

ORIGINAL

Commissioner	Yes	No	Not Participating
Zay	√		
Deig	√		
Swinger		√	
Veleta	√		
Ziegner			√

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

**VERIFIED PETITION OF INDIANA MICHIGAN)
POWER COMPANY FOR APPROVAL OF A)
CHANGE IN THE METHODOLOGY FOR)
ALLOCATING BETWEEN INDIANA AND) CAUSE NO. 46305
MICHIGAN RETAIL JURISDICTIONS THE COSTS)
OF CURRENT GENERATION RESOURCES AS AN) APPROVED: APR 22 2026
ALTERNATIVE REGULATORY PLAN PURSUANT)
TO IND. CODE CH. 8-1-2.5.)**

INTERIM ORDER OF THE COMMISSION

**Presiding Officers:
David E. Veleta, Commissioner
Lorraine L. Seyfried, Chief Administrative Law Judge**

On October 3, 2025, Indiana Michigan Power Company (“I&M” or “Petitioner”) filed its Verified Petition with the Indiana Utility Regulatory Commission (“Commission”) requesting approval of an alternative regulatory plan (“ARP”). Also on October 3, 2025, I&M prefiled its prepared testimony and exhibits constituting its case-in-chief.

On October 20, 2025, Citizens Action Coalition of Indiana, Inc. (“CAC”) filed a petition to intervene in this Cause, which was granted by docket entry on October 29, 2025.

On November 4, 2025, the City of Marion, Indiana and Marion Municipal Utilities, along with the City of Fort Wayne, Indiana and the City of South Bend, Indiana (collectively the “Joint Municipals”), filed a petition to intervene. The Joint Municipals’ petition to intervene was granted by docket entry on November 12, 2025.

On January 9, 2026, the Indiana Office of Utility Consumer Counselor (“OUCC”), CAC, and the Joint Municipals prefiled their respective testimony and exhibits. I&M filed its rebuttal testimony on January 23, 2026.

The Commission conducted an evidentiary hearing on February 16, 2026, at 9:30 a.m. in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. I&M, the OUCC, CAC, and the Joint Municipals appeared and participated in the hearing, by counsel, and the evidence of the parties was admitted into the record without objection.

The Commission, based upon the applicable law and evidence of record, now finds as follows:

1. Notice and Jurisdiction. Notice of the hearing in this Cause was given and published by the Commission as required by law. Additionally, in accordance with Ind. Code § 8-

1-2.5-6(d), I&M submitted proofs of publication of notice of the filing of its Verified Petition on December 3, 2025. I&M is a “public utility” within the meaning of that term as used in Ind. Code § 8-1-2-1. I&M is also an “energy utility” providing “retail energy service” as defined in Ind. Code §§ 8-1-2.5-2 and -3. Under Ind. Code § 8-1-2.5-6, the Commission has jurisdiction over an energy utility’s request to adopt an ARP. Therefore, the Commission has jurisdiction over I&M and the subject matter of this proceeding.

2. Petitioner’s Characteristics. I&M is a wholly owned subsidiary of American Electric Power Company, Inc. (“AEP”) with its principal offices at Indiana Michigan Power Center, Fort Wayne, Indiana. I&M is engaged in, among other things, rendering electric service in Indiana and Michigan. I&M owns and operates generation, transmission, and distribution plant and equipment within Indiana and Michigan that are in service and used and useful in the furnishing of such electric service to the public.

I&M supplies electric service to approximately 484,000 retail customers in northern and east-central Indiana and 134,000 retail customers in southwestern Michigan. I&M’s Indiana service area covers approximately 3,200 square miles. In Indiana, I&M provides retail electric service to customers in the following counties: Adams, Allen, Blackford, DeKalb, Delaware, Elkhart, Grant, Hamilton, Henry, Howard, Huntington, Jay, LaPorte, Madison, Marshall, Miami, Noble, Randolph, St. Joseph, Steuben, Tipton, Wabash, Wells, and Whitley. In addition, I&M serves customers at wholesale in Indiana and Michigan.

3. Background and Relief Requested. I&M’s generating facilities, augmented with wholesale power purchases and demand response and energy efficiency programs, have historically operated as a single system on an integrated basis to provide service to both Indiana and Michigan customers. I&M recovers its costs of owning and operating its generation system in retail rates established from time to time in Indiana and Michigan regulatory proceedings (as well as through wholesale formula rates).

With respect to recovery of I&M’s generation costs in retail rates, state regulatory proceedings in both Indiana and Michigan have generally determined what assets are used and useful in providing service to customers, as well as the reasonableness of associated costs to be included in Petitioner’s revenue requirement in the applicable state proceeding. Each state’s respective proceedings have determined what portion of these costs should be allocated to customers in each state for purposes of ratemaking. This jurisdictional allocation process has historically been updated during general rate cases based on the relative share of demand and energy during a specific period of time.

In this case, I&M requests approval of an ARP that establishes a new jurisdictional cost allocation framework. I&M asserts that its proposed ARP is needed to address the differing state energy policies and the rapidly diverging load in Indiana and Michigan. Specifically, I&M proposes, on a going forward basis, to use the currently approved jurisdictional allocation factors to allocate the non-fuel costs and fuel costs associated with its Current Generation Resources,¹

¹ Current Generation Resources are all existing generation assets used to serve retail customers in Indiana and Michigan, as well as new resources approved through I&M’s 2022 and 2023 All Source Requests for Proposals, excluding resources already specifically assigned to one jurisdiction.

subject to future changes in I&M's wholesale load. For non-fuel costs, I&M proposes setting the retail jurisdictional allocation of the Current Generation Resources using Primary Allocation Factors² approved in I&M's most recent Indiana and Michigan base rate cases, Cause No. 45933 and Case No. U-21461, respectively, subject to future adjustment only to the extent I&M's wholesale demand energy percentages change. For fuel costs and PJM Interconnection LLC ("PJM") market revenues associated with the Current Generation Resources, I&M also proposes to allocate these using the Primary Allocation Factor for each generation resource and, similar to non-fuel costs, adjust in the future for changes in I&M's wholesale demand and energy.

Under I&M's proposed ARP, the jurisdictional allocation of the costs of the Current Generation Resources between the states will no longer change from base rate case to base rate case other than to reflect changes in I&M's wholesale demand and energy. I&M is not proposing to change or establish different allocation policies and procedures for purposes of allocating costs and revenues within Indiana among Petitioner's retail Indiana customer classes, nor is I&M seeking to adjust customer rates. However, because I&M has filed a similar case in Michigan and the decisions of the two state commissions must be consistent, I&M requests the Commission issue a preliminary, or interim, decision in this case to afford I&M the opportunity to determine its consistency with the determination to be made by the Michigan Public Service Commission.

4. Evidence Presented.

A. Petitioner's Case-in-Chief Testimony. Mr. Andrew J. Williamson, I&M's Vice President, Regulatory and Finance, testified that I&M's proposed ARP is designed to respond to the unprecedented load growth in Indiana, reflect divergent state energy policies in Indiana and Michigan, and provide a transparent, stable, and equitable allocation of the Current Generation Resources across I&M's jurisdictions.

Mr. Williamson defined Current Generation Resources to include all existing generation assets used to serve retail customers in Indiana and Michigan, as well as new resources approved through I&M's 2022 and 2023 All Source Requests for Proposals, excluding resources already specifically assigned to one jurisdiction. He testified that I&M's Indiana retail load is expected to more than double over the next five years, primarily due to hyperscale commercial development; in contrast, Michigan retail and wholesale load growth is projected to remain flat. He testified that this creates a significant imbalance under historic cost allocation practices that rely on proportionate load. He stated that traditional cost allocation mechanisms could result in disproportionate shifts in resource responsibility, whereby one state (e.g., Michigan) could lose access to long-utilized generation assets due solely to unrelated growth in the other state. He explained that I&M's proposal preserves historical allocation percentages and ensures each respective state continues to benefit in the future from a similar amount of I&M's Current Generation Resources as they do today and have over many years.

Mr. Williamson also addressed the state energy policy divergence between Indiana and Michigan. He stated that Indiana has adopted an "all-of-the-above" strategy including fossil, nuclear, and renewable resources, while Michigan has enacted a 100% clean energy standard by

² The Primary Allocation Factor is the jurisdictional allocation factor by which the majority of the cost for each Current Generation Resource is allocated between I&M's retail jurisdictions.

2040. He testified that I&M proposes state-specific resource planning to better align with each state's legislative and regulatory direction.

Mr. Williamson testified that I&M requests approval of an ARP to establish and implement its proposed jurisdictional allocation methodology outside of a base rate case, given the urgency driven by Indiana's rapid growth. He stated the ARP will produce customer and statewide benefits by providing transparency and predictability regarding the baseline generation capacity required to meet Indiana's future energy and capacity needs. In addition, he stated that the ARP will promote utility efficiency. He said the ARP leverages I&M's existing Commission-approved allocation factors, enhancing administrative and operational efficiency, and will create clarity to expedite the planning and acquisition of new generation resources in a cost-effective and timely manner. He further testified that approval of the ARP will enhance I&M's ability to compete for and secure energy resources necessary to meet future obligations and denial of the request could hinder I&M's competitive position against other energy providers in obtaining needed resources.

Mr. Williamson also testified that I&M's proposal aligns with Indiana's five pillars of energy policy ("Five Pillars") set forth in Ind. Code § 8-1-2-0.6, as follows:

- Reliability, Resiliency, and Stability: By preserving consistent access to Current Generation Resources and enabling state-specific planning where each state has a predictable amount of generation resources.
- Affordability: By reducing exposure to market volatility, supporting rate stability, and avoiding overbuilds or stranded assets.
- Environmental Sustainability: By maintaining a diverse and largely clean energy portfolio (approximately 80% clean energy today).

Mr. Williamson emphasized that because I&M is regulated in both Indiana and Michigan, consistent outcomes are essential. He stated Petitioner proposes a two-phase process, beginning with preliminary orders, to ensure coordinated and feasible implementation across jurisdictions.

Mr. Jason M. Stegall, AEP Service Corporation's Director of Regulatory Services, explained I&M's proposed methodology for allocating both non-fuel and fuel-related costs associated with the Current Generation Resources. He stated the non-fuel costs include depreciation, decommissioning, operations and maintenance expenses, authorized return on rate base, and other costs such as income tax expense. He stated that historically, jurisdictional allocation of non-fuel costs has been updated through periodic base rate cases using demand- or energy-based allocators that reflect each jurisdiction's share of I&M's total system demand or energy. He testified demand has generally been used to allocate non-fuel costs for owned and dispatchable resources, while energy has been used for renewable power purchase agreements, and these allocation percentages have historically been relatively stable.

