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**

FILED
September 18, 2019
INDIANA UTILITY
REGULATORY COMMISSION

I&M SUBMISSION OF REBUTTAL EVIDENCE AND INDEX

Petitioner, Indiana Michigan Power Company (I&M), by counsel, respectfully submits the rebuttal testimony and attachments of:

1. Toby L. Thomas, I&M President and Chief Operating Officer;
2. Andrew J. Williamson, Director of Regulatory Services;
3. Andrew R. Carlin, AEPSC Director of Compensation & Executive Benefits
4. Kamran Ali, AEPSC Managing Director of Transmission Planning;
5. Aaron Hill, AEPSC Director of Trusts and Investments;
6. Jason A. Cash, Accounting Senior Manager in AEPSC Corporate Accounting
7. David S. Isaacson, I&M Vice President of Distribution Operations,
8. Shane Lies, I&M Cook Plant Site Vice President;.
9. Timothy C. Kerns, I&M Managing Director – Generating Assets
10. David A. Lucas, I&M Vice President Finance and Customer Experience
11. Jeffrey W. Lehman, AEPSC Electric Transportation Program Manager
12. Robert B. Hevert, Partner at ScottMadden, Inc.
13. Tyler H. Ross, AEPSC Director of Regulatory Accounting Services
14. Chad M. Burnett, AEPSC Director of Economic Forecasting;

15. Jennifer C. Duncan, Regulatory Consultant Principal in the AEPSC Regulated Pricing and Analysis Department;

16. Michael M. Spaeth, Senior Regulatory Consultant in the AEPSC Regulatory Services Department;

17. Matthew W. Nollenberger, AEPSC Manager, Regulated Pricing and Analysis; and

18. Kurt C. Cooper, Regulatory Consultant Principal in I&M Regulatory Services Department.

To facilitate review, an index of the rebuttal filing is attached hereto as Exhibit A. I&M's workpapers are being submitted separately.

Respectfully submitted,

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CERTIFICATE OF SERVICE

The undersigned certifies that the foregoing was served upon the following via electronic email, hand delivery or First Class, or United States Mail, postage prepaid this 17th day of September, 2019 to:

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INDIANA MICHIGAN POWER COMPANY

DMS 15056383v2

Indiana Michigan Power Company
2019 Rate Case
Index of Issues, Party, Rebuttal Witnesses[1]

	Subject	Other Parties	I&M Rebuttal Witness	I&M Rebuttal Overview
1.	**Revenue Increase**			
1.A	Calculation of Revenue Increase	<u>OUCC</u> • Recommends I&M's revenue be increased by no more than $1,732,530. (Eckert, 8; M. Garrett, 59). <u>IG</u> • (the only other party that calculated a revenue requirement) recommends an adjusted Revenue Deficiency of $32.5M. (Gorman, 3).	Thomas Williamson	• The other parties' proposals do not properly recognize the Company's cost of providing service and, if adopted, would harm both I&M and the long term interests of the customers I&M serves. • In many respects, the other parties' proposed cost disallowances are not based on Indiana's existing general rate case rules and practices. Rather, the other parties urge the Commission to sweep aside the extensive evidence submitted by I&M based on new rules or practices from other states. I&M can best manage its business in the public interest when the regulatory framework is stable. • The Company has complied with the governing statute and MSFR and has cooperated throughout the extensive discovery process. • I&M urges the Commission to reject the recommendations of the OUCC and Intervenors and support I&M's path forward.

[1] This Index is intended facilitate review of issues and is not an exhaustive list of matters addressed in I&M's rebuttal evidence or the other parties' filings. The absence of a response to an issue or position taken in the other parties' testimony does not imply I&M acceptance of the other parties' position over that proposed by I&M.

2	**Rate Base: Distribution**			
2.A	Affordability	<u>OUCC</u> • The Indiana General Assembly has declared a policy that specifically recognizes affordability of utility services for present and future generations of Indiana citizens. (Eckert, 4).	Thomas	• I.C. § 8-1-2-.05 is titled "State policy to promote utility investment in infrastructure while protecting affordability of utility service." • The statute provides that this policy is intended to "create and maintain conditions under which utilities plan for and invest in infrastructure necessary for operation and maintenance while protecting the affordability of utility services for present and future generations of Indiana citizens." • This acknowledges and supports the good utility planning and prioritization of resources as a means for promoting affordability. This is precisely what I&M is seeking to do through its Distribution Management Plan, AMI deployment and other capital expenditures in this case.
2.B	Advanced Metering Infrastructure (AMI)	<u>OUCC</u> • Deny AMI deployment until I&M conducts a robust cost benefit analysis; implement a "collaborative pilot"; recovery should be through an AMI rider, net of reductions for AMR meters. (Alvarez, 2, 4-20, 38; Wallach, 4, 9-10). <u>Walmart</u> • Commission should make transitioning away from hours-use rates a near-term priority and should include a stakeholder process to explore this transition as part of the conditions of approval of an AMI deployment in this cause. (Chriss, 5). <u>JM</u> • Disallow AMI capital and operating expense in base rates and use of AMI Rider. (Cannady, 4). <u>SB</u>	Thomas Isaacson Williamson	• I&M's AMR meters are reaching the end of their design life. They must be replaced with AMI meters as a practical matter because manufacturers are phasing out AMR technology (there is only one vendor remaining that makes AMR meters, and most of its business is AMI meters). • The only matter for debate is whether I&M should replace AMR meters with AMI meters in a random, reactive way, which would be much more costly and inefficient. Or whether I&M should install AMI meters through the systematic, proactive deployment proposed in this proceeding, which would minimize costs and maximize benefits for customers. I&M should take the proactive, less costly approach. • Replacing AMR meters with AMR meters would put an outdated technology in-service for possibly another 15 years and would deny any realized customer

	Advanced Metering Infrastructure (AMI) (*continued*)	• I&M has not shown that the AMI deployment is cost effective; AMI request should not be approved at this time. (Sommer, 5).		benefits that Mr. Isaacson discussed in his direct testimony. • AMI infrastructure investment is reasonably necessary to address technological change and will improve service reliability and the customer experience. • I&M's customers have benefited from the operational savings of automated meter technology (AMR) for years. This should not be held against I&M in a "cost benefit analysis." • The robust "societal" cost benefit analysis urged by other parties should be rejected. This would require I&M, other parties, and the Commission to quantify the monetary value of intangible "benefits" such as safety and security. The Commission has not involved itself in this sort of quantification in the past or placed a monetary value on a life, injuries to people or property, or potential damage from a terrorist attack. Such an analysis would not further the objective of providing safe and reliable service or otherwise serve the public interest. • The TDSIC statute does not apply here. In any event, this statute takes a portfolio approach, and the Commission recognizes it is difficult to quantify the economic value of the incremental benefits and undertake a meaningful cost/benefit analysis.

2.C	Asset Renewal and Reliability Programs	OUCC • Remove over $75.12M in capital projects from rate base and exclude associated O&M until I&M provides project status and work order details enumerated in OUCC testimony and other parties provided time to conduct independent review and evaluation. (Alvarez, 3, 20-30, 38).	Isaacson Williamson	• The Company's case-in-chief provided considerable support and documentation to detail the programs included in I&M's Distribution Management Plan (including distribution plant activity for forecasted plant balances; I&M's "capital project life file" in WP-DAL-2, which contains project-by-project line item support for all forecasted distribution capital costs, including project name, breakdown between transmission and distribution, project type, and forecasted expenditures by month for 2019 and 2020); and an Indiana Service Territory Map that shows the locations of select Distribution Management Plan Programs. • The Company hosted OUCC personnel to review I&M's distribution planning information at I&M's Fort Wayne headquarters, where the OUCC had an opportunity to view documentation for I&M's forecasted distribution costs. I&M provided detailed work-order-level information for distribution projects in discovery. • 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. • Providing Class 2 cost estimates for projects two years out is unnecessary and would add costs needlessly. • I&M's distribution "indirect costs" are not excessive and unreasonable. Mr. Alvarez's criticism appears to reflect a misunderstanding in regards to indirect costs. I&M defines "indirect costs" (as they relate to overheads) as administration overhead and labor

	Asset Renewal and Reliability Programs (*continued*)			overhead only. Mr. Alvarez seems to incorrectly use total overheads for his indirect costs. • The Company has complied with the governing statute and MSFR.
2.D	Major Projects	<u>OUCC</u> • Remove $32.57M in capital projects and associated O&M; require I&M to provide detailed project cost estimate with the corresponding approved Capital Improvement Requisition for each Major Project prior to approval. (Alvarez, 3, 30-35, 38).	Isaacson	• Major projects are projects that I&M has identified as necessary to improve the reliability of the system, to improve the ability to serve increased load, and to promote safety and enhance the technological capabilities of I&M's system. • The Company provided a reasonable level of documentation and support for the Major Projects (including forecasted major distribution project capital expenditures, the scope and benefits of the major projects, and a map of the specific locations of the major projects in Attachment DSI-3). • Subsequently, in discovery, the Company provided financial detail in support of seven major projects (including project start and end dates, total costs, material costs, internal and contractor labor costs, and total indirect costs). The information provided is sufficient and adequate support for the major projects. • The information provided in the direct testimony is consistent with the level of detail provided in Cause No. 44967.

3.	**Rate Base: Non-Nuclear Production Plant:**			
3.A	Rockport Enhanced DSI System	<u>OUCC</u> • I&M should take action to keep Rockport operational and not terminate lease early; costs of DSI enhancements should be borne by I&M's shareholders as they receive the benefits of the Consent Decree modification; in the alternative, deny recovery of cost related to Unit 2 DSI enhancement because Lease expires in December 2022. (Armstrong, 2, 11-12). See ECR entry below for OUCC position that consumables and allowances should not be tracked. <u>IG</u> • If Commission decides to approve cost recovery for this investment at Rockport Unit 2 it should do so with the requirement that I&M reimburse those customers for any costs recovered from lessors pursuant to terms of lease. (Gorman, 40-41). <u>ICC</u> • Commission should limit recovery of costs related to the Fifth Modification because such costs are akin to a fine for failure to perform and was only necessary due to I&M's failure to timely install SCR on Rockport Unit 2. (Medine, 4-5).	Thomas Kerns	• Opposing party recommendations are based on a flawed understanding of the Consent Decree and the manner in which it came about. The execution of and modifications to the Consent Decree are not the result of "questionable management decisions," as alleged by OUCC, but have been a series of actions taken by AEP to comply with environmental requirements in a cost effective manner that have avoided the expenditure of billions of dollars. • Regardless of whether the lease is renewed or not, the modest adjustments to the DSI system are reasonable and necessary and will be used and useful in the provision of service to I&M's customers. • The relatively modest cost of the DSI Enhancement Project would not have changed the results of I&M's IRP. • The DSI Enhancement Project is a necessary project to comply with the environmental requirements applicable to both Rockport units. The consequence of non-compliance would be severe if the DSI Enhancement Project is not in operation by the end of 2020. • The lease requires I&M to return Rockport Unit 2 to the lessors at the end of the lease term in a condition to comply with all of the applicable environmental requirements. • The lease was approved by the Commission and I&M must continue to comply with the lease through its full term.

