have funded and fails to 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. Intervenor Alliance Ex. 1 at p. 3.

4. Rebuttal. Mr. Thomas testified the OUCC recommendations that Ms. Armstrong presented are based on a flawed understanding of the Consent Decree and the manner in which it came about. Petitioner’s Ex. 2 at pp. 21-22. He stated the execution of and modifications to the Consent Decree are not the result of “questionable management decisions,” as Ms. Armstrong alleged, but rather, 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. Per Mr. Thomas, 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<sub>2</sub> and NO<sub>x</sub> controls, and this means I&M customers will benefit from the proven performance of lower-cost DSI technologies that only recently became available. *Id.* at p. 22. Mr. Thomas testified that 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, and takes advantage of mixing plates that are included in the SCR design for both units, thereby significantly increasing the achievable SO<sub>2</sub> removal efficiency. Mr. Thomas testified with the continued uncertainty about future environmental requirements, the DSI enhancements also provide additional compliance margin for a new standard under review by the EPA. *Id.* at pp. 23-24.

Mr. Thomas stated the consequences of non-compliance with the Consent Decree would be severe because the units cannot comply with the 30-day average emission rates if the DSI Enhancement Project is not in operation by the end of 2020. Petitioner’s Ex. 2 at p. 24. He also stated the lease requires I&M, at the end of the lease term, to return Rockport Unit 2 to the lessors in a condition to comply with all of the applicable environmental requirements. *Id.* Mr. Thomas added that the lease was approved by the Commission, and I&M must continue to comply with its terms through the full term. *Id.* He stated I&M’s customers benefit from the enhanced DSI system more than they would from any alternative means of complying with the lease terms. *Id.*

Mr. Thomas testified that Ms. Armstrong confused two different versions of the Fifth Modification of the Consent Decree, explaining that what she discussed was a contested motion AEP filed, not the settlement agreement among all parties that became the Fifth Joint Modification. *Id.* at pp. 24-25. Mr. Thomas also opined that the relatively modest cost of the DSI Enhancement Project would not, as explained in discovery, have changed the results of I&M’s IRP. *Id.* at p. 25.

With respect to the Industrial Group recommendation, Mr. Thomas stated that while it may be appropriate to credit I&M's depreciation accounts with amounts received from the transfer of assets to the lessors upon the expiration of the Rockport Unit 2 lease, it is inappropriate to create a refund obligation to customers. Petitioner's Ex. 2 at pp. 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, and it is premature and unreasonable to impose a different obligation at this time. *Id.* at p. 26.

5. Discussion and Findings. The OUCC proposed disallowing the DSI system enhancement costs through base rates, instead proposing shareholders bear these expenses. I&M asserts that the OUCC's position fails to recognize the Commission authorized use of the DSI systems at both Rockport Units in its Order dated November 13, 2013, approving the settlement agreement in Cause No. 44331. But, the issue here concerns the costs related to the Enhanced DSI Project. In Cause No. 44331, Ms. Armstrong testified that "[t]he DSI systems are necessary for I&M to comply with MATS, CAIR, CSAPR, and the NSR Consent Decree." Petitioner's Ex. 2 at p. 23, fn. 8 (citing Cause No. 44331, Public's Exhibit No. 2, page 16). The testimony shows the Enhanced DSI Project is the product of the Fifth Modification to the Consent Decree which did not exist in 2013; consequently, the Commission disagrees that recovery of the Enhanced DSI costs was resolved in Cause No. 44331. That said, we find I&M has demonstrated this cost recovery from ratepayers is reasonable to keep Rockport operational. As Mr. Thomas testified, the Enhanced DSI Project will maintain the availability of relatively low cost, coal-fired generation that complies with environmental regulations and will allow the plant to continue serving customers in a manner that mitigates the rate impact, Petitioner's Ex. 1 at pp. 18-19, since the Enhanced DSI Project is estimated to cost significantly less than the cost of a dry scrubber. *Id.* at pp. 17-18.

The OUCC agrees that I&M should take action to keep Rockport operational and should not terminate the Unit 2 lease early but recommends the Commission disallow the cost of the DSI enhancements. Public's Ex. 9 at p. 11. We find this position illogical because the cost of the DSI enhancement is being incurred to keep Rockport operational and avoid potentially more costly lease compliance requirements, including those associated with early termination.

As shown by OUCC Attachment CMA-3, Petitioner's IRP contains the DSI Project approved in Cause No. 44331. While the modeling for the IRP submitted on July 1, 2019, was completed prior to release of the revised Consent Decree language requiring enhancements to the DSI equipment, I&M conducted an analysis of plant investments on Rockport Unit 2 that demonstrates these investments, including the Enhanced DSI Project, continue to be more economical than terminating the lease early.<sup>10</sup> Mr. Thomas was unequivocal that, "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." Petitioner's Ex. 2 at p. 24.

The record shows the enhancements to the DSI system are forecasted to be in service during the test year. Petitioner's Ex. 14 at p. 15. This project will relocate the sodium bicarbonate injection points to increase the utilization and removal efficiency of the DSI system on both

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<sup>10</sup> The IRP submitted on July 1, 2019, includes a scenario where an FGD system is installed on Rockport Unit 1 by December 2028 for approximately \$1.4 billion.

Rockport generating units. *Id.* Completing this project substantially lowers the cost of environmental compliance at Rockport and may also support compliance with new regulations the EPA is considering. Petitioner's Ex. 1 at p. 18; Petitioner's Ex. 2 at p. 24.

Accordingly, we find I&M presented substantial evidence demonstrating the DSI enhancements will be used and useful in the provision of retail electric service during the test year, and the associated cost is reasonable. The Commission, therefore, approves recovery of the projected Enhanced DSI Project costs, provided the lease for Rockport Unit 2 shall not be terminated early. In the event of such termination, I&M shall promptly seek appropriate relief. Further, while the Commission finds Industrial Group witness Gorman's recommendation well taken that I&M reimburse certain amounts that are recovered from the lessor potentially via a credit to the appropriate depreciation account, because the full extent of any costs ultimately recovered from the lessor at the end of the lease term is not now known, we decline to order such a credit or other reimbursement at this time.

**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 stated 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). Petitioner's Ex. 14 at p. 14.

2. OUCC. Ms. Aguilar testified I&M should not earn a return on closure activities as a capital expenditure. She stated I&M's closure of the east bottom ash pond at Rockport does not involve installing new equipment, results in that asset no longer being used and useful, and does not further the generating capabilities of the Rockport Units. Public's Ex. 10 at pp. 23-24. She stated closure costs are not appropriately collected as a capital expenditure, *Id.* at p. 24, and asserted that I&M provided insufficient information to establish the CCR closure costs will be incurred within the test year. *Id.* at p. 27. Ms. Aguilar testified the OUCC is recommending the Commission deny recovery of I&M's requested \$4,069,000 for closure of the east bottom ash pond. *Id.*

3. Rebuttal. Mr. Kerns testified I&M continues to refine the details of the forecasted CCR project. He stated it is possible some of the forecasted capital costs will be reclassified as fuel or closure costs. Petitioner's Ex. 15 at p. 8. Mr. Kerns testified 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 testified 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. *Id.* at pp. 8-9.

4. Discussion and Findings. The Commission finds 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 testified this project involves rebuilding the Unit 2 HP turbine, including installation of the system spare turbine rotor and inner shell (inner block) and blade carriers during a scheduled Unit 2 outage in 2020. He stated the 1300 Series turbines have a service life of eight to ten years based on good engineering practices and testified this project is forecasted to be placed in service by June 1, 2020, at a total cost of \$1.323 million (including AFUDC). Petitioner’s Ex. 14 at p. 15.

At the hearing, Mr. Kerns explained that rebuilding this turbine is consistent with good utility practice, Tr. at p. D-69, while not rebuilding the turbine would be “too high a risk” to take:

We [I&M] don’t let turbines fail. There are catastrophic consequences when turbines fail. At best, you only wreck that turbine. At worst, you cause collateral damage and expose our employees to a safety risk. We’ve got experience with that here in I&M with Cook several years ago. We have experience with that at other spots in the fleet.

So I do not recommend and cannot sit here and endorse not rebuilding that turbine regardless of the end date of the Lease or anything else. We just – It’s just too high a risk for us to accept.

Tr. at p. D-70.

2. OUCC. Mr. Alvarez testified 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, i.e., the time remaining under the Rockport Unit 2 lease. He recommended removing \$1.323 million (including AFUDC) in capital expenditures and all O&M expenditures associated with the HP turbine replacement project. Public’s Ex. 8 at pp. 4, 36-37. Mr. Alvarez expressed concern with I&M embedding replacement costs for the Rockport Unit 2 HP turbine in the forecasted test year because if the lease ends in 2022, I&M will continue collecting (and ratepayers will continue paying) the return on and of this investment beyond 2022. *Id.* at p. 37.

3. Rebuttal. Mr. Kerns stated not rebuilding the Unit 2 HP Turbine exposes I&M and its customers to more risk than the risk of taking on the Rockport Unit 2 investments Mr. Alvarez identified. Petitioner’s Ex. 15 at p. 5. He explained that 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). Mr. Kerns stated it is prudent utility practice to avoid a turbine failure (which could cause extensive damage and result in a lengthy forced outage), and 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. *Id.* at pp. 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.* at p. 8.

4. Discussion and Findings. Based on the record, particularly Mr. Kerns' testimony, the Commission finds the Unit 2 HP Turbine Replacement Project is consistent with prudent utility practice and avoids increasing the risk assessment ranking for the turbine. The evidence shows the failure of a rotating or stationary blade could cause extensive damage and result in a forced outage of, at minimum, eight weeks. Petitioner's Ex. 15 at p. 6. In addition to increased capital and O&M costs, Unit 2 would be unavailable during the repair timeframe. As Mr. Kerns noted, collateral damage due to a turbine failure cannot be accurately predicted and could be greater. *Id.* at p. 7. While the OUCC objected to the project based on the current expiration date of the Unit 2 lease, the Commission finds the record shows the HP turbine rebuild is the reasonable course of action regardless of whether the Unit 2 lease will expire at the end of 2022. Accordingly, the Commission approves I&M's request to recover the 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). Petitioner's Ex. 14 at p. 13.

2. OUCC. Mr. Blakley recommended the \$29.303 million 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 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 will receive the benefit of a return "of" and a return "on" through the rider while ratepayers will benefit from accumulated depreciation applied to lower plant investment and recalculation of earnings. He also testified that Indiana law permits a wide variety of clean energy resources, and a renewable rider will make it easier to evaluate and gain a better understanding of costs associated with renewable technologies. Public's Ex. 3 at pp. 11-14, 15.

3. Rebuttal. Mr. Williamson testified that I&M disagrees with the OUCC's proposal to track the SBSP and said he expects the Commission to decide this issue in Cause No. 45245, the related, separate pending case. He recommended for purposes of this rate case that the SBSP project costs be included in rate base, as I&M proposed, if the project is approved. Petitioner's Ex. 25 at p. 68.

4. Discussion and Findings. The Commission finds, based on the record, that if the Commission approves the SBSP 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. The Commission finds it is reasonable for purposes of this rate case that the accounting and ratemaking for the SBSP project be based on the outcome determined in Cause No. 45245, given its focus specifically on the SBSP.

**G. Prepaid Pension Asset.**

1. I&M. I&M witness Hill testified in support of continuing to include Petitioner's prepaid pension asset in rate base. He noted this treatment is consistent with the Commission's Orders in Cause Nos. 44967 and 44705. Mr. Hill stated a prepaid pension asset can be defined as the cumulative pension cash contributions less cumulative pension cost. Petitioner's Ex. 6 at p. 37.

Mr. Hill described the process of forecasting the prepaid pension asset, including forecasted contributions and costs. Specifically, he testified the value of the prepaid pension asset was \$97,553,896 as of December 31, 2018, and the forecasted pension cash contributions of \$1,110,000 and \$6,391,000 for years 2019 and 2020, respectively, are added to the December 31, 2018, prepaid pension asset balance in forecasting the prepaid pension asset. He testified that forecasted pension costs of \$8,062,000 and \$7,749,000 for years 2019 and 2020, respectively, are subtracted, resulting in the projected December 31, 2020, prepaid pension asset balance. Mr. Hill stated I&M uses the services of a professional actuarial firm, Willis Towers Watson, to develop this forecast, and he, along with internal AEP departments such as accounting and human resources, collaborates with them to ensure the assumptions included in Willis Towers Watson's model are consistent with plan provisions, participant demographics, asset balances, and other important data and plan characteristics. Petitioner's Ex. 6 at pp. 37-38.

2. OUCC. Ms. Stull recommended the Commission reject I&M's proposal to include its \$89,244,007 prepaid pension asset in rate base. She testified the term prepaid pension asset is not a defined term for accounting purposes under the Financial Accounting Standards Board's ("FASB") Accounting Standards Codification ("ASC"). Public's Ex. 4 at p. 3. According to Ms. Stull, 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 ASC 715 requires an employer to recognize the "funded status" of a defined benefit pension in its balance sheet with the "funded status" defined or measured by the difference between (1) plan assets at fair value and (2) the benefit obligation; therefore, if an employer's defined benefit pension plan funding is less than its benefit obligation, the company will record a liability, and conversely, if an employer's defined benefit pension plan funding exceeds its obligation, the company will record an asset. *Id.* at p. 4. Ms. Stull testified that AEP currently 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, quantifying I&M's share. Public's Ex. 4 at p. 5.

Ms. Stull testified there is no prepaid pension asset reflected on I&M's 2018 historical balance sheet, that while I&M reflects an amount for a prepaid pension asset, it is offset by another account; therefore, she asserted the total amount of prepaid pension asset included in I&M's balance sheet is zero. Public's Ex. 4 at pp. 7-8. Ms. Stull noted a difference between the prepaid pension asset amount included in I&M's direct testimony and in discovery. *Id.* at pp. 8-9. She testified that I&M provided no calculation or support for how the prepaid pension asset was determined, and a prepaid pension asset is not mentioned in AEP's defined benefit pension plan actuarial reports. Ms. Stull stated I&M provided only a partial calculation of its prepaid pension

asset from 2006 to 2018 but should be able to support the entire prepaid pension asset. *Id.* at p. 11.

Ms. Stull reviewed the previous regulatory treatment for prepaid pension assets in Indiana, noting the Commission approved I&M's request for rate base treatment in Cause No. 44075. She was critical of the Commission doing so, testifying the findings did not explain how the prepaid pension asset qualified to be included in rate base under the strictures of Ind. Code § 8-1-2-6; nevertheless, the Indiana Court of Appeals, in a memorandum opinion, affirmed the Commission's decision. Public's Ex. 4 at p. 13. Ms. Stull testified the OUCC opposes 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 cannot be considered inventory, a prepaid asset, or working capital. *Id.* at p. 14.

To recognize that the prepaid pension asset lowers pension cost, Ms. Stull proposed an alternative calculation for pension expense for ratemaking. She determined the cumulative amount of Employee Retirement Income Security Act ("ERISA") minimum contributions in excess of cumulative pension costs, which excluded any "discretionary contributions" to the fund. She then multiplied the excess of the ERISA-required contributions by the 6.25% return on plan assets from the actuarial report and added this amount to pro forma pension expense. *Id.* at p. 18. Ms. Stull acknowledged her proposal will require further adjustments in I&M's next base rate case. *Id.* at p. 20.

Ms. Stull opined that while some utilities contend fully funding their defined benefit pension plans makes them more secure or benefits customers, a pension plan does not need to be 100% funded to be strong or secure. She stated these funding decisions need to be reviewed and a determination made as to their prudence. Ms. Stull recommended that for ratemaking purposes, any prepaid pension asset 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. Public's Ex. 4 at p. 25.

3. Intervenors. After acknowledging and reviewing Commission precedent for including a prepaid pension asset in rate base, Industrial Group witness Gorman testified that he opposed the continued inclusion of a prepaid pension asset in I&M's rate base. Intervenor IG Ex. 3 at p. 11. Mr. Gorman testified I&M had not demonstrated its prepaid pension asset was funded by investor capital, *Id.* at p. 13, or justified why I&M should be allowed to earn a return on the asset. *Id.* at p. 12. He stated I&M's description of a prepaid pension asset supports the notion that this asset can be funded from either investor capital or other sources. *Id.* at pp. 12-13. Mr. Gorman testified that to the extent I&M's total contributions to the trust are no more than ERISA minimum funding requirements, it is reasonable to conclude I&M has fully recovered all contributions from the trust from collections from customers and is, therefore, not owed a return on that asset. *Id.* at p. 13. Mr. Gorman also testified that to the extent the return on pension trust assets was large enough to offset pension service costs and interest costs, the return on the pension assets would contribute to the recording of a prepaid pension asset.

Mr. Gorman testified that I&M has not proven the prepaid pension asset was funded by investor contributions that were not fully recovered from customers, and I&M is, thus, entitled to a return on this asset. He asserted that I&M also failed to describe how much of the prepaid

pension asset may have been produced by returns on the pension trust funds. *Id.* at p. 14. In his view, evidence was needed substantiating the prepaid pension asset resulted from capital investors provided.

4. Rebuttal. On rebuttal, Petitioner's witness Hill explained that I&M's cumulative pension cost is greater than the cumulative minimum ERISA contributions, so the minimum required contributions are not included in the prepaid pension asset. He testified the minimum required contributions are a legal obligation and will still need to be included even if they did make up a part of the prepaid pension asset. Petitioner's Ex. 7 at pp. 16-17. Mr. Hill disagreed with Ms. Stull's alternative calculation of pension expense, characterizing her alternative treatment of the prepaid pension asset as a fictitious cost calculation. *Id.* at p. 19. He described the prepaid pension asset as prepayment of an allowable cost which directly reduces annual pension costs. Mr. Hill testified the projected \$85 million prepaid pension asset on a total company basis at December 31, 2018, will serve to reduce 2018 pension cost by approximately \$5.1 million (\$85 million times 6.00% investment return equals \$5.1 million FAS 87 pension cost savings) which is included and lowers the projected 2020 pension cost to about \$7.7 million. *Id.* at p. 22. He stated that without the prepaid pension asset, 2020 pension costs would instead be projected to total nearly \$13 million.

Mr. Hill testified that funding included in the prepaid pension asset represents amounts I&M expended in providing utility service in advance of receiving related goods and services. He testified the cost of this service is recognized in the ratemaking process because a utility is entitled to have all of its reasonable costs reflected in the ratemaking process. According to Mr. Hill, when a utility has prepaid an allowable cost, inclusion of the prepayment in rate base is consistent with well-accepted ratemaking principles and is necessary to compensate for use of the funds advanced and to avoid a disincentive for making similar prudent advances in the future. *Id.* at p. 22. He stated if the Commission were to exclude the prepaid pension asset from rate base, the savings should also be removed from the cost of service, as well as the benefits from their compounding effect. *Id.* at p. 23. Mr. Hill testified the contributions and return have also contributed to the avoidance of paying the variable Pension Benefit Guaranty Corporation premiums since 2012. *Id.* at p. 23.

Tyler H. Ross, Director of Accounting and Regulatory Services for AEPSC, testified a prepaid pension asset does exist, consistent with GAAP, when contributions to the related trust fund exceed the amount of pension expense that is recorded. He stated pension expense required to be recorded under GAAP is net of the earned return on pension-related investments. Petitioner's Ex. 23 at p. 2. He disagreed that I&M's prepaid pension asset was funded by any source other than investor capital. Mr. Ross testified I&M's customers pay rates that reflect the level of GAAP-determined pension costs used in I&M's cost of service, and I&M does not recover through rates any pension amounts above and beyond that cost of service level. Mr. Ross stated the prepaid pension asset at issue consists of cumulative contributions to the pension fund less the GAAP-determined cost and is funded solely by investors. *Id.* at pp. 10-11. He testified these contributions earn returns that benefit customers through lower pension costs; consequently, the prepaid pension asset represents a prudent investment made to help meet utility obligations and reduce the cost of service for customers and is, therefore, used and useful in providing public utility service and is necessary for responsible management of the pension plan.

*Id.* at p. 11. He described the inclusion of these funds in rate base as akin to the inclusion of working capital, fuel inventory, materials and supplies, and prepayments. *Id.* at p. 12.

Mr. Ross testified the prepaid pension asset is not a new rate base item and has existed on I&M's books since 2005. He stated the Commission expressly approved this rate base treatment in Cause No. 44075 and, most recently, approved a settlement in Cause No. 44967 including the prepaid pension asset. Mr. Ross noted the forecasted prepaid pension asset included in I&M's forecast for this case (\$85 million) is slightly less than the prepaid pension asset included in I&M's forecast in Cause No. 44967 (\$93.3 million). Petitioner's Ex. 23 at p. 14.

5. Discussion and Findings. The question of what, if any, rate recovery should be approved for a utility prepaid pension asset has previously been before the Commission in 2013 in Cause No. 44075, an I&M base rate case, and more recently in Cause No. 44576, a base rate case Indianapolis Power and Light Company ("IPL") initiated. In the Order issued in Cause No. 44075, the Commission approved rate base recovery of I&M's prepaid pension asset, stating:

The record reflects that the prepaid pension asset was recorded on the Company's books in accordance with governing accounting standards. The record also reflects that the prepaid pension asset has reduced the pension cost reflected in the revenue requirement in this case and preserves the integrity of the pension fund. Petitioner made a discretionary management decision to make use of available cash to secure its pension funds and reduce the liquidity risk of future payments. In addition, the prepayment benefits ratepayers by reducing total pension costs in the Company's revenue requirement. Therefore, we find that the prepaid pension asset should be included in Petitioner's rate base.

*Indiana Michigan Power Co.*, Cause No. 44075, p. 10, 2013 WL 653036, 303 P.U.R.4<sup>th</sup> 384 (IURC February 13, 2013), *aff'd mem.* (Ind. Ct. App. 2014), *trans. denied* (the "44075 Order"). The OUCC appealed this finding, and the 44075 Order was affirmed on appeal.

In Cause No. 44576, the Commission similarly approved recovery of IPL's prepaid pension asset in rate base, concluding it represents a component of working capital. *Indianapolis Power & Light Co.*, Cause No. 44576, 2016 WL 1118795 23, 329 P.U.R.4<sup>th</sup> 486 (IURC March 16, 2016) (the "44576 Order"), *aff'd*, *Citizens Action Coal. v. Indianapolis Power & Light*, 74 N.E.3d 554 (Ind. Ct. App. 2017).

The Commission finds no alternative proposal or changed circumstances were presented in this matter that cause us to change our treatment of I&M's prepaid pension asset. Indeed, the prepaid pension asset amount to be included in rate base (\$62,209,786)<sup>11</sup> is similar to the \$61,691,738 amount the Commission approved including in rate base in the 44075 Order.

The Commission is persuaded by Mr. Ross that the prepaid pension asset continues to be reflected on I&M's books pursuant to GAAP. We further find, and as will be explained further in

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<sup>11</sup> In response to an informal discovery inquiry, I&M stated Petitioner's original proposal incorrectly included amounts related to an unregulated subsidiary, River Transportation Division; therefore, the correct amount of the prepaid pension asset on an Indiana jurisdictional basis is \$62,209,786. Public's Ex. 4 at pp. 9-10.

our finding on pension expense, that the prepaid pension asset continues to reduce overall pension costs, which is reflected in I&M's cost of service. It, therefore, continues to provide benefits to customers. Based on the evidence, inclusion of the prepaid pension asset is akin to including working capital and other prepayments and should be similarly reflected in I&M's rate base. As recognized in the 44576 Order, p. 23, materials, supplies, and fuel inventory are typically included in utility rate base, *i.e.*, used and useful utility property. As such, these items recognize capital that has been put to work for the purpose of providing utility service. While a "cash" working capital allowance is one type of "working capital", it is not the only type. 44576 Order, p. 23, fn. 4. Recognizing working capital in rate base is an appropriate method of compensating investors for the cost of capital they have advanced in the course of providing service.

Finally, the Commission finds, based upon I&M's testimony—particularly Mr. Ross' rebuttal testimony upon the nature of the prepaid pension asset calculation, that the prepaid pension asset at issue was funded by investors, and customer rates have reflected the level of pension expense calculated pursuant to GAAP. I&M's prepaid pension asset was shown to be the cumulative total of cash contributions *in excess of* cumulative pension expense pursuant to GAAP and not, as Mr. Gorman testified, the result of growth in the pension fund through return on pension assets; rather, its calculation is directly from cash contributions. In other words, we find, based on Petitioner's testimony, that the prepaid pension asset reflects cash amounts contributed over and above the level of costs that have been recovered through rates and has been supplied by investor capital. Accordingly, the Commission finds the prepaid pension asset should continue to be reflected in I&M's rate base.

#### **H. Unamortized Nuclear Decommissioning Study and Rate Case Expense**

##### **Asset.**

1. Petitioner. I&M proposes to amortize its deferred rate case expense and incremental nuclear decommissioning study expense over a two year period. I&M also proposes the deferred amount be included in forecasted rate base. Petitioner's Ex. 24 at p. 30. Mr. Williamson testified the proposed rate case expenses include incremental costs such as the cost of outside counsel, outside witness/consulting services, and the cost of internal personnel travel in direct support of the hearings associated with this proceeding. He stated these types of costs are consistent with those approved in past rate case filings, including Cause No. 44967, and if this adjustment were not made, test year capital and O&M would be understated, and I&M's base rates would be understated. *Id.*

2. OUCC. Mr. Eckert testified it is inappropriate for I&M to include nuclear decommissioning study expenses and rate case expenses in rate base. Public's Ex. 1 at p. 17. Mr. Eckert opined that rate case and nuclear decommissioning study expenses are cash working capital items, not rate base items. *Id.* He stated 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 testified it is inappropriate to include these expenses as a single issue working capital requirement, and he testified the OUCC recommends the Commission approve Petitioner's request to amortize these expenses but deny I&M's request for rate base treatment of these expenses. *Id.*

3. Petitioner's Rebuttal. Mr. Williamson testified the OUCC's view is too narrow and that rate case expenses are reasonable and necessary costs incurred to provide service to customers. According to Mr. Williamson, 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 stated that deferring the 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. Petitioner's Ex. 25 at p. 39.

4. Discussion and Findings. The Commission concurs with OUCC witness Eckert that rate case expenses and nuclear decommissioning study expenses are O&M expenses and, consequently, finds these expenses should not be included in I&M's rate base. Both rate case expenses and nuclear decommissioning expenses are operating expenses that are typically normalized for ratemaking purposes. It has been the Commission's longstanding practice to normalize rate case expense and amortize it over a period of years to be recovered from ratepayers without a return being earned on such expense. The Commission concurs with OUCC witness Eckert that I&M's proposal is inconsistent with basic ratemaking principles. While Mr. Williamson testified these costs were amortized in Cause No. 44967, that amortization was the result of a Stipulation and Settlement Agreement ("Settlement Agreement") that is not precedent for rate base inclusion in this Cause. The Commission, therefore, finds I&M's rate base should be reduced by \$776,941 as the OUCC recommended.

#### **I. Conclusion on Rate Base.**

Based upon the foregoing findings, the Commission finds the test year end net original cost rate base (Indiana Jurisdictional) for I&M is \$4,896,419,619 and is calculated as follows:

Net Plant in Service	\$	4,673,793,109
Fuel Stock	\$	23,146,671
Other Materials & Supplies	\$	116,811,112
Allowance Inventory	\$	17,043,356
Prepaid Pension Expense	\$	62,209,786
Regulatory Assets	\$	57,073,922
Deferred Gain Rockport 2 Sale	\$	(5,061,526)
Regulatory Liabilities	\$	(2,588,975)
Deferred Income Taxes	\$	(46,007,835)
Original Cost Rate Base	\$	<u>4,896,419,619</u>

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 he 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, and 369.**

1. OUCC. OUCC witness David Garrett used the same Simulated Plant Record ("SPR") Method that Mr. Cash used for purposes of evaluating mass property



accounts when aged data is not available for certain accounts. Public's Ex. 11B at pp. 28, 30. He stated 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.* Mr. D. Garrett testified 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.* at pp. 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.* at pp. 30, n. 26; 31-32. Based on these scales, Mr. D. Garrett testified the Iowa Survivor Curves selected by Mr. Cash are generally too short and result in unreasonably high depreciation rates. *Id.* at pp. 32-47. Based in part on the approved service lives of his comparable peer group and the results of the SPR Method, Mr. D. Garrett proposed adjustments to the service lives for Accounts 354, 355, 364-66, and 368-69. *Id.* at pp. 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. Intervenor IG Ex. 1 at p. 7. In his opinion, I&M's analysis results in service lives for these accounts that are too short, referencing the National Association of Regulatory Utility Commissioners ("NARUC") Public Utility Depreciation Practices Manual, discussing the analysis of the Bauhan SPR procedure. *Id.* at pp. 15-18. Mr. Andrews, instead, based his recommendation on his informed judgment, selecting a survivor curve rather than relying on the results of the SPR analysis. 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.* at p. 20.

3. Rebuttal. Mr. Cash testified he had not relied solely on the CI, and that instead, he 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. Petitioner's Ex. 5 at p. 24. He opined that the Bauhan scale is arbitrary. *Id.* at p. 23. Mr. Cash stated he mainly focused his comparison to the results from the last two approved depreciation studies because there was no indication I&M's historical data, and thus the resulting survivor curve and average service life assigned to each account, should not be used. *Id.* at pp. 24-25. He explained the results from the Company's analysis should be given primary weight since the factors affecting 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 Mr. D. Garrett and Mr. Andrews proposed as well as to those that had been approved for comparable AEP affiliates. *Id.* at p. 25; Attachments JAC-R1 and JAC-R2. Mr. Cash testified the comparison to other nearby AEP affiliates validates the results of his analysis and confirms it is reasonable. *Id.* at p. 25. He added that his comparison also shows the service 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 Findings. The selection of the appropriate survivor curve involves the use of professional judgment. I&M asserts that using the SPR Method is necessary because of the lack of aged data. The OUCC and Industrial Group seek to use curves that have much longer service lives than those Mr. Cash selected, and they do this based upon data gathered from other utilities. We find more compelling the data I&M witness Cash provided, particularly the comparisons on rebuttal, than the scales from an unpublished 1947

Bauhan paper. In his rebuttal testimony, Mr. Cash compares his proposed survivor curves to the survivor curves used in I&M's last two depreciation studies, one of which was fully litigated. Petitioner's Ex. 5 at p. 23. This comparison shows Mr. Cash's proposed curves for these seven accounts is more in line with what the Commission has previously approved; whereas, the curves Messrs. D. Garrett and Andrews selected represent significant changes for which the OUCC and Industrial Group explanation was insufficient. Mr. Cash's proposed curves, although producing higher depreciation rates, were also shown to be more representative to the service lives of I&M's affiliates. The Commission, therefore, finds the survivor curves Mr. Cash recommended should be approved.

**B. Account 370 (Meters).**

1. I&M. As discussed above, I&M proposed to transition all its AMR meters to AMI meters over the next three years. Mr. Cash explained that I&M's proposal with respect to Account 370 (Meters) is to recover any undepreciated balance related to its current AMR meters that are retired over the lives of the new AMI meters. He stated this proposal is consistent with standard retirement accounting policies and procedures. Petitioner's Ex. 4 at pp. 10-11.

2. OUCC. Mr. David Garrett proposed the currently approved depreciation rate for meters be kept at 6.78% based on the OUCC's recommendation that the Commission reject I&M's AMI deployment proposal. Public's Ex. 11B at p. 47.

3. Industrial Group. Mr. Andrews testified I&M's proposal for Account 370 differs from 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 is no need to treat meters differently for purposes of setting depreciation rates. Intervenor IG Ex. 1 at 14. He recommended the average service life used to determine the depreciation rate be based on the meters that are actually providing utility service. *Id.* at pp. 14-15. Based on that approach, Mr. Andrews proposed a depreciation rate of 7.67% for the meter account. *Id.* at p. 15.

