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INDIANA MICHIGAN POWER COMPANY

PRE-FILED VERIFIED DIRECT TESTIMONY

OF

STEVEN F. BAKER

Content

DIRECT TESTIMONY OF STEVEN F. BAKER ON BEHALF OF INDIANA MICHIGAN POWER COMPANY

I. Introduction of Witness

Q1. Please state your name and business address.

My name is Steven F. Baker and my business address is Indiana Michigan Power Center, P.O. Box 60, Fort Wayne, IN 46801.

Q2. By whom are you employed and in what capacity?

I am employed by Indiana Michigan Power Company (I&M or Company) as its President and Chief Operating Officer.

Q3. Briefly describe your educational background and professional experience.

I earned a bachelor's degree in Electrical Engineering from Texas Tech University in 1990. I am a registered professional engineer in the State of Texas and have over 28 years of electric utility operations experience in the areas of distribution system planning, construction design and engineering, electrical safety, major storm restoration, construction management, project management, financial planning and the development of operating policies and procedures. I began my career in 1990 with West Texas Utilities Company (WTU, which is now AEP Texas Inc.) as a Distribution Engineer. During my time at WTU, I developed hands-on experience designing, planning, constructing and maintaining the distribution system. While at WTU, I also held a variety of leadership positions and worked directly with customers to meet expectations and resolve system performance issues. In 2003, I joined PSO as the Tulsa District Distribution System Manager. In that role, I had oversight responsibilities for the design, construction and overall operation of the distribution system serving Tulsa and northeast Oklahoma. I held that position until I was named to Vice-President, Distribution Operations for PSO in 2010. I became President and Chief Operating Officer of I&M in 2021.

Q4. What are your responsibilities as Chief Operating Officer?

I am responsible for the safe, reliable, and efficient day-to-day operation of I&M, which is an operating company subsidiary of AEP. I am accountable and responsible for I&M's financial performance and the quality of the services we provide to our customers.

My responsibilities include I&M's community involvement and economic development, and ensuring compliance with federal regulatory and statutory rules, as well as laws of Indiana and Michigan, the states comprising the Company's electric service territory. Essentially, I am accountable for the Company's distribution, customer service, transmission, and generation functions to provide safe, adequate and reliable service to I&M's customers.

Q5. Have you previously testified before any regulatory commissions?

Yes. I filed testimony before the Oklahoma Corporation Commission in the following cases:

- Cause No. PUD 200600275 - Addendum to a Territorial Boundary Agreement.
- Cause No. PUD 200700397 - Application on behalf of the Company to defer, amortize, and recover storm costs associated with the January 2007 ice storm that impacted the Company's service territory.
- Cause Nos. PUD 201000050 and PUD 201300217 - Applications on behalf of the Company to adjust its rates.
- Cause No. PUD 201300202 - PSO's System Reliability Rider.

- Cause Nos. PUD 201500208 and 201700151 - Applications on behalf of the Company to adjust its rates.
- Cause No. PUD 201800097 - Application on behalf of the Company to adjust its rates.

II. Purpose of Testimony

Q6. What is the purpose of your testimony?

My testimony provides an overview of I&M's overall request. I discuss ongoing operating challenges and the need to replace aging infrastructure and strengthen the grid. I generally describe the Company's integrated investment plans to continue to modernize our systems, including information technology and the distribution systems, to enhance reliability, to deploy grid technologies such as Advanced Metering Infrastructure (AMI), to maintain safe and reliable generation resources, and to take advantage of new technologies to efficiently manage our business and improve our customer's experience. My testimony also discusses I&M's efforts to control costs for the benefit of our customers. Together with Company witness Bulkley, I support the Company's requested return on equity (ROE) of 10.00 percent. Finally, to provide context, I provide an overview of I&M's service area and organizational structure and the Company's relationship with AEP.

Q7. Are you sponsoring any attachments?

Yes. I am sponsoring the following Attachments:

- Attachment TLT-1, which is a copy of the Petition in this Cause and attached filing index and summary. As the Petition has been filed separately it is not reproduced with my testimony but will be offered into evidence with my testimony at the hearing in this Cause.

- Attachment TLT-2, which is a copy of the 2019 IEI report identified below.

Q8. Were the attachments that you sponsor prepared or assembled by you or under your direction?

Yes.

Q9. Please summarize your testimony.

As a regulated company, the price we charge for retail electric service is necessarily underpinned by the cost the Company incurs to provide service. The Test Year results demonstrate that the Company's rates will not be sufficient to cover the Company's Test Year cost of providing service. I&M requests that the Commission approve a total annual increase in revenues of approximately $104 million, or 6.5%. Commission approval of the proposed package of base rates and rate adjustment mechanisms is reasonable and necessary to allow the Company to continue to meet our customers' needs for service.

The Rockport Unit 2 Lease ends in December 2022, the last month of the Test Year. The Company proposes to recognize the annual Lease payment savings as a reduction to cost of service in I&M's Resource Adequacy Rider (RAR) filings. Reflecting these cost savings in the RAR will largely offset the impact of the proposed rate increase on customers.

Similarly, the Cook Life Cycle Management (LCM) Project is nearly complete. The Company proposes to wind down the LCM Rider in an efficient manner. The PJM Rider, on the other hand, remains important due to the grid investment needs and associated cost of transmission service within PJM.

The rate adjustment mechanisms included in the Company's filing are an important tool in our effort to timely reflect variable costs and savings in I&M's rates for electric service while providing reliable service to our customers.

The Company's filing includes an average annual capital expenditure of $539.9 million during the Capital Forecast Period (January 2021 – December 2022). The capital investments reflected in the Company's filing focus on infrastructure improvements and complying with environmental and regulatory requirements. The Company is continuing to execute its integrated grid modernization package, which incorporates technologies such as AMI, Enhanced Conservation Voltage Reduction (Enhanced CVR), distribution automation circuit reconfiguration (DACR), supervisory control and data acquisition (SCADA), distribution line sensors, smart reclosers and smart circuit ties. Embracing new technology and automated controls, including AMI, will improve and modernize our energy delivery infrastructure and service and improve the customer experience. Customers will benefit from this investment through improved system reliability and improved tools to manage energy usage and cost. The Company also continues to invest in technologies that improve internal business processes and customer interactions, which are essential to I&M's strategy to control costs and improve the customer experience.

The Company requests an authorized ROE of 10.00 percent in conjunction with Commission approval of the rate relief package proposed by the Company in this Cause. The Company's requested ROE and associated rate relief supports the Company's ongoing ability to secure access to comparatively low cost capital to fund its operations, which is heavily dependent on regulatory support that authorizes rate increases in a timely manner, manages known risks, provides predictability and fairly compensates equity investors.

The AMI Project that is part of I&M's integrated distribution strategy is scheduled to occur over four years (2021 through 2024) and is estimated to have a cumulative capital cost of approximately $121 million. The age of our existing meters, our experience and knowledge of AMI, and a cost-benefit analysis prepared by Accenture (Accenture CBA) give us confidence that investing in AMI technology can provide many benefits to the distribution system and our customers. The Company proposes to include the capital cost contained in the 2021–2022 Capital Forecast Period in base rates and address the ongoing investment, as well as operational cost savings identified in the Accenture CBA through the proposed AMI Rider so that this benefit also flows through to customers as AMI is deployed.

In sum, rate relief is necessary and appropriate to support our ongoing effort to address aging infrastructure, secure long-term reliability and resiliency, enhance the service we provide through new technology and automation, and otherwise meet the ongoing energy and capacity needs of our customers.

III. Overview of I&M's Request

Q10. What is the annual revenue increase sought by I&M in this proceeding?

I&M is requesting that the Commission approve a total annual increase in revenues of approximately $104 million, or 6.5%, based on a forward looking calendar Test Year ending December 31, 2022. The Company proposes to phase-in the increase over two steps. The initial step will reflect an increase of $73 million, or 4.55%; the second step will reflect an increase of $31 million, or approximately 2% as adjusted for actual Test Year investments. As discussed by Company witness Williamson, I&M proposes to use the Resource Adequacy Rider (RAR) to reflect the net reduction in expense associated with the Rockport Unit 2 Lease expiration in December 2022. The use of the RAR will allow customers to realize approximately $82 million of annual Lease savings in a timely fashion which will significantly offset the proposed rate increase.

Q11. Why is the requested rate increase necessary?

The Company's ongoing investment in infrastructure remains important to our efforts to maintain and improve our service and our customers' experience. As shown by the Company's case-in-chief, the Test Year results demonstrate that the Company's rates will not be sufficient to cover the Company's Test Year cost of providing service. As a regulated company, the price we charge for retail electric service is necessarily underpinned by the cost the Company incurs to provide service. Commission approval of the Company's proposed package of base rates and rate adjustment mechanisms is necessary for the Company to continue to meet our customers' needs for service.

Q12. Please provide an overview of the infrastructure investment underlying the need for a rate adjustment.

The Company's filing includes average annual capital expenditures of $539.9 million during the Capital Forecast Period (January 2021 – December 2022).[1] The investments reflected in the Company's filing focus on infrastructure improvements, investments in cybersecurity and information technology, and complying with environmental and regulatory requirements. Embracing new technology and automated controls will improve and modernize our energy delivery infrastructure and service and improve the customer experience. Customers will benefit from this investment through improved system reliability and improved tools to manage energy usage and cost.

As explained below, AMI is an essential and integral element of the Company's grid modernization strategy, as it provides wide ranging operational and customer benefits, allows the Company to meet the ongoing need for service

[1] Company witness Lucas Direct Testimony, Q35 (average annual capital expenditures in 2021 – 2022 is forecast to be $539.9 million compared to $566.3 million in 2016 – 2020).

and facilities, and builds the foundation for ongoing technological advancement, personalized customer experience and evolving customer service needs.

Q13. How does the Company make investment decisions regarding its electricity generation and energy delivery system?

To make investment decisions in our electricity system, our management team considers numerous factors, including environmental and regulatory compliance, integrated resource planning, the service reliability metrics reported to the Commission, age and condition of the Company's facilities, the consequence of failure, customer and employee safety, avoidance of outages, preservation and improvement of operational integrity, equipment protection, evolving customer demands, and taking advantage of new technology options.

Once we determine and prioritize the investments or maintenance needs required to serve our customers, we then employ industry proven design, engineering, and project execution methods to ensure the desired results are achieved in a timely and efficient manner. Our approach is a thoughtful, reasoned, flexible process that ensures we are doing the right projects or activities at the right time, at a reasonable cost to ensure we have reliable and efficient generation resources and a safe and resilient electricity system capable of meeting customers' needs 24/7.

Q14. Are the costs reflected in I&M's filing and the proposed rates reasonable and necessary to allow I&M to provide service to its customers?

Yes. Recognizing the cost of providing service in the ratemaking process in a timely manner better positions the Company to provide service and the customer to utilize service in an informed manner. I&M has worked hard to responsibly grow our business by attracting and retaining customers and we remain committed to supporting economic development of the communities in which we serve. The costs reflected in the proposed rates are reasonably representative of the Test Year cost of service and are reasonable and necessary for the Company to provide safe, adequate and reliable service during the time the rates are expected to be in effect.

Q15. Do other Company witnesses support the Company's request?

Yes. Company witness Seger-Lawson summarizes I&M's requested rate relief, and together with the Company's other witnesses supports the accounting and ratemaking reflected in the Company's filing. Company witness Fischer supports our proposed rate design, including the proposed changes in the residential rate design. The Company's request is further supported by the witnesses identified on the Index of the Company's filing included with the Petition. This support includes testimony and evidence from subject matter experts, including subject matter experts responsible for providing generation and energy delivery services. This support also includes testimony of financial experts to discuss the financial needs of the Company and technical witnesses to describe the level of costs that will be incurred going forward.

While I further discuss certain aspects of the Company's filing below, to provide context the next section of my testimony turns to an overview of I&M.

IV. I&M Overview

Q16. Please describe I&M and its organizational structure.

I&M supplies electric service to approximately 470,000 retail customers in northern and east-central Indiana and 130,000 retail customers in southwestern Michigan. I&M operates plant and equipment in Indiana and Michigan that are in service and used and useful in the generation, transmission, and distribution of electric service to the public. I&M's Indiana service territory consists of over

3,200 square miles and includes the Cities of Fort Wayne, South Bend, Elkhart, Muncie, Marion, Kendallville and Decatur.

The Company's principal offices are located in Fort Wayne, Indiana. I&M's four distribution and customer service districts (Benton Harbor (MI), Fort Wayne, South Bend/Elkhart, and Muncie/Marion) are each responsible for a specific geographic portion of I&M's service territory.

I&M is subject to the regulatory authority of the Commission, the Michigan Public Service Commission (MPSC), and the Federal Energy Regulatory Commission (FERC). I&M is a member of PJM Interconnection, LLC (PJM), which is a regional transmission organization (RTO) serving the eastern portion of the country.

Q17. Please describe the relationship between AEP and I&M.

AEP owns electric operating companies located in the Midwestern and central parts of the country, including I&M. In key respects, the operating companies function as an integrated utility system that provides electric service to approximately 5.4 million customers located in eleven states. To effectively manage the costs of joint activities, American Electric Power Service Corporation (AEPSC) provides corporate support services to the operating companies, including generation-related services, human resources, information technology, accounting, finance and legal.

I&M is located in the AEP System – East Zone (AEP East), which is an integrated generation and transmission network located in Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia, and West Virginia. AEP's operating companies, including I&M, are responsible for day-to-day operations and management of local business affairs, including responsibility and accountability for the operation of each operating company's generating plants.

I&M participates in a FERC-approved Power Coordination Agreement (PCA) with the three other regulated, vertically-integrated AEP East Operating Companies (Appalachian Power Company, Wheeling Power Company and Kentucky Power Company). The PCA is the successor agreement to the AEP Interconnection Agreement that terminated in January 2014. Through the PCA, I&M is responsible for planning for and serving our customers' capacity and energy resource needs. The PCA also provides for the direct assignment of traditional Off System Sales (OSS) and for the allocation of asset hedges and trading.

V. Ongoing Challenges and Service to Customers

Q18. Please describe the ongoing challenges faced by the Company with respect to the ongoing provision of adequate and reliable retail electric service and facilities.

Key challenges facing I&M include how to continue to provide reliable electric service at a comparatively low price when costs are rising, environmental regulation is changing and, customer needs and technology are evolving. Because many electronic devices and equipment used by our customers today are less tolerant of even minor service interruptions, continued diligence with respect to service reliability remains important. I&M also continues to recognize developing environmental concerns, including those addressed to the issues surrounding climate change and customer interest in renewable energy resources.

It is important to improve the alignment between our rate structures and the fixed and variable cost of the service we provide so that customers are sent appropriate price signals. As the Commission has previously recognized:

> *Cost recovery design alignment with cost causation principles sends efficient price signals to customers, allowing customers to make informed decisions regarding their consumption of the service being provided.*[2]

Q19. Is it important to continue the use of general rate cases in combination with ongoing rate adjustment mechanisms?

Yes. I&M seeks to continue the timely recovery of costs because rate adjustment mechanisms are an important tool in our effort to meet ongoing challenges while providing reliable service to our customers. We appreciate the ability to better match the time costs are incurred with their inclusion in rates through the use of a forward-looking Test Year and the Commission's approval of timely cost recovery mechanisms.

As stated below, and further discussed by Company witness Williamson, the Rockport Unit 2 Lease ends in December 2022, the last month of the Test Year, and the Company proposes to timely recognize the elimination of the annual Lease payment as a reduction to cost of service in I&M's RAR filings. Similarly, the Cook LCM Project is nearly complete. Company Witness Seger-Lawson (Adopted) explains the Company's proposal to wind down the LCM Rider in an efficient manner.

As shown by Company witness Koehler, the PJM Rider remains important due to the grid investment needs and associated cost of transmission service within PJM. The transfer of functional control of the Company's transmission facilities to PJM was authorized by the Commission's September 10, 2003 Order in Cause Nos. 42350/52. The Company's membership in PJM has allowed I&M's

[2] *Indianapolis Power & Light Company*, Cause No. 44576 (IURC 3/16/2016), p. 72.

customers to benefit from the independent regionally operated, and jointly planned and coordinated, PJM transmission grid necessary to enhance competitive wholesale markets, resource diversity and system reliability and security. The PJM rate adjustment mechanism remains reasonable and necessary.[3]

Q20. Has the Company considered these challenges in developing its proposals in this case?

Yes. The package of rate relief including the adjustment to base rates and ongoing use of rate adjustment mechanisms is reasonably designed to meet these objectives while also remaining mindful of rate impacts, as well as the Company's need for a reasonable opportunity to earn a fair return.

Q21. Has the Company considered these objectives in developing its return on equity recommendation?

Yes. Company witness Bulkley presents her analysis and conclusion that the Company's return on equity is within a range between 9.75 percent and 10.45 percent. Within this range, the Company requests an authorized ROE of 10.00 percent. Company witness Bulkley testifies that while this request falls below the midpoint of her range, the requested ROE is reasonable in conjunction with Commission approval of the rate relief package proposed by the Company in this Cause.

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[3] The history, rationale and benefits the FERC's efforts to transition to a competitive market are summarized in the FERC's Order No. 2000 (In Re Regional Transmission Organizations, dated December 20, 1999, 89 FERC ¶ 61,285).

Q22. Do I&M's customers benefit from I&M being able to secure capital at a competitive cost?

Yes. Maintaining access to the capital markets for competitive low cost debt and equity financing continues to be paramount for I&M and its customers. I&M's ability to access capital to fund its operations is heavily dependent on regulatory support that authorizes rate increases in a timely manner, manages known risks, provides predictability and fairly compensates equity investors. Being in good financial health and having predictable revenues benefit customers by allowing I&M to compete both internally and externally for access to capital at reasonable terms relative to others in the utility industry.

Q23. How does the Company's proposal to update its residential rate design further those objectives?

Company witness Fischer presents the Company's proposed rate design for residential service, including the proposal to increase the residential monthly service charge from $15.00 to $20.00. Importantly, it should be recognized that the percentage increase in the service charge relates only to one component of the customer's entire bill and should not be confused as equating to an overall increase in the entire bill. As previously recognized by the Commission, "gradualism is best considered in the context of the entire customer bill and not discrete charges within the bill."[4]

While proposals to change the residential rate design have been controversial in past cases, as noted above, it is important that we continue to make progress on properly designing our rates to align cost recovery with cost causation principles. Doing so sends efficient price signals to customers so as to allow

[4] Cause No. 45235 Order dated March 11, 2020, p. 96 (quoting March 16, 2016 order in *Indianapolis Power & Light Company,* Cause No. 44576, p. 72).

them to make informed decisions regarding their consumption of the service being provided.

If I&M's rates are not properly designed, some customers will be incented to avoid fixed costs buried in the variable charge, leaving those fixed costs to be spread among the other customers. Under I&M's proposed rate design, the total bill for all customers will better reflect the underlying cost of service. Additionally, the proposed rate design provides benefits for those low income, high usage customers, while remaining fair to low income, low usage customers.

VI. Grid Modernization Strategy (including AMI)

Q24. Please summarize the Company's integrated distribution service strategy.

The goal of I&M's distribution service strategy is to provide customers with a reliable, high quality experience that allows them to optimize the use of our energy delivery platform. We began executing our strategy several years ago as we renewed our focus on energy delivery service. I am pleased to report that the strategy is showing results that demonstrate we are headed in the right direction.

At its core, I&M's distribution strategy is based on three guiding principles:

- Improve the reliability of the system today and in the future.
- Utilize technology to increase operational efficiency and create a more optimized system.
- Position I&M to meet changing regulatory requirements and customer expectations.

These principles guide our identification of needs and opportunities for enhancing our distribution service and our thoughtful and deliberate plans to implement projects and process improvements.

To improve the reliability of the system, I&M is continuing its strategic approach to asset renewal, which is necessary to maintain a safe and reliable system. We are also continuing the vegetation management program that protects our facilities and promotes reliable service, while being considerate of the interests of property owners. The efforts I&M has made over the past five years have produced improvements in our reliability metrics that show customers are benefiting from our strategic initiatives.

The utilization of technology allows us to increase operational efficiency, which benefits our customers' experiences with our service. For example, grid modernization technologies, including AMI, allow the Company to have a more predictive and data-driven approach to managing the system. Through technology, we can safeguard against potential outages, take advantage of self-healing opportunities, and reduce outage restoration times. Combining AMI with the use of Enhanced CVR can reduce system losses and provide more insight into customer end use points.

Last, but not least, our distribution system strategy prepares us to provide a system on which customers can optimize their use of our service in a changing energy world. The energy industry is starting to move away from a linear paradigm where electrons flowed in one direction from large central power stations to end users and moving towards a more complex matrix of customer options, including distributed energy resources (DER) that provide a two-way power flow. Customer and regulatory expectations are evolving in parallel with the changing industry. The Company's proposals provide customers with more control, optionality and new program offerings. Regulators expect us to integrate our generation and energy delivery planning and to accommodate the increasing penetration of DERs. For example, we must be ready to proactively and collaboratively address the implications of FERC's recent Order 2222. Our strategy is intended to allow us to meet the changes in customer expectations and regulatory requirements.

Company witnesses Isaacson, Lucas and Walter provide details of the specific elements of our plans in their respective testimonies.

Q25. Please provide an overview of the AMI Project that is an integral part of I&M's distribution service strategy.

As discussed by Company witness Isaacson, I&M plans to deploy AMI across its Indiana service territory over the four-year period of 2021 through 2024. The Company's AMI program provides for the efficient deployment of this technology and will enable the Company and our customers to realize the value of this technology in a timely manner.

I&M has been assessing the deployment of AMI for years as part of its grid modernization efforts intended to improve customer experience and provide other operational benefits. In fact, we proposed a deployment plan in the 2019 base rate case (Cause No. 45235). The Commission's March 11, 2020 Order in Cause No. 45235 (45235 Order) (p. 12) recognized that:

> *Given the industry advancements in AMI technology, we find the key question is not 'whether' AMI technology should be deployed, but rather, 'when' it is reasonable to do so and recover these costs from I&M's ratepayers.*

Following issuance of the 45235 Order, the Company engaged Accenture to assess the costs and benefits associated with an AMI deployment and usefulness of this technology in the provision of retail electric service. The Accenture CBA, which is described in detail by Company witness Bech, furthered the Company's understanding of the value streams from this technology, as well as the integrated nature of the wide-ranging benefits across the Company's operations. This in turn facilitated the development of the deployment plan and customer programming presented in this case.

Q26. Why is it appropriate to proceed with AMI deployment at this time?

As also discussed by Company witness Isaacson, the Company's current metering infrastructure is predominantly an AMR Standard Consumption Meter (SCM) metering system. The one vendor (Itron) that remains in the AMR meter business no longer supports this platform. Consequently, the Company has two choices: 1) make a substantial investment in a declining technology; or 2) move to AMI technology.

Given the age of the existing meters, it is reasonable to move to AMI. In making our decision, we recognized that AMI technology has matured, its pricing has stabilized and its importance to system and customer operations has increased.

Our experience and knowledge of AMI technology and the Accenture CBA tell us that investing in AMI technology can provide many benefits to the distribution system and our customers.

From an operational perspective, as discussed by Company witnesses Isaacson and Walter, AMI integrates with other grid modernization technologies to provide insight into optimizing the reliability of the grid. For customers, AMI provides more insight and control into how and when they use the electric service, which enhance the customer's experience by enabling customer programs and services (e.g. the proposed voluntary Flex Pay service), as discussed by Company witnesses Lucas and Walter.

Finally, I&M can take advantage of the lessons learned from AMI deployment by our AEP affiliated operating companies in other states.

Taken together and as further discussed by the other Company witnesses identified above, these factors support the systematic move to AMI at this time.

Q27. Why is it appropriate to pace the deployment of AMI over a 45-month period?

As shown by Company witness Bech, once the investment decision is made, it is cost effective to roll out the new technology in a timely manner via a systematic replacement plan. The Accenture CBA found that a 27-month deployment scenario had the best score (net present value). However, this deployment scenario introduced additional execution and cost overrun risks, which can be mitigated if the deployment period is lengthened. While the net present value of a 45-month deployment plan was lower, it is still reasonably close to the 27-month deployment scenario and an appropriate way to mitigate risks.

The Accenture CBA also found that an end of life (EOL) scenario where meters are randomly replaced when they fail and reach EOL (full deployment reached at 2035) had a much lower net present value and would not permit the Company to achieve efficiencies associated with a systematic replacement plan. This kind of reactive approach would also delay the opportunity for our customers to benefit from AMI technology.

Therefore, the 45-month deployment scenario is reasonable and financially justified.

Q28. What is the timeline for achieving customer benefits from the AMI deployment plan?

As discussed by Company witness Lucas, the Company proposes to roll-out the customer engagement platform and AMI enabled customer programs contemporaneous with the deployment of AMI meters to allow customers to take advantage of the AMI technology as it is installed. As explained by Company witness Seger-Lawson, the Company proposes to reflect the ongoing post Test Year capital investment, as well as operational cost savings identified in the

Accenture CBA, through the proposed AMI Rider so that this benefit also flows through to customers as AMI is deployed.

Q29. Has the Company considered the impact to customer bills of the proposed AMI deployment plan?

Yes. Like all major investment decisions, I&M considered the impact on customers and the bills they pay for service when deciding the merits of installing AMI. To mitigate the bill impact, we developed a thoughtful, cost effective plan to install AMI efficiently and effectively. The 45-month deployment period mitigates the bill impact by more gradually reflecting the costs in rates and the proposed AMI Rider will flow through cost savings to customers' bills. We have also included depreciation of the remaining AMR meters over the life of the AMI meters to reduce the impact of depreciation expense reflected in rates, as discussed by Company witness Cash. We are confident that the cost of the AMI deployment plan is worthwhile to provide our customers with a quality of service that meets their needs for transparency into and control over their consumption of electricity.

Q30. Is the transition to AMI meters reasonable and necessary to maintain the Company's utility property in an operating state of efficiency corresponding to the progress of the industry?

Yes. Most of the investor-owned utilities in Indiana and Michigan have begun or completed smart meter deployments.[5] I&M's sister companies have moved to this technology and utilities across the U.S. have reported strong acceptance of Smart Grid technology. The state of AMI meter deployment is illustrated by Figure 2 in the Accenture CBA reproduced below:

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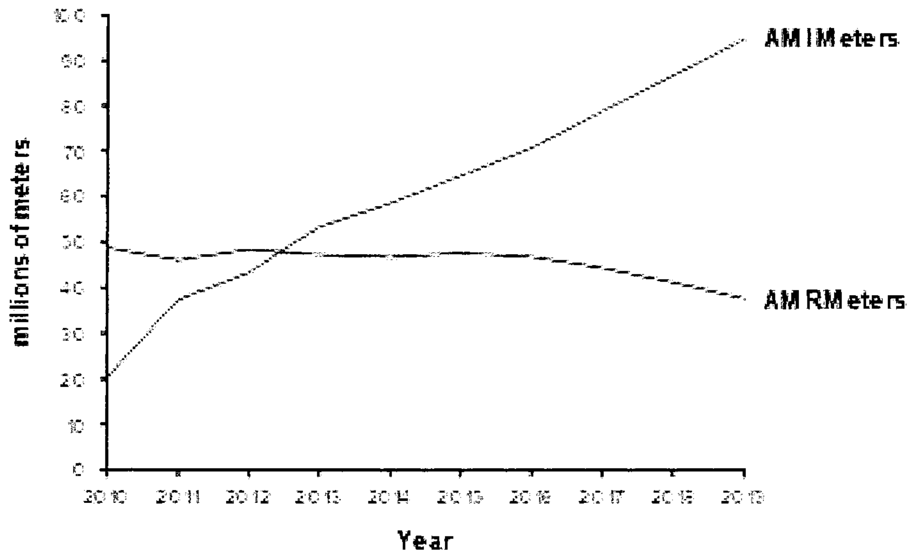
[5] The IEI report (pp. 12, 14) indicates that Vectren expects to fully deploy 153,000 smart meters by the end of 2019 in Indiana; and Duke Energy Indiana completed its deployment in 2019. The Commission has also approved IPL's transition from AMR to AMI meters. IPL, Cause No. 45264 (IURC 3/4/2020).