3.B	Rockport CCR Compliance Project	<u>OUCC</u> • I&M has not supported need for the Ash Pond Closure project; these capital costs should not be included in rate base. (Aguilar, 22-28).	Kerns	• As I&M continues to refine the details of the forecasted CCR project, it is possible that some of the forecasted capital costs will be reclassified as fuel or closure costs. Currently, 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 fuel or closure costs. As for the remaining $3,271,000 of the forecasted $4,069,000 investment, 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.
3.C	Rockport Unit 2 HP turbine replacement project	<u>OUCC</u> • Remove $1.323 M capital project and associated O&M because Unit 2 lease ends in December 2022. (Alvarez, 36-37, 38).	Kerns	• No matter what happens with I&M's lease of Unit 2 after 2022, Unit 2 is and will continue to be an important part of I&M's generation portfolio at least through the end of 2022. • It would be unreasonable to accept the higher risk of failure of the HP Turbine during those years. The failure of a rotating or stationary blade will cause extensive damage to the downstream rotating blades resulting in a forced outage. • A forced outage on the HP turbine would require, at minimum, eight (8) weeks to install a spare inner block, and I&M will have to repair collateral damage to other turbine components.
3.D	South Bend Solar Project (SBSP)	<u>OUCC</u> • Recommends denial of the SBSP in Cause No. 45245 and therefore the OUCC removes the $29.3M project cost from I&M's proposed rate base in this proceeding. If the Commission allows recovery of SBSP, OUCC recommends this be done through a Solar Power Rider tracker mechanism. (Blakley, 11-14, 15).	Williamson	• I&M filed rebuttal on this issue in Cause No. 45245. The Company expects that the Commission will decide this issue in the separate pending case. The Company recommends, for the purposes of this rate case, that the SBSP project costs be included in rate base, as proposed by I&M, if the project is approved.

4.	**Rate Base: Other Assets:**			
4.A	Prepaid Pension	<u>OUCC</u> • Deny rate base treatment of prepaid pension asset and approved OUCC's proposed operating expense method and adjust capital structure to reduce accumulated deferred income taxes. (Stull at 25-26). <u>IG</u> • Prepaid pension asset should be removed from rate base. I&M has not proven that it is appropriate to allow it to earn a return on this asset. (Gorman 10-15).	Hill Ross	• The opposing party recommendations that the Company's additional cash investment in its prepaid pension asset should be removed from rate base are based on a series of misconceptions and incorrect arguments. • Consistent with GAAP, a prepaid pension asset exists when contributions to the related trust fund exceeds the amount of pension expense that is recorded. Pension expense required to be recorded under GAAP is net of the earned return on pension-related investments. Under SFAS 87, the GAAP accounting predecessor to ASC 715, the prepaid pension asset is explained as arising from an employer's cumulative cash contributions in excess of cumulative pension cost. Today's accounting standards still use this approach for calculating a pension prepayment asset. • Company Witness Ross demonstrates that the prepaid pension asset was funded by investor supplied capital and why a return is required. • The Company's additional pension contributions beyond the amount of pension cost included in cost of service were prudently made to reduce the shortfall between pension plan assets and the pension benefit obligation. • These additional pension contributions benefit customers by creating additional trust fund investment income that serves to reduce each subsequent year's pension cost included in cost of service. • Ms. Stull is incorrect when she asserts I&M's prepaid pension asset "doesn't depreciate and continues to grow in size" and is contradicted not only by the definition of the prepaid pension asset itself, but

	Prepaid Pension *(continued)*			also by the facts. In its prior rate case, I&M's prepaid pension asset stood at $104 million. In this case, I&M's prepaid pension asset is $19 million dollars less at $85 million. • ERISA minimum funding contributions are guide rails that "you do not want to hit." Just like it is inadvisable to make a minimum payment on a credit card balance, since often you will pay less now, while paying more later, it can be inadvisable to only make minimum required contributions without consideration of funded status, market expectations, asset allocations, the Company's financial position and projected liability growth rates. • OUCC's proposed alternative treatment attempts to circumvent the rate making process by removing a previously justified asset, the prepaid pension asset, from rate base, and substituting the loss with a complicated, fictitious cost calculation. It is not even clear that Ms. Stull's hypothetical calculation would be supported by GAAP. • While there is always risk of large losses in the short-term, I&M's pension plan investment time horizon is truly long term and essentially continues in perpetuity. I&M's pension is thoughtfully, prudently and professionally managed by plan fiduciaries in accordance with the plan's investment policy, the requirements of ERISA and all applicable fiduciary standards. •The utility has prepaid an allowable cost and the inclusion of the prepayment in rate base is consistent with well-accepted ratemaking principles and necessary both to compensate the utility for use of the funds it has advanced and to avoid a disincentive to the utility for making similar prudent advances in the future.

	Prepaid Pension *(continued)*			• The cost of including the asset in rate base are commensurate with the benefits. • Pension contributions have benefited customers by creating additional trust fund principal and investment income that has served to reduce each subsequent year's pension cost included in cost of service. • The contributions and returns have also contributed to the avoidance of paying the variable Pension Benefit Guaranty Corporation ("PBGC") premiums since 2012 that other utilities in the state and nation have had to pay when a pension plan falls below certain funded levels.
4.B	Unamortized Nuclear Decommissioning Study and Rate Case Expense Asset	<u>OUCC</u> • Amortize nuclear decommissioning study expenses and rate case expenses over three years; deny I&M's request to include in rate base because I&M did not submit a lead/lag study and I&M's proposal to earn a return goes beyond basic ratemaking principles and is unreasonable. (Eckert, 17-18, 20; M. Garrett, 53). •Impose 50/50 sharing of legal fees incurred for case up to time of final order. (M. Garrett, 53).	Williamson	• Mr. Garrett fails to provide any specific evidence to show his comparison to other rate case expense for other companies in western states is relevant to I&M's request. • I&M's rate case expense compares extremely well to rate case expense in the Company's last rate case and several recent significant public utility rate cases in Indiana. • I&M's rate case expense is a reasonable and necessary costs of providing service to customers and should be fully recoverable consistent with past general rate cases. • The Company's proposed two year period should be approved by the Commission as it best aligns with the Company's expected timeframe between general rate cases and avoids unnecessary compounding of rate case expenses in customer rates. • While there is no certainty as to when I&M will file its next general rate case, flat to declining load in an increasing cost environment makes it increasingly

	Unamortized Nuclear Decommissioning Study and Rate Case Expense Asset *(continued)*			difficult to extend the period of time between general rate cases. • Mr. Eckert's suggestion that rate case expense represents "cash working capital" lacks merit. The rate case expense issue here concerns a cost deferral and the time value of money. It does not relate to the utility's day-to-day cash needs (i.e. "cash working capital) which when requested in a rate case are supported by a lead-lag study.
5.	**Depreciation:**			
5.A	Accounts 354, 355 364, 365, 366, 368, 369	<u>OUCC</u> •Recommends different curves for various Accounts (*e.g.* 354, 355, 364, 365, 366, 368, 369). (D. Garrett Part II, 36-47). <u>IG</u> • I&M overstates the depreciation rate for Accounts 364, 365, and 368, due to assuming too short of an average service life for these assets. (Andrews, 4, 15-22). •The Simulated Plant Record ("SPR") analysis results for Accounts 364, 365, and 368 should not be relied on as a basis for estimating the average service lives for the equipment in these accounts. (Andrews at 4, 9-10, 15-22). •The depreciation rates for Accounts 364, 365, and 368 should be based on average service lives similar to those that are utilized by nearby utilities. (Andrews, 4, 12, 15-22).	Cash	• Mr. Garrett and Mr. Andrews both cite the Company's Conformance Index ("CI"), which they both characterize as low or poor according to Bauhan scale, as their primary reason for questioning the average service lives proposed by the Company. As a result, both witnesses then compare to other peer utilities to develop their recommendations to the accounts where they disagree. •The "…arbitrary scale for the CI proposed by Bauhan" is one resource of a Simulated Plant Record ("SPR") analysis used to determine the best survivor curve and average service life of an account. • However, it is not the only factor that should be considered. In fact, as stated in the NARUC Manual on page 99: "It is not uncommon . . . for the model to produce results with low CI's for all curves over several test periods." which means that caution should be used when interpreting the results. • During the analysis of each account, Mr. Cash also considered a number of other factors in order to determine the best survivor curve and average service life to assign to each account. Other statistical and non-statistical measures that Mr. Cash used in his analysis included the retirement experience index

	Accounts 354, 355 364, 365, 366, 368, 369 *(continued)*			("REI"), which measures the maturity of the account, and the survivor curves and average service lives that were approved in previous depreciation studies. •Although the average service lives of other AEP affiliates were not considered as a part of Mr. Cash's analysis, a comparison to other nearby AEP affiliates provides a point of reference which validates the results of Mr. Cash's analysis and confirming that it was reasonable. This comparison also shows that the proposed services lives proposed by witnesses Garrett and Andrews are significantly outside the range of comparable AEP affiliates that have similar operating conditions to I&M. • The Commission should accept the Company's average service life assigned to Transmission Accounts 354 and 355 and Distribution Accounts 364, 365, 366, 368 and 369 and also accept the corresponding depreciation rates that were proposed by the Company for each account.
5.B	Contingency	<u>OUCC</u> • Remove contingency costs from the Company's proposed terminal net salvage rates. (D. Garrett Part II, 8, 23). <u>Auburn</u> • Disallow contingency in depreciation rates proposed for Steam and Hydraulic Production Plant. (Rutter, 11-12).	Cash	• S&L has estimated the likely cost of demolishing the Company's Hydroelectric facilities based on the characteristics of the facilities at the time of the studies. • Contingency is "intended to cover unknowns," and is included in the estimates because "experience teaches that almost every complex project, such as demolition of a generation station, ends up with unknowns." • Contingencies included in the demolition cost estimates are necessary to account for the unknowns that are anticipated to occur during these complex projects. Accordingly, the contingencies included in the S&L demolition studies are reasonable.

5.C	Escalation Rates	<u>OUCC</u> • Remove escalation factors from the Company's proposed terminal net salvage rates. (D. Garrett Part II, 8, 48).	Cash	• The IURC has previously ruled a number of times that escalation of terminal removal cost and salvage is reasonable. • The Commission should reject Mr. Garrett's recommendations and adopt Mr. Cash's calculations as being reasonable, appropriate, and in accordance with both accepted depreciation principles and prior Commission precedent.
5.D	Interim Retirements	<u>OUCC</u> • Remove interim retirements from the calculation of production plant depreciation rates. (D. Garrett Part II, 7, 48).	Cash	• The interim retirements reflect the lives of equipment that need to be replaced during the remaining life of the generating station. They have an effect on the remaining life of the plant investment included in the depreciation study since not all of the investment will last through the terminal retirement date. For that reason, the interim retirements need to be factored in the depreciation rate calculation. • Mr. Garrett offers no substantive reasons for excluding interim retirements, only that it was disallowed in a previous Texas case. • If interim retirements are not included in the Company's depreciation rates, the cost of those assets will be depreciated over the entire life of the facility rather than the actual life of the assets retired early. This will shift the cost of early retirements to future customers, who will pay for service from assets that have been retired and are no longer providing service to them, while current customers will pay less than the full cost of the assets providing service to them. • The Commission has previously approved production plant depreciation rates that included interim retirements.