Mr. Stegall testified that in 2023, I&M filed base rate cases in Indiana and Michigan using a forecasted 2024 test year and coordinated demand and energy studies, resulting in a recent and consistent set of Commission-approved jurisdictional allocation factors. He explained that I&M proposes to use the Primary Allocation Factor approved in those most recent rate cases to allocate non-fuel costs for Current Generation Resources going forward, rather than recalculating

jurisdictional allocation factors in future proceedings. Under this proposal, the fixed retail allocation percentages assigned to Indiana and Michigan would change only to reflect changes in I&M's wholesale demand and energy percentages.

Mr. Stegall defined the Primary Allocation Factor as the jurisdictional allocation factor by which the majority of the cost for each Current Generation Resource is allocated between I&M's retail jurisdictions. He explained that for some resources, such as the Rockport plant and the Donald C. Cook Nuclear Plant, costs have historically been allocated using both demand and energy allocators, but the Primary Allocation Factor reflects the allocator used for the majority of each resource's costs. He provided a summary of the Primary Allocation Factors approved in I&M's most recent base rate cases, which would be used for all costs associated with Current Generation Resources under I&M's proposal. Pet. Ex. 2, Figure JMS-2 at 6.

Mr. Stegall testified significant growth in Indiana retail load is expected to increase I&M's overall system load, causing wholesale generation contracts to decline as a percentage of total system demand and energy. To account for this shift, I&M proposes to adjust retail jurisdictional allocations of Current Generation Resources to reflect changes in wholesale load using "Retail-Only Percentages." He explained this approach will allow I&M to periodically rebalance allocations so that, if wholesale contracts were to end, Current Generation Resources would be fully allocated to Indiana and Michigan retail operations based on the most recently approved retail allocation percentages.

Mr. Stegall explained I&M's long-term wholesale customers take service under formula rate agreements that pay a "slice of system" based on their load ratio share, meaning wholesale customers pay a proportionate share of I&M's total generation costs. He said as I&M's total system load grows, wholesale customers' relative share declines, reducing their cost responsibility for Current Generation Resources and allowing a greater portion of those resources to be allocated to retail jurisdictions.

With respect to fuel costs and PJM market revenues, Mr. Stegall testified these costs include fuel for fossil and nuclear generation, spent nuclear fuel, purchases from AEP Generating Company, wind purchases, and associated off-system sales. He explained that I&M proposes to allocate fuel costs and PJM revenues using the same Primary Allocation Factor used for non-fuel costs for each resource, beginning June 1, 2026, at the start of the 2026/2027 PJM Planning Year. He said this proposal is intended to align the allocation of fuel costs and market revenues with the allocation of fixed costs for each generation resource.

Mr. Stegall explained that currently, fuel costs and PJM revenues are allocated strictly on an energy basis through a monthly net energy requirement calculation reflected in Michigan's Power Supply Cost Recovery mechanism and Indiana's Fuel Cost Adjustment rider. He testified that continuing this approach would cause Indiana customers to receive disproportionate energy benefits before corresponding changes in fixed cost allocation occur, due to the monthly updating of fuel allocators versus periodic updating of non-fuel allocators. He stated that allocating fuel costs and PJM revenues using the Primary Allocation Factor avoids these disparate results and better matches energy benefits with the fixed costs borne by each jurisdiction.

Mr. Stegall further explained how the ARP would operate in practice, including the creation of separate Indiana Retail and Michigan Retail jurisdictions for PJM, submission of hourly load data, allocation of generation output and market transactions, calculation of fuel deferrals, crediting of wholesale revenues, and filing of appropriate jurisdictional fuel reconciliation mechanisms.

Mr. Stegall concluded that I&M's proposal to use the Primary Allocation Factor to allocate both non-fuel and fuel costs for Current Generation Resources provides a reasonable and consistent framework that supports safe, reliable, and affordable service for retail customers in Indiana and Michigan. He testified that the proposal addresses disparate results that could arise under historical allocation practices as retail load composition changes and aligns energy benefits with capacity and related costs.

B. OUCC's Testimony. Mr. Kaleb G. Lantrip, Senior Utility Analyst in the OUCC's Electric Division, testified he did not oppose I&M's request to set its Primary Allocation Factor at the factors approved in Cause No. 45933 and Case No. U-21461, on the condition that such approval does not supersede prior Commission orders concerning decommissioning and demolition costs of Current Generation Resources upon retirement, and is consistent with the Cause No. 45235 base rate decision regarding the support needed to reallocate wholesale contract costs to retail ratepayers.

Mr. Lantrip summarized I&M's proposed ARP. He stated that I&M indicated it was proposing the ARP because for many years Petitioner's retail load has been relatively stable across Indiana and Michigan, but over the next five years I&M forecasts Indiana's retail load to more than double, due primarily to hyperscaler business development. He also noted that I&M anticipates additional large load growth beyond 2030 that could be similar to or exceed the load growth expected through 2030.

With respect to wholesale contracts, Mr. Lantrip explained I&M has long-term wholesale generation contracts structured as formula rate agreements that pay a "slice of system" based on I&M's Federal Energy Regulatory Commission ("FERC") Form 1 reporting of load shares of generation costs, essentially operating as a third jurisdiction. He noted that I&M's witness testimony explained that as I&M's total company system load increases, assuming no change in wholesale load, wholesale customer load will become a smaller percentage of the total system.

Mr. Lantrip identified certain broader regulatory concerns, testifying that this filing is the latest in a series of multiple filings that have "deprioritized its rate case process in favor of single issue approvals sought outside the context of a holistic rate case consideration." Pub. Ex. 1 at 5. He characterized this as a "concerning trend." Mr. Lantrip further noted that, in I&M's base rate case, Cause No. 45235, the Commission disallowed I&M's request to reallocate wholesale capacity costs to retail customers, finding that a requested shift of risk to Indiana captive retail customers was not warranted. While acknowledging I&M's current request features different forecasted load characteristics, Mr. Lantrip testified that I&M will still bear the burden of proof in future cases if it seeks to match wholesale portions of the jurisdictional allocation factor and corresponding costs to Indiana jurisdictional load.

Finally, Mr. Lantrip addressed decommissioning and demolition costs, testifying I&M did not address the effect of the ARP on decommissioning and demolition cost responsibilities between Indiana and Michigan jurisdictions. He noted OUCC discovery responses stating that each state will continue to be responsible for such costs based on jurisdictional cost allocation over time and expressed concern that the request in this Cause should not supersede previously approved orders on this issue.

C. CAC's Testimony. Mr. Benjamin Inskeep, CAC's Program Director, recommended that the Commission deny I&M's proposed ARP because I&M has failed to demonstrate that its proposed modifications are warranted or reasonable, and that I&M's next base rate case is the appropriate venue to comprehensively address jurisdictional cost allocation and related issues.

Mr. Inskeep disagreed with I&M's justifications of forecasted large load growth in Indiana, relatively stable load in Michigan, and differences in state energy policies for its proposed ARP. He stated that load growth in one jurisdiction is not, by itself, a problem that necessitates a fundamental change to longstanding jurisdictional cost allocation practices, noting that Indiana's allocation percentages have increased substantially in the past without prompting such changes. He further testified that I&M has provided no analysis demonstrating that Indiana customers would be harmed by maintaining the status quo and therefore has failed to meet its burden of proof to show that the requested relief is necessary and reasonable.

With respect to differing state policies, Mr. Inskeep testified that I&M has not adequately explained what those differences are or why they require modifying the current "slice of system" allocation framework. He stated that I&M has provided no statutory analysis showing it would be impossible to meet the needs of both states under existing practices, and that if a specific state policy results in a specific additional cost, such costs could be directly assigned to the adopting jurisdiction (for example, renewable energy certificates for Michigan) without dismantling the existing allocation methodology.

Mr. Inskeep also objected to I&M's proposal to fix, or set, demand allocation factors approved in its most recent rate case going forward. He testified that those approved factors were based on a forward-looking test year that did not include large load customers, and since that time, I&M's Indiana load has materially increased, with hyperscaler data centers already taking service and paying rates that include demand-related costs of Current Generation Resources. He concluded that the existing allocation factors have already become "stale" and do not reasonably reflect current or near-term system usage, particularly given I&M's own forecast that data center peak demand will add more than 1,000 MW by early 2026.

Mr. Inskeep further testified that I&M's proposal to allocate fuel costs and PJM market revenues using the Primary Allocation Factor is unreasonable and inconsistent with cost causation. He stated that energy-related costs and revenues are currently allocated strictly on an energy basis and reallocating them based on demand would directly contradict the principle that energy-related costs should be assigned based on energy usage, while demand-related costs should be assigned based on demand.

Mr. Inskeep warned that I&M's proposal could result in higher rates for Indiana customers. He explained that if new generation resources procured to meet Indiana load growth are more expensive than the Current Generation Resources, I&M's proposal would cause Indiana customers to bear higher costs while Michigan customers would "lock in" a disproportionately higher share of lower-cost existing resources compared to the current allocation framework.

Mr. Inskeep also testified that I&M has not justified why this major change should be adopted in a standalone proceeding rather than addressed in I&M's next base rate case, which is required in 2026. He stated that a base rate case is the appropriate forum to holistically evaluate jurisdictional cost allocation issues and to update allocation factors to reflect load changes that have already occurred, rather than perpetuating outdated factors for Current Generation Resources.

Finally, Mr. Inskeep identified additional jurisdictional cost allocation concerns related to transmission investments driven by large load customers across the AEP system. He testified that under I&M's extension of service policy and PJM cost allocation rules, large load customers are generally not directly assigned the costs of transmission upgrades needed to serve them. Instead, these costs are socialized through Network Integrated Transmission Service charges and recovered from all Indiana retail ratepayers through the Off-System Sales Margin Sharing/PJM Cost Rider. As a result, Indiana customers may pay for transmission upgrades to serve data centers in Michigan or other AEP territories, and vice versa. He stated that these practices are inconsistent with cost causation and underscores that large load growth raises numerous cost allocation issues that should not be addressed piecemeal.