A recent report published by The Edison Foundation Institute for Electric Innovation (IEI) corroborates the view that the transition to AMI remains an industry priority. The IEI report projects that U.S. electric companies have installed 98 million smart meters as of year-end 2019, covering more than 70 percent of all U.S. households.[6] The report also projects the total number of installed smart meters will rise to 107 million by the end of 2020.[7]

While the timing and nature of the Company's decisions regarding infrastructure are necessarily Company specific, these materials illuminate and validate the Company's plan to deploy AMI.

VII. Efforts to Mitigate Increasing Costs

Q31. Please discuss the ongoing efforts taken by I&M to manage costs.

The Company is keenly focused on maximizing the value of the service we provide to our customers. One way we seek to achieve this is by mitigating cost increases where possible without negatively impacting service quality or accepting unreasonable risk to infrastructure or safety.

We manage our operations based on continuous improvement principles. Our Company currently has programs underway to utilize new technologies, to automate manual and repetitive tasks, and use advanced data analytics to drive efficiencies.

Once the annual budget is approved by management, the individual managers in charge of each department, operating district, power plant, or other functional area, are responsible and accountable for operating within the approved amounts.

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[6] Electric Company Smart Meter Deployments: Foundation for a Smart Grid (2019 Update), at 3; IEI_Smart-Meter-Report_2019_FINAL.ashx (edisonfoundation.net). The IEI reports are publicly available on the Internet and I have included a copy of the 2019 Report with my testimony as Attachment TLT-2.

[7] *Id.*

Our commitment to and success with operating cost control is demonstrated by the year-over-year operating cost comparisons in Company witness Lucas' testimony.[8]

VIII. Impact on Customers

Q32. Is the Company mindful of the impact of rate increases on customers?

Yes. We consider our ongoing investments through a lens of providing safe and reliable electric service while being mindful of the cost impacts. I&M undertakes asset management and replacement consistent with Ind. Code § 8-1-2-0.5. This statute provides that the State 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." The reference to conditions "under which utilities plan for and invest in infrastructure" suggests to me that the General Assembly acknowledges and supports the good utility planning and prioritization of resources as a means for promoting affordability. In my view, the policy recognizes that addressing infrastructure issues on an emergent basis is more costly than taking a planned approach to investment. This is precisely what I&M is seeking to do through capital expenditures, including the AMI and other technology deployment.

Finally, I&M ratemaking and rate design proposals seek to reflect the way a customer uses the system accurately and fairly in the customer's rates. This enables customers to reasonably evaluate options and make rational decisions.

[8] See Lucas Direct Testimony, Section IV.

Company witnesses Duncan, Fischer, and Williamson further address the customer impact through the Company's two-step phase-in rate adjustment mechanism and RAR.

Q33. Does the Company offer assistance to customers who may need help paying their bill?

Yes. We recognize that it is difficult for some customers to pay their electric bills, and we continue to offer payment assistance programs ranging from agreements to extend a bill payment a few days to longer monthly payment programs. In addition, I&M continues to offer a portfolio of cost effective energy efficiency programs to help customers reduce their energy usage.

The deployment of AMI will give our customers better insight into their energy usage. This in turn will allow informed decisions and opportunities for customers to reduce their electric bill by changing their use of electricity. Company witness Lucas discusses the proposed I&M Flex Pay Program and the diversified suite of optional rates and load management programs included in the Company's filing to allow customers to utilize AMI technology and benefit through reduced energy and load requirements.[9]

IX. Conclusion

Q34. What is your recommendation?

As mentioned above, the electric business continues to change as a result of environmental regulation, economic conditions, evolving technology and changes in the way our customers use electricity and want to be served. Our

[9] Lucas Direct Testimony, Section VII.

goal is to invest wisely, operate our business efficiently, and provide a customer experience that serves customers the way they want to be served.

Rate relief is necessary and appropriate to support our ongoing effort to address aging infrastructure, secure long-term reliability and resiliency, enhance the service we provide through new technology and automation, and otherwise meet the ongoing energy and capacity needs of our customers. The proposals we make in this case allow us to continue to embrace technology advancements and use them for the benefit of customers.

We ask the Commission to find that I&M's proposal is a balanced and rational solution to the Company's need for both cost recovery and a reasonable opportunity to earn a reasonable return, while we continue to fulfill I&M's duty to provide reliable electric service and facilities to our customers.

Finally, we at I&M have a responsibility to our customers to manage our business properly so I ask the Commission to timely approve the proposed rate relief to allow I&M to continue to provide customers adequate and reliable electric service and facilities.

Q35. Does this conclude your pre-filed verified direct testimony?

Yes, it does.

VERIFICATION

I, Steven F. Baker, President and Chief Operating Officer for Indiana Michigan Power Company, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information, and belief.

Date: October 13, 2021 Steven F. Baker

Steven F. Baker

FILED
July 1, 2021
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF INDIANA MICHIGAN POWER COMPANY, AN INDIANA CORPORATION, FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN RATE ADJUSTMENT; AND FOR APPROVAL OF RELATED RELIEF INCLUDING: (1) REVISED DEPRECIATION RATES; (2) ACCOUNTING RELIEF; (3) INCLUSION OF CAPITAL INVESTMENT; (4) RATE ADJUSTMENT MECHANISM PROPOSALS; (5) CUSTOMER PROGRAMS: (6) WAIVER OR DECLINATION OF JURISDICTION WITH RESPECT TO CERTAIN RULES; AND (7) NEW SCHEDULES OF RATES, RULES AND REGULATIONS.	)	**CAUSE NO.** 45576

VERIFIED PETITION FOR GENERAL RATE INCREASE AND ASSOCIATED RELIEF UNDER IND. CODE § 8-1-2-42.7 AND NOTICE OF PROVISION OF INFORMATION IN ACCORDANCE WITH THE MINIMUM STANDARD FILING REQUIREMENTS

INDIANA MICHIGAN POWER COMPANY (I&M, Company or Petitioner) respectfully petitions the Indiana Utility Regulatory Commission (Commission or IURC) for authority to increase its retail rates and charges for electric service rendered by I&M in the State of Indiana through a phase-in rate adjustment; and for approval of related relief including: revised depreciation rates; accounting relief; inclusion of capital investment; rate adjustment mechanism proposals; customer programs; waiver or declination of jurisdiction with respect to certain rules; and new schedules of rates, rules and regulations. This filing is made pursuant to Ind. Code § 8-1-2-42.7 (Section 42.7). In support of this Petition, I&M represents the following:

Petitioner's Corporate Status

1. I&M, a wholly-owned subsidiary of American Electric Power Company, Inc. (AEP), is a corporation organized and existing under the laws of the State of Indiana, with its principal offices at Indiana Michigan Power Center, Fort Wayne, Indiana.

2. I&M is engaged in, among other things, rendering electric service in the States of Indiana and Michigan. I&M owns and operates plant and equipment within the States of Indiana and Michigan that are in service and used and useful in the generation, transmission, distribution and furnishing of such service to the public. I&M has maintained and continues to maintain its properties in an adequate state of operating condition.

Petitioner's Service Territory

3. I&M supplies electric service to approximately 470,000 retail customers in northern and east-central Indiana and 130,000 retail customers in southwestern Michigan, within a service area covering approximately 4,573 square miles. In Indiana, I&M provides retail electric service to 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 the States of Indiana and Michigan. I&M's electric system is an integrated and interconnected entity that is operated within Indiana and Michigan as a single utility.

Petitioner's "Public Utility" Status

4. I&M is a "public utility" under Ind. Code § 8-1-2-1 and is subject to the jurisdiction of this Commission in the manner and to the extent provided by the Public Service Commission Act, as amended, and other pertinent laws of the State of Indiana.

5. I&M is also subject to the jurisdiction of the Michigan Public Service Commission and the Federal Energy Regulatory Commission (FERC) as to electric service provided by I&M to retail customers in Michigan and to wholesale customers, respectively.

6. I&M's transmission system is under the functional control of PJM Interconnection, L.L.C., a FERC-approved regional transmission organization (RTO), and is used for the provision of open access non-discriminatory transmission service pursuant to PJM's Open Access Transmission Tariff on file with the FERC. As a member of PJM, charges and credits are billed to AEP and allocated to I&M for functional operation of the transmission system, management of the PJM markets including the assurance of a reliable system, and general administration of the RTO. I&M must also adhere to the federal reliability standards developed and enforced by the North American Electric Reliability Corporation (NERC), which is the electric reliability organization certified by the FERC to establish and enforce reliability standards for the bulk power system. ReliabilityFirst (RF) is one of eight NERC Regional Entities and is responsible for overseeing regional reliability standard development and enforcing compliance. I&M's transmission facilities are wholly located within the RF region.

Petitioner's Electric Utility System

7. I&M renders electric service by means of electric production, transmission and distribution plant, as well as general property, equipment and related facilities, including office buildings, service buildings and other property, all of which is used and useful in the generation, purchase, transmission, distribution and furnishing of electric energy for the convenience of the public. In order to continue to properly serve the public located in its service area and to discharge its duties as public utility, I&M has and continues to make numerous additions, replacements and improvements to its electric utility systems.

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

9. I&M's hydro, fossil, nuclear and solar generating fleet, transmission and distribution systems and other facilities are well-maintained, in good condition, and reasonably necessary for I&M's provision of electric service to I&M's customers in a safe, reliable, efficient, environmentally compliant, and low-cost manner for the benefit of its customers.

Statutory Authority for Requested Relief

10. This Petition is filed pursuant to Section 42.7. Other provisions of the Public Service Commission Act, as amended, Ind. Code § 8-1-2-1, *et seq.*, that may be applicable to the subject matter of this proceeding, include, but are not limited to: Ind. Code §§ 8-1-2-4, 6, 6.7, 10, 12, 14, 19, 20, 21, 23, 29, 42, 61, 68 and 71, and Ind. Code § 8-1-2.5-5.

GAO 2013-5

11. In accordance with the guidance provided by the Commission's General Administrative Order 2013-5 (Rate Case Standard Procedural Schedule and Recommended Best Practices for Rate Cases Submitted under Ind. Code § 8-1-2-42.7) (GAO 2013-5), I&M provided its Notice of Intent to File Rate Case to the Commission on June 1, 2021. This Notice was provided at least 30 days prior the date of filing this Petition. I&M also reached out to the Indiana Office of Utility Consumer Counselor (OUCC) and other stakeholders to discuss the filing.

Test Year, Rate Base Cutoff Dates

12. Pursuant to Section 42.7(d), I&M is utilizing a forward looking test period determined on the basis of projected data for the twelve (12) months ending December 31, 2022 (Test Year). In accordance with Section 42.7, this Test Year (which commences January 1, 2022), begins not later than 24 months after the date on which this Petition is filed. This test period is entirely within the twenty-four month period following the date on which I&M is filing its Petition.

13. I&M is utilizing the Test Year end, December 31, 2022, as the general rate base cutoff date. I&M proposes the Commission establish I&M's authorized net operating income by applying the overall weighted average cost of capital to the Test Year end original cost rate base. The Company also proposes the Test Year end original cost rate base be used as the fair value of the Company's utility property.

Submission of Case-in-Chief and Other Supporting Documentation

14. I&M is filing its case-in-chief, including the information required by Section 42.7(b), in written form contemporaneous with this Petition. In accordance with the

Commission's GAO-2020-05, and to facilitate review of the filing, I&M has attached to this Petition, as Petition Exhibit A, an index of issues, requests, and supporting witnesses. A summary of the witness testimony is attached hereto as Petition Exhibit B.

15. I&M has elected to file its case in accordance with the Commission's Minimum Standard Filing Requirements (MSFRs) (170 IAC 1-5-1 *et seq.*). As recognized in GAO 2013-5, a future test year does not align with all of the Commission's pre-existing MSFRs. I&M has provided supporting documentation in accordance with the MSFRs, GAO 2013-5, and GAO 2020-5, modified where appropriate to be compatible with the forward-looking test year authorized by Section 42.7. In accordance with GAO 2013-5 and GAO 2020-05, this information is provided electronically (in Excel format where appropriate) and includes workpapers for the revenue requirements, the forecast (including the load forecast), the cost of service study, the proposed return on equity and fair rate of return, the depreciation study, and nuclear decommissioning.

16. I&M's supporting documentation also includes historical data for the calendar year 2020, the most recent audited set of financial statements at the time I&M began preparing this filing, and additional historical information by month for the period January 2021 through March 31, 2021 (the most recent month for which reviewed financial information is available at the time of this filing).

17. The Company's prefiled case-in-chief includes I&M Exhibit A which consolidates the data supporting I&M's projected costs and revenues for the Test Year. Each Test Year adjustment is sponsored and described by an I&M witness, as shown in I&M Exhibit A. I&M Exhibit A-1 presents I&M's overall requested rate relief for the Test

Year, including I&M's proposed base rates and riders. I&M Exhibit A-2 presents the Test Year balance sheet. I&M Exhibits A-3 and A-4 present the Statement of Cash Flows and Income Statement, respectively, for the Test Year. I&M Exhibit A-5 identifies the net operating income per books and adjusted for ratemaking purposes and identifies the associated adjustments. I&M Exhibit A-6 sets forth the Test Year rate base and related adjustments. I&M Exhibit A-7 presents the capital structure and cost of capital for the Test Year. Finally, I&M Exhibits A-8 and A-9 present the calculation of the gross revenue conversion factor and the effective tax rate, respectively, for the Test Year. The items included in I&M's Exhibit A satisfy Section 6 of the MSFRs for the Test Year.

Petitioner's Existing Rates and Rate Structure

18. I&M's existing retail rates in Indiana were established pursuant to the Commission's March 11, 2020, Order in Cause No. 45235. Those basic rates and charges remain in effect today, as modified by various riders approved by the Commission from time to time.[1] These riders adjust I&M's rates for service to timely recover changes in certain costs associated with the provision of service.

19. The petition initiating Cause No. 45235 was filed with the Commission on May 14, 2019. Therefore, in accordance with Ind. Code § 8-1-2-42(a), more than fifteen months have passed since the filing date of I&M's most recent request for a general increase in its basic rates and charges.

Petitioner's Operating Results Under Existing Rates

20. I&M's underlying revenue requirements have and continue to change. Since its basic rates and charges were last established, I&M has continued to make

[1] In this filing, I&M uses the terms "basic rates" and "base rates" interchangeably.

significant capital expenditures for additions, replacements and improvements to its electric utility system.

21. The open access requirements applicable to I&M's transmission system also continue to impose obligations, costs and risks on I&M as a grid user and operator.

22. As a result, I&M's Test Year return upon its electric utility property is below the level required (i) to permit I&M to earn a fair return on its electric utility property equal to that available on other investments of comparable risk; (ii) to provide revenues which will enable I&M to continue to attract capital required for additions, replacements and improvements to its electric utility property and to comply with regulatory mandates at a reasonable cost; (iii) to maintain and support I&M's credit; and (iv) to assure confidence in I&M's financial soundness. As a consequence, I&M's existing rates and charges will be insufficient to provide revenues adequate to cover its necessary and reasonable operating expenses and to provide the opportunity to earn the fair return to which I&M is lawfully entitled. I&M's existing rates, therefore, are unjust, unreasonable, insufficient and confiscatory, and should be increased.

Petitioner's Proposed Rates and Charges and Tariff Terms

23. Adequate rates are essential to allow I&M to achieve financial results that will be necessary to attract needed debt and equity capital on reasonable terms, to comply with environmental and other mandates, and to otherwise invest to meet the continued need for reliable electric service within I&M's service area. I&M's filing supports the Company's ongoing effort to address aging infrastructure, secure long-term reliability, address system modernization and otherwise meet the ongoing energy and capacity needs of its customers. I&M requests that new rates and charges and

associated relief be authorized to enable I&M to realize a reasonable and adequate net operating income to render adequate and reliable service and facilities to the public.

24. As proposed in its case-in-chief, I&M requests the Commission to approve an overall annual increase in revenues from base rates and charges, including rate adjustment mechanisms, in the total amount of approximately $104 million or approximately 6.5%.

25. The testimony of Company witnesses Hornyak and Fischer address how the Company's various customer classes will be affected by the proposed revenue increase.

Phase-In Rate Adjustment

26. As explained in the filed testimony of Company witness Seger-Lawson, I&M proposes to implement the requested revenue increase in two steps through the Phase-In Rate Adjustment (PRA) process used in the Company's two most recent basic rate cases. In Phase I, revenue would increase by approximately $73 million or 4.55%. The second step will reflect an increase of $31 million, or approximately 2%, as adjusted for actual Test Year investments.

27. Implementation of the requested rate increase in phases reasonably reflects the utility property that is used and useful at the time rates are placed into effect. I&M's proposed PRA process balances customer and Company interests and is detailed in I&M's case-in-chief filed contemporaneous herewith.

Offsetting Expense Reduction

28. The Rockport Unit 2 Lease ends in December 2022, the last month of the Test Year. The Company proposes to recognize the annual Lease payment savings as

a reduction to cost of service in I&M's Resource Adequacy Rider (RAR) filings. Reflecting these cost savings in the RAR will significantly offset the impact of the proposed rate increase on customers.

Authorized Fair Rate of Return

29. The Company requests an authorized return on equity (ROE) of 10.00 percent in conjunction with Commission approval of the rate relief package proposed by the Company in this Cause. The proposal falls within the ROE range presented by the Company's ROE witness (Bulkley), and is slightly below the midpoint her analyses support. The requested ROE is reasonable in conjunction with Commission approval of the rate relief package proposed by the Company. A fair return is reasonable and necessary to support the ongoing infrastructure investment for the benefit of customers.

Capital Forecast

30. The Company's filing includes average annual capital expenditures of $539.9 million during the Capital Forecast Period (January 2021 – December 2022). This investment is reasonably necessary to comply with regulatory mandates, enhance reliability, to modernize systems, including information technology and advanced metering infrastructure, to maintain safe and reliable generation resources and to take advantage of new technologies to efficiently manage the business and improve the customer experience. Customers benefit from this investment through improved system reliability, improved tools to manage energy usage and cost, and an otherwise improved customer experience. The Company's infrastructure investment planning processes as well as major projects are discussed in the Company's written testimony. Each

budgeted project is identified in a Project Life File included with the Financial Forecast (Capital Forecast by Project) presented by Company witness Lucas.

Generation

31. The Capital Forecast Period includes all of the Company's projected generation capital expenditures in 2021 and 2022. Company witnesses Kerns and Lies support the ongoing investment. Among other things, they show that advances in technologies provide opportunities to operate the facilities in a more efficient manner. Investments are necessary to maintain safe, reliable, efficient, environmentally compliant, and low-cost service. The amount of capital investment to be made during the Capital Forecast Period is prudent and reasonable based on the needs of the generating facilities to maintain the expected level of service.

Distribution Management Plan

32. The Company's investments in the distribution system have yielded results that show reliability improvement. The capital investment in the Distribution system, is primarily focused on asset renewal, grid modernization, and improved customer engagement. The grid modernization components of the distribution work plan incorporate technologies, such as advanced metering infrastructure (AMI), Enhanced Conservation Voltage Reduction (Enhanced CVR), distribution automation circuit reconfiguration (DACR), supervisory control and data acquisition (SCADA), distribution line sensors, smart reclosers and smart circuit ties. This integrated package of investment is prudent and reasonably necessary for the sustainability of a resilient and reliable distribution grid.

33. The state and age of the existing meter technology, the Company's experience and knowledge of AMI technology, and the Accenture Cost Benefit Analysis (CBA) included with the Company's prefiled case-in-chief support the conclusion that investing in AMI technology provides many benefits to the distribution system and customers. The Company's full AMI deployment began in 2021 and is projected to conclude in late 2024. The AMI project is an integrated part of the overall distribution modernization plan and lays the foundation for substantial customer and system benefits.

34. The Company's revenue requirement includes the used and useful AMI investment in-service through the end of the Test Year in rate base. The Company asks the Commission to approve the post Test Year AMI investment pursuant to Ind. Code § 8-1-2-23. I&M also requests, pursuant to Ind. Code § 8-1-2-42(a), approval of a new AMI Rider to track incremental AMI capital investment and associated O&M that the Company incurs after the Test Year. Further, I&M proposes to credit customers the prospective incremental O&M savings starting in 2023 based on the Accenture AMI CBA presented in this case by Company witness Bech. The new AMI Rider provides the regulatory support necessary to capture the elements of this capital investment and the associated customer savings.

Customer Programs

35. In order for I&M's customers to be able to fully receive the benefits of the AMI technology, the Company is proposing certain voluntary tariff offerings and customer programs to utilize the AMI technology and allow customers to better manage their energy usage and costs for their benefit and the benefit of all I&M customers.

Offering these AMI-based programs in conjunction with the AMI roll-out leverages a unique opportunity to capture customer interest in the technology, time variable rate options and load management programs.

Depreciation Rates

36. The Company seeks approval of revised depreciation accrual rates for I&M's electric plant in service based on a depreciation study for I&M's electric utility plant in service at December 31, 2020 (as adjusted). In addition to the Company's electric utility plant in service and accumulated depreciation on the books at December 31, 2020, the depreciation study includes an adjustment for the 2021-2022 forecasted additions to plant in service at Rockport, Cook, and the Company's hydraulic and solar generating stations to reflect a forward looking test period for the Company's steam, nuclear, hydraulic and other production plant investment. The depreciation study also includes a calculation to estimate a corresponding adjustment to accumulated depreciation for all of production plant that reflects an additional two years of depreciation accrued through 2022. The depreciation rates determined by the study are intended to provide recovery of invested capital, cost of removal, and credit for salvage over the expected life of the property.

Major Storm Damage Restoration Reserve and Rate Adjustment Mechanisms

37. I&M proposes to continue the Major Storm Damage Restoration Reserve as approved in the Company's last three basic rate cases and update the baseline used for this reserve.

38. I&M seeks to continue timely recovery of costs through rate adjustment mechanisms because rate adjustment mechanisms are an important tool in the

Company's effort to meet ongoing challenges while providing reliable service to customers.

39. The Rockport Unit 2 Lease ends in December 2022, the last month of the Test Year. The Company proposes to recognize the annual Lease payment savings as a reduction to cost of service in I&M's Resource Adequacy Rider (RAR) filings. Similarly, the Cook Life Cycle Management (LCM) Project is nearly complete. The Company proposes to wind down the LCM Rider in an efficient manner. The PJM Rider also remains important due to the grid investment needs and associated cost of transmission service within PJM.

40. Table 1 below summarizes the relief sought with respect to existing riders, which continue to be an efficient way to ensure transparent tracking of costs for significant projects and programs, to encourage investors, and to enable projects to be funded at a reasonable cost of capital:

Table 1

Demand Side Management/ Energy Efficiency Program Cost Rider (DSM/EE Rider)	Adjust net lost revenues.
Environmental Cost Rider (ECR)	The total amount of consumables and allowances expense incurred by the Company each year varies considerably based on how much the Rockport units operate. The Company proposes to reset the level of consumables and allowances included in base rates and track above and below the embedded amount in ECR. The Company also proposes accelerated recovery of noncurrent sulfur dioxide (SO_2) allowance inventory that is currently recorded in FERC Account 158.

	For administrative efficiency, the Company also proposes to use ECR to reflect final true-up of LCM project in 2023.
Fuel Cost Adjustment Rider (FAC)	The Company proposes to reset the base cost of fuel; and to continue to flow to customers through the FAC IM Green Program Renewable Energy Certificate (REC) net revenues and net revenues from the sale of certain unsubscribed RECs.
Life Cycle Management Rider (LCM Rider)	The Company proposes to update the LCM Rider for new LCM-related capital included in base rates. As the LCM work at Cook Nuclear Plant is forecasted to be completed during the Test Year, capital associated with the LCM project will be included in base rates. The Company proposes to file a final reconciliation of the LCM Rider in I&M's ECR proceeding in 2023.
Off-System Sales Margin Sharing /PJM Cost Rider (OSS/PJM Rider)	The Company proposes to continue to track 100% of OSS margins with no OSS margins embedded in base rates and flow back to customers 100% of these margins. The Company proposes to continue to fully recover PJM Network Integration Transmission Service (NITS) charges in the OSS/PJM Rider with no costs embedded in base rates. The Company proposes to reset the base cost of PJM non-NITS charges and to continue to recover costs above and below this embedded in the OSS/PJM Rider.

Resource Adequacy Rider (RAR)	The Company proposes to continue to track incremental changes in the Company's purchased power costs. Costs embedded in base rates will be updated and the RAR will recover amounts above and below the embedded cost. Capacity purchases and sales will also be tracked in the RAR. The RAR will also include net impacts of Rockport Unit 2 lease expiration.
Solar Power Rider (SPR)	The Company proposes to rename this rider as the "Renewable Projects Rider."

41. As stated above, I&M proposes a new AMI Rider as part of its advanced metering infrastructure proposal.

42. I&M also proposes to implement the Tax Rider to address the ongoing rate impacts of the 2017 Tax Cuts and Jobs Act (TCJA), as authorized in Cause No. 45235. The Tax Rider allows for a smooth sun setting of the final amortization of non-normalized (unprotected) excess accumulated deferred federal income tax (ADFIT) credit that resulted from the TCJA. The Company also proposes to use the Tax Rider to address future changes in corporate federal income tax rates.

43. These proposals address costs that are largely outside the Company's control and provide efficient and timely cost recovery.

Nuclear Decommissioning Expense

44. The Company recommends maintaining the current level of annual decommissioning funding of $2.0 million in the revenue requirement in this case.

PJM Capacity Performance Insurance

45. Capacity Performance is a PJM requirement that first applied to the Company's FRR capacity obligations in the 2019/2020 delivery year, which began on June 1, 2019. Capacity Performance insurance allows I&M to reasonably mitigate a large portion of the significant financial risk that a generating unit would underperform or not be available during a Performance Assessment Interval (PAI), which events are determined by PJM and are not within the control of the Company. The group insurance policy, which allows I&M to manage cost, was selected from options solicited through a competitive procurement process. This expense should continue to be included in cost of service.

Prepaid Pension and Other Postretirement Employee-Benefit (OPEB) Assets

46. Consistent with I&M's last three rate cases (Cause Nos. 45235, 44967 and 44075), I&M continues to include its prepaid pension asset in rate base. The Company has also included its prepaid OPEB asset in rate base consistent with Cause Nos. 39314, 43306 and 44075. These assets have lowered both the current and future cost of providing service and benefited customers and the utility's ongoing ability to provide reliable service. Inclusion of these assets in rate base is consistent with well-accepted ratemaking principles and necessary both to compensate the utility for use of funds it has advanced and to avoid a disincentive to the utility for making prudent advances in the future.

Regulatory Assets

47. The proposed revenue requirement includes the recovery and amortization of regulatory assets including those authorized by the Commission orders

in Cause No. 45380, 4523, 44967 and 44075. As discussed by Company witnesses Seger-Lawson and Ross, the Company requests to continue certain deferrals, including the deferral of all costs associated with Dry Cask Storage costs that are not reimbursed by the Department of Energy (DOE).

Vegetation Management

48. Vegetation management remains the most impactful investment I&M can make to improve overall reliability. I&M began a comprehensive and systematic vegetation management program at the beginning of 2018. This program has reduced outages. The fourth and final year of the initial program is 2021 and 2022 begins the start of the next four year cycle, which is detailed in the testimony of Company witness Isaacson. Continuation of this program, starting with the next four-year rotation period in 2022, remains important to maintain or improve reliability and avoid preventable, vegetation-caused service interruptions.

Jurisdictional Separations, Class Cost of Service and Rate Design

49. The Company's filing uses the long standing Test Year separations process to jurisdictionalize costs. The Company's jurisdictional separations study reasonably allocates system-related costs based on established cost allocation procedures using the underlying data that represents how the system is used during the Test Year to meet customer requirements. As explained by Company witness Williamson, I&M's generating capacity, including Rockport Unit 2 capacity, is needed to meet the Company's capacity requirements during the 2022/2023 PJM Delivery Year (which runs from June 2022 to May 2023). The Company's jurisdictional separations study reasonably reflects the value of the Company's generating facilities used and

useful for the convenience of the public and this value, as well as the fairly allocated operating expenses and benefits, are reasonably included in the retail revenue requirement as proposed by I&M. The separations study is being submitted to the Commission as required by the MSFR (170 IAC 1-5-15).

50. The cost allocation methodology used in I&M's class cost-of-service study assigns costs among the customer classes in a fair and equitable manner based on principles of cost causation. Customers who cause costs to be incurred are allocated such costs in the Company's class cost-of-service study. The class cost of service study is being submitted to the Commission as required by the MSFR (170 IAC 1-5-15).

51. The Company's overall revenue increase among the customer classes is allocated following certain ratemaking principles to meet several objectives. First, the revenue allocation on the Company's proposed cost of service was based on the principal of cost causation to design rates that reflect as nearly as possible the actual costs of service to the customer. Second, the total revenue increase was allocated in a manner that moved all classes to earning the class average rate of return by eliminating the current level of inter-class revenue subsidies. Finally, the principle of gradualism was applied when determining the individual customer class revenue increases. In this case, mitigation was applied such that no class received a revenue decrease or an increase greater than 10%. Each of these principles and objectives was applied in the development of the Company's proposed equal percentage subsidy reduction method of revenue allocation.

52. In general, the Company's approach is to design rates and rate components that reflect the Company's underlying costs. This includes collecting fixed

costs through fixed and/or demand charges and variable costs through energy charges whenever practical.

53. In order to better align the Company's cost of service with the revenues recovered from its residential customers, I&M proposes to increase the fixed monthly service charge for residential service from the current level of $15.00 per month to $20.00 per month. This change continues to gradually improve the alignment between the Company's costs incurred to serve the residential customer class and the charges paid by residential customers taking service. It should be recognized that the percentage increase in the fixed monthly service charge relates only to one component of the customer's entire bill and should not be confused as equating to an overall increase in the entire bill. As previously recognized by the Commission, "gradualism is best considered in the context of the entire customer bill and not discrete charges within the bill."[2]

Terms and Conditions of Service

54. The Company's filing includes: changes to I&M's Terms and Conditions of Service, including the Flex Pay payment option; revisions to certain one-time Service, Reconnect and Trip Charges; modifications to the language and rates of existing tariff schedules; new tariff options for customers; and changes to specific rider language and rates including the proposal of two (2) new riders (as stated above). These changes are shown in redline and clean versions of the Company's Tariff Book which is included as an attachment to the testimony of Company witness Cooper.

[2] *I&M*, Cause No. 45235 (IURC March 11, 2020), p. 96 (quoting March 16, 2016 order in *Indianapolis Power & Light Company,* Cause No. 44576, p. 72).

Rule Waivers or Declination of Jurisdiction

55. Per the settlement agreement approved in Cause No. 44967, I&M is authorized to disconnect remotely customers who have demonstrated a safety risk to I&M personnel. In this proceeding, I&M requests authority to more broadly implement remote disconnect as well as remote reconnect processes. To facilitate this process, I&M requests the Commission waive the requirements of 170 IAC 4-1-16(f).

56. I&M also proposes to implement FlexPay, which is a voluntary program allowing residential customers to prepay for electric service and thereby manage their electricity based on their own personal budget. If the FlexPay program is approved, I&M will be sending periodic electronic notifications to the customer about the amount of their account balance that remains. Therefore, requirements that the utility send a bill that contains certain billing line items, including late payment charges, due date of the bill, and the 17-day grace period for payments will be unnecessary. To facilitate this voluntary customer option, I&M requests waiver of billing rules that require certain charges to be presented to customers on an electric utility bill (170 IAC 4-1-13) and customer notifications prior to being disconnected (170 IAC 4-1-16).

57. In the alternative, and in accordance with Ind. Code § 8-1-2.5-5, I&M asks the Commission to decline to exercise its jurisdiction under these rules so as to allow the Company to implement these programs.

Other Proposals Included In Filing

58. These and other I&M proposals are explained in the case-in-chief filed contemporaneous herewith. An index of the filing is included herewith as Petition Exhibit A.[3]

Confidential Information

59. Contemporaneous with the filing of this Petition, I&M is also filing a motion for protective order to protect certain confidential, proprietary, competitively-sensitive and/or trade secret information related to I&M's filing from public disclosure. I&M has entered into a nondisclosure agreement with the OUCC and will work together with any intervenors to negotiate an acceptable confidentiality agreement to facilitate the production of the confidential information as appropriate.

Procedural Schedule

60. Petitioner's proposed procedural schedule based and associated terms is attached hereto as Petition Exhibit C. This proposed schedule is based on the Commission's GAO-2013-5. In accordance with 170 IAC 1-1.1-9(a)(8), Petitioner is working with the Indiana Office of Utility Consumer Counselor and potential intervenors to reach agreement on these matters. To the extent necessary or appropriate and pursuant to 170 IAC 1-1.1-15, I&M requests that a date for a prehearing conference and preliminary hearing be promptly set by the Commission to address procedural matters so as to allow completion of the case within 300 days in accordance with GAO-2013-5 and Section 42.7.

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[3] The overview of the Company's proposals herein and in the Petition Exhibits is intended to highlight issues and is not an exhaustive list of I&M's requests in this proceeding. A complete account of I&M's requested relief can be found in I&M's case-in-chief.

Customer Notification

61. In accordance with Ind. Code § 8-1-2-61(a), I&M will publish notice of the filing of this Petition in a newspaper of general circulation published in each Indiana county in which I&M renders service. The proofs of publication of notice will be late-filed as an exhibit.

62. In accordance with 170 IAC 4-1-18(c), I&M will furnish to each residential customer within forty-five (45) days of this Petition, a notice which fairly summarizes the nature and extent of the proposed changes. This notice will be provided via bill messaging, bill inserts, or similar mailing.

Attorneys for Petitioner

63. The names and addresses of I&M's duly authorized representatives, to whom all correspondence and communications concerning this Petition should be sent, are as follows:

Teresa Morton Nyhart (Atty. No. 14044-49)
Jeffrey M. Peabody (Atty. No. 28000-53)
BARNES & THORNBURG LLP
11 South Meridian Street
Indianapolis, Indiana 46204

Nyhart Phone:	(317) 231-7716
Peabody Phone:	(317) 231-6465
Fax:	(317) 231-7433
Nyhart Email:	tnyhart@btlaw.com
Peabody Email:	jpeabody@btlaw.com

With courtesy copy to:

Jessica A. Cano
Senior Counsel
American Electric Power Service Corporation
1 Riverside Plaza, 29th Floor
Columbus, Ohio 43215
Phone: (614) 716-2921
Fax: (614) 716-2950
Email: jacano@aep.com

WHEREFORE, I&M respectfully requests that the Commission promptly establish a procedural schedule and associated terms, make such investigation and hold such hearings as are necessary or advisable in this Cause, and thereafter make and enter an appropriate order in accordance with the 300-day time frame provided in GAO-2013-5 and Section 42.7:

(i) finding that the existing rates for electric service rendered by I&M in the State of Indiana are insufficient to provide revenues to cover the reasonable and necessary Test Year operating expenses and fair return and are therefore unjust, unreasonable, insufficient, and confiscatory;

(ii) determining and, by order, fixing increased rates and charges to be imposed, observed and followed commencing as soon as practicable in lieu of those so found to be unjust, unreasonable, insufficient and confiscatory;

(iii) authorizing I&M to revise and place into effect for accrual accounting purposes its depreciation rates as proposed in its evidence herein;

(iv) including in rate base the Company's prepaid pension and OPEB assets;

(v) including all of I&M's utility plant in service, including plant to be in service by end of 2022, in the revenue requirement to be established in this Cause;

(vi) maintaining nuclear decommissioning expense as proposed by I&M;

(vii) approving the Company's AMI Rider to track AMI costs and operating savings as explained in the Company's evidence herein;

(viii) approving implementation of the Tax Rider as explained in the Company's evidence herein;

(ix) approving the continuation of the Major Storm Damage Restoration Reserve as proposed in I&M's evidence herein;

(x) approving the Company's other rate adjustment mechanism proposals as proposed in I&M's evidence herein;

(xi) approving the Company's proposed customer programs;

(xii) approving the accounting relief and other requests identified in I&M's evidence herein (and indexed in <u>Petition Exhibit A</u> and in <u>I&M Exhibit A</u>);

(xiii) approving I&M's jurisdictional separations, cost allocation and rate design;

(xiv) approving and authorizing I&M to implement various changes in the terms, conditions and provisions of I&M's tariff for electric service rates as proposed in I&M's evidence;

(xv) waiving or declining to exercise jurisdiction with respect to certain rules as proposed in I&M's evidence;

(xvi) approving I&M's Test Year end rates and proposal to phase in the new rates as discussed in I&M's evidence herein;

(xvii) authorizing and approving the filing by I&M of new schedules of increased rates and charges for electric service so as to provide just, reasonable, sufficient and nonconfiscatory rates; and

(xviii) granting to I&M such other and further relief as may be appropriate and proper.

Dated this 1st day of July, 2021.

Respectfully submitted,

INDIANA MICHIGAN POWER COMPANY

By: Toby L. Thomas

Toby L. Thomas
President and Chief Operating Officer

Teresa Morton Nyhart (Atty. No. 14044-49)
Jeffrey M. Peabody (Atty. No. 28000-53)
BARNES & THORNBURG LLP
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Attorneys for INDIANA MICHIGAN POWER COMPANY

STATE OF INDIANA)
) SS:
COUNTY OF ALLEN)

AFFIDAVIT

Toby L. Thomas, being first duly sworn, upon oath, deposes and says that he is the President and Chief Operating Officer of Indiana Michigan Power Company, the Petitioner in the above-entitled Cause; that as such he executed the above and foregoing Petition and has authority so to do; that he has read said Petition and knows the contents thereof; and that the statements and representations therein contained are true to the best of his knowledge, information and belief.

Toby L. Thomas

Toby L. Thomas

Subscribed and sworn to before me, a Notary Public, in and for said County and State this 1st day of July, 2021.

Regiana M. Sistevaris, Notary Public

I am a resident of Allen County, Indiana.
My commission expires: January 7, 2023

REGIANA MARIA SISTEVARIS
Notary Public - Seal
State of Indiana
Allen County
My Commission Expires Jan 7, 2023

CERTIFICATE OF SERVICE

The undersigned certifies that a copy of the foregoing was served upon the following via electronic email, hand delivery or First Class, United States Mail, postage prepaid this 1st day of July, 2021 to:

William I. Fine
Abby R. Gray
Indiana Office of Utility Consumer Counselor
Office of Utility Consumer Counselor
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Indianapolis, Indiana 46204
infomgt@oucc.in.gov
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Attorneys for INDIANA MICHIGAN POWER COMPANY

DMS 20388858v1

Indiana Michigan Power Company
2022 Rate Case
Index of Issues, Requests, and Supporting Witnesses[1]

GENERAL		
Subject	**Description**	**Supporting I&M Witness**
Test Year	Twelve Months Ended December 31, 2022.	• Seger-Lawson.
Historical Base Period	Twelve Months Ended December 31, 2020.	• Seger-Lawson. • Lucas. • Lucas Attach: o DAL-1 (historical and forecasted O&M). o DAL-2 (historical and forecasted cap. ex).
Financial Information and Revenue Requirement Details	I&M Exhibit A: presents overall requested rate relief and consolidates data supporting I&M's project costs and revenues for the Test Year (TY).	• Various as reflected in I&M Exhibit A index and supporting workpapers.

[1] This Index of the Company's case-in-chief is intended to highlight issues and is not an exhaustive list of I&M's requests in this proceeding. A complete account of I&M's requested relief can be found in I&M's case-in-chief, including but not limited to I&M's petition, testimony, exhibits, workpapers, and MSFR responses. The I&M Financial Exhibit provides an additional index.

<table>
<tr><th colspan="4">REVENUE REQUIREMENT</th></tr>
<tr><th>Subject</th><th>I&M Request</th><th>Supporting I&M Witness</th><th>Workpaper or Exhibit Reference</th></tr>
<tr><td>Overall Revenue Increase</td><td>• Total annual increase in revenue of approximately $104 million, or 6.5% to be phased in over two steps.
• Phase-In Rate Adjustment (PRA):
o Phase I: $73 million or 4.55%.
o Phase II (which commences January 1, 2023): $31 million, or approximately 2% (adjusted for actual TY investments).</td><td>• Thomas (overview).
• Seger-Lawson (policy; PRA).
• Ross (general regulatory accounting and various adjustments).</td><td>• I&M Exhibit A-1 (rate relief).</td></tr>
<tr><td>Financial Forecast</td><td>• Set rates based on I&M's TY financial forecast.
• Reflect forecasted revenues, O&M, and capital investments in rates.</td><td>• Lucas (overall forecast approach).
• Heimberger (forecasting model).
• Lies (nuclear O&M and capital).
• Kerns (non-nuclear generation O&M and capital).
• Isaacson (distribution O&M and capital).
• Koehler (PJM costs).
• Burnett (load forecast).</td><td>• Heimberger Attach:
o NAH-1 (operating income comparison).
o NAH-2 (revenue comparison).
o NAH-3 (fuel, consumables, allowances and purchased power expenses).
o NAH-4 (transmission revenues and expenses).
o NAH-5 (historical functional plant activity).
o NAH-6 (I&M plant summary).
o NAH-7 (UI model overview).
• WP NAH-1 - NAH-8 (support).
• Burnett Attach:
o CMB-1 (load forecast results).</td></tr>
</table>

REVENUE REQUIREMENT			
Subject	**I&M Request**	**Supporting I&M Witness**	**Workpaper or Exhibit Reference**
Return on Equity (ROE).	• Authorize 10.0% ROE.	• Thomas (policy). • Bulkley (ROE support).	• Bulkley Attach: o AEB-2 & AEB-4 (DCF). o AEB-3 (screening criteria proxy grp). o AEB-5 (CAPM). o AEB-6 (Risk Premium). o AEB-7 (Expected Earnings). o AEB-8 (issuance costs). o AEB-9 (proxy grp. trackers). o AEB-10 (proxy grp. cap. structures).
Weighted Average Cost of Capital (WACC)	• Authorize WACC applied to original cost rate base. • I&M's forecast overall WACC, inclusive of ratemaking adjustments: 6.07% at the beginning of the TY (December 31, 2021), and 6.08% at the end of the TY (December 31, 2022).	• Messner (overall WACC calculation, financing activity). • Heimberger (equity balance, customer deposits balance). • Criss (ADFIT balance). • Bulkley (ROE).	• I&M Exhibit A-7 (TY capital structure and WACC).
Depreciation	• Set new depreciation rates and reflect the resulting depreciation expense in base rates based on depreciation study.	• Cash (depreciation).	• Cash Attach: o JAC-1 (depreciation study). o JAC-2 (Brandenburg dismantlement study). o JAC-3 (Sargent & Lundy dismantling studies). • WP JAC-1 - JAC-3.

REVENUE REQUIREMENT			
Subject	**I&M Request**	**Supporting I&M Witness**	**Workpaper or Exhibit Reference**
Prepaid Pension and OPEB Assets	• Consistent with I&M's last three rate cases (Cause Nos. 45235, 44967 and 44075), Continue to include I&M's prepaid pension asset in rate base. • Include I&M's prepaid OPEB asset in rate base consistent with Cause Nos. 39314, 43306 and 44075.	• Ross (Accounting Treatment). • Hill (forecasted assets). • Seger-Lawson (policy).	• I&M Exhibit A-6 (TY rate base).
Taxes	• Reflect forecasted TY tax expense in base rates, excluding amortization of excess unprotected ADFIT. • Apply gross revenue conversion factor (GRCF). • Implement Tax Rider authorized in Cause No. 45235 and use rider for potential increase in corporate federal income tax rate.	• Criss (federal and state income taxes; other taxes). • Seger-Lawson (Tax Rider and policy). • Ross (Tax Rider over-/under-recovery accounting, deferral accounting for potential increase in corporate federal income tax rate).	• I&M Exhibits A-8 and A-9 (GRCF and effective tax rate). • Criss Attach: o JMC-1 (TY state inc. tax rate). o JMC-2 (TY int. synchronization). o JMC-3 (TY NOLC). o JMC-4 (illustrative tax increase calculation). • WP-JMC-1 (TY tax expense calculations and tax adjustments).

REVENUE REQUIREMENT			
Subject	**I&M Request**	**Supporting I&M Witness**	**Workpaper or Exhibit Reference**
Forecasted Rate Base	• Reflect forecasted capital projects in rate base using PRA as used in last two general rate cases. • Capital forecast methodology is consistent with last two general rate cases. • Capital forecast reflects average annual capital expenditure of $539.9 million during the Capital Forecast Period (Jan. 2021 – Dec. 2022). • See also entries below.	• Seger-Lawson (policy and PRA). • Lucas (forecast). • Isaacson (distribution). • Kerns (non-nuclear generation). • Lies (nuclear generation). • Thomas (overview, AMI).	• Lucas WP-DAL-2 Project Life File (Capital Forecast by Project).
Distribution	• Continue Distribution Management Plan. • I&M's asset renewal projects: ○ Overhead Line Rebuild; ○ Pole Replace./Reinforce; ○ Underground Residential Distribution (URD) Cable and Live-Front Replace; ○ Underground Station Exit Cable Replacement Projects; and ○ Underground (UG) Network Rebuild. • Combined Projects are a collection of projects that vary in size.	• Isaacson (distribution). • Walter (Enhanced CVR).	• Isaacson Attach: ○ DSI-2 (Asset Renewal Plan). ○ DSI-3 (Combined Projects Plan). ○ DSI-4 (Grid Mod. Plan). ○ DSI-5 (Enhanced CVR Plan).

REVENUE REQUIREMENT			
Subject	**I&M Request**	**Supporting I&M Witness**	**Workpaper or Exhibit Reference**
Distribution (cont'd)	• Risk mitigation programs to identify and remediate assets: o Underground locates; o Pole inspections; o URD equipment inspections; o Overhead line inspections; and o Contact voltage inspections. • Grid modernization projects include: o AMI; o Enhanced Conservation Voltage Reduction (Enhanced CVR); o Distribution Automation Circuit Reconfiguration (DACR); o Supervisory Control and Data Acquisition (SCADA); o Distribution Line Sensors; o Smart Reclosers; and o Smart Circuit Ties.	• Isaacson (distribution). • Walter (Enhanced CVR).	• Isaacson Attach: o DSI-2 (Asset Renewal Plan). o DSI-3 (Combined Projects Plan). o DSI-4 (Grid Mod. Plan). o DSI-5 (Enhanced CVR Plan).

REVENUE REQUIREMENT			
Subject	**I&M Request**	**Supporting I&M Witness**	**Workpaper or Exhibit Reference**
Advanced Metering Infrastructure (AMI)	• Systematically deploy AMI throughout service territory over a 4 year period (2021-2025). • Bring the benefits of AMI to customers through access to data, operational improvements, and demand response and other programs that will allow customers to receive benefits of AMI as meters are installed. • Implement remote disconnect/reconnect. • Implement AMI Rider for post TY capital investment and flow to customers operational cost savings identified in AMI CBA.	• Thomas (overview). • Bech (AMI Cost Benefit Analysis (CBA)). • Isaacson (AMI deployment). • Lucas (AMI customer engagement, education plan and customer programs). • Walter (AMI customer programs). • Seger-Lawson (AMI Rider; rule waiver for remote disconnect).	• Bech Attach. CHB-1 (AMI CBA). • WP-CHB-1 (support). • WP-A-O&M-11 (AMI operational savings and incremental O&M). • Cooper Attach. KCC-2 (tariffs for customer programs). • Thomas Attach. TLT-2 (IEI report).

REVENUE REQUIREMENT			
Subject	**I&M Request**	**Supporting I&M Witness**	**Workpaper or Exhibit Reference**
AMI-Enabled Customer Programs	• Approve following programs: o Residential AMI HVAC Direct Load Control Program; o Residential AMI Electric Water Heater Direct Load Control Program; o Residential Customer Engagement Demand Response Program; o Small Business AMI Direct Load Control Program; o Critical Peak Pricing; o Residential AMI Customer Portal; o C&I AMI Customer Portal; and o Flex Pay Program (see separate entry below).	• Lucas (overview). • Walter (programs).	• Lucas Attach: o DAL-3 (AMI customer engagement plan). o DAL-4 (AMI residential customer engagement platform). o DAL-5 (AMI C&I customer engagement platform). • Walter Attach: o JCW-1 (Res. Engagement DR). o JCW-2 (Res. HVAC DLC). o JCW-3 (Res. Elec. Water Heater DLC). o JCW-4 (Sm. Bus. DLC). o JCW 5 (Critical Peak Pricing Prog.).
Flex Pay	• Flex Pay – voluntary payment option allows residential customers to pay for electric service based on a frequency and budget that reflects their own personal preferences without incurring cost of a deposit or other fees associated with current post-pay billing.	• Lucas (program overview). • Walter (program design and benefits). • Seger-Lawson (rule waivers).	• Residential Service Flex Pay (RS-FP) tariff provision (Cooper Attach. KCC-2.

REVENUE REQUIREMENT			
Subject	**I&M Request**	**Supporting I&M Witness**	**Workpaper or Exhibit Reference**
Crossroads EV Corridor Project	• Approve recovery of capital costs for 12 corridor fast charging sites net of grant funding received from Indiana Department of Environmental Management (IDEM) for the joint utility statewide charging network program. • Total estimated cost: $3.57 million.	• Walter.	• Walter Attach: ○ JCW-6 (Cross. EV. Corr. Application). ○ JCW-7 (I&M site detail). ○ JCW-8 (IDEM grant press release). ○ -JCW-9 (Cross. EV Corr. Project). • Also WP-JCW-1 & JCW-2.
Transmission	• Continue to embed TY level of non-NITS PJM costs in base rates. • Continue to track all NITS costs in OSS/PJM Rider as was approved in CN 45235.	• Koehler (transmission investment, PJM cost forecast). • Seger-Lawson (OSS/PJM Rider). • Fischer (trans. cost revenue adjustment).	• Koehler Attach. NCK-1 (AEP Trans. Planning). • Koehler Attach. NCK-2 (Owner Projects). • Fischer Attach. JLF-1 (trans. cost rev. adj).
Generation (Fossil, Hydro, and Solar)	• Reflect forecasted generation O&M in rates. • Reflect forecasted generation capital investment in rate base. • Reflect remaining net book value associated with RU 2 investment made by I&M during Lease in rate base. • Reflect fuel inventories in rate base. • Embed TY consumables and allowances expense in base rates and track over/under expense through ECR.	• Kerns (generation O&M and capital investment, variability of consumables and allowances expense, fuel inventories). • Seger-Lawson (tracking consumables and allowances). • Williamson (excluded capacity from CN 45235; remaining net book value RU2 improvements).	• WP-TCK-1 (O&M). • WP-TCK-2 (consumable expense). • WP-TCK-3 (capital). • WP-TCK-4 (fuel inventory). • Williamson Attach. AJW-3 (Rockport Ownership Diagram). • Williamson Attach. AJW-4 (notice of non-renewal).

REVENUE REQUIREMENT			
Subject	**I&M Request**	**Supporting I&M Witness**	**Workpaper or Exhibit Reference**
Nuclear Decommissioning	• Maintain the current level of decommissioning funding of $2.0 million in the revenue requirement. • No current need to resume funding for Pre-April 7, 1983 spent nuclear fuel disposal fund. • Incorporate language in order in this Cause to assist I&M in obtaining compliance with IRS regulations.	• Hill (funding analysis). • Knight (nuclear decommissioning study).	• Knight Att. RWK-2 (decomm. study). • Hill Attach. ALH-1 (summary decommissioning liability). • WP-ALH-1 - 3 (escalation rates). • WP-ALH-4 (expected return on assets). • WP-ALH-5 (hist. annual inv. Returns). • WP-ALH-6 –ALH-7 (trust assets). • WP-ALH-8-AJH-9 (spent fuel asset growth and liability amt).
Nuclear Operations	• Capital expenditures can be categorized into four types: LCM, Major Projects, Regulatory Compliance and Other. • Cook will complete transition to Maximo Work and Asset Management software in 2021.	• Lies.	• Lies Attach. QSL-1 (Cook Plant systems diagram).
PJM Capacity Performance Insurance	• Cost of group insurance policy, selected through a competitive procurement process, should continue to be included in cost of service.	• Williamson.	• Williamson Attach: o AJW-1 (insurance analysis). o AJW-2 (insurance policy).
Vegetation Management	• I&M will begin its second four-year vegetation management cycle in 2022. • Include costs in revenue requirement.	• Isaacson.	• Isaacson Attach DSI-1 (VM Plan).

REVENUE REQUIREMENT			
Subject	**I&M Request**	**Supporting I&M Witness**	**Workpaper or Exhibit Reference**
Regulatory Assets	• Revenue requirement includes recovery and amortization of regulatory assets including those authorized by Commission orders in Cause No. 45380, 45235, 44967 and 44075. • Company requests to continue certain deferrals, including the deferral of all costs associated with Dry Cask Storage costs that are not reimbursed by the Department of Energy (DOE).	• Ross (regulatory accounting and adjustments). • Seger-Lawson (regulatory assets and dry cask deferral). • Lies (description dry cask storage).	• Exhibit A-5 o WP-A-O&M-4 o WP-A-O&M-7 o WP-A-O&M-9 o WP-A-O&M-10 • Exhibit A-6 o WP-A-RB-5 o WP-A-RB-6
EZ Bill	• Proposal of EZ Bill Program revenues and expenses above-the-line for regulatory accounting purposes because the program is a customer rate offering like any other I&M rate offering.	• Auer.	• See Testimony.

COST OF SERVICE AND RATE DESIGN			
Subject	**I&M Proposal**	**Supporting I&M Witness**	**Workpaper or Exhibit Reference**
Jurisdictional Separation Study.	• Use of same TY separations allocation process as proposed by I&M in 44075, 44967 & 45235.	• Duncan.	• Attach. JCD-1. • WP-JCD-1-JD-3 (support).