	Interim Retirements *(continued)*			• The Commission should reject Mr. Garrett's proposal and accept the use of interim retirements in Production Plant depreciation rates.
5.E	Meters (Account 370)	<u>OUCC</u> • Use currently approved rate of 6.78% as the OUCC proposed disallowance of AMI. (D. Garrett Part II, 9, 47-48). <u>IG</u> • There is no need for a special procedure for this single account. The depreciation rate for meters should be calculated in the same manner as all other accounts and the average service life should be 16 years, based on estimate of the average service life of meters currently providing service. (Andrews, 4, 13-15). <u>Auburn</u> • Disallow return of and on the retired AMR meters. (Rutter, 12).	Cash Williamson	• Neither witness Garrett nor witness Andrews acknowledges the retirement of the existing meters in their proposals. If they did, both witnesses would need to calculate a depreciation rate which fully depreciates the balance of Account 370 at December 31, 2018 in the next 4 years (2019-2022). •The Commission should approve I&M's single depreciation rate for Account 370. • Mr. Rutter's proposal departs from proper accounting and ratemaking for the remaining book value of retired property. Depreciation of assets is not perfect and should not dictate the ratemaking and recovery associated with assets found to be reasonable and necessary in the provision of service to customers.
5.F	Rockport	<u>ICC</u> • Commission should not approve the requested changes to depreciation rates related to Rockport Unit 1 and 2. (Medine, 3).	Cash	• Ms. Medine's recommendation fails to recognize that additional investment has been made to both Rockport Units since the last depreciation study was performed in Cause No. 44967. • As a result, depreciation rates need to be updated to reflect the additional investment made at the plant and designed to allow for the assets at the plant to be fully depreciated upon retirement.
5.G	Rockport Enhanced DSI	<u>JM</u> • Proposes recovery of Enhanced DSI over at least 10 years. (Cannady, 4, 11-20, 36).	Cash	• The Commission should reject Ms. Cannady's proposal to extend depreciating the Enhanced DSI projects beyond the expected life of the Rockport Plant and accept the Company's proposed depreciation rates for the Rockport Plant.

	Rockport Enhanced DSI *(continued)*			• Although the depreciation rates for the Rockport Unit 2 SCR and DSI are not perfect by allowing depreciation to go beyond the lease term of Rockport Unit 2, the depreciation rates that are currently approved and that are proposed in this Cause allow the Rockport Unit 2 assets to be fully depreciated when the entire Rockport Plant is expected to retire in 2028.
6.	**Capital Structure:**			
6.A	ROE	<u>OUCC</u> • Recommends a 9.1% ROE. (D. Garrett at 11). <u>IG</u> •Recommends a 9% ROE and overall rate of return of 5.35% (Gorman at 4). •Takes no issue with I&M's proposed capital structure and embedded debt costs. (Gorman at 4). <u>Walmart</u> •Commission should consider the impact to customers; use of future test year; recent ROE's proposed by this commission & other commissions (Chriss at 4). <u>39 North</u> •Adopt a return that recognizes I&M's declining residential customer satisfaction scores. (Cearley at 9).	Hevert	• There are several methodological, theoretical, and practical reasons why the Opposing ROE Witnesses' recommendations are unduly low. • Because the Opposing ROE Witnesses give meaningful weight to their DCF-based results, it is not surprising that their recommendations fall well below currently authorized returns. Given their common reliance on the DCF method, it also is not surprising that the Opposing ROE Witnesses' recommendations generally fall within a narrow range. But the fact that their recommendations are similar does not mean their approaches and conclusions are reasonable. • In some cases, the Opposing ROE Witnesses' recommendations stem from unreasonably low DCF estimates, which themselves are the result of tenuous assumptions. • There is no reasonable basis to assume the current volatile capital market environment will remain in place in perpetuity. • 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. Those valuation levels are more likely

	ROE (*continued*)			related to the "reach for yield" that often occurs during periods of low Treasury yields. • Certain of the Opposing ROE Witnesses' recommendations are fundamentally disconnected from their own analyses and conclusions, and are far removed from observable and relevant data. • Although Mr. Gorman suggests the Cost of Equity has fallen to a level that supports his recommendation, observable data (as shown in Chart 6 of Mr. Hevert's rebuttal) does not support his position. • The opposing ROE witnesses are not consistent with returns authorized by the Commission and elsewhere in the U.S. • If the Commission were to authorize a return of 9.10 percent or lower as the Opposing ROE Witnesses recommend, it would represent a significant departure from returns previously authorized by the Commission. • The financial community carefully monitors utility companies' financial conditions, both current and expected as well as the regulatory environment in which those companies operate. A consequence of an authorized ROE in the range of the Opposing ROE Witnesses' recommendations would be to increase investors' perceptions of regulatory risk. • As I&M Witness Mr. Williamson explains, the Company expects its NITS costs to increase by about $48 million in 2021, just one year beyond the test year in this Cause. Mr. Williamson further explains that, absent the ability to recover the increased NITS cost, the Company's earned Return on Common Equity

	ROE (*continued*)			would fall by about 1.90 percentage points (190 basis points). • Because operating cash flow is directly related to income, the earnings erosion brought about by the inability to recover increased NITS costs will put downward pressure on I&M's financial profile, increasing the financial community's perceptions of the Company's risk. • The combination of the opposing witnesses' unduly low ROE recommendations and the increased likelihood of under-earning absent the timely recovery of increased NITS costs suggests returns that are far too low to be considered reasonable. • Based on the analyses discussed throughout Mr. Hevert's Direct and Rebuttal Testimony, the reasonable range of ROE estimates is from 10.00 percent to 10.75 percent, and within that range, 10.50 percent is a reasonable and appropriate estimate of I&M's Cost of Equity.
7.	**Revenue Adjustments:**			
7.A	Customer Count Adjustment	<u>OUCC</u> • OUCC provides a revenue adjustment to correct the Company's TY customer billing determinants, resulting in an increase to forecasted TY revenues at current rates of $3,758,305. (Watkins, 2, 52-53).	Nollenberger	• I&M agrees with this change to test year revenues. Although this correction does not change the Company's overall revenue requirement, it does reduce the revenue deficiency by the amount of the correction.
7.B	IMMDA	<u>IG</u> •I&M did not take reasonable steps to retain the load or find replacement load. The additional capacity allocated to Indiana Retail Customers is not needed. (Gorman, 8-9, 34-38). <u>39 North</u>	Thomas Duncan	• Jurisdictional allocation should reflect the load conditions expected during the period the rates established in this Cause will be in effect. • Regardless of when the Rockport Unit 2 lease terminates, I&M will face a capacity gap of approximately 500 MW.

	IMMDA *(continued)*	•I&M should not be allowed to decrease test year revenues for loss of wholesale load unit it has reasonably demonstrated what it has done to either retain or replace this lost load beyond just making claims of support of economic development. (Cearley, 9). JM • I&M is using retail customers as a hedge against lost load attributable to the wholesale business. 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 lost load after receiving the early termination notices from IMMDA customers prior to May 31, 2016. (Mancinelli, 19).		• Mr. Gorman's contention that this generation that has been used to serve the IMMDA load is not used and useful in the provision of retail service takes an unreasonably short sighted perspective in that it fails to recognize the capacity additions or subtractions will rarely exactly match changes in load requirements. Mr. Gorman's view is inconsistent with the need to maintain flexibility in our resource planning. • I&M actively negotiated with the IMMDA members to find creative alternatives that would allow the contracts to be renewed or reformed. The Company has also explored other options. If additional revenues result from those activities, the Off System Sales tracker will flow the vast majority of the margins back to customers. • I&M works hard every day to grow its business as doing so is beneficial to our customers. It may not be evident from far away, but it is incorrect for Mr. Mancinelli to imply that I&M was passive in reacting to the termination of the IMMDA contracts.
8.	**Expense Adjustments:**			
8.A	Cook 316b	OUCC • Deny I&M's request to create a regulatory asset for the Cook Plant's Rule 316(b) study expense. I&M could have sought recovery in previous rate cases earlier; because I&M's rates already include an embedded level of compliance cost expense it would be inappropriate to provide I&M additional recovery. (Eckert, 15-16, 20).	Lies Ross	• Mr. Eckert does not challenge the reasonableness of the 316(b) Project costs. Rather, he is concerned that I&M is seeking "additional recovery" related to these costs over and above a level of compliance costs reflected in the cost of service used to establish I&M's base rates in Cause No. 44075. But I&M's 316(b) Project costs are not similar to the Fire Suppression System compliance costs that were expensed, considered and approved in Cause No. 44075. I&M expects to regularly incur O&M compliance costs to comply with emerging requirements that are relatively limited in scope. The 316(b) Project costs, on the other hand, were incurred cumulatively over the course of ten years in anticipation of a major capital

	Cook 316b (*continued*)			project that itself also would have taken several years to complete. • The 316b studies allowed I&M to avoid a major capital project. This outcome was a positive outcome for I&M's customers. • These costs were properly recorded to Account 107 (Construction Work in Progress) in anticipation of these costs being part of a new property asset that would go into service. Thereafter, management concluded that it was uncertain at the time as to whether I&M would be required to construct a property asset based on the water intake study. I&M properly reclassified the 316(b) study costs to Account 183 for Preliminary Survey and Investigation Charges in accordance with the FERC USofA. • As also supported by Company witness Lies, management does not believe that the MDEQ's ruling on I&M's water intake study will result in I&M's construction of a capital asset. • Rather than expensing the 316(b) study costs in 2018, I&M properly deferred 316(b) study costs in accordance with ASC 980, Regulated Operations, based on I&M management's conclusions that such costs were probable of recovery based on prudency and past precedent of recovery of similarly incurred costs related to I&M's Cook Plant. • There is no dispute that these costs were prudently incurred for the benefit of our customers. Had they been expensed, there would have been no opportunity to recover these costs. • Deferring them as a regulatory asset was proper accounting pursuant to ASC 980. Under witness Eckert's approach, the Company would be in a position of prudently incurring costs for the benefit of

	Cook 316b (*continued*)			its customers with no opportunity to recover these costs.
8.B	Customer Assistance Programs	<u>OUCC</u> • Deny I&M's request for customer assistance programs. (Haselden, 7). <u>IG</u> • Objects to concept that funds for customer assistance pilots should come from ratepayers. (Gorman, 39). <u>CAC</u> • Instruct I&M to reconvene the Low Income Collaborative to redesign Neighbor to Neighbor Pilot and related aspects of Low Income Arrearage Forgiveness Pilot. (Olson, 18-19). • Approve Energy Share Pilot, Low-Income Weatherization program and Income Qualified Safety & Health Pilot. (Olson, 20). <u>SB</u> • I&M should do more to protect the financially vulnerable from hardship caused by increased rates. Supports expansion of customer assistance programs. (Dorau, 10-12).	Lucas	• The initiatives I&M has proposed are designed to address and gather additional information as whether and how customer assistance programs can improve the longer term cost of providing service (reducing costs associated with credit and collections, minimizing costs of disconnecting and reconnecting customers, and avoiding potential write-offs due to lack of payment). • Because these costs are reflected in the revenue requirement, this in turn helps to maintain I&M's overall cost of providing service for the benefit all of I&M's customers. • I&M disagrees the collaborative should be reconvened. I&M should be given the opportunity to execute the programs and generate performance data so as to be in a much better position to meet with stakeholders to assess the overall effectiveness.
8.C	Economic Development	<u>OUCC</u> • Deny I&M's request for economic development programs. (Haselden, 7). <u>IG</u> • Objects to concept that funds for new economic development pilots should come from ratepayers. (Gorman, 39). <u>JM</u>	Lucas	• Customer load continues to be flat to declining and it is becoming exceedingly difficult to manage customer rates by managing costs. Economic development is arguably one of the best tools we have to manage the cost of electricity for customers. • All I&M customers benefit from strong economic development programs because the increase in load created by economic development provides a larger base over which the fixed costs necessary to maintain the electric delivery system can be spread.