D. Joint Municipals' Testimony. Jill A. Schuepbach, Principal in the Energy Practice of NewGen Strategies and Solutions, LLC, objected to the ARP as not being in the public interest. She characterized I&M's petition as a departure from prior practice because jurisdictional cost allocation studies have historically been reviewed and approved as part of a utility's base rate proceeding, not through a separate standalone filing. She stated that I&M asserts concern with recovering its full cost of service but provided no data showing how its proposal impacts cost of service, and she raised concerns about the allocation of potential stranded generation costs when multiple wholesale customer contracts expire between 2033 and 2038.

Ms. Schuepbach identified the following concerns: cost allocation is part of Commission-approved base rates and cannot be separated from ratemaking; the economic effects of I&M's proposal are unknown and the proposal is presented without quantitative outcomes; I&M's generation operations will remain integrated across its multi-state service territory with no evidence of operational change, making state-specific assignment an accounting construct without operational justification; and the forecasted large load may not materialize, creating risk of stranded costs and upward pressure on remaining customers' rates; and the cost impact of the differing state regulatory policies is unknown and may change.

Ms. Schuepbach emphasized that I&M has historically operated generation resources as a pooled system serving its entire territory and allocated generation costs among Indiana, Michigan, and wholesale customers through jurisdictional separation studies recalculated from one base rate case to the next. She explained that jurisdictional cost allocation is integral to setting rates and materially affects which customers pay which costs; freezing allocations using several-year-old

factors deviates from standard ratemaking practices and would “freeze retail cost allocation for Current Generation Resources as though customer rates were permanently fixed.” JM Ex. 1 at 11.

Ms. Schuepbach discussed Indiana’s ARP statute and concluded I&M has not shown its proposal satisfies ARP standards or serves the public interest. She testified that reliance on projected load growth is premature, reliance on state policy that can change does not justify altering cost allocation practices, and the established base rate case process remains appropriate. She stated the outcomes and impacts of the proposed changes are uncertain and stakeholders lack sufficient information to assess the effects on customers, classes, and jurisdictions.

Ms. Schuepbach further testified that the quantitative impacts of using different allocation methodologies for fuel-related versus non-fuel-related costs cannot be determined from the record, but that allocating variable fuel-related costs using demand-based factors would be inconsistent with cost causation and fundamental cost-of-service principles, undermining the analytical integrity of the cost-of-service study and setting an inappropriate precedent.

Finally, Ms. Schuepbach raised a specific concern regarding wholesale contract expirations and the potential for improper cost shifting to retail customers. Citing Cause No. 45235, Ms. Schuepbach stated the Commission rejected I&M’s attempt to shift stranded wholesale costs to retail customers and directed I&M to file a different jurisdictional separation study. She asserted that I&M’s proposal to “rebalance” allocations to 100% could force stranded wholesale generation costs onto retail load when remaining wholesale contracts expire, contrary to Commission precedent, and she stated this issue alone warrants rejection of the ARP.

Ms. Schuepbach recommended that the Commission deny I&M’s request for the ARP and not allow I&M to separate cost allocation from its next base rate case. However, if the Commission approves the ARP, she recommended denying the Current Generation Resource cost allocation using Primary Allocation Factors and indicate I&M will be responsible for any stranded costs resulting from wholesale customers leaving or forecasted large load not materializing.

E. I&M’s Rebuttal Testimony. Mr. Williamson noted that the OUCC does not oppose I&M’s proposal but seeks certain clarifications. With respect to OUCC witness Lantrip’s requested clarification that approval of the requested ARP should not supersede prior approvals concerning decommissioning and demolition cost responsibility between Indiana and Michigan, Mr. Williamson stated I&M’s proposal would not supersede prior orders and does not change how responsibility for those costs will be determined over time, as each state will remain responsible based on its jurisdictional cost allocation.

Mr. Williamson further testified that I&M recognizes the Commission’s findings in Cause No. 45235 and that future changes to jurisdictional allocation factors will remain subject to Commission review and approval. He asserted that I&M’s proposal will make future changes in allocation more predictable by limiting changes in jurisdictional allocation of Current Generation Resources to changes in wholesale load, which he characterized as stable and predictable given defined contract end dates and contractual protections against abnormal wholesale load growth. He contrasted this with future retail load, which he testified will be subject to significant and unpredictable changes, making historical allocation practices difficult to plan for and manage.

Next, Mr. Williamson disagreed with CAC witness Inskeep’s recommendation to deny I&M’s proposed ARP, and his views that Indiana load growth and policy differences do not justify changes, that Primary Allocation Factor treatment for fuel/PJM revenues is inconsistent with cost causation, and that cost allocation should be addressed in a base rate case. Mr. Williamson emphasized that I&M is not proposing in this Cause to change the jurisdictional allocation factors approved in Cause No. 45933. Instead, I&M proposes to modify the process for reviewing allocation going forward by limiting changes for Current Generation Resources to those driven by wholesale load changes.

Mr. Williamson testified that historical Indiana/Michigan demand and energy ratios have been stable (approximately 82% Indiana and 18% Michigan), but this stability is now threatened by unprecedented, jurisdictionally asymmetric large-load growth. He reiterated I&M expects Indiana retail load to more than double over the next five years and argued that continuing historical allocation practices would cause abrupt shifts of generation resources and costs to the jurisdiction experiencing load growth. He testified these shifts can create counterintuitive “need” outcomes—requiring new generation additions in the state that did not experience load growth—and may increase market exposure and customer rate volatility. He presented illustrative scenarios to show how load growth in one jurisdiction can create generation “need” in the other under historical practices, and asserted that I&M’s proposal will alleviate these challenges by creating stability in the allocation of Current Generation Resources and better aligning generation needs and associated costs with the state experiencing load growth.

Mr. Williamson disagreed with CAC’s claim that prior allocation factors are “stale,” noting that customers pay for electric service, not specific assets. He testified that I&M is already procuring additional, state-specific (Indiana-only) resources to serve Indiana load growth. He also disputed CAC’s contention that I&M’s proposal could increase Indiana rates, emphasizing that the proposal is intended to prevent load growth in one state from driving significant generation needs in the other. Mr. Williamson rejected the recommendation to defer the matter to the next base rate case, testifying that coordinated, stand-alone decisions in both Indiana and Michigan are necessary for generation planning that must occur now and cannot wait for a rate case conclusion projected in mid-to-late 2027.

Regarding CAC’s discussion of transmission cost allocation, Mr. Williamson testified that transmission cost allocation is governed by the PJM Tariff approved by FERC, and that nothing in this proceeding can change how PJM allocates transmission costs. He acknowledged CAC’s description of I&M’s extension of service tariff provision but testified it applies broadly to all customers and that customers cover such costs through payment of rates. He further testified CAC’s network upgrade concerns related to PJM’s “beneficiary pays” framework, which has been litigated at FERC and found reasonable.

Regarding Joint Municipals’ witness Schuepbach’s argument that cost allocation should not be separated from a base rate case, Mr. Williamson responded that filing outside a base rate case is not inherently unreasonable and is justified here to create a transparent baseline and achieve a coordinated outcome between the two states before the next general rate case. He disputed the claim that I&M provided no supporting data, explaining that the relevant jurisdictional allocation factors were established in I&M’s most recent base rate in 2024 and that this proceeding does not

seek rate changes. He also denied that I&M is proposing to directly assign future generation resources by state, stating that the ARP proposal is limited to Current Generation Resources.

Mr. Williamson rejected assertions that I&M is separating cost allocation from ratemaking or pursuing an improper “piecemeal” approach, stating the ARP proposal reflects what was used to establish current rates and is necessary to deviate from historical jurisdictional allocation processes for Current Generation Resources in light of unprecedented load growth. He distinguished class cost allocation from jurisdictional cost allocation, explaining that jurisdictional allocation determines how shared resources and costs are assigned among Indiana, Michigan, and wholesale jurisdictions, while class allocation occurs later within a jurisdiction; he testified the ARP proposal has no impact on class allocation or future rate design. He further testified that large load growth in Indiana is not speculative, citing executed Electric Service Agreements totaling approximately 3,400 MW of contract capacity through 2031, and disputed claims that I&M’s proposal would strand costs or shift them to retail customers, stating those claims are unfounded and that future wholesale-related allocation changes remain subject to Commission review and approval.

Responding to arguments that allocation methodology changes should only be addressed in base rate proceedings, Mr. Stegall explained the distinction between jurisdictional cost allocation and class cost allocation. He stated that jurisdictional allocation determines how costs are assigned among Indiana retail, Michigan retail, and wholesale jurisdictions, and that class cost allocation occurs only after jurisdictional allocation. He testified this case concerns only jurisdictional cost allocation and does not impact class cost allocation or rate design going forward.

Mr. Stegall testified that Petitioner is not requesting a rate change and is not proposing to modify the existing jurisdictional allocation factors approved in Cause No. 45933, except to reflect future changes in wholesale load. He stated that Petitioner seeks to establish a baseline for future jurisdictional and class cost-of-service studies that preserves the relationship between historical demand, energy usage, and cost responsibility prior to the inclusion of large load customers in Indiana. He asserted that addressing this issue now is reasonable, particularly given the relative historical stability of Indiana and Michigan retail allocation factors and the need for coordination with a companion filing in Michigan.

Mr. Stegall rejected the Joint Municipals’ claim that the proposal creates a mismatch between cost causation and cost allocation or weakens the analytical integrity of cost-of-service studies. He testified that the proposed “ownership share” methodology better aligns variable, fuel-related costs with cost causation and is a commonly used approach relied upon by the Commission for jointly owned resources. He further stated that I&M will continue to support review and analysis of future jurisdictional cost-of-service studies.

Mr. Stegall also responded to CAC’s suggestion that costs associated with state-specific policies could be directly assigned, stating that Petitioner’s proposed ARP is limited to Current Generation Resources and is intended to establish a necessary starting point for calculating future cost responsibility as jurisdictional loads change. He characterized Petitioner’s proposal as a reasonable and necessary step to address potential instability in jurisdictional cost allocation going forward.

Addressing claims that the proposal is an effort to reallocate costs and risks among states without operational justification, Mr. Stegall testified that I&M's proposal does not affect base rates and is driven by significant changes in relative retail load between Indiana and Michigan. He stated that the Current Generation Resources were required to serve load in both jurisdictions prior to recent Indiana load growth and that separate PJM settlements for each retail jurisdiction more accurately assigns costs and risks associated with meeting PJM energy obligations. He further clarified that the proposed ARP does not require changes to I&M's operational or dispatch practices in PJM markets, but only modifies the allocation of fuel costs, purchased power costs, and off-system sales to reflect a joint ownership approach.

Mr. Stegall concluded that Petitioner's proposal establishes a clear baseline for allocating the Current Generation Resources among Indiana and Michigan retail jurisdictions. He stated that approval will support a transparent and predictable jurisdictional allocation process, provide a more stable proportional relationship between the retail jurisdictions for allocating non-fuel costs, and improve the allocation of fuel-related costs and PJM revenues by aligning variable costs and benefits with the fixed cost responsibility borne by each jurisdiction.

5. Commission Discussion and Findings. The Commission has broad authority over a utility's rates, including the allocation of costs between jurisdictions. *See, e.g.*, Ind. Code §§ 8-1-2-10, -19, and -20. In addition, Ind. Code § 8-1-2.5-6 allows an energy utility to seek approval of alternative regulatory practices, procedures, and mechanisms to establish rates and charges that enhance or maintain the value of the energy utility's retail energy services or property; that are designed to promote efficiency in the rendering of retail energy services; and that are in the public interest. In determining whether the public interest will be served, the Commission is required to consider the following factors enumerated in Ind. Code § 8-1-2.5-5:

- (1) Whether technological or operating conditions, competitive forces, or the extent of regulation by other state or federal regulatory bodies render the exercise, in whole or in part, of jurisdiction by the commission unnecessary or wasteful;
- (2) Whether the commission's declining to exercise, in whole or in part, its jurisdiction will be beneficial for the energy utility, the energy utility's customers, or the state;
- (3) Whether the commission's declining to exercise, in whole or in part, its jurisdiction will promote energy utility efficiency;
- (4) Whether the exercise of commission jurisdiction inhibits an energy utility from competing with other providers of functionally similar energy services or equipment.

Although these four factors contemplate the Commission's declination of jurisdiction over a utility's operations, we are also required to consider these factors when evaluating a proposed ARP.

Based on the evidence presented, we find I&M's proposed ARP satisfies these statutory criteria. The evidence demonstrates that the proposed ARP reasonably addresses the changing operating conditions and competitive forces associated with I&M's asymmetrical load growth in Indiana and Michigan and the two state's diverging state energy policies while establishing a

baseline definition of Indiana retail customer benefits from I&M's Current Generation Resources. The proposed ARP will benefit the utility, its customers, and the state of Indiana by promoting efficiency through the establishment of a predictable amount of generation that can be relied upon to serve the capacity and energy needs of I&M's customers during this period of rapid load growth. It will also enable I&M to better manage its planning for generation resources and associated costs on a going-forward basis, which will reduce the risk of excess generation costs in the future, and assist I&M in meeting its obligations efficiently, avoiding supply shortfalls or over-reliance on market purchases. The Commission has previously noted that addressing cost allocation issues driven by large load additions could create additional regulatory workload. *See Indiana Michigan Power Co.*, Cause No. 46097 at 45 (IURC February 19, 2025). Accordingly, the proposed ARP will serve to promote utility efficiency by application in multiple proceedings.

Both CAC and the Joint Municipals argued that a base rate case, rather than this proceeding, is the more appropriate venue to address a change in methodology for allocating I&M's Current Generation Resources to Indiana and Michigan. Although jurisdictional cost allocation has generally been addressed in I&M's base rate cases, the framework here is anchored to a rate case for specific assets that were in place at the time. Petitioner seeks to establish a baseline for future jurisdictional and class cost-of-service studies that preserves the relationship between historical demand, energy usage, and cost responsibility prior to the inclusion of large load customers in Indiana. The Settlement Agreement approved in Cause No. 46097, specifically Paragraph I.A.13., deferred cost allocation issues to subsequent proceedings such as this one. Ind. Code § 8-1-2.5-6 was enacted to provide energy utilities with regulatory flexibility through the adoption of an ARP when in the public interest to do so. The evidence demonstrates that while the jurisdictional split between Indiana and Michigan has been historically stable, Petitioner is now facing unprecedented and asymmetric load growth in Indiana versus Michigan. Not acknowledging this dynamic and retaining the current allocation methodology could challenge the reasonableness of balancing the historical treatment of the Current Generation Resources, as well as the efficiency of planning for future resources. I&M's proposed ARP, in contrast, is intended to prevent load growth in one state from driving significant generation needs in the other. Thus, the proposed ARP will create stability in the allocation of Current Generation Resources and better align generation needs and associated costs with the state (i.e., Indiana) that is already beginning, and will continue to experience load growth. In addition, Indiana and Michigan are embarking on significantly differing energy policies. While we recognize that state energy policies are subject to change, Petitioner's proposal is limited to Current Generation Resources and is intended to establish a starting point for calculating future cost responsibility as jurisdictional loads change.

CAC and the Joint Municipals also took issue with I&M's proposal for allocating fuel costs and PJM revenues using the Primary Allocation Factors as they are inconsistent with cost causation principles. As an initial matter, we note that cost allocation is more often art than science and there are legitimate reasons to deviate from traditional or strict cost allocation principles. For example, the Commission has long held that allocating generation plant on a demand-only basis is an appropriate method of cost allocation because all generation resources are used to meet peak demand, even though many generation resource types (e.g., wind and solar) provide relatively little capacity value. *See e.g., Duke Energy Indiana, LLC*, Cause No. 46038 at 93-94 (IURC January 29, 2025). Similarly, in this instance, we find that I&M's proposal to use an ownership share methodology, i.e., to treat the fixed allocation of Current Generation Resources as if those

resources are “owned” by the respective state jurisdictions, is reasonable. Just as the owner of a particular generating resource must incur the fuel costs for, and reaps the benefits of, that generating resource, under I&M’s proposal, each of the two state jurisdictions will pay for and benefit from its own resources. Importantly, I&M will not change its operational or dispatch practices in PJM markets, but only modify the allocation of fuel costs, purchased power costs, and off-system sales in the same manner as a joint ownership approach. The record further shows the Primary Allocation Factors are reasonably representative of each state’s relative causation of historical investment for purposes of I&M’s Current Generation Resources. Accordingly, we find I&M’s proposed use of the Primary Allocation Factors to be both reasonable and consistent with principles of cost causation.

The OUCC did not oppose I&M’s proposed ARP, subject to clarification that Commission approval of any future reallocation of contracted wholesale capacity will be evaluated consistent with the Commission’s March 11, 2020 Order in Cause No. 45235 and that the existing decommissioning and demolition cost responsibilities for the Current Generation Resources are not affected by the Commission’s approval of I&M’s proposed ARP. I&M witness Williamson confirmed that future changes to jurisdictional allocation of costs between retail and wholesale customers will remain subject to Commission review and approval. He also clarified that approval of I&M’s proposed ARP will not supersede prior Commission orders and will not change how responsibility for decommissioning and demolition costs will be determined over time, as each state will remain responsible based on its jurisdictional cost allocation. We agree with Mr. Williamson’s clarifications and further emphasize that our approval of the ARP does not alter I&M’s burden of proof in future proceedings.

Finally, we find that I&M’s proposed ARP is consistent with Indiana’s Five Pillars set forth in Ind. Code § 8-1-2-0.6. The proposed ARP supports reliability, resiliency, and stability by preserving historically consistent access to the Current Generation Resources and establishing a framework for state-specific planning on a going-forward basis. It supports affordability by reducing potential exposure to market volatility and avoiding overbuilding or stranded assets. Additionally, the proposed ARP supports environmental sustainability through the continued historical dependence on a diverse energy portfolio.

Accordingly, we find Petitioner’s proposed ARP will enhance or maintain the value of I&M’s electric service, is in the public interest, and should be approved on a preliminary basis, as further discussed below.

6. Post-Order Process. I&M explained that the outcome of this proceeding needs to be coordinated with the corresponding case pending before the Michigan Public Service Commission because the decisions of the two state commissions must be consistent with one another to be feasible to implement. As noted above, we have considered I&M’s proposal and approve it on a preliminary basis, subject to resolution of the pending Michigan case. Accordingly, I&M is directed to provide an update to the Commission through a compliance filing in this docket within seven calendar days of an order being issued in the Michigan case. In its compliance filing, I&M shall indicate whether: (1) the two states’ orders are consistent and can be feasibly implemented, in which case the Commission shall issue an order in this Cause making its preliminary findings final; or (2) the two states’ orders are inconsistent, in which case the

Commission shall schedule an attorneys conference to discuss the need for a second phase of this proceeding.

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

1. Petitioner's proposed alternative regulatory plan is approved on a preliminary basis, pending the outcome of Petitioner's filing in Michigan.

2. I&M shall file a compliance filing in this Cause within seven calendar days of an order in its Michigan case, as set forth herein.

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

ZAY, DEIG, AND VELETA CONCUR; SWINGER DISSENTS AND ZIEGNER ABSENT:

APPROVED: APR 22 2026

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

**Dana Kosco
Secretary of the Commission**

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF INDIANA MICHIGAN)
POWER COMPANY FOR APPROVAL OF A)
CHANGE IN THE METHODOLOGY FOR)
ALLOCATING BETWEEN INDIANA AND) CAUSE NO. 46305
MICHIGAN RETAIL JURISDICTIONS THE COSTS)
OF CURRENT GENERATION RESOURCES AS AN) APPROVED: APR 22 2026
ALTERNATIVE REGULATORY PLAN PURSUANT)
TO IND. CODE CH. 8-1-2.5.)

DISSENTING OPINION OF COMMISSIONER ANTHONY F. SWINGER

I am persuaded by the intervening parties' arguments and agree that any changes to a utility's cost allocation factors and methodologies should be considered within the boundaries of a general rate case. I respectfully dissent from the majority with this in mind.

In addition, I am concerned about the practical extent to which the efforts of Commission staff and the parties to this proceeding may be duplicated in Indiana Michigan Power Company's next general rate case.

Indiana Michigan Power Company is required to file such a proceeding this year (or more specifically, no earlier than July 1, 2026, and no later than October 31, 2026) pursuant to Commission-approved settlement agreements in Cause Nos. 43774 PJM 15 and 46217, respectively. I am not convinced that an emergency exists in the meantime.