<table>
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<tr><th>Subject</th><th>I&M Proposal</th><th>Supporting I&M Witness</th><th>Workpaper or Exhibit Reference</th></tr>
<tr><td>Class Cost of Service Study (CCOSS).</td><td>• Use of same allocation methodology as proposed by I&M in 44967 & 45235.
• Continue using the 6 CP demand allocator, consistent with the methodology found appropriate in I&M's last three basic rate cases.</td><td>• Hornyak.</td><td>• Hornyak Attach. SH-1 (TY CCOSS).
• WP-SH-1-SH-20 (support).</td></tr>
<tr><td>Overall Rate Design</td><td>• Follow same methodology established in Cause No. 44075 and reflected in the Company's succeeding basic rate cases.
• Increase standard residential tariff service charge from the current level of $15.00 per month to $20.00 per month; continue declining block volumetric energy rate structure.
• Consolidation of the GS and LGS tariffs into one Tariff GS.
• Modify demand billing for Tariff LGS and Tariff IP from billing on kVA to billing on kW.
• Use equal percentage subsidy reduction method of revenue allocation.
• Continue to reflect URT in base rates and rider rates rather than as separate lint item on bills.</td><td>• Fischer (rate design).
• Seger-Lawson (efforts to delineate URT as sep. item).</td><td>• Fischer Attach:
o JLF-1 (trans. cost rev. adj).
o JLF-2 (cust. class rev. allocation).
o JLF-3 (present & proposed rev.)
o JLF-4 (typical bill comparison).
o JLF-5 (IOU & REMC res. fixed charges).
• WP-JLF-1 (rev. reconciliation).
• WP-JLF_2 (Class CP per kWh ratios).
• WP-JLF-3 (class rev. req.).
• WP JLF-4 (basic rate design computations).
• WP JLF-5 (current rider factor computations).
• WP-JLF-6 (proposed rider rate design).
• Figure JLF-3 (effect of PRA on 1,000 kWh residential customer).</td></tr>
</table>

COST OF SERVICE AND RATE DESIGN			
Subject	**I&M Proposal**	**Supporting I&M Witness**	**Workpaper or Exhibit Reference**
Phase-In Rate Adjustment (PRA)	• PRA credit for rate base additions during TY as in 44967 & 45235. • I&M to certify actual Test-Year-end rate base pursuant to same procedure as in 44967 & 45235.	• Seger-Lawson (description of PRA). • Duncan (calculation of credits). • Hornyak (Phase-In COSS). • Fischer (PRA rate design).	• Duncan Attach. JCD-2 (PRA Rev. Req.). • WP-JLF-7 (PRA factor rate design). • WP-JCD-4-6 (PRA rev. req. support). • WP-SH-17 thru 20. •
Major Storm Damage Reserve	• Continue Major Storm Reserve as approved in last three basic rate cases. • Update baseline for the reserve.	• Seger-Lawson (policy). • Isaacson (historical trends).	• Exhibit A-5 o WP-A-O&M-7 o WP-A-O&M-8 • Exhibit A-6 o WP-A-RB-6
Existing Rider Proposals			
DSM/EE Rider	• Adjust net lost revenues.	• Auer.	• See Testimony
ECR	• Reset level of consumables and allowances included in base rates and track above and below the embedded amount in ECR. • Also accelerate recovery of noncurrent sulfur dioxide (SO_2) allowance inventory that is currently recorded in FERC Account 158. • See also LCM Rider.	• Seger-Lawson.	• See Testimony
FAC	• Reset base cost of fuel. • Continue to flow to customers through the FAC IM Green Program Renewable Energy Certificate (REC) net revenues and net revenues from the sale of unsubscribed RECs.	• Auer. • Kerns (base cost of fuel). • Heimberger (FAC basing point).	• Heimberger Attach. NAH-8 (FAC basing point).

COST OF SERVICE AND RATE DESIGN			
Subject	**I&M Proposal**	**Supporting I&M Witness**	**Workpaper or Exhibit Reference**
LCM	• Update the LCM Rider for new LCM-related capital included in base rates. • As the LCM work at Cook Nuclear Plant is forecasted to be completed during the TY, capital costs will be included in base rates at the end of the TY. • Company proposes to file a final reconciliation of the LCM Rider in 2023.	• Lies (LCM project status). • Auer (LCM Rider).	• See Testimony
OSS/PJM	• Continue to track 100% of OSS margins and flow back to customers 100% of these margins. • Continue to fully recover PJM Network Integration Transmission Service (NITS) charges in the OSS/PJM Rider with no costs embedded in base rates. • Reset the base cost of PJM non-NITS charges and to continue to recover costs above and below this embedded in the OSS/PJM Rider.	• Seger-Lawson.	• Exhibit A-5 o WP-A-Rider-2
RAR	• Continue to track incremental changes in the Company's purchased power costs. • Costs embedded in base rates will be updated and the RAR will recover amounts above and below the embedded cost. • Capacity purchases and sales will also be tracked in the RAR. • RAR will also include net impacts of Rockport Unit 2 lease expiration.	• Williamson. • Seger-Lawson.	• Exhibit A-5 o WP-A-Rider-6

COST OF SERVICE AND RATE DESIGN			
Subject	**I&M Proposal**	**Supporting I&M Witness**	**Workpaper or Exhibit Reference**
SPR	• Rename as the "Renewable Projects Rider."	• Auer.	• See Testimony.
New Riders			
AMI Rider	• Track incremental post TY AMI investment and credit back incremental O&M cost savings.	• Seger-Lawson.	• See Testimony.
Tax Rider	• Implement Tax Rider to address the ongoing rate impacts of the 2017 Tax Cuts and Jobs Act (TCJA) rate as authorized in Cause No. 45235. • Use Tax Rider to address future changes in corporate federal income tax rates.	• Seger-Lawson. • Ross. • Criss.	• WP-A-RIDER 4 (excess unprotected ADFIT adjustment).

COST OF SERVICE AND RATE DESIGN			
Subject	**I&M Proposal**	**Supporting I&M Witness**	**Workpaper or Exhibit Reference**
Terms and Conditions of Service and Tariffs	• Add Residential Critical Peak Pricing Tariff. • Commercial Critical Peak Pricing Tariff. • Update Non-Residential Deposit terms to include previously approval interest rate. • Close Tariffs RS ROD and GS TOD; expand RS TOD2 and GS TOD2. • Modify fee language in Tariffs RS EZB and GS EZB. • Consolidate Tariffs GS and LGS. • Remove Other Sources of Energy Clause in all pertinent tariffs. • Change kVa billing determinants to KW for Tariffs LGS and IP. • Raise threshold for written contract under Tariff IP. • Implement minor language changes to bring better definition or clarity to Terms and Conditions of Service.	• Cooper. • Walter. • Fischer (rate design).	• Cooper Attach: o KCC-1 (tariff TOC and terms and conditions of service (redline)). o KCC-2 (tariffs and rider sections (redline)). • WP-A-OR-2 (support for service, reconnect and trip charges).

COST OF SERVICE AND RATE DESIGN			
Subject	**I&M Proposal**	**Supporting I&M Witness**	**Workpaper or Exhibit Reference**
Rule Waivers (or declination of jurisdiction)	• Request Waiver of 170 IAC 4-1-16(f) which requires a Company employee to make an on-site visit prior to disconnection – this waiver would allow for remote disconnection/ reconnection. • Request Waiver of 170 IAC 4-1-13 and 170 IAC 4-1-16 which require certain charges to be shown on the bill and requires an on-site visit prior to disconnection – this waiver would allow for customers to participate in a voluntary FlexPay program.	• Seger-Lawson.	• See Testimony.

1. Toby L. Thomas, I&M President and Chief Operating Officer. This testimony provides an overview of I&M's overall request. As a regulated company, the price I&M charges for retail electric service is necessarily underpinned by the cost the Company incurs to provide service. The Test Year results demonstrate that the Company's rates will not be sufficient to cover the Company's Test Year cost of providing service. I&M requests that the Commission approve a total annual increase in revenues of approximately $104 million, or 6.5%. Commission approval of the proposed package of base rates and rate adjustment mechanisms is reasonable and necessary to allow the Company to continue to meet customers' needs for service. The Company proposes to phase-in the increase over two steps. The initial step will reflect an increase of $73 million, or 4.55%; the second step will reflect an increase of $31 million, or approximately 2% as adjusted for actual Test Year investments.

The Rockport Unit 2 Lease ends in December 2022, the last month of the Test Year. The Company proposes to recognize the annual Lease payment savings as a reduction to cost of service in I&M's Resource Adequacy Rider (RAR) filings. Reflecting these cost savings in the RAR will significantly offset the impact of the proposed rate increase on customers.

Mr. Thomas explains that the rate adjustment mechanisms included in the Company's filing are an important tool in the Company's effort to timely reflect variable costs and savings in I&M's rates for electric service while providing reliable service to its customers.

The Cook Life Cycle Management (LCM) Project is nearly complete. The Company proposes to wind down the LCM Rider in an efficient manner. The PJM Rider remains important, reasonable and necessary due to the grid investment needs and associated cost of transmission service within PJM.

Mr. Thomas discusses the need to replace aging infrastructure and strengthen the grid. The Company's filing includes an average annual capital expenditure of $539.9 million during the Capital Forecast Period (January 2021 – December 2022). Mr. Thomas generally describes the Company's integrated investment plans to continue to modernize its systems, including information technology and distribution systems, to enhance reliability, to deploy grid technologies, such as Advanced Metering Infrastructure (AMI), to maintain safe and reliable generation resources, and to take advantage of new technologies to efficiently manage its business and improve the customer experience. Customers will benefit from this investment through improved system reliability and improved tools to manage energy usage and cost.

To improve the reliability of the system, I&M is continuing its strategic approach to asset renewal, which is necessary to maintain a safe and reliable system. I&M is also continuing the vegetation management program that protects its facilities and promotes reliable service, while considering the interests of property owners. The efforts I&M has made over the past five years have produced improvements in I&M's reliability metrics that show customers are benefiting from its strategic initiatives.

AMI is an essential and integral element of the Company's grid modernization strategy, as it provides wide ranging operational and customer benefits, allows the Company to meet the ongoing need for service and facilities, and builds the foundation for ongoing technological advancement, personalized customer experience and evolving customer service needs.

The AMI Project that is part of I&M's integrated distribution strategy is scheduled to occur over four years (2021 through 2024) and is estimated to have a cumulative capital cost of approximately $121 million. The age of the existing meters, Company experience and knowledge of AMI, and a cost-benefit analysis prepared by Accenture (Accenture CBA) give I&M confidence that investing in AMI technology can provide many benefits to the distribution system and I&M's customers. The Accenture CBA shows the 45-month deployment scenario is reasonable and financially justified. The Company proposes to include the AMI Project capital cost contained in the 2021–2022 Capital Forecast Period in base rates and address the ongoing investment, as well as operational cost savings identified in the Accenture CBA through the proposed AMI Rider so that this benefit also flows through to customers as AMI is deployed.

Together with Company witness Bulkley, Mr. Thomas also supports the Company's requested authorized return on equity (ROE) of 10.00 percent in conjunction with Commission approval of the rate relief package proposed by the Company in this Cause. The Company's requested ROE and associated rate relief support the Company's ongoing ability to secure access to comparatively low cost capital to fund its operations, which is heavily dependent on regulatory support that authorizes rate increases in a timely manner, manages known risks, provides predictability and fairly compensates equity investors.

To provide context, the testimony provides an overview of I&M's service area and organizational structure and the Company's relationship with AEP. Mr. Thomas also discusses ongoing challenges faced by the Company with respect to the provision of adequate and reliable retail electric service and facilities.

Key challenges facing I&M include how to continue to provide reliable electric service at a comparatively low price when costs are rising, environmental regulation is changing and, customer needs and technology are evolving. Because many electronic devices and equipment used by I&M's customers today are less tolerant of even minor service interruptions, continued diligence with respect to service reliability remains important. I&M also continues to recognize developing environmental concerns, including those addressed to the issues surrounding climate change and customer interest in renewable energy resources.

Company witness Fischer presents the Company's proposed rate design for residential service, including the proposal to increase the residential monthly service charge from $15.00 to $20.00. Importantly, it should be recognized that the percentage increase in the service charge relates only to one component of the customer's entire bill and should not be confused as equating to an overall increase in the entire bill. As previously recognized by the Commission, gradualism is best considered in the context of the entire customer bill and not discrete charges within the bill. While proposals to change the residential rate design have been controversial in past cases, it is important to continue to make progress on properly designing rates that align cost recovery with cost causation principles. Doing so sends efficient price signals to customers so as to allow them to make informed decisions regarding their consumption of the service being provided.

This testimony also discusses I&M's efforts to control costs for the benefit of customers. I&M's commitment to and success with operating cost control is demonstrated by the year-over-year operating cost comparisons in Company witness Lucas' testimony.

I&M recognizes that it is difficult for some customers to pay their electric bills, and continues to offer payment assistance programs ranging from agreements to extend a bill payment a few days to longer monthly payment programs. The deployment of AMI will give customers better insight into their energy usage. This in turn will allow informed decisions and opportunities for customers to reduce their electric bill by changing their use of electricity. Company witness Lucas discusses the proposed I&M Flex Pay Program and the diversified suite of optional rates and load management programs included in the Company's filing to allow customers to utilize AMI technology and benefit through reduced energy and load requirements.

In sum, the electric business continues to change as a result of environmental regulation, economic conditions, evolving technology and changes in the way customers use electricity and want to be served. I&M's goal is to invest wisely, operate its business efficiently, and provide a customer experience that serves customers the way they want to be served. Rate relief is necessary and appropriate to support I&M's ongoing effort to address aging infrastructure, secure long-term reliability and resiliency, enhance the service it provides through new technology and automation, and otherwise meet the ongoing energy and capacity needs of I&M's customers. The proposals I&M makes in this case allow the Company to continue to embrace technology advancements and use them for the benefit of customers.

I&M asks the Commission to find that I&M's proposal is a balanced and rational solution to the Company's need for both cost recovery and a reasonable opportunity to earn a reasonable return, while I&M continues to fulfill its duty to provide reliable electric service and facilities to customers.

2. Dona Seger-Lawson, I&M Director of Regulatory Services. This testimony supports the overall request for rate relief, the use of a forecasted test year and Phase-In Rate Adjustment in accordance with Commission directives and past practices. The testimony addresses certain Test Year adjustments; rate recovery and continued deferral of certain costs; implementation of an AMI Rider; and implementation of the Tax Rider authorized in Cause No. 45235.

I&M proposes the Commission authorize recovery of I&M's cost to serve customers using the forward-looking calendar year test year of January 1, 2022 through December 31, 2022 (Test Year). This cost recovery will be implemented through a combination of base rates and rate adjustment mechanisms. I&M's overall requested rate relief for the Test Year is approximately $104 million, or approximately 6.5%.

I&M proposes to implement the requested rate increase in two steps through the Phase-In Rate Adjustment (PRA) process used in I&M's last two rate cases. In Phase I, revenue would increase by approximately $73 million or 4.55%. The overall increase identified above would be implemented in Phase II, which would commence in January 2023.

I&M's Financial Exhibit A shows the calculation of the revenue increase. In accordance with GAO-2013-5 and 2020-5 and the Minimum Standard Filing Requirements (MSFR), the Company has presented substantial support for the revenue increase and related relief. This support includes historical data using a 2020 calendar year historical base period.

Many of the Company's proposals reflect a continuation of existing rate structures and processes. For example, I&M proposes to implement the rate increase in phases consistent with the PRA used to implement rates resulting from our last two general rate cases. The Company also proposes to continue both the Major Storm Restoration Reserve and the Dry Cask Storage deferral. Similarly, I&M proposes to retain all existing rate adjustment mechanisms (i.e., riders) with certain modifications and to implement two additional mechanisms -- the Advanced Metering Infrastructure (AMI) Rider and the Tax Rider.

For purposes of this rate case, most deferred balances (including rate case expense and nuclear decommissioning study expense) are amortized over a period of two years as this period represents the most likely period between re-setting base rates in this case. Other previously-approved deferrals are proposed to be reflected in rate base and through amortization expense consistent with the Commission's prior orders regarding those deferrals.

One of the key components of this case is to support significant investment that I&M is making to its distribution system in the form of AMI and associated systems to use the AMI data to bring customer programs and information to our customers. The AMI project lays the foundation for substantial customer and system benefits as discussed by Company witnesses Thomas, Isaacson, Walter, and Lucas. The new AMI Rider provides the regulatory support necessary for this significant capital investment, program costs, and related O&M savings.

I&M also proposes to implement the Tax Rider approved in Cause No. 45235 to track ongoing impacts of the 2017 Tax Cuts and Jobs Act and the potential impacts of future changes to the corporate federal income tax rate.
Ms. Seger-Lawson explains that moving the Utility Receipts Tax (URT) to be a separate line item does not change the overall revenue requirement or customer bills, but would introduce a number of complications to I&M's accounting and billing processes. Accordingly, I&M recommends the URT continue to be reflected in base rates, rather than as a separate line item on customer bills.

In this proceeding, I&M is requesting Commission authority to more broadly implement remote disconnect as well as remote reconnect processes. Using AMI meters and back office infrastructure, I&M will be able to disconnect and reconnect customers that have AMI meters installed and are coded in I&M's system as being eligible for remote disconnect/reconnect. The Company also proposes to implement FlexPay, which is a voluntary program allowing residential customers to prepay for electric service and thereby manage their electricity based on their own personal budget. If the FlexPay program is approved, I&M will be sending periodic electronic notifications to the customer about the amount of their account balance that remains. Therefore, requirements that the utility send a bill that contains certain billing line items, including late payment charges, due date of the bill, and the 17-day grace period for payments will be unnecessary. Ms. Seger-Lawson explains that it is reasonable and appropriate for the Commission to waive certain rules to enable I&M to implement both remote disconnect/reconnect and the FlexPay program.

In this case, the Company also proposes to reflect changes that are occurring during and just after the Test Year with the ending of the Rockport Unit 2 Lease. Ms. Seger-Lawson explains that the Company plans to update certain riders to reflect changes in costs that are in base rates.

Commission approval of the Company's proposed revenue increase through the package of base rates and riders presented in the Company's filing is necessary to ensure I&M is provided a reasonable opportunity to recover its cost to serve customers, including a fair return on its underlying investments used to serve customers.
The regulatory support sought by the Company is important to the ongoing provision of retail electric service. The Test Year commences January 1, 2022. I&M asks the Commission to issue an order within 300 days of the date of filing (July 1) in accordance with Indiana Code 8-1-2-42.7 and GAO 2013-5.

3. David A. Lucas, I&M Vice President – Regulatory and Finance. This testimony explains the forecast approach and methods used to develop the operation and maintenance (O&M) expenses and capital expenditures included in this proceeding; supports the customer engagement plan and customer programs related to the Advanced Metering Infrastructure (AMI) deployment; and addresses related matters.

A forecast takes the assumptions developed from the Company's management experience, knowledge and judgment and uses those to develop the work plans that become the basis for I&M's forecast. The O&M and capital forecasts prepared by each business unit are based on work plans that use business objectives to prioritize work activities. In addition to the functional business unit forecasts, I&M also incorporates the capital and O&M budgets and long range forecasts from AEP Service Corporation for corporate services including, but not limited to, IT and shared services. I&M management works across the business units to evaluate the drivers behind the components of the work plan to ensure capital and O&M are prioritized, allocated properly, and are within available capital and O&M guardrails.

It is important in this proceeding to recognize that the Historical Period is a highly unusual year given the COVID-19 impacts. The primary impacts of COVID-19 on the Company's capital and O&M expenses are in the 2020 Historical Period. In order to mitigate the financial impacts of COVID-19, the Company acted in 2020 to safeguard financial health. These actions, such as reductions in expenses and deferral of capital projects, were taken in concert with efforts the Company took to work with customers who were impacted by COVID-19. The prudent management decisions made by the Company during the Historical Period are not sustainable to maintain the safe and reliable operations of the Company. The Company's support for Test Year Capital and O&M expenses includes multiple years of actual costs to provide a more representative comparative basis.

I&M has successfully managed its O&M and capital investment expenditures and will continue to do so in a manner that prudently serves its customers. Test Year O&M levels are justified by the projected needs of the utility and are not excessive. I&M has maintained O&M expenses with minimal or no increase over the past several years while at the same time absorbing inflationary impacts. I&M's cost projections hold business unit O&M expenses essentially flat, as compared to the Historical Year, unadjusted for inflation. This is particularly noteworthy given that the baseline Historical Year reflects the temporary cost-cutting measures taken in reaction to the business effects of COVID.

Specifically, I&M's projected O&M expenses for Steam Generation, Nuclear Generation, Hydro Generation, Other Generation, Distribution, Customer and Information, Sales, and Administrative and General reflect a 1.2% increase from 2020 actuals and a 0.1% increase on average compared to the previous five (5) years of actual expenses. Transmission O&M expenses are expected to increase 16% from 2020 levels driven by increases in costs that are largely outside the control of the Company, such as PJM NITS and Enhancements. The Test Year level of Distribution O&M expenses reflects a compound annual growth in Distribution of O&M expenses of 0.9% on average for the last five calendar years, without any inflationary adjustments to historical costs.

I&M's capital investment continues to be focused on infrastructure improvements, integrating new technology, improving the customer experience, and environmental and regulatory compliance. I&M's projected investments over the Capital Forecast Period demonstrate the careful manner in which the Company deploys capital. The average annual capital expenditures in 2021 – 2022 is forecast to be $539.9 million, compared to $566.3 million in the previous five (5) years of actual expenses. The Project Life File included with Mr. Lucas' workpapers contains a list of all capital projects; capital expenditures by month during the Capital Forecast Period; and plant in-service information. All information is broken down by function (Distribution, Generation, Nuclear, Transmission, and Corporate).

More specifically, capital investment in generation is projected to be significantly lower than the previous five (5) years of actuals, in light of the end of major projects at those sites. Transmission capital investment will remain essentially flat, while capital projects in Distribution reflect an increase, primarily driven by AMI and Grid Modernization investments to improve reliability and the customer experience. Information Technology (IT) capital investment is also forecast to increase primarily driven by investments in cybersecurity and modernizing critical systems. Considering inflationary factors and the capital programs taking place during the Capital Forecast Period, the overall amount is reasonable.

A significant benefit associated with the deployment of AMI technology is the opportunity for customers to have access to better information to make informed decisions about their energy consumption. As a result, I&M will be engaging in customer education and initiating the use of customer engagement platforms that allow residential and commercial customers to access information on their home or business energy usage, energy costs, and energy savings tips. The costs associated with these activities are included in I&M's forecast.

Additionally, I&M is proposing certain voluntary tariff changes and programs to allow customers to take full advantage of AMI and better manage energy usage and costs for their own benefit, and ultimately, the benefit of all I&M customers. These activities are supported by the AMI Cost Benefit Analysis performed by Accenture and presented by Witness Bech.

The Flex Pay program is a voluntary payment option that allows residential customers to prepay for their electric service without incurring the cost of a deposit or other fees associated with the current post-pay billing. The program provides I&M's customers with more choices regarding when and how to pay for electric service. Offering customers additional voluntary payment options allows them to decide which payment options and schedules best meet their individual needs. Customers may choose to make smaller, more frequent payments that may be more in-line with their cash flows, rather than a larger, single monthly payment. Not only does a prepay program help customers avoid larger than expected bills, it also provides customers more flexibility in many situations. Additionally, Flex Pay enables participants to gain a better understanding of how much their electricity usage actually costs, making them more aware of how long their dollars last, and are able to better manage energy consumption.

Each of the proposed programs are reasonable and necessary, and will provide substantial benefits to I&M customers.

The proposed revenue requirement (Adjustment O&M-11) includes AMI related operational savings and increases the O&M expense related to AMI programs that were not included in the Company's forecast. The O&M savings are associated with remote disconnection/ reconnection, reduction in bad debt expense, reduction in tamper and theft costs, and reduction in costs associated with reduced unauthorized energy use. This adjustment provides these savings as a credit assuming the AMI implementation and customer programs as proposed by the Company in this case are approved. The cost savings are included in the Cost Benefit Analysis supported by Company witness Bech. The O&M costs included in this adjustment are associated with AMI related program administration costs the Company plans to implement upon approval by the Commission and are necessary to realize the benefits of the AMI program.

Overall, the levels of expense and investment included in the forecast, combined with the adjustments proposed in this case, are reasonable and necessary in the provision of service to I&M's customers and are justified by I&M's projected needs.

4. David S. Isaacson, I&M Vice President of Distribution Operations. This testimony provides an overview of I&M's distribution system and supports the Company's distribution planning and expenditures. Mr. Isaacson discusses the condition of I&M's distribution system and the metrics the Company uses to measure the reliability of its distribution system. He presents the Company's Distribution Management Plan (Plan), a comprehensive, forward-looking capital and operations plan under which the Company continues to make significant investments to maintain and improve the reliability of its distribution system, to enhance safety, and to leverage technology to benefit the grid. He addresses I&M's advanced meter infrastructure (AMI) and Conservation Voltage Reduction (CVR) deployment. The testimony and attachments include a considerable amount of support and documentation for the forecast expenditures in I&M's Distribution Management Plan.

I&M Distribution Operations has experienced improvement in reliability performance, consistent safe operations, and control of its operating costs. This includes improvements in the key areas of historical performance issues, including vegetation, failed equipment, and station/transmission lines. Although the total number of events and the inconvenience caused by these incidents has declined over the past two years, I&M remains committed to maintaining and further improving customer experience.

The primary basis for many of the projects planned for 2021 and 2022 is improving reliability and sustaining a good overall system performance, which requires ongoing, active engagement and investment. I&M cannot pause in these activities for the simple facts that trees continue to grow, assets continue to age and customers continue to expect reliable service.

I&M's Distribution Management Plan defines and itemizes a portfolio of programs and projects that ensure the system operates in a safe manner, provides for continuous improvement in reliability, and enhances customers' experience.

Vegetation management remains the most impactful investment I&M can make to improve overall reliability. As discussed in Cause Nos. 44967 and 45235, I&M's vegetation management program involves moving from a reactive approach to managing vegetation to a systematic, cycle-based approach. I&M is on schedule to complete the initial four-year program by the end of 2021. I&M will begin its second four-year vegetation management cycle in 2022. During the first three years of this initial four-year cycle-based program, I&M's vegetation caused SAIDI has favorably declined by nearly 30% (from the end of 2017 to the beginning of 2021). Continuation of this program, starting with the next four-year rotation period in 2022, is equally as important to further improve reliability and avoid returning to a system plagued by controllable vegetation-caused service interruptions.

I&M's asset renewal projects replace aged infrastructure with the purpose of ensuring the distribution system remains reliable and safe. These projects include: Overhead Line Rebuild Projects, Pole Replacement/Reinforcement Projects, Underground Residential Distribution (URD) Cable and Live-Front Transformer Replacement Projects, Underground Station Exit Cable Replacement Projects and Underground (UG) Network Rebuild Projects.

Although age is not the only factor for failure, assets that are approaching or exceeding the end of design life are much more likely to fail. These concerns are compounded when multiple assets begin to reach the end of their design life in the same general time span, creating a compounding effect on the number of outages and the length of time it takes to restore service after an outage. In addition, older assets tend to be harder to recover or replace after a failure, because it is often difficult to obtain available parts for aging equipment. Without these planned projects, I&M would experience more asset failures and the quality of service to customers would unnecessarily suffer.

Each year, I&M also completes distribution projects termed "Combined Projects", which are a collection of projects that vary in size. Completing the Combined Projects helps improve the reliability of the system, improve the ability to serve increased load, promotes safety and enhances the technological capabilities of I&M's system by replacing or upgrading aging or obsolete station equipment.

I&M has also developed the following risk mitigation programs to identify and remediate assets that may pose a potential reliability and/or safety risk to the public or employees: Underground locates; Pole inspections; Underground Residential Distribution (URD) equipment inspections; Overhead line inspections; and Contact voltage inspections.