4. Rebuttal. Mr. Cash testified that neither Mr. Garrett nor Mr. Andrews considered the retirement of the existing meters in their proposal. He cited 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. Petitioner's Ex 5 at p. 20. Mr. Cash stated he could have calculated two different depreciation rates – one for the current meters (recovering over the average remaining life of four years) and one for the new AMI meters (15 years). He testified the existing meters also have an expected useful life of 15 years. Using the average age of the existing meters in Account 370 (10.18 years) would produce a remaining life of 4.82 years for the existing meters. *Id.* at p. 21. Mr. Cash stated under his alternative, he calculated a depreciation rate for existing meters of 15.66% and 8.13% for new meters. *Id.*

5. Discussion and Findings. As discussed above, I&M may operationally proceed with deploying AMI meters as I&M determines prudent and, therefore, incur the associated expenses. The Commission finds acceptable I&M's proposed 9.27% depreciation rate for Account 370, and we accept the planned test year additions in determining

the associated annual depreciation expense (*see* WP JAC-2) for establishing I&M's rates in this proceeding.

**C. Contingency.**

1. OUCC. Mr. David Garrett testified that I&M's demolition studies include contingency factors that increase the base estimated demolition costs by more than 85% for some generating facilities. Public's Ex. 11B at p. 22. Mr. D. 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.* at pp. 22-23. Mr. D. Garrett also testified the same arguments used in support of a contingency cost increase could be used to support a contingency cost decrease. *Id.* at p. 23.

2. City of Auburn. Auburn witness Rutter also proposed to remove contingency costs from the demolition studies, claiming they were unknown. Intervenor Auburn Ex. 1 at p. 12.

3. Rebuttal. Mr. Cash testified the Commission has previously approved the inclusion of contingency, specifically the contingencies used in I&M's demolition estimates that Sargent & Lundy proposed in Cause No. 44075. Petitioner's Ex. 5 at p. 8.

4. Discussion and Findings. The Commission has previously recognized the inclusion of a contingency factor in demolition studies for purposes of computing final terminal salvage. As Mr. Cash testified, the Commission accepted the inclusion of contingencies in Cause No. 44075. 44075 Order, p. 105. In the 44075 Order, the Commission cited the Order in *Northern Indiana Pub. Serv. Co.*, Cause No. 43526, p. 54, 2010 WL 3444546, 284 P.U.R. 4th 369 (IURC August 25, 2010), wherein the Commission approved the inclusion of contingency in the calculation of depreciation. We find Mr. D. Garrett and Mr. Rutter, without saying so, are asking the Commission to disregard our prior acceptance of contingency in I&M's demolition estimates without showing us why this change is warranted. The Commission accepts Petitioner's proposed contingency factor.

**D. Escalation Rates.**

1. OUCC. OUCC witness D. Garrett proposed removing escalation from demolition cost estimates for purposes of computing terminal net salvage. Public's Ex. 11B at p. 8. While I&M had applied an escalation factor of 2.23% to the estimated demolition costs, Mr. D. Garrett testified this is inappropriate. *Id.* at p. 23. According to Mr. D. Garrett, the accounting for asset retirement obligations is governed by Statement of Financial Accounting Standard 143 ("SFAS 143"), under which the future cost of demolition is discounted. *Id.* at p. 24. He also cited a decision by the Oklahoma Corporation Commission rejecting the use of contingency and escalation factors in calculating net salvage rates. *Id.* at p. 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. Petitioner's Ex. 5 at p. 8. He stated 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. Mr. Cash further testified that 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.* at p. 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.* at p. 11. In response to Mr. D. Garrett's citation of the Oklahoma decision, Mr. Cash cited numerous orders from the Commission specifically approving escalation rates in depreciation calculations. *Id.* at pp. 12-13.

3. Discussion and Findings. Mr. D. Garrett urges the Commission to follow a decision from another state without acknowledging the Commission has previously decided the question before us. "We have repeatedly rejected attempts to eliminate or curtail the effects of future inflation when calculating net salvage." *Indiana-American Water Co.*, Cause No. 44992, p. 10, 2018 WL 2739913 (IURC May 30, 2018). In I&M's last litigated depreciation proceeding, the Commission found "inflation should be factored into dismantlement cost estimates and [we] reject the OUCC's proposal to restate costs of removal at present value." 44075 Order, p. 106; *see also PSI*, Cause No. 42359, p. 71, 2004 WL 1493966, 234 P.U.R.4th 1 (IURC May 18, 2004) (Inflation has been a fact of life in the American economy for many years. Not factoring inflation into dismantlement costs to be incurred in the future would understate those costs, with the result being that future customers would have to pay costs arising from facilities that are not serving them.) The Commission finds the inclusion of the escalation factor at issue was appropriate based upon Mr. Cash's rebuttal testimony.

#### **E. Interim Retirements.**

1. OUCC. Mr. David Garrett proposed disallowing the inclusion of interim retirements in the calculation of depreciation rates. He stated disallowing interim retirements alone would not preclude I&M from recovering its prudent plant investments. Public's Ex. 11B at p. 19. Mr. D. Garrett testified he had not reviewed any Commission order specifically addressing the issue of interim retirements, *Id.* at p. 20, and he discussed, instead, the rejection of recovery of interim retirements in a 2012 Texas Commission rate case involving an AEP affiliate. *Id.* at pp. 18-20.

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. Petitioner's Ex. 5 at p. 14. In responding to the Texas Commission decision Mr. Garrett referenced, Mr. Cash stated it is unreasonable to exclude interim retirements because otherwise, the retired components will be depreciated beyond their service life, shifting the cost of interim retirements to future customers. *Id.* at pp. 16-17. He testified this Commission previously considered the application of interim retirements to I&M's steam production plant depreciation rates in Cause No. 44075, ultimately accepting the proposed rates and finding interim retirements should be included in the calculation of depreciation rates. *Id.* at p. 17.

3. Discussion and Findings. In Cause No. 44075, when presented with the inclusion of interim retirements in the calculation of depreciation rates, as Mr. Cash testified, the Commission found: "Interim net salvage relates to retirement costs for property that is retired prior to the final terminal retirement of the property. It is important to include an analysis of interim retirements in a depreciation study since all of the property that is initially

placed in service will not last until the final retirement date.” 44075 Order, p. 108. The Commission finds Mr. D. Garrett provided no persuasive basis for changing our prior position and excluding interim retirements.

**F. Rockport.**

1. I&M. I&M proposes changing the 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 when the lease agreement currently expires for that unit. Attachment JAC-1 at p. 8. The text of Attachment JAC-1, sponsored by Mr. Cash, indicates I&M added \$21.7 million to the original cost of the Rockport Plant since the last depreciation study, and these additions are reasons for the slightly higher recommended depreciation rates for steam production plant. *Id.*

2. ICC. ICC witness Medine opposed the change in depreciation rates for steam production. Intervenor ICC Ex. 1 at p. 4. She testified I&M is proposing to change certain Rockport-related depreciation schedules which align with I&M’s preferred case in its IRP. *Id.* at p. 6. Ms. Medine noted, however, that I&M stated the IRP and this case are two separate matters, and the petition in this proceeding makes no mention of the IRP. *Id.* at pp. 5-6. Ms. Medine testified that I&M provided no evidence in this case to support the Rockport retirement dates, and absent a justification of the retirement dates, it is inappropriate to adjust the depreciation schedules. *Id.* at p. 6.

3. Rebuttal. Mr. Cash testified there was no change in the estimated useful life of the Rockport units in the depreciation study presented in this proceeding. He reiterated that additional investment has been made to the Rockport units since the last depreciation study, and the depreciation rates need to be updated to reflect that additional investment. Petitioner’s Ex. 5 at p. 4. Mr. Cash asserted that Ms. Medine’s recommendation fails to recognize the additional investment made to both Rockport units since the depreciation study performed for Cause No. 44967. *Id.*

4. Discussion and Findings. The Commission finds the basis for I&M’s proposed change in steam production depreciation rates is the additional investment made since depreciation rates were approved under the settlement in Cause No. 44967. The estimated useful life of the Rockport units was not changed in this case. Because it remains unknown whether the Rockport Unit 2 lease will be extended, the Commission finds it appropriate at this time to continue depreciating the Rockport Plant as approved in Cause No. 44967 since this ensures the assets are fully depreciated by 2028. Although Ms. Medine objected to doing so since renewal of the Rockport Unit 2 lease is an open question, she offered no alternative estimated useful life for the Rockport units and did not object to the inclusion of the additional investment in the calculation of the depreciation accrual rates for steam generation. Given the record, the Commission approves I&M’s proposed depreciation rates for steam production plant with the caveat that these be appropriately revisited if the Rockport Unit 2 lease is extended.

**G. Rockport Enhanced DSI.**

1. Joint Municipal Group. Ms. Cannady testified on behalf of the Joint Municipal Intervenor with respect to the depreciation accrual rate for Petitioner's proposed enhanced DSI project at the Rockport plant. She testified I&M is proposing a 12% depreciation rate for the enhanced DSI system on Unit 1 and a 20% rate for the system on Unit 2. Ms. Cannady disagreed with this proposal, testifying the enhanced DSI investment should be recovered over no less than ten years and not greater than 20 years from the in-service date as allowed by Ind. Code § 8-1-2-6.7(b). Intervenor Jt. Municipal Ex. 2 at pp. 3-4, 11-18.

2. Rebuttal. On rebuttal, Mr. Cash testified Ms. Cannady is mistaken concerning I&M's proposal. He stated she confused the depreciation rate for the enhanced DSI project with the rate for the selected catalytic reduction ("SCR") system. He testified the 12% and 20% rates are the proposed rates for the SCR, not the enhanced DSI. Petitioner's Ex 5 at p. 4. Mr. Cash testified that no depreciation rate was calculated specifically for the enhanced DSI project. *Id.* at pp. 4-5. Accordingly, he testified that since no rate was proposed for the Rockport Unit 1 enhanced DSI project, I&M proposes to apply the same depreciation rates that are approved for Rockport Unit 1 when the enhanced DSI project goes into service. *Id.* at p. 4. He testified no depreciation rate was calculated or proposed for the Rockport Unit 2 enhanced DSI project; therefore, I&M also proposes to apply the same depreciation rates that are approved for Rockport Unit 2 when the project goes into service. *Id.* at p. 5. Thus, the general depreciation rates approved for Rockport will apply. *Id.* Mr. Cash testified it is a fundamental principle of cost-of-service ratemaking that the cost of an asset should be recognized over the period it is used and useful to provide service to customers; consequently, I&M has and continues to work to place into effect depreciation rates that will depreciate the investment in the Rockport Units by the end of the expected life of the Rockport Plant. *Id.* at p. 6.

3. Discussion and Findings. It appears Ms. Cannady was mistaken about the depreciation rates being proposed. The enhanced DSI project is included in the total Rockport Unit 2 investment and, based upon Mr. Cash's testimony, I&M is proposing the same depreciation rates that are approved for Rockport Unit 2 apply to the enhanced DSI project. Petitioner's Ex. 5 at p. 5. We disagree with Ms. Cannady's assertion that Ind. Code § 8-1-2-6.7(b) prescribes a minimum recovery of no less than ten years with respect to the investment in enhanced DSI at Unit 1, Intervenor Jt. Municipal Ex. 2 at p. 15, and that depreciation of the enhanced DSI at Unit 2 should exceed the current remaining life of the lease. *Id.* at p. 16. This statutory provision provides for depreciation of certain technology "over a period of not less than ten (10) years or the useful economic life of the technology, whichever is less ... ." Ms. Cannady neither asserted nor demonstrated this timeline must be applied to the enhanced DSI investment at issue, particularly in the absence of a request to do so. Accordingly, the Commission finds, based upon the evidence, that I&M's depreciation proposal is approved because it coincides with the projected used and useful life of the assets at this time.

**9. Fair Rate of Return.**

A. I&M. Mr. Hevert testified that his analyses indicate I&M's cost of equity ("COE") currently is in the range of 10.00% to 10.75%. Petitioner's Ex. 26 at p. 2. He testified

based on the quantitative and qualitative analyses discussed throughout his testimony, 10.50% is a reasonable estimate of I&M's COE. *Id.*

In developing his recommendation Mr. Hevert relied on several 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. Petitioner's Ex. 26 at pp. 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.

Mr. Hevert stated 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 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. Petitioner's Ex. 26 at p. 4. Mr. Hevert testified that since 2014, the DCF model has produced results (i.e., mean results) consistently and meaningfully below authorized returns. He stated the data suggests state regulatory commissions have recognized the DCF model's results are not necessarily reliable estimates of COE. *Id.* at p. 5. According to Mr. Hevert, the DCF model's underlying structure and assumptions are not compatible with the recent capital market and economic environment. *Id.* at p. 8. He testified the Commission should carefully consider the range of results the DCF model produces in arriving at ROE recommendations. *Id.* at p. 9.

Mr. Hevert discussed his proxy group and explained his recommendation takes into consideration the risk factors associated with: (1) I&M's generation portfolio and related environmental regulations; (2) customer concentration; and (3) I&M's planned capital expenditures and the effect, if any, of certain regulatory mechanisms. Petitioner's Ex. 26 at pp. 3-4. 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 that although those factors are very relevant to investors, their effect on I&M's COE cannot be directly quantified; therefore, although he did not make explicit adjustments to his COE estimates, he considered these factors in determining where I&M's COE falls within the range of analytical results. *Id.* at p. 4. Mr. Hevert opined that he believes his recommended range is reasonable and appropriate. *Id.*

With respect 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% common equity and 53.20% long-term debt, Mr. Hevert concluded I&M's proposal is consistent with the capital structures that have been in place over several fiscal quarters at the operating companies within the proxy group. Petitioner's Ex. 26 at p. 57. Considering the range of proxy company equity ratios from 46.73% to 62.16%, Mr. Hevert concluded I&M's proposed capital structure is reasonable and appropriate. Regarding the cost of debt, Mr. Hevert said he understands that I&M's projected weighted average cost of long-term debt at the end of the test year is 4.54%, which he believes is reasonable and appropriate. *Id.* at pp. 3, 57-58.

**B. OUCC.** 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 that in estimating I&M's COE, 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 Mr. Hevert used, he evaluated the results of the two most common financial models for calculating COE in utility rate proceedings: the CAPM and DCF Model. Mr. D. Garrett stated applying his inputs and assumptions to these models indicates I&M's estimated COE is about 6.5%. Public's Ex. 11A at pp. 10-11. He testified that although the awarded ROE should be based, or reflective of, the utility's COE, these legal standards do not mandate the awarded ROE be set exactly equal to the COE. Rather, under *Federal Power Comm'n v. Hope Natural Gas Co.*, the "end result" should be just and reasonable. Applying the concept of gradualism to I&M's shareholders, Mr. D. Garrett recommended the Commission award an ROE of 9.1%, which he testified is within a reasonable range of 9.0% – 9.5%. *Id.* at p. 11. Mr. D. Garrett testified an awarded ROE of 9.1% represents a gradual move toward I&M's market-based COE and would be fair to I&M's shareholders because 9.1% is nearly 200 basis points above I&M's market-based COE. *Id.* at p. 12. Mr. D. Garrett was unequivocal that I&M's proposed ROE of 10.5% is excessive and unreasonable. *Id.*

Mr. D. Garrett criticized Mr. Hevert's terminal growth rate, equity risk premium, bond yield plus risk premium model, and discussion of capital market environment. Public's Ex. 11A at pp. 14-19. He discussed the legal standards and awarded returns. *Id.* at pp. 20-29. Specifically, Mr. Garrett was critical of 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 stated Mr. Hevert's growth rate inputs exceed projected growth rates for the entire United States' economy, as measured by GDP growth. *Id.* at p. 14. Regarding the equity risk premium ("ERP"), Mr. Garrett testified 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.* at p. 15. He opined that Mr. Hevert's CAPM COE estimate is overstated and unreasonable. *Id.*

**C. Industrial Group.** Industrial Group witness Gorman also testified 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, AEP. Intervenor IG Ex. 3 at pp. 43-61.

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

Mr. Gorman testified regarding his recommendation for I&M's cost of common equity in light of the *Hope* and *Bluefield* standard. He reviewed the methods he used to estimate I&M's cost of common equity, including several variations on the DCF model, the Risk Premium Model, and the CAPM and the inputs he used in applying these models.



Based on the results of his analyses, Mr. Gorman recommended a return on common equity of no higher than 9.0%, Intervenor IG Ex. 3 at p. 93, with a ratemaking overall rate of return of 5.35%. *Id.* at p. 4. Mr. Gorman testified his recommended rate of return will support an investment grade bond rating for I&M. *Id.* at p. 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%, *Id.* at p. 93, which he testified reflects the current low capital market cost for a utility with risks similar to I&M. Mr. Gorman stated his ROE 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.* at p. 93.

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.* at pp. 62-220.

**D. Other Intervenor.** Walmart witness Chriss provided Walmart's perspective as a nation-wide electricity consumer. Mr. Chriss recommended the Commission closely examine the ROE in light of customer impact, I&M's use of the future test year, and recent ROE decisions approved by the Commission and nationwide. Intervenor Walmart Ex. 1 at pp. 4, 7-14. In this regard, Mr. Chriss testified the impact of I&M's requested ROE increase from the current authorized ROE of 9.95% to 10.5%, using I&M's proposed rate base constant, cost of debt, and capital structure, results in an impact on customers of approximately \$13.8 million or 8.1% of I&M's claimed revenue deficiency in this proceeding. *Id.* at p. 9.

Mr. Chriss further testified that I&M's proposed ROE is significantly higher than ROEs the Commission has approved since 2016, noting the average of Commission-approved ROEs since 2016 is 9.94%. *Id.* In comparison with ROEs approved by other regulatory commissions, Mr. Chriss demonstrated 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.* at p. 11. Mr. Chriss stated that for vertically-integrated utilities reported by S&P Global over the same time period, the average reported ROE was 9.73% which remained relatively stable over that time. *Id.* at pp. 11-12. Mr. Chriss concluded that I&M's requested ROE and ROE range are, thus, contrary to broader electric industry trends. *Id.* at p. 11.

Intervenor 39 North witness Cearley, while not performing a cost of equity analysis, recommended the Commission recognize I&M's poor customer satisfaction scores in adopting a return. Intervenor 39 North Ex. 1 at pp. 8-9. Specifically, Mr. Cearley recommended the Commission adopt a return that recognizes I&M's declining residential customer satisfaction performance levels and by doing so, properly incentivize I&M's management. *Id.* at p. 9.

**E. Rebuttal.** Mr. Hevert testified there are several methodological, theoretical, and practical reasons why the other ROE witnesses' (collectively, "Opposing ROE

Witnesses”) recommendations are unduly low. Petitioner’s Ex. 27 at p. 2. He stated because the Opposing ROE Witnesses give meaningful weight to their DCF-based results, it is not surprising their recommendations fall well below currently authorized returns. *Id.* He added that given their common reliance on the DCF method, it also is not surprising the Opposing ROE Witnesses’ recommendations generally fall within a narrow range. *Id.* at pp. 2-3. Mr. Hevert stated the fact that the Opposing ROE Witness recommendations are similar does not mean their approaches and conclusions are reasonable. *Id.* at p. 3.

Mr. Hevert stated in some cases, the Opposing ROE Witnesses’ recommendations stem from unreasonably low DCF estimates, which themselves are the result of tenuous assumptions. *Id.* He testified there is no reasonable basis to assume the current volatile capital market environment will remain in place in perpetuity. Mr. Hevert stated 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. *Id.* Mr. Hevert testified those valuation levels are more likely related to the “reach for yield” that often occurs during periods of low Treasury yields. *Id.*

Mr. Hevert also testified that certain Opposing ROE Witnesses’ recommendations are fundamentally disconnected from their own analyses and conclusions and are far removed from observable and relevant data. Petitioner’s Ex. 27 at p. 4. For example, Mr. D. Garrett asserts I&M’s true COE is in the range of 6.5%, yet he recommends an ROE of 9.10% as a means of mitigating what he believes would otherwise be an increase in I&M’s risk profile. *Id.* Mr. Hevert also stated that although Mr. Gorman suggests the COE has fallen to a level that supports his recommendation, observable data does not support this position. *Id.* at p. 5.

Mr. Hevert stated the Opposing ROE Witnesses are not consistent with returns authorized by the Commission and elsewhere in the United States. He contended if the Commission were to authorize a return of 9.10% or lower as the Opposing ROE Witnesses recommend, this would represent a significant departure from returns the Commission previously authorized. Petitioner’s Ex. 27 at pp. 5-6; Chart 1. Notably, Chart 1 shows the Commission has not approved an ROE of 10% or higher since 2013.

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 stated a consequence of an authorized ROE in the range of the Opposing ROE Witnesses’ recommendations would be to increase investors’ perceptions of regulatory risk. Petitioner’s Ex. 27 at p. 6.

Mr. Hevert also noted that I&M expects its Network Integration Transmission Services (“NITS”) costs to increase by about \$48 million in 2021, one year beyond the test year in this Cause, pointing out Mr. Williamson’s testimony that absent the ability to recover the increased NITS cost, I&M’s earned Return on Common Equity would fall by about 1.90 percentage points (190 basis points). *Id.* at p. 94. Mr. Hevert stated that because operating cash flow is directly related to income, an earnings erosion brought about by an inability to recover increased NITS costs will put downward pressure on I&M’s financial profile, increasing the financial community’s perceptions of I&M’s risk. *Id.* at p. 94. Mr. Hevert testified the combination of the Opposing ROE Witnesses’ unduly low ROE recommendations and the increased likelihood of

under-earning absent timely recovery of increased NITS costs suggests returns that are far too low to be considered reasonable. *Id.* at pp. 94-95.

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

**F. Discussion and Findings.** In setting the rate of return for I&M, the Commission's decision must be framed by *Bluefield Waterworks & Improvements Co. v. Pub. Serv. Comm'n*, 262 U.S. 679, 43 S.Ct. 675 (1923) and *Federal Power Comm'n v. Hope Natural Gas, Co.*, 320 U.S. 591, 64 S.Ct. 281 (1944).<sup>12</sup> The general standards these cases established require a cost of common equity set by the Commission be sufficient to establish a rate of return that will maintain the utility's financial integrity, attract capital under reasonable terms, and be commensurate with the returns that could be earned in investments in other enterprises of comparable risk.

The Commission is also mindful that "the cost of common equity cannot be precisely calculated and estimating it requires the use of judgment." *Indiana-American Water Co.*, Cause No. 44022, p. 35 (June 6, 2012). Due to this lack of precision, the use of multiple methods is desirable, in part, because no one method will produce reasonable results under all conditions and in all circumstances. The Commission is also mindful of the strengths and weaknesses of the various models typically used to estimate a utility's cost of common equity, and we find that with appropriate and reasonable inputs, models such as the DCF and CAPM can produce reasonable estimates of a utility's cost of common equity. Consistent with the standards in *Hope* and *Bluefield*, as well as under Indiana law, I&M's authorized return on equity should be reasonable given the totality of the circumstances.

To meet the requirements set forth in *Bluefield* and *Hope*, the parties proposed various returns using the DCF model and other methods as bases for their positions. Mr. Hevert's analysis produced a range of 10.0% to 10.75%. He recommended the Commission adopt a COE of 10.50%. Mr. D. Garrett's estimated COE is about 6.5%, but he recommended a COE 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 testimony of these experts yields a recommended range of 9.00% to 10.5%.

In addition to the recommendations of these experts, while not determinative of the COE the Commission approves in this Cause, we note the COE awarded Indiana's vertically-integrated electric utilities outside of settled cases has been trending lower over time. *See, e.g.*, PSI Energy, Inc. (now Duke Energy Indiana) 10.5% in Cause No. 42359 (2005); Southern Indiana Gas and Electric Company 10.4% in Cause No. 43839 (2011); Indiana Michigan Power 10.2% in Cause No. 44075 (2013); and Indianapolis Power and Light Company 9.85% in Cause No. 44576 (2016), with the most recent COE award for such an electric utility being 9.75% approved on December 4, 2019, for Northern Indiana Public Service Company LLC in Cause No. 45159. We find the evidence shows Mr. Hevert's recommended COE of 10.50% exceeds a reasonable estimate of I&M's COE given current market conditions and recent COE decisions

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<sup>12</sup> *See also Re Indianapolis Power & Light Co.*, Cause No. 44576, p. 41, 2016 WL 1118795 \*43 (IURC March 16, 2016).

approved by the Commission and approved nationwide for investor-owned electric utilities. More specifically, the record reflects Mr. Hevert's constant growth DCF analysis relies on unsustainably high growth rates the Commission finds are unrealistic. In addition, we are not persuaded he appropriately considered the mitigation of risk associated with various regulatory mechanisms, including I&M's use of a future test year in this proceeding and the riders and/or trackers approved for I&M. His recommendations are also inconsistent with recent COE decisions approved nationwide for investor-owned electric utilities, based on intervenor Walmart's evidence, and with the lower trend, generally, by the Commission. While the Commission does not base its COE conclusion on national averages, the evidence presented demonstrates the trend in approved COEs for vertically-integrated utilities, both in Indiana and nationwide, is lower than I&M requests. We recognize financial strength is important for a utility to attract capital at a reasonable cost in order to make the investment necessary to fulfill its service obligations, but the evidence demonstrates investor-owned utilities similar to I&M and located in similar regulatory jurisdictions have been awarded reasonable and fair COEs that are below I&M's requested range. Tr. C-21-32.

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

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

Having taken into consideration the foregoing factors and observable market data reflected in the record, including the impact of Federal Reserve policies on current and expected long-term capital market costs, an assessment of the current risk premium built into current market securities, expected inflation rates, and a general assessment of the current investment risk characteristics of the electric utility industry, combined with a thorough understanding of the Indiana jurisdiction and its risk mitigation ratemaking mechanisms, and I&M in particular, the Commission finds a reasonable range for Petitioner's COE is 9.50% to 10.00%. Taking into consideration all the evidence presented, the Commission finds and concludes a 9.70% COE is fair and reasonable under the totality of the circumstances, particularly the Commission's decision with respect to the PJM tracker. This moderate decrement below the mid-point of the reasonable range recognizes the significant risk reduction afforded I&M through the PJM tracker.

**G. Overall Weighted Cost of Capital.** Mr. Hevert's testimony regarding I&M's capital structure was not challenged. Having reviewed his testimony and that of Mr. Gorman, the Commission finds I&M'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 COE authorized above, the Commission finds Petitioner's capital structure and weighted cost of capital are as follows:

<u>Description</u>	<u>Total Company Capitalization</u>	<u>Percent of Total</u>	<u>Cost Rate</u>	<u>Weighted Average Cost of Capital</u>
Long Term Debt	\$ 2,926,531,185	42.69%	4.54%	1.94%
Common Equity	\$ 2,574,496,077	37.55%	9.70%	3.64%
Customer Deposits	\$ 37,972,608	0.55%	2.00%	0.01%
ACC. DEF. FIT	\$ 1,297,621,545	18.93%	0.00%	0.00%
ACC. DEF. JDITC	\$ 18,960,268	0.28%	7.33%	0.02%
Total	\$ 6,855,581,684	100.00%		5.61%

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. Public's Ex. 12 at p. 49. He testified I&M 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 testified I&M agreed with this change to test year revenues. Petitioner's Ex. 21 at p. 42. Mr. Nollenberger further testified that while this correction does not change I&M's overall revenue requirement, it does reduce the revenue deficiency by the amount of the correction. *Id.*

3. Discussion and Findings. The Commission finds the use of the updated test year number of bills to be appropriate. Consistent with Mr. Nollenberger's rebuttal testimony, this update does not change I&M's overall revenue requirement, but it does reduce the revenue deficiency by the correction amount.

**11. Disputed Test Year O&M Expenses.**

**A. Cook 316(b).**

1. I&M. Messrs. Williamson and Lies supported I&M'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 I&M has deferred. Through these studies, I&M determined no additional capital costs are needed to comply with this federal environmental requirement. Petitioner's Ex. 24 at p. 29; Petitioner's Ex. 33 at p. 24. I&M proposes to include the deferred costs of compliance with Section 316(b) in rate base and amortize these through rates over 15 years, which Mr. Williamson testified reasonably approximates the remaining life of the Cook Plant. Petitioner's Ex. 24 at p. 29.

2. OUCC. OUCC witness Eckert recommended the Commission deny I&M's requests to create a regulatory asset for the Cook Nuclear Plant's Rule 316(b) study expenses, treat it as rate base, and amortize it over 15 years. Public's Ex. 1 at p. 16. He testified the 316(b) costs did not constitute a financial impact to the utility because I&M was incurring these costs during its last two rate cases and waited until the Rule 316(b) study was complete and all study costs were incurred before requesting Commission authority to defer these costs in this rate proceeding. *Id.* at p. 14. Mr. Eckert stated I&M had full control over when it started incurring Rule 316(b) study expenses, as well as when I&M decided to seek their recovery, and I&M, therefore, 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.* at pp. 15-17. According to Mr. Eckert, this cost is the type of compliance expense the Commission included in base rates (Cause No. 44967) to be replaced by new one-time expenses that will be incurred in the future, *Id.* at p. 16; consequently, Mr. Eckert concluded I&M's rates already include an embedded level of compliance cost expense, and it is inappropriate to provide I&M with additional recovery. *Id.* Mr. Eckert recommended the Commission reject I&M's requested deferral and amortization of these costs. *Id.* at p. 20.

3. Rebuttal. I&M witness Ross testified the Cook 316(b) costs were properly recorded to Account 107, Construction Work in Progress, Petitioner's Ex. 23 at p. 16, and properly reclassified to Account 183 for Preliminary Survey and Investigation Charges in accordance with the FERC USOA. *Id.* He stated when it was determined it was uncertain 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. *Id.* Mr. Ross testified, as also supported by Mr. Lies in his direct testimony, that I&M does not believe the result will be I&M's construction of a capital asset. Rather than expensing these deferred Section 316(b) compliance costs in 2018, Mr. Ross stated I&M properly deferred the costs in accordance with ASC 980, Regulated Operations, *Id.* at p. 17, 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.*

In his rebuttal testimony, Mr. Lies responded to Mr. Eckert's testimony that the 316(b) costs were embedded in the calculation of base rates in Cause No. 44075. Mr. Lies stated the 316(b) project costs are not similar to the Fire Suppression System costs that were expensed and

approved in Cause No. 44075, that the Fire Suppression System costs of about \$1.7 million were related to an O&M project, not a capital project. Petitioner's Ex. 34 at p. 2. Mr. Lies added that I&M expects to regularly incur O&M compliance costs to comply with emerging requirements that are relatively limited in scope. He stated 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 would have taken several years to complete and would have been necessary to ensure the on-going operation of the Cook Plant. Mr. Lies testified the possible outcome of the 316(b) study could have been the installation of cooling towers costing upwards of \$1 billion. Petitioner's Ex. 34 at pp. 2-3. He added, as appropriate for any possible capital project of this scope, studies were used to determine the path forward. *Id.* at p. 3. Mr. Lies stated the 316(b) studies allowed I&M to avoid a major capital project, and this was a positive outcome for I&M's customers. *Id.*

4. Discussion and Findings. The Commission finds the 316(b) costs were prudently incurred because by incurring the study costs, I&M has avoided a substantial additional compliance cost, thereby benefitting its customers. It is appropriate to reflect the study cost in rates as it has reduced the ongoing cost of service. The Commission finds the evidence persuasive that costs such as these have not been recovered through I&M's existing rates. Mr. Lies testified these costs are significantly different from the Fire Suppression System costs at issue in Cause No. 44075. As to the OUCC's argument that I&M should have sought authority to defer these costs as a regulatory asset, based on the accounting testimony presented, GAAP does not require such authorization. The question for recording a regulatory asset under ASC 980 is the probability of recovery (Petitioner's Ex. 23 at 17), which may come from a Commission order, but such an order is not the only means. For instance, rate case expense is deferred without a Commission order in advance. Accordingly, the Commission finds the 316(b) costs at issue will provide a benefit over the balance of the Cook Plant's remaining life; therefore, the Commission authorizes the requested inclusion of the unamortized balance in rate base and authorizes the costs to be amortized over a period of 15 years as representative, at this time, of the remaining life of the Cook Units.

## **B. Customer Assistance Programs.**

1. I&M. Mr. Lucas testified that as outlined in the Settlement Agreement in Cause No. 44967, 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. Petitioner's Ex. 18 at p. 29. He provided an update on each pilot and stated I&M is proposing each of these programs continue through 2020 as currently defined through the collaborative process with stakeholders. *Id.* In addition, Mr. Lucas testified I&M is proposing to establish an Income Qualified Safety and Health Pilot Program to address safety and health issues that prevent the completion of an income-qualified energy audit. *Id.* at p. 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. Mr. Haselden testified there are a number of state and local programs designed to assist low-income customers, and I&M presented no compelling evidence why it is appropriate to include the expense to offer these programs as a cost to ratepayers. Public's Ex. 6 at pp. 3-7.

Mr. Haselden recommended the Low-Income Weatherization Program be proposed as part of I&M's next three-year DSM Plan and, if approved, the costs be recovered through the DSM tracker. *Id.* at pp. 5-6. He stated the Income Qualified Safety and Health Pilot Program is essentially part of the Low Income Weatherization Program and, consequently, should also be addressed in the DSM Plan and recovery of costs, if approved, be through the DSM tracker. Mr. Haselden testified that programs of this type that are used to satisfy certain requirements regarding restitution or funding to come into compliance with the law should not be recoverable from ratepayers. *Id.* at p. 6.

3. Intervenors. Industrial Group witness Gorman stated that funds for customer assistance pilots should continue to come from shareholders, not ratepayers. Intervenor IG Ex. 3 at p. 39. Mr. Phillips testified that, while helping low income individuals is laudable, it should be voluntary and not a hidden income transfer mechanism included in customer rates. Intervenor IG Ex. 4 at p. 26. He added that no reasons were set forth for switching the funding responsibility from I&M's shareholders to ratepayers, and if I&M wants to pursue the programs, it should provide the funding, not force its customers to do so. Mr. Phillips stated that requiring customers to fund these programs distorts the ratemaking process by building in subsidies to certain customers. He added that if the Commission decides in favor of ratepayer funding, the assistance programs should be done on a cost of service basis, should be voluntary, and should be funded by the class or classes receiving the benefits. It should also be transparent so customers are aware of the purpose of the payments. *Id.* at pp. 26-27. Finally, Mr. Phillips testified because the cost is not related to energy consumption, if recovered from ratepayers, it should be a uniform per customer charge, not a usage charge. *Id.* at p. 27.

CAC-INCAA witness Olson provided an update on the Low Income Arrearage Forgiveness Pilot Program, noting the launch of this program was delayed for modifications in I&M's billing system. He stated I&M now intends to launch this pilot during the fourth quarter of 2019. Mr. Olson testified CAC-INCAA is generally pleased with this proposed pilot program with one exception. He recommended I&M go back and work with stakeholders to coordinate this program with the Neighbor to Neighbor Pilot Program. Intervenor CAC-INCAA Ex. 1 at pp. 13-18. Mr. Olson expressed disappointment with the design of the Neighbor to Neighbor pilot program, stating that from the outset of the collaborative process, the design of this program appeared to be a "done deal," identical to AEP's Ohio Neighbor to Neighbor Program instead of I&M being open to adopting program design changes stakeholders advocated. *Id.* at pp. 13-14. According to Mr. Olson, CAC took issue with the Company's desire to help as many customers as possible because this spread the limited available funding over too many customers, quickly exhausting the funds and lessening the ability to collect meaningful data. *Id.* at p. 14. He stated CAC was also concerned that participating customers, after bringing themselves out of arrears, will immediately return to a non-discounted bill upon completing the Low Income Arrearage Forgiveness Pilot Program. *Id.* at p. 12. CAC and INCAA recommended the Commission instruct I&M to go back and work with stakeholders to discuss their differences and coordinate the Neighbor to Neighbor and the Low Income Arrearage Forgiveness Pilot Programs. Mr. Olson supported I&M's proposal regarding the Energy Share Program, the Low Income Weatherization Program, and the Income Qualified Safety and Health Pilot Program and expressed appreciation for I&M's commitment to these programs. *Id.* at pp. 18-19.



South Bend witness Dorau testified South Bend is, in principle, supportive of I&M's four pilot customer assistance programs as they complement South Bend's programs to help the most financially vulnerable. She stated South Bend is enthusiastic about I&M's proposed Income Qualified Safety and Health Pilot Program as it complements South Bend's Home Repair Initiative. Intervenor South Bend Ex. 1 at pp. 11-12. In her cross-answering testimony, Ms. Dorau elaborated on her view as to the benefits of these customer assistance programs. Intervenor South Bend Ex. 4 at pp. 7-8. She testified there are I&M customers in South Bend who simply do not have the money to pay I&M's increased rates, and existing safety nets like LIHEAP may not be available or are inadequate. *Id.* at p. 8. Ms. Dorau stated these financially vulnerable customers need the help of all stakeholders – ratepayers, regulators, and investor-owned utilities. Ms. Dorau opined that these customer assistance pilot programs are relatively modest, totaling \$550,000 out of I&M's proposed annual operating revenues of \$1,313,249,251, and she supported I&M's proposed inclusion of these programs in base rates. *Id.*

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. Petitioner's Ex. 19 at p. 19. He explained the connection between these pilot programs and I&M's cost of service and said it is premature to categorically rule out that the results of these programs will provide reductions of equal or greater value than the program costs as Mr. Haselden does. *Id.* at pp. 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 CAC proposed. *Id.* at p. 20.

5. Discussion and Findings. While I&M currently has several customer assistance pilot programs, these were agreed to and approved in I&M's last rate case as part of a settlement. Importantly, under that settlement the programs were not funded by ratepayers. I&M now proposes to continue these programs, along with a new pilot program to assist income-qualified customers in addressing certain safety and health issues preventing completion of a home energy audit, but I&M proposes requiring ratepayers—not I&M's shareholders—to fund these programs. The OUCC and the Industrial Group opposed shifting this funding to ratepayers because 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 pilots, designed to gather information on expenses that may affect overall cost of service. Petitioner's Ex. 19 at p. 19. While these pilot programs are designed to gather information upon whether programs like these can help reduce the long-term cost of providing service, I&M currently has three of the four programs in place and is in the process of implementing the Low Income Arrearage Forgiveness Pilot program with funds allocated based upon the Settlement Agreement in Cause No. 44967. Petitioner's Ex. 18 at pp. 32-33. I&M has not, however, demonstrated the extent to which it has collected and studied information from the current pilot programs, why these pilots should be extended to collect more information, and/or why funding should shift to ratepayers rather than remain with the Company's shareholders.

When a regulated entity asks the Commission to approve a pilot, this request should demonstrate the pilot's value for ratepayers and show the entity has thought past the pilot to assure the data to be captured is meaningful given the pilot's objective. In addition, since I&M

wants to shift pilot funding from its shareholders to ratepayers, it was incumbent upon I&M to show the value of continuing the pilot at ratepayers' expense. Importantly, the Commission also expects an approved low income or customer assistance pilot, like those agreed upon in Cause No. 44967, to be implemented with dispatch, not learn, as we did in this Cause, that the Low Income Arrearage Forgiveness Pilot approved on May 30, 2018, in the 44967 Order is not yet in place. Pilots are not a chess piece to be played to engender positive public relations or as trade-offs for rate case concessions. Such programs are an opportunity to capture specific data needed to evaluate contemplated initiatives, mindful of the impact upon all customers. And, asking for approval of more low income pilot programs, while those already approved linger, is unlikely to be well-received. Further, if stakeholders believe a utility is not abiding by the terms of an Order in implementing a pilot or when engaging in a collaborative, we encourage promptly bringing such non-compliance to the Commission's attention. Notably, not every difference of opinion or perspective equates to such non-compliance. The Commission finds the subject pilot programs are not necessary for the provision of electric service, and in the absence of information supporting continuation of the pilots, these programs should not be continued at ratepayers' expense. Accordingly, the Commission declines to approve I&M's request to now recover these pilot costs through rates. I&M may continue these pilots but not at ratepayers' expense.

### **C. Economic Development.**

1. I&M. Mr. Lucas discussed the importance of economic development and I&M's support of economic development in its service area. Petitioner's Ex. 18 at pp. 18-19. He testified that increased load resulting 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. *Id.* at p. 19. Mr. Lucas stated I&M implemented the EIG (Economic Impact Grant) Program agreed upon in the settlement in Cause No. 44967 and now proposes 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 p. 21. Mr. Lucas testified these funds will allow I&M to continue providing grants to eligible customers, including members of the Joint Municipal Group and 39 North, to support qualifying projects. *Id.* He testified that challenges to continued economic growth include the availability of a skilled workforce and the need for an inventory of desirable existing buildings, available for sale or lease. *Id.* at pp. 21-22. Mr. Lucas stated 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.* at p. 22; consequently, Mr. Lucas described two new pilot programs I&M is proposing to address these challenges, those being an Apprenticeship and Training pilot program and a Building Development pilot program. Petitioner's Ex. 18 at pp. 23-24.

Mr. Lucas testified the Apprenticeship and Training pilot program, in collaboration with local workforce development organizations, will assist eligible customers in providing apprenticeship and employee training programs. He stated I&M is proposing to make \$350,000 per year available for two-years to support these training programs. Petitioner's Ex. 18 at p. 23. Mr. Lucas testified that under the Building Development pilot, I&M will provide \$150,000 per year for two years to assist communities with the development of "spec" buildings. *Id.* at p. 24.

2. OUCC. Mr. Haselden recommended the funding source for EIG and the two proposed economic development pilot programs not be I&M's ratepayers. Public's

Ex. 6 at p. 4. He testified that while the OUCC does not oppose prospectively disbursing any of the unallocated funding for the EIG that does not affect I&M's revenue requirement, it is not appropriate to begin funding these grants in base rates. *Id.* Mr. Haselden recognized the availability of a well-trained workforce and developable sites is valuable to economic development, but he testified these kinds of programs are not necessary for the provision of energy utility service; they relate to issues state and local economic development agencies are intended to address. *Id.* at pp. 4-5.

3. Intervenors. Industrial Group witness Phillips and Joint Municipal Group witness Mancinelli also recommended the funds proposed for workforce training and building development not be included in I&M's cost of service. Intervenor IG Ex. 4 at p. 27; Intervenor Joint Municipal Ex. 1 at p. 58. South Bend, the Joint Municipal Group, and 39 North all suggested modifications to I&M's proposed economic development pilot programs. Intervenor South Bend Ex. 1 at pp. 21-23; Intervenor Joint Municipal Ex. 1 at pp. 57-59; Intervenor 39 North Ex. 1 at pp. 11-13. The Joint Municipal Group and 39 North also raised concerns regarding the consistency with which I&M has managed and administered the EIG program since its establishment in Cause No. 44967. Intervenor Joint Municipal Ex. 3 at pp. 5-14; Intervenor 39 North Ex. 1 at p. 12. Specifically, Joint Municipal witness Fasick expressed frustration that I&M's EIG eligibility requirements have been a moving target resulting in what Fort Wayne perceives as I&M unreasonably delaying or withholding approval of an eligible application from Fort Wayne for a new water pressure station. Intervenor Joint Municipal Ex. 3 at pp. 9-12. In her cross-answering testimony, Ms. Dorau reiterated the importance of economic development support to municipalities seeking to maintain and grow their communities, and she viewed I&M's pilot programs as modest investments in developing I&M's expanded portfolio of economic development efforts. Intervenor South Bend Ex. 4 at pp. 6-7.

4. Rebuttal. In his rebuttal testimony, Mr. Lucas 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 customer load continues to be flat to declining, and it is becoming difficult to manage customer rates by managing costs. Petitioner's Ex. 19 at pp. 8-9. He testified that economic development is, arguably, one of the best tools I&M has to manage the cost of electricity for its customers. *Id.* at p. 8. Mr. Lucas reiterated that I&M has worked with its 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.* at pp. 8-9. He added that in many of these opportunities, safe, reliable, and reasonable electric service was a significant consideration in attracting new companies to the area. Mr. Lucas stated these economic development successes benefit all of I&M's customers by spreading I&M's fixed costs over a broader customer base. *Id.* at p. 9.

Mr. Lucas stated I&M appreciates the constructive feedback from the City of South Bend on the economic development pilot programs proposed in this case and is open to including the energy and construction trades in the Workforce Development pilot program. Petitioner's Ex. 19 at p. 11. He stated I&M would also be willing to incorporate modernizing existing commercial buildings or new commercial construction on an infill site in the Building Development pilot so long as they meet all of the eligibility requirements. *Id.*

Mr. Lucas disagreed with Mr. Mancinelli's testimony that a better use of EIG funds would be a permanent expansion of the existing grant programs in coordination with local government authorities. *Id.* at pp. 11-12. He testified that Mr. Fasick's recommendation to fund the EIG program from I&M's earnings 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.* at pp. 12-13. That said, Mr. Lucas stated I&M proposes to continue the EIG program into the future and has reflected \$137,500 in the test year revenue requirement for the EIG program. *Id.* at p.12.

Mr. Lucas also responded to concerns Mr. Fasick raised regarding I&M's administration of the existing EIG program. He asserted I&M is managing the program consistent with the eligibility requirements for qualifying projects and disagreed that I&M is not administering the program correctly or purposely slow walking quality economic development projects. Petitioner's Ex. 19 at p. 14. He testified since the start of the EIG program, I&M has conducted two economic development stakeholder meetings with local economic development organizations and municipal staff responsible for economic development activities. He stated in both meetings, I&M discussed the EIG program, the application process, and encouraged all attending to participate in the program. Additionally, Mr. Lucas stated 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.* at pp. 14-15. He testified much of the concern Mr. Fasick raised 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.* at p. 17. Mr. Lucas testified 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 at issue. He stated 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.* at p. 17. Mr. Lucas stated I&M looks forward to working with Fort Wayne on future applications that will benefit all I&M customers by promoting economic development opportunities in I&M's service area. *Id.* at p. 18.

With respect to Mr. Cearley's concerns, Mr. Lucas testified 39 North has submitted five applications under the EIG program. Petitioner's Ex. 19 at p. 16. He stated three applications were approved for funding, and the other two applications did not meet the eligibility criteria. *Id.* Mr. Lucas stated I&M has provided 39 North feedback on both applications, and he reiterated that 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.* at p. 16,

5. Discussion and Findings. In this case, I&M seeks authority to recover funds from its customers to support three economic development programs. These include the continuation of the EIG program the Commission initially approved as part of the Settlement Agreement,<sup>13</sup> an Apprenticeship and Training pilot program, and a Building Development pilot program.

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<sup>13</sup> The Settlement Agreement provided that I&M's revenue deficiency in Cause No. 44967 would "not be adjusted to include any incremental costs" associated with the EIG program. Settlement Agreement, p. 17, ¶ 17.8.

The Commission has supported the growth of economic development programs through the use of specialized economic development rates, also known as economic development riders, that provide preferential rates for new or expanding businesses meeting certain conditions. *Indiana-Michigan Power Co.*, Cause No. 43953 (IURC February 23, 2011). In doing so, the Commission “has long recognized the importance of economic development programs and has supported efforts by Indiana utilities to attract additional investments within their service territories through economic development rates.” (emphasis added). *Indiana-Michigan Power Co.*, Cause No. 43953, p. 4 (IURC February 23, 2011).

This Commission fully recognizes the importance of electric economic development rates in aiding the attraction and retention of job intensive industrial and large commercial enterprises. As such, we have done our best to accommodate the specific needs of each and every electric utility in the state in the design and approval of economic development rates. It is our intent to continue to foster quality economic development whenever possible.

*Indiana Michigan Power Co.*, Cause No. 41366, p. 7 (IURC October 13, 1999); *see also Northern Indiana Pub. Serv. Co.*, Cause No. 42348, pp. 4-5 (IURC March 26, 2003) (explaining economic development riders benefit utility customers and the state.) The Commission’s support of economic development must, however, be done within the context of our statutory authority.

What I&M proposes in this case is not a specific rate or economic development rider, but programs that will provide grants for non-utility related activities, including employee training for I&M’s customers and site/building development; consequently, the question is whether, for purposes of I&M’s request to recover the costs of these programs from its customers, they constitute utility service. Indiana’s appellate courts, in reviewing the definition of “service” in Ind. Code § 8-1-2-1(e), have identified three categories of service as that term is defined in regulating public utilities. These categories include: (1) the use or accommodation afforded customers or patrons; (2) any product or commodity furnished by a utility; and (3) the plant, equipment, apparatus, appliances, property, and facility employed by a utility in performing any service or in furnishing any product or commodity and devoted to the purposes in which such utility is engaged and to the use and accommodation of the public. *Illinois-Indiana Cable Television Ass’n, Inc. v. Public Serv. Comm’n*, 427 N.E.2d 1100, 1109 (Ind. Ct. App. 1981); *see* Ind. Code § 8-1-2-1(e).

Under this definition, at best the proposed new Apprenticeship and Training and the Building Development pilots would constitute a product being furnished by I&M. But, it is difficult to reconcile how the proposed pilots have an actual connection to I&M’s provision of electric service. Both programs will simply help underwrite non-electric related costs that eligible customers might otherwise incur in their operations. The Apprenticeship and Training pilot is to be offered to certain commercial and industrial customers meeting eligibility criteria to support established and credible apprenticeship and employee training programs. Petitioner’s Ex. 18 at DAL-3. The Building Development pilot is to be offered to owners, developers, and local economic development organizations to support development and marketing of specific types of property. *Id.* at DAL-4. Neither pilot is required or devoted to providing utility service.

Billed as economic development programs that meet the needs of I&M's customers, I&M states these pilots will provide benefits including, potentially, increased load. The connection of these pilot programs to I&M's role in providing electric service to its ratepayers is, however, too tenuous to justify the inclusion of their costs in I&M's revenue requirements and, thus, customers' rates. Rather, the Commission finds what is being proposed are customer funded payments to support certain independent, non-energy related activities of others, including training employees who may or may not ultimately put the skills to work long-term within I&M's service area. Requiring ratepayers to fund such programs is simply too abstract from the concept of utility service for the Commission to approve recovering these costs in rates. On the other hand, if I&M is persuaded these pilots will enhance its customer load, perhaps I&M's shareholders will not discontinue funding the EIG and will fund the proposed two new pilots.

With respect to the EIG program, I&M's current EIG pilot was implemented as part of the settlement in Cause No. 44967 in which I&M agreed shareholders would fund this program. I&M now proposes to continue one component of the EIG program. Under the Settlement Agreement, p. 16 at ¶ 17.4, qualifying projects for the EIG program include, but are not limited to, "industrial and headquarter site development due diligence, workforce development initiatives, housing development initiatives, spec building development, and job creation and retention." These are non-energy related projects. The Commission also notes that based on the intervenors' testimony, I&M and some government entities have disagreed over I&M's management of the existing EIG program. These disputes seemed to focus on I&M's administration of the program, particularly the approval process, and these disagreements persist. Based on the record, the Commission is not persuaded the disputed EIG applications all met the original intent of the settlement approved in Cause No. 44967 and were wrongly denied. Now, I&M wishes to recover the costs of the EIG program from its customers, with ultimate approval of a qualifying project to remain within I&M's discretion. However well-intended the EIG program may be, the Commission agrees with the OUCC that this program is not reasonably necessary for the provision of electric service. Reimbursement of local development projects that I&M deems qualifying projects falls outside of being reasonably necessary to provide electric service. The direct benefits of the EIG program are outside of the reasonable provision of electric service; consequently, the Commission denies I&M's request that ratepayers prospectively fund the EIG program. Again, in so finding, I&M is not precluded from continuing to use shareholders' investment to fund the EIG program. Also, given the past disagreements in administering the EIG program, the Commission encourages I&M to be more transparent prospectively in processing applications.

#### **D. Employee Medical Expenses.**

1. OUCC. Mr. Mark Garrett testified the Company's forecasted test year includes \$27 million for employee medical costs, which represents an increase of \$6.2 million over the test year level of \$20.8 million and an increase of 30% for the 24-month forecast period or 15% annually. Public's Ex. 2 at p. 43. 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.* at p. 44. Mr. M. Garrett testified 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 that I&M relied on third-party actuarial experts to evaluate and project I&M's future medical costs. He stated that 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. Petitioner's Ex. 40 at p. 62. In addition, he noted I&M relied on third-party experts to inform the medical expense growth rates used to project 2020 medical expenses. *Id.* Mr. Carlin discussed the factors affecting I&M's 2020 medical cost trend, and he concluded I&M'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.* at pp. 63-64.

3. Discussion and Findings. The record shows I&M used data from its actuarial consultants, Willis Towers Watson, to determine the 2019 I&M specific forecast for medical expenses. The 2020 test year forecast was then calculated using a 5.5% medical expense escalation rate. Petitioner's Ex. 40 at p. 63. The record shows the 5% escalation rate Mr. M. Garrett used does not reflect utility industry specific data or take into account plan sponsor specific information, such as participant demographics. The energy and utilities rates in the same survey Mr. M. Garrett relied on were 6.8% and 6.2% for 2018 and 2019, respectively. *Id.* Other factors affecting I&M's 2020 medical cost trend included the saturation of generic drugs that previously helped hold down prescription drug expense increases, relatively fewer patented drugs being eligible for traditional generic competition, and the impact of higher priced specialty drugs, especially biologics. *Id.* Mr. Carlin explained that due to I&M's proactive management of its medical plan design and efficiency to both contain medical cost increases and maximize its value to participants, I&M was comfortable applying a 5.5% escalation rate, rather than the 6.0% rate the survey projected for the energy and utilities sector. *Id.* at pp. 63-64. The Commission finds it is unreasonable to further decrease the escalation rate to reflect non-utility industry data as OUCC witness M. Garrett proposed. Accordingly, the Commission further finds the test year forecast I&M presented for employee medical expenses is reasonable.

#### **E. Employee Adjustment – Full Time Employee.**

1. Industrial Group. Industrial Group witness Gorman recommended I&M's projected Full Time Employee ("FTE") level of 2,305 be reduced to 2,199, i.e., I&M's actual level of FTEs in 2018, because I&M's actual employee headcount has been substantially less than its budgeted level of FTEs over the past several years. Intervenor IG Ex. 3 at pp. 7-8; 31. He stated I&M has consistently had approximately 100 employee budgeted positions that were not filled. *Id.* at p. 48. Mr. Gorman recommended an adjustment to the test year budgeted costs of FTEs to recognize I&M's actual cost of FTEs is expected to be less than its budgeted amount. *Id.* at p. 30. He also 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 of \$4,323,000 and a decrease of \$822,000 in capitalized costs. *Id.* at pp. 8, 30-32; Attachment MPG-6.

2. Rebuttal. 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. Petitioner's Ex. 19 at p. 25. He stated that to the extent I&M has unfilled positions in 2020 there are other components of the forecast, such as contract labor, overtime, or outside services that could

potentially increase to compensate. *Id.* Mr. Lucas 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 when the forecast was prepared and reflect what is reasonably necessary to complete the test year work plans. *Id.*

3. Discussion and Findings. While I&M prepared a comprehensive O&M forecast designed to accomplish the work plans presented in this case, Petitioner's Ex. 18 at pp. 8-13; Petitioner's Ex. 19 at p. 25, its forecast apparently does not take into account the downward trend in I&M's actual FTEs since 2014 or the likelihood of ongoing employee vacancies. The evidence shows I&M's actual versus budgeted FTEs varies significantly. I&M includes 2,305 FTEs in its test year, but a five-year review shows I&M's actual historical headcounts have consistently been less than budgeted, have not been close to 2,305, and are trending downward.

<u>Budgeted vs. Actual FTEs</u>			
<u>Description</u>	<u>Actual</u>	<u>Budgeted</u>	<u>Difference</u>
2014	2,267	2,391	(124)
2015	2,265	2,389	(124)
2016	2,230	2,301	(71)
2017	2,212	2,329	(117)
2018	2,199	2,336	(137)
<u>Five Year Average Under-budgeted FTE</u>			(115)

Intervenor IG Ex. 3 at p. 31. Taking into consideration I&M's use of a future test year, its O&M forecast assumptions must still be reasonable and not ignore I&M's historical FTE vacancy data.

While I&M suggests the forecasted work will still need to be completed, Petitioner's Ex.19 at p. 25, the Commission finds the historical financial data which I&M based its projections on should already have any higher cost of contract labor, overtime, and outside services embedded given the historical level of actual FTEs. Having actual FTEs well below 2,305 is not a new circumstance. Based on the evidence, the Commission finds I&M has overstated its level of actual FTEs in the test year, but we are not persuaded Mr. Gorman's recommendation to reduce I&M's projected FTE level to 2,199 is reasonable because this reflects the lowest level of actual FTEs I&M has experienced over the last five years. Essentially, I&M and the Industrial Group are on opposite ends of the FTE spectrum. The Commission finds that, given the record, it is more appropriate to use the median, i.e. 2,230, as the level of FTEs that will be embedded in I&M's rates. This change results in a decrease in test year O&M expense of \$2,194,317 and a decrease of \$417,280 in capitalized costs.

#### **F. EZ Bill Program.**

1. I&M. Mr. Williamson testified the EZ Bill Program was approved in Cause No. 45114 (December 27, 2018) and is a voluntary billing option designed to allow eligible residential and small commercial customers to be charged a fixed monthly amount for electric service over a 12-month period. Petitioner's Ex. 24 at p. 63. He stated I&M is proposing



EZ Bill Program costs and revenues be accounted for above-the-line because the program is a customer rate offering like any other I&M rate offering. Mr. Williamson noted I&M has just begun to enroll customers in the EZ Bill Program and has not yet received any EZ Bill revenues. *Id.* at p. 65.

2. OUC. Mr. Lantrip recommended the Commission require I&M to treat all EZ Bill Program profits and losses below-the-line. He stated 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. Public's Ex. 5 at p. 12. Mr. Lantrip suggested that in lieu of deciding in this case 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 initial three-year period, review I&M's data to verify program costs and profitability, as well as customer data and participation, and determine whether recovery above-the-line is appropriate in I&M's next rate case. *Id.* at p. 13.

3. Rebuttal. Mr. Williamson testified it is not reasonable to account for program costs and revenues below-the-line. He stated the EZ Bill program is one of several customer programs I&M provides, and the costs of offering these programs are part of I&M's overall cost of serving its customers. Petitioner's Ex. 25 at p. 51. He stated since the program will be offered to a large number of customers, it is reasonable that program costs be viewed as a cost of providing service for all customers and not just those who participate. *Id.* at p. 54. Mr. Williamson testified the preliminary status of the program is not cause for disallowance of these program costs, *Id.* at p. 52, and the OUC's "wait-and-see" approach indicates the OUC's recommendation is outcome based, not principle based. *Id.* at p. 55.

4. Discussion and Findings. Initially, the Commission notes I&M is not proposing to include any costs or revenues associated with the EZ Bill Program in its revenue requirement in this Cause. Mr. Williamson recognized the preliminary status of the EZ Bill Program and that I&M does not yet have actual data on program profits and losses. Petitioner's Ex. 24 at pp. 65-66. Rather, I&M is requesting regulatory accounting treatment to treat program costs and revenues as a component of I&M's cost of service in subsequent rate proceedings. *Id.* at p. 66.

The evidence shows the EZ Bill Program is the newest of the budget billing programs I&M offers its customers. It is too early to know the extent to which customers will participate or whether this program may be perceived as duplicative of existing alternatives. The Commission finds the accounting treatment of I&M's EZ Bill Program is better addressed after sufficient data is available to review and verify actual program costs and profitability, as well as customer participation. At this time, I&M is unable to provide financial information due to the newness of this initiative. The Commission finds it prudent to wait to know and verify the EZ Bill Program costs before approving their recovery above-the-line. We, therefore, decline to determine the appropriate treatment in this Cause of these costs.

**G. Factoring Expense.**

1. OUCC. Mr. Mark Garrett explained that I&M and another AEP affiliate, AEP Credit, Inc., maintain a contractual arrangement whereby AEP Credit purchases, without recourse, certain accounts receivable arising from the sale and delivery of electricity in Indiana. Public's Ex. 2 at p. 54. He testified the process of one company selling its accounts receivable, usually at a discount, to a third-party purchaser is called factoring, and this process gives rise to factoring expense. *Id.* Mr. M. Garrett stated I&M included \$9.701 million in factoring expense in the 2020 forecasted test year, of which \$7.825 million is assigned to the Indiana jurisdiction based upon the receivables I&M sells. *Id.* Mr. M. Garrett compared I&M's forecast against its actual factoring expense for years 2016 through 2018, and he found I&M's three-year average factoring expense is \$7.632 million. He recommended I&M's forecasted factoring expense be reduced to reflect the most recent three-year average. Mr. M. Garrett testified that all indications are interest rates will be lower in the rate effective period as the Federal Reserve cut interest rates by 25 basis points on July 31, 2019, and further cuts are expected; thus, I&M's requested level of factoring expense is overstated. *Id.* at pp. 54-55. Using the three-year average expense, he recommended I&M's factoring expense be reduced by \$1,668,892. *Id.* at p. 55.

2. Rebuttal. Mr. Lucas testified the test year factoring expense forecast is based on reasonable assumptions at the point in time the forecast was prepared. Petitioner's Ex. 19 at p. 23. He stated 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 three-year average of historical data as Mr. M. Garrett proposes. Mr. Lucas testified that contrary to Mr. M. Garrett's assumptions, recent trends in I&M's factoring expense show the amount included in the test year may be understated. From his perspective, this corroborates the test year level is reasonable, and no adjustment should be made. *Id.* at pp. 24-25.

3. Discussion and Findings. I&M's factoring expense includes four primary components: bad debt expense, agency fees, carrying cost, and bank fee expense. Petitioner's Ex. 19 at p. 23. The OUC identified a recent decline in one component but did not take into account other trends that also impact factoring expense. For example, the amount of I&M's bad debt expense from January through July of 2019 increased by 23% as compared to the same period in 2018. *Id.* at p. 24. The record also shows I&M's factoring expense for the period from August 2018 through July 2019 was \$10.6 million (total Company) which exceeds the \$9.7 million reflected in the test year. *Id.* Accordingly, the Commission finds I&M's test year forecasted level of factoring expense is reasonable.

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

1. I&M. Mr. Lehman discussed I&M's proposed three-year pilot program to encourage plug-in electric vehicle ("PEV") adoption in a way that optimizes the overall electric system. Petitioner's Ex. 16 at pp. 7-8. The proposed program, *IM Plugged In*, includes 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. *Id.* at p. 3. Mr. Lehman described the need for the pilot and identified prospective benefits to participants and I&M's other customers. *Id.* at pp. 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. Petitioner's Ex. 24 at p. 59. Instead, he testified 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.* Mr. Williamson explained I&M's 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 weighted average cost of capital ("WACC") rate approved by the Commission in this proceeding. *Id.*

2. OUCC. Ms. Aguilar raised concerns regarding I&M's proposal to use ratepayer funds to provide customer rebates to offset the 240 volt charging equipment cost. Public's Ex. 10 at pp. 16-20. She stated I&M's witness Lehman made numerous claims about optimizing unused off-peak system capacity, but I&M provided no empirical data other than opinions to support the program's benefits. Ms. Aguilar highlighted I&M's discovery responses which she testified assert that the program benefits identified are "based on Mr. Lehman's general industry experience and knowledge, and not specific documentation or analysis." *Id.* at p. 17. Ms. Aguilar also expressed concern with I&M's lack of a robust cost-benefit analysis. To derive the net benefit of \$108, she testified I&M made crude assumptions about how many miles will be driven by a customer and how often a customer will utilize off-peak charging. *Id.* at p. 18. Given the reduced off-peak rate to be offered to pilot participants, Ms. Aguilar questioned whether a rebate for the 240 volt charging equipment is needed. Ms. Aguilar testified the OUCC recommends the Commission deny I&M's requested recovery of the proposed 240 volt circuit rebate. *Id.* at p. 21.

3. South Bend. South Bend witness Dorau agreed the *IM Plugged In* program is sensible and helps overcome barriers to individual PEV adoption while avoiding potential negative impacts to the shared grid. Intervenor South Bend Ex. 1 at p. 16. She commended this encouragement and expansion of electric vehicles. *Id.*

4. Rebuttal. On rebuttal, Mr. Lehman clarified that I&M is not proposing the incentive because 240 volt charging is a barrier to electric vehicle adoption. Petitioner's Ex. 17 at p. 5. He testified many PEV owners can support their daily driving through 120 volt charging; however, 240 volt charging is necessary for customers to have the ability to easily shift their entire charging load to off-peak times. *Id.* He stated the number of hours necessary to charge a PEV is significantly reduced when using 240 volt charging as opposed to 120 volt charging, and this is why I&M is proposing to provide an incentive for customers to install 240 volt charging equipment – so they can take advantage of the proposed off-peak charging rate and shift their PEV charging to off-peak times. *Id.* Mr. Lehman testified 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. *Id.* at p. 2. He stated one reason I&M proposed implementing 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 Findings. The record shows PEV adoption is accelerating, and with this acceleration, it is important the load from electric transportation be integrated into the grid in a manner that minimizes or eliminates additional system costs. Petitioner's Ex. 16 at pp. 4-7. The Commission recognizes that as the electric vehicle market matures in Indiana, electric providers will need to implement strategies, such as leveraging smart meter data, to manage the integration of widespread charging on the system. Thus, structuring well designed, right sized, pilot programs to advance utilities' knowledge and ability to successfully adapt is appropriate.

In this instance, I&M's pilot is relatively modest in size and reasonably focused on the highest value applications for customers and on grid optimization. Petitioner's Ex. 17 at p. 11. The *IM Plugged In* pilot, with the additional information to be reported per our discussion below, will gather information to inform future PEV program offerings. While Ms. Aguilar asserted I&M lacked empirical data to support the pilot, we note that I&M used Indiana-specific census information, data from PEV charging studies, and other reasonable assumptions to estimate the benefit of the program to non-participants. Petitioner's Ex. 17 at pp. 2-4. That estimate shows each residential and small commercial participant is expected, on average, to provide net benefits of \$579 to all I&M customers over a 10-year period. Petitioner's Ex. 16 at p. 17. The Commission is, nonetheless, concerned with certain design elements of the *IM Plugged In* pilot because program costs will be sustained by all ratepayers and not just those receiving the direct benefit of participation in the PEV program. Ideally, such programs should be designed without or with minimal impact to nonparticipating ratepayers.

Based on the evidence, the Commission finds the *IM Plugged In* pilot program is reasonable given its modest size coupled with the opportunity it presents for I&M to enhance its understanding and management of the impact of electric vehicle charging on its distribution system, thereby benefitting all I&M customers. Mr. Lehman testified I&M is amenable to adjusting the terms of the program to allow existing PEV owners who have not yet installed 240 volt charging equipment at their parking location to also be eligible to receive the incentive under the program. Petitioner's Ex. 17 at p. 8. The Commission finds this modification is appropriate and consistent with the program's intent. Also, the Commission is concerned about excluding distributed generation or net-metered customers from the pilot, but we understand the limitations of I&M's billing system at this time. I&M should, however, further explore the feasibility of their future inclusion.

In implementing this pilot, I&M is encouraged to evaluate and improve its program plans for educating customers on the benefits of off-peak charging. The Commission also approves I&M's request for deferral accounting authority related to the *IM Plugged In* program, including carrying costs on the unrecovered balance using the pre-tax WACC. In approving this pilot, I&M is directed, in advance of its launch, to identify and define measurable metrics that will be used to determine the success of each pilot subset and, ultimately, enable the overall

benefits for I&M's customers to be evaluated. These metrics shall be filed under this Cause number as a compliance filing at least 30 days in advance of I&M initiating the pilot. The Commission further finds it is crucial I&M harvest and report, at a minimum, not only the information I&M proposed to collect, but all the following information and file a compliance report under this Cause number semi-annually, commencing on or before January 15, 2021, and continuing for the duration of this pilot:

- number of participants enrolled, by pilot subset;
- aggregated participant on-peak PEV usage (kWh);
- aggregated participant off-peak PEV usage (kWh);
- identify what time pilot participants are charging and the average duration for the (a) residential and the (b) small business customer subsets;
- number of incentives by pilot subset;
- number of customers choosing a five-year revenue credit by pilot subset;
- for each pilot subset, identify and report whether the rebate and/or revenue credit influenced the customer's (a) PEV decision and (b) decision to participate in the pilot program;
- expenditures and cumulative expenditures by pilot subset;
- the amount/level of interest I&M receives in siting EV site installations at (a) multi-unit dwellings and at (b) workplaces; and
- such other pilot related information as the Commission's Energy Division may request in writing to prospectively evaluate transportation electrification and/or develop best practices.

Ultimately, if I&M seeks to offer the *IM Plugged In* program or an iteration thereof more permanently, the Commission encourages I&M to explore innovative rate design proposals with respect to PEV charging, integrating the information gleaned from this pilot.

## **I. Incentive Compensation.**

1. OUCC. Mr. Mark Garrett testified on the OUCC's behalf with respect to I&M's short-term and long-term incentive compensation plans, noting I&M included copies of the incentive plans in its MSFR submission. Mr. M. Garrett provided a brief overview of I&M's incentive plans which he stated are heavily dependent on financial performance measures. Public's Ex. 2 at p. 7.

Mr. M. Garrett recommended two adjustments in connection with the ratemaking treatment of I&M's incentive compensation plan costs: (1) the costs should be adjusted to target levels (which was proposed by I&M) and (2) the target-level costs should then be allocated 50/50 between ratepayers and shareholders. Public's Ex. 2 at pp. 29-30. Mr. M. Garrett testified this allocation is appropriate because of the specific metrics of I&M's annual short-term plan. He testified the plan has an earnings-per-share ("EPS") trigger (minimum threshold) below which no incentive payments will be made. Second, the plan has an EPS funding mechanism that provides for increased levels of funding for employee incentives based on AEP's achievement of higher earnings levels. *Id.* at pp. 7-8. Mr. M. Garrett stated AEP's funding is tied to EPS (70% weight), safety and compliance (10% weight), and strategic initiatives (20% weight). *Id.* at p. 11. He

opined 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, Mr. M. Garrett stated I&M's "strategic initiatives" category contains a combination of operational and financially-based performance measures. *Id.* at p. 11. He testified financial performance metrics benefit shareholders more than ratepayers; therefore, the Commission could allocate 79% of the plan to shareholders – based on a 70% EPS metric and 9% infrastructure investment metric. *Id.* at p. 11.

Mr. M. Garrett testified AEP's plan also has other problems. As shown in the MSFR I&M filed, he testified the plan is structured to benefit highly-compensated senior level employees more than the rank and file employees. Public's Ex. 2 at p. 10. He stated employees who are decision makers, i.e., in higher 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 limited incentive opportunities. *Id.* at pp. 10-11.

Mr. M. Garrett testified he applied the following Commission standards for recovery of incentive compensation and his recommendations adhere to the Commission's criteria for recovery in rates: (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.* at pp. 14-15. Mr. M. Garrett testified his recommendations with respect to I&M's plan are consistent with how AEP's incentive plan has been treated in other jurisdictions, including Texas and Oklahoma. *Id.* at pp. 17-19. He also testified an incentive survey of western states shows 19 of 24 western states disallow financial-based incentives. Mr. M. Garrett represented that with respect to the other five states in the survey, one state disallows all incentives; two states use some other sharing approach; and in two states incentive pay is not an issue. *Id.* at p. 20. With respect to the treatment of incentives in some of the states closer to Indiana, he testified Illinois, Michigan, Kentucky, and Wisconsin generally disallow incentive compensation based on financial incentives, *Id.* at pp. 22-23, which means I&M will not be at a competitive disadvantage for talent if 50% of its target level (market level) incentive compensation is allocated to shareholders. *Id.* at p. 27.

Mr. M. Garrett provided multiple rationale as to why financial based incentive compensation is disfavored among many regulators, including 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.* at pp. 24-26. Mr. M. 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.* at p. 24.

Mr. M. Garrett also proposed disallowing in its entirety I&M's long-term incentive plan ("LTIP") for executives and managers. Public's Ex. 2 at p. 30. He cited the disallowance of LTIP

in Indiana American's rate case in Cause No. 44022 and orders from other states. *Id.* at pp. 32-36. Mr. M. Garrett testified that long-term incentives, especially stock-based incentives such as AEP's, are financially-based and should be disallowed for all of the reasons set forth above. *Id.* at p. 31. According to Mr. M. Garrett, incentive compensation payments to officers, executives, and key utility employees such as the long-term incentive payments, are generally excluded for ratemaking purposes. Mr. M. Garrett testified the LTIP is designed to tie compensation to the Company's financial performance to further align the employee's interest with those of shareholders. *Id.* at 31.

Mr. M. Garrett stated this intentional alignment of employee and shareholder interests means the costs of these plans should be borne by I&M's shareholders. *Id.* at p. 32. He testified it would be inappropriate to require ratepayers to bear the costs of incentive plans designed to encourage employees to put shareholders' interests first. *Id.* at p. 32. Mr. M. Garrett recommended adjustments to reduce the short-term incentive plan expenses by \$9,022,802 and the LTIP expenses by \$6,980,198.

2. Industrial Group. On behalf of the Industrial Group, Mr. Gorman testified against including portions of I&M's incentive plan in its revenue requirement. Mr. Gorman stated incentive compensation programs designed to align the interests of executives with shareholders should be paid for by shareholders, not by customers through rates; however, he stated to the extent incentive compensation reflects customer direct goals, then the costs of those programs can be incurred by ratepayers, depending upon whether the performance metrics are met. Mr. Gorman recommended disallowing all compensation relating to the LTIP and the 70% portion of the Annual Incentive Compensation Plan ("ICP") which is based on financial goals. Intervenor Industrial Group Ex. 3 at p. 29. Mr. Gorman testified this proposed disallowance would remove \$19 million from I&M's cost of service. *Id.*

3. Rebuttal. Petitioner's witness Carlin testified in rebuttal to the proposed incentive pay disallowances. He testified Mr. M. Garrett disregarded that the Commission has allowed recovery for more than 20 years of incentive pay, including I&M's incentive compensation (albeit via a settlement). Petitioner's Ex. 40 at pp. 2-3. He noted the recovery of incentive pay dates back to *Public Service Indiana*, Cause No. 40003 (IURC September 27, 1996). He testified the presence of a financial metric trigger has previously been rejected by the Commission as a reason to disallow recovery of incentive pay, citing *Indiana American Water Co.*, Cause No. 42029, (IURC November 6, 2002), wherein Indiana American had an earnings per share "gatekeeper" similar to the trigger I&M used. Petitioner's Ex. 40 at p. 8. Mr. Carlin provided the various factors that go into the calculation of incentive pay, and he testified both Mr. Garrett and Mr. Gorman overstated the portion made up by financial performance. Per Mr. Carlin, only 40% of the total annual incentive plan award is related to financial performance. *Id.* at p. 10. He testified the primary measures are non-financial operating measures. *Id.* Mr. Carlin disputed Mr. Garrett's testimony that operational portions are also tied to financial metrics. He testified the transmission construction measurement is tied to completing approved projects expeditiously and under budget and not to the selection of projects to complete. *Id.* at p. 24.

Mr. Carlin corrected Mr. Garrett's recitation of the Commission's standard. While Mr. Garrett stated it is whether incentive compensation is reasonably necessary to attract a talented

workforce, Mr. Carlin stated 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.* at p. 11. Mr. Carlin stated the significance of this distinction is that the Commission does not look at incentive pay in isolation, but rather, looks at total compensation and asks whether total compensation is greater than reasonably needed to attract a talented workforce, *Id.* at p. 12, citing *Indiana American Water Co.*, Cause No. 43680 (IURC April 30, 2010) as support for this position. Mr. Carlin 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 below the median if the incentive compensation were not provided. *Id.* at pp. 13-14. Mr. Carlin also testified the incentive compensation opportunity I&M provides employees is necessary to maintain the competitiveness of I&M's total compensation, and this package, in total, is a reasonable cost of doing business that, practically speaking, cannot be eliminated without a corresponding base pay increase. He stated I&M's incentive compensation is not a "bonus" on top of already market-competitive compensation. Petitioner's Ex. 40 at p. 14.

Mr. Carlin, in responding to Mr. Garrett's reliance upon the 15% allocation to shareholders in *Indiana American* (Cause No. 44022), testified 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.* at pp. 18-19. With respect to the earnings per share trigger, Mr. Carlin testified it is set at a low level that is readily achievable and is only intended to protect against particularly difficult financial circumstances. *Id.* at p. 22. He then responded to Mr. Garrett's survey of other states. *Id.* at pp. 25-30.

With respect to Petitioner's LTIP, Mr. Carlin explained LTIP is available to 1,150 employees. He stated 75% of the LTIP award is based upon financial performance, but 25% consists of restricted stock units. Mr. Carlin testified the restricted stock units are provided as a retention goal and do not have any metrics, goals, or measures. *Id.* at pp. 48-49, 51.

4. Discussion and Findings. "The Commission has long recognized the value of incentive compensation plans as part of an overall compensation package to attract and retain qualified personnel." *Northern Ind. Pub. Serv. Co.*, Cause No. 43526, p. 63, 2010 WL 3444546, 284 P.U.R.4th 369 (IURC August 25, 2010); *see Indiana-American Water Co.*, Cause No. 44022, p. 66, 2012 WL 2154248 (IURC June 6, 2012); *Southern Ind. Gas & Elec. Co.*, Cause No. 43839, p. 50, 2011 WL 1690057, 289 P.U.R.4th 9 (IURC April 27, 2011); *Indiana-American Water Co.*, Cause No. 43680, p. 74, 2010 WL 1806474 (IURC April 30, 2010); *PSI Energy, Inc.*, Cause No. 42359, p. 89, 2004 WL 1493966, 234 P.U.R.4th 1 (IURC May 18, 2004); *Indiana-American Water Co.*, Cause No. 42029, p. 45, 2002 WL 32091039 (IURC November 6, 2002), and *PSI Energy, Inc.*, Cause No. 40003, p. 56, 1996 WL 767535, 173 P.U.R.4th 393 (IURC September 27, 1996). There are also numerous other orders where recovery of incentive pay has been authorized through settlement agreements or where the recovery was not opposed. *See Indiana-American Water Co.*, Cause No. 45142, 2019 WL 2903633, 352 P.U.R.4th 402 (IURC June 26, 2019); *Northern Ind. Pub. Serv. Co.*, Cause No. 44688, 2016 WL 3996436 (IURC July 18, 2016); *Indianapolis Power & Light Co.*, Cause Nos. 44576 & 44602, 2016 WL 1118795, 329 P.U.R.4th 486 (IURC March 10, 2016); *Southern Ind. Gas & Elec. Co.*, Cause No. 43112, 2007 WL 8420645 (IURC August 1, 2007). While Mr. M.



Garrett provided a lengthy discussion of decisions from regulatory commissions in other states, the Commission finds it more valuable to rely upon our own analyses and long-held standard.

The recovery of incentive compensation through rates dates at least back to *PSI*, Cause No. 40003, with the initial pronouncement of the Commission's standard for recovery found in *Indiana American*, Cause No. 42029. There, the Commission reviewed *PSI* and distinguished it from the order in *Indiana Natural Gas*, Cause No. 40382, 1996 WL 34604585 (IURC February 29, 1996), issued one week earlier wherein the Commission had addressed recovery of a profit sharing plan. In distinguishing these two cases, the Commission stated:

Two things can be taken from these orders: (1) a pure profit-sharing plan which only incents employees to become more profitable may be more appropriate for funding solely by the shareholders than a plan which also ties compensation levels to better service to the customers; and (2) a plan which causes compensation to exceed levels which are reasonably necessary for the utility to attract its workforce should be disallowed as an unnecessary expense.

*Indiana American*, Cause No. 42029, p. 45.

Indiana American's plan consisted of three components: gatekeepers, performance goals, and individual multipliers: "First, the AIP contains a gatekeeping component that ensures that AIP payments are made only when two targets are met: A minimum earnings per share ('EPS') of American and the attainment of individual performance expectations of the participating company and the employee." *Id.* at p. 43. If the gatekeepers were met, the plan consisted of two performance goals: financial performance goals and operational goals. *Id.* The Commission allowed full recovery applying the new test announced.

In the next *PSI* rate order, Cause No. 42359, the Commission confirmed the third component of the test: "shareholders are allocated part of the cost of the incentive compensation programs." *Id.* at p. 89. This three-part test has been consistently applied since, and the Commission finds it is appropriate to again apply this test in evaluating the objections to I&M's recovery.

Based on Mr. Carlin's testimony, the Commission finds I&M's plan incorporates operational as well as financial performance goals and is not a pure profit sharing plan. Mr. Garrett's objection to the presence of a financial "trigger" overlooks that there was a financial trigger or "gatekeeper" tied to parent company earnings per share in our order authorizing recovery of Indiana American's incentive compensation in Cause No. 42029. As to the suggestion of Mr. M. Garrett and Mr. Gorman that the Commission should exclude from recovery the portion of incentive compensation that is related to financial metrics, this has not been the standard, and it is an argument the Commission has specifically rejected. *NIPSCO*, Cause No. 43526, p. 63 and *SIGECO*, Cause No. 43839, p. 50. The fact that there are financial metrics in an incentive compensation plan does not make it a pure profit sharing plan, and the Commission has historically not been receptive to excluding recovery of those portions of the plan that are tied to financial metrics.

The second element of the Commission's standard is whether the plan "causes compensation to exceed levels which are reasonably necessary for the utility to attract its workforce." We concur with Mr. Carlin that Mr. M. Garrett has misquoted this standard. The question is not whether incentive compensation, by itself and in isolation, is necessary to attract the workforce; the question is whether the entire compensation package (including the incentive compensation plan) produces compensation levels that are excessive. This should have been clear from our orders in *NIPSCO*, Cause No. 43526, *Indiana American*, Cause No. 43680, and *SIGECO*, Cause No. 43839. No one claims I&M's total compensation levels are excessive, and Mr. Carlin's presentation of the salary bands in comparison to the medians confirms total compensation is not excessive. Petitioner's Ex. 40 at pp. 13-15.

The next issue is the portion of incentive compensation to be assigned to shareholders. I&M's evidence is that only the target level of incentive compensation is included in its revenue requirement, and all incentive compensation in excess of target is effectively allocated to shareholders. Petitioner's Ex. 40 at p. 17. A five-year history of incentive compensation payouts was provided. This showed the five-year average payout was more than 150% of target and had been as high as 191% of target. *Id.* at p. 18 (revised). These facts align with the facts in *SIGECO* and are readily distinguishable from the facts presented in *Indiana-American*, Cause No. 44022. There, *Indiana American's* historic payout averaged 100.33% of the target proposed to be included in rates such that only 0.33% of the historic average was being allocated to shareholders. In *Indiana American*, the Commission distinguished those facts from *SIGECO* and noted: "However, in that case [*SIGECO*], the evidence demonstrated that the petitioner's average payout had exceeded target by as much as 190% over the past ten years, and that shareholders absorbed the cost of incentive compensation that exceeded the target level." *Indiana American* (IURC June 6, 2012), Cause No. 44022, p. 66; Petitioner's Ex. 40 at p. 19. In the instant case, the portion of incentive compensation that is allocated to shareholders is all payments in excess of target, which the Commission finds is appropriate.

The final issue raised is with respect to recovery of LTIP. This was described by Mr. M. Garrett as incentive compensation for executives, but the evidence shows otherwise. More than 1,100 employees received LTIP. Moreover, while the portion of LTIP tied to financial metrics is greater than the portion tied to short-term incentive compensation, neither Mr. Garrett nor Mr. Gorman made mention of the remaining portion, the restricted stock units that are intended to encourage retention. The LTIP the Commission rejected in Cause No. 44022 was reserved for high-level management positions at *Indiana American*. That is not the case here; consequently, the Commission finds it is recoverable as we did in *SIGECO* and *PSI*. Accordingly, the Commission declines to approve the OUCC and Industrial Group's proposed adjustments to short-term and long-term incentive pay.

## **J. Pension Expense.**

1. OUCC. OUCC witness Mark Garrett testified that I&M did not include the return on pension benefit plan assets in its calculation of pension expense for ratemaking purposes. He stated that as a result, I&M had included test year employee benefits expense of \$39.5 million. Public's Ex. 2 at pp. 41-42. Mr. M. Garrett based this on his review of MSFR 1-5-8(a)(13). He ultimately proposed to reduce I&M's test year pension expense on a jurisdictional basis by \$15,496,003. At the evidentiary hearing, in response to cross-examination,

Mr. M. Garrett testified if there was a discrepancy between I&M's filed MSFR 1-5-8(a)(13) Projected and the amount I&M actually used to set rates, that difference should have been corrected in I&M's rebuttal testimony. Tr. p. K-59, lines 19-25.

2. Rebuttal. Mr. Ross testified that I&M's contributions to the pension fund in excess of pension expense lower pension expense and result in lower customer rates. Petitioner's Ex. 23 at p. 11. He was asked on redirect about a cross-examination exhibit and testified the return on the pension fund is included as an offset to the revenue requirement in the cost of service. Mr. Ross 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. pp. I-65-66.

3. Discussion and Findings. Based on Mr. Ross' testimony, the apparent confusion in this case over pension expense results from a recent Financial Accounting Standards update changing how pension expense is reported for GAAP purposes. While I&M could have better brought to light this change, that does not alter the impact of FASB Update No. 2017-07 which, according to Mr. Ross, requires the service cost component of pension expense to be reported in the same line item or items as other compensation costs, with other components of pension expense (*i.e.*, "non-service costs," which would include return on pension plan assets) reported separately from the service cost and outside a subtotal of income from operations. Petitioner's Cross Ex. Exhibits 3, 2; Tr. pp. K-18-19; K-21-23. This change is reflected in Petitioner's income statement Exhibit A-4, where employee benefits (\$25,796,466) and pension plan (\$13,721,467) are shown as a component of O&M expense on page 8 and the non-service cost components (including return on plan assets) is reported as non-operating income (\$20,226,564) on page 10. The MSFR upon which Mr. M. Garrett relied for purposes of his proposed adjustment requests the pension expense included in O&M, and it sets forth the service cost component as the amount to be charged to O&M expense, consistent with the new accounting standard. Pet. Cross Ex. 2. The MSFR does not request the amount of pension expense included in the revenue requirement.

The OUCC inquired in discovery about this MSFR, and I&M responded, in part, "The non-service benefits amount of (\$20,226,564) represents a reduction to O&M for the non-service components primarily of pension, supplemental pension and OPEB." Pet. Cross Ex. 4. The attachment provided with this response shows \$20,226,564 of non-operating income reported as non-service costs was a reduction to the \$25,796,466 in employee benefits and \$13,721,467 in pension benefits representing the service cost component, producing a net total of \$19,291,369. The workpapers showing the calculation of Petitioner's revenue requirement were admitted as Petitioner's Cross Ex. Exhibit 5. This is the Excel version of Petitioner's Net Operating Income Statement Adjusted for Ratemaking Purposes. This exhibit confirms that net employee pension and benefits included in the revenue requirement total \$19,291,369, which is the amount of total employee benefits and pension expense net of the non-service component of pension costs. *Id.*, Tab – "Adjustments", Cell F-152.

The Commission finds Indiana customers' rates should reflect the non-service cost components of pension expense notwithstanding the new financial accounting standard update requiring them to be reported outside of operating income. Petitioner's proposed revenue

requirement does include the non-service cost component; consequently, the Commission finds Mr. M. Garrett's proposed adjustment is not appropriate.

**K. Major Storm Expense and Major Storm Reserve.**

1. I&M. Mr. Williamson testified that I&M seeks to continue the Major Storm Damage Restoration Reserve as approved in Cause Nos. 44075 and 44967. Petitioner's Ex. 24 at pp. 6, 58. Messrs. Williamson and Isaacson testified 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. *Id.* at p. 58; Petitioner's Ex. 37 at p. 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. Petitioner's Ex. 24 at p. 58; Petitioner's Ex. 37 at p. 41. Mr. Isaacson testified the Major Storm Reserve helps I&M maintain the reliability of its distribution system and ensures I&M's customers pay rates that reflect the true costs of a major storm – no more and no less. Petitioner's Ex. 37 at p. 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. Public's Ex. 8 at pp. 18-19, 38.

3. Rebuttal. Mr. Williamson testified I&M is agreeable to the OUCC's proposal with one modification. He stated if historical dollars are used to determine a future cost, inflation must be considered. Petitioner's Ex. 25 at p. 63. He applied the Gross Domestic Product as a general measure of inflation and recommended the Commission use \$2,675,000 as the distribution major storm reserve baseline. *Id.* at pp. 63-64.

4. Discussion and Findings. 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 I&M's control. Petitioner's Ex. 24 at p. 58; Petitioner's Ex. 37 at pp. 39-41. No party opposed continuation of the Major Storm Reserve, and the Commission finds it to be a reasonable approach to addressing these significant, variable costs. Accordingly, the Commission approves the continuation of the Major Storm Expense Reserve, and we 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 2014-2018. The Commission is not persuaded it is necessary to modify this methodology by adjusting 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. I&M is granted 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 \$2 million level. Petitioner's Ex. 6 at p. 2. He discussed the estimation of future decommissioning costs Mr. Knight presented, the rules and guidelines for determining adequate funding levels, and his Monte Carlo methodology

for determining an appropriate funding level. *Id.* at pp. 3-23. Mr. Hill stated his modeling shows that at an annual funding level of \$10 million, the probability of having sufficient decommissioning funds is approximately 90%. *Id.* at p. 23. He testified it is important to increase the funding level now, when there is time to gradually protect against a future shortfall, rather than risk that Indiana retail customers will need to significantly increase this annual funding late in the Cook Plant's life. *Id.* at pp. 23-24. Mr. Hill testified I&M will continue to report to the Commission every three years on the adequacy of the existing provision, however, and I&M may in the future recommend adjusting the level of decommissioning fund contributions. *Id.* at p. 25.

Mr. Hill stated the spent nuclear fuel trust is adequately funded at the present time, and the fund does not appear to be in danger of becoming under-funded in the near future. Petitioner's Ex. 6 at p. 30. He 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 be permitted to be invested pursuant to the investment guidelines currently in place for the Indiana Nuclear Decommissioning Trust. *Id.* at pp. 31-32. Mr. Hill testified that 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.* at pp. 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. Public's Ex. 1 at p. 13. Mr. Eckert testified the liquidated value of the Indiana portion of the estimated Nuclear DTF at December 31, 2037, and the Nuclear Regulatory Commission's ("NRC") estimate in its 2017 Decommissioning Funding Status Report show there will be sufficient funds available as of December 31, 2037, to support discontinuing Indiana ratepayers' annual contribution to the Nuclear DTF in this case. *Id.* at p. 12. Based upon Mr. Eckert's Attachment MDE-5, I&M's Nuclear DTF value has increased by at least 7.73% over the last 6.5 years. *Id.* at p. 11. Specifically, since December 31, 2012, Mr. Eckert reflected I&M's Nuclear DTF has increased by approximately \$1 billion and approximately \$510 million since December 31, 2016. Public's Ex. 1, Attachment MDE-5. Mr. Eckert's Attachment MDE-4 summarizes the NRC's staff's findings upon the 2017 decommissioning funding status. Mr. Eckert testified I&M's compliance with the NRC minimum funding requirements and his review of the market value of the DTF support his recommendation to discontinue DTF funding. *Id.* at pp. 9-13.

3. Intervenors. Industrial Group witness Gorman and Joint Municipal Group witness Cannady both recommended annual funding remain at \$2 million. Intervenor IG Ex. 3 at p. 23; Jt. Municipal Ex. 2 at p. 4. Mr. Gorman stated the forecasted value of trust fund assets, using I&M's Monte Carlo modeling but assuming more reasonable modeling assumptions, is adequate. Intervenor IG Ex. 3 at p. 24. He testified I&M ignored significant contingencies and risk mitigation factors that support the trust fund's ability to fully pay the cost of decommissioning. *Id.* Mr. Gorman stated I&M'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, and this recurring review of the actual

performance of the trust fund relative to projections mitigates the risk the fund will not grow to be adequate to pay decommissioning cost at retirement. *Id.* at p. 24. Mr. Gorman testified I&M also 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. He testified I&M's projected asset returns are very low compared to historical actual returns on the security investments. *Id.* at p. 22. He testified that if I&M'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%, I&M's statistical model utilizing its other assumptions increases the probability of successfully funding the trust to 88%. *Id.* at p. 23. Mr. Gorman testified these conservative return projections mitigate the risk that actual returns will be less than projected returns, and this risk mitigation reduces the risk the trust fund will be inadequate to fully fund the decommissioning cost. *Id.* at p. 24.

Mr. Gorman also commented on I&M's proposed new methodology employing a Monte Carlo statistical method of estimating annual returns on trust fund assets based on varying levels of actual achieved trust fund earnings. Intervenor IG Ex. 3 at pp.17-20. While Mr. Gorman did not dispute that annual returns on trust fund assets can vary, he observed that I&M did not symmetrically consider variations in annual returns, with a symmetrical outlook that decommissioning escalation costs will also vary. Mr. Gorman testified basic economic inflation will impact both the earned return on trust fund assets and the nuclear decommissioning costs escalation. He stated if inflation is up, returns on trust fund assets will increase as will escalation and decommissioning costs, with the reverse also being true. Mr. Gorman reran the Monte Carlo method, assuming both variations in annual returns and annual variations in inflation escalation. His revised statistical model demonstrated variation in trust fund earnings is offset by variation in cost escalation. Based on these sensitivity runs, Mr. Gorman found a \$2 million annual contribution to the nuclear trust fund assets, with variations in annual returns and inflation outlooks, creates a high probability the nuclear trust funding will cover the decommissioning costs prior to actual decommissioning of the Cook Nuclear Plant. *Id.* at pp. 19-24.

Ms. Cannady testified the current balance meets NRC requirements, and the Monte Carlo simulation results from I&M show scenarios using \$2 million per year provide over 84% probability the fund will be fully funded by the time decommissioning begins. Jt. Municipal Ex. 2 at p. 21. She questioned the reasonableness of the increased cost components reflected in the decommissioning cost estimate. *Id.* at pp. 21-26. Ms. Cannady testified the decommissioning studies were developed with the assumption that Unit 1 at the Cook Nuclear Plant will be retired in 2034, and Unit 2 will be retired in 2037; therefore, the decommissioning studies assume decommissioning funds will start being needed in 2034 and continue through 2100, but there is a possibility the Cook operating licenses could be extended. *Id.* at pp. 28-29.

4. Rebuttal. Mr. Hill stated Mr. Eckert's estimated decommissioning cost incorrectly excludes on-going spent fuel storage costs and stated Mr. Eckert's reference to the NRC minimum value excludes removal and disposal of spent fuel and the removal of clean structures. Petitioner's Ex. 7 at pp. 2-3. He disagreed that compliance with NRC minimum funding assurance requirements guarantees I&M will have sufficient funds at the end of the Cook Plant's life to successfully decommission the plant. *Id.* at pp. 3-4. Mr. Hill also responded to Mr. Gorman's testimony against increasing nuclear decommissioning contributions, and he defended the reasonableness of his Monte Carlo modeling. *Id.* at pp. 8-13.

5. Discussion and Findings. The purpose of funding the nuclear decommissioning trust is to ensure 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. Petitioner's Ex. 6 at p. 3. The nuclear decommissioning expense is included in the revenue requirement to allocate the cost of decommissioning the Cook 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, the regulatory objective will have been accomplished and generational inequity avoided; if funds are inadequate, then future customers will pay higher rates to recover these costs. 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.

The parties disagreed over the appropriate annual funding level of the trust. The testimony showed I&M is in compliance with the NRC minimum funding requirement, although the Commission recognizes the NRC's funding requirements "are not intended to be used by themselves or by other agencies to establish rates." Petitioner's Ex. 7 at p. 4; 10 C.F.R. § 50.75. I&M claims both Mr. Eckert and Ms. Cannady assume riskless investment return and ignore necessary decommissioning costs that are not captured in the NRC minimum requirement and that Mr. Gorman, while using I&M's Monte Carlo model, manipulated the assumptions in ways that are all favorable to his arguments. Petitioner's Ex. 7 at pp. 5-8. We note, however, that I&M's requested 400% increase in the decommissioning fund expense only produces an increased probability of funding from 85% to 90% based on Mr. Hill's projections. I&M admitted to running various Monte Carlo scenarios between the current \$2 million funding level and the \$8 million increase I&M proposes, Tr. pp. C-85-88, but I&M inexplicably presented none of these alternate scenarios, Tr. pp. C-85-88, sharing with the Commission only the \$10 million funding level analysis.

What is in evidence shows I&M's decommissioning cost estimate contains a material contingency. We are persuaded that I&M used conservative assumptions regarding the expected trust fund asset return. As Mr. Gorman testified, if I&M's inflation rate is reduced to 2.1% to be more consistent with the Federal Reserve's and consensus economists' inflation outlooks, the probability of fully funding the trust increases to 88% under the current funding level of \$2 million. Intervenor IG Ex. 3 at p. 23. We also anticipate, as Mr. Gorman testified, that the level of adequate funding for the trust will be reviewed in I&M's next rate case, which I&M projects filing in two years. Keeping the current funding level does not preclude revisiting the appropriate funding level and is, the Commission finds, reasonable given the decommissioning fund balance and I&M's election to only present the Commission with its Monte Carlo analysis for an \$8 million annual increase. Just two years ago in Cause No. 44967, Mr. Hill recommended the Commission set the annual decommissioning expense at \$4 million, Tr. pp. C-94-95, but in this proceeding jumped this expense to \$10 million providing the Commission with none of the alternative Monte Carlo analyses performed at a lesser increase. The evidence shows that assuming minimal fund growth, the fund should continue to grow to meet the projected decommissioning costs. Accordingly, the Commission finds I&M's proposed annual contribution level of \$10 million is unreasonable. Rather, the evidence, particularly the testimony of Industrial Group witness Gorman, supports a finding that the current funding level of \$2 million is reasonable, and the Commission finds this funding level should continue.

I&M requested 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. Petitioner's Ex. 6 at p. 25. The language I&M requests updates language incorporated into previous Commission rate orders. No party objected to this request. Accordingly, the Commission incorporates 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 \$1.00 million and \$1.00 million, 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) Decommissioning costs to be included in the cost of service are an amount of \$2.0 million apportioned between units as shown in Item No. 1 expected to be included annually in the cost of service for each of the two units, continuing through the dates shown in Item (f), unless changed by future order of the Commission.
  - (f) 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.
  - (g) The TLG Study was utilized in determining the amount of decommissioning costs to be included in I&M's cost of service.



Finally, I&M proposed certain changes in the spent nuclear fuel trust investment guidelines. No party challenged these changes, and the Commission finds them to be reasonable. The record shows the current investment guidelines were established in the 1980s and that circumstances warrant change. Petitioner's Ex. 6 at p. 32. I&M presented a Monte Carlo simulation to evaluate potential asset allocation policies and showed the proposed investment guidelines will potentially extend the surplus life and provide benefits through diversification. *Id.* at pp. 35-36. Accordingly, the Commission approves 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 rate case expense of \$1.55 million, which he proposed amortizing over two years. Petitioner's Ex. 24 at p. 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 limiting I&M's recovery of outside counsel fees to \$500,000. Mr. M. Garrett testified the amount being proposed for outside legal services is \$1,170,000 which is about 75% of the total rate case budget. Public's Ex. 2 at p. 51. He viewed the legal fees in the instant case to be high as a percentage of overall rate case expense. *Id.* Mr. Garrett testified his recommendation is consistent with recent rate cases involving other AEP subsidiaries in states in which Mr. M. Garrett has participated. In those cases, although some outside legal expenses was incurred, he stated the AEP companies relied more heavily on AEP's in-house legal counsel for rate case work. In Mr. M. Garrett's opinion, doing so is more cost effective for ratepayers. *Id.* at pp. 52-53.

3. Rebuttal. Mr. Williamson challenged the value of using rate case expense figures in other jurisdictions because regulatory requirements 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. Petitioner's Ex. 25 at pp. 32-33. Mr. Williamson also compared I&M's proposed rate case expense in this proceeding to rate case expense in other recent Indiana cases. Here, the total rate case expense is estimated at \$1.55 million while he testified the total rate case expense estimated in other recent Indiana cases is as follows: *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) - \$6,000,000; *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 I&M's total rate case expense estimate is lower than the other two major electric cases that were pending in 2019 and was the lowest, excluding the *NIPSCO Gas* rate case (involving fewer intervenors) and I&M's last rate case (filed two years earlier). *Id.* at p. 35.

4. Discussion and Findings. The Commission reviews rate case expense for reasonableness to ensure regulated utilities are diligently and affirmatively

controlling costs so ratepayers are only asked to pay reasonable rate case expenses—not necessarily lower amounts comparatively speaking, but reasonable expenses. In his testimony, Mr. M. Garrett did not question the amount of work required for a rate case in Indiana or the reasonableness of the fee outside counsel is charging I&M. His recommendation focused upon the relative percentage of overall rate case expense attributable to outside legal fees and the assertion that it would be more cost effective for I&M to rely on in-house legal counsel. Given Mr. Williamson’s rebuttal testimony that I&M’s legal department does not include a lawyer licensed to practice in Indiana, Petitioner’s Ex. 25 at p. 37, the record falls short of demonstrating the relative cost-effectiveness of Mr. M. Garrett’s position. Our focus is upon whether the dollars incurred for rate case expenses are reasonable as opposed to second guessing I&M’s allocation of legal work between in-house and outside counsel.

That I&M has structured its organization differently than other utilities, including other AEP affiliates, does not demonstrate its overall rate case expense is unreasonable. Per Mr. Williamson, while recent *NIPSCO Electric* and *Duke* rate cases relied upon experienced in-house counsel licensed to practice in Indiana to lead their respective rate case efforts, both of those utilities relied upon outside consultants for cost of service and rate design, and for both, this element was the largest component of their total rate case expense. I&M, however, relied upon internal resources for cost of service and rate design. Further, Mr. M. Garrett did not factor the additional labor and benefits to hire the additional lawyers that would be necessary for Petitioner to have relied on in-house legal counsel. While we are not persuaded that reducing I&M’s legal fees based on their percentage of rate case expense and use of outside counsel is reasonable or appropriate given this record, I&M is cautioned to manage future rate case expenses to assure their reasonableness. Based upon the record, we find Petitioner’s total estimated rate case expense to be reasonable. As to the amortization period, based upon the projected life of the rates, we find Petitioner’s two-year proposed amortization period to be proper. Accordingly, the Commission approves Mr. Williamson’s proposed two-year amortization of rate case expense.

## 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. Petitioner’s Ex. 24 at p. 60. He testified that in settling Cause No 44967, 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 ADIT will be increased or decreased to ensure that the total amortization of normalized and non-normalized excess ADIT [each year] is equal to \$429.9 million.” Petitioner’s Ex. 24 at p. 60; Settlement Agreement, p. 3, ¶ 1.4. In other words, as the amortization of normalized EADFIT fluctuates each year pursuant to ARAM, the amortization of non-normalized EADFIT each year will be adjusted to “balance” the fluctuations in ARAM and ensure the combined amortization each year equals \$29.9 million. Petitioner’s Ex. 24 at p. 60. Mr. Williamson stated

this “balancing” methodology ensures (a) I&M follows ARAM for normalized EADFIT and, therefore, does not commit a normalization violation and (b) I&M’s total amortization each year equals \$29.9 million as agreed in the settlement. *Id.* at p. 61.

Mr. Williamson testified that while the total amortization levels are the same as the settlement, the normalized EADFIT amortization has been less than was estimated in Cause No. 44967, resulting in faster amortization of the non-normalized EADFIT than was anticipated. Petitioner’s Ex. 24 at p. 61. Mr. Williamson testified I&M estimates it will run out of non-normalized EADFIT as early as 2022, *Id.* at pp. 60-61, whereas I&M expects to amortize normalized EADFIT well past 2022. *Id.* at pp. 61-62.

To address this issue and avoid a normalization violation, Mr. Williamson testified once the non-normalized 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 EADFIT reflected in base rates (*i.e.*, \$29.9 million in this case) and (ii) the actual annual normalized ADFIT amortization required by ARAM. Petitioner’s Ex. 24 at p. 62. He stated the deferral will begin once the non-normalized EADFIT has been fully amortized. *Id.*

(b) OUCC. OUC witness Blakley opposed I&M’s deferral request as stated and proposed an alternative. He testified that when unprotected EADFIT runs out because it has been fully amortized back to customers, I&M should make a compliance filing to change the EADFIT credit. According to Mr. Blakely, after unprotected EADFIT has been fully amortized, the EADFIT credit should be based only on the protected EADFIT amount (\$8.8 million), and going forward, I&M should defer only the difference between protected EADFIT amortization embedded in base rates (\$8.8 million) and its actual protected EADFIT amortization. He stated this proposal will not create a normalization violation, as variances between ARAM and the embedded protected EADFIT amortization will be trued-up in I&M’s next base rate case. Public’s Ex. 3 at pp. 7-9.

(c) Intervenors. Mr. Gorman explained how the Tax Cut and Jobs Act of 2017 and the Settlement Agreement impacted I&M’s EADIT. He stated the Settlement Agreement recognized the protected and unprotected EADIT were estimates, with the final amounts to be determined at a later time. He testified the Settlement agreement required I&M to adjust the amount of protected and unprotected EADIT to ensure a \$29.9 million credit is embedded in base rates. Mr. Gorman opposed 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. He provided alternative approaches to I&M’s proposed treatment and stated the Commission could delay addressing the matter until I&M’s next base rate case, at which time the base rates should be adjusted when the unprotected EADIT has been exhausted. Intervenor IG Ex. 3 at pp. 43-44. Additionally, Mr. Gorman testified 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 I&M reduce the amortization of EADFIT from \$29.9 million to \$28.8 million. She also objected to I&M's proposal to establish a regulatory asset and associated carrying charges. Intervenor Jt. Municipal Ex. 2 at pp. 3, 6-10.

(d) Rebuttal. Mr. Williamson testified that he agrees there is uncertainty as to when unprotected EADFIT will be fully amortized and stated I&M's proposed mechanism addresses this uncertainty, while ensuring customers fully benefit from EADIT going forward and the intent of the Settlement Agreement in Cause No. 44967 continues to be carried out. Petitioner's Ex. 25 at p. 57. In response to the Industrial Group and OUCC testimony, Mr. Williamson proposed modifying I&M's original proposal. *Id.* Mr. Williamson proposed the Commission approve the following ongoing ratemaking treatment:

- (i) Once non-normalized (unprotected) EADFIT is fully amortized, I&M makes a compliance filing to confirm the occurrence.
- (ii) 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 will 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 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 will be the basis for the change in rates.
- (iii) Establish rider rates using two-part rates for demand-metered customers and an energy only rate for non-demand metered customers.
- (iv) 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.

Petitioner's Ex. 25 at pp. 59-60. Mr. Williamson stated this proposal ensures customers continue to receive the benefits of EADFIT going forward, maintains the intent of the Settlement Agreement in Cause No. 44967, allows I&M to continue to comply with tax normalization rules, and addresses the Industrial Group's and the OUCC's concerns by minimizing the level of deferred costs. *Id.* at p. 60. He added the rider mechanism will provide a more efficient way to address this singular topic, rather than revise all the applicable rates in I&M's tariff book.<sup>14</sup> *Id.*

As to Ms. Cannady's position, Mr. Williamson responded there is no need to revisit the settlement 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. Petitioner's Ex. 25 at pp. 60-63.

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<sup>14</sup> The Commission notes Mr. Williamson's proposal for a new tracker to address EADFIT was provided for the first time in I&M's rebuttal testimony. Generally, it is recommended the petitioning party present all its requests to the Commission in its case-in-chief.

(e) Discussion and Findings. The parties concur that something must be done when unprotected EADFIT is fully amortized. Otherwise, a normalization violation is risked. In light of the objections to the indefinite nature of the deferral authority as originally proposed, the Commission finds the most reasonable response is the mechanism I&M proposed on rebuttal; consequently, the Commission finds upon completion of amortization of unprotected EADFIT, I&M should defer the difference between the total EADFIT amortization reflected in base rates (as the same may be adjusted by the rider mechanism we are approving) and actual amortization expense based on ARAM for protected EADFIT. I&M shall make a compliance filing confirming all non-normalized (unprotected) EADFIT has been amortized and submit a rider that reflects the removal of the test year level of non-normalized (unprotected EADFIT) amortization as Mr. Williamson proposed. Consistent with Mr. Williamson's proposal, the Commission finds the rider should also reflect the removal of unprotected EADFIT from rate base. Finally, we further find the two-part mechanism for demand metered customers and energy only mechanism for all other customers, as proposed by Mr. Williamson, is reasonable and approved.

## 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 testified some utilities have removed the URT from base rates and include it as an item on customers' bills. He testified such a change on I&M's customers' bills would reduce I&M's claimed revenue deficiency by \$2.3 million. Additionally, Mr. Gorman recommended I&M remove any URT operating expenses from the test year and I&M's cost of service. Intervenor IG Ex. 3 at p. 9.

(b) Rebuttal. Mr. Williamson did not disagree in theory with Mr. Gorman's proposal, noting it would only change "how" this cost is recovered and not "if" the cost is recovered. Petitioner's Ex. 25 at p. 69. Nevertheless, he stated Petitioner is not prepared at this time to implement this proposal and would need time to determine how this change would be structured and billed. *Id.*

(c) Discussion and Findings. As Mr. Williamson pointed out, adopting Mr. Gorman's proposal would not affect whether the URT cost is recovered, only how it is recovered and reflected on customer bills. It should not affect the total bills customers pay. The Commission, however, declines in this Cause to order I&M to change how the URT is recovered and billed given Mr. Williamson's testimony evidencing time is needed for this implementation and I&M's intention to file its next rate case within two years. Based on the evidence, the Commission finds it is reasonable for I&M to study implementation of this proposal before its implementation is ordered in the context of this general rate case. The Commission, therefore, encourages I&M to work with stakeholders and make a proposal changing the URT treatment either in advance of I&M's next rate case or, at the latest, in its next rate case. If not implemented before I&M's next rate case filing, the Commission directs I&M to provide specific detail in that proceeding regarding the difficulties that have hindered implementation, such as billing software limitations and/or prohibitive costs associated with changing the URT to a line item on customer bills.

**O. Vegetation Management.**

1. I&M. Mr. Isaacson summarized I&M's vegetation management program shown in the capital forecast period and test year O&M. He stated the program involves ongoing work to move away from a reactive approach to managing vegetation to a systematic, cycle-based approach. Petitioner's Ex. 37 at p. 13. Mr. Isaacson testified I&M's vegetation management program began with an initial four-year period (2018 through 2021) that involves two components. First, I&M is expanding overhead conductor clearance zones that generally should be free of vegetation. He stated I&M is widening narrow zones and addressing issues such as trees affected by the emerald ash borer beetle because it has undermined the integrity of many ash trees in I&M's service territory. Second, for clearance zones that are already sufficiently wide, he stated I&M performs remedial maintenance to restore clearance zones to their original width. According to Mr. Isaacson, I&M is on schedule to complete the initial four-year period as planned. He testified that in 2022, I&M will begin a regular four-year vegetation management cycle. *Id.* at pp. 13-14. He summarized results for 2018 and I&M's work plan for 2019-2022. *Id.* at p. 14. Mr. Isaacson also identified the drivers and benefits of I&M's vegetation management program, *Id.* at pp. 14-15, testifying that vegetation management remains the single biggest investment I&M can make to improve reliability. *Id.* at p. 14.

2. OUCC. Mr. M. Garrett stated the test year forecast for vegetation management is higher than I&M's actual spending levels most of the prior five years. He testified I&M's higher level of vegetation management spending in 2018 does not justify I&M's request for ongoing recovery at an elevated level. Public's Ex. 2 at p. 47. Mr. M. Garrett asserted the higher expenditures were largely related to remedial work that should have been completed in prior years, and I&M has not historically spent the projected amounts for vegetation management that it now claims are necessary. *Id.* at pp. 48-49. Mr. M. Garrett pointed out that I&M failed in 2017 to spend the amount it said was required, spending only \$8.483 million of its forecasted \$14.712 million. *Id.* at p. 49. Mr. M. Garrett stated the Michigan commission recently expressed concerns that over the last ten years, I&M's inconsistent spending demonstrates a lack of commitment to its vegetation management program. *Id.* at p. 50. He recommended using a five-year historical average of actual expenditures, which would reduce vegetation management expense by \$5,803,400. *Id.* at pp. 50-51.

3. Rebuttal. Mr. Isaacson testified I&M began its cycle-based vegetation management program to establish a regular four-year vegetation management cycle, with the first four-year period being 2018-2021. Petitioner's Ex. 38 at p. 13. He stated it is unreasonable to compare I&M's forecasted test year level of vegetation management expenditures to its five-year historical average because I&M's new four-year vegetation management cycle began in 2018. He testified the significant reduction Mr. M. Garrett proposed would hamper I&M's implementation of a proactive vegetation management approach and could eliminate the significant customer reliability benefits this proactive approach will bring. *Id.* at p. 14. He disagreed that I&M is "catching up" on deferred maintenance as Mr. M. Garrett asserted. He also disagreed that I&M diverted funds allocated to vegetation management to I&M's bottom line, pointing out that I&M's actual vegetation O&M expenditures in 2018 were greater than I&M's forecasted amount and exceeded the test year level of O&M reflected in the settlement approved in Cause No. 44967. *Id.* at pp. 15-16. He stated Mr. M. Garrett's reference to a

Michigan commission order is distinguishable from the present case and raised issues not shown to be applicable to I&M's Indiana jurisdiction. Petitioner's Ex. 38 at p. 17.

4. Discussion and Findings. In I&M's last rate case, the Commission observed that I&M committed to achieving a four-year trim cycle. *Indiana Michigan Power Co.*, Cause No. 44967, p. 28 (IURC May 30, 2018). The record shows I&M initiated this four-year vegetation management cycle in 2018, and its actual vegetation management expenditures in 2018 reflect this commitment. I&M's distribution tree-caused SAIDI declined by 12% in 2018, supporting the premise that this approach will produce positive results. The OUCC proposes to reduce I&M's level of vegetation management expense to a level below that necessary for I&M to continue implementing the initial four-year cycle. The Commission finds the level of vegetation management expense should not be reduced at this time so as to not hinder I&M from fulfilling the approved initial four-year cycle. I&M spent more in 2018 than was budgeted and was on pace to exceed the budgeted amount in 2019. The Commission, therefore, approves \$16.2 million for vegetation management since the record shows I&M's test year level of vegetation management expense is consistent with that experienced in 2018 and with year-to-date results in 2019. Petitioner's Ex. 38 at p. 16, Figure DSI-R1. In doing so, the Commission notes that at the time of I&M's next rate case, more data will be available regarding I&M's expenditures using the four-year cycle, including the extent to which I&M has adhered to the level of vegetation management expenses being approved.

## **12. Financial Forecast.**

1. I&M. Ms. Heimberger presented I&M's 2020 test year financial forecast and discussed the forecast process. Petitioner's Ex. 12 at p. 2. She testified the forecasting process used in this proceeding is the same as was used in I&M's last rate case, Cause No. 44967. *Id.* at p. 4. She discussed the major components of I&M's financial forecast and identified the other I&M witnesses who support the O&M and capital expenditure work plan activities. *Id.* at pp. 5-10. Ms. Heimberger also presented the forecasted operating revenues, generation forecast, O&M, depreciation and amortization, taxes, plant in service, construction work in progress, and accumulated depreciation. *Id.* at pp. 10-23. She stated 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.* at p. 28.

Mr. Burnett testified the test year load forecast for the twelve-month period ending December 2020 is reasonable and was derived using widely accepted modeling techniques based on the best information available at the time it was completed. Petitioner's Ex. 35 at p. 18. He described the load forecasting methods I&M used 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.* at pp. 5-8. Mr. Burnett stated the test year forecast assumes normal weather conditions throughout the forecast horizon and is adjusted for the impacts of I&M's approved Demand Side Management ("DSM") and Energy Efficiency ("EE") programs or for the longer term, contained within I&M's Integrated Resource Plan ("IRP"). *Id.* at pp. 9-11. He testified I&M's load forecast methodology is proven to produce accurate and reliable projections that are useful for planning and setting rates. *Id.* at p. 11. Mr. Burnett stated the average accuracy of the budget load forecasts for I&M since 2008 has been within 0.3% on a weather-normalized basis. *Id.* at p. 12; Figure CMB-2. He testified the test year forecast incorporates information from

Moody's Analytics, which predicts the end of the current business cycle and the start of the next recession in the year 2020. *Id.* at pp. 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. Intervenor Jt. Municipal Ex. 1 at pp. 4, 31-34. He asserted I&M has the burden of proof to show its test year assumptions are reasonable, and I&M provided no definitive information as to the timing of the recession. *Id.* at pp. 31-33. He referenced an April 2019 economic outlook prepared for the State of Indiana, which Mr. Mancinelli said does not indicate a recession. *Id.* at p. 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. Petitioner's Ex. 36 at p. 4. He testified no "adjustment" was made to the forecast to account for the economic downturn and opined that Mr. Mancinelli did not provide data to support such an adjustment. *Id.* at pp. 2-5. He testified the economic outlook Mr. Mancinelli provided supports, rather than contradicts, the general economic assumptions I&M used in its load forecast. *Id.* at pp. 5-7.

Mr. Burnett stated 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. Petitioner's Ex. 36 at pp. 13-15. Mr. Burnett also showed 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.* at pp. 11-12. At the hearing, Mr. Burnett testified the newest update to the load forecast shows 2020's load projected to be 1.4% below the level used in this proceeding. Tr. pp. G-109-10.

4. Discussion and Findings. Initially it is noted I&M filed this case under Section 42.7 utilizing a forward-looking test year. The "fixed, known, and measurable" standard applies to a historic test year or the historic portion of a hybrid test year; consequently, Mr. Mancinelli's application of this standard to I&M's test year is misplaced. Ind. Code § 8-1-2-42.7(d). Mr. Mancinelli's focus on the word "recession" and the specific timing of an economic downturn ignores Mr. Burnett's broader point that reputable indicators are suggesting the economy is slowing down. Indeed, the economic outlook Mr. Mancinelli cited identifies rising risks of a downturn after 2019, which is consistent with the Moody's Analytics base forecast I&M relied upon. Intervenor Jt. Municipal Ex. 1, Attachment JAM-7 at p. 10; Petitioner's Ex. 36 at pp. 5-7. The reasonableness of I&M's load forecast is also borne out by I&M's updated load projections. These show 2020 load forecasted to be 1.4% lower than the test year load forecast used in this case. Tr. pp. G-109-10. While Mr. Mancinelli proposed the load forecast be adjusted, he did not provide substantial evidence as to what that adjustment should be. With respect to his proposal to rerun the load forecast using historical DSM information, the record shows Mr. Mancinelli compared the wrong data points, and the load forecast reasonably used I&M's IRP as the source for long-term DSM/EE savings assumptions. Accordingly, the Commission finds I&M's test year forecast to be reasonable.

**13. Net Operating Income at Present Rates.** Based upon the evidence and the determinations made above, and prior to the Indiana and Michigan Municipal Distributors



Association (“IMMDA”) related determination below, the Commission finds I&M test year operating results under its present rates are as follows:

Operating Revenues	\$ 1,501,500,440
Less: O&M Expenses	\$ 930,770,970
Depreciation/Amortization	\$ 320,953,695
Taxes Other Than Income	\$ 84,046,118
State Income Taxes	\$ (378,023)
Federal Income Taxes	\$ (15,600,759)
Total Operating Expenses	\$ 1,319,792,001
Net Operating Income (“NOI”)	\$ 181,708,439

However, as discussed below in Finding No. 15.A., the Commission is also adjusting the jurisdictional separation study to reflect our rejection of I&M’s adjustment for the loss of IMMDA load. Based on I&M’s IMMDA credit of \$46,442,922, the table below credits the test year operating revenues by this amount. The Commission acknowledges this is a simplified approximation of what may result from I&M’s compliance filing with an order compliant jurisdictional separation study. Nonetheless, for comparative purposes, we present the following table:

Operating Revenues	\$ 1,547,943,362
Less: O&M Expenses	\$ 930,869,707
Depreciation/Amortization	\$ 320,953,695
Taxes Other Than Income	\$ 84,753,647
State Income Taxes	\$ 2,020,731
Federal Income Taxes	\$ (6,520,800)
Total Operating Expenses	\$ 1,332,076,981
Net Operating Income (“NOI”)	\$ 215,866,381

In summary, the Commission finds I&M’s annual net operating income under its present rates for electric utility service under the conditions modeled above to be approximately \$215,866,381, which is insufficient to represent a reasonable return; therefore, I&M’s present rates are unreasonable. Accordingly, it is reasonable and necessary for new rates and charges to be established.

**14. Authorized Revenue Requirement.** Based on the evidence before us and the results modeled above, the Commission finds I&M should be authorized to increase its basic rates and charges to produce operating revenue of approximately \$1,627,918,786. This revenue

is reasonably estimated to afford I&M the opportunity to earn net operating income of approximately \$274,690,598 as follows:<sup>15</sup>

Calculation of Authorized Increase in Revenue:

Rate Base	\$ 4,896,419,619
Required Rate of Return	5.61%
Allowable Electric Operating Income	\$ 274,689,141
Less: Adjusted NOI at Present Rates	\$ 215,866,381
Deficiency in Electric Operating Income	\$ 58,822,760
Times: Revenue Conversion Factor	1.3596
Jurisdictional Revenue Deficiency	\$ 79,975,424
Remove Transmission Owner Costs, Revenues <sup>16</sup>	\$ 3,909,218
Total Required Rate Relief Before Phase-In Credit	\$ 83,884,642
Less: Current Revenue for Ongoing Riders	\$ 221,393,319
Plus: Proposed Rider Revenue	\$ 221,646,844
Total Rate Change Before Phase-In Credit	\$ 84,138,167
Operating Revenues	\$ 1,627,918,786
Less: O&M Expenses	\$ 931,135,869
Depreciation/Amortization	\$ 320,953,695
Taxes Other Than Income	\$ 85,870,923
State Income Taxes	\$ 6,151,683
Federal Income Taxes	\$ 9,116,017
Total Operating Expenses	\$ 1,353,228,188
Net Operating Income ("NOI")	\$ 274,690,598

The phase-in of I&M's rates as I&M proposed was not challenged by any party. Given the record, the Commission finds approval of a rate phase-in to be reasonable except, since the IMMUDA credit is not being created, that credit will not expire. More specifically, when I&M's new base rates are first effective, they will include a "Forecasted Plant Credit" to reflect forecasted plant additions during the test year,<sup>17</sup> but not the "IMMUDA Credit" of \$46,442,922 Ms. Duncan identified (Petitioner's Ex. 10 at p. 20), so no IMMUDA Credit will expire on June 1, 2020. On June 1, 2020, the Forecasted Plant Credit will continue to remain in effect until I&M's final compliance filing (now Phase II) 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. Petitioner's Ex. 10 at p. 21.

<sup>15</sup> To the extent the modified jurisdictional separation study alters the Indiana jurisdiction rate base, the authorized NOI will change.

<sup>16</sup> As-filed amount is shown. Final value will change consistent with approved calculation methodology when approved changes are flowed through class cost-of-service. Petitioner's Ex. 20 at p. 5.

<sup>17</sup> While I&M originally calculated a Forecasted Plant Credit of \$43,051,354 (Petitioner's Ex. 10 at p. 20), we note the approved Forecasted Plant Credit will be slightly different as a result of the rate base approved herein. I&M shall submit the updated amount based upon the Commission's approved rate base adjustments and provide documentation to support its calculation.

We find Phase II rates should utilize the same compliance filing process as “Phase II” rates in Cause No. 44967. I&M shall certify to the Commission its net plant at December 31, 2020, and thereafter calculate the resulting Phase II rates. For purposes of the Phase II certification, I&M shall use the forecasted test year end net plant of \$4,896,419,619 approved above. The Phase II rates shall go into effect on the date I&M certifies its test year end net plant, or January 1, 2021, whichever is later. The net plant for Phase II 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 certification is served to file written objections to I&M’s certified test year end net plant. If there are objections, a hearing will 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, notwithstanding when Phase II 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 stated the same overall methods employed to develop the jurisdictional study in Cause No. 44967 were used to develop the jurisdictional study in this case. Petitioner’s Ex. 10 at pp. 6-7. She testified adjustments were made to annualize known interruptible customer load changes and the loss of wholesale load associated with the IMMIDA members effective June 1, 2020. *Id.* at pp. 9-10. Mr. Thomas testified that all but one of the IMMIDA contracts will expire on or before June 1, 2020, with the last IMMIDA contract to expire on or before June 1, 2026. Petitioner’s Ex. 1 at p. 6. Mr. Williamson explained that I&M’s proposed phase-in of base rates will ensure these contracts continue to benefit retail customers until the contracts expire. Petitioner’s Ex. 24 at pp. 5-6, 19, and 24. Ms. Duncan also supported new demand and energy allocation factors required as a result of Michigan’s Electric Customer Choice program. Petitioner’s Ex. 10 at p. 10.

2. Intervenors. Industrial Group witness Gorman testified I&M did not take reasonable steps to retain the IMMIDA load or find replacement load. He stated 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 IMMIDA capacity is not necessary to meet Indiana retail customers’ needs in 2020 through 2022, Intervenor IG Ex. 3 at pp. 34-35; therefore, Mr. Gorman proposed to make permanent \$6.44 million in offsets to I&M’s cost of service that I&M currently receives from its expiring IMMIDA contracts. Mr. Gorman added that if the Commission approves reallocating the IMMIDA 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, i.e., \$25.4 million Indiana retail, which is substantially below the \$46.44 million per year in wholesale capacity costs I&M is reallocating to Indiana retail customers. *Id.* at pp. 8-9.

Joint Municipal witness Mancinelli stated fixed costs associated with the IMMIDA load loss should be recovered within the wholesale jurisdiction, not shifted to I&M’s retail

jurisdictions. Intervenor Jt. Municipal Ex. 1 at pp. 9-11, 59. Mr. Mancinelli testified that under the FERC's rules at 18 C.F.R. § 35.26(b)(1), I&M had the right to recover stranded costs in the IMMUDA contracts. *Id.* at pp. 21-26. He reasoned that because the IMMUDA contracts do not include an exit fee or other stranded cost recovery, I&M is responsible for all stranded costs associated with loss of IMMUDA customers and should not be allowed to recover costs associated with this IMMUDA wholesale load loss through retail customers. *Id.* at p. 25. From his perspective, I&M's reallocation uses retail customers as a hedge against lost load attributable to the wholesale business. Mr. Mancinelli testified this practice should not be allowed, as I&M bears no risk and, therefore, has little motivation to replace lost load, as demonstrated by I&M's inability to replace the IMMUDA load despite receiving early termination notices from IMMUDA customers prior to May 31, 2016. *Id.* at p. 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. *Id.* at p. 26. He stated he agreed with I&M's treatment of Michigan load loss in the jurisdictional separation study, and this treatment is consistent with his recommendation pertaining to the loss of firm wholesale load, which Mr. Mancinelli testified should be borne by wholesale customers. *Id.* at pp. 26-28.

39 North witness Cearley stated I&M should not be allowed to decrease its test year revenues because of its loss of wholesale load until I&M has reasonably demonstrated what it has done either to retain or replace this lost load beyond just making claims of support for economic development. Intervenor 39 North Ex. 1 at p. 9.

3. I&M Rebuttal. Ms. Duncan explained the jurisdictional allocation should reflect the load conditions expected during the period the rates established in this Cause will be in effect. She disagreed that performing a jurisdictional separation study is "raising rates" on customers. Petitioner's Ex. 11 at p. 3. She testified Mr. Mancinelli's and Mr. Gorman's treatment of costs associated with serving the Company's retail and wholesale customers is not consistent with cost allocation principles and deviates from I&M's historical practice. *Id.* at p. 2. According to Ms. Duncan, loss of load is the mirror image of adding load. She testified that if wholesale load were to be added or a large customer were added in Michigan, no credible argument could be made to say Indiana customers should continue to pay the same level of fixed costs, that when I&M enters into contracts for new load, whether retail or wholesale, I&M's fixed costs are spread over the new larger base, whether the load is Indiana retail, Michigan retail, or wholesale. Ms. Duncan stated that, similarly, when I&M loses a customer, regardless of jurisdiction, the fixed costs should be spread over the now smaller base. She testified this is consistent and proper ratemaking and reflects how jurisdictional separation studies should be prepared. *Id.*

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. Petitioner's Ex. 11 at p. 9. She also disagreed with Mr. Mancinelli's assertion that I&M's treatment of the IMMUDA load is inconsistent with its treatment of the Michigan Choice customers. *Id.* She stated all costs related to the wholesale jurisdiction have been allocated using the allocation factors proposed in this case, which includes the loss of the IMMUDA load. *Id.* at pp. 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 testified

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.* at pp. 10-11.

Mr. Thomas testified the Company’s current IRP shows that in 2023 I&M will face a capacity shortfall of approximately 484 MW based upon an assumption of not renewing the Rockport Unit 2 lease. Petitioner’s Ex. 2 at p. 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 capacity additions or subtractions will rarely exactly match changes in load requirements. *Id.*

Mr. Thomas stated 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. Petitioner’s Ex. 2 at p. 29. Mr. Thomas testified 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 experienced generation marketing team at AEP made best efforts to avoid termination of these agreements. *Id.* He stated that since receiving the contract termination notices, I&M explored options available in the wholesale market in anticipation of the capacity and energy becoming available. Mr. Thomas testified if additional revenues result from those activities, the Off System Sales (“OSS”) tracker will flow the majority of the margins back to customers. *Id.* He added that I&M has aggressively pursued the development of economic growth in its communities and has had success doing so. *Id.* Mr. Thomas disagreed with the implication that I&M was passive in reacting to the IMMDA contract terminations. *Id.*

4. Discussion and Findings. I&M provides retail service in Indiana and Michigan and full-requirements wholesale service to non-retail customers. Customers in each retail and wholesale jurisdiction benefit from the combined scale and scope of the integrated utility systems. In each I&M general rate case, a jurisdictional separations study is performed to separate I&M’s test year cost of service among the three jurisdictions, i.e., Michigan retail, Indiana retail, and wholesale. I&M contends that when it loses or adds load, regardless of jurisdiction, I&M’s test year costs are spread over the smaller or larger customer base using a jurisdictional separation study. *See* Petitioner’s Ex. 11 at p. 8.

The record shows IMMDA members are municipal utilities who have received wholesale electric service from I&M for more than 50 years. Intervenor Jt. Municipal Ex. 5. They represent a wholesale contractual load for whom I&M has planned and incurred costs for many years, with I&M’s current full requirements agreements with IMMDA members having begun in July 2006. Intervenor Jt. Municipal Ex. 5. The IMMDA customers elected to end their wholesale contracts with I&M consistent with the terms and conditions of their contracts. Petitioner’s Ex. 44 at 1 (I&M Response to Commission Request for Information). Significantly, our review of the IMMDA contracts does not disclose the inclusion of a provision addressing cost recovery in the event of their early termination nor a provision mitigating how such early termination may create a misalignment between planned for load and the planned for resources to meet such load. Instead of contractually ensuring I&M recovered certain costs from IMMDA members before

they could terminate their wholesale contracts, in effect, I&M now looks to recover IMMDA related costs from its other customers, including Indiana retail customers.

The Intervenor did not challenge the allocation and assignment methods employed in Ms. Duncan's jurisdictional separation study, but they do oppose the adjustment of I&M's test year to reflect the lost IMMDA load. Although the change in IMMDA's load will occur during the test year, the issue is whether Indiana retail customers or I&M should bear the cost of the reduced revenue associated with losing this load. I&M claims the Company's generation will continue to be used and useful in the provision of service to Indiana customers. Petitioner's Ex. 2 at p. 28. However, the evidence shows the 312 MW capacity from the wholesale load is not necessary to service Indiana retail customers. Intervenor IG Ex. 3 at pp. 35-36; Tr. pp. A-76-78. I&M has used the excess 312 MW to increase the OSS tracker adjustment. That adjustment values the excess capacity at \$36.4 million, much less than the \$46.44 million jurisdictional adjustment I&M made to its revenue requirement for the lost IMMDA load. I&M claims the increased OSS will mitigate the revenue adjustment to Indiana's retail customers; however, its proposal does not address the critical fact that this significant excess capacity is not necessary to serve the Indiana retail load. Contrary to I&M's assertion that because it has incurred the cost of the capacity, Indiana retail customers have somehow "caused" these costs to be incurred so under cost causation principles they should be required to cover those costs, *see, e.g.*, Tr. pp. D-12-14, the Commission finds the evidence does not support that position.

I&M's witnesses testified to I&M undertaking a number of steps to try and retain the IMMDA load, including holding meetings with IMMDA members, meeting with IMMDA leadership, and then following up with the affected IMMDA customers describing the offer I&M had made and advising that IMMDA leadership had rejected the offer on behalf of the members. Petitioner's Ex. 44 at p. 1 (I&M Response to Commission Request for Information). Mr. Thomas also described efforts both I&M and its AEP generation marketing team made to explore options available in the wholesale market. Petitioner's Ex. 2 at p. 29. Importantly, the efforts Mr. Thomas described were reactions to IMMDA's prospective termination. Although he testified capacity additions or subtractions will rarely exactly match changes in load requirements, the Commission finds I&M should bear the ramification of not contractually protecting the Company from termination of the IMMDA load well before the Rockport Unit 2 lease is to expire, exposing I&M to loss of the IMMDA load years before the IMMDA capacity may be needed to meet Indiana retail customers' needs. We cannot find support for the lack of management foresight in allowing a wholesale contract misalignment of load and resources as warranting what is, effectively, shifting I&M's risk to Indiana captive retail customers.

Based on the record as a whole and our discussion above, the Commission finds I&M's forecasted test year revenues should not reflect the expiration of the IMMDA wholesale contracts, including the adjustment of OSS margins, and with regard to the jurisdictional cost allocation, the adjustment Ms. Duncan made is not approved. Accordingly, the Commission approves I&M's jurisdictional separation study as modified to exclude the adjustment for the lost IMMDA load to Indiana retail jurisdiction customers.

**B. Class Cost of Service and Revenue Allocation.**

1. I&M. Mr. Spaeth, presented Petitioner's class cost-of-service study at present rates, Petitioner's Ex. 31, Attachment DEH-1, which allocates the total Indiana retail jurisdiction rate base, revenues, and expenses to each rate schedule. He testified 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. *Id.* at pp. 2-3.

Mr. Spaeth testified that I&M is proposing to continue using the six 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. Petitioner's Ex. 31 at p. 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. Mr. Spaeth stated classifying services and meters as customer-related (and primary and secondary poles, lines, and transformers as demand-related) has been accepted by this and other Commissions and is consistent with cost causation principles. *Id.* at pp. 15-16.

2. OUC. OUC witness Watkins opposed I&M'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. Public's Ex. 12 at 33. Mr. Watkins testified 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. But, he stated this is not the case with utilities such as I&M wherein the portfolio of 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.* at p. 14.

Mr. Watkins testified 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 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 peak responsibility methods such as the 1 CP, 4 CP, and 6 CP ignore the planning criteria utilities use to minimize the total cost of providing service, do not reflect utilization of the portfolio of generating assets throughout the year and, therefore, do not reflect how capital costs are incurred, i.e., do not reflect cost causation. *Id.* at p. 15.

According to Mr. Watkins, there are two general philosophies relating to the proper allocation of transmission-related plant. The first philosophy 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. Under this philosophy, transmission costs are allocated using the same method as 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. Public's Ex. 12 at p. 24. Mr. Watkins testified 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, used to move the energy generators produce to where customers actually consume electricity; (2) transmission facilities are used virtually every hour of an entire year and not just during periods of peak load; and (3) it implies there is a direct and linear relationship between cost and load, which is not the case since there are significant economies of scale associated with high voltage transmission lines.

In his cross-answering testimony, Mr. Watkins opposed the Industrial Group, South Bend, and Joint Municipals' proposals to use either a 3 CP, 4 CP, or 5 CP demand allocation method, and he recommended their proposals related to distribution plant be rejected. Public's Ex. 14 at p. 9.

3. Intervenors. Industrial Group witness Phillips initially explained the importance of adhering to cost of service principles in allocating a utility's cost among the various customer classes and in the rate design process. Intervenor IG Ex. 4 at pp. 5-10. He recommended that because the peaks that determine I&M's capacity requirement all occur in the summer months and it is I&M's load at the time of PJM's Peak Load Contribution ("PLC") peaks that determine I&M's capacity requirements, including its reserve requirement, I&M should allocate its production plant and transmission plant on either a 5 CP (PJM PLC) or 4 CP summer method. *Id.* at p. 13. He also recommended the Commission include a customer component for the allocation of distribution system costs using the minimum system approach, particularly for accounts 364 through 368 which relate to poles, lines, underground conduit, and transformers. *Id.* at pp. 16-24. In his cross-answering testimony, Mr. Phillips responded to Mr. Wallach's and Mr. Watkins' energy-related cost allocation proposals, recommending the Commission deny those proposals. Intervenor IG Ex. 5 at pp. 2-3.

Joint Municipal witness Mancinelli recommended I&M 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. Jt. Municipal Ex. 1 at pp. 38-40.

CAC-INCAA witness Wallach proposed the use of an energy-weighted demand allocation methodology (Equivalent Peaker) for the allocation of production plant. Intervenor CAC-INCAA Ex. 2 at pp. 14-16. Mr. Wallach's cross-answering testimony opposed the Industrial Group and South Bend recommendations that I&M rely on minimum-system methods to classify distribution costs. Intervenor CAC-INCAA Ex. 3 at pp. 1-7.

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. Intervenor South Bend Ex. 3 at pp. 2-3, 11, 14. In his cross-answering testimony, Mr. Seelye responded to the testimony of Mr. Watkins, Mr. Wallach, and Mr. Phillips. Intervenor South Bend Ex. 5.

Kroger witness Bieber's cross-answering testimony recommended the Commission reject the OUCC and CAC's alternative class cost of service studies. Intervenor Kroger Ex. 2 at pp. 1-2. He further recommended the use of a minimum distribution system method to classify certain distribution plant costs. *Id.* at pp. 2, 12.



4. Rebuttal. Mr. Spaeth testified an energy-weighted demand allocator should not be used because it does not recognize the fixed nature of production plant costs, which do not vary based on the level of energy consumption. Petitioner's Ex. 31 at p. 3. With respect to the OUCC's 12 CP proposal and the Intervenor's alternative 3 CP, 4 CP, and 5 CP demand allocation methodologies, Mr. Spaeth explained how these approaches fail to recognize that I&M's load profile shows I&M continues to be a summer and winter peaking utility. *Id.* at pp. 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. Petitioner's Ex. 31 at pp. 11-14.

5. 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 Commission approved the same demand classification and 6 CP allocation methodology for production plant in I&M's 2013 rate case, Cause No. 44075, 2013 WL 653036, 303 P.U.R.4th 384 (IURC February 13, 2013), and its 1993 rate case, Cause No. 39314, 1993 WL 602559 (IURC November 12, 1993). In *PSI Energy, Inc.*, the Commission recognized a change in cost allocation methodology can have significant impacts on customer classes and, thus, such a change should not be lightly undertaken, especially where much of the plant was in service at the time of the utility's last rate case, and costs were assigned on the same basis in that case. *PSI Energy, Inc.*, Cause No. 42359, p. 102, 2004 WL 1493966 (IURC May 18, 2004). In this proceeding, no operational changes were identified by the parties that we are persuaded warrant a departure from I&M's long-standing 6 CP approach. In so finding, the Commission acknowledges that since the orders in Cause Nos. 44075 and 39314, I&M ceased participation in the AEP East Pool Agreement effective January 1, 2014, and to some extent the Pool impacted I&M's operations, whereas I&M now acts solely as a PJM member, but we find this insufficient to change I&M's allocation methodology.

The record shows the energy-weighted demand allocation methodologies the OUCC and CAC-INCAA proposed do not recognize production plant costs are fixed in nature and exist regardless of how much energy customers consume. Because production plant capacity is required to meet peak demand requirements, we find plant capacity costs are appropriately allocated to customers based on their contribution to peak demands since there is a direct relationship to the demand that customers place on the system.

The record further shows the various alternative demand allocation methodologies the OUCC, the Industrial Group, Joint Municipal Group, and South Bend proposed are not consistent with the Company's load profile during the test year and should not be accepted. More specifically, the evidence shows I&M Indiana has historically been a two-seasonal peaking utility, and I&M's 2018-2019 IRP shows this profile is expected to continue through 2038. Petitioner's Ex. 31 at pp. 5-7, Figure MMS-R1. The Commission, therefore, finds, based on the

evidence presented, that I&M's load profile on the primary distribution system during the test year supports a 6 CP allocation. Considering I&M's long-standing use of a 6 CP demand allocation factor in its previously-filed rate cases and, since the test year load profile continues to reflect six monthly peaks, the Commission finds it appropriate to continue the 6 CP demand allocation.

(b) Transmission and Distribution Plant Allocation Methodology. The parties also disagreed over the methodology of allocating transmission and distribution plant. As discussed above, the OUCC's proposed allocation of transmission plant using a 12 CP methodology does not appropriately consider the two-seasonal peaking nature of I&M's system. Accordingly, the Commission approves I&M's allocation methodology for transmission plant.

The Commission also rejects the Industrial Group and South Bend recommendations to change the classification of distribution plant accounts 364 through 368 to classify and allocate a portion of these accounts as customer-related. The record shows I&M's classification of distribution plant is consistent with the NARUC Manual and is based on principles of cost causation. *See* Petitioner's Ex. 31 at pp. 13-14. More specifically, Mr. Spaeth testified I&M's classification of distribution plant accounts 364 through 368 is consistent with actual Company distribution engineering practice of sizing distribution poles, lines, and transformers based on expected peak demand and, therefore, is consistent with principles of cost causation. He stated distribution plant costs included in account 364 through 368 are incurred based on peak demand; therefore, the costs included in these accounts should be classified as demand-related and allocated using I&M's demand allocation factors. Mr. Spaeth testified this classification and allocation of distribution plant continues to be an appropriate method due to its foundation in cost-causation, with I&M appropriately classifying distribution plant accounts 360-368 as demand-related and accounts 369-373 as customer-related. Petitioner's Ex. 31 at p. 14. Based on Mr. Spaeth's testimony, the Commission is persuaded that distribution plant costs included in accounts 364 through 368 are incurred based on peak demand and should be classified as demand-related and allocated using the Company's demand allocation factors. We further find I&M's proposed classification and allocation of distribution plant continues to be an appropriate method due to its foundation in cost causation.

### C. Subsidy Reduction.

1. I&M. Mr. Nollenberger testified the revenue allocation is based on the class cost of service study Mr. Spaeth performed. Petitioner's Ex. 20 at p. 6. He explained the principles and objectives underlying I&M's proposed revenue allocation among the customer classes and stated I&M's approach reduced the current level of inter-class revenue subsidies by 25%, while also ensuring no class received a revenue decrease based on cost of service. *Id.* at pp. 7-8. Mr. Nollenberger stated I&M chose not to eliminate all subsidies in this Cause; however, it is important to make progress toward eliminating interclass subsidies so customer class revenues more closely align with their respective class cost of service. *Id.* at p. 7.

2. OUCC. Mr. Watkins proposed an alternative class revenue allocation methodology after considering the results of his various recommended class cost of service studies. Public's Ex. 12 at pp. 36-39.

3. Intervenors. Joint Municipal Group witness Mancinelli disagreed with I&M's allocation condition that ensures no tariff class receives a decrease in total revenues and recommended street lighting rates be lowered to cost of service because street lighting is provided by local governments and provides many public benefits, with the resulting shortfall prorated across all other rate classes. Intervenor Jt. Municipal Ex. 1 at pp. 41-43.

CAC-INCAA witness Wallach proposed: (1) maintaining 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) increasing base revenues for all other classes by the same percentage to recover any authorized revenue deficiency. Intervenor CAC-INCAA Ex. 2 at p. 17.

South Bend witness Seelye recommended 50% of the subsidies be eliminated, and he disagreed with I&M's proposal that no tariff class receive a decrease in total revenues. Intervenor South Bend Ex. 3 at pp. 3, 26. According to Mr. Seelye, street lighting is an important and costly public service municipalities pay for each month, and I&M's proposal leaves municipalities like South Bend paying a large subsidy in street lighting rates with no corrective reduction. He testified this is not equitable. *Id.* at p. 5. Auburn witness Rutter disagreed that I&M has moved all classes closer to earning the class average rate of return. He recommended a rate of return for the SL class of 9.35%. Intervenor Auburn Ex. 1 at pp. 8-10.

Walmart witness Chriss noted 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. Intervenor Walmart Ex. 1 at 14. Mr. Chriss also discussed I&M's proposal to eliminate 25% of the current inter-class subsidies within the Company's rate schedules. *Id.* at p. 16 (*citing* Petitioner's Ex. 20 at p. 7). Mr. Chriss testified Walmart does not oppose I&M's proposed revenue allocation at the requested revenue requirement, but he recommended the Commission apply any reduction to the revenue requirement in a manner that further moves customer classes toward their respective costs of service. Intervenor Walmart Ex. 1 at p. 17.

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. Petitioner's Ex. 21 at pp. 5-6. With respect to Mr. Seelye's recommendations, Mr. Nollenberger stated that since other customer classes are experiencing an average total revenue increase of more than 11%, it is reasonable to expect no rate class will receive a rate reduction. He testified that I&M's approach strikes a reasonable balance between reducing current subsidies and managing class impacts as compared to South Bend and Auburn's proposals. *Id.* at p. 7. He stated Mr. Wallach's approach would make uneven progress towards mitigating the current level of inter-class subsidies. *Id.* at p. 8.

5. Discussion and Findings. We find I&M's proposed method of distributing its requested rate increase in a manner to reduce current interclass subsidies by 25% is a reasonable step toward cost-based rates and appropriately progresses toward eliminating interclass subsidies while recognizing the rate impacts on the various tariff classes; however, movement toward cost of service also causes the Commission to find a revenue decrease in

I&M's street lighting rates is appropriate to lessen the subsidy street lighting customers will otherwise continue providing.

Mr. Nollenberger testified, "[t]he current subsidy is defined as the difference between the equalized revenues (revenues if the class rate of return were set equal to the total retail current rate of return of 3.41%) and current class revenues." Petitioner's Ex. 20 at p. 7. As shown on Petitioner's Attachment MWN-2, page 2 of 4, column 12, street lighting customers are providing \$2,308,131 in current subsidy revenues. This results in a class rate of return ("ROR") of 11.27%, while the current overall ROR is 3.41%. *Id.* at p. 1 of 4, column 5. Thus, street lighting customers are presently providing one of the largest subsidies among I&M's rate classes. Under I&M's current rate proposal, street lighting customers will have a class ROR of 12.83% compared to I&M's proposed overall ROR of 5.86%. *Id.*, column 12. While this proposal reduces the street lighting subsidy, the Commission finds this adjustment should be more aggressive to better capture I&M's cost of service and reduce one of its largest interclass subsidies; consequently, the Commission approves Petitioner's proposal to reduce its current interclass subsidies by 25%, with one exception. We find I&M shall adjust its Rate Class SL Streetlight subsidy reduction to 50%, and any revenue deficiency resulting from this adjustment shall be reallocated among the remaining rate classes.

**16. Rate Design.** Mr. Nollenberger presented the rate design supporting I&M's proposed tariffs and stated, in general, I&M's approach is to design rates and rate components that reflect I&M's underlying costs. Petitioner's Ex. 20 at p. 9. He testified this includes collecting fixed costs through fixed and/or demand charges and variable costs through energy charges whenever practical. *Id.* He also described rate design changes proposed for certain I&M riders. *Id.* at pp. 28-30. Based on the record presented, the Commission finds I&M's undisputed rate design proposals are reasonable and should be approved. The disputed rate design issues are discussed below.

**A. Plug In Electric Vehicle, Commercial, and Industrial Rates.**

**1. Tariffs R.S. PEV and G.S. PEV.**

(a) I&M. Mr. Cooper testified Tariffs R.S. PEV and G.S. PEV are being proposed as part of a multifaceted endeavor to facilitate growth in the plug-in electric vehicle ("PEV") industry in Indiana. He stated this is a comprehensive package containing new tariffs, rebates, and incentives to attract residential, commercial, and industrial customers to the electric vehicle market. Petitioner's Ex. 8 at p. 16. Both tariffs are designed to encourage customers to charge PEVs during off-peak hours.

(b) OUCC. Ms. Aguilar expressed concern that I&M is not proposing a companion on-peak charging rate. She testified the proposed PEV pilot tariff does nothing to dissuade individual customers from charging during peak times and using 240 volt chargers to do so, which she stated could inflict greater system stress. Public's Ex. 10 at p. 20. She opined that with 240 volt charging equipment, users are capable of more system stress during on-peak times than if a 120 volt charger is used. *Id.* Ms. Aguilar recommended the Commission approve I&M's proposed off-peak rate and impose an on-peak rate. *Id.* From her

perspective, I&M's PEV pilot should, in addition to offering reduced rates during delineated off-peak hours, include a disincentive for on-peak charging. *Id.*

(c) South Bend. South Bend witness Seelye testified the off-peak energy charge should be lowered to reflect cost of service and to encourage greater utilization of the service. Intervenor South Bend Ex. 3 at pp. 5, 43-46. He also stated there is no basis for the restriction in the tariff prohibiting net metering customers from taking service under Tariff G.S. PEV and the exclusion is unduly discriminatory. *Id.* at pp. 5, 46. According to Mr. Seelye, customers who have installed distributed generation technology are likely the progressive and conservation minded people who will be utilizing PEV technologies. *Id.* at p. 46.

(d) Rebuttal. Mr. Lehman disagreed with Ms. Aguilar that a punitive approach is necessary to accomplish off-peak PEV charging. Petitioner's Ex. 17 at p. 6. He stated I&M's proposed tariff designs are expected to achieve off-peak charging simply through beneficial off-peak rates. Mr. Lehman testified that to achieve the greatest benefit for all customers, I&M needs to maximize enrollment of eligible participants and shift their PEV charging load to off-peak hours. *Id.*

Mr. Lehman also disagreed with Mr. Seelye's recommendation to lower the off-peak charging rate. He stated 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. *Id.* at p. 11. Mr. Lehman testified the proposed off-peak PEV charging rate reasonably incents the desired off-peak charging behavior while ensuring non-participating customers also benefit from this activity. *Id.* Mr. Lehman also testified it is reasonable to exclude distributed generation or net-metered customers from the pilot program at this time because the proposed implementation relies on a per-kWh credit to encourage off-peak charging, and this is not compatible with net-metered billing for customers who have distributed generation and a single premise meter. *Id.* at p. 9. He added that although witness Dorau stated the PEV sub-meter could be excluded from accessing the bank of solar kWh that net-metering customers draw from during off-peak times, I&M is not currently aware of methods to accomplish this with its billing system. *Id.*

(e) Discussion and Findings. The record shows the alternative rate designs the OUCC and South Bend proposed may discourage enrollment (in the case of the OUCC) and eliminate the incremental contribution to fixed costs from participants (in the case of South Bend). In contrast, the Commission finds I&M's proposed Tariffs R.S. PEV and G.S. PEV are reasonably designed to encourage off-peak charging behavior while ensuring non-participating customers also benefit from this activity. The record further shows that South Bend's recommendation to allow distributed generation customers to participate is incompatible with the per-kWh credit design of the tariff and impractical at this time from a billing standpoint. Petitioner's Ex. 17 at p. 9. Accordingly, the Commission finds, based on this evidence, that Tariffs R.S. PEV and G.S. PEV as proposed by I&M should be approved. In doing so, however, I&M is encouraged to further investigate how its billing system might be modified to enable future net-metered customer participation in PEV rates.

## 2. Tariff IP.

(a) Walmart. Walmart witness Chriss testified that I&M'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, I&M's proposed rate design for Tariff IP is inconsistent with I&M's statements that rate components should "reflect the underlying costs of the Company" which includes "collecting fixed costs through fixed and/or demand charges at variable costs through energy charges whenever practical." Intervenor Walmart Ex. 1 at pp. 19 (quoting Petitioner's Ex. 20 at p. 9), 20-22, 31. Mr. Chriss recommended that at I&M's requested revenue level: (1) any approved revenue increase to the IP class be applied to each service level's demand charge; (2) I&M maintain the first block energy charges at current levels; and (3) the second block energy charges be reduced as I&M proposed. Intervenor Walmart Ex. 1 at pp. 31-32. In the event the Commission approves a lower revenue increase than I&M has requested, Mr. Chriss recommended the Commission apply Walmart's proposal but then reflect the reduced revenue increase in the first block energy changes. *Id.* at p. 32.

(b) Rebuttal. On rebuttal, Mr. Nollenberger provided a comparison of estimated total bill impacts between I&M's and Walmart's recommended Tariff IP rate design. Petitioner's Ex. 21 at p. 17; Attachment MWN-R3. He continued to support I&M's proposed Tariff IP rate design but stated Walmart's proposed Tariff IP rate design is not unreasonable. Mr. Nollenberger testified that if I&M's revenue requirement is changed, a uniform change in all Tariff IP rate components, excluding customer charges, may be more reasonable than a change focused on a specific rate component. *Id.* at p. 18.

(c) Discussion and Findings. The Commission finds the record shows Walmart's proposed rate design more properly aligns demand-related costs to demand charges, which results in rates that are more closely cost-based and send better price signals to customers. Intervenor Walmart Ex. 1 at pp. 21-28, 31-32. For these reasons, and also considering that Mr. Nollenberger found Walmart's proposal is not unreasonable, the Commission finds Walmart's proposed Tariff IP rate design is reasonable and is, therefore, approved; provided, the Commission is persuaded that it is appropriate to apply any changes to I&M's proposed revenue requirement to all of the IP rate components, excluding customer charges, as Mr. Nollenberger proposed.

## 3. Tariff LGS.

(a) Intervenors. Kroger witness Bieber testified that I&M's proposed LGS rate design significantly understates demand-related charges while overstating energy charges relative to the underlying cost components. Intervenor Kroger Ex. 1 at p. 4. To address this misalignment of costs and rates within the LGS class, he recommended a rate design that will 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. Mr. Bieber proposed that I&M maintain the proposed demand charges for Tariff LGS and increase the differential between the LGS-Secondary Block 1 rate and Block 2 rates so it is equal to the differential between the GS-Secondary Block 1 and Block 2 energy rates. *Id.* at p. 14. He testified the Tariff LGS Block 1 and Block 2 rates for the other voltage subclasses should

incorporate the loss factor adjustments as proposed by I&M. *Id.* at pp. 13-14. Mr. Bieber stated his recommended change does not result in cost-based rates, but it makes a step in the right direction towards improving the alignment between the charges and underlying costs for the LGS rate schedule. *Id.* at p. 14.

Walmart witness Chriss generally agreed with the position set forth by Kroger witness Bieber. He testified I&M'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. Intervenor Walmart Ex. 1 at pp. 21-29. According to Mr. Chriss, I&M's proposed rate design for Tariff LGS, like I&M's rate design for Tariff IP, is inconsistent with I&M's 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.* at p. 19 (quoting Petitioner's Ex. 20 at p. 9). Mr. Chriss recommended that at I&M's requested revenue level: (a) any approved revenue increase to the LGS class be applied to each service level's demand charge; (2) I&M maintain the first block energy charges at current levels; and (3) I&M 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. Intervenor Walmart Ex. 1 at pp. 21-30. In the event the Commission approves a lower revenue increase than I&M has requested, Mr. Chriss recommended the Commission apply Walmart's methodology at I&M's proposed revenue requirement but then apply the revenue requirement reduction to the energy charges. *Id.* at p. 1.

(b) Rebuttal. 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. Petitioner's Ex. 21 at pp. 15-16; Attachment MWN-R1. He testified that while he did not agree with each of Mr. Bieber's concepts and assumptions, he did not find the rates Kroger proposed unreasonable. *Id.* at p. 17. Likewise, Mr. Nollenberger stated he did not agree with each of Mr. Chriss' concepts and assumptions, but he did not find Walmart's proposed rate design methodology to be unreasonable; however, Mr. Nollenberger continued to support I&M's LGS rate design. Mr. Nollenberger noted that his assessment of Kroger's and Walmart's Tariff LGS proposals was based on the current revenue requirement level I&M is proposing. He testified if the revenue requirement level changes, a uniform change in all Tariff LGS rate components, excluding customer charges, may be more reasonable than a change focused on a specific rate component. *Id.*

(c) Discussion and Findings. The record shows Walmart's and Kroger's proposed rate designs improve the alignment between demand and energy charges and I&M's cost of service study, which results in rates that are more closely aligned with the underlying cost components and send customers more efficient price signals. Intervenor Walmart Ex. 1 at pp. 21-28, 31-32; Intervenor Kroger Ex. 1 at pp. 9-15. For these reasons, and also considering that Mr. Nollenberger found Walmart's and Kroger's proposals are not unreasonable, the Commission finds the principle underlying these Intervenor's proposed Tariff LGS-Secondary rate design is reasonable. Specifically, the Commission finds I&M should maintain the proposed demand charges for Tariff LGS and increase the differential between the LGS-Secondary Block 1 rate and Block 2 rates so it is equal to the differential between the GS-Secondary Block 1 and Block 2 energy rates. The Tariff LGS Block 1 and Block 2 rates for the

other voltage subclasses should incorporate the loss factor adjustments as proposed by I&M; provided, the Commission finds it is appropriate to apply any changes to I&M's proposed revenue requirement to all the LGS rate components, excluding customer charges, as Mr. Nollenberger proposed.

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

(a) I&M. Mr. Nollenberger testified the proposed changes to tariff classes MS and WSS align with I&M's general rate design objective of recovering proportional amounts of fixed costs through fixed and/or demand charges. Petitioner's Ex. 20 at pp. 27-28.

(b) Intervenors. Mr. Mancinelli testified I&M's implementation of a demand charge when presently no demand charges apply means some WSS customers jump from a demand charge of zero to as high as \$11.369 per kW in a single step. Intervenor Jt. Municipal Ex. 1 at p. 49. While Mr. Mancinelli agreed that adding a demand charge to the WSS rate structure incentivizes customers to improve load factors, he testified I&M's proposal is overly aggressive and unduly burdens lower load factor customers in the WSS class. *Id.* at p. 50. He recommended 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.* at pp. 50-53. Mr. Mancinelli testified that MS customers are also receiving significant rate increases due to the introduction of demand charges. *Id.* at pp. 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. *Id.* at 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 the month, whenever it occurs, 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. Intervenor South Bend Ex. 3 at pp. 41-43.

(c) Rebuttal. Mr. Nollenberger stated 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. Petitioner's Ex. 21 at p. 11. Mr. Nollenberger testified Mr. Mancinelli's Tariff MS recommendation is not an unreasonable alternative to I&M's proposed basic rate structure; however, he stated I&M disagrees with Mr. Mancinelli's recommendation to implement a flat energy charge (per kWh), which would conflict with the current Tariff GS block energy charge. Mr. Nollenberger testified 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. *Id.* at pp. 12-13.

(d) Discussion and Findings. Based on the record, the Commission finds that while it is reasonable for I&M to implement some level of demand charges into Tariffs MS and WSS to better reflect the cost to serve these customers, we concur with Mr. Mancinelli that the demand charges, as proposed, are aggressive. Mr. Mancinelli



proposes an hours-use rate structure be utilized to recover demand-related costs for I&M's Tariff WSS because this will be a more gradual approach, and he contends no demand charge should be applied to a Tariff MS customer's first 10 kW of monthly demand. Mr. Nollenberger found these are reasonable alternatives to I&M's initial proposal, but he recommended I&M be allowed to implement blocked base energy charges for Tariff MS comparable to Tariff GS and an energy charge for the PJM/OSS Rider under this alternative approach. The Commission finds this is an acceptable compromise because it enables I&M to recover some fixed costs from customers without customers absorbing aggressive rate increases because of a high monthly demand charge. Accordingly, the Commission approves the proposed rate design for Tariffs MS and WSS that Mr. Mancinelli recommended, as modified by Mr. Nollenberger in his rebuttal, consistent with the discussion above. In doing so, the Commission notes the record shows Mr. Seelye's proposal could require additional or alternative metering and related costs that are not reflected in I&M's test year forecast. Petitioner's Ex. 21 at p. 11.

### **B. Residential Rates.**

1. I&M. Mr. Nollenberger testified I&M is proposing two primary changes to its standard residential rate design. First, I&M proposes to increase the monthly service charge from \$10.50 to \$15.00. Second, 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. Petitioner's Ex. 20 at p. 15. Mr. Nollenberger stated I&M is also proposing a new optional residential rate schedule (Tariff RSD) that will be available as a pilot program for up to 4,000 customers. *Id.* at p. 25. He testified 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. *Id.* at pp. 25-26. Mr. Nollenberger discussed I&M's objective in offering this pilot tariff and described how I&M designed the proposed Tariff RSD rates. Petitioner's Ex. 20 at pp. 26-27.

2. OUC. Mr. Watkins testified that while Mr. Nollenberger asserts I&M's Tariff RS rate structure poses challenges for both customers and I&M, 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 over 100 years in the industry. Public's Ex. 12 at p. 40. He stated the electric industry continues to remain profitable under this rate structure. *Id.* Mr. Watkins testified I&M is utilizing a forecasted test year that incorporates normal weather conditions such that the revenue requirement established in this case is not based upon abnormal weather or other usage characteristics. He opined that I&M is a business enterprise and should not act as a governmental taxing agency with guaranteed revenue recovery. Mr. Watkins testified regulation should serve as a surrogate for competition for investor-owned utilities to the largest extent practical. *Id.* at p. 41. Mr. Watkins interpreted Mr. Nollenberger's testimony that I&M's proposal is cost justified as being based on his perception that I&M is entitled to a guaranteed recovery of fixed costs. According to Mr. Watkins, I&M's rate design proposals are nothing more than an attempt to further reduce the Company's risk of revenue collection. *Id.* at p. 41.

Mr. Watkins recommended there be no change in I&M's monthly residential service charge. He also recommended I&M maintain a flat volumetric energy rate per kWh of usage and compared I&M's proposal to the FERC's adoption of a straight-fixed variable ("SFV") pricing method. Public's Ex. 12 at p. 44. He testified the proposed customer charge and implementation

of a declining-block energy rate will promote additional consumption and stifle customers' abilities to manage their electric bills, whereas maintaining the current residential customer charges will promote rate continuity and conservation. *Id.* at p. 48. Mr. Watkins did not oppose the pilot Tariff RSD, but he recommended several administrative and reporting requirements in connection with the pilot program. *Id.* at pp. 48-49.

3. CAC-INCAA. Mr. Wallach testified I&M's proposal to increase the residential fixed charge will inappropriately shift load-related costs from the volumetric energy rate to the fixed service charge, dampen price signals to consumers about reducing energy usage, disproportionately and inequitably increase bills for I&M's smallest residential customers, and result in subsidization of larger residential customers' costs by customers with below-average usage. Accordingly, Mr. Wallach recommended I&M's proposal to increase the monthly fixed service charge for residential customers be rejected and, instead, the residential fixed service charge be set at a cost-based rate of \$10.12 per residential customer per month. Intervenor CAC-INCAA Ex. 2 at pp. 42-43. He also recommended I&M's proposed declining-block rate structure be rejected. *Id.* at p. 43. With respect to I&M's proposed Tariff RSD, Mr. Wallach expressed concern that the demand charge will dampen signals for conservation, encourage inefficient customer behavior, and undermine customers' ability to control electricity costs. *Id.* at pp. 43-44.

4. Rebuttal. On rebuttal, Mr. Nollenberger testified the OUCC and CAC-INCAA recommendations do not provide efficient price signals because they would overstate the variable cost associated with the incremental consumption or conservation of electricity. Petitioner's Ex. 21 at pp. 22-23. He testified 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. *Id.* at p. 24. Mr. Nollenberger stated I&M's rate design proposal will recover close to 90% of total residential costs through the volumetric energy charge and, thus, I&M is not proposing to implement a "high" customer charge or a straight-fixed variable rate structure. *Id.* at pp. 27-28. Mr. Burnett testified the OUCC and CAC-INCAA's positions rest on a hypothetical that does not reflect what is actually being proposed in this case. Petitioner's Ex. 36 at pp. 15-17. He testified actual experience following I&M's last rate case demonstrates increasing the fixed customer charge did not lead to an increase in residential usage. *Id.* at pp. 17-19. Mr. Burnett testified the proposed price signal here incentivizes I&M's customers to use electricity more efficiently. *Id.* at p. 18.

Mr. Nollenberger stated 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. Petitioner's Ex. 21 at p. 35. He stated the proposed pilot tariff, by including a demand charge in the overall rate structure, will provide the customer with a third dimension to control his or her bill as opposed to a two-part rate structure. *Id.* Mr. Cooper testified implementation of Tariff RSD will be similar to that of other new tariff offerings, and I&M will provide customers with information on this alternative. Petitioner's Ex. 9 at p. 7. He opined that Mr. Watkins failed to show why his proposed reporting and record keeping requirements related to the pilot are reasonable or show any potential benefits will be greater than the associated administrative costs. *Id.*

5. Discussion and Findings.

(a) Residential Customer Charge and Declining Block Rates.

The OUCC and CAC-INCAA opposition to I&M's customer charge and declining block rate proposal focused on whether I&M's proposed rate design will send inefficient price signals. Initially, it is noted I&M has not proposed SFV rates. In Cause No. 44576, the Commission approved an increase to IPL's customer charge and continuation of a declining-block rate structure, *Re Indianapolis Power & Light Co*, Cause No. 44576, p. 72, 2016 WL 1118795, 329 P.U.R.4th 486 (IURC March 16, 2016), finding IPL's increased customer charge was "demonstrably short of SFV rates." Here, I&M's rate design proposal, based on Mr. Nollenberger's testimony, will still recover close to 90% of total residential costs through the volumetric energy charge. Petitioner's Ex. 21 at pp. 27-28. The evidence does not show the customer charge, as designed, reaches the level of full distribution system fixed cost recovery. Moreover, based on Mr. Burnett's testimony, residential usage did not increase following the rate design changes approved in I&M's last rate case, contrary to OUCC and CAC-INCAA assertions otherwise. Petitioner's Ex. 36 at pp. 17-18. Cost recovery design alignment with cost causation principles sends efficient price signals to customers, allowing customers to make informed decisions regarding their consumption of the service being provided. The Commission finds I&M's proposed increase in the monthly customer charge is reasonable and consistent with effectuating gradual changes in Petitioner's rate structures. Generally, the Commission prefers gradual changes in rate structures.

With respect to I&M's declining-block rate structure, the record shows I&M's proposal is more cost-justified than collecting demand-related costs through a flat volumetric energy charge. Petitioner's Ex. 21 at p. 24. I&M's proposal to recover all customer-related costs, plus the total secondary distribution costs, through the combination of the monthly service charge and first block volumetric energy charge is a reasonable step towards a better alignment between the collection of these costs with the local, fixed nature of the costs; consequently, the Commission finds I&M's proposed residential rates are reasonable, just, non-discriminatory, and should be approved. We further find this structure does not violate principles of gradualism, noting gradualism "is best considered in the context of the entire customer bill and not discrete charges within the bill." *IPL*, Cause No. 44576, p. 72.

In approving I&M's proposed residential rates the Commission notes that multiple different sets of revenue allocation factors have been provided in this proceeding; consequently, following the issuance of this Order, we find prior to these rates going into effect, I&M shall submit a compliance under this Cause containing its full tariff and revenue proof for all customer classes.

(b) Optional Residential Demand Metered Tariff. 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, the Commission finds 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 I&M will provide customers with information on this tariff, including how to best utilize their electric service to provide a least cost, efficient solution to their specific energy needs. The Commission finds such customer education is important and integral to this pilot offering. With respect to the OUCC and CAC-

INCAA's recommended reporting requirements, we find such requirements to be unnecessary at this time. Although pilot programs generally serve as an opportunity to gather and obtain meaningful information, the Commission is not persuaded the information and related analysis suggested should be required in the absence of identified benefits.

C. **Riders.** I&M proposes to retain all existing rate adjustment mechanisms, with certain modifications, and to add one new mechanism – the AMI Rider. The Commission finds the unopposed continuation of certain I&M riders to be reasonable, and we find they should be approved. The contested riders and/or issues are discussed 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. Petitioner's Ex. 24 at p. 37. He testified I&M proposes to track the following costs incremental to the level included in base rates: (1) pre-tax return on net plant in-service; (2) depreciation and amortization expense; (3) property tax expense; (4) O&M expense; and (5) gross revenue conversion factor costs. *Id.* Mr. Williamson explained how the AMI Rider will be implemented and the deferred accounting authority I&M is requesting. *Id.* at pp. 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. Public's Ex. 3 at pp. 1, 9-11, 15.

(c) **Intervenors.** Kroger witness Bieber opposed the AMI Rider as single-issue ratemaking and stated it does not meet the generally accepted criteria for this type of regulatory treatment. Intervenor Kroger Ex. 1 at pp. 5, 23-24. Joint Municipal Group witness Cannady also opposed the AMI Rider to reconcile estimated AMI costs and testified if AMI deployment is approved, the Commission can conduct a prudence review of the costs in I&M's next rate case. Intervenor Jt. Municipal Ex. 2 at pp. 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. Intervenor Auburn Ex. 1 at p. 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 I&M's intent and proposal. Petitioner's Ex. 25 at p. 26. With respect to intervenors' testimony, Mr. Williamson explained why I&M's proposed AMI Rider, from his perspective, is a better option for I&M's customers. *Id.* at pp. 26-27. He testified the proposed AMI Rider is a better option for customers because it avoids compounding the rate impact in I&M's next general rate case when the deferral is then reflected in I&M's cost of service, in addition to the full cost of the AMI deployment. Mr. Williamson stated I&M's proposed AMI Rider better reflects the cost of providing service to customers over time, avoids compounding the costs onto future customers, and provides routine updates to the Commission and I&M's stakeholders. *Id.* at p. 27. He stated

Mr. Rutter's recommendation is troubling in many ways and should not be adopted by the Commission as it departs from proper accounting and ratemaking for the remaining book value of retired property. *Id.* at pp. 27-30.

(e) Discussion and Findings. As discussed above, as to Account 370 depreciation rates, the Commission accepts the rate I&M proposed which recognizes the movement planned to AMI meters. This is not, however, the same as approving rate recovery for AMI deployment as I&M proposed. Instead, the Commission is, in effect, approving depreciation expense in this proceeding that provides for the addition of the 2020 plant as presented on WP-JAC-2. The Commission is not persuaded additional incentive, such as that provided by I&M's proposed AMI Rider, is warranted in this Cause, particularly given I&M's stated intention to return to the Commission in the approximate time frame as completion of the planned transition to AMI at which time a prudence review can be conducted. The Commission, therefore, declines to approve I&M's proposal to recover AMI costs through an AMI Rider or its implementation.

## 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 Armstrong, there are presently no known regulations that would lead to an increase in I&M's environmental consumables or emissions allowance costs. Public's Ex. 10 at p. 14. She testified I&M's 2020 forecast includes only additional sodium bicarbonate use to support the proposed Enhanced DSI and the previously approved Unit 2 Selective Catalytic Reduction ("SCR"). *Id.* As for emissions allowances, she testified I&M is projecting \$1,160,000 in the test year, which is a small decrease from \$1,224,000 in 2018. *Id.* at p. 15. Ms. Aguilar testified the OUCC recommends the Enhanced DSI capital expenditure be denied and, therefore, the Commission deny any associated O&M for the sodium bicarbonate increases, and the OUCC is recommending \$13,830,135 be embedded in rates for environmental consumables and emission allowance costs. She testified if the Commission rejects her recommended denial of all Enhanced DSI costs for Rockport Units 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.* at pp. 15-16. Ms. Aguilar opposed tracking environmental consumables and emission allowances above or below the embedded base rate amount, stating such amounts are not variable and not expected to increase over the next few years. *Id.* at pp. 14-15, 28.

Mr. Blakley opposed continued tracking of I&M's consumables expense, i.e., the costs for chemicals used in the operation of pollution control equipment, in its ECR Rider. Public's Ex. 3 at p. 1. He testified that when a utility requests a base rate increase, the completed pollution control equipment with its associated costs should be included in base rates, and given the inclusion of a completed plant investment in base rates, it is inappropriate then to allow an

individual operating expense to continue to be tracked. *Id.* at p. 6. Mr. Blakely testified that tracking an associated individual expense after a completed plan investment has been included in base rates deviates from long-standing ratemaking principles. In this Cause, he stated I&M forecasted a pro forma amount of \$21,785,467 for consumables expense on a total Company basis while OUCC witness Aguilar supports a total company pro forma consumables expense of \$13,830,135. *Id.* According to Mr. Blakely, when the Commission determines the appropriate amount of consumable expense, that amount should be included in base rates along with the associated capital project(s). *Id.* Mr. Blakely opposed tracking expenses related to capital projects that have been embedded in base rates. *Id.* at pp. 1, 3-6, 14.

(c) ICC. ICC witness Medine testified that typically test-year pollution control consumables and emission allowances are embedded in base rates, but I&M is proposing an ECR Rider to track such expenses going forward. Intervenor ICC Ex. 1 at p. 17. Ms. Medine stated she does not object to the recovery of such costs in a rider provided I&M does not include the costs in its Rockport wholesale market offer price. *Id.* Ms. Medine testified DSI has comparatively high operating costs compared to dry and wet scrubbers. *Id.* at p. 18. Thus, the inclusion of high operating costs in I&M's offer price suppresses generation from the Rockport units, which further disadvantages the units. She testified that lower utilization reduces plant efficiency, increases O&M costs, and increases wear and tear on the units. *Id.*

(d) Rebuttal. Messrs. Williamson and Kerns responded to the OUCC and ICC positions and identified numerous factors contributing to the uncertainty and volatility around future consumables and allowances costs. Petitioner's Ex. 25 at pp. 19-21; Petitioner's Ex. 15 at pp. 2-5. In responding to Ms. Medine's testimony, Mr. Kerns testified 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. Petitioner's Ex. 15 at p. 5. He stated 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. *Id.*

(e) Discussion and Findings. The record shows I&M's consumables and allowances expenses are much like fuel costs in that they vary considerably based on how much the Rockport Units operate. Petitioner's Ex. 14 at pp. 25-26; Petitioner's Ex. 24 at p. 44. While the OUCC challenged the variability of these costs, the evidence shows consumables expenses have varied historically, are projected to continue to vary significantly (both up and down) over time, and that the primary drivers are PJM market prices and the fuel mixture. Petitioner's Ex. 15 at pp. 3-4. With respect to allowances costs, the record shows I&M has been able to reduce allowance costs to the benefit of customers, but volatility remains. New environmental regulations or restrictions can be introduced at any time, resulting in changes that are outside I&M's control. Other factors largely outside I&M's control can also impact market energy prices and the dispatch of the Rockport Units, resulting in changes to both consumables and allowances expenses. Petitioner's Ex. 25 at p. 19. I&M's proposal ensures customer rates ultimately reflect only the actual cost of consumables and allowances costs incurred to provide service. With respect to the ICC's recommendation, the Commission finds 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 through the prices

I&M charges for retail services. The Commission declines to pre-define how I&M offers its power into PJM as doing so, based on the evidence, could increase the cost of generation for I&M's customers by eliminating I&M's ability to manage costs. Accordingly, the Commission approves I&M's proposed changes to the ECR.

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. Petitioner's Ex. 12 at p. 27; Attachment NAH-8. Mr. Williamson stated I&M seeks to update the base cost of fuel and 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 testified circumstances today render it unnecessary for this issue to be revisited in each general rate case. Petitioner's Ex. 24 at p. 46. Mr. Williamson testified I&M also proposes to continue crediting customers for revenues associated with participation in I&M's voluntary renewable programs. *Id.* at p. 7.

(b) OUC. Mr. Eckert accepted I&M's recommended base cost of fuel and request for a permanent waiver of the purchased power benchmark. Public's Ex. 1 at pp. 18-20. He testified the OUC does 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.* at p. 19. Mr. Eckert stated I&M offers all its generation into the PJM market and controls only the generation availability and the day ahead offer price, and PJM controls the dispatch of I&M's generation. He recommended as a condition of permanently waiving the purchased power over the benchmark, I&M continue to provide in its initial FAC audit package: (1) all internal, external, and root cause analyses for any forced outages greater than 72 hours; and (2) its day ahead offers and the real time awards for the test days, requested by the OUC. Public's Ex. 1 at pp. 19-20.

Mr. Eckert also did not oppose the Commission continuing to allow I&M to include renewable energy certificate ("REC") revenues in its FAC filings, but he testified this should be contingent on I&M agreeing to allow the OUC a minimum of 35 days to review I&M's FAC proceedings. Public's Ex. 1 at pp. 18-20. Mr. Eckert recommended the Commission allow the OUC 35 days to file its FAC testimony after I&M files its case-in-chief in FAC proceedings. *Id.* at p. 18. He testified that under the applicable statute, the OUC only has 20 days to review an FAC filing. According to Mr. Eckert, I&M is the only utility filing its FAC semi-annually, which requires the OUC to review six months of data in 20 days. *Id.* Mr. Eckert testified that by agreement with Duke Energy, NIPSCO, Indianapolis Power & Light, and Vectren South, the OUC has 35 days within which to review three months of data and file the OUC's testimony after these utilities file their FAC applications. He testified I&M is proposing to continue to include the GPR in its FAC proceeding, and I&M's FAC proceeding is more involved because it requires review of six months of data. *Id.* He recommended if the Commission continues to allow I&M to include its GPR in its FAC filing, this approval be contingent on I&M's agreement to allow the OUC a minimum of 35 days to review I&M's FAC proceedings. *Id.* at p. 19.

(c) Rebuttal. Mr. Williamson testified that Mr. Eckert claims the OUC's need for additional review time is related to I&M adding the Green Power Rider ("GPR") revenues to the FAC proceeding, but Mr. Williamson stated the revenue calculation for

sales of renewable energy certificates (“RECs”) is a very simplistic calculation that does not justify additional days to review the FAC filing. Petitioner’s Ex. 25 at p. 67. Mr. Williamson also testified that while I&M makes its FAC filings on a semi-annual basis, the OUCC performs an interim audit that reviews, to a large degree, the first three months of the semi-annual period. *Id.*

(d) Discussion and Findings. 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 evidence demonstrates the factors that led to development of the benchmark conditions adopted in Cause No. 43306 have been heavily mitigated. Accordingly, under the conditions existing today, the Commission waives I&M’s need to provide testimony on this issue in its FAC filing. But, the Commission recognizes the conditions that exist today may not exist in the future; consequently, we find a permanent waiver is a bridge too far. Should circumstances change, the Commission is not foreclosing the option of reinstating the benchmark process if found reasonable in a future proceeding.

Finally, with respect to the OUCC’s request for additional FAC review time, the Commission notes the deadline for the OUCC to file its FAC report is set by statute. Ind. Code § 8-1-2-42(b). Based on the evidence, the inclusion of REC sales in the FAC proceeding should have minimal impact on reviewing this filing. Petitioner’s Ex. 25 at p. 67. We also note the OUCC performs an interim audit during which the first three months of the semi-annual FAC period are reviewed. I&M has committed to continue providing the OUCC and its consultant an audit package immediately following its FAC filing to expedite and facilitate the review process. Petitioner’s Ex. 25 at p. 67. The Commission finds the OUCC presented no compelling basis upon which to deviate from the statutory FAC filing process; provided, however, I&M shall continue to include the following in its initial FAC audit package provided to the OUCC: (1) all internal, external, and root cause analyses for any forced outages greater than 72 hours; and (2) its day ahead offers and the real time awards for the test days, as the OUCC requested. Public’s Ex. 1 at pp. 19-20.

#### 4. IM Green Rider.

(a) I&M. Mr. Lucas testified I&M is proposing to consolidate its 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. Petitioner’s Ex. 18 at p. 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.* at p. 35. Mr. Lucas stated large commercial and industrial customers can participate under the basic terms of the *IM Green* program or through a second option that 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.* at pp. 37-38. He testified participating customers will benefit from the ability to attribute some or all of their service to renewable generation sources at a reasonable, market-based rate, and all proceeds of the *IM Green* program, net of any negotiated administrative fees associated with tailored commercial and industrial arrangements, will be used



to offset the cost of the FAC Rider for all customers. He stated this ensures all customers will benefit from program participation. *Id.* at pp. 38-38.

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 he discussed I&M's proposed treatment of RECs that customers purchase. Petitioner's Ex. 8 at pp. 17-19.

(b) OUCC. Ms. Aguilar supported I&M's proposal to consolidate the existing GPR and REO into the new *IM Green* Rider. She testified this proposal provides a lower cost option for I&M customers to obtain RECs than the existing GPR and REO options. Public's Ex. 10 at p. 7. She recommended I&M investigate sourcing RECs from a voluntary market, which she stated is typically more affordable than using I&M's own generated RECs that can be sold on the market and the proceeds passed on to ratepayers. *Id.* at p. 8. Ms. Aguilar expressed concern with I&M's current strategy for unsubscribed RECs. She testified I&M currently has a large inventory of RECs it does not monetize and only actively retires RECs customers purchase through its green power riders. Ms. Aguilar also testified I&M makes general claims that certain amounts of generation and energy consumption are carbon free or green; however, she stated I&M does not account for how many of the RECs represent these claims. Ms. Aguilar opined that I&M's strategy for REC management may run afoul of the Federal Trade Commission's green guide obligations. *Id.* at p. 11. She testified the OUCC recommends I&M monetize unsubscribed RECs and pass the proceeds onto ratepayers through the FAC for the benefit of all ratepayers. She testified the OUCC does not oppose I&M's proposal to consolidate the GPR and REO into a single *IM Green* Rider, but the OUCC recommends I&M investigate supplying the programs offered through the *IM Green* Rider with more affordable RECs from the voluntary market so the *IM Green* Rider allows customers to purchase renewable energy at an economical rate. Public's Ex. 10 at p. 13.

(c) Intervenors. Industrial Group witness Dauphinais recommended I&M work with its large customers to provide expanded options for those customers. Intervenor IG Ex. 2 at pp. 3, 32-33. Specifically, he testified 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 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, but he proposed alternative language related to REC pricing to remove the reference to New Jersey solar RECs as a basis for pricing this option. Intervenor Walmart Ex. 1 at pp. 6-7, 35-37.

(d) Rebuttal. Mr. Lucas stated 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. Petitioner's Ex. 19 at pp. 27-29. He testified I&M appreciates Walmart's leadership in developing renewable energy resources and Walmart witness Chriss' explanation of Walmart's channels for securing renewable energy resources. He acknowledged this testimony reflects Walmart's extensive experience working with utilities on innovative approaches to bring renewable energy to areas that are currently underserved. Mr. Lucas testified I&M would be interested in exploring utility partnership opportunities in northeast Indiana similar to the example projects included in Mr. Chriss'

testimony and will bring the proposed structure of those opportunities before the Commission at the appropriate time. Petitioner's Ex. 19 at p. 29.

Mr. Lucas stated that with respect to the *IM Green* program, I&M included the reference to the New Jersey REC to establish a market based index to value the price of RECs absent a market in the State of Indiana. He testified I&M believes this index provides a reasonable and independent pricing basis for customers interested in purchasing REC through the program. *Id.* at pp. 29-20.

(e) Discussion and Findings. 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. Petitioner's Ex. 18 at pp. 35-36; Petitioner's Ex. 8 at pp. 17-18. While the OUCC recommended I&M be required to monetize all of its unsubscribed RECs, the record shows this requirement would prevent I&M and its customers from claiming part of their generation came from carbon free energy sources and is contrary to the expressed interest from I&M's customers that I&M provide energy from renewable resources, Petitioner's Ex. 19 at p. 28; provided, however, the Commission finds if I&M is in possession of RECs that will expire without I&M claiming their environmental benefits, I&M should offer the RECs for sale and use the proceeds from any sale to reduce the cost of fuel in its FAC.

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. p. 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 would provide a relatively stable price index, Petitioner's Ex. 8 at pp. 17-18, but based on Mr. Chriss' testimony, the Commission is persuaded the reference to New Jersey REC pricing in the custom agreement option should be replaced by the following language Intervenor Walmart proposed, which we find is also reasonable: "Charges for service under this option will be set forth in the written agreement between the Company and the Customer and will reflect a combination of the tariff service rates otherwise available to the Customer and the cost of the renewable energy being contracted for by the Customer." 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, the Commission directs I&M to promptly begin pursuing and entering into these agreements with larger customers, and we find the *IM Green* Rider should be approved as proposed by I&M, subject to the foregoing discussion and findings.

5. Off-System Sales Margin Sharing.

(a) I&M. I&M proposes to continue sharing OSS margins on a 95/5 basis, meaning 95% goes to customers and 5% goes to I&M, with zero embedded in base rates. Petitioner's Ex. 24 at pp. 7-8; 48-49. Mr. Williamson said continuing to share OSS margins is reasonable because it provides an incentive for I&M to maximize the benefits of OSS for both

the Company and its customers. *Id.* at p. 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.* at pp. 49-50. Mr. Williamson testified 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 I&M's control, and in total, OSS margins are significant and can vary significantly from year to year. *Id.* at p. 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. Public's Ex. 5 at pp. 1, 5-8, 13. He testified it is ratepayers who pay I&M's retail rates to support the O&M expenses and provide a return on rate base for the assets that create the opportunity for OSS sales; therefore, I&M ratepayers should be the ones benefitting from OSS margins. *Id.* at p. 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, IM'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 with 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 OSS margin outcomes and should not be entitled to receive OSS margin revenues. *Id.* Likewise, Mr. Lantrip testified if the OSS margins are handled through PJM's administration, and I&M passes through these administrative fees to ratepayers, then ratepayers are the rightful beneficiaries of the OSS margins. *Id.* at pp. 7-8. Finally, although Mr. Williamson stated I&M's commercial operations organization provides substantial value to I&M and its customers by optimizing I&M's OSS margins, Mr. Lantrip testified that maximizing the use of I&M's generation facilities is something I&M should do as part of prudent utility business practice. Mitigating the costs its customers are paying for those generation facilities should not necessitate an incentive. *Id.* at p. 8.

(c) Intervenors. The Industrial Group and Joint Municipal Group both proposed 100% of OSS margins above zero be allocated to I&M's customers. Intervenor IG Ex. 2 at pp. 3, 30-31, 33; Intervenor Jt. Municipal Ex. 1 at pp. 3-4, 28-30, 59. Industrial Group witness Dauphinais testified I&M does not need an incentive to make OSS because the Company is required to offer all of its generation into the PJM day ahead and real time energy markets. He further testified I&M does not need an incentive to make OSS because I&M is already required to offer all of its generation into the PJM markets on a daily basis. Intervenor IG Ex. 2 at p. 30. Mr. Dauphinais stated customers should be entitled to the entirety of I&M's OSS margins because those OSS margins would not be possible but for the utility's customers covering the fixed costs of the generating units that make those OSS margins possible. *Id.* at pp. 30-31. Mr. Mancinelli testified 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 investments; and (3) OSS provide other benefits to the Company such as efficient use of generation assets. Intervenor Jt. Municipal Ex. 1 at pp. 29-30. 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. Intervenor Kroger Ex. 1 at pp. 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 stated 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 margins to reduce the cost of providing service to all customers. Petitioner's Ex. 25 at pp. 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 I&M is taking to create the value being shared with customers. *Id.* at p. 23. Mr. Williamson objected to Kroger's alternative proposal, stating embedding such a high level of OSS margins shifts a significant amount of risk to I&M's shareholders in exchange for a very small potential benefit of retaining 5% if annual OSS margins exceed the test year level. *Id.* at pp. 25-26.

(e) Discussion and Findings. I&M proposes to continue its existing OSS margin sharing mechanism. The OUCC and intervenors propose to change the current mechanism to provide 100% of Indiana jurisdictional OSS margins to customers. The Commission finds the OUCC and intervenors have convincingly shown a continued sharing of these OSS margins is not warranted, reasonable, or appropriate. 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 does not merit an additional incentive beyond what has already been provided through regulatory approval; therefore, the Commission approves the OUCC's and intervenors' proposal to embed zero dollars of Indiana jurisdictional OSS margins in I&M's base rates with 100% of OSS margins above zero through the OSS/PJM Rider to benefit I&M's ratepayers. With respect to Kroger's proposal to embed \$38.4 million in base rates, we find embedding zero dollars is more appropriate because it avoids artificially reducing I&M's revenue requirement. Otherwise, if an amount is embedded in basic rates, a decline in OSS margins going forward could dramatically reduce I&M's operating income. Petitioner's Ex. 43 at pp. 21-23.

## 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 stated 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. Petitioner's Ex. 24 at pp. 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". *Id.* at p. 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 risk associated with these PJM rules. *Id.* Mr. Thomas also supported the reasonableness of the Capacity Performance Insurance expense in light of the potential risk it mitigates. He testified the cost for Capacity Performance Insurance is a reasonable and necessary cost of being a PJM member and should be recovered through the PJM Rider. Petitioner's Ex. 1 at pp. 33-34.

Mr. Ali testified I&M currently has three distinct roles within PJM. He described I&M's role as a Generator, Load Serving Entity, and Transmission Owner ("TO") in PJM and the various charges and credits I&M experiences from each role. Petitioner's Ex. 29 at pp. 7-9. He testified 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.* at p. 9. Mr. Ali discussed the transmission planning process and the forecast of PJM revenues and charges. *Id.* at pp. 9-19. He stated the costs to be recovered through the OSS/PJM Rider are significant, and the NITS costs in particular are expected to increase. *Id.* at pp. 19-20. He testified NITS costs are potentially variable or volatile and are largely outside of I&M's control. *Id.* at pp. 20-21. Mr. Ali testified NITS costs are a necessary cost to maintain the reliability of the transmission grid and ensure all users equal transmission system access. He stated continued recovery of NITS costs through the OSS/PJM Rider remains a reasonable process. *Id.* at pp. 21-22.

(b) OUCC. Mr. Gahimer contended the AEP Transmission Agreement and creation of I&M Transco ceded I&M's control of its NITS charges to other AEP affiliates; therefore, the proposal to continue to track NITS charges should be denied. Public's Ex. 7 at pp. 6-7, 20. More specifically, he stated that in I&M's service territory, transmission is owned by I&M and I&M Transco. *Id.* at p. 6. Mr. Gahimer testified through the AEP Transmission Agreement, each of the AEP Operating Companies providing utility service in PJM's footprint pays a share of the NITS costs associated with every Attachment H-14 and H-20 transmission facility in the PJM AEP East footprint, not just the projects it owns or even those in its own service territory. *Id.* at pp. 6-7. He stated by shifting some of I&M's transmission costs to other AEP utilities, the AEP Transmission Agreement effectively cedes some of the other AEP utilities' control to I&M while ceding some of I&M's control to them. *Id.* at p. 7. Mr. Gahimer proposed the estimated test year level of NITS charges be included in base rates, subject to a compliance filing through which base rates are adjusted downward if I&M's actual NITS charges are lower than the estimated level. Public's Ex. 7 at p. 27. With respect to the PJM Capacity Performance insurance cost, Mr. Gahimer stated this insurance is discretionary, not required, and because I&M failed to demonstrate the premiums were prudently incurred, these costs should not be recovered from ratepayers. *Id.* at pp. 22-27. Mr. Lantrip testified continued tracking of non-NITS costs seems appropriate at this time, as well as I&M's proposal to embed forecasted test year level of all non-NITS costs in base rates. *Id.* at pp. 8, 13-14.

(c) Intervenors. Industrial Group witness Dauphinais and Kroger witness Bieber opposed NITS tracking, stating the costs are largely under the control of I&M and its affiliates and are not volatile or variable in a manner that warrants a tracker. Intervenor IG Ex. 2 at p. 15. Mr. Dauphinais stated 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, he stated the NITS costs are largely within the control of I&M and its affiliates and should be recovered through base rates. *Id.* 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. *Id.* He testified the NITS costs have nearly consistently grown since 2012 and are forecasted to continue to consistently grow through at least 2021. *Id.* at pp. 15-16. He added the only 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.

Mr. Dauphinais testified that due to their consistently upward behavior, these costs also represent the worst type of costs to track and recover through a rate adjustment rider because such recovery allows the utility to recover a single known rising cost outside a base rate case in which all utility expenses and revenues are examined and, perhaps, offset all or part of the rising cost.

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. *Id.* at p. 17. He stated at least some of the projected growth may be due to the lack of independent review and I&M's parent company's strategic plans, as opposed to demonstrated need. He stated there is evidence it is likely a very large portion of the transmission capital expenditures of I&M and its AEP East affiliates driving I&M's forecasted large growth in NITS costs between 2019 and 2023 is for Supplemental Projects and Non-Topology Projects proposed by I&M and its AEP East affiliates rather than PJM. He noted such projects are what Mr. Ali collectively refers to as "Owner Projects" on page 11 of his direct testimony.

Mr. Dauphinais testified that Supplemental Projects are projects that change the transmission network and are proposed by TOs like I&M and its affiliates rather than by PJM. He stated 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. He testified Non-Topology Projects are projects that do not change the transmission network. *Id.* at pp. 17-18. He stated 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 (60%) of the \$321.20 million of I&M and I&M Transco NITS capital project costs I&M identified as being started in 2019 are for Supplemental or Non-Topology capital projects. *Id.* at p. 24. 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 not to believe a similarly 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. *Id.*

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. As a result, the AEP Service Corporation employees who propose the Supplemental and Non-Topology capital projects AEP would like pursued 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. *Id.* at pp. 26-27.

In support of his testimony, Mr. Dauphinais provided a copy of an article posted on AEP's website as of June 8, 2018, titled, "Investing in Transmission." He testified the article

notes that AEP's Chairman, President, and Chief Executive Officer has called AEP Transmission "the flagship" of the organization [AEP and its subsidiaries]. He testified the article 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. Intervenor IG Ex. 2 at p. 27. He testified the article further 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.

Intervenor IG Ex. 2 at p. 27. Mr. Dauphinais stated 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. *Id.*

Ms. Cannady recommended disallowing recovery of the PJM Capacity Performance 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 I&M's control. Intervenor Jt. Municipal Ex. 2 at pp. 4, 33. In addition, Ms. Cannady noted under the PJM Capacity Performance Rules, I&M could possibly receive compensation for the non-performance of other PJM members. *Id.* at pp. 34-35. Mr. Bieber testified I&M earns a rate of return on its production plant that is intended to provide an appropriate balance between the risks and rewards for I&M's operations. He stated if I&M elects to purchase insurance to mitigate its operational risk from incurring a non-performance charge for failure to meet PJM's resource requirements, that cost should not be passed on to customers. Intervenor Kroger Ex. 1 at p. 5.

(d) Rebuttal. Mr. Williamson testified a review of historical and future trends demonstrates from year to year NITS costs are subject to change. Petitioner's Ex. 25 at p. 7. He stated 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. Mr. Williamson disagreed that tracking PJM costs reduces or eliminates I&M'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.* at p. 13. Mr. Williamson reiterated that PJM NITS charges are expected to increase significantly the year following the test year, and if I&M does not continue to track PJM NITS as the Company proposed, I&M's earned ROE will decrease by approximately 1.90% in the first calendar year following this rate case, making I&M's earned ROE less than any intervenor recommended. *Id.* at p. 12. Mr. Williamson testified it is clear not tracking PJM NITS will eliminate any reasonable opportunity I&M has to earn its authorized return. *Id.*

Mr. Ali disagreed with Messrs. Dauphinais and Gahimer's contention that I&M has ceded control. He stated I&M does not have control over costs other TOs in the AEP Zone incur, including AEP affiliates, just as other TOs and their respective state utility commissions do not have control over I&M's costs. Petitioner's Ex. 30 at p. 6. He testified projects giving rise to I&M's NITS expenses are outside the control of I&M and its affiliates because TOs cannot

decline to make reasonable and necessary investments in the transmission grid. Mr. Ali stated 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. *Id.* at p. 5. He testified 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 Good Utility Practice requirements that are the foundation for utility planning and operations and continue to be imposed on the RTO TOs by FERC. *Id.* at p. 6. Mr. Ali stated, ultimately, AEP's structure does not supplant the respective obligations of the RTO members to fulfill their respective public utility obligations to serve. *Id.* at pp. 6-7. Rather, 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.* at p. 7.

Mr. Ali testified the transmission projects are subject to a robust PJM and stakeholder process which provides the opportunity for stakeholders to review and provide input regarding Owner Projects. Petitioner's Ex. 30 at p. 7; *see also* Petitioner's Ex. 25 at p. 13. He discussed the multiple opportunities for stakeholders to comment, provide input on additional needs, and propose alternative solutions for PJM TOs to consider. Petitioner's Ex. 30 at p. 8. Mr. Ali testified I&M and AEP consider all input stakeholders provide. *Id.* Additionally, he stated I&M and AEPSC Transmission include the stakeholders directly impacted by a given project in the project's development, and prior to its submission as a Solution, coordinate with PJM stakeholders to ensure direct impacts are considered in identifying and evaluating potential Solutions. *Id.* at pp. 8-9. Mr. Ali stated I&M and AEPSC Transmission also go beyond what the M-3 Process requires by annually meeting with customers to discuss transmission needs, thereby providing an additional opportunity for stakeholder feedback. *Id.* at p. 9.

Mr. Ali 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.* at pp. 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.* at p. 11. Instead, Mr. Ali testified 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.* at p. 12. He testified 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.* at p. 13. Mr. Ali stated 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 testified the question is not whether I&M is required to purchase this insurance, but whether doing so is a reasonable cost of doing business. Petitioner's Ex. 2 at p. 7. He stated I&M considered both the risk of an event occurring and its consequence in making the decision to purchase this insurance, and like



the cost of I&M's other types of insurance, it should be recognized as a reasonable and necessary cost of service. *Id.* at pp. 7-8. Mr. Hevert responded to Mr. Bieber's testimony and stated if Mr. Bieber's proposal are adopted, this will require an increase in the authorized ROE. Petitioner's Ex. 27 at pp. 95-96.

(e) Discussion and Findings. No party disputes that NITS costs are significant and projected to increase. The OUCC, Industrial Group, and Kroger recommend recovery of I&M's test year PJM NITS costs. Thus, the pivotal question is whether I&M should continue to track these costs as I&M proposed. The Commission finds substantial evidence, particularly I&M's rebuttal testimony highlighted above, supports I&M's proposal.

I&M has been and remains a member of PJM as encouraged and authorized by this Commission. *Re Commission's Investigation*, Cause Nos. 42350/42352 (IURC September 10, 2003). I&M incurs costs for transmission service provided to its customers entirely based on FERC-regulated and approved charges from PJM. The record shows I&M's membership in PJM has allowed I&M's customers to benefit from the independent, regionally operated, and jointly planned and coordinated PJM transmission grid. This grid enhances competitive wholesale markets, resource diversity, and system reliability and security. Petitioner's Ex. 2 at p. 4. Based on the evidence, it is reasonable that I&M recover the costs it incurs based on the PJM structure as this is the structure I&M operates under.

Substantial evidence shows NITS costs are variable and subject to potentially significant changes due to market and economic conditions, public policy, NERC and FERC requirements, environmental and state regulatory requirements, and other factors that can be unpredictable. Petitioner's Ex. 24 at pp. 52-53; Petitioner's Ex. 25 at p. 7; Petitioner's Ex. 29 at p. 20; Petitioner's Ex. 30 at pp. 4-7. The record also shows the drivers of transmission projects are not under I&M's exclusive control, and include regulatory requirements, interconnection requests, asset performance, and the need for modernization of protection and control systems. Petitioner's Ex. 29 at p. 13. While the OUCC asserted AEP's corporate structure warranted denying I&M's request to track NITS costs, the record shows that although other TOs may be I&M affiliates, this does not alter the obligation each TO has to pursue prudent projects to address safety, security, and efficiency as well as asset condition, performance, and risk to provide reliable service in that owner's service territory. Petitioner's Ex. 30 at p. 6. Moreover, the record shows I&M's customers benefit through the coordinated efforts of the AEPSC Transmission organization that supports I&M and other affiliates and allows AEP to achieve economies of scale, maintain low costs, and provide operational expertise and efficiencies in managing the I&M transmission system. *Id.* at p. 14. Accordingly, the Commission finds the AEP Transmission Agreement and the formation of I&M Transco are not themselves grounds to deny continued tracking of NITS costs.

The record also shows denial of I&M's request for continued tracking of NITS costs could significantly decrease I&M's earned ROE in the first calendar year following this rate case, making I&M's earned ROE less than any intervenor recommended and lower than the Commission found above is reasonable. Petitioner's Ex. 25 at p. 12. Based upon the evidence, the Commission finds I&M's request to embed the forecasted test year level of non-NITS PJM costs and track any annual over/under variance from the embedded level should be approved. I&M is further authorized to continue to recover 100% of NITS charges through the OSS/PJM

Rider, with no amount of NITS costs embedded in base rates. In arriving at this determination, the Commission acknowledges concern over the magnitude of the projected NITS cost increases and is not closing the door on a docket or subdocket investigation potentially being opened in the future to review NITS charges, particularly if these spiral after the cumulative cap agreed upon in the Settlement Agreement in Cause No. 44967, p. 5, ¶ 3.1 expires.

With respect to the PJM Capacity Performance Insurance premium, the record shows PJM made changes to its capacity performance rules that create the potential for I&M to be subject to significant penalties if any of I&M's resources are experiencing an unexpected forced outage and are not available during a performance assessment interval, Petitioner's Ex. 2 at p. 6; consequently, I&M, like other generator owners in PJM, has acquired Capacity Performance Insurance to offset the risk of generator non-performance. *Id.* Insurance is generally an accepted means of safeguarding against loss, and the OUCC and intervenors have not persuaded the Commission this particular insurance should be treated differently than other types of insurance recognized as a reasonable and necessary cost of service. The annual premium expense is currently a fraction of the potential Non Performance Charges that could be in the tens of millions of dollars per event. To mitigate this risk, the Commission approves I&M's proposal to embed in base rates \$1.5 million for the annual cost of PJM Capacity Performance Insurance, but any annual over/under variance from the embedded level is not authorized to be tracked. The variability and materiality of the prospective premium charges were not shown to support tracking at this time. Given I&M's plan to file its next rate case within two years, the benefit of additional data points should be available at that time to further consider this topic if warranted.

Notwithstanding our findings above, the Commission recognizes the PJM capacity performance construct was in place a relatively short time for purposes of evaluating Capacity Performance Insurance in this proceeding. For continued recovery of this premium, I&M is directed to more robustly explain in its next rate case, given I&M's experience by then and any penalties assessed, the Company's analysis of its risk under PJM's capacity performance rules, including identifying the coverage the Capacity Performance Insurance provides with respect to this risk and any potential coverage gap. I&M should also provide a copy of the policy then in effect and the assessment I&M performed of its penalty risk in determining the coverage secured.

#### 7. Resource Adequacy Rider ("RAR").

(a) I&M. 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 stated 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. Petitioner's Ex. 24 at pp. 54-55.

(b) OUCC. Mr. Lantrip did not oppose I&M's request to continue the RAR and recommended any excess capacity sales be passed back to customers through the RAR as a means of reducing capacity purchase costs. Public's Ex. 5 at pp. 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. Intervenor IG Ex. 2 at pp. 3, 31-33; Intervenor Kroger Ex. 1 at pp. 22-23. Mr. Dauphinais testified these costs are not volatile, but rather, are relatively predictable rising costs. Intervenor IG Ex. 2 at p. 32. He also noted the tracked costs would be for the recovery of costs that are paid to I&M affiliates. *Id.* He testified affiliated costs should not be tracked as there would be less incentive than normal for I&M to keep these costs in line. *Id.* Finally, Mr. Dauphinais 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 a base rate proceeding provides, not RAR reconciliation proceedings. *Id.* Mr. Bieber asserted that tracking these costs reduces the inherent incentive for I&M to manage its costs. Intervenor Kroger Ex. 1 at p. 24.

(d) Rebuttal. Mr. Williamson supported tracking both capacity purchases and sales through the RAR as the OUCC proposed. He stated the main arguments the Industrial Group and Kroger raised to continue tracking directly conflict with OUCC witness Lantrip's testimony. Mr. Williamson stated 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. Petitioner's Ex. 25 at pp. 21-23. He also disagreed that tracking these costs will influence any incentive I&M has to manage the underlying costs. Mr. Williamson testified 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.* at p. 22.

(e) Discussion and Findings. Both I&M and the OUCC support continued tracking of purchased power costs through the RAR. While the Industrial Group and Kroger witnesses suggest these costs are not sufficiently variable to warrant tracking, the evidence shows these costs to be significant in amount and variable across years. Public's Ex. 5 at p. 4. The record further shows these costs are currently subject to FERC-approved and regulated purchased power contracts and are, thus, largely outside I&M's control. Petitioner's Ex. 24 at pp. 54-55. The Commission finds continued use of the RAR will help 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. The Commission, therefore, approves 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 asserted 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. Intervenor ICC Ex. 1 at pp. 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) determine what, if any, of these incremental costs should be recoverable. *Id.* at p. 5.

2. Rebuttal. Mr. Thomas testified Ms. Medine's recommendations are based on her findings and statements that are simply wrong. Petitioner's Ex. 2 at p. 26. He stated there is 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.* at pp. 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.* at p. 27. Mr. Thomas testified that while the deadline was extended 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 stated, 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." Petitioner's Ex. 2 at p. 27; Attachment TLT-1R. Mr. Thomas testified 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. Petitioner's Ex. 2 at p. 27. He noted the Fifth Joint Modification provides that optionality for the owners to exercise if they choose. *Id.* Mr. Thomas testified the appropriate forum to consider the resources to serve I&M's customers is through I&M's periodic IRP process, not a general rate case. *Id.* He testified 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 Findings. The record shows the ICC's request to investigate I&M options for keeping Rockport Unit 2 on line past 2028 is based on a faulty premise. More specifically, the record evidences that decisions about the continued operation of Rockport Unit 2 will be made by the owners of the unit, not I&M. Petitioner's Ex. 2 at p. 27. Further, Ms. Medine's assertions that I&M failed to timely install the Rockport Unit 2 SCR, and the costs related to the Fifth Modification "are akin to a fine for failure to perform, not a regulatory requirement" are not substantiated by the evidence. More specifically, Mr. Thomas testified installation of the Rockport Unit 2 SCR is proceeding on track and is expected to be in operation by the time set forth in the Consent Decree. *Id.* In other words, there has been no failure to timely install the Rockport Unit 2 SCR. Similarly, Ms. Medine's claim that the requirements of the Fifth Modification are a "penalty" is contradicted by the plain language of the Consent Decree, which states it is being entered into "without any admission by Defendants, and without adjudication of the violations alleged in the complaints or the [Notices of Violations]". I&M Admin. Notice 3 (AEP Consent Decree), p. 8 of 121; *see also* Petitioner's Ex. 2 at p. 27; Attachment TLT-1R at 4 (explaining the AEP Companies "admitted no violations of law and all claims against them were released"). Finally, the issue Ms. Medine raises relates to I&M's resource planning; consequently, we find the appropriate forum to consider the resources to serve I&M's customers is through its periodic IRP process, not this general rate case. Petitioner's Ex. 2 at p. 27. The ICC's request for an investigation is, therefore, denied.

## B. Streetlighting.

1. South Bend. South Bend witness Dorau stated I&M's rates for LED streetlighting conversions are overstated and unreasonable. Intervenor South Bend Ex. 1 at p. 19. She stated streetlights are an essential public service which promotes public safety and economic development. *Id.* at p. 20. Ms. Dorau testified every street light fixture I&M installs at South Bend's request, while adding to safety and quality of life, 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. Intervenor South Bend Ex. 3 at pp. 4, 35-37. He testified there appears to be an error in the development of I&M's proposed streetlighting rates in that while SL rates were 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.* at p. 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.* at pp. 33-35. Mr. Seelye also asserted there are flaws in I&M's Public Efficient Streetlight ("PES") program because it fails to capture the significant O&M savings that results from converting to LED lights. *Id.* at pp. 37-40. Mr. Seelye presented revised lighting rates for Tariffs ECLS and SLS. *Id.* at pp. 40-41; Attachment WSS-11.

Mr. Sommer testified LED streetlights have substantially reduced maintenance costs associated with the LED fixture, longer lives, and require reduced energy use. Intervenor South Bend Ex. 2 at p. 13. He stated LED maintenance costs should be about 25% of what they are for HPS. He also stated LED streetlights are more durable, last more than three times as long as an HPS bulb, need limited cleaning, and have substantially lower energy costs. *Id.* Mr. Sommer testified I&M should be ordered to revise its LED streetlighting rates to reflect lower maintenance costs and longer fixture lives, Intervenor South Bend Ex. 2 at pp. 5, 12-17, and should also be required to work with interested municipalities to fashion a mass LED retrofit plan that meets each municipality's needs and results in economy of scale retrofit savings. *Id.* at pp. 17-18.

2. Rebuttal. Mr. Nollenberger testified I&M is not proposing new LED-specific basic rates in this proceeding. Petitioner's Ex. 21 at p. 36. He stated on May 31, 2019, I&M filed a 30-day filing with the Commission requesting LED rates for tariff classes OL, ECLS, and SLC, and the Commission approved I&M's 30-day filing on July 10, 2019. *Id.* In responding to Mr. Seelye's claim that there are errors in I&M's proposed street lighting rates in this case, Mr. Nollenberger testified the proposed rate increases Mr. Seelye identifies are specific to the basic rate components and ignores the effect of "Fuel + All Riders" identified in each of the applicable pages of his workpaper WP-MWN-4. Petitioner's Ex. 21 at pp. 36-37. He testified page 46 of WP-MWN-4 summarizes I&M's proposed total revenue change across all streetlighting 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.* at p. 37.

Mr. Nollenberger also responded to Mr. Seelye's testimony upon the impact of the change in I&M's fuel basing point on streetlighting rates. He stated in isolation, a reduction in the fuel basing point should result in a net decrease in basic rates. Petitioner's Ex. 21 at pp. 37-38. However, Mr. Nollenberger testified I&M's case includes the movement of various revenue

recoveries from I&M's riders to its basic rates; therefore, it is necessary to account for the net effect of fuel and all other riders when assessing the change in I&M's proposed basic rates. *Id.* at p. 38. Mr. Nollenberger 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 testified the O&M costs included in developing I&M's streetlighting rates are not significantly overstated. Petitioner's Ex. 21 at p. 39. He added that if Mr. Seelye was correct that I&M'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 collect the fully supported embedded costs from I&M's class cost of service study. *Id.* With respect to the PES Program rates, Mr. Nollenberger testified he updated the PES conversion rates following the methodology agreed upon in the settlement in Cause No. 44841. *Id.* at p. 40. And, he disagreed with the recalculated Tariffs ECLS and SLS rates Mr. Seelye presented. *Id.* at p. 41.

Mr. Lucas agreed with the general concept that LED street lighting technology can be beneficial. Petitioner's Ex. 19 at p. 21. He stated the issue is how best to implement a mass conversion from existing street lighting technology to new LED technology for the customers seeking to move to LED technology. Mr. Lucas testified a mass conversion project requires new capital investment, and this cost must be reflected in the rates charged streetlighting customers who elect a mass conversion. *Id.* He stated it would not be in I&M's interest or the interest of its customers for I&M 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.* at pp. 21-22.

Mr. Lucas testified the PES Program approved in Cause No. 44841 reflects I&M's effort to facilitate mass conversion projects. Petitioner's Ex. 19 at p. 22. He stated 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.* Mr. Lucas testified there are no current or forecasted participants in the PES Program, which expires at the end of 2019; therefore, it is unnecessary for the Commission to address the criticisms of the current PES Program in this general rate case. *Id.* at p. 22. He testified that 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. Mr. Lucas proposed I&M work with South Bend regarding the concerns raised with the design and implementation of the PES Program in that separate docket. *Id.* at pp. 22-23.

3. Discussion and Findings. Initially, the Commission notes I&M is not proposing any LED-specific basic rates in this case since the Commission approved such rates on July 10, 2019, in a 30-day filing (No. 50279). The record shows Mr. Seelye's testimony upon alleged errors in calculating I&M's street lighting rates is based on an incorrect understanding of I&M's rate design. Mr. Nollenberger testified on rebuttal 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. Petitioner's Ex. 21 at p. 37. The Commission is, nevertheless, concerned that I&M's cost of service study supports a rate decrease for the street lighting rate class, but under I&M's proposal, there is no rate decrease; consequently, the Commission finds, consistent with our discussion above, that the revenue increase approved in this Cause shall be reallocated to reduce the street lighting class subsidy by

50% to better reflect the cost of service. The street lighting rates should be reduced, not held constant, to reflect the subsidy reduction.

With respect to the PES Program, the existing PES Program was to expire at the end of 2019, and there were no current or forecasted participants. Petitioner's Ex. 19 at p. 22. Based on Mr. Lucas' rebuttal testimony, I&M has proposed a revised PES Program in Cause No. 45285 in connection with I&M's pending DSM Plan. The revised PES Program apparently includes updated energy savings and incremental measure costs. Petitioner's Ex. 19 at pp. 22-23. Given the record, the Commission finds there is no need to address South Bend's criticisms of the current PES Program in this rate case. In lieu of addressing the criticisms upon what was the PES Program, the Commission encourages South Bend to participate and provide input upon I&M's revised PES Program in Cause No. 45285 since it is the revised PES program that will, presumably, apply prospectively. In the interim, I&M is directed to meet and attempt to work with South Bend regarding its concerns with the design and implementation of the PES Program, consistent with Mr. Lucas' proposal on rebuttal, so as to not delay the prospect of reasonable LED conversion rates. *Id.* at pp. 22-23.

### **C. Dry Cask Storage Deferral.**

1. I&M. Mr. Williamson stated that as agreed in Cause No. 44967, I&M currently defers all costs associated with dry cask storage that are not reimbursed by the U.S. Department of Energy ("DOE"). Petitioner's Ex. 24 at p. 56. He testified I&M is requesting 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.* Mr. Williamson testified I&M is not seeking recovery of any deferred costs in this proceeding pursuant to the 44967 Order and stated I&M will address any related deferral in I&M's next base case proceeding. *Id.* at p. 57.

2. Discussion and Findings. No party objected to I&M's request to continue deferral accounting for dry cask storage costs, and the Commission finds 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. Petitioner's Ex. 24 at p. 56; Petitioner's Ex. 33 at pp. 19-20. However, the DOE 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. Petitioner's Ex. 24 at p. 57. The record shows there are no dry cask storage costs included in the 2020 test year because I&M anticipates the DOE will continue reimbursing I&M for these costs. *Id.* If the DOE reimbursements cease or if ongoing costs exceed the amount reimbursed, the Commission finds 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 all deferred costs will be subject to review for reasonableness before being reflected in rates as set forth in the 44967 Order. Consistent with the foregoing, the Commission grants 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 I&M'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. Petitioner's Ex. 8 at pp. 3-17. He stated all of the proposed changes to the Tariff Book are just and reasonable and should be approved. *Id.* at p. 21.

Mr. Cooper testified I&M 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. Petitioner's Ex. 8 at p. 7. He stated 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 who notify I&M of their opt-out preference after an AMI meter is installed at their residential location. He testified this language recognizes the additional costs associated with the monthly meter reading process required by opting out of AMI technology. According to Mr. Cooper, I&M received approval of a similar opt-out provision in its Michigan jurisdiction. *Id.* at p. 8.

2. OUC. Ms. Aguilar testified that absent a no-cost option, I&M's proposed opt-out charge is, in effect, a deterrent intended to force I&M customers to convert to AMI. She recommended I&M allow a self-read option. Public's Ex. 10 at p. 3. Ms. Aguilar testified that in response to OUC discovery, I&M originally stated it would allow self-reads, but subsequently withdrew this customer option. *Id.* Ms. Aguilar testified I&M has provided no compelling reason why self-read should not be offered to AMI opt-out customers in I&M's service territory. *Id.* at p. 4. She also testified I&M should include all AMI opt-out information, including a no cost or self-read option, in all AMI communications to its customers. She noted the OUC is recommending AMI deployment costs be denied, but she testified if AMI deployment is approved, the OUC recommends I&M provide the OUC and the Commission with quarterly progress reports that include information on the status of AMI deployment, including an update of I&M's regional deployment map and projected deployment schedule, and a list of all AMI opt-out requests, with these progress reports starting the first full calendar quarter after any AMI deployment begins. *Id.* at p. 5.

3. Intervenors. South Bend witnesses Dorau and Sommer also recommended I&M offer an AMI self-read option. Intervenor South Bend Ex 1 at p. 19; Intervenor South Bend Ex. 2 at p. 34. Auburn witness Rutter recommended the Commission, working with I&M and the intervenors, adopt policies and procedures to protect customer data gathered from AMI meters. Intervenor Auburn Ex. 1 at p. 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 they may not want to be in. Petitioner's Ex. 9 at p. 2. He discussed the challenges and difficulties associated with self-reading meters and testified these issues are avoided by using I&M's meter readers and the communicating radio frequency meters if customers opt-out. *Id.* at pp. 2-4. Mr. Cooper stated Ms. Aguilar did not explain why the OUC's proposed quarterly reporting is necessary, and he expressed concern about publishing data with the specific customers who have chosen to opt-out identified. *Id.* at p. 5. With respect to Mr. Rutter's



recommendation regarding data privacy, Mr. Cooper stated I&M has a Data Privacy Policy in place and has dedicated a portion of its website to describing this policy in detail. *Id.* at p. 6.

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

While no party objected to I&M's proposed AMI opt-out language, the OUCC and South Bend both proposed I&M create a self-read alternative for customers who opt-out of AMI. I&M claims a self-read option could cause difficulties for customers, yet I&M acknowledges other AEP operating companies under various scenarios allow a self-read option. Petitioner's Ex. 9 at pp. 4-5. Additionally, while Mr. Cooper stated 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, he was unable to specify to what extent this is an actual problem, referring only to anecdotal information upon self-read issues. Tr. p. B-131. The Commission is not persuaded I&M's customers should not be afforded a self-read option in lieu of incurring an ongoing monthly fee if they opt-out of an AMI meter, subject to reasonable limitations, such as I&M's ability to convert the customer to the opt-out fee program if the customer fails to timely and/or accurately report his/her meter readings a minimum number of readings each year. The Commission, therefore, approves the OUCC's and South Bend's recommendation that I&M allow its customers to have the option to self-read their meters and not pay an AMI opt-out fee; provided, I&M shall be entitled to terminate a customer's self-read option consistent with our discussion above. With respect to the OUCC's recommendation that certain reporting occur if AMI deployment is approved, the Commission directs I&M to provide an annual report as a compliance filing in this proceeding consistent with the OUCC's recommendation, with the first such report to be filed as soon as practical after December 31, 2020, but not later than February 15 annually.

The record shows I&M's AMI opt-out charges are reasonable and are cost-based. Petitioner's Ex. 8 at pp. 8-9. While we, therefore, do not accept the OUCC's assertion that these costs are "punitive" in nature, the Commission recognizes they may deter AMI opt-out because they will be an additional monthly charge. But, I&M's AMI opt-out charges reflect the additional meter reading expense associated with reading meters from customers who choose to opt out of receiving AMI technology. *Id.* We find I&M's opt-out charges appropriately ensure opt-out customers are allocated the costs associated with their choice, assuming they do not elect the self-read option. The Commission finds I&M's AMI opt-out tariff, as proposed by I&M, should be revised consistent with our discussion above to afford a self-read alternative.

19. Confidentiality. I&M filed motions for protection and nondisclosure of confidential and proprietary information on May 14, September 3, and September 17, 2019, which were each 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 preliminarily be confidential, after which the information was submitted under seal. The Commission finds all such information preliminary granted confidential treatment is confidential under Ind. Code §§ 5-14-3-4 and 8-1-2-29, is exempt from public access and disclosure by Indiana law, and shall continue to be held by the Commission as confidential and protected from public access and disclosure.

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

1. I&M is authorized to adjust and increase its rates and charges for electric utility service to produce forecasted total annual operating revenues of approximately \$1,627,918,786, which are expected to produce annual net operating income of approximately \$274,690,598. To the extent the modified jurisdictional separation study alters the Indiana jurisdictional rate base, the authorized NOI will change.

2. Prior to Phase I rates becoming effective, I&M shall file its new schedule of rates and charges and full tariff, revised to comply with the findings in this Order, and revenue proof for all customer classes for approval by the Commission's Energy Division. Said filing shall apply and be consistent with the text of this Order, notwithstanding whether it is determined any numbers need revision; provided, the propriety of any such revisions shall be explained in said filing. Any party contesting the derivation of the rates and charges shall file a notice within ten business days of I&M's filing of the new rate schedules and proof of revenues.

3. I&M 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.

4. Petitioner's new schedules of rates and charges for Phases I and II shall be subject to Energy Division review and agreement with the amounts reflected and be implemented upon Energy Division approval.

5. I&M shall certify its net plant at December 31, 2020, and calculate the resulting Phase II rates and charges, which shall be made effective in accordance with the findings herein, subject to being contested and trued-up consistent with Finding No. 14.

6. I&M's proposed depreciation accrual rates set forth in Attachment JAC-1 and Petitioner's proposal to place these rates into effect for accrual accounting purposes are approved as set forth in this Order.

7. I&M's proposed three-year AMI deployment and the expenditures associated therewith are not approved as proposed. AMI deployment may proceed consistent with Finding No. 7.A.5.

8. Consistent with Finding No. 15.C.1.(e), I&M is not authorized to implement an AMI Rider.

9. I&M shall make a compliance filing and submit its rider adjustment mechanism as set forth in Finding No. 10.N.1.(e) (Excess ADFIT) and is granted all necessary associated accounting authority.

10. The deferral accounting authority sought by Petitioner is approved in accordance with Finding No. 10.H.5 (*IM Plugged In*), Finding No. 10.K.4 (Major Storm Damage Restoration Reserve), Finding No. 10.N.1.(e) (Excess ADFIT), and Finding No. 16.C.2 (dry cask storage).

11. I&M's request for an ongoing waiver at this time of the purchase power benchmark procedures as applied to I&M in Cause No. 43306 is approved.

12. The information filed in this Cause pursuant to I&M'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.

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

**HUSTON, KREVDA, OBER, AND ZIEGNER CONCUR; FREEMAN ABSENT;**

APPROVED: MAR 11 2020

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

  
\_\_\_\_\_  
Mary M. Becerra  
Secretary of the Commission