	Economic Development *(continued)*	• EIG program established in CN 44967 should be continued without adding to I&M revenue requirement; recommend Commission expand I&M's contributions towards EIG program in amount of $450,000 annually from shareholder earnings. I&M should be required to contribute $364,000 of unspent funds associated with the Settlement Agreement in CN 44967. (Fasick, 3-4, 15-16; Mancinelli, 60-61). <u>39 North</u> •I&M should expand its focus and funding of Economic Development (Cearley, 11-12). <u>SB</u> •Recommends list of eligible industries for Workforce Development pilot be expanded to include energy and construction trades and that Building Development pilot be expanded to include vacant commercial buildings and new construction on infill sites and budget be increased. (Dorau at 21-23).		• I&M disagrees with Mr. Cearley regarding the scope and funding of the economic development programs. I&M's proposal in this case for economic development programs provides an appropriate balance for I&M to support economic development project activities, while also targeting specific areas that have been identified as challenges in the I&M service area. • Given the importance of economic development with respect to maintaining or increasing load, we must reasonably expand our efforts to address the specific needs in our area if we want our efforts to be successful. • I&M appreciates the constructive feedback from the City of South Bend on the programs I&M proposed in this case.
8.D	Electric Transportation (*I&M Plugged In* Pilot Program)	<u>OUCC</u> • Deny recovery of $700,000 annual cost of charging equipment rebates because I&M provided no empirical evidence to suggest that access to 240V charging equipment is an actual barrier to EV adoption or that a rebate will overcome the alleged barrier. (Aguilar, 17-19).	Lehman	• I&M is not proposing the incentive because 240V charging is a barrier to electric vehicle adoption. 240V charging is necessary for customers to have the ability to easily shift their entire charging load to off-peak times. • I&M used reasonable projections for customer driving miles, amount of home charging used, and the likely charging behavior of participating customers to estimate that each residential and small commercial customer participating in the Pilot can be expected, on average, to provide $579 in net benefits to *all* I&M customers over a 10-year period. • I&M agrees that empirical data is important and this is one important reason that I&M has proposed to

	Electric Transportation (*I&M Plugged In* Pilot Program) *(continued)*			implement the PEV program as a pilot in this proceeding. I&M's *IM Plugged In* pilot program will provide empirical data, evidence, and customer feedback necessary for developing future programs that focus on increased system utilization and downward pressure on customer electric rates.
8.E	EZ Bill	<u>OUCC</u> • EZ Bill Program costs should be booked below the line subject to review after costs and profitability of program established. (Lantrip, 15).	Williamson	• It is not reasonable to account for program costs and revenues below-the-line.
8.F	Factoring Expense	<u>OUCC</u> • Use three-year average for factoring expense. (M. Garrett, 55).	Lucas	• I&M has developed its forecast for factoring expenses in the TY based on reasonable assumptions at the point in time the forecast was prepared. • These assumptions take into consideration the best information available at the time and is more accurate than using historical data to develop a forward-looking projection. • Contrary to witness Garrett's assumptions, recent trends in I&M's factoring expense show the amount included in the TY may be understated. • I&M's most recent projection for 2020 is consistent with our recent experience at approximately $10.6 million which corroborates that the TY level is reasonable and no adjustment should be made.
8.G	Employee Benefits	<u>OUCC</u> • Use 2018 expense levels for pension and OPEB costs; use 5% increase for employee medical and dental expenses; include remaining employee benefit expenses at 2018 level. (M. Garrett, 44-45).	Carlin	• The Company relied on third-party actuarial experts to evaluate and project its future medical costs. As a self-insured plan, AEP's medical benefit expense is actuarially determined based on the plan design, past participant medical expenses, healthcare trends and the rates and terms of existing vendor contracts. The Company also relied on third-party experts to inform the medical expense growth rates used to project 2020 medical expenses.

8.H	Full Time Employee (FTE) Adjustment	IG • Reduce I&M's projected FTE level of 2,305 down to 2,199, or I&M actual 2018 headcount because I&M has not filled all budgeted positions in the past. (Gorman, 30-32).	Lucas	• I&M has provided a comprehensive O&M forecast to accomplish the work plans presented in this case. The overall forecasted O&M dollars being requested were reviewed by the business units and I&M management at the time the forecast was prepared and reflect what is reasonably necessary to complete the work plans in the TY. •To the extent I&M has unfilled positions in 2020 there are potentially other components of the forecast, such as contract labor, overtime, or outside services that could potentially increase.
8.I	Incentive Compensation	OUCC • Adopt a 50/50 sharing approach to allocate annual incentive plan costs evenly between shareholders and ratepayers. (M. Garrett, 29). •Remove 100% of long-term incentive compensation costs. (M. Garrett, 37). •Disallow supplemental employee retirement plan non-qualifying costs (M. Garrett, 38). IG • Disallow all compensation related to LTI and the 70% portion of ICP which is based on financial goals. (Gorman, 25-29).	Carlin	• Annual and long-term incentive compensation is a necessary and prudent part of I&M's overall labor expenditures and brings numerous benefits to I&M and its customers. • The amount of incentive compensation reflected in the test year is reasonable, and I&M should continue to recover the full cost of its incentive compensation in its Indiana retail rates, including the capital portion and attendant expenses, as it has done for many years. Proposed incentive compensation adjustments should be denied. • Contrary to the opposing party's claims, the incentive compensation opportunity the Company provides to employees satisfies all three Commission-established criteria for inclusion of such costs in rates. • Short and long-term incentive pay must be reviewed in combination with the entire base salary. The incentive compensation is simply part of the total compensation package. It is generally only when base salary is combined with incentive compensation, that the Company's compensation packages are reasonable and competitive.

	Incentive Compensation (*continued*)			• I&M's compensation is below the market-competitive range. • I&M provides market-competitive total compensation to all levels of employees because to provide less compensation would increase employee turnover, and the resulting increase in hiring, training and other turnover related expenses, such as lost productivity, would increase total cost for the Company and its customers. • LTI benefits customers by creating a longer-term focus for decision makers, reducing leadership turnover and increasing management continuity, which leads to more efficient, effective and consistent operations and improved long-term decision-making. LTI does not have any incremental cost, beyond the cost of providing market-competitive compensation through base pay alone. • OUCC's arguments for denying recovery of I&M's incentive compensation costs rely heavily on largely irrelevant rulings from commissions in other states that are inconsistent with this Commission's precedent, and which Mr. Garrett mischaracterizes. • The Transmission Business Expansion – Plant in Service measure should not be considered financial or excluded from the Company's cost of service. This is a measure of *timely completion* of approved transmission and telecommunications construction, replacement, and rebuilding projects. The key to bringing in construction projects on or under budget is completing them expeditiously, which this goal encourages. This reduces the potential for cost overruns, better assures capital budget adherence and is in customers' interests. • Claims that incentive compensation is uncertain are without merit in light of the Company's history of

	Incentive Compensation (*continued*)			awarding above target incentive compensation and I&M's adjustment to remove the very substantial above target portion. • The Commission's rulings in many prior rate cases indicate that the Commission sees value for customers in both financial and non-financial incentive compensation. • Intervenors' recommended adjustment are overstated because they ignore the equal weight that operating measures and the normalizing function have on annual incentive awards. In all cases, the disallowances they propose, when corrected for their errors, would be are significantly less than the 50/50 sharing that witness Mark Garrett proposes and the 70% disallowance the Gorman proposes. • Similarly, SERP expense is a reasonable, necessary and market-competitive expense for more highly paid employees that should also be included in the Company's cost of service as it has been for many years.
8.J	Major Storm Expense	<u>OUCC</u> • Does not oppose I&M continuing Major Storm Reserve; decreases the forecasted Test Year Major Storm Reserve to $2,473,000 based on the five-year average major storm expenses for the period 2014 – 2018. (Alvarez, 18-19, 38).	Williamson	• I&M is agreeable to the OUCC's proposal with one modification.
8.K	Nuclear Decommissioning Expense	<u>OUCC</u> • Reduce current annual contribution to $0. (Eckert, 20). <u>IG</u> • funding should remain at $2M. Forecasted value of trust fund assets is adequate and additional factors that act as contingencies provide	Hill	• OUCC's proposal to eliminate continued funding and Intervenor proposals to maintain the current funding level, are based on a series of misconceptions and incorrect arguments. • OUCC's estimate incorrectly excludes on-going spent fuel storage costs. • The NRC Report shows I&M is in compliance with NRC minimum funding requirements; this does not

	Nuclear Decommissioning Expense (*continued*)	assurance that trust fund will be capable of paying decommissioning costs. (Gorman, 15-24). <u>JM</u> • Set annual expense at $2 million. (Cannady, 4).		guarantee there will be enough funds at end of plant's life to successfully decommission the plant. • The OUCC comparison of asset values assumes riskless investment return. The Monte Carlo simulation, presented in the Company's direct testimony does a much better job calculating real-world risk and return trade-offs to capture investment and liability growth risks. • Additionally, the NRC minimum total decommissioning cost includes the radiological portion of decommissioning costs and therefore is not comparable to the cost in TLG's study. • IG analysis manipulates assumptions in I&M's Monte Carlo model to be all favorable to IG argument. IG neglects to consider that future returns could be different than past returns. I&M's return assumptions consider forward looking expectations and use the same return expectation setting methodology that is presented in AEP's 10k, which is audited by PricewaterhouseCoopers LLP and based on assumptions from financial industry experts. • We are in a different economic environment than we were in the past and IG is incorrect to say that the Company's return assumptions are "very conservative", when current yields are less than half of what is projected in the model, TIPS can be seen yielding negative returns and equity prices have run up to all-time highs. • Despite well intentioned efforts, using the best available resources, experts and knowledge in developing forecasts, there is a risk that actual results do not turn out as planned. Seemingly subtle changes in inputs and variables, such as increasing inflation

	Nuclear Decommissioning Expense (*continued*)			just 0.65% from 2.25% to 2.9% in I&M example, can have a significant impact on results. • The contingency factor in the cost of nuclear decommissioning addresses the possibility that there will be additional work scope or costs associated with decommissioning that have not been included in the estimate beyond general price escalation and inflation. Therefore, it is incorrect for Mr. Gorman to remove contingency amounts from the Monte Carlo analysis and imply that contingency included in the decommissioning cost study insures against adverse asset and liability return realizations. • While the ratemaking process allows for recovery of a utility's cost of service, it is still important to plan for decommissioning in a way that avoids large rate shocks for future generations of customers. • As of December 31, 2018, the decommissioning trust fund was underfunded at 79%, which equates to a shortfall of $378 million. If there is a large shortfall at the time of decommissioning, then the customers at the time of decommissioning will need to fund the shortfall, rather than the customers that used the plant's capacity during its useful life. • Maintaining funding discipline now helps ensure the trust is funded gradually over time, rather than all at once, at a potential steep cost to customers. • As we get closer to decommissioning the plant, we need to be 100% certain that we have enough decommissioning funds. As we move forward in time to the eventual decommissioning date, we cannot put off funding the decommissioning trust at an appropriate level. • Opportunity to earn future returns is much less than it was in the past. We are currently only five years

	Nuclear Decommissioning Expense (*continued*)			away from the point that we plan on de-risking the trust asset investment profile to preserve cumulative principal and investment gains build up during the plant's life.
8.L	Vegetation Management	OUCC • Use 5-year average for vegetation management expense (M. Garrett, 50).	Isaacson	• It is unreasonable to compare I&M's forecasted test year level of vegetation management expenditures to the five-year historical average. • In 2018, I&M began the proactive four-year vegetation management cycle proposed in Cause No. 44987. Using a five year average would reduce the level of expense to essentially what was incurred under I&M's historical reactive vegetation management program. • The significant reduction proposed by Mr. Garrett would hamper the Company's move to a proactive vegetation management approach and the customer benefits that yields.
9.	**Taxes:**			
9.A	Excess Accumulated Deferred Federal Income Taxes (EADFIT)	OUCC – • Once I&M's unprotected EADFIT credit has been fully amortized back to customers, I&M should make a compliance filing to change the EADFIT credit at which time EADFIT credit should be based only on the protected EADFIT amount; going forward I&M should defer EADFIT based on the difference between the amount embedded in base rates for protected EADFIT and the actual protected EADFIT calculated each year under ARAM (and any variances trued up in next base rate case). (Blakley, 7-8, 15). IG • Suggests alternative approaches, including delaying the issue to I&M's next base case or	Williamson	• The Company agrees with Mr. Gorman that there is uncertainty as to when unprotected EADIT will be fully amortized and there is no certainty as to how that timing aligns with the timing of I&M's future general rate cases. The Company's proposed mechanism responds to and 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. • Mr. Blakley's testimony lacks key information to determine whether his recommendation is reasonable. This is important as there is a timing element that must be recognized.

	Excess Accumulated Deferred Federal Income Taxes (EADFIT) *(continued)*	change the Settlement Agreement and 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. (Gorman, 41-44) <u>JM</u> •Reduce current annual amortization from $29.9 million to $28.8 million in 2020-2022. Also recommends Company's request to establish a regulatory asset be denied. (Cannady, 3).		• The Company's rebuttal includes a proposal that ensures that customers continue to receive the benefits of excess ADFIT going forward, maintains the intent of the settlement agreement in Cause No. 44967, allows the Company to continue to comply with tax normalization rules and addresses the concerns of the IG and OUCC by minimizing the level of deferred costs. • The Company disagrees with Ms. Cannady's recommendation. There is no need to revisit the settlement agreement in Cause No. 44967. I&M's proposed level of annual excess ADFIT amortization is supported by the OUCC and IG and maintains the agreement of the parties in CN 44967 and provides a consistent level of benefits to customers until such time as the non-normalized excess ADFIT is fully amortized.
9.B	Utility Receipt Tax (URT)	<u>IG</u> • Recommends the URT be removed from the GRCF and be recovered through a charge on the customer bill instead. (Gorman, 9)	Williamson	• Mr. Gorman's recommendation would change "how" the cost is recovered, not "if" the cost is recovered. I&M is not opposed to this proposal but isn't prepared to implement it at this time and would need time to determine how this change would be structured and billed.
10.	**Financial Forecast:**			
10.A	Load Forecast	<u>Joint Municipals:</u> • I&M should remove recession assumptions from the 2020 Test Year. (Mancinelli, 30-35). •I&M's load forecast assumes overly aggressive incremental savings associated with DSM/EE programs compared to what has been achieved historically and should rerun load forecast using historical results. (Mancinelli, 35-36).	Burnett	• I&M's load forecast reflects the base economic forecast from Moody's Analytics, a trusted and reputable provider of economic forecast data; no "adjustment" was made for the recession. • Mr. Mancinelli's cited economic outlook actually supports the general economic assumptions used in I&M's load forecast. • I&M's updated June 2019 load forecast for 2020 is 1.2% lower than the forecast used in this case,

	Load Forecast *(continued)*			underscoring the reasonableness of the Test Year load forecast. • Mr. Mancinelli's Table 5 erroneously compares annual incremental savings for the historical data to a cumulative number for 2020. This error undermines Mr. Mancinelli's claim that the DSM assumptions in I&M's load forecast are too high.
11.	**Cost of Service: Jurisdictional Cost of Service**			
11.A	IMMDA Load Allocation	IG: • IG proposes to make permanent $46.44 million in offsets to I&M's cost of service related to expiring IMMDA contracts because this production capacity cost should not be allocated to I&M's retail jurisdictions. (Gorman, 8, 33-35, 38). • If wholesale capacity is allocated to IN retail jurisdiction, only the market value cost of this resource should be included in retail cost of service. (Gorman, 9, 37-38). Joint Municipals: •Fixed costs associated with abrupt and significant load loss (*e.g.*, IMMDA) should be recovered within the jurisdiction that the load loss occurs or borne by I&M, not shifted to I&M's retail jurisdictions. (Mancinelli, 3, 9-11, 59). •Impact of the 12CP jurisdictional allocator disproportionately shifts total Company costs to Indiana retail customers. (Mancinelli, 12-14). • The fixed costs associated with the IMMDA load would be considered "stranded" under FERC precedent and should not be recovered from Indiana retail customers. (Mancinelli, 21-26).	Duncan Williamson	• The Commission should reject witness Gorman and witness Mancinelli's proposals to use hypothetical allocation methodologies to assign the loss of IMMDA load to the wholesale jurisdiction. • It would be inappropriate to deviate from the standard allocation approach in the current case as this method appropriately computes each jurisdiction's proportional share of current test year data. • 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 the Company's historical practice. • Loss of load is the mirror image of adding load. 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. • I&M disagrees with the notion that there is a "shifting" of costs. While the loss of wholesale demand does have an effect on the costs to be recovered from retail customers, that effect is the result of how the mix of

	IMMDA Load Allocation *(continued)*			customers affects cost recovery and are not the result of a process of allocation. •A basic principle of cost allocation is to spread Total Company costs over the jurisdictions the Company serves using appropriate allocation factors, which the Company has done. The hypothetical methods proposed by Gorman and Mancinelli do not abide by this basic principle and are therefore not reasonable.
12.	**Cost of Service: Class Cost of Service Study**			
12.A	Distribution Plant Allocation Methodology	OUCC: • I&M's classification and allocation of distribution plant reasonably reflect cost causation and fairly allocate distribution-related costs. (Watkins, 25-26). IG: • I&M's 6CP method understates LGS and IP rates of return because it fails to use customer component to allocate certain distribution system facilities. (Phillips, 4, 23). • Recommends use of minimum system approach for the allocation of distribution costs regardless of the use of a 4, 5 or 6 CP allocation. (Phillips, 17-24). South Bend: • I&M's CCOSS failed to classify portion of distribution poles, conductor, and line transformers as customer related, which SB says is standard approach in the industry. (Seelye, 2-3, 13-15).	Spaeth	• The Company's classification of distribution plant accounts 364-368 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. • The Minimum System approach of classifying a portion of the costs included in accounts 364 through 368 as customer related, as Mr. Phillips is recommending, does not recognize the Company's standard engineering practice of planning and sizing distribution facilities to meet the peak demand of the customers served by those facilities. • The approach offered by Mr. Seelye is flawed and should not be adopted. It is illogical to attempt to reduce distribution accounts 364-368 to a non-load carrying "customer-related component" because, without load-carrying ability the Company would not install this equipment. The absence of load would not necessitate the installation of distribution facilities.

12.B	Production Plant Allocation Methodology	OUCC: • Use of 6CP method does not reasonably reflect cost causation and proposes alternative studies based upon the Peak & Average, 12CP and Base-Intermediate-Peak methods. (Watkins, 2, 6-15, 20-24). IG: •Recommends the 5 CP PJM peak or 4 summer CP method should be used because I&M is a summer peaking utility. (Phillips, 4, 13-15). •States any method of cost allocation that utilizes average demand or energy is at odds with I&M's dominant system peaks and should be rejected. (Phillips, 4, 16). Joint Municipals: •Proposes Company allocate both production and transmission plant on either a 4 CP or 5CP method because I&M is a summer peaking utility. (Mancinelli, 4, 37-40, 60). CAC: • I&M should use an energy-weighted demand allocation methodology (Equivalent Peaker) to allocate production plant to properly reflect investment decision-making. (Wallach, 12-15). South Bend: • I&M is a strictly summer peaking utility and should use 3 CP methodology using only summer peak months. (Seelye, 2, 9-12).	Spaeth	• Since the Company reflects two seasonal monthly peaks during the test period, the 12 CP demand allocator is not an appropriate peak demand cost allocation methodology. I&M Indiana has historically been a two-seasonal peaking utility, reflecting both summer and winter peak months. This supports I&M's use of a 6 CP demand allocator. • The concern with using the PJM five summer peaks hours approach is that they dismiss the Company's winter peak months and the need to provide required capacity during these months as well. Company engineers plan and size our facilities to meet the expected peak demands of its customers; therefore, the Company's six monthly peaks during the test period best represent how costs are incurred. • The Peak & Average energy weighted allocation methodology, proposed by Mr. Watkins, and the Equivalent Peaker energy weighted allocation methodology, proposed by Mr. Wallach, do not recognize the fact that production plant costs are fixed in nature and still exist regardless of how much energy customers consume. The level or fluctuation of energy has no impact on production plant costs. • Although it is true the Company peaks higher during the summer months, the Company's allocation factor also reflects winter peak months as mentioned above and in my direct testimony. Notably, the winter peaks of December, January, and February are higher than the shoulder months of the historical test year and must be accounted for in system planning. Mr. Seelye's proposed 3 CP methodology would ignore the winter peaks experienced by I&M's system.

12.C	Transmission Plant Allocation	OUCC: • Recommends use of 12CP demand allocator to allocate transmission costs. (Watkins, 24-25).	Spaeth	• Company engineers plan and size transmission facilities to meet the expected peak demand on its transmission system. • Therefore, since the Company experiences summer and winter peak months, the Company builds its transmission facilities to meet the peak demand requirements of these two peak seasons. As a result, the 6 CP demand allocator best represents how costs should be allocated among the customer classes.
12.D	Revenue Allocation	OUCC • I&M's proposed class revenue allocations are unreasonable because they are predicated entirely on the results of the 6CP CCOSS, which does not fairly reflect cost causation nor produce reasonable class rates of return; recommends that all classes move closer to rate parity, limiting all firm class increases to no more than 1.50 times the system-wide average firm percentage increase, and requiring that all classes receive at least half of the system-wide average firm percentage increase. (Watkins, 36-37). IG: • Any increase should be distributed to classes based on either the 5CP study or the 4 summer CP study with the minimum distribution system (MDS), or at least a 6CP with the MDS, in a manner that significantly reduces subsidies. (Phillips, 24-25). Walmart: •Any reduction in revenue requirement should be applied in a manner that further moves customer classes towards their respective costs of service. (Chriss, 5, 16-17). Joint Municipals:	Nollenberger	• I&M's revenue allocation proposal make progress toward reducing current inter-class subsidies, consistent with all parties' general interests. By moving each class' proposed RoR Index closer to 100, the Company's revenue allocation achieves the objective of reducing the current level of inter-class subsidies. •The Company's proposal to ensure that no customer class receives a rate decrease is aimed at supporting inter-class equity in this case; it is reasonable to expect that no rate class receive a rate reduction when some are experiencing an average total revenue increase of 11.75%. •The Company's proposal strikes a reasonable balance between reducing current subsidies and managing class impacts. A greater subsidy reduction as Mr. Seelye recommends would result in larger increases for the Residential and Industrial customer classes, which are currently earning below the overall average RoR. •Conceptually, a uniform class increase like the one supported by Mr. Wallach, can reduce inter-class subsidies. However, in contrast to I&M's proposed equal subsidy mitigation method, Mr. Wallach's

	Revenue Allocation (*continued*)	•Do not agree with preventing all classes deserving of a rate decrease from receiving one. (Mancinelli, 42). •Lighting Service provides an important public service to the various communities served by I&M and, therefore, this customer class should not pay more than cost of service. (Mancinelli, 4, 43-44). <u>CAC:</u> •A fair and reasonable approach would be to: (1) maintain base revenues at current levels for those rate classes where the cost of service studies show a revenue decrease at an equalized ROR; and (2) increase base revenues for all other classes by the same percentage in order to recover any authorized revenue deficiency. (Wallach, 4, 18-19, 42). <u>South Bend:</u> • Eliminate 50% of inter-class subsidies and the requirement that rates for no class be reduced. Placing an artificial restriction on the elimination of subsidies allows those subsidies to grow and continue to get out of hand. (Seelye, 3, 24-32). <u>Auburn:</u> •The proposed revenue from Tariff SL far exceeds the cost to serve which produces a rate of return for that tariff class projected to be 12.83% far exceeding the overall rate of return being sought in this proceeding of 5.86%. Auburn recommends that the ROR for rate class SL be set in between the class average rate of return and the proposed ROR, or 9.35%. (Rutter, 2, 8-10).		approach would make uneven progress towards mitigating the current level of inter-class subsidies. • Mr. Rutter's comparison does not recognize that I&M's starting point for class revenue allocation in each case is the Company's class cost of service study that is re-established in each case. Likewise, Mr. Rutter does not acknowledge the movement of each class toward the class average RoR in this case.

13.	**Rate Design: Commercial Industrial and End Use Tariffs**			
13.A	PEV Tariffs	OUCC: • I&M's PEV Pilot should include higher rates for charging during on-peak hours to disincent individual customers from charging during peak times and using 240V chargers. (Aguilar, 20). SB: •Agrees the *IM Plugged In* program is sensible and helps overcome barriers to individual EV adoption while avoiding potential negative impacts to the shared grid (Dorau, 16). •The off-peak energy charge in I&M's proposed Tariff GS – PEV should be lowered to reflect cost of service and to encourage greater utilization of the service. (Seelye, 5, 43-46). •There is no basis for prohibiting net metering customers from taking service under Tariff G.S. – PEV and the exclusion is unduly discriminatory (Seelye, 5, 46).	Lehman	• I&M is proposing not to charge a "higher rate" during on-peak periods for PEV charging because this may be perceived as a risk by customers and result in lower enrollment. • If the off-peak PEV charging rate were lowered to match I&M's actual off-peak cost of service as recommended by Mr. Seelye, there would be no incremental contribution to fixed costs from off-peak PEV charging, and no corresponding benefit to other customers. • It is reasonable to exclude DG net-metered customers from the pilot program. The proposed implementation relies on a per-kWh credit to encourage off-peak charging, which is not compatible with net-metered billing for customers who have distributed generation and a single premise meter.
13.B	Tariff IP	Walmart: •When setting IP rates, the Commission should: a) apply any approved revenue increase to the IP class to each service level's demand charge; b) maintain the first block energy charges at current levels; and c) reduce the second block energy charges as proposed by the Company. If the Commission approves a lower revenue requirement, the Commission should apply the revenue requirement reduction to the first block energy charges. (Chriss, 6, 31-32).	Nollenberger	• Although I&M continues to support its proposed Tariff IP rate design, I&M does not find Walmart's proposed Tariff IP rate design to be unreasonable. • Should the revenue requirement level change, 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.
13.C	Tariff LGS	Kroger: • Kroger recommends a rate design that increases Tariff LGS demand-related charges to 65% of the	Nollenberger	• Although I&M continues to support its proposed LGS rate design, I&M does not find Kroger's and Walmart's

	Tariff LGS *(continued)*	demand-related costs and reduces the energy charges by a corresponding amount to recover I&M's total proposed revenues for the LGS rate schedule. (Bieber, 4, 6-17). <u>Walmart:</u> • When setting LGS rates, the Commission should: a) apply any approved revenue increase to the LGS class to each service level's demand charge; b) maintain the first block energy charges at current levels; and c) reduce the second block energy charges to reflect the Company's proposed 69.2% ratio between the first and second blocks, and increase the demand charge to account for the reduced second block energy charge revenues. (Chriss, 5, 17-31).		proposed rate design methodology in this Cause to be unreasonable. • Should the revenue requirement level change, 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. • Should the Commission determine that a change in any Tariff LGS component is warranted at this time, the Company requests that the Commission's determination maintain the current companion tariff relationship between Tariffs LGS and GS.
13.D	Tariff MS & WSS	<u>Joint Municipals:</u> • I&M's rate design proposals for the WSS and MS rate classes should be rejected because the Company's proposal to introduce significant demand charges are overly aggressive and punitive. (Mancinelli, 4, 44-55). •Alternative WSS rate structures should include caps for low load factor customers, while retaining incentives for high load factor customers, and tempered demand charges. (Mancinelli, 5, 44-53). •Alternative MS rate structures should temper demand charges by including 10kW with no demand charge. Also, the applicable OSS/PJM rider should be recovered on an energy basis rather than a demand basis for this class. The class should have a single flat energy charge. (Mancinelli, 5, 53-55).	Nollenberger	• While JM's Tariff WSS improves the alignment between demand-related costs and the recovery through demand-related charges, the Company's Tariff WSS proposal goes even further in recovering demand-related costs based on customer's actual demands. • Mr. Mancinelli's recommendation regarding the Tariff MS basic rate demand charge is not an unreasonable alternative to the Company's proposed basic rate structure. Should Mr. Mancinelli's demand charge proposal be adopted, a blocked base rate energy charge comparable to Tariff GS and an energy charge for the PJM/OSS Rider should also be implemented. • Regarding Mr. Seelye's recommendation, there is a conceptual basis for a demand charge that

	Tariff MS & WSS (*continued)*	South Bend: • Because I&M's proposed demand charge for Tariff WSS is a single-part demand rate, that is not time-differentiated, it provides little opportunity for the customer to manage its demands. At the very least, the demand charge should be broken into distribution/transmission and production cost components with a time-of-use structure for the production cost component. Strong consideration should be given to the implementation of conjunctive demand rates for the production demand component of Schedule WSS. (Seelye, 5, 41-43). •I&M should be required to introduce a more flexible demand structure for Tariff WSS on an optional basis that includes demand charges structured to encourage customers to operate off peak and coordinate peak demands at multiple locations. (Seelye, 49).		segregates recovery of distribution costs from the recovery of production and transmission costs. • However, a 2-part demand charge is more complex than a single demand charge and would be unique among I&M's current C&I tariffs. Implementing a time-based demand charge may also require additional or alternative metering and related costs that are not reflected in I&M's test year forecast.
14.	**Rate Design: Residential**			
14.A	Fixed Monthly Residential Service Charge and Declining Block Energy Charge	OUCC: • Commission should maintain the current level of Residential customer charges. This will promote rate continuity as well as promoting conservation. (Watkins, 2, 46-48). •I&M's proposed Rate RS fixed customer charges and implementation of a declining-block energy rate is contrary to effective conservation efforts. (Watkins, 2, 40-46). CAC: • Commission should reject Company's proposal to increase the residential monthly charge because	Nollenberger Burnett	• The Company's residential rate design proposal in this Cause represents a gradual move towards improving the alignment of fixed costs with fixed cost recovery. • Both Mr. Wallach's and Mr. Watkins' recommendations would provide inefficient price signals to customers by overstating the variable cost associated with the incremental consumption or conservation of electricity. • Recovering a greater proportion of these fixed costs through the volumetric energy (kWh) charge would distort price signals and deter electricity consumption

	Fixed Monthly Residential Service Charge and Declining Block Energy Charge (*continued*)	I&M's proposal would lead to subsidization of high-use residential customers' costs by low-usage customers, and thereby inequitably increase bills for the Company's low-usage residential customers. (Wallach, 5, 28-30). • I&M's proposal would dampen price signals to consumers for controlling their bills through conservation or investments in energy efficiency or distributed renewable generation. (Wallach, 5, 30-34). • CAC recommends residential service charge be set at $10.12. (Wallach, 5, 23-28). • I&M's proposal to implement a declining-block structure for residential volumetric energy rates would further dampen energy price signals and promote inefficient customer behavior. (Wallach, 5-6, 34-39).		that would otherwise be efficient by overstating the variable cost of energy-related costs of service. • Contrary to CAC's assertions, it is in fact customers who use an amount of energy above the residential average who are impacted by rate design proposals such as CAC's. • Mr. Wallach's assumption that I&M would necessarily lower the volumetric energy rate when it raises its fixed service charge is simply not the case under I&M's proposal. • I&M's own experience, and that of its sister company PSO, shows residential usage has not increased when the fixed customer charge has increased. • Mr. Wallach has misrepresented the change in the volumetric energy rate in the Company's proposed rate design and is using an overstated price elasticity estimate for I&M's residential customers that is over two times larger than the observed price elasticity based on the Company's own price elasticity study. • Demand-related distribution costs are not directly related to a customer's actual kilowatt hour consumption or load factor over the course of a month. • The Company'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 (kWh) charge.

14.B	Optional Pilot Residential Demand-Metered Tariff	<u>CAC:</u> • A residential demand charge such as the Company proposes for the pilot will dampen price signals for conservation, encourage inefficient customer behavior, and undermine customers' ability to control electricity costs. (Wallach, 6, 39-41).	Nollenberger	• Giving customers a tariff option that better aligns customers' rates with the types of costs being recovered will provide improved price signals than one that recovers demand-related costs through volumetric energy charges. • A demand-metered service would give a customer more control over their bill, not less, because it provides the customer with a third dimension to control his or her bill in addition to the service and volumetric energy charges.
15.	**Rate Design: Street Lighting**			
15.A	Tariff SL	<u>South Bend:</u> •I&M should be ordered to revise its LED rates to reflect a lower level of maintenance costs and longer fixture lives. (Sommer, 5, 12-18). •I&M is proposing street lighting rates that are excessive. South Bend is being overcharged for streetlighting service. Furthermore, South Bend has identified problems with the modification of base fuel costs in the development of I&M's proposed SL rates which cause the rates to go up when they should be going down. (Seelye, 4, 32-37). •I&M should work with interested municipalities to fashion a mass LED retrofit plan to meet each municipality's needs. (Sommer, 17).	Nollenberger Lucas	• I&M is not proposing new LED-specific basic rates in this proceeding. The Commission approved I&M's LED rates on July 10, 2019. • The proposed rate increases that Mr. Seelye identifies are specific to the basic rate component and ignores the effect of "Fuel + All Riders." 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. • It is necessary to account for the net effect of fuel and all other riders when assessing the change in the Company's proposed basic rates. As illustrated in Table MWN-1R, the net effect of I&M's proposed ECLS rates is an approximately 0% increase. • The O&M costs included in I&M's street lighting rates are not significantly overstated. I&M only uses the relative relationship of the full cost estimates for each fixture to establish proposed rates that only collect the

	Tariff SL *(continued)*			fully supported embedded costs from the Company's CCOSS. • The PES Program approved in Cause No. 44841 reflects the Company's effort to facilitate mass conversion projects. Concerns with the design and implementation of the PES Program should be addressed in I&M's pending three-year DSM Plan filing.
16.	**Riders:**			
16.A	AMI Rider AMI Rider *(continued)*	<u>OUCC</u> • Should the AMI Rider be accepted over OUCC's objection to AMI deployment (Alvarez), then the retirement of the AMR meters should be recognized as a decrease in depreciation expense in the new rider. (Blakley, 1, 9-11, 15). <u>Kroger</u> • Commission should reject the proposed AMI rider as it amounts to single-issue ratemaking that does not address compelling public interest or meet the generally accepted criteria for this type of regulatory treatment. (Bieber, 5, 23-24). <u>South Bend:</u> • Commission should disallow use of an AMI Rider to reconcile any estimated AMI costs to those actually incurred. If AMI deployment approved, the Commission can conduct a prudence review of the costs in the next base rate case. (Cannady, 4, 32, 36).	Williamson	• OUCC's recommendation that the reduction to depreciation expense associated with retired AMR meters be reflected as a reduction to the AMI Rider revenue requirement is consistent with the Company's intent and proposal. • It is common to track the costs of AMI deployments given the significant nature of the investment that is incurred over a relatively short period of time yet necessarily spread out over multiple years due to the nature of the activity (i.e. replacing metering infrastructure). It also allows for the Commission and stakeholders to receive timely and valuable updates on the progress of the deployment and associated costs.

16.B	ECR	<u>OUCC</u> • Other than the Consent Decree there are no presently known regulations that would cause I&M's consumables or emission allowance costs to vary or increase over the next few years. (Aguilar, 14). • Recommends denying I&M's request to track environmental consumables and emission allowances above or below the embedded base rate amount as amounts not variable. Should embed $13.8 M in base rates (not $21.78M as proposed by I&M) because Enhanced DSI O&M costs should be denied recovery and expenses for capital projects embedded in rates should not be tracked. (Aguilar, 14-15, 28; Blakley, 1, 3-6, 14). •Alternative recommendation is to embed $17.8M in O&M to reflect exclusion of Rockport Unit 2 Enhanced DSI O&M costs (Aguilar, 15-16). <u>ICC:</u> •Commission should accept ECR only if I&M agrees to exclude all consumable costs in rate base from the price Rockport power is offered. DSI has comparatively high operating costs when compared to both dry scrubbers and wet scrubbers. (Medine, 5, 17-18).	Williamson Kerns	• I&M's proposal to embed TY level of consumables and allowances costs in base rates and track any annual over/under variance in the ECR is reasonable because these costs are variable, volatile, and largely outside of the Company's control. • 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. Furthermore, 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. • New environmental regulations or restrictions can be introduced at any time and Rockport operations are influenced by market conditions.
16.C	FAC	<u>OUCC</u> •Accepts I&M's recommended base of fuel. (Eckert, 18). •Should the Commission continue to allow I&M to include its GPR in its FAC filing, OUCC requests the Commission make the approval contingent on I&M's agreement to allow the OUCC a minimum 35	Williamson	• The revenue calculation for the sale of RECs is a very simplistic calculation and the additional revenue has a minimal impact on the FAC filing and does not justify the need for additional days to review the filing. In addition, the OUCC performs an interim audit that reviews, to a large degree, the first three months of the semi-annual FAC period. I&M continues to provide OUCC and its consultant an audit package

	FAC *(continued)*	days to review I&M's FAC proceedings. (Eckert, 19). •OUCC recommends approval of I&M's request for a permanent waiver of purchased power over the benchmark (Eckert, 20).		immediately following the filing of the FAC to expedite and facilitate the review process.
16.D	*IM Green*	OUCC •Supports consolidating GPR and REO into single *IM Green Rider*. •Recommends I&M monetize unsubscribed RECs and pass the proceeds onto ratepayers through the FAC for the benefit of all ratepayers. (Aguilar, 9-13). IG: • I&M should be encouraged to expand upon its IM Green Tariff proposal by working with its large customers to provide for those customers who must meet their sustainability goals by acquiring renewable power (bundled power and RECs) from an identified source. (Dauphinais, 3, 32-33). Walmart: • Commission should approve Custom Agreement option in proposed IM Green program, but eliminate reference to NJ REC pricing and substitute Walmart's alternative language. (Chriss, 6-7, 35-37).	Lucas	• OUCC's recommendation that I&M monetize RECs in the open market 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. I&M's *IM Green* program should be approved as requested by I&M. I&M would be interested in engaging with Walmart to explore potential utility partnership opportunities for renewable projects in Northeast Indiana.
16.E	LCM	OUCC • Recommends continuation of the LCM Rider (Eckert at 18, 20).	N/A	No rebuttal – No party opposes I&M's proposal.

16.F	OSS Margin Sharing	OUCC: • Recommends continued tracking of OSS margins, but with 100% of all OSS margins greater than zero dollars allocated to ratepayers. (Lantrip, 1, 5-8, 13). IG • If OSS margins included in I&M's base rates are set to zero as proposed by I&M, 100% of all of I&M's OSS margins above zero should flow to customers through OSS/PJM Cost Rider. I&M does not need an incentive to make OSS because it is required to offer all of its generation into PJM. Customers should be entitled to entirety of OSS margins because customers are covering the fixed costs of the generating units that are used to make OSS margins. (Dauphinais at 3, 30-31, 33). Kroger: •Company's proposal to embed zero OSS margins in base rates and share OSS margins with 95% going to customers fails to properly recognize the contribution customers have made to the capital and operating costs that enable I&M to conduct OSS trading. Recommend Commission order I&M to include $38.4 million forecasted amount of OSS margins in base rates and allow 95/5 sharing of the incremental OSS margins above or below that amount. To the extent Commission allows I&M to embed zero OSS margins in base rates, customers should receive 100% of the OSS margins. (Bieber, 5-6, 26). Joint Municipals: •I&M's allocation of OSS margins should be allocated 100% to firm retail customers in recognition that firm customers bear the responsibility of fixed cost recovery for all I&M generation assets. (Mancinelli, 3-4, 29-30, 59).	Williamson	•. Completely eliminating the incentive associated with sharing OSS margins will not properly compensate I&M for its efforts to effectively compete in the market and the risks it is taking to create the value being shared with customers. I&M's proposal to retain 5% of OSS margins is a very modest and reasonable request that provides nearly all incentives to customers while maintaining a small yet meaningful share to further incentivize optimizing off-system sales margin to reduce the cost of providing service to all customers. • Kroger's recommendation is unreasonable and should not be approved. Embedding such a high level of OSS margins in base rates and tracking above and below that amount shifts a significant amount of risk to the Company's shareholders in exchange for a very small potential benefit of retaining 5% if annual OSS margins exceed the test year level. I&M's proposal to share from $0 is consistent with I&M's current OSS margin sharing mechanism.

16.G	PJM Rider	OUCC • Commission should reject I&M's request to recover NITS Charges through OSS/PJM Rider and include the TY level of NITS Charges 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. (Gahimer at 27). • Commission should open investigation of prudence of Indiana Supplement Projects that result in NITS Charges to I&M and explore potential to shield I&M customers from the costs of Supplemental Projects built outside of Indiana, but in the AEP East zone. (Gahimer, at 20-22; 27). • Continued tracking of non-NITS costs seems appropriate at this time, as well as proposal to embed forecasted Test Year level of all non-NITS costs in base rates. (Lantrip, 8, 13-14). IG • Commission should deny NITS tracking; recovery through a rider would lead to interclass cost subsidies between customers due to it not considering the customer's delivery voltage; costs are largely under the control of the company and not volatile or variable in a manner that warrants tracking; other utility NITs costs are reflected in base rates and tracking limited to TDSIC plans; Supplemental Projects and Non-topology Projects (Owners Projects) are not independently verified by PJM. (Dauphinais at 2, 9-30, 33). Kroger •I&M's proposal to remove the sunset provision and continue fully tracking PJM costs amounts to single-issue ratemaking and should be denied.	Williamson Ali Thomas	• I&M has demonstrated that NITS costs are significant, potentially variable or volatile, and are largely outside I&M's control. In addition, NITS costs are rising so rapidly that it is not possible to set a test year level in base rates that is reasonably representative of ongoing NITS costs. I&M has also demonstrated these are reasonable and necessary costs incurred to provide service to customers. These are the standards upon which I&M's request should be judged and these criteria have been satisfied. • Neither IG witness Dauphinais nor OUCC witness Gahimer disputes that NITS Costs are significant. •NITS costs are variable because they are recurring and have significant increases due to the transmission system requiring substantial investment to address (a) the condition of the assets. Additionally, these costs, during any given period, are subject to potentially significant changes due to market and economic conditions, public policy, North American Electric Reliability Corporation, Federal Energy Regulatory Commission (FERC), environmental, and state regulatory requirements and other factors that can be unpredictable. • The projects giving rise to I&M's NITS expenses are outside the control of I&M and its affiliates because Transmission Owners do not have discretion to decline to make reasonable and necessary investments in the transmission grid. It is also important to note that none of the transmission projects giving rise to NITS expense have been alleged to be unreasonable or unnecessary. Nor have any such projects been found unreasonable or unnecessary by FERC through the existing review and discovery processes. Moreover, if any AEP transmission projects are ever determined to be unreasonable or unnecessary by FERC in a formula

	PJM Rider (*continued*)	Recommends reasonable PJM costs for the TY be embedded in base rates with no incremental tracker recovery. PJM costs are not subject to significant or unknown volatility and allowing these costs to be tracked diminishes the incentive for I&M and its affiliates to reduce costs below the level that is necessary in order to be deemed prudent in a rider reconciliation proceeding. (Bieber, 5, 20-21).		rate proceeding, the cost of such projects will be disallowed and not be included in the NITS bill that I&M receives from PJM. •I&M does not have control over costs that other transmission owners in the AEP Zone incur, including AEP affiliates. Each Transmission Owner in the AEP Zone has an obligation to ensure capital investments are prudent and necessary to maintain a reliable transmission grid. • AEP's structure does not supplant the respective obligations of the RTO members to fulfill their respective public utility obligations to serve. 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. • The continued recovery of the NITS costs through I&M's OSS/PJM Rider is a reasonable process for the recovery of I&M's portion of the total NITS costs for the AEP Zone. • Mr. Gahimer's recommendation to open an investigation is misplaced and should be denied. NITS costs are developed via FERC approved tariffs and are subject to prudence review through both the PJM stakeholder process and through the annual FERC formula rate filings. Mr. Gahimer's desire for additional information regarding NITS costs is better addressed through these processes which exist to further the state and federal goals underlying the RTO framework.

16.H	PJM Capacity Performance Insurance	<u>OUCC</u> • Capacity Performance Insurance cost is discretionary; deny recovery (Gahimer, 22-28). <u>Kroger</u> • I&M earns a rate of return on its production plant and other rate base assets that is intended to compensate for the business risks of running a utility. (Bieber, 5). <u>JM</u> • Deny recovery of any insurance premiums related to PJM performance requirements because Company has not shown expense provides a benefit to customers at this time. (Cannady, 4, 35).	Thomas Hevert	• Under the new PJM rules that began to apply to I&M In the 2019/2020 Deliver Year, I&M is subject to Non-Performance Charges in the event an I&M generating resource experiences an unexpected forced outage or otherwise fails to capacity performance requirements. •The question is not whether I&M is "required" to purchase this insurance, but whether doing so is reasonable. • In making the decision to purchase this insurance I&M considered both the risk of an event happening, as well as the consequence of an event happening. Insurance is a generally accepted means of safeguarding against loss and the cost of this insurance is not excessive. Given that Capacity Performance Insurance is available at a reasonable cost (about $1.00/MW-day with a reasonable deductible and policy loss limit) it is a prudent business decision to purchase it. The insurance safeguards customers because the potentially significant Performance Charges would be eligible for recovery through retail rates. • Because the PJM Rider is the ratemaking mechanism used to recover other PJM costs, the cost of the PJM Capacity Insurance is also reasonably included in the PJM Rider. • Kroger witness Bieber suggests the Company should not be allowed to recover the costs of PJM capacity performance insurance because "I&M earns a rate of return on its production plant and other rate base assets that is intended to compensate for the business risks of running a utility." However, the authorized return should fairly compensate investors for risks faced by comparable utilities. Here, Mr. Bieber suggests the business risks investors contemplate in establishing their return requirements for I&M should include those that otherwise would be,

	PJM Capacity Performance Insurance (*continued*)			and have been, insurable. If those risks are shifted to investors, the return they require would increase. Consequently, if Mr. Bieber's proposal were to be adopted, it would require an increase in the authorized ROE.
16.I	Phase-In Adjustment Rider (PRA)	<u>OUCC:</u> • I&M's PRA proposal is to use the methodology approved in CN 44967. Using this process again is reasonable. (Blakley, 2-3).	Williamson	• To clarify, the distinction between this case and CN 44967 is Phase II simply adjusts customer rates on June 1, 2020 to eliminate a credit associated with the IMMDA wholesale customer contracts that end on June 1, 2020. • There is no need to file a compliance filing for Phase II rates, these contracts are already known to be ending and will not be renewed and the Company has included Phase II rates in the tariff book submitted with this case. However, Phase III rates will utilize the same compliance filing process as Phase II rates in CN 44967.
16.J	Resource Adequacy Rider (RAR)	<u>OUCC</u> • Does not oppose I&M request to continue RAR. (Lantrip, 4). <u>IG</u> • I&M request to continue its RAR should be denied. These costs can be planned for, they are not volatile in nature, and they are relatively predictable. In addition, affiliated costs should not be tracked. (Dauphinais 3, 31-32, 33). <u>Kroger</u> • Deny tracking; the costs for I&M's non-fuel purchased power contracts are predictable long-term costs that don't meet the generally accepted criteria for cost trackers because the costs are not volatile. (Bieber, 22).	Williamson	• I&M recommends the Commission approve the Company's request as modified by the OUCC to include tracking of capacity sales revenues. • The fact that these costs may be predictable is precisely why we know the Test Year level of these costs is not representative of the costs on a going forward basis. • Forecasting is undertaken in all rate adjustment mechanisms; it does not change the fact that the costs are significant, potentially variable or volatile and largely outside the Company's control. • Additionally, costs are subject to FERC-approved and regulated purchased power contracts. Tracking these costs does not influence any incentive I&M has to manage the underlying costs.

17.	**Terms and Conditions of Service and Tariffs:**			
17.A	AMI Opt-Out	OUCC: • I&M should offer a self-read program for AMI opt-out customers at no additional charge (Aguilar, 3, 28). • Absent a no-cost option, I&M's monthly AMI opt-out fee is a deterrent intended to force I&M customers to convert to AMI (Aguilar, 4). • Recommends progress reports for AMI opt-out (Aguilar, 5). South Bend: •Recommends I&M offer a self-read option to AMI opt-out customers (Dorau, 19; Sommer, 34).	Cooper	• I&M did not propose a self-read option because this risks putting customers in a position that they may not necessarily want to be in. • I&M does not agree that the opt-out program charge is a "deterrent". I&M wants a customer to be able to opt-out of AMI if they so desire. That is why I&M has developed opt-out charges and processes. However, it is important that from a cost-causation standpoint, opt-out customers be allocated the costs associated with their choice. • The OUCC does not explain why quarterly reporting is necessary. If AMI reporting is required, it should not include sharing and publishing data around specific customers that have chosen to opt-out of an AMI meter. Customers should be able to opt-out without concern of being on a list that is shared between the utility, the OUCC, the Commission and possibly others.
17.B	Data Privacy	Auburn: • The Commission, working with I&M and the intervenors should adopt policies and procedures to protect customer data gathered from AMI meters (Rutter, 6).	Cooper	• I&M is committed to protecting customer data and has a data privacy policy. I&M disagrees that further adoption of policies and procedures is needed regarding I&M's data privacy policy, particularly in the context of this rate case.
17.C	Innovative Rate Options	South Bend: • I&M is not being sufficiently proactive in developing innovative rate options for its customers (Seelye, 47).	Cooper	• I&M does communicate with customers to find out what they want to see in the way of tariff and rate design and utilizes this feedback when developing new offerings. Contrary to Mr. Seelye's claim, I&M is very focused on providing innovative rate options for its customers.
17.D	Residential Demand Metered Pilot Tariff	OUCC: • Recommends I&M keep and maintain specific records on a customer by customer basis and should submit detailed reports, data and	Cooper	• Mr. Watkins has not explained why his proposed reporting and recordkeeping requirements related to the pilot are reasonable nor shown that any potential

		workpapers to the Commission, OUCC, and other interested parties on at least an annual basis (Watkins, 2-3, 48-49). CAC: • Extensive education to eligible customers will be needed for the residential demand metered option (Wallach, 40-41).		benefits would be greater than the associated administrative costs. • Implementation of Tariff RSD would be similar to that of other new tariff offerings in that the customer would be provided with the information on the tariff and how to best utilize their electric service to provide a least cost, efficient solution to their specific energy needs.
18.	**OTHER:**			
18.A	Renewable Energy	SB • South Bend is interested in renewable energy. A municipal solar program that partner with I&M would be potentially advantageous. (Sommer, 15).	Lucas	•To the extent the Municipal and Community solar programs suggested by witness Sommer are able demonstrate a benefit for all I&M customers, I&M would be interested in considering those options in I&M's renewable strategy.
18.B	Customer Satisfaction	SB • I&M can support customer satisfaction by supporting energy efficiency; implementing automated benchmarking; enabling aggregated net metering for public distributed generation; enabling meter aggregation and billing for renewable energy; and supporting reduced vehicle emissions. (Dorau, 23-27). 39 North • I&M should consider and review outside, independent reviews such as the J.D. Power Electric Satisfaction Surveys and evaluate how such information and feedback can be used to effectively address concerns and improve its customer service experiences and needs. (Cearley, 7-8).	Lucas	• I&M and AEP currently have activities underway to evaluate a number of the items that witness Dorau has mentioned and will take South Bend's feedback into consideration as we consider new program offerings and changes to existing programs. • I&M disagrees with Mr. Cearley's characterization that our customer satisfaction is "poor." I&M has made improvements in customer service over the past several years. • On the residential side, Mr. Cearley's Table 1 shows I&M's residential J.D. Power scores have actually increased every year from 2016 through 2018. I&M's witnesses have identified investments, plans and programs that demonstrate Company engagement and plans to proactively address ongoing challenges. • I&M has spent time with J.D. Power to discuss customer satisfaction trends and also performed peer research.

	Customer Satisfaction (*continued*)			• As an example, J.D. Power performed a study for I&M regarding the customer satisfaction impact of AMI meters and the associated customer engagement platform. The results showed Overall Satisfaction of utility customers with AMI meters was 20 points higher in the J.D. Power survey than customers without AMI technology. • I&M's proposed programs such as *IM Green*, Electric Vehicles, and Customer Assistance, and partnering with local organizations to promote a healthy and vibrant economy through Economic Development programs are all critical components of our customer experience strategy. • When these customer programs are combined with strategies proposed in this case to invest in reliability improvements in the Transmission and Distribution systems, the resulting customer benefits should improve the customer experience and customer satisfaction.
18.C	Investigation	<u>ICC</u> • Commission should 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 and direct I&M to calculate the incremental cost of compliance as a result of the Fifth Modification and determine what if any of these incremental costs should be recoverable. (Medine, 5).	Thomas	• 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. The Fifth Joint Modification provides optionality for the owners to exercise if they so choose. • The appropriate forum to consider the resources to serve I&M's customers is through its periodic Integrated Resource Planning process, not a general rate case. There is no need for the Commission to order and investigation as part of this proceeding.