I&M's grid modernization projects are designed to leverage technology for the purpose of improving system resiliency and functionality. In addition to allowing I&M to respond quicker once an event occurs, some of these technologies enhance how the Company can detect potential safety risks. The grid modernization projects include: Advanced Metering Infrastructure (AMI); Conservation Voltage Reduction (CVR); Distribution Automation Circuit Reconfiguration (DACR); Supervisory Control and Data Acquisition (SCADA); Distribution Line Sensors; Smart Reclosers; and Smart Circuit Ties. The majority of I&M's grid modernization projects improve resiliency of the system by providing real time information of event occurrences, allowing I&M to provide a more rapid response. Additionally, these projects enhance grid safety and operation through early detection of potential component failures. This technology will better positon the system to incorporate emerging technologies and concepts, such as energy storage and microgrids.

Due to the progressing obsolescence of AMR technology, I&M has determined that new meter installations and replacement should be AMI meters. Therefore, I&M is building out the communications backbone across I&M in 2021, which allows AMI to be used for any new meters installed. The move from AMR to AMI meters provides significant improvements in customer service, as well as additional operational benefits, including improved reliability, improved public and employee safety, mitigation of tampering and theft, improved meter accuracy, remote reconnection, and real-time loading and voltage level monitoring. These benefits, combined with the general obsolescence of the Company's current AMR metering system, demonstrate that the Company's investment in AMI technology is necessary to continue to provide safe and reliable service to its customers. The Company's proposed AMI deployment plan minimizes costs and maximizes benefits for customers by utilizing a systematic, proactive approach.

Conservation Voltage Reduction (CVR) is a grid modernization technology that allows the voltage on specific circuits to be reduced, thereby optimizing the efficiency of the delivery voltage and saving a marginal amount of capacity. When taken collectively, across a number of circuits, it can provide a cumulative amount of capacity savings, resulting in a reduced cost of service to customers. AMI offers the Company the ability to actively monitor, in real-time, the service delivery voltage to the customers' premises and this, in turn, enables additional CVR circuits and the corresponding energy and capacity savings.

The Company's proposed Distribution Management Plan, including AMI, and CVR deployment, represents prudent investment necessary to allow the Company to continue to provide safe, reliable and resilient service to its customers.

Major areas of distribution O&M expense are: ongoing O&M, Vegetation Management O&M and Major Storm O&M. The Test Year level of O&M expense is reasonable and representative of distribution service activities that are necessary to serve I&M's customer base and maintain the reliability of I&M's distribution system.

The Major Storm Reserve helps I&M maintain the reliability of its distribution system. Use of a reserve allows I&M to recover the true costs of a major storm without the need to use other funds already allocated to other necessary distribution O&M activities, such as reliability-related activities. Also, the Major Storm Reserve ensures that I&M customers pay rates that reflect the true costs of a major storm – no more and no less.

5. Quinton Shane Lies, I&M Site Vice President at Donald. C. Cook Nuclear Plant (Cook). This testimony provides an overview of I&M's nuclear generating asset, the Cook Plant. The Cook Plant is a two-unit nuclear power plant located along the eastern shore of Lake Michigan in Bridgman, Michigan. Unit 1 is currently licensed to operate until 2034, and Unit 2 until 2037.

The testimony supports Cook's operation and maintenance (O&M) expenses during the Test Year and the historical period. The testimony also supports the projected capital expenditures at Cook and provides an overview of the status of Cook's Life Cycle Management Project.

The Cook Nuclear power plant provides safe, low-cost, and carbon-free generation to I&M's customers while maintaining the highest standards of regulatory compliance. The station continues to receive the highest industry performance rating for nuclear power plants and it also remains in the highest achievable performance category of the NRC's Revised Reactor Oversight Process. These performance levels are being sustained due, in large part, to the type of expenditures supported in this testimony.

I&M has a long history of operating the Cook Plant, thereby allowing I&M to understand the ongoing O&M needs. I&M employs a rigorous process to identify projects that are necessary to meet regulatory requirements and support continued safe and reliable operations. The O&M and capital project costs discussed in the testimony are the result of that process, and are reasonable and necessary for the continued operation of the Cook Nuclear power plant for the benefit of I&M's customers.

O&M expenses include base operating expenditures and non-outage equipment reliability expenditures. Included in the base operating expenditures are refueling outage amortizations, which can have a significant impact on O&M expenditures in any given year depending on the refueling outage cycle. Operating and maintaining the Cook Plant involves managing technically complex systems and components. Practically all of Cook's O&M activities are subject to comprehensive regulation and continuous inspection by the NRC.

The projected Cook O&M expense for the Test Year is $243.1 million. The Cook O&M expense for the historical period was $240.3 million.

The Test Year O&M expenses represent a reasonable level going forward. These O&M expenses have been scrutinized at the plant, operating company, and corporate levels, and are representative of the necessary Cook Plant O&M expenses.

Capital expenditures can be categorized into four types: Life Cycle Management (LCM), Major Projects, Regulatory Compliance and Other. I&M forecasts $217 million of capital investment related to Cook to be placed in service in 2021 and 2022. Similar to O&M expenses, proposed capital expenditures undergo an extensive development and refinement process. If and when capital investments are made is based on a combination of factors, including whether the investment is needed to fulfill regulatory or safety requirements, the urgency of the need, and economic benefit. All of these factors are evaluated by the management teams responsible for approving capital projects. All of these projects are necessary for the facility to operate to the end of its approved license. The level of capital investment to be made during the Capital Forecast Period represents a reasonable level of spending needed to ensure the safe and reliable operation of the Cook Plant which in turn provides low cost, safe, environmentally compliant, reliable electric generation for I&M's customers.

The LCM Project is a comprehensive effort that identified and undertook Cook Plant capital investments needed to ensure the units operate through the end of their license extensions. Cook is on track to complete the overall LCM Project on budget, with all projects installed by the end of 2022. I&M remains confident the LCM Project will be completed at or below the approved project cost estimate of $1.145 billion. Company witness Auer explains the Company's proposal to sunset the LCM Rider given the anticipated completion of the project.

I&M has a settlement agreement with the United States Department of Energy (DOE) as a mechanism for submitting and recovering costs associated with Dry Cask Storage.

In approximately 2012, the current Work and Asset Management (WAM) software program vendor (ABB) notified its users that it would no longer support their current software platform. With this notification, AEP completed a comprehensive evaluation of its options and ultimately determined that the Maximo WAM software to Maximo, an IBM product, was the best choice. Maximo is highly scalable, supports a broad range of functionality, and has been successfully deployed and used at several other large US utilities. AEP transitioned other business units to Maximo in 2020 and Cook will complete the transition in 2021.

6. Timothy C. Kerns, I&M Vice President – Generating Assets. This testimony describes I&M's non-nuclear generating fleet, which is comprised of fossil fueled and hydro assets, as well as I&M's universal solar generating assets. I&M's hydro, fossil, and solar generating fleet are well-maintained, in good condition, and necessary to provide electric service to I&M's customers.

The testimony also supports historical and forecasted O&M expenses and capital investments for I&M's generating fleet. Non-fuel generation O&M expense includes costs associated with the operation, maintenance, administration, and support of I&M's generating units. I&M's total forecast Test Year O&M expense for its generating fleet is slightly less than its total Historical Period O&M expense, reflecting I&M's continuous focus on keeping O&M costs low while maintaining the safe and reliable operation of its generating units. These generation O&M expenses have been scrutinized at the plant, operating company, and corporate levels, and are representative of the level of O&M expense necessary to continue providing on-going safe, reliable, efficient, and environmentally compliant electric generation to I&M's customers.

Three consumables (sodium bicarbonate, activated carbon, and anhydrous ammonia) are included in the Test Year Fossil (Steam) Generation O&M expense. It is important to recognize that consumable costs vary in the same way that fuel costs vary with respect to generation levels. The Company utilizes a competitive Request for Proposal (RFP) process to procure consumables, which helps ensure the best available market pricing. Because the RFP prices are market driven, the Company does not have full control to maintain a steady procurement price.

The components of I&M's generating fleet deteriorate, fail, or become obsolete over time and must be replaced to maintain safe, reliable, efficient, and environmentally compliant service. Environmental compliance is a key performance driver in the Capital Forecast Period. Additionally, capital investment must be made in response to evolving environmental regulatory requirements. The Capital Forecast Period capital expenditures are reasonable and necessary for I&M to continue to operate its generating units in a safe, reliable, efficient, environmentally compliant manner for the benefit of its customers.

I&M 2021-2022 Total Capital Expenditures (excluding AFUDC) for Coal Combustion Residual Rules (CCR) compliance projects are approximately $2.760 million. I&M's Capital Forecast for 2021-2022 also includes approximately $20.007 million (Total Capital Expenditures (excluding AFUDC)) for Steam Electric Effluent Limitations Guidelines (ELG) Environmental Compliance; however, this investment would be avoided if the plant is retired by 2028.

Approximately $83.6 million of generation capital (including AFUDC) is forecasted to be placed in service during the Capital Forecast Period. The testimony identifies the in-service generation projects with capital expenditures greater than $1 million during the Capital Forecast Period and discusses capital expenditures associated with smaller projects (Other Capital Investment). Each project is summarized in a Project Life File (Capital Forecast by Project), included as WP-DAL-2 to Company witness Lucas' testimony. The projects in the Other Capital Investment category represent the type of continuous investment that is necessary to maintain the availability and reliability of the generating units.

Finally, this testimony presents the projected fuel inventories and shows I&M has and continues to prudently manage its fuel supplies in a manner to reduce overall fuel costs, manage its inventory positon, and monitor conditions in the fuel market.

7. Nicolas C. Koehler, Director of East Transmission Planning, American Electric Power Service Corporation. This testimony describes the transmission system that is necessary for I&M to provide retail service and supports the recovery of transmission costs charged to I&M as a result of its membership in the PJM Interconnection LLC (PJM) regional transmission organization (RTO). In particular, I&M incurs charges under the PJM tariffs approved by the Federal Energy Regulatory Commission (FERC), including the PJM Open Access Transmission Tariff (PJM OATT). This testimony supports the nature and reasonableness of those costs. The recovery of these costs via the Off System Sales Margin Sharing/PJM Cost Rider (OSS/PJM Rider) is addressed by Company Witness Seger-Lawson.

Recent transmission investment at AEP and across the industry is directed toward addressing aging grid infrastructure, maintaining and improving reliability and resilience, and protecting the grid from physical and cyber threats. Such investment needs continue, as do associated costs. As a Load Serving Entity within PJM, I&M incurs costs to use the transmission system supported by such investments, irrespective of whether it owns the facilities that are being used.

I&M's PJM costs, including the Network Integrated Transmission System (NITS) costs that make up the bulk of its PJM costs, are reasonable and necessary to provide reliable electric service to I&M's customers. NITS charges represent the cost for I&M and other PJM network customers to integrate, economically dispatch, and regulate their current and planned network resources to service their network load. I&M's PJM costs are supported by robust PJM vetting processes for Baseline Upgrades and Network Upgrades, and detailed protocols for consideration of AEP Owner Projects that assure only projects that are needed in each transmission owner's service territory are pursued. Further, Owner Projects are subject to a transparent stakeholder process to ensure that Owner Projects are appropriate, efficient, and cost-effective solutions for customers.

Although I&M commits significant resources to reduce safety risks, maintain transmission assets consistent with industry practices, and plan capital investment to increase reliability performance, many of the drivers of Owner Projects are outside of I&M's control and include regulatory requirements, interconnection requests, asset performance, and the need for modernization of protection and control systems. Transmission Owners also do not have discretion to decline to make reasonable and necessary investments in the transmission grid. Rather these investments must be made to fulfill I&M's obligation to operate pursuant to Good Utility Practice and to serve customers. Each Transmission Owner in the AEP Zone, including I&M affiliates, has an obligation to ensure capital investments are prudent and necessary to maintain a reliable transmission grid.

As provided by Company witness Heimberger, PJM NITS charges are forecasted to be approximately $337.7 million (Total Company) for the Test Year. In addition, I&M is forecasted to incur approximately $35.0 million (Total Company) in non-NITS costs in the Test Year.

The increase in the Company's PJM costs is primarily driven by PJM NITS costs. The forecasted increase in NITS charges is being driven by necessary investment in transmission infrastructure, both within I&M's service territory and throughout the remainder of the AEP Zone. Similar to the national trend, I&M expects robust levels of investment will continue beyond the Test Year.

NITS costs are billed to I&M consistent with the FERC-approved PJM OATT and AEP Transmission Agreement. I&M recovers NITS costs through the OSS/PJM Rider (discussed by Company witness Seger-Lawson). Both NITS and Non-NITS costs are significant. These costs flow to I&M through the PJM tariffs and are potentially variable or volatile.

NITS costs are a necessary cost to maintain the reliability of the transmission grid and ensure equal access by all users of the transmission system.
NITS costs are variable and volatile and subject to significant changes due to the transmission system requiring substantial investment to address (a) the condition of the assets, which includes many assets that exceed their expected or designed life; (b) the performance of the infrastructure; (c) cyber and physical security threats; (d) modernization of protection and control equipment; (e) obsoleteness of major equipment necessary for safely, securely, efficiently, and reliably operating the grid; and (f) changes in industry regulations. During any given period, these costs are subject to potentially significant changes due to market and economic conditions, public policy, North American Electric Reliability Corporation (NERC), Federal Energy Regulatory Commission (FERC),

environmental, and state regulatory requirements and other factors that can be unpredictable. Baseline projects are included in the NITS rate if they are 100 percent allocated to the AEP Zone, which further contributes to the volatility of NITS costs. The costs recovered through the PJM Cost Rider are also largely outside of I&M's control and are driven by external factors. Each of the drivers of cost increases is largely or entirely outside the control of I&M and other transmission owners. Each transmission owner in the AEP Zone has an obligation to ensure capital investments are prudent and necessary to maintain the reliability of the transmission grid.

8. Nancy A. Heimberger, American Electric Power Service Corporation, Financial Analyst Senior Staff in Corporate Planning and Budgeting. This testimony presents I&M's 2022 Test Year financial forecast, which is unadjusted, and discusses the forecast process, which is the same as the process used in I&M's last basic rate case, Cause No. 45235. I&M's Test Year financial forecast is the result of a thorough forecasting process which supports each element presented in the jurisdictional cost of service.

I&M utilizes a financial modeling program designed specifically for investor-owned utilities by Utilities International (UI) to prepare the Total Company, integrated financial forecast. This model integrates I&M's work plans with a number of other forecast inputs to generate a financial forecast. The financial forecast is necessarily informed by a number of subject matter experts that are also being presented by the Company. The forecast accurately reflects the data and inputs provided at the time it was developed, is reasonable, and is representative of I&M's going forward cost of providing service.

Ms. Heimberger also supports several adjustments to the Test Year cost of service and the Fuel Adjustment Clause (FAC) basing point.

9. Andrew J. Williamson, I&M Director of Regulatory Services. This testimony addresses I&M's recovery of PJM Capacity Performance Insurance; I&M's recovery of its Test Year generating plant without adjustment, through the jurisdictional allocation factors prepared by Company witness Duncan; and the appropriate treatment of Rockport Unit 2-related matters as a result of termination of the Rockport Unit 2 Lease in December 2022.

The Company's ongoing participation in a group insurance policy to cover PJM Capacity Performance risks is reasonable and necessary. Capacity Performance insurance allows I&M to reasonably mitigate a large portion of the significant financial risk that a generating unit(s) would underperform or not be available during a Performance Assessment Interval (PAI), which events are determined by PJM and are not within the control of the Company. The group insurance policy, which allows I&M to manage cost, was selected from options solicited through a competitive procurement process. The related expense should continue to be included in cost of service.

There is no basis for the continued disallowance of a portion of I&M's generation resources. The timing considerations that were the foundation for the Commission's disallowance in Cause No. 45235 will become moot before the end of the Test Year, at which time I&M's Lease of Rockport Unit 2 will end and I&M will not have sufficient generating capacity to meet its load obligations. The procurement of other generating capacity to meet I&M's customers' ongoing capacity needs will be the subject of other causes.

I&M plans and operates its capacity resources as a single integrated system for the benefit of all customers. This is evidenced by I&M's Integrated Resource Plans, how capacity is submitted to PJM to meet load obligations and historical cost of service calculations.

During the construction of Cook Units 1 and 2 and Rockport Units 1 and 2, I&M was a party to the AEP-East Interconnection Agreement, which created the AEP-East Pool. This agreement was first approved by the Federal Power Commission, the predecessor to FERC. The generating facilities of the Pool members were planned, designed, built (or purchased), and operated on an integrated system basis to meet the needs of all of the AEP-East operating companies. Given the integrated nature of the AEP-East Pool and the dispatch of its resources, the addition of an individual I&M customer, whether retail or wholesale, would not have driven a decision to add generation.

This construct provided significant benefits to I&M's retail customers, much in the same way that RTOs benefit customers today. For example, capacity equalization revenues and primary energy payments from sales of capacity and energy length in the AEP-East Pool were used to reduce retail customer rates or delay rate increases. This approach preserved I&M's integrated generation capacity for the benefit of Indiana retail electric service as the retail load changed from year to year. In addition, retail customers benefited significantly over many years from the allocation of generation costs to wholesale customers who have a choice whether to purchase generation from I&M.

The Company's generating capacity has and continues to be actually devoted to providing utility service. The facilities are reasonably necessary to the efficient and reliable provision of retail electric utility service.

I&M's proposed base rates include all of the Rockport Unit 2 costs and capital investments that are forecasted during the term of the lease. This is consistent with past forecasted rate case filings.

I&M proposes to use the Resource Adequacy Rider (RAR) to reflect the net reduction in I&M's cost of service associated with the Rockport Unit 2 Lease expiration in December 2022. The use of the RAR will allow customers to realize the overall cost reductions in a timely fashion. Other changes in operating costs such as fuel expense, consumables expense, purchase power expense and off-systems sales will naturally be captured by other existing rider mechanisms, namely the fuel cost adjustment (FAC), Environmental Cost Rider (ECR), RAR and OSS/PJM Rider.

The remaining net book value (NBV) associated with Unit 2 investments made by I&M during the term of the Lease will, upon expiration of the Lease, be in net plant in-service and therefore rate base at the end of the Test Year. The remaining NBV is primarily related to environmental control equipment approved in Cause No. 44331 Rockport Dry Sorbent Injection (DSI) and Cause No. 44871 Rockport Unit 2 Selective Catalytic Reduction (SCR). I&M is proposing the remaining NBV of Unit 2 be recovered over the remaining life of the Rockport plant as a whole (i.e., Rockport Unit 1 and plant common to both units), which is estimated to reach end of life in 2028 for depreciation rate purposes. This treatment recognizes the Unit 2 investments made in accordance with the terms of the Lease were reasonable and necessary in the provision to service to customers and allows I&M to mitigate the impact on customers by extending the recovery beyond the period currently used for Rockport Unit 2 depreciation rates.

Finally, as described in Cause No. 45546, costs associated with potential ownership of Rockport Unit 2 will be addressed in a later IURC filing addressing the associated cost recovery and retail ratemaking.

10. Brent E. Auer, I&M Regulatory Analysis & Case Manager: I&M proposes to maintain its previously approved cost recovery riders, which have been an efficient way to ensure transparent tracking of costs for significant projects and programs.

Calculating Test Year revenue requirements for I&M's riders is necessary in order to accurately forecast I&M's Test Year operating revenue. I&M calculated the revenues the respective riders would be expected to collect during 2022 absent any changes to base rates or riders as a result of this filing. I&M also calculated the revenues the Company is proposing to remove from base rates and to continue to fully recover via the respective rider; these calculations reflect any changes to the rider the Company is proposing in this Cause. So as not to understate rider rates, I&M's rider revenue requirements include a gross revenue conversion factor (GRCF) calculated consistent with the methodology that has been approved by the Commission.

The Company's proposals for its ongoing rate adjustment mechanisms and the EZ Bill program include the following:

> <u>DSM/EE Rider</u>: consistent with I&M's last base rate case in Cause No. 45235, I&M is proposing to reset legacy net lost revenue to zero when new base rates are implemented.
>
> <u>FAC</u>: I&M proposes to continue the current structure of the FAC, including semi-annual filings and the use of the FAC to flow back to customers the net revenues from sale of Renewable Energy Certificates (RECs). Company witness Heimberger calculates and supports an updated base cost of fuel for FAC-related costs in the Test Year.
>
> <u>LCM</u>: As part of I&M's final Phase-In Adjustment compliance filing on January 12, 2021 in Cause No. 45235, all LCM related capital investments through December 31, 2020 are now included in base rates. As such, the LCM Rider recovers only the capital-related costs of LCM projects placed in-service after December 31, 2020. The LCM project is forecast to be completed during the Test Year. To facilitate the conclusion of this project and the sunsetting of the LCM Rider: (a)

I&M LCM Rider factors for calendar year 2022 will be established in accordance with the ongoing LCM Rider process (LCM 11); (b) after issuance of a rate order in the instant Cause, I&M's compliance filing will adjust rider rates to reflect the recovery of ongoing independent monitor costs, 2022 investment, and the inclusion of LCM project investment in base rates through 2021; and (c) the final reconciliation of the LCM over/under recovery and on-going recovery of property tax expense on LCM investment made in 2022 will be made in a subsequent filing in 2023.

In Cause No. 44182, the Commission authorized I&M to timely recover within the LCM Rider the incremental property tax expenses associated with the LCM Project. Therefore, because I&M's base rates, after the final Phase-in Rate Adjustment (PRA) compliance filing in this rate case, will not reflect property tax expense on the authorized LCM plant the Company places into service in 2022, I&M proposes to include that annual expense in its ECR Rider until it is reflected in base rates in the Company's next rate case. This proposal promotes administrative efficiency by eliminating the need to continue annual over/under reconciliations and LCM Rider filings that would be based only on the LCM property tax expense not reflected in I&M's base rates.

<u>SPR:</u> The SPR was approved by the February 19, 2020 Order in Cause No. 45245, which authorized the construction and procurement of the 20MW St. Joseph Solar Farm (SJSF) and approved the SPR rider to facilitate recovery of capital related costs and O&M expenses. I&M is only proposing to change the name of the Rider to the Renewable Projects Rider. Although I&M is not proposing any new renewable projects in this rate case, the proposed name change will more broadly represent the purpose of the Rider if projects are added in the future.

Shortly after I&M receives an order in this Cause, I&M, as part of its rate case compliance filing will update its SPR rider factors to adjust for approved changes in ROE, GRCF, and jurisdictional allocation factors.

<u>EZ Bill</u>: I&M's EZ Bill Program is a voluntary billing option approved in Cause No. 45114 which is designed to allow eligible residential and small commercial customers to be charged a fixed amount per month for electric service over a twelve-month period. The EZ Bill Program is an option for residential and small commercial customers who strongly value rate stability. I&M proposes to reflect EZ Bill Program revenues and expenses above-the-line for regulatory accounting purposes because the program is a customer rate offering like any other I&M rate offering.

In Cause No. 45235, the Commission found it prudent to wait to know and verify the EZ Bill Program costs and profitability before approving the accounting of revenues and expenses above-the-line. The EZ Bill Program annual report filed in Cause No. 45114 on May 27, 2021 shows 1,099 customers are enrolled as of April 30, 2021 and EZ Bill Program profits exceed losses. Overall program revenue is expected to exceed what I&M's revenue would otherwise be under applicable standard rates and over the long-run, EZ Bill Program profits are expected to continue to exceed losses. Therefore, accounting for EZ Bill Program revenue above-the-line is expected to benefit customers by offsetting I&M's cost of service.

11. Curtis H. Bech, Senior Manager, Utilities Strategy and Consulting, Accenture PLC. This testimony presents the Advanced Metering Infrastructure (AMI) cost benefit analysis (CBA). A cost benefit analysis (CBA) is a systematic approach to calculating and comparing the benefits and costs of a course of action in a given situation. Accenture mobilized the CBA effort, engaged with a cross-functional Company team, calculated AMI program costs and benefits, and developed a business case that leveraged both Company data and Accenture expertise.

The largest cost elements are upfront capital costs which include meter replacement costs, meter communications upfront costs, IT upgrade costs, and program management costs. Other significant cost elements are associated with ongoing O&M expenses (support costs for new metering and communications equipment, IT related expenses, and customer portal vendor expenses) and run the business O&M expenses (DSM program administration costs and costs associated with data warehousing, AMI-related advanced analytics, and customer engagement).

The benefit areas include those that are utility-driven cost reductions, impacts that are a result of customer behavior changes, and select societal benefits. The CBA report included with this testimony break down the benefit areas into the following categories: Avoided O&M Expenses, Revenue Protection Benefits, Revenue Protection Benefits, Customer Benefits, Avoided Capital Cost and two Societal Benefits (customer value from improved system reliability and reduced emissions). The CBA captures benefits that are generally included in AMI business cases and because AMI is widely considered to be an enabling technology, reasonably quantifies how AMI can improve and drive incremental customer benefits in related programs like DSM and CVR.

Based on the results of the analysis, the expected cumulative benefits are distributed across multiple value streams that are associated with the AMI technology. This diversity of benefits is reflective of a comprehensive strategy by the Company to ensure that new AMI capabilities are leveraged across a wide range of program areas to drive incremental customer benefits.

The deployment alternatives assessed by Accenture depict a reasonable range of options available with respect to the Company's deployment of AMI. The Moderate AMI deployment plan (which is the scenario the Company proposes to use) balances deployment pace with other considerations, such as program risk management and launch of programs enabled by AMI, such as demand side management and new rate structures.

A planned and continuous deployment plan allows the Company to complete the AMI meter replacements in a more cost-effective manner than replacing meters as they reach their end of life, therefore resulting in a lower capital cost. Also, capital investments, such as communication networking, IT system enhancements, customer program fixed costs, are required in order to obtain the benefits of the AMI technology. These investments are required at the time the AMI meter replacements start. Under the Moderate scenario, many benefits ramp up faster in proportion to the number of meters deployed. A longer deployment schedule delays the utility's and the customer's ability to recognize many of the program benefits thereby reducing the overall NPV. The Moderate scenario also offers the opportunity for the Company to engage in a planned wide scale customer engagement and marketing campaign that will increase participation levels in programs such as DSM, electric vehicle time of use rates, and customer engagement tools. The increased participation and earlier adoption of these benefits increases the financial results of the Moderate plan versus the longer deployment scenario.

The net present value (NPV) for the Moderate deployment scenario is a positive $62.3M (not including societal benefits). The NPV including societal benefits is $83.3M. Using the Total Resource Cost (TRC) ratio, the score not including societal benefits is 1.61 (1.81 with societal benefits). Overall, these results mean that the benefits exceed the costs and the proposed capital investment is forecasted to reduce costs and ultimately customer bills over the 20-year forecast period compared to what costs would be otherwise. After considering the CBA results, it is Accenture's conclusion that the Moderate scenario the Company proposes to implement is reasonable, financially justified, and valuable for both the Company and its customers.

12. Jon C. Walter, I&M Consumer and Energy Efficiency (EE) Programs Manager. Mr. Walter's testimony supports the Company's proposed Enhanced Conservation Voltage Reduction (Enhanced CVR) program and the following proposed advanced metering infrastructure (AMI)-enabled customer programs:

- Residential AMI HVAC Direct Load Control (DLC) Program;
- Residential AMI Electric Water Heater DLC Program;
- Residential Customer Engagement Demand Response (DR) Program;
- Small Business AMI DLC Program;
- Critical Peak Pricing Program;
- Residential AMI Customer Portal;
- Commercial and Industrial (C&I) AMI Customer Portal; and
- Residential Flex Pay Program.

This testimony also supports I&M's investment in the Crossroads EV Corridor Project.

CVR is a program implemented by the Company to manage voltage levels on the distribution system, which results in lower power consumption. The Company proposes to apply Enhanced CVR operation to the existing set of distribution circuits that employ CVR today and to new, additional circuits that do not currently operate with CVR. Pairing the CVR equipment and system management software with AMI technology through the Enhanced CVR Program maximizes the energy efficiency and demand reduction benefits available with CVR technology. Enhanced CVR uses AMI meter voltage readings to further optimize distribution circuit voltage levels which correspondingly improves energy and demand savings performance.

The Company proposes to recover the Enhanced CVR O&M, EM&V and lost revenues through the DSM Program Cost Rider. I&M proposes to recover capital costs associated with Enhanced CVR in rate base and depreciation expense consistent with how other distribution system capital investment is recovered.

The Enhanced CVR and AMI-enabled customer programs align with and support I&M's proposed AMI deployment. The proposed portfolio of programs are reasonable, cost effective, and provide significant benefits to both customers and the Company.

The proposed AMI-enabled customer programs seek to broaden the reach and accessibility of DSM and demand response benefits for customers and by extension, I&M, by leveraging improvements in AMI system technological capabilities that have occurred over the past several years, including AMI communications network capability and back-office support system enhancements.

The Test year capital costs and O&M expenses associated with these programs are included in the Company's forecast revenue requirement presented by Company witness Duncan. The proposed program portfolio provides net positive benefits that in the aggregate support the cost-effectiveness of the overall AMI CBA presented by Company witness Bech.

The Company plans to measure the effectiveness of the proposed programs by measuring customer participating levels and program cost. The Company will also establish and track program participation requirements for each AMI-driven customer program to ensure each program only claims the level of coincident peak demand reduction for which it is responsible. I&M will also work in concert with a third-party evaluation, measurement, and verification (EM&V) vendor to verify demand response reductions.

I&M proposes to install twelve corridor fast charging sites within its service territory at a total estimated estimate of $3.57 million. These twelve I&M sites are part of 61 total locations included for a corridor fast charging network for the State of Indiana. The Company's investment supports the State of Indiana's goal, through the IDEM Indiana Statewide Charging Network Program, to construct and deploy a statewide Direct Current Fast Charging (DCFC) electric vehicle (EV) charging network. I&M proposes to recover its capital costs net of grant funding received from Indiana Department of Environmental Management (IDEM) for the joint utility statewide charging network program. The Commission should approve the Company's proposal for cost recovery for the project because it promotes EV adoption by addressing EV driving range anxiety and benefits Indiana consumers through development of emissions free EV use.

13. Jason A. Cash, Accounting Senior Manager in Corporate Accounting, American Electric Power Service Corporation. I&M's current depreciation rates are based on the Commission Order received in Cause No. 45235. The results of the recent depreciation study, supports revisions to the depreciation rates and accruals previously approved by the Commission, resulting in an annual depreciation expense increase of $10,500,192 on a Total Company basis. The primary driver of this increase is investment at the Cook Nuclear Plant.

All of the property included in the Depreciation Study Report was considered on a group plan. Under the group plan, depreciation is accrued upon the basis of the original cost of all property included in each depreciable plant group instead of individual items of property. Upon retirement of any depreciable property, its full cost, less any net salvage realized, is charged to the accumulated provision for depreciation regardless of the age of the particular item retired. In this study, the plant groups consisted of the individual primary plant accounts for Production, Transmission, Distribution, and General Plant property. The depreciation rates were calculated by the Average Remaining Life Method, which is the same method that was used to calculate I&M's current depreciation rates. The Average Remaining Life Method recovers the original cost of the plant (adjusted for net salvage) less accumulated depreciation over the average remaining life of the plant.

For Production Plant, the generating unit retirement dates and the interim retirement history for the individual plant accounts were used to determine the average service lives and the remaining lives of the plants. The average service lives for the Company's Transmission, Distribution, and General Plant were determined using statistical procedures similar to those used in the insurance industry in studies of human mortality. The historical retirement experience of property groups was studied, and retirement characteristics of the property were described using the Iowa-type retirement dispersion curves.

Net salvage for each property group was determined based on actual historical experience for Production, Transmission, Distribution, and General Plant accounts. In addition, Production Plant included terminal retirement net salvage amounts for Steam and Hydraulic Production Plant.

To determine terminal net salvage for Steam Production Plant, the depreciation study used the conceptual dismantling cost estimates reflected in I&M's current depreciation rates. These estimates, prepared by Brandenburg Industrial Service Company and Sargent & Lundy (S&L) remain reliable.

The depreciation study includes plant investment through the Test Year net of accumulated depreciation to properly match depreciation rates with plant in service when rates become effective in 2022. Including the forecasted additions and accumulated depreciation will ensure that more accurate depreciation rates are established for each generating station when rates become effective in 2022.

Establishing depreciation rates in this manner better supports the full depreciation of such assets and better aligns customer rates with the remaining service life of each generating station while reducing the extent to which the costs will need to be reflected in rates after the assets are no longer in service.

In this depreciation study, all of the Company's investment in Rockport Unit 1 and certain leasehold improvements made at Rockport Unit 2 are presented together as the Rockport Plant and depreciation rates were calculated for each utility account used by the Rockport Plant. The change was made primarily to summarize all of the investment made at the Rockport Plant, including the SCR, DSI and ACI investments made on each Rockport Unit, and calculate an individual depreciation rate for each utility account used by the Rockport Plant through 2028.

Summarizing the depreciation rates by each utility account establishes depreciation of the existing Rockport Plant through 2028 (or the remaining life of Rockport Unit 1), considers the lease ending for Rockport Unit 2 in December 2022, and also incorporates the remaining net book value associated with the certain leasehold improvements of Rockport Unit 2 at December 2022.

The depreciation study uses the same approach to Account 370 (Meters) that was approved by the Commission in I&M's last rate case. The revised depreciation rates are reasonable and should be approved.

The composite depreciation rate for Steam Production Plant decreased from 8.16% to 7.99% mainly due to depreciating the expected remaining balance of Rockport Unit 2 through 2028.

The composite rate for Nuclear Production Plant increased from 4.10% to 4.52% mainly due to a $146.9 million increase in the depreciable plant in service balance since the 2018 depreciation study. The increase in depreciable nuclear plant in service since 2018 is mostly due to the LCM Project, which is discussed in detail by Company witness Lies.

The composite rate for Hydraulic Production Plant increased from 2.74% to 4.33% due a $17.4 million increase in the depreciable plant in service balance since the 2018 depreciation study.

The composite depreciation rate for Other Production Plant increased slightly from 5.29% to 5.37% due to a $0.3 million increase in the depreciable plant in service balance since the 2018 depreciation study.

The depreciation rate for Transmission Plant increased from 2.48% to 2.67% due to increases in the net salvage ratio for three accounts (Accounts 353, 354 and 355) and decreases in the average service life for four accounts (Accounts 352, 353, 355 and 358). The depreciation rate increase was partially offset by an increase in the average service lives for three accounts (Accounts 354, 356 and 357) and decreases in the net salvage ratio for three accounts (Accounts 352, 356 and 358).

The depreciation rate for Distribution Plant decreased from 3.48% to 3.17% due to increases in the average service life for eight accounts (Accounts 364, 365, 366, 367, 368, 369, 371, and 373) and a decrease in the net salvage ratio for Account 370. The decrease was offset by increases in the net salvage ratio for seven accounts (Accounts 361, 362, 364, 365, 368, 369 and 373), decreases in the average service life of two accounts (Accounts 361 and 362), and updating the depreciation rate that was calculated for Account 370.

The depreciation rate for General Plant increased from 3.55% to 4.00% due to increases in the net salvage ratio for three accounts (Accounts 390, 391, and 398) and a decrease in the average service life of Account 390.

14. Aaron L. Hill, Director of Trusts and Investments American Electric Power Service Corporation: The purpose of the external nuclear decommissioning trust is to ensure that adequate funds are available to pay for the safe dismantlement of the Cook Plant and related facilities, disposal of the radioactive portions of the plant, storage of spent nuclear fuel as needed, and restoration of the plant site. The external decommissioning trust is also needed to comply with certain State and Nuclear Regulatory Commission ("NRC") requirements. Making regular, periodic contributions to fund the decommissioning trust helps provide funds for the future cost of decommissioning the nuclear power plant. The inclusion of the decommissioning expense in retail rates seeks to align the cost of decommissioning the Cook Plant with the benefits of its electric power generation during the plant's useful life.

Mr. Hill discusses the estimation of future decommissioning costs, the rules and guidelines for determining adequate funding levels, and a methodology for determining an appropriate funding level.

Unit 1 of the Cook Nuclear Plant is scheduled to be retired in 2034, and Unit 2 of the plant is scheduled to be retired in 2037. The modeling results show the current funding rate of $2.0 million annually for the Indiana jurisdiction should be adequate for expected decommissioning costs and this current level should be maintained in the revenue requirement in this case. The probability of having sufficient funds at the current level of contributions is approximately 84%.

The costs in the TLG Study presented by Company witness Knight are expressed in 2018 dollars. Mr. Hill projected the costs to the time of decommissioning in order to assess the sufficiency of the level of decommissioning contributions. The formula prescribed by the NRC for development of escalation rates for nuclear decommissioning costs was used.

As in previous cases, a Monte Carlo simulation technique was used to determine the probability of whether the current contribution rates would provide sufficient funds to decommission the plant. Monte Carlo simulation is a problem solving technique utilized to approximate the probability of certain outcomes by performing multiple trial runs, called simulations.

Although I&M certainly intends to operate the plant until its planned retirement there still remains the possibility that the plant may be shut down prior to the expiration of the operating license. This possibility would have the effect of not allowing the decommissioning funds to grow for as long as is currently planned, and would increase the probability that the decommissioning funds available may be insufficient to pay for the decommissioning expenses.

I&M will continue to report to the Commission every three years on the adequacy of the existing provision, and may recommend adjusting the level of decommissioning fund contributions needed in the future.

Similar to past orders, the Commission order in this Cause should incorporate language regarding the funding to assist I&M in obtaining compliance with regulations of the Internal Revenue Service regarding qualified nuclear decommissioning trust funds similar to past orders.

In addition to the liability for decommissioning the nuclear plant, I&M also has an obligation to the DOE to pay for the disposal of spent nuclear fuel used prior to April 7, 1983. The obligation is a fixed amount that increases with interest accumulated each year. The Indiana jurisdictional balance of the spent nuclear fuel trust fund is currently greater than the spent fuel liability allocated to it, and is projected to remain so for the projected test year. As such, the trust may be considered fully funded at this time and for the duration of the projected test year. The spent nuclear fuel liability will continue to increase through the accrual of additional interest until paid. Furthermore, the liability can move from fully funded to less than fully funded through changes in the market value of trust fund securities, differences between the liability accretion rate and the investment earnings rate and other factors. Mr. Hill concludes that there is no current need to resume funding for the Pre-April 7, 1983 spent nuclear fuel disposal fund.

Mr. Hill also supports I&M's forecasted prepaid pension asset and prepaid OPEB asset. Consistent with the Orders in IURC Cause Nos. 45235, 44967 and 44075, I&M seeks to continue the inclusion of the prepaid pension asset in I&M's rate base. The order in Cause No. 44075 stated that the prepaid pension asset was recorded on the Company's books in accordance with governing accounting standards, the prepaid pension asset reduced the pension cost reflected in the revenue requirement in the case, preserves the integrity of the pension fund, and should be included in rate base. In its Order in Cause No. 45235 (p. 27), the Commission again concluded that the prepaid pension asset should be included in rate base. The reasons underlying the Commission's previous determinations remain unchanged.

Funding included in the prepaid pension asset represent amounts expended by the Company in providing utility service in advance of receiving related goods or services. The cost of this service is recognized in the ratemaking process because a utility is entitled to have all of its reasonable costs reflected in the ratemaking process. In other words, 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.

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 must be made when a pension plan falls below certain funded levels. This ultimately reduces plan costs and helps preserve the plan's funded status.

The value of the prepaid pension asset for the Indiana jurisdiction is projected to be \$58,104,811 on December 31, 2022, I&M's Test Year end, which is a decrease compared to the \$64 million asset[1] (Indiana jurisdictional) included in Cause No. 45235. The continued inclusion in I&M's rate base is appropriate.

Similar to the prepaid pension asset, a prepaid OPEB asset can be defined as cumulative OPEB cash contributions less cumulative OPEB cost. There are multiple Voluntary Employees Beneficiary Association (VEBA) trusts established, as well as a 401(h) account, to fund retiree medical obligations. The trusts qualify as plan assets in accordance with GAAP accounting, meaning that the trusts are irrevocable. The trust designation requires I&M to keep within the trusts, all funds not used to pay employee retiree benefits.

I&M has prudently invested and earned a return on plan assets in the VEBA trusts allowing the Company to reduce OPEB costs incurred and reduce the amounts reflected in the revenue requirement used to establish base rates. Changes in the OPEB plan implemented in 2012 and 2014 reduced the Company's future exposure to medical cost inflation and have also reduced the retiree medical liability. As a result of the investment of trust assets and changes in the OPEB plan, the trust fund assets are currently adequate to fund the post retirement liability without ongoing contributions to the trust funds. The value of the prepaid OPEB asset on an Indiana jurisdictional basis is projected to be \$69,324,472 on December 31, 2022 (the end of the Test Year) and this asset is reasonably included in rate base as discussed by Company witness Ross.

15. Roderick W. Knight, Decommissioning Manager TLG Services, Inc. (TLG). Mr. Knight's testimony presents the site-specific decommissioning cost analysis prepared by TLG Services for Indiana Michigan Power Company in 2019 (TLG Study). The analysis provides the estimated costs associated with the shutdown and eventual decommissioning of the D. C. Cook Nuclear Power Plant, Units 1 & 2 in the years 2034 and 2037.

The TLG Study contains a description of the decommissioning cost estimate considered to be feasible for the Cook Plant, the cost estimate itself, and the estimate of the schedule of performance. The TLG Study incorporates the most current information available to date. The costs developed for the TLG Study provide a realistic estimate of the actual

[1] Includes RTD.

future costs and is reliable for I&M's financial planning purposes. It is reasonable for the Company to rely on the results of the TLG Study to support its decommissioning costs sought to be recovered as part of this proceeding.

The total estimated cost for the decommissioning is $2,032 million in 2018 dollars. This means that although a task may not actually occur until after final shutdown, its cost is estimated as if it occurred in 2018. These costs should be escalated to 2021 for purposes of this proceeding.

The cost estimate reflects removal of the Cook Plant using the DECON scenario. The DECON alternative allows for a quick termination of the license and a return to unrestricted use of the site, eliminating long-term maintenance and surveillance costs. The DECON scenario is typically the preferred scenario when the funds are available to proceed with decommissioning immediately after cessation of operations and is the scenario adopted as a basis for funding nuclear plant decommissioning in every I&M case in which a TLG witness has testified. The estimated cost includes costs to remove all radioactive materials from the site, which exceed the release criteria, terminate the NRC operating licenses, remove all structures above the three foot below grade elevation and backfill all below grade voids to the surface elevation and transfer all spent fuel from all the spent fuel pool to the on-site Independent Spent Fuel Storage Installation (ISFSI). Costs have also been determined to operate the ISFSI on an annual basis and to decommission and restore the site on an as yet to be determined date.

16. Jessica M. Criss, Tax Accounting and Regulatory Support Manager, American Electric Power Service Corporation. Ms. Criss' testimony describes the methods used to develop the federal and state income tax expense for the Test Year. The methods used are consistent with prior rate filings.

The Company's state and federal income tax expense has been properly recomputed to reflect the appropriate tax effects resulting from the various ratemaking adjustments supported in this case. The Company's accumulate deferred federal income tax (ADFIT) and Accumulated Deferred Investment Tax Credit (ADITC) are properly computed and incorporated in the capital structure used by Company Witness Messner to calculate the Weighted Average Cost of Capital (WACC). The adjusted Test Year level of other tax expense is appropriate and necessary and reflects the proper amount of going-level expense. The Company's treatment of its net operating loss carryforward is reasonable and consistent with stand-alone ratemaking practices and IRC normalization requirements.

The Gross Revenue Conversion Factor calculated on Exhibit A-8 indicates the appropriate factor that should be applied to the income deficiency in order to determine the amount of incremental revenue needed to obtain the required level of operating income. Exhibit A-9 calculates the Company's effective federal income tax rate after taking into consideration permanent and flow-through timing differences, excess deferred federal income taxes, and deferred investment tax credit amortization.

Finally, witness Criss' Attachment JMC-4 provides an illustrative calculation of the potential effects of a future change in the federal statutory tax rate.

17. Ann E. Bulkley, Senior Vice President, Concentric Energy Advisors, Inc. (Concentric). The ROE is an income from the investor's perspective. It is the formulaic calculation of the income return to an investor. The COE is a cost. It is the return that is required by investors or shareholders for making an equity investment. In the context of a regulated utility, the authorized return is a ROE. The analyses that led to the Return on Equity (ROE) recommendation applied the Constant Growth form of the Discounted Cash Flow (DCF) model, the Capital Asset Pricing Model (CAPM), the Empirical Capital Asset Pricing Model (ECAPM), the Bond Yield Plus Risk Premium Analysis (Risk Premium), and the Expected Earnings analysis. The recommendation also takes into consideration: (1) flotation costs; (2) the Company's generation portfolio and environmental regulations; (3) the Company's capital expenditure requirements; and (4) the regulatory environment in which the Company operates. Consideration was also given to the Company's projected capital structure as compared to the capital structures of the proxy companies. While no specific adjustments to the ROE estimates were made for any of these factors, they were taken into consideration in aggregate when determining where the Company's ROE falls within the range of analytical results.

I&M's recommended ROE considers:

- The *Hope* and *Bluefield* decisions that established the standards for determining a fair and reasonable allowed ROE, including consistency of the allowed return with the returns of other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and the requirement that the result lead to just and reasonable rates.

- The effect of current and projected capital market conditions on investors' return requirements.

- The results of several analytical approaches that provide estimates of the Company's cost of equity.

- The Company's regulatory, business, and financial risks, relative to the proxy group of comparable companies, and the implications of those risks.

The ROE estimation models produce a wide range of results. While it is common to consider multiple models to estimate the cost of equity, it is particularly important when the range of results is wide, in order to appropriately consider the factors that have resulted in the diverging range of results. Based on current market conditions, the ROE recommendation considers the results of the DCF model, forward-looking CAPM and ECAPM analyses, Risk Premium analysis, and an Expected Earnings analysis. Company-specific risk factors and current and prospective capital market conditions were also considered.

Considering the analytical results, as well as current capital market conditions and the level of regulatory, business, and financial risk faced by I&M's Indiana operations, relative to the proxy group, the COE is within a range of between 9.75 percent and 10.45 percent. Within that range, the Company's requested authorized ROE of 10.00 percent is below the midpoint of the range. The Company makes this request in conjunction with the Commission's approval of the rate relief package proposed by the Company in this case, as referred to in Company witness Thomas' testimony.

It is important for a utility to be allowed the opportunity to earn an ROE that is adequate to attract capital at reasonable terms. This enables the Company to continue to provide safe, reliable electric service while maintaining its financial integrity. To the extent the Company is provided the opportunity to earn its market-based cost of capital, neither customers nor shareholders are disadvantaged.

I&M's projected capital structure consisting of 50.94 percent common equity and 49.06 percent long-term debt is reasonable when compared to the capital structures of the companies in the proxy group and taking in consideration the impact of the Tax Cuts and Jobs Act of 2017 on the cash flows.

18. Franz D. Messner, Managing Director of Corporate Finance, American Electric Power Service Corporation. This testimony presents the capital structure and weighted average cost of capital for I&M, describes the forecast financing activity between December 31, 2020, the end of the historical period, and December 31, 2022, the end of the forward-looking Test Year, and describes I&M's credit ratings and why regulatory outcomes are important in the rating process.

I&M's forecast overall weighted average cost of capital, inclusive of ratemaking adjustments, is 6.07% at the beginning of the Test Year (December 31, 2021), and 6.08% at the end of the Test Year (December 31, 2022). In both cases, the Company utilizes a 10.00% cost of equity supported by Company witnesses Thomas and Bulkley. I&M's overall proposal will help maintain solid credit ratings and ready access to capital over the forecast period.

The projected cost rates for long-term debt at the beginning of the Test Year (December 31, 2020) and at the end of the Test Year (December 31, 2022) (shown on pages 1 and 3 of Exhibit A-7) are 4.44%. The Test Year capital structure and weighted average cost of capital are shown on I&M Exhibit A-7.

Financing activity that was forecast for the period between the end of the historical period (December 31, 2020) and the end of the Test Year (December 31, 2022) includes a $450,000,000 issuance of new long-term debt to offset the existing $200,000,000 local bank term loan facility that matured in May 2021 and to supplement the needs of its ongoing capital investment program. The forecast reflects a cost rate of 3.75% based on prevailing treasury market conditions and credit spread information provided by banks used in issuing long-term debt. The Company forecasted remarketing the currently outstanding $40,000,000 City of Rockport Series D pollution control revenue bonds. The forecast reflects a cost rate of 1.5% based on prevailing market conditions and pricing information provided by banks used in issuing long-term debt.

Credit ratings are opinions on a company's ability to repay its debt and other obligations in full and on time. The credit ratings facilitate the process of issuing bonds by providing a widely recognized measure of relative credit risk. Investors may also use ratings as a screening device to determine investments.

Credit ratings are important to I&M. A higher credit rating results in lower cost of debt and better access to capital in times of financial volatility. The credit rating is the primary criteria by which fixed income investors evaluate debt investments. Additionally, fixed income investors are limited in the amount of non-investment grade securities that they can purchase, so it is important for a utility to maintain investment grade ratings.

A portion of the Company's credit rating is based on qualitative factors related to regulatory environment. Rating agencies closely follow regulatory outcomes for a utility. Consistent and appropriate regulatory treatment is a credit positive and supports the Company's credit ratings which in turn affords the Company better access to capital markets to better source capital at lower cost.

19. Tyler H. Ross, Director of Regulatory Accounting Services, American Electric Power Service Corporation. This testimony provides an overview of accounting-related ratemaking adjustments impacting I&M's cost of service for the 2022 forward-looking Test Year. The majority of the adjustments described in this testimony are consistent with adjustments that were made and accepted in Cause No. 45235 and prior I&M rate cases. The remaining adjustments are consistent with Commission orders as referenced in the testimony. The ratemaking adjustments are reasonable and necessary to properly reflect I&M's cost of service for the forward-looking 2022 Test Year.

The data relied on were acquired from numerous sources, including but not limited to I&M and AEPSC accounting records. This is the type of supportable data that has been found to be reliable and regularly used in I&M's business for this type of analysis.

I&M's books and records follow the directives of the FERC Uniform System of Accounts (USOA). As a Securities and Exchange Commission (SEC) registrant company, I&M is also required to follow Generally Accepted Accounting Principles (GAAP), comply with specific SEC reporting requirements, and maintain controls over financial reporting in compliance with the Sarbanes Oxley Act of 2002.

The adjustments related to changes in electric plant in service and accumulated depreciation were provided to Company witness Heimberger for appropriate calculations of depreciation expense and accumulated depreciation in the forecasted Test Year. The rate base adjustments were also provided to Company witness Duncan for inclusion in the jurisdictional separation study.

For purposes of determining the necessary adjustments to retail rates for amortization of regulatory assets as described below, the Company proposes a two-year amortization. The amortization period is based on a reasonable period of time the base rates approved in this proceeding may be in effect as further described by Company witness Seger-Lawson.

The Company proposes to perform deferral accounting consistent with that approved by the Commission in Cause No. 45235 for: ongoing unprotected excess Accumulated Deferred Federal Income Tax (ADFIT) amortization; and ongoing protected excess ADFIT amortization.

The Company also proposes new deferral accounting related to a potential future increase to the corporate federal income tax rate. This would apply to: increased federal income tax expense; unprotected deficient ADFIT amortization; and protected deficient ADFIT amortization. The Company's proposed accounting in response to a potential increase in the corporate federal tax rate is reasonable and similar to the deferral accounting performed by the Company following the enactment of the TCJA and the Commission's order on Cause No. 45032 for the decrease in the corporate federal income tax rate from 35% to 21%. The Company proposes that the deferral be reflected in I&M's monthly Tax Rider over-/under-recovery calculation and entry.

Consistent with I&M's last three rate cases (Cause Nos. 45235, 44967 and 44075), I&M continues to include its prepaid pension asset in rate base. The Order in Cause No. 45235 found (at 27-28) that the prepaid pension asset was recorded on the Company's books in accordance with governing accounting standards and was properly reflected in the Company's approved level of rate base. It is clear that I&M's prepaid pension asset (cumulative contributions less cumulative GAAP-determined benefit cost) are funded solely by investors. On a cumulative basis, I&M's customers have only funded, through I&M's cost of service, the level of GAAP-determined pension cost and nothing more. The only funds available to I&M from customers are for the level of GAAP-determined pension expense. Amounts in Account 165 represent cumulative contributions in excess of pension costs, which were provided by investors.

I&M's prepaid pension asset earns a return that benefits customers. The return is used and useful as it lowers future pension expense, resulting in a lower cost of service. 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 the cost of service. The prepaid pension asset represents a prudent investment made to help meet utility obligations and to reduce cost of service for customers, is used and useful in providing public utility service, and is necessary for the responsible management of the Company's pension plan.

I&M is also including its OPEB prepaid asset balance in rate base, consistent with the Orders in Cause Nos. 39314, 43306 and 44075. This asset stems from the Company's creation, in 1990, of a separate Voluntary Employees Beneficiary Association (VEBA) trust fund related to the Company's OPEB obligations. The Company did not use the OPEB-related cost of service as cost-free capital. Instead, the Company contributed to the VEBA trust fund, which is invested and earns a return that stays within the trust fund. The return earned by the VEBA trust increased the funds available to satisfy the OPEB obligations.

Over time, due to the trust fund returns and changes in the OPEB benefits described by Company witness Hill, the trust fund has grown to an amount that exceeds the expected OPEB obligation. Starting in 2013, I&M began experiencing a net OPEB credit to expense due to the changes made to retiree medical coverage. Based on the changes to I&M's OPEB plan, I&M began amortizing the prior service credit to expense in accordance with GAAP, specifically ASC 715-60-35-20. As a fully-regulated utility, I&M recorded the prior service credit to a regulatory asset instead of accumulated other comprehensive income. Annual amortization of the prior service credit (credit to expense) is recorded as a component of the Company's net periodic benefit cost which is included in I&M's cost of service used in determining I&M Indiana base rates. In accordance with GAAP accounting guidance (specifically ASC 715-60-35-20), annual actuarial reports prepared by I&M's third party actuary, Willis Towers Watson, continue to reflect annual net negative OPEB expense due to the expected return on assets and amortization of the prior service credit.

While I&M continues to experience negative OPEB expense, the funds in the VEBA trust must remain in the trust until the trust is terminated, which is not until the last beneficiary is deceased.

Yet, for retail ratemaking purposes, the negative OPEB expense is reflected as a credit to the retail revenue requirement. As a result, this credit effectively flows the "overfunding" back to customers. However, since the funds in the VEBA trust cannot be withdrawn until the trust is terminated, the credit is not tied to the actual return of dollars. Rather, the ratemaking credit is essentially an advance payment with the Company fronting the cost of the advance.

As summarized above, I&M currently records a significant net credit to expense that is reflected in the Company's previous and currently-proposed cost of service and resulting Indiana base rates. Because the funds in its OPEB trusts cannot be accessed, the resulting GAAP accounting creates I&M's prepaid OPEB asset, which continues to grow. The return of this asset to customers is being financed by investor funding. Therefore, I&M reasonably seeks a fair return on this asset balance through rate base treatment, similar to the Company's prepaid pension asset.

20. Chad M. Burnett, Director of Economic Forecasting, American Electric Power Service Corporation. Mr. Burnett presents the kilowatt-hour (kWh or energy), customer, and kilowatt (kW or peak) forecasts used by the Company to develop its Test Year billing determinants. In the course of the presentation, the witness explains the processes and methodology employed to forecast the Test Year, which is the 12-month period ending December 2022. The load forecast is used by Company witness Duncan in the jurisdictional and class cost study allocations. Company witness Hornyak uses the Test Year load forecast to develop the forecasted billing determinants used in rate design.

The Test Year forecast is based on the Company's load forecast which is generated once a year as part of its normal planning process. The load forecast used in this proceeding was completed in September 2020 using actual data through July 2020. The pandemic had just started when the Company developed its initial load forecast for 2020. As part of its normal monitoring process, the Economic Forecasting group determined there would be value in re-estimating the models to include the actual data since the pandemic began to capture any observed changes in consumer behavior as a result of the historic recession and pandemic. The Economic Forecasting group recommended the updated load forecast be used for planning purposes. The load forecast presented as the Test Year in this proceeding is the same vintage that is being used for I&M's 2021 Control Budget.

The forecast assumes normal weather conditions throughout the forecast horizon, including the Test Year. It is appropriate to utilize weather normalized billing determinants when setting customer rates since it represents the most likely outcome (i.e., highest probability of occurrence) that minimizes the possibility that the Company will under or over collect the intended revenue requirement set by the Commission.

For the Test Year, the Company adjusted the load forecast for the impact of DSM programs that had been implemented prior to 2020 or were included in I&M's 2020-2022 DSM Plan filing in Cause No. 45285.

The Test Year forecast is a reasonable projection of I&M's customer count, sales, and peak load. I&M's load forecast methodology, which is unchanged from the prior rate case, is proven to produce reliable projections that are useful for planning and setting rates.

The forecast techniques utilized by the Company are widely accepted across the electric utility industry and utilize data inputs from recognized third-party sources.

The same methodology is used in the Company's FAC and other filings where the Company's projection of kWh sales is used to set the rates. This methodology is also used in the Company's most recently filed Integrated Resource Plan (with the exception of long-term DSM impact which is excluded from the load forecast so that the IRP optimization so that can determine the optimal level of DSM for the Company to pursue in future years, based on market fundamentals, technology costs, etc.).

The forecast methodology produced an Indiana retail jurisdictional forecast sales that are 24 GWh higher than the normalized actuals in 2020. The Test Year forecast reflects a gradual recovery from a historic reference year in 2020, which included both the impacts of a recession and a global pandemic. This includes an increase in Industrial class sales that is partially offset by lower Commercial and Residential class sales and also reflects Test Year wholesale sales that are lower than the 2020 wholesale load. Putting the wholesale load change aside, the Test Year forecast for the I&M system is slightly above the 2020 levels.

Overall, the customer count for the Indiana jurisdiction was forecasted to be relatively flat. This is generally consistent with the demographic and economic projections.

I&M's Total Company forecasted peak demand for the Test Year is 3,898 MW in August of 2022. By comparison, I&M's actual peak demand in 2020 was 3,970 MW on July 9, 2020. The weather normalized peak estimate for 2020 was 3,955 MW. A weather normalized peak represents what the peak value would have been if the temperature on the peak day had been normal for a peak day, so the actual peak came in higher than it would have been under normal peak day conditions. In 2020, the temperatures were slightly warmer than normal for peak day, so the actual peak came in higher than it would have been under normal peak day conditions.

21. Jennifer C. Duncan, American Electric Power Service Corporation, Regulatory Consultant Staff in the Regulated Pricing and Analysis Department. This testimony presents the Test Year jurisdictional separation study, which reasonably allocates Total Company Test Year rate base, revenues and expenses to the Indiana retail jurisdiction. The purpose of the jurisdictional separation study is to reasonably allocate the Company's Test Year cost of providing service to the Company's Indiana retail jurisdiction. The allocation of Total Company Test Year costs to the three jurisdictions I&M serves is based on established cost allocation procedures, using underlying data that represents how the system is used to meet customer requirements. The Company's forecast, as provided by Company witness Heimberger, serves as the source of information for the Test Year jurisdictional separation study.

This testimony also supports the demand and energy allocation factors which are calculated using an average of 12 monthly loss adjusted coincident peak demands (12 CP) (demand factors) and annual loss adjusted kWh usage provided by Company witness Burnett (energy factors). Developing the allocation factors based on Test Year demand and energy usage reasonably allocates costs and benefits among the various jurisdictions.

Since 1990, I&M's Commission-approved or settled allocation factors have ranged from a 65% to 74% demand allocation factor and a 63% to 72% energy allocation factor for its Indiana retail jurisdiction. The Indiana demand and energy allocation factors proposed in this Cause are 70.69600% and 68.56712%, respectively. These allocation factors are within the historical range of approved allocation factors for the Company.

This testimony also supports several operating revenue adjustments included in the Test Year jurisdictional separation study. Ms. Duncan generally supports the revenue credit adjustment split amount between firm and interruptible sales revenues. Other witnesses provide further support for the adjustments.

Finally, Ms. Duncan presents the calculation of the Company's proposed Phase-in Rate Adjustment (PRA) mechanism following the same methods employed to develop the Phase-In Rate Adjustments in Cause Nos. 44967 and 45235.

22. Stephen Hornyak American Electric Power Service Corporation, Regulatory Consultant Principal in the Regulated Pricing and Analysis Department. A cost-of-service study is a basic analytical tool used in traditional utility rate design. Cost studies are utilized to determine the revenue requirement for the services offered by the utility and to determine the costs that different classes of customers cause costs to be incurred on the utility system. When all of the jurisdictional costs are allocated to the various customer classes, the result is a fully allocated class cost study that is a guide in establishing rates based on costs.

This testimony describes the class cost-of-service allocation study for the Test Year and presents the resulting class-by-class rates of return. The cost allocation methods used to prepare the study meet the criteria identified in the testimony and assign costs based on Commission approved cost causations approaches. Customers who cause costs to be incurred are allocated such costs in the Company's class cost-of-service study.

The class cost-of-service study equitably allocates costs among the customer classes based on contributions to demand and energy levels and number of customers.

The Company proposes to continue using the 6 Coincident Peak (CP) demand allocator, consistent with the 6 CP methodology found appropriate Coincident Peak in I&M's last three basic rate cases (Cause Nos. 45235, 44967, and 44075). The CP cost allocation refers to the process of determining each class's hourly contribution to the Company's monthly peak demand. The 6 CP is the most appropriate demand allocator considering the load profile during the Test Year continues to reflect six monthly peaks, three during the summer and three during the winter. The benefit of the 6 CP demand allocator is that each customer class is being allocated their fair share of demand costs based on their contributions to the average of the six monthly peaks during the Test Year.

When all of the costs are allocated to the customer classes, the result is a fully allocated cost-of-service study that establishes cost responsibility and the Test Year rate of return earned from each class, making it possible to determine the rates each class of customer should pay based on costs that are just and reasonable. Company witness Fischer explains that the results of the study help guide the allocation of the proposed changes in sales revenue to each customer class.

23. Jenifer L. Fischer, American Electric Power Service Corporation (AEPSC), Manager, Regulated Pricing and Analysis. Following the same methodology established in Cause No. 44075 and reflected in the Company's succeeding basic rate cases, I&M's entire traditional embedded cost of transmission, as well as the revenues the Company receives from PJM as a Transmission Owner, have been excluded from the Company's class cost of service study, as supported by Company witness Hornyak. As a result, these costs and revenues have been removed from the Company's revenue requirement in this proceeding, as shown on Exhibit A-1.

The Company's class cost of service study, supported by Company witness Hornyak, equitably allocates the total Indiana retail jurisdiction cost of service among the customer classes. I&M has appropriately used the results of that study to allocate the proposed revenue increase, based on principles of cost causation and gradualism, to design rates that reflect as nearly as possible the actual costs of service to the customer, eliminate subsidies, and move all classes towards earning the class average rate of return.

In general, the Company's approach is to design rates and rate components that reflect the Company's underlying costs. This includes collecting fixed costs through fixed and/or demand charges and variable costs through energy charges whenever practical.

In order to continue to improve the alignment of the Company's cost of service with the revenues recovered from its residential customers, I&M proposes to increase the standard residential tariff service charge from the current level of $15.00 per month to $20.00 per month. The Company maintained the current design of the rates to recover all customer-related costs, plus the total secondary distribution costs, based on cost of service, through the combination of the monthly service charge and an increment in the first block volumetric energy charge. The remainder of the Company's total residential costs were designed to be recovered through a charge for all kWh. Under the Company's proposal, 84% of proposed demand- and energy-related costs are recovered in the volumetric energy charges.

Importantly, it should be recognized that the percentage increase in the monthly service charge relates only to one component of the customer's entire bill and should not be confused as equating to an overall increase in the entire bill. As previously recognized by the Commission, gradualism is best considered in the context of the entire customer bill and not discrete charges within the bill.

A common misconception is that low income customers use significantly less energy than average or above average income customers. However, low income does not necessarily equate to low energy consumption among residential customers. Like other residential customers, low income customers are weather-sensitive energy customers. Therefore, collecting a disproportionate amount of fixed costs through volumetric charges can expose these customers to more severe bill impacts during periods of weather extremes.

The proposed consolidation of the GS and LGS tariffs into one Tariff GS will provide needed flexibility to address changes in general service customer load without requiring customers to move back and forth between tariffs.

The Company's proposal to modify demand billing for Tariff LGS and Tariff IP from billing on kVA to billing on kW will avoid unnecessary meter replacements and eliminate inconsistencies that lead to customer confusion and difficulty transitioning between Tariffs GS, LGS and IP as their usage characteristics change.

The Company's proposed introduction of two new optional critical peak pricing tariffs for residential and small commercial customers will provide customers with price signals which encourage them to reduce usage during a limited number of high cost hours during the year.

The proposed Phase-In Rate Adjustment rate design is consistent with I&M's current Phase-In Rate Adjustment and reflects the proposed merger of the GS and LGS Tariff classes.

Attachment JLF-4 presents a comparison of typical bills under present and proposed rate structures at the end of the Test Year for each of the major tariff classes at a range of usage levels. Figure JLF-3 illustrates the effect of the Company's Phase-In Rate Adjustment on a residential customer that uses 1,000 kWh per month.

24. Kurt C. Cooper, Regulatory Consultant Principal in the Regulatory Services Department Indiana Michigan Power Company. Company witness Cooper explains that the Company's filing includes: changes to I&M's Terms and Conditions of Service, including the Flex Pay payment option; revisions to certain one-time Service, Reconnect and Trip Charges; modifications to the language and rates of existing tariff schedules; new tariff options for customers; and changes to specific rider language and rates including the proposal of two (2) new riders (as stated above). These changes are shown in redline and clean versions of the Company's Tariff Book which is included as an attachment to Company witness Cooper's testimony. The updated tariff continues to include the AMI meter Opt out provision approved by the Commission in Cause No. 45235.

The Company seeks to provide additional, voluntary tariff offerings to its customers, the policy and rate design of which are sponsored by Company witnesses Walter and Fischer. To accommodate these proposed tariff offerings, the Company is adding the Residential Critical Peak Pricing Tariff and the Commercial Critical Peak Pricing Tariff to its current tariff offerings.

The Company has also identified the need to make a variety of changes to its existing tariffs. Specifically, the Company proposes to update the Non-Residential Deposit terms to include the previously approved interest rate the Company pays customers for Non-Residential deposits. The Company will close Tariffs R.S. TOD and G.S. TOD to new customers, expand R.S. TOD2 and G.S. TOD2, modify the fee language in Tariffs R.S. EZB and G.S. EZB, consolidate Tariffs G.S. and L.G.S., remove the Other Sources of Energy Clause in all pertinent tariffs, change kVA billing determinants to KW for Tariffs L.G.S. and I.P., and raise the threshold for a written contract under Tariff I.P. The Company also proposes minor language changes to bring better definition or clarity to the Terms and Conditions of Service. The changes to the Company's existing tariffs seek to better serve its customers' needs and to allow the Company to provide better customer service.

Finally, the Rider Section of the Company's tariff book has been updated to accommodate two new riders, the AMI Rider and Tax Rider, which are sponsored by Company witness Seger-Lawson, and to capture changes to I&M's Home Energy Management and Work Energy Management Riders as sponsored by Company witness Walter.

Petition Exhibit C

IURC Cause No. _________
I&M Proposed Rate Case Schedule Under
IURC GAO 2013-5 and Ind. Code § 8-1-2-42.7

		Per GAO	I&M Proposal
Day 0	Petition & Case-in-Chief	Thursday, July 1, 2021	Thursday, July 1, 2021
@ Day 77	Field Hearing(s) (Sept 16th is day 77)	TBD	TBD
Day 98	OUCC & Intervenors Cases-in-Chief	Thursday, Oct. 7	Thursday, Oct. 7
Day 126	Rebuttal/Cross-Answering	Thursday, Nov. 4	Thursday, Nov. 4
Day 133	Settlement Agreement and supporting testimony[1]	Thursday, Nov. 11 (State & Federal Holiday)	Friday, Nov. 12
Three business days before hearing	Witness Order submitted	Monday, Nov. 29	Monday, Nov. 29
Days 154-168	Evidentiary Hearing	Th-F, Dec. 2-3, M-Th, Dec. 6-9 M-Th, Dec. 13-16	Th-F, Dec. 2-3, M-Th, Dec. 6-9 M-Th, Dec. 13-16
Day 182	I&M Proposed Order	Thursday, Dec. 30	Thursday, Dec. 30
Day 203	OUCC & Intervenors Post-Hearing Filings	Thursday, Jan. 20	Thursday, Jan. 20
Day 210	I&M Reply Brief and OUCC/Intervenor Cross-Answering Briefs	Thursday, Jan. 27	Thursday, Jan. 27

Other terms:

Technical Conference: Nothing in this schedule precludes a party from proposing a technical conference.

[1] Per GAO 2013-5 this is the last day to submit settlement agreement with supporting testimony and maintain overall schedule. If settlement covers less than all the parties, the schedule may need to be modified to accommodate testimony objecting to settlement and contested settlement hearing.

Service: The parties will provide same day service of filings via email, hand delivery or large file transfer.

Discovery: Discovery is available to all parties and shall be conducted on an informal basis. Any response or objection to a discovery request shall be made within ten (10) calendar days of the receipt of such request until October 7, 2021. Thereafter, any response or objection to a discovery request shall be made within five (5) calendar days of the receipt of such request. Any discovery communication received after noon on a Friday or after 5:00 p.m. on any other business day shall be deemed to have been received the following business day. The last discovery response due date shall be two (2) business days before the evidentiary hearing. There will be blackout dates for discovery from November 25, 2021 through November 28, 2021. Dates designated as "blackout dates" shall not be included in determining the number of days provided for responding to a discovery request. The Parties may conduct discovery through electronic means. Subject to the protection of confidential information, all parties will be served with discovery requests and responses.

Workpapers: When prefiling technical evidence with the Commission, each party shall file copies of the work papers used to produce that evidence within two (2) business days after the prefiling of such technical evidence. Copies of the same shall also be served on the other parties to this Cause.

Number of Copies/Corrections: Filings with the Commission shall comply with General Administrative Order 2016-2. Any corrections to prefiled testimony shall be made in writing as soon as possible after discovery of the need to make such corrections.

Objections to Prefiled Testimony and Attachments: Any objections to the admissibility of prefiled testimony or attachments shall be filed with the Commission and served on all parties of record not less than five (5) business days prior to the date scheduled for commencement of the hearing at which the testimony or exhibit will be offered into the record.

Temporary Rates: This schedule does not address temporary rates.

The Edison Foundation
INSTITUTE for
ELECTRIC INNOVATION

Report

Electric Company Smart Meter Deployments: Foundation for a Smart Grid (2019 Update)

December 2019

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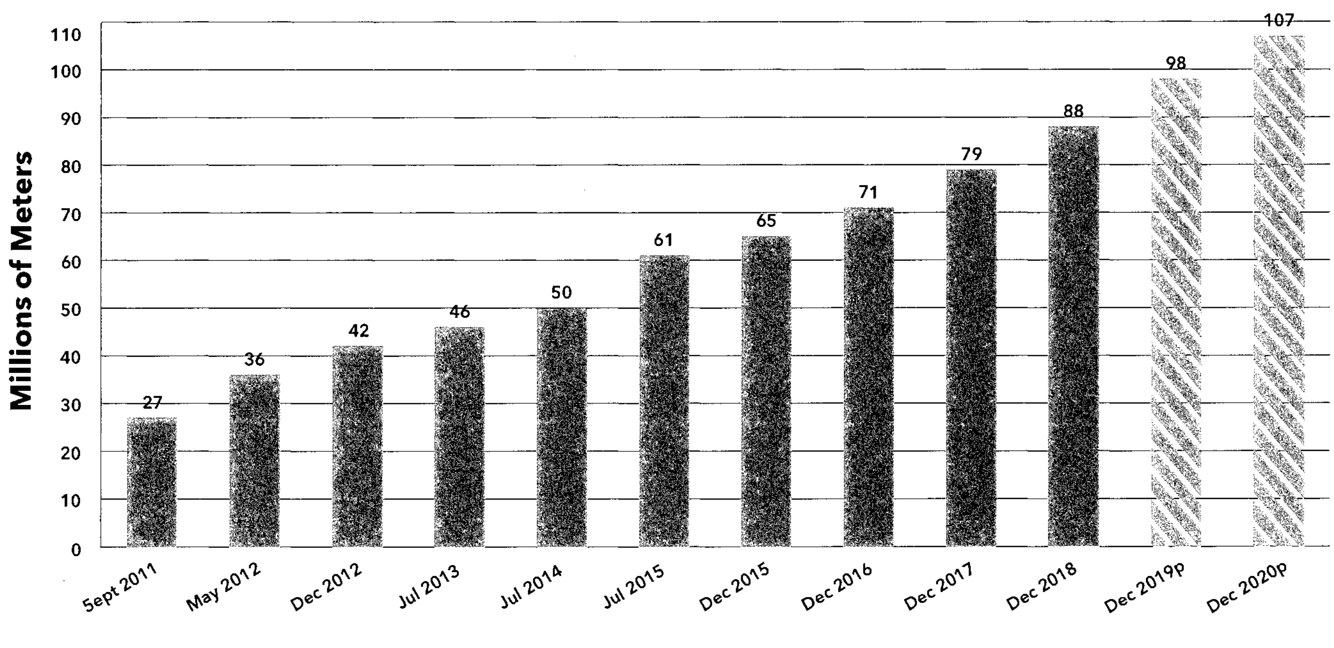
EXECUTIVE SUMMARY

The transition of the electric power system is underway, and smart meters continue to be a key technology that enables customer services and communications and enhanced energy grid operations.[1] Investing in the distribution grid, particularly in smart meters, is the foundation for a customer-facing, modern energy grid. While deployment of smart meters began more than a decade ago, electric companies continue to find ways to create value from the data and capabilities smart meters enable.[2]

In this report, we discuss some of the innovations, benefits, and capabilities enabled by smart meters; summarize the current status and projected number of smart meters installed nationwide; and, provide our perspective on the growing importance of investing in the distribution grid.

As shown in Figure 1, smart meter installations have grown dramatically since 2011. As of year-end 2018, electric companies had installed more than 88 million smart meters, covering nearly 70 percent of U.S. households. Based on survey results and approved plans, estimated deployments are expected to reach 98 million smart meters by the end of 2019 and 107 million by year-end 2020.

Figure 1: U.S. Smart Meter Installations Approach 98 Million; Projected to Reach 107 Million by December 2020



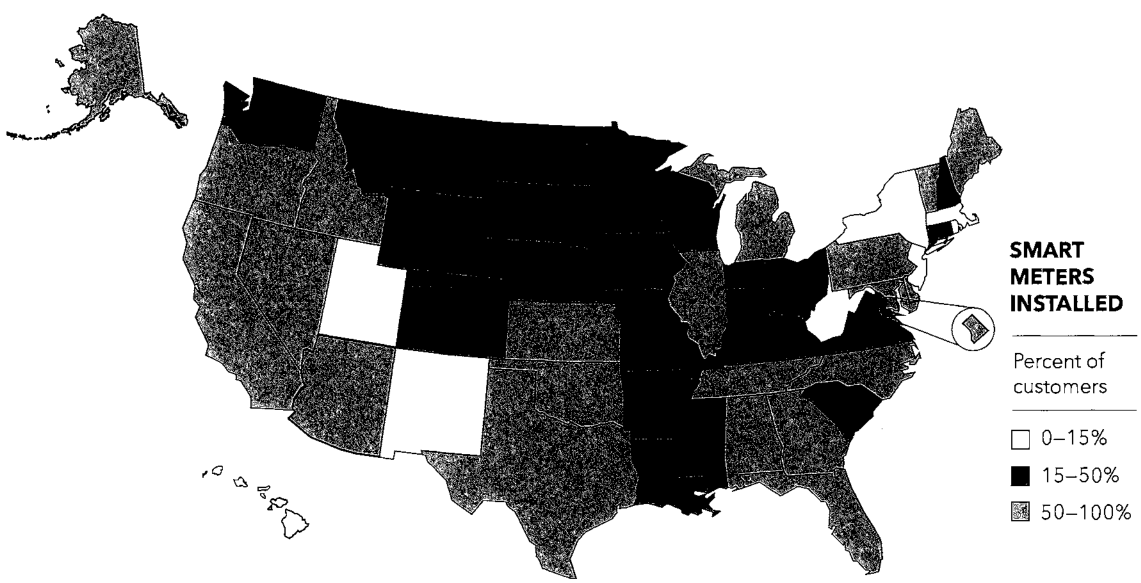
1. Smart meters, or advanced metering infrastructure (AMI), are digital meters that measure and record electricity usage data hourly, or more frequently, and allow for two-way communication between electric companies and their customers.
2. For the purposes of this report, the electric power industry includes investor-owned electric companies, public power utilities, electric cooperatives, and federal utilities. We use the term 'electric companies' in this report to encompass all of these industry segments.

HIGHLIGHTS

Electric companies across the United States are leveraging smart meter data to better monitor the health of the energy grid, more quickly restore electric service when outages occur, integrate distributed energy resources (DERs), and deliver energy solutions to customers. Figure 2 shows smart meter deployments by state through 2018.

- Electric companies have installed more than 88 million smart meters, covering nearly 70 percent of U.S. households, as of year-end 2018.
- Deployments are estimated to reach 98 million smart meters by the end of 2019 and 107 million by year-end 2020.
- More than 50 investor-owned electric companies in the United States have fully deployed smart meters.[3]
- Electric companies are using smart meter data to provide customer solutions, to enhance grid resiliency and operations, and to support electric company planning, rate design, and DER integration.
- Smart meters provide a digital link between electric companies and their customers by opening the door to new and expanded services, such as smart home energy management, load control, budget billing, usage alerts, outage notifications, and time-varying pricing.
- Smart meters enable two-way power and information flows that improve visibility into the energy grid.
- Electric companies are focused on modernizing the energy grid and are projected to invest more than $39 billion in the distribution system alone in 2019 (out of a projected $135.6 billion total investments).[4]

Figure 2. Smart Meter Deployments by State, 2018 (% of Customers)



3. Table 2 provides an in-depth list of smart meter deployments by electric company. Table 3 provides smart meter counts by state. Table 4 provides a listing of the companies that have fully deployed meters.
4. EEI Industry Capital Expenditures with Functional Detail (October 2019).

INTRODUCTION

Smart meters are the building blocks of a digital energy grid and are the foundation for a smart grid. Electric companies have installed more than 88 million smart meters as of year-end 2018, covering nearly 70 percent of U.S. households. Based on approved plans, completed and ongoing deployments, and proposals before state regulatory commissions, 98 million smart meter are estimated to be in place at the end of 2019 and 107 million by year-end 2020.

- Table 1 provides a summary of smart meter installations and projected deployments.
- Table 2 provides an in-depth list of smart meter deployments by electric company.
- Table 3 provides smart meter counts by state.
- Table 4 provides a listing of the more than 50 companies that have fully deployed meters.

This report highlights how electric companies are using smart meter data and underlying communications systems to provide customer solutions, enhance grid resiliency and operations, and support other efforts such as rate design and distributed energy resource (DER) adoption.

ENHANCING CUSTOMER SOLUTIONS IN MOMENTS THAT MATTER

Smart meters provide a digital link between electric companies and their customers that opens the door to new or expanded customer solutions. This section provide examples and describes how smart meter data and analytics are helping electric companies to communicate and engage with customers during moments that matter and to provide personalized services and insights.

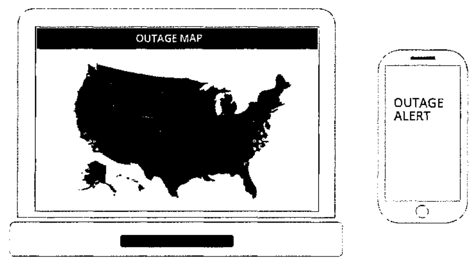
Proactive Outage Communications

Smart meters help to notify customers if their power is out, provide an estimated time to restore service, and deliver a final notice when the power is back on.

- As of 2018, more than 1.4 million customers in the Houston area were enrolled in **CenterPoint Energy's** Power Alert Service (PAS). Using data collected through smart meters to pinpoint addresses affected by power outages, PAS notifies customers within minutes of confirmed outages. The PAS notifications include the estimated time of restoration, status of repair crews, number of affected customers, and outage cause, helping to keep customers informed throughout the outage restoration process. Surveys of PAS enrollees in 2018 consistently showed customer satisfaction around 92 percent with only 5 percent of PAS enrollees calling in to report an outage compared to 25 percent of those not enrolled.
- **San Diego Gas & Electric (SDG&E)** proactively sends out outage notifications to about 1 million customers, including information on why an outage occurred and an estimated restoration time for when power will be restored. Overall, customers are satisfied with the outage notifications; 6 of 10 survey respondents were satisfied with the timeliness of notifications, and nearly 7 of 10 customers said they received the right number of notifications. As a result of proactive notifications, SDG&E has realized a 36-percent reduction in agent-handled outage calls.

Going forward, electric companies are investing in technology and process enhancements to improve the accuracy, convenience, and timeliness of outage notifications. This includes expanding the types of outage cause descriptions; developing status trackers for restoration work; enabling two-way text messaging; and improving accuracy of estimated restoration times by shifting away from system-wide averages to more precise estimates based on substation and circuit-level data.

Smart meters help keep customers informed



about outages and restoration times.

Proactive Customer Notification and Engagement

Smart meters support budget-setting tools and alerts that notify customers if their bill is projected to be higher than normal.

- More than 500,000 **Southern California Edison (SCE)** customers have signed up for Budget Assistant, a proactive performance notification tool that provides residential customers with information on how their projected costs compare to their preselected monthly spending targets for each billing period. Customers can select to receive periodic (e.g., weekly, mid-month) updates or a conditional notification if their projected bill is trending higher than budget. On average, customers enrolled in Budget Assistant save 0.5 percent on their energy usage compared to non-enrolled customers.
- **Georgia Power's** Online Customer Care platform is a self-service tool that gives more than 1.5 million customers more flexibility to manage home electricity usage. With this tool, customers are able to pay their bills, view their energy usage, set alerts, report outages, and make service requests. Through My Power Usage Alerts, more than 100,000 customers monitor their electricity usage with daily and/or monthly email notifications. This personalized tool provides customers with tailored information about their energy usage and daily costs, eliminating surprises at the end of the month.

Residential Bill Payment Options

Smart meters support pre-payment and/or pay-as-you-go options.

- **Baltimore Gas and Electric (BG&E)** launched a one-year pre-pay energy pilot in 2019 for up to 1,000 residential customers with smart meters to study the costs, benefits, and experiences that customers encounter while on the pre-pay pilot. Since payments are made prior to actual energy consumption, BG&E partnered with PayGo Utilities to analyze customers' smart meter data, develop daily account calculations for each household, and send account balance information to customers. Other electric companies offering pre-pay services have reported customers use from 5 percent to 15 percent less energy, largely because of this real-time feedback.

Home Energy Insights

Smart meter data is used in decision support tools that assist customers in the evaluation of energy management options, solar or battery energy storage installations, and electric vehicle purchases.

- In December 2018, **Commonwealth Edison (ComEd)** launched the Green Power Connection Toolkit, which helps customers evaluate private (rooftop) solar options. In the toolkit, customers can access a solar calculator that leverages their smart meter recorded energy usage history, rate, and solar exposure to help customers understand what solar could mean for them. As of May 2019, 6,000 customers have used the toolkit to create a solar calculator report.

Smart meters support household load disaggregation and visualization.

- **DTE Energy's** Insight App helps customers make informed home energy management decisions by applying analytics to smart meter data to deliver device-level energy usage data to customers with 99.8 percent accuracy. Examples of real-time insights include visualization of a customer's HVAC system energy usage, on/off control of thermostats, and alerts for appliances left on.

Time-Varying Rates

Smart meters enable electric companies to offer new pricing options to customers to incent load shifting, reduce energy consumption, and align consumption with clean energy production.

Today, millions of customers with smart meters are enrolled in time-varying pricing programs that incent customers to reduce energy consumption during peak times when demand for electricity is expected to be especially high.

- In 2019, **Arizona Public Service (APS)** migrated approximately 1 million residential customers to five new rate plans that encourage more efficient electric consumption, support alignment of energy demand with clean energy production, and provide cost savings opportunities for shifting energy usage. Having fully deployed smart meters throughout their service territory helped APS design and communicate to customers how the new rate plans (in particular the rates with demand charges) can help to ensure clean energy plays a larger role in meeting customer energy needs. With this information, about 20 percent of APS customers selected plans that include a basic service charge, a time-of-use (TOU) energy rate, and peak usage (demand) charges.
- **Southern California Edison (SCE)** offers EV-specific TOU rates either for whole house or for separately-metered EV charging. Smart meter data supports analysis of the TOU rates to shift EV charging to off-peak periods, maximize distribution system upgrades, and increase the

efficient use of the energy grid. Results of the program show that SCE customers using whole house EV TOU rates with smart meters consume 10 percent more of their energy during off-peak hours than customers under normal residential rates.

Demand response and energy efficiency programs also are benefitting from the deployment of smart meters by enabling electric companies to send price signals to customers and to get an accurate estimate of demand and usage reductions. Smart meter data also is used to determine bill credits based on actual reductions during demand response events.

Distributed Energy Resources Integration

Smart meters help electric companies identify and understand the impact of customer-sited DERs on system operations and planning.

As DERs—such as private or rooftop solar PV, energy storage systems, electric vehicles (EVs), and connected home devices like smart thermostats and grid interactive heat pump water heaters—continue to grow, having greater visibility into the performance of these systems allows electric companies to better utilize these resources for efficient distribution grid operations.

- In 2018, **Arizona Public Service (APS)** launched three new programs that incent residential customers to adopt smart thermostats, battery energy storage, or grid-interactive heat pump water heaters. Since APS has deployed smart meters fully throughout its service territory, the company can evaluate how demand-based rate structures, technologies, and/or customer behaviors influence system load shape and deliver customer savings.
- Smart meters also enable smart charging for EVs so that customers can manage their EV charging in response to price signals. And, in the future, customers may make their EVs available as a grid resource.

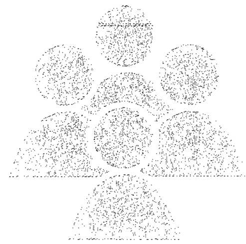
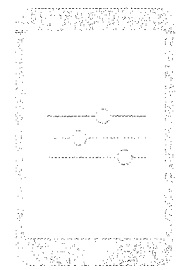
Other Services

Electric companies are supporting a range of other customer services using smart meter data, including:

- Offering online access to view and download energy use information from company websites and increasingly through mobile apps.
- Providing fewer estimated bills for a better customer experience.
- Providing remote connect and disconnect services to customers who are moving.
- Training customer service representatives using smart meter data to resolve billing questions.

Customers are benefitting from smart meters in many ways today. And, as electric companies increasingly engage with customers via online platforms, apps, and other channels, more customer services and solutions will be powered by smart meter data.

Smart meters provide customers control &

flexibility over their energy use.

ENHANCING GRID RELIABILITY, OPERATIONS, AND RESILIENCE

Having a reliable supply of electricity is more than just a convenience; it's a necessity. Our economy—and our way of life—depend on it. Customers expect continual improvements to resilience and reliability, and smart meters, coupled with other advanced technologies and continued investment in people and processes, are changing the way electric companies identify, respond to, and recover from problems on the energy grid. For example:

- Smart meter data and analytics provide situational awareness so that crews can be sent to the highest priority outage locations.
- On circuits that have switching devices or automation, faults are isolated and a large percentage of customers can be restored within minutes.

Electric company investments in the distribution grid are projected to be more than $39 billion in 2019.[5] Through targeted investments, electric companies are developing a digital distribution grid that can serve as a platform to enhance energy grid resiliency and reliability, integrate a growing number of DERs, and provide more customer solutions.

In recent years, extreme weather has impacted the electric power system in different parts of the United States. This section outlines how electric companies use smart meter data, analytics, and communication networks to predict, mitigate, and enhance energy grid reliability and operations.

Hurricanes

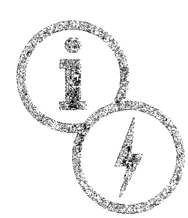
Smart meters were instrumental in the speedy recovery efforts following Hurricanes Harvey and Irma in 2017, Hurricane Michael in 2018, and Hurricane Dorian in 2019. The data from smart meters, when integrated with other systems, gave electric companies visibility into the distribution grid and the ability to better coordinate storm response efforts and communicate outage information to customers.

5. EEI Industry Capital Expenditures with Functional Detail (October 2019).

- During Hurricane Harvey, **CenterPoint Energy** operated more than 250 intelligent grid switching devices covering more than 140,000 customers. The company also flew 15 drones over more than 500 locations to assess damage, efficiently direct crews to accessible locations, and identify equipment needing further inspection. Real-time analytics were used to correlate weather and flood information with outage information and to provide operations crews with critical situational awareness and decision-making tools. These capabilities helped CenterPoint avoid almost 41 million outage minutes during Hurricane Harvey, a huge benefit to customers.
- In 2017, Hurricane Irma impacted about 4.4 million of **Florida Power & Light's** (FPL's) more than 5 million customers. Irma caused the largest outage in FPL's history and impacted all 27,000 square miles of FPL's service territory. FPL's grid hardening investments helped to make the system more resilient, and investments in digital grid technologies–5 million smart meters and more than 110,000 intelligent grid devices and smart switches–and data analytics greatly improved FPL's visibility into the nature, extent, and locations of outages, allowing the company to restore hundreds of thousands of customers during the storm without the need to roll trucks. As a result of FPL's visibility into its energy grid and the enhanced operational capabilities of the distribution network, approximately 1 million customers were restored before Irma exited FPL's service territory. And, for 2 million customers, power was restored by the end of the first full day of restoration work.

Smart meters played a key role in CenterPoint's and FPL's ability to respond rapidly and accurately to outages resulting from the hurricanes. By investing in smarter energy infrastructure, physical grid hardening, digital grid technologies, and data analytics to enhance grid resiliency and to improve visibility into outages, electric companies are able to restore power faster when outages do occur, resulting in millions of avoided outage minutes.

Smart meters enable two-way power and information flows to



improve visibility into the health of the energy grid.

Technologically Advanced Grid Operations & Analytics

The sensing capabilities in smart meters continue to advance, and electric companies now are collecting more complete power characteristics (e.g., voltages and reactive power) in addition to consumption and power on/off status from the meters.

By integrating voltage and reactive power data collected by smart meters with distribution management systems (DMS), electric companies are implementing distribution automation and circuit reconfiguration, volt/VAR management, device monitoring, and predictive asset maintenance capabilities. For example:

- American Electric Power, Baltimore Gas & Electric, Dominion Energy, DTE Energy, Evergy, FPL, Pepco, and several other electric companies are using voltage and power quality data collected and transmitted by smart meters for voltage optimization that provides energy efficiency benefits and proactively identifies distribution transformers that are at risk to fail.

As the energy grid integrates more DERs and as switching and dynamic automation capabilities proliferate, having an accurate representation and mapping of transformers to customer meters is critical for public safety, faster outage restoration, and the integration of DERs. These capabilities depend, in part, on data collected by smart meters.

CONCLUSION

The role of the distribution grid continues to evolve, but smart meters remain the fundamental building block. Increasingly, electric company distribution resource plans identify and prioritize grid modernization investments–both software and hardware–that must be made to improve visibility into the distribution system, enhance resiliency, integrate growing numbers of DERs, and provide a platform for new customer solutions.

As electric companies continue to manage, operate, and invest in an increasingly digital energy grid, the next steps are to continue to utilize the data being generated as a strategic asset to improve grid operations, use customer resources more efficiently, and offer new services to customers.

Table 1. Summary of Smart Meter Installations and Projected Deployments

Electric Company Type	Total Installed Smart Meters		
	2018	2019p	2020p
Investor-Owned	64,344,000	72,161,000	78,531,000
Public Power Utilities & Electric Cooperatives	23,721,000	26,234,000	28,496,000
U.S. Total	**88,065,000**	**98,395,000**	**107,027,000**

Note: Totals are rounded to nearest thousand and are projected for 2019 and beyond.

Table 2. Smart Meter Installations and Projected Deployments by Investor-Owned Electric Company

Electric Company	State	Meters Installed (2018)	Projected Meters Installed (2019)	Projected Meters Installed (2020)	Notes
Alliant	IA WI	670,000	972,000	972,000	Alliant Energy Corporation is comprised of two subsidiaries, Wisconsin Power and Light (WPL) and Interstate Power and Light (IPL). The WPL smart meter implementation was completed in December of 2011, now totaling 476,000 meters. In Fall of 2017, IPL began deploying smart meters in Iowa, with anticipated full deployment of 497,000 meters by the end of 2019.
Ameren Illinois	IL	1,070,000	1,246,000	1,246,000	Ameren Illinois is expected to fully deploy 1,246,000 smart meters by the end of 2019.

Electric Company	State	Meters Installed (2018)	Projected Meters Installed (2019)	Projected Meters Installed (2020)	Notes
American Electric Power	IN MI OH OK TX VA WV	2,543,000	3,138,000	3,334,000	AEP Indiana Michigan Power has deployed 15,000 meters; AEP Ohio has deployed 675,000 and will complete its Phase 2 deployment of 1,046,000 smart meters by Q1 2020, with approval for phase 3 (approximately 500,000 meters) pending; AEP Texas reached full deployment of 1,082,000 meters; AEP Public Service Company of Oklahoma reached full deployment of 578,000 meters; and AEP Appalachian Power deployed 190,000 smart meters in Virginia through 2018 and expects to deploy roughly 400,000 more throughout Virginia and West Virginia by the end of 2020.
Arizona Public Service	AZ	1,251,000	1,251,000	1,251,000	APS achieved full deployment of smart meters in March 2016.
Avista Corporation	WA	17,000	120,000	256,000	Avista installed 17,000 smart meters as part of a Smart Grid Demonstration Grant project and Phase 1 of AMI deployment. Avista anticipates a full rollout of 256,000 smart meters in Washington by the end of 2020.
Baltimore Gas & Electric	MD	1,290,000	1,309,000	1,328,000	BG&E, a subsidiary of Exelon Corporation, has fully deployed 1,290,000 smart meters, with anticipated growth through new customer enrollments.

Electric Company	State	Meters Installed (2018)	Projected Meters Installed (2019)	Projected Meters Installed (2020)	Notes
Black Hills Corporation	CO MT SD WY	212,000	212,000	212,000	Black Hills Energy has fully installed 212,000 smart meters in its service territory across four states.
CenterPoint Energy	IN TX	2,493,000	2,646,000	2,646,000	CenterPoint Energy received approval in 2008 to install an advanced metering system across its Texas service territory. It completed deployment in July 2012 and currently has 2,493,000 smart meters installed in the greater Houston area. Vectren, recently acquired by CenterPoint, expects to fully deploy 153,000 smart meters by the end of 2019 in Indiana.
Central Maine Power	ME	632,000	632,000	632,000	Central Maine Power, a subsidiary of AVANGRID, completed its smart meter deployment in 2012 and currently has 632,000 smart meters installed.
Cleco	LA	287,000	287,000	287,000	Cleco fully deployed 287,000 smart meters across the company's entire service territory after receiving approval from the Louisiana Public Service Commission in 2011.
Commonwealth Edison	IL	4,131,000	4,131,000	4,131,000	In June 2013, ComEd, a subsidiary of Exelon Corporation, received regulatory approval for full deployment of 4,131,000 smart meters, which was completed in 2018.

Electric Company	State	Meters Installed (2018)	Projected Meters Installed (2019)	Projected Meters Installed (2020)	Notes
ConEdison	NY	796,000	2,276,000	4,113,000	ConEdison deployed 796,000 smart meters through 2018 and is projected to deploy 4,113,000 by year-end 2020. As of December 2019, ConEdison has deployed 2,276,000 smart meters.
Consumers Energy	MI	1,831,000	1,831,000	1,831,000	Consumers Energy, a subsidiary of CMS Energy, achieved full deployment in 2017. Through 2019, new customer enrollments have led to a total of 1,831,000 smart meters deployed.
Dominion Energy	NC SC VA	453,000	526,000	996,000	Dominion Virginia has completed installation of 475,000 smart meters through 2019 and plans to have more than 1 million deployed by the end of 2021. Dominion South Carolina expects 27,000 smart meters deployed by the end of 2019 and 465,000 by the end of 2021. Dominion North Carolina is currently in early stage AMI deployment.
DTE Energy	MI	2,533,000	2,533,000	2,533,000	DTE Energy achieved full deployment in 2016 and currently has 2,533,000 smart meters.

Electric Company	State	Meters Installed (2018)	Projected Meters Installed (2019)	Projected Meters Installed (2020)	Notes
Duke Energy	FL IN KY NC OH SC	3,865,000	6,207,000	7,521,000	Through the end of 2019, Duke has deployed 705,000 smart meters in Florida; 147,000 in Kentucky; 2,974,000 in North Carolina; 741,000 in Ohio; 783,000 in South Carolina; and 857,000 in Indiana. As of end of 2019, deployments are complete in Kentucky, Indiana, Ohio, and South Carolina. More than 7.5 million smart meters are projected to be deployed by 2020; Duke is projected to reach full deployment by 2021 with nearly 8 million customers.
Duquesne Light Company	PA	600,000	600,000	600,000	Duquesne Light has fully deployed 600,000 smart meters.
Emera Maine	ME	122,000	122,000	122,000	Emera Maine has fully deployed 122,000 smart meters in its service territory.
Entergy Corporation	AR LA MS TX	21,000	1,065,000	2,244,000	In 2019, Entergy deployed 1,065,000 smart meters of an enterprise-wide deployment for 2,943,000 smart meters by December 2021. Entergy has deployed 247,000 in Arkansas; 328,000 in Louisiana; 183,000 in Mississippi; 108,000 smart meters in New Orleans; and 199,000 in Texas.
Evergy	KS MO	1,526,000	1,559,000	1,568,000	Evergy expects 1,559,000 smart meters (610,000 in Kansas and 948,000 in Missouri) deployed by the end of 2019.

Electric Company	State	Meters Installed (2018)	Projected Meters Installed (2019)	Projected Meters Installed (2020)	Notes
FirstEnergy Corporation	NY OH PA	1,973,000	2,100,000	2,100,000	Through end of 2019, FirstEnergy subsidiary Penn Power has fully deployed 169,000 smart meters; West Penn Power has deployed 729,000; MetEd has deployed 575,000; and Penelec has deployed 593,000. FirstEnergy operating company The Illuminating Company in Cleveland installed 34,000 meters as part of a pilot.
Green Mountain Power	VT	268,000	268,000	270,000	Green Mountain Power has deployed 268,000 smart meters to customers across Vermont.
Hawaiian Electric Industries	HI	5,000	28,000	50,000	Hawaiian Electric installed 5,000 smart meters during the first phase of its smart grid program. The company filed a grid modernization plan with its state regulatory commission and will make targeted smart meter investments through 2020.
Idaho Power	ID OR	546,000	546,000	546,000	Idaho Power has fully deployed 546,000 smart meters across its service territories in Idaho and Oregon.
Indianapolis Power & Light	IN	147,000	185,000	295,000	IPL, a subsidiary of AES Corporation, has installed 147,000 smart meters and is strategically deploying smart meters where needed. IPL has a pending application for full deployment of smart meters by 2022.

Electric Company	State	Meters Installed (2018)	Projected Meters Installed (2019)	Projected Meters Installed (2020)	Notes
MGE Energy	WI	9,000	9,000	9,000	MGE Energy has deployed 9,000 smart meters.
Minnesota Power	MN	79,000	93,000	109,000	Minnesota Power, a subsidiary of ALLETE, deployed 93,000 smart meters by year-end 2019 in north-east Minnesota and expects to complete full deployment by the end of 2020.
National Grid	MA NY RI	19,000	30,000	30,000	National Grid is piloting 30,000 smart meters in Massachusetts and New York, and actively working on rate cases to fully install smart meters in New York and Rhode Island.
NextEra Energy	FL	5,517,000	5,517,000	5,536,000	FPL has fully deployed 5,054,000 smart meters to residential, commercial, and industrial customers. Gulf Power reached full deployment in 2012 and has 463,000 meters.
NV Energy	NV	1,310,000	1,310,000	1,310,000	NV Energy, a subsidiary of Berkshire Hathaway Energy, has fully deployed 1,310,000 smart meters.
OGE Energy Corporation	AR OK	879,000	879,000	879,000	OG&E has fully installed 879,000 meters: 809,000 in Oklahoma and 70,000 in Arkansas.
Oncor	TX	3,611,000	3,611,000	3,611,000	Oncor has fully deployed 3,611,000 smart meters across its service territory.

Electric Company	State	Meters Installed (2018)	Projected Meters Installed (2019)	Projected Meters Installed (2020)	Notes
Orange and Rockland Utilities	NJ NY	217,000	382,000	446,000	Orange and Rockland Utilities, a subsidiary of ConEdison, has installed 217,000 smart meters through end of 2018 and plans to achieve full deployment of 446,000 by 2020.
Pacific Power	CA OR	517,000	655,000	655,000	Pacific Power, a subsidiary of Berkshire Hathaway Energy, expects full deployment of smart meters across service territories by year-end 2019 in California (47,000) and Oregon (608,000).
PECO	PA	1,675,000	1,675,000	1,675,000	PECO, a subsidiary of Exelon Corporation, has fully deployed 1,675,000 smart meters.
Pepco Holdings	DC DE MD	1,340,000	1,340,000	1,340,000	Pepco, a subsidiary of Exelon Corporation, has reached full deployment in the District of Columbia with 278,000 smart meters installed. Pepco and Delmarva Power in Maryland have reached full deployment, with 555,000 and 213,000 smart meters, installed respectively. In Delaware, Delamarva Power has reached full deployment with 293,000 meters installed.
PG&E Corporation	CA	5,323,000	5,323,000	5,323,000	PG&E has fully deployed 5,323,000 smart meters across its service territory.

Electric Company	State	Meters Installed (2018)	Projected Meters Installed (2019)	Projected Meters Installed (2020)	Notes
Portland General Electric	OR	888,000	888,000	888,000	PGE's smart meter program was approved by the state regulatory commission in 2008; full deployment was completed by the fall of 2010.
PPL Corporation	KY PA	1,450,000	1,450,000	1,450,000	PPL is in compliance with PA Act 129 and has fully deployed 1,441,000 smart meters in its Pennsylvania service territory. Pilot programs in Kentucky have deployed 9,000 smart meters.
Public Service Enterprise Group	NJ NY	144,000	513,000	882,000	In 2018, PSE&G filed a proposal with the New Jersey Board of Public Utilities to deploy 2.2 million smart meters by 2024. PGE&G's NY service territory has a pilot program with 129,000 smart meters deployed.
Puget Sound Energy	WA	190,000	374,000	564,000	Puget Sound Energy plans to deploy smart meters to all electric customers by the end of 2023.
San Diego Gas & Electric Company	CA	1,449,000	1,449,000	1,449,000	SDG&E has fully deployed 1,449,000 meters across its service territory.
Southern California Edison	CA	5,139,000	5,139,000	5,139,000	SCE has fully deployed more than 5 million smart meters and will continue to accommodate population growth.

Electric Company	State	Meters Installed (2018)	Projected Meters Installed (2019)	Projected Meters Installed (2020)	Notes
Southern Company	AL GA MS	3,951,000	3,951,000	3,951,000	Southern Company's Georgia Power and Alabama Power are fully deployed. Georgia Power reached full deployment in 2012 and has 2,498,000 meters. Alabama Power reached full deployment in 2010 and has 1,453,000 meters. Mississippi Power received approval to deploy 200,000 smart meters in late 2018.
Tampa Electric	FL	75,000	145,000	300,000	TECO (an Emera company) has installed 75,000 smart meters through 2018 with plans to complete deployment of 750,000 meters in early 2022.
Texas-New Mexico Power	TX	247,000	247,000	247,000	TNMP, a subsidiary of PNM Resources, has fully deployed 247,000 smart meters.
United Illuminating	CT	237,000	294,000	350,000	United Illuminating, a subsidiary of AVANGRID, has installed 237,000 of its projected 350,000 smart meters by the end of 2020.
Unitil Corporation	MA NH	108,000	108,000	108,000	Unitil has fully deployed 108,000 smart meters across its service territory around Concord, NH, and Fitchburg, MA.
WEC Energy Group	WI	662,000	946,000	1,145,000	WE Energies has deployed 662,000 smart meters to customers in Wisconsin.

Electric Company	State	Meters Installed (2018)	Projected Meters Installed (2019)	Projected Meters Installed (2020)	Notes
Xcel Energy	CO MN	13,000	32,000	40,000	Full deployment of smart meters in Colorado for 1.5 million customers will not begin until 2020 and will conclude in 2024. Xcel has publicly filed for full deployment of smart meters in Minnesota by 2024.
Other		13,000	11,000	11,000	Limited deployments by multiple operating companies account for roughly 13,000 smart meters deployed through 2018.
U.S. Total		**64,344,000**	**72,161,000**	**78,531,000**	

Note: Totals are rounded to nearest thousand.

Table 3. Smart Meter Installations by Electric Company Type and State (2018)

State	Investor-Owned Electric Company	Public Power Utilities & Electric Cooperatives	Total
AK	0	219,000	219,000
AL	1,453,000	483,000	1,936,000
AR	70,000	476,000	546,000
AZ	1,259,000	1,285,000	2,544,000
CA	11,956,000	1,102,000	13,058,000
CO	109,000	519,000	628,000
CT	237,000	41,000	278,000
DC	278,000	0	278,000
DE	294,000	45,000	339,000
FL	5,683,000	1,217,000	6,900,000
GA	2,498,000	1,918,000	4,416,000
HI	5,000	32,000	37,000
IA	196,000	239,000	435,000
ID	528,000	99,000	627,000
IL	5,203,000	238,000	5,441,000
IN	728,000	563,000	1,291,000
KS	944,000	327,000	1,271,000
KY	152,000	770,000	922,000
LA	307,000	171,000	478,000
MA	44,000	111,000	155,000
MD	2,059,000	219,000	2,278,000
ME	754,000	6,000	760,000
MI	4,365,000	306,000	4,671,000
MN	80,000	733,000	813,000
MO	582,000	647,000	1,229,000
MS	<1,000	562,000	562,000
MT	<1,000	145,000	145,000
NC	1,796,000	1,159,000	2,955,000

State	Investor-Owned Electric Company	Public Power Utilities & Electric Cooperatives	Total
ND	<1,000	118,000	118,000
NE	0	291,000	291,000
NH	78,000	85,000	163,000
NJ	84,000	23,000	107,000
NM	<1,000	123,000	123,000
NV	1,310,000	12,000	1,322,000
NY	1,077,000	19,000	1,096,000
OH	1,426,000	279,000	1,705,000
OK	1,387,000	434,000	1,821,000
OR	1,378,000	285,000	1,663,000
PA	5,655,000	234,000	5,889,000
RI	<1,000	2,000	2,000
SC	581,000	569,000	1,150,000
SD	70,000	147,000	217,000
TN	0	2,639,000	2,639,000
TX	7,434,000	3,171,000	10,605,000
UT	0	105,000	105,000
VA	614,000	424,000	1,038,000
VT	268,000	36,000	304,000
WA	207,000	737,000	944,000
WI	1,145,000	296,000	1,441,000
WV	1,000	7,000	8,000
WY	45,000	53,000	98,000
U.S. Total	**64,344,000**	**23,721,000**	**88,065,000**

Note: Totals are rounded to nearest thousand.

Table 4. Electric Companies with Full Smart Meter Deployment (2018)

AMI Full Deployment by Operating Company	
AEP Texas	Georgia Power
Alabama Power	Green Mountain Power
Arizona Public Service	Gulf Power
Baltimore Gas & Electric	Idaho Power
Black Hills Colorado Electric	Idaho Power (OR)
Black Hills Power (MT)	NV Energy
Black Hills Power (SD)	Oklahoma Gas & Electric (AR)
Black Hills Power (WY)	Oklahoma Gas & Electric (OK)
CenterPoint Energy (TX)	Oncor Electric Delivery
Central Maine Power	Pacific Gas & Electric
Cheyenne Light Fuel & Power (WY)	PacifiCorp (CA)
Cleco	PECO Energy
Commonwealth Edison	Pennsylvania Electric
Consumers Energy	Pennsylvania Power
Delmarva Power (DE)	Portland General Electric
Delmarva Power (MD)	Potomac Electric Power (DC)
DTE Energy	Potomac Electric Power (MD)
Duke Energy (KY)	PPL Electric Utilities
Duke Energy (NC)	Public Service Company of Oklahoma
Duke Energy (OH)	San Diego Gas & Electric
Duke Energy (SC)	Southern California Edison
Duquesne Light	Texas-New Mexico Power
Evergy (KS)	Unitil Energy Systems (NH)
Evergy (MO)	West Penn Power
Fitchburg Gas & Electric Light	Wisconsin Power & Light
Florida Power & Light	

Note: Full deployment may exclude customer with opt-out clauses or hard-to-access meters.

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About the Institute for Electric Innovation

The Institute for Electric Innovation focuses on advancing the adoption and application of new technologies that will strengthen and transform the energy grid. IEI's members are the investor-owned electric companies that represent about 70 percent of the U.S. electric power industry. The membership is committed to an affordable, reliable, secure, and clean energy future.

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