

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter of the application of
INDIANA MICHIGAN POWER COMPANY
for authority to increase its rates for the
sale of electric energy and for approval of
other related matters.

Case No. U-21461

INDIANA MICHIGAN POWER COMPANY
TESTIMONY: VOLUME II

KELLY J. FERNEAU
NICOLAS C. KOEHLER
JOE BRENNER
KATHERINE K. DAVIS
DANIEL M. WHITE
TYLER H. ROSS
JESSICA M. CRISS

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PRE-FILED DIRECT TESTIMONY

OF

KELLY J. FERNEAU

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**PRE-FILED DIRECT TESTIMONY OF KELLY J. FERNEAU
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY**

INTRODUCTION OF WITNESS

Q1. Please state your name and business address.

A1. My name is Kelly J. Ferneau and my business address is One Cook Place, Bridgman, MI 49106.

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

A2. I am employed by Indiana Michigan Power Company (I&M or Company) as the Site Vice President at Donald C. Cook Nuclear Plant (Cook or Cook Plant or the Plant). I&M is a wholly owned subsidiary of American Electric Power Company, Inc. (AEP).

Q3. Please briefly summarize your educational and professional background.

A3. I received a Bachelor of Science Degree in Mechanical Engineering from Trine University.

I began my career with Constellation Energy Corporation in June 1990 as a System Engineer at Byron Generating Station. In 1994, I joined the Operations Department and in 1996 I obtained my Senior Reactor Operator's license. After serving in the Byron Control Room as a Unit Supervisor and Shift Manager, I held the positions of Operations Work Control Manager and Maintenance Manager. In 2009, I transitioned to Entergy Nuclear at the Palisades Nuclear Generating Station as the Assistant Outage Manager. In 2013, I began my career with I&M at Cook as an Operations Manager. Since that time I served as the Operations Director and Plant Manager prior to assuming my current position as Site Vice President in July 2022. In this position, I report directly to Cook's Chief Nuclear Officer.

1 **Q4. What are your principal areas of responsibility with I&M?**

2 A4. I am responsible for providing overall management and oversight of Operations,
3 Radiation Protection, Chemistry, Maintenance, Work Control, Outage Management,
4 Environmental, Safety and Human Performance, Regulatory Affairs, Training,
5 Continuous Improvement, Security, Projects, Emergency Preparedness, and
6 Materials Management

7 **Q5. Have you previously testified in any regulatory proceedings?**

8 A5. Yes. I have submitted testimony with the Indiana Utility Regulatory Commission in
9 I&M's most recent base rate filing, Cause No. 45933.

10 **PURPOSE OF TESTIMONY**

11 **Q6. What is the purpose of your testimony in this proceeding?**

12 A6. The purpose of my testimony is to:

- 13 1) provide an overview of I&M's nuclear generating asset, the Cook Plant,
- 14 2) support Cook's operation and maintenance (O&M) expenses during the
15 twelve-month, forward-looking test period ending December 31, 2024 (the
16 Test Year),
- 17 3) support an adjustment to the Test Year level of O&M expenses to reflect an
18 increase to outage amortization expense and plant activities identified after
19 the Company's forecast was complete. (O&M-17),
- 20 4) support the projected capital expenditures at Cook from January 1, 2023
21 through December 31, 2024 (the Capital Forecast Period),

- 5) provide an update on the status of the Dry Cask Storage Project,
- 6) provide information on Cook's Subsequent License Renewal effort.

Q7. Are you sponsoring any Exhibits?

A7. Yes. I am sponsoring the following Exhibits

- Exhibit A-12, Schedule B5.2: Projected Capital Expenditures, Nuclear Production Plant
- Exhibit IM-2 (KJF-1): Cook Plant Systems Diagram
- Exhibit IM-3 (KJF-2) Enercon Study (Confidential)

In addition, I co-sponsor the Cook Plant information contained in Exhibit IM-22 (ZBW-11), the I&M Project Life File which contains a list of all capital projects; capital expenditures by month during the Capital Forecast Period; and plant in-service information.

Q8. Were these Exhibits that you sponsor prepared or assembled by you or under your direction?

A8. Yes.

Q9. Please summarize your testimony.

A9. My testimony provides an overview of the Cook Plant operations and performance. In addition, my testimony supports that Cook's operation and maintenance (O&M) expenses during the Test Year have been developed using a robust planning and review process and are reasonable and necessary to maintain the safe and reliable operation of the facility. Additionally, I describe the projected capital expenditures at Cook during the Capital Forecast Period and the process used to ensure the

1 portfolio of projects the Company is proposing in this case are necessary for the
2 continued operations of the Cook plant.

3 I describe the status of the settlement agreement with the United States
4 Department of Energy (DOE) as a mechanism for submitting and recovering costs
5 associated with Dry Cask Storage.

6 Finally, I explain that upgrades done at the Cook Plant over the last several
7 years has allowed Cook to provide safe and reliable power through its initial license
8 extension period and has also better prepared Cook for a potential Subsequent
9 License Renewal (SLR). The SLR process is a complex undertaking that includes
10 development of a Subsequent License Renewal Application (SLRA), inspections
11 of the plant, environmental reviews, Nuclear Regulatory Commission (NRC)
12 reviews, and public participation.

13 A SLR feasibility study (Feasibility Study) prepared for Cook Units 1 and 2
14 indicated that no obstacles exist that would prevent Cook from operating another
15 20 years beyond its current renewed license. As a result, the Company is
16 proposing a multi-year SLR Project, a large undertaking by multiple engineering
17 groups to determine if a renewal of Cook's license for the continued operation of
18 Units 1 and 2 through 2054 and 2057, respectively, is appropriate. The SLR Project
19 will also provide the necessary inputs into the SLRA. To obtain the information
20 necessary to maintain the timelines associated with the SLRA process it is
21 reasonable and necessary to commence this work now. Taking these steps is also
22 consistent with the Short-Term Action Plan in the Company's Integrated Resource
23 Plan (IRP).

COOK NUCLEAR PLANT OVERVIEW

Q10. Please describe the design of the Cook Plant.

A10. The Cook Plant is a two-unit nuclear power plant located along the eastern shore of Lake Michigan in Bridgman, Michigan. Both units are pressurized water reactors with four-loop Westinghouse nuclear steam supply systems. The combined nominally rated net electrical output for both units is 2278 megawatts. A diagram of the Cook Plant Systems is provided as Exhibit IM-2 (KJF-1).

Unit 1 received its operating license from the NRC in 1974 and began commercial operation in 1975. Unit 2 received its operating license in 1977 and began commercial operation in 1978. The NRC initially granted 40-year licenses to each unit and granted 20-year license extensions in 2005. Unit 1 is currently licensed to operate until 2034, and Unit 2 until 2037.

The Cook Plant provides safe, low-cost, and carbon-free generation to I&M's customers while maintaining the highest standards of regulatory compliance. 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 herein are the result of that process and are reasonable and necessary for the continued operation of the Cook Plant for the benefit of I&M's customers.

Q11. Please describe the Cook Plant's organization.

A11. The Cook Plant is operated by I&M's Nuclear Generation Group (NGG), which consists of approximately 990 full time I&M employees. Cook also employs approximately 100-200 contract workers on a long-term basis and 600-1000

temporary contract workers for refueling outages. The NGG is organized to ensure that all activities required to operate and maintain the Cook Plant are accomplished in a safe, reliable, and efficient manner.

Q12. Please describe the Nuclear Regulatory Commission's regulation of the Cook Plant.

A12. The NRC provides specific technical requirements through regulations, regarding the components that must be incorporated into the design of the systems, to ensure the protection of public health and safety. The NRC defines compliance with these regulations during facility operation, in part, by incorporating certain Technical Specifications into the facilities' Operating License.

These Technical Specifications include Limiting Conditions for Operation (LCO), for use during abnormal, temporary operational circumstances. In order for the Plant to continue operating during this time, the LCO must be continuously met, and the temporary operational circumstance remedied within a specified time. If an LCO is not met within the specified timeframe, the plant must be shut down until the temporary circumstance is remedied. These NRC regulations drive certain investments at the Cook Plant as described further below.

Q13. Please describe the Cook Plant's overall performance.

A13. Cook's overall performance remains excellent. 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.

1 **Q14. How has this performance been achieved?**

2 A14. Cook is a continuous learning organization, which is steadily strengthened through
3 the application of internal lessons learned, operating experience, benchmarking, and
4 industry best practices to all facets of the plant's design, maintenance, and operation.
5 These practices have directly contributed to the cost-effective, efficient, safe, and
6 reliable operation of the Cook Plant.

7 **Q15. Please describe the planning and management practices of the Cook Plant.**

8 A15. Cook engages in planning and resource allocation through a Nuclear Asset
9 Management (NAM) Process and a strategic Long-Range Plan (LRP), which identify
10 critical components and the projects necessary to ensure their reliability.

11 The NAM Process is used for making operational, resource allocation, and
12 risk management decisions to maximize the asset while maintaining the safety of the
13 plant and meeting regulatory requirements. NAM helps to ensure only necessary
14 capital improvements are made.

15 The LRP is an element of the NAM Process and is used to identify necessary
16 work years in advance of actual implementation. Plant needs are evaluated and
17 refined by key plant personnel and undergo multiple internal reviews. Cook also
18 works collaboratively with I&M and the American Electric Power Service Corporation
19 (AEPSC)¹ to evaluate the Plant's needs.

20 As part of the NAM Process and LRP, Cook identifies projects that are
21 necessary to meet regulatory requirements and support safe and reliable operations.

¹ AEPSC supplies engineering, financing, accounting, planning, advisory, and other services to the subsidiaries of the AEP system, one of which is I&M.

1 Cook applies industry best practices to identify optimum refurbishment and
2 replacement schedules for critical plant components. Projects are prioritized and
3 strategically scheduled in the LRP. The goal is to ensure that components continue
4 to operate consistent with our NRC operating license so as to maintain reliable
5 operations at the Cook Plant.

6 **Q16. Please describe Cook's refueling outages.**

7 A16. Refueling outages occur every 18 months at each unit. The cost of these outages is
8 amortized over a period of 18 months consistent with past practices and concurrent
9 with the timing of the outages. Typically, every year at least one unit is refueled (in
10 either the Spring or Fall), and every third year both units are refueled (one each in
11 the Spring and Fall). Refueling outages are also the time when other capital
12 improvements and operation and maintenance activities are completed which require
13 the unit to be out of service to complete. This increases the scope and risk of refueling
14 outages and makes each refueling outage unique.

15 Most recently, Cook has had dual unit outages in 2022 and will again in 2025.
16 The work scope included in each outage is thoroughly reviewed and managed to
17 minimize duration while ensuring the safety of employees, the plant and the public.
18 Minimizing the duration of refueling outages allows the plant to maximize the
19 reliability and low-cost generation Cook provides to I&M's customers.

20 **Q17. Does the Cook Plant benefit customers?**

21 A17. Yes. Nuclear power is an important resource in I&M's energy portfolio. Cook provides
22 safe, reliable, low-cost, and carbon-free generation to I&M's customers. Annually, the
23 Cook Plant generates enough electricity to supply approximately 1.5 million homes.

1 Additionally, Cook has a long-standing commitment to nuclear education, community
2 outreach, and non-profit agency support.

3 **COOK PLANT OPERATION AND MAINTENANCE EXPENSE**

4 **Q18. Please summarize the Cook Plant's O&M expenses.**

5 A18. O&M expenses include base operating expenditures and non-outage equipment
6 reliability expenditures. Included in the base operating expenditures are refueling
7 outage amortizations, which can have a significant impact on O&M expenditures in
8 any given year depending on the refueling outage cycle. The majority of Cook O&M
9 expenses can be described as: 1) labor, including straight time and over time; 2)
10 planned outages; 3) plant maintenance activities; and 4) operating expenses.

11 Operating and maintaining the Cook Plant involves managing technically
12 complex systems and components. Practically all of Cook's O&M activities are
13 subject to comprehensive regulation and continuous inspection by the NRC.

14 **Q19. What is the Cook Plant doing to maintain a reasonable level of O&M expense?**

15 A19. As described above, Cook is a continuous learning organization, and that behavior
16 is evident in our consistent focus on O&M expenses to ensure they are reasonable.

17 We take actions to shorten our outages by reviewing planned work,
18 benchmarking our peer nuclear plants, and incorporating operating experience and
19 efficiencies. Cook continues to review our preventative maintenance schedules and
20 activities to eliminate unnecessary work. Cook continually looks for ways to keep its
21 O&M expenses low without compromising the safe and reliable operation of its Units.

1 **Q20. How did you develop the forecast Test Year O&M expenses for the Cook Plant?**

2 A20. The NGG is constantly evaluating the future needs of Cook to ensure it continues to
3 operate safely, reliably, efficiently, and in compliance with all regulatory
4 requirements. Cook employees continually assess the condition of plant equipment
5 and plan not only for the modification or replacement of equipment when it reaches
6 the end of its useful life, but also for unforeseen failures. The NGG and Cook
7 management review the Plant's current and future needs along with historical O&M
8 expenses to develop forecasts, and then reassess those forecasts prior to approval.
9 Forecasts are then refined annually in a collaborative process that involves Cook
10 Plant management, I&M management, and AEPSC management. These reviews
11 ensure that work is performed at a reasonable cost.

12 **Q21. What is the forecasted Cook O&M expense for the Test Year ending December**
13 **31, 2024?**

14 A21. The unadjusted Cook O&M expense for the 12-month Test Year ending
15 December 31, 2024 is approximately \$254 million as shown on Exhibit A-13,
16 Schedule C-5. This represents the total O&M costs to maintain the Cook facility.
17 Company witness Morgan describes the cost allocation calculations that determine
18 the Michigan jurisdictional share of the total O&M costs.

19 **Q22. Please describe the major areas of O&M expense.**

20 A22. *Figure KJF-1* identifies Cook's four major O&M expense categories.

Figure KJF-1. Cook O&M Forecast Period O&M Expense (\$000)

Category	2024 O&M Projected Expense
Labor	\$129,946
Planned Outages	\$59,868
Operating Expenses	\$46,163
Plant Maintenance	\$18,304
Total	\$254,281

1 The largest portion of the Cook O&M expense is the labor category. Labor includes
2 the expenses associated with employing the workforce that is necessary to operate
3 the facility and to perform the necessary maintenance to sustain safe and reliable
4 operations.

5 Planned Outages are the second largest O&M expense category. As
6 required by the fuel cycle, each unit must be shut down every 18 months so that
7 the nuclear fuel can be replenished. While the unit is shutdown, maintenance and
8 testing activities that can only be performed while the unit is offline, are performed.
9 Outage cost can vary based upon the work scope that is being completed.

10 A rigorous scoping process is utilized to ensure that the approved work
11 scope is limited to those items that are necessary to ensure safe and reliable
12 operation during the next operating period. Once the work scope has been
13 determined, great effort is taken to optimize the outage schedule so as to minimize
14 the outage duration. Scope control and outage scheduling combined with
15 disciplined execution, ensure that refueling outages are completed in the most
16 cost-effective manner.

1 Operating Expenses represent the third largest O&M category. These
2 expenses are further broken down into the sub-categories of outside services, staff
3 augmentation, materials, and other. Outside services includes a broad collection
4 of services ranging from radioactive waste disposal; trash and water bills; and state
5 and NRC fees. Staff augmentation significantly represents the facilities cleaning,
6 building, and grounds services. Materials includes costs incurred due to part repair
7 and return, as well as personal protective equipment. Finally, other includes items
8 such as benchmarking and fees. All of these expenses are necessary to ensure
9 the various departments operate in a manner that supports plant operation.

10 The final O&M category is Plant Maintenance. These expenses include the
11 outside services, materials, and supplies necessary to perform the required
12 preventive and corrective maintenance activities while the units are online so as to
13 support safety and reliability. Various management committees, such as Plant
14 Health Committee and the Preventive Maintenance Oversight Group, provide
15 oversight of the preventive and corrective maintenance activities to ensure that
16 only necessary work is performed.

17 Also included in this category are expenses that are incurred to maintain
18 compliance with regulatory requirements. Specifically, these activities include
19 accident analysis revisions, regulatory required programs, and the resolution of
20 NRC inspection findings.

1 **Q23. Did the Company have to make any adjustments to its forecasted Test Year**
2 **O&M expense for the Cook Plant?**

3 A23. Yes. Adjustment O&M-17 increases the Test Year amount of O&M expense for the
4 Cook Plant for an identified increase to outage amortization and plant maintenance
5 expense. The increase in outage amortization expense is related to ice condenser
6 scope, updated vendor proposals and cost escalations since the Test Year forecast
7 was complete. Specifically, labor rates for radiation protection technicians and
8 decontamination technicians have increased due to a shortage of the skill set in the
9 industry. Cook has also seen an increase in rates for welders, tensioning technicians,
10 and overall craft labor. The plant maintenance increase is related to projects such as
11 the Isophase Bus Duct work for Unit 2 and work on Cook's Risk Informed Engineering
12 Program. In addition, please see Exhibit IM-50 (JWM-1) Summary of Projected
13 Adjustments, which identifies the forecasted adjustments and provides a brief
14 description, the adjustment amount, and the page and line number where the
15 adjustment is located in the jurisdictional cost-of-service allocation study.

16 **Q24. Is Adjustment O&M-17 reasonable and necessary to provide service to I&M**
17 **customers?**

18 A24. Yes. This level of O&M represents a reasonable level of spending needed to meet
19 regulatory requirements, provide reliable power to the grid, and reduce the amount
20 of time Cook is single point vulnerable to an equipment issue. In turn this will ensure
21 the safe and reliable operation of the Cook Plant, providing low cost, safe,
22 environmentally compliant, reliable electric generation for I&M's customers.

1 **Q25. What was the Cook O&M expense for the Historical Period ending**
2 **December 31, 2022?**

3 A25. The Cook O&M expense for the 12-month Historical Period ending December 31,
4 2022 was approximately \$243 million as shown on Exhibit A-13, Schedule C-5.

5 **Q26. What is the primary reason for the difference between the Historical Period and**
6 **the Test Year O&M expense?**

7 A26. The main drivers for the difference of approximately \$11 million between the
8 Historical Period and Test Year O&M expense is outage amortization, and inflation
9 related to services and material costs. As many industries have seen over the last
10 few years the prices of goods and services have increased due to shortages in
11 supply-chain, reduction in material production, and labor resource constraints. The
12 result for Cook as with many companies, is higher prices. In addition, as mentioned
13 above, outage amortization can have a significant impact on O&M expense. In this
14 case, outage amortization from the longer outages completed in 2022 is the result.

15 **Q27. Is the Test Year O&M expense representative of I&M's expected activities and**
16 **expenses necessary to provide ongoing safe and reliable generation to its**
17 **customers?**

18 A27. Yes. I&M has a long history of operating the Cook Plant, thereby allowing I&M to
19 understand the ongoing O&M needs. The Test Year O&M expenses represent a
20 reasonable level going forward. These O&M expenses have been scrutinized at the
21 plant, operating company, and corporate levels, and are representative of the
22 necessary Cook Plant O&M expenses.

COOK PLANT CAPITAL EXPENDITURES

Q28. Please summarize the type of capital expenditures forecast for the Cook Plant during the Capital Forecast Period of January 1, 2023 through the Test Year ending December 31, 2024.

A28. Capital expenditures can be categorized into four types: Major Projects, Regulatory Related Investments, Preventative/Corrective Maintenance and Other. The expenditures during the Capital Forecast Period through the Test Year in each category are described in more detail below, and provided in Exhibit A-12, Schedule B5.2 and in Exhibit IM-22 (ZBW-11), the I&M Project Life File which contains a list of all Cook capital projects; capital expenditures by month during the Capital Forecast Period; and plant in-service information.

Q29. What is the amount of capital expenditures forecast for the Cook Plant during the Capital Forecast Period?

A29. Excluding AFUDC, the capital expenditures for the Cook Plant during the Capital Forecast Period are approximately \$139 million, as shown on *Figure KJF-2*. This amount of capital spending is included in the forecast presented by Company witness Wnek². These values represent I&M's total capital expenditures. Company witness Morgan describes the cost allocation calculations that determine the Michigan jurisdictional share of the total capital expenditures.

² Figure ZBW-3 of Company witness Wnek's direct testimony shows the AFUDC amounts added to capital expenditures.

Figure KJF-2. Cook Capital Expenditures, excluding AFUDC (\$000)

	<u>2023</u>	<u>2024</u>	<u>Total</u>
Major projects	\$29,876	\$18,102	\$47,977
Regulatory Related Investments	\$4,531	\$12,530	\$17,061
Preventative/Corrective Maintenance	\$18,101	\$21,090	\$39,191
<u>Other</u>	<u>\$18,348</u>	<u>\$16,254</u>	<u>\$34,603</u>
Total	\$70,856	\$67,976	\$138,832

1 *Figure KJF-3* shows that I&M forecasts \$134 million of capital investment related
2 to Cook to be placed in service (EPIS) in 2023 and 2024.³

Figure KJF-3. Cook additions to EPIS in 2023-2024, including AFUDC (\$000)

Major Projects	\$60,575
Regulatory Related Investments	\$570
Preventative/Corrective Maintenance	\$41,051
<u>Other</u>	<u>\$31,771</u>
Total	\$133,968

3 **Q30. How are capital expenditures forecast?**

4 A30. Similar to O&M expenses, proposed capital expenditures undergo an extensive
5 development and refinement process. As discussed above, the LRP identifies
6 necessary expenditures years in advance of implementation and the Cook Plant's
7 needs are evaluated and refined through multiple levels of review involving Cook
8 Plant personnel, I&M and AEPSC management.

³ Figures ZBW-2 and ZBW-3 of Company witness Wnek's direct testimony shows how nuclear additions to EPIS are used to forecast total Company Plant in Service activity during the Capital Forecast Period.

1 Decisions regarding if and when capital investments are made are based on a
2 combination of factors, including whether the investment is needed to fulfill regulatory
3 or safety requirements, the urgency of the need, and economic benefit. All of these
4 factors are evaluated by the management teams responsible for approving capital
5 projects.

6 **Q31. Please describe the Capital Forecast Period capital expenditures in the Major**
7 **Projects category.**

8 A31. Capital Forecast Period expenditures in the Major Projects category are those
9 projects which are valued at \$3 million or greater and can be found in the Exhibit A-
10 12, Schedule 5.2, and Exhibit IM-22 (ZBW-11), the Project Life File in the testimony
11 of Company witness Wnek.

12 These projects are approved utilizing the previously defined review and approval
13 process through both Cook and I&M management. For the Capital Forecast Period,
14 examples of Major Projects include:

- 15 • Cook local area network expansion project which will create a wireless
16 infrastructure backbone that will support wireless gauge readers, mobile
17 applications, an electronic Work Management System, and wireless remote
18 monitoring and predictive technologies allowing Cook to move from time-
19 based preventative maintenance to condition-based preventative
20 maintenance. The wireless infrastructure backbone will be installed
21 throughout Cook's Auxiliary, Turbine and Screenhouse Buildings and will
22 include the installation of new cabinets, network switches, Wi-Fi access
23 points, and wireless controllers. Additionally, new Radiation Protection (RP)

1 equipment will be integrated into the wireless backbone to ensure
2 compliance with station configuration management processes, and to
3 address fire protection loading,

- 4 • Makeup Plant (MUP) Chemical Container Upgrade which will replace
5 chemical containers and injection equipment components to maintain
6 reliability, eliminate industrial safety concerns, and reduce equipment
7 failures,
- 8 • Replacement of obsolete systems and equipment that has reached the end
9 of its useful life, such as the auxiliary building passenger elevator
10 replacement and the auxiliary building freight elevator replacement.

11 **Q32. Please describe the Capital Forecast Period expenditures in the Regulatory**
12 **Related Investments category.**

13 A32. The Capital Forecast Period expenditures in the Regulatory Related Investments
14 category reflect plant modifications required by the NRC and mainly consists of costs
15 related to Cook's Subsequent License Renewal (SLR) Project which is described in
16 more detail below.

17 Additional capital expenditures in this category relate to required
18 improvements to replace the Protected Area perimeter intrusion detection system
19 microwaves and lasers, in which obsolete equipment is being replaced.

Q33. Please describe the Capital Forecast Period expenditures in the Preventative/Corrective Maintenance category.

A33. Capital expenditures in the Preventative/Corrective Maintenance category relate to capital expenditures necessary for maintaining and pre-emptively replacing plant components prior to failure.

These expenditures include fire protection piping replacements, steam generator Leading Edge Flow Meter (LEFM) replacements, Cook's routine capital blanket Nuclear Minor Improvement Blanket (NMIB), the Unit 1 and Unit 2 Circulating Water Pump replacement, and Reactor Coolant Pump (RCP) Motor replacement .

Q34. Please describe the Capital Forecast Period expenditures in the Other category.

A34. Capital Forecast Period expenditures in the Other category relate to capital projects that are not captured in the categories discussed above. Such expenditures include:

- Owner Controlled Area (OCA) diesel generator upgrade as it has reached the end of its useful life;
- Replace refueling cameras which are degraded and obsolete;
- Compressed air dryer control replacement because the current equipment is degraded and obsolete; and
- Other general plant improvements.

All of these projects are necessary for the facility to operate to the end of its approved license.

Q35. Is the forecast level of capital expenditures reasonable and necessary?

A35. Yes. As the systems, structures, and components reach their end of useful life or become obsolete, they must be replaced. Additionally, capital expenditures must be made to ensure compliance with evolving regulatory requirements.

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.

DRY CASK STORAGE

Q36. Please describe the breach of contract by the United States Department of Energy (DOE) as it pertains to the Dry Cask Storage Project?

A36. I&M is the "Purchaser" under a Standard Contract with the DOE for the acceptance of spent nuclear fuel (SNF) and high-level radioactive waste (HLW) under the Nuclear Waste Policy Act. See 10 CFR 961.11. Under the Standard Contract, DOE agreed to begin accepting SNF and HLW from Cook "not later than January 31, 1998."

However, the DOE has neither accepted this material from any facility nor issued an acceptance schedule as required. This has resulted in a partial breach of contract. Because the DOE has failed to fulfill its contractual obligation to accept Cook's SNF and HLW, Cook has been required to construct Dry Cask Storage to store this material on site. The purpose of the Dry Cask Storage Project is to provide spent nuclear fuel dry storage capacity at the Cook Plant at an Independent Spent Fuel Storage Installation (ISFSI) pad.

1 This project consists of loading SNF assemblies into stainless steel canisters
2 which are then transferred into dry concrete casks. To date, Cook Plant has loaded
3 57 casks with 1,824 fuel assemblies. The next loading campaign is scheduled to
4 occur in 2024.

5 **Q37. Does I&M have a settlement agreement with the DOE as a mechanism for**
6 **submitting and recovering costs associated with Dry Cask Storage?**

7 A37. Yes. I&M has had a Settlement Agreement (Agreement) with the DOE since October
8 2011. Claims are submitted on an annual basis according to terms laid out within the
9 Agreement. The Agreement has recovered costs incurred through December 31,
10 2022. At this time, I&M has received a Settlement extension with the DOE through
11 December 31, 2025. As of December 31, 2022 I&M has submitted thirteen claims
12 and has recovered \$209.2 million from the DOE. This equates to a recovery rate of
13 approximately 97%. Company witness Seger-Lawson discusses I&M's request for
14 continued deferral accounting authority related to this Settlement Agreement claims
15 process.

16 **COOK SUBSEQUENT LICENSE RENEWAL PROJECT**

17 **Q38. What is the Cook Subsequent License Renewal Project?**

18 A38. The Cook SLR Project includes the activities, and associated costs, necessary to
19 evaluate, prepare and submit an application to the NRC seeking to extend the
20 operation of Cook Units 1 and 2 through 2054 and 2057. This project will involve
21 several steps that will take place through the 2027 calendar year including
22 engineering reviews, site inspections, scope definition, capital investment and

1 maintenance requirements and cost estimates. These efforts will provide the needed
2 information to assemble a SLRA.

3 **Q39. What is the current status of the Cook Plant's license?**

4 A39. Cook was initially granted a license to operate each unit for 40 years. In 2005, Cook
5 was granted a renewed license allowing each unit to operate an additional 20 years
6 (Unit 1 until 2034 and Unit 2 until 2037). This additional 20 years is known as the
7 period of extended operation (PEO). The NRC and the nuclear industry are currently
8 focusing on subsequent license renewals which authorize plants to operate through
9 a second PEO for a total of 80 years. Subsequent license renewals are also for a 20-
10 year period.

11 **Q40. Does the SLR Project build on the Life Cycle Management Project?**

12 A40. Yes. The Life Cycle Management Project investments and other major capital
13 investments made during the first PEO have better prepared Cook for a SLR. Plant
14 equipment that otherwise would require replacement or refurbishment has now been
15 resolved. The SLR will allow the Company and its customers to extract more value
16 out of the LCM investments by allowing for an extended operation of the associated
17 equipment upgrades. In addition, the project management experience gained from
18 such a large and complex project provides Cook personnel valued experience in the
19 areas of project management, staffing, scheduling and cost tracking in preparation
20 for the SLR Project.

21 **Q41. Has any work been done on the Cook SLR Project?**

22 A41. Yes. Cook contracted with Enercon Services Inc, an outside engineering firm
23 experienced in the development, defense, and implementation of license renewals

1 to perform a Feasibility Study. The Feasibility Study was performed as a preliminary
2 step to identify any technical issues or circuit breakers that would prevent Cook from
3 moving forward with the SLR project. The Feasibility Study, Exhibit IM-3 (KJF-2), also
4 assessed challenges with continuing plant operation for an additional 20 years. The
5 Feasibility Study included a proposed milestone timeline and budgetary estimate for
6 the Cook SLRA.

7 **Q42. Please summarize the results of the feasibility study.**

8 A42. The Feasibility Study for Cook Units 1 and 2 indicated that no obstacles exist that
9 would prevent Cook from operating another 20 years beyond its current renewed
10 license. The Feasibility Study also indicated:

- 11 • that obtaining a second renewed license would involve a four-
12 to-seven-year process, assuming specialty vendor activities are
13 contracted early;
- 14 • no environmental issues were identified to prevent an SLR; and
- 15 • Cooks aging analyses demonstrates a proactive approach to
16 aging management

17 **Q43. Are other nuclear power plants submitting SLRAs?**

18 A43. Yes. To date, there are sixteen units at eight nuclear power sites that have submitted
19 SLRAs. Eight of these are Westinghouse Pressurized Water Reactors (PWR) that
20 are similar to Cook's four loop Westinghouse PWR design. In addition, there are eight
21 units at four nuclear sites that have submitted formal letters of intent to the NRC to
22 apply for an SLR. One of these units is a PWR that is similar to Cook's PWR design.

1 I&M has been able to leverage this industry experience and shared knowledge in its
2 SLR Project and will continue to do so as the SLR Project continues.

3 **Q44. Why is the Company engaging in this project now?**

4 A44. The SLR Project process is a complex undertaking that includes development of a
5 SLRA, which involves extensive inspections of the plant, environmental reviews,
6 NRC reviews, and public participation. If a licensee submits a renewal application at
7 least five years before expiration of the existing license, the plant can continue to
8 operate until the application is approved by the NRC. Moving forward with the
9 additional SLRA work now allows I&M the needed time to make an informed decision
10 and, if NRC approval of a SLRA is received and SLR is pursued, adequately plan for
11 the additional inspections of components that are required to be performed before
12 entering a subsequent PEO at the end of our current license.

13 **Q45. How does the SLR Process fit with the Company integrated resource planning**
14 **process?**

15 A45. The Company's 2021 IRP, approved by the Commission in Case No. U-21189
16 included efforts to evaluate Cook relicensing in the IRP's Short Term Action Plan.
17 The Company was very intentional and thoughtful to structure the near-term IRP
18 plans in a manner that maintains optionality regarding the future decisions at the
19 Cook Plant. This approach recognizes that significant analysis is necessary to
20 assess the potential extension of the operating life of the Cook Plant. The SLR work
21 reflects the Company's effort to implement this aspect of its Short-Term Action Plan.
22 Additionally, in term 8a. of the Settlement Agreement approved in Case No. U-21189,
23 the Company is required to provide an analysis in its next IRP to determine if it is

more reasonable and prudent that the Cook Plant retires at the end of the current units' license lives or seek relicensing. The SLR work will help to inform this analysis in its next IRP and maintain the optionality to pursue a SLRA if it is deemed the best course of action as a result of the IRP process.

Q46. Please elaborate on the SLR Project work and milestones necessary to meet the SLRA November 2027 this target filing date.

A46. The development of the SLRA includes multiple integrated steps that must be completed to determine if the SLR is an appropriate course of action, the physical modifications that would be required if the Company were to proceed with a SLRA, and to be prepared to support the approval process through multiple regulatory processes.

The following is a high-level scope of work necessary to complete the SLRA:

- Engage with an Engineering Consultant to complete the following tasks:
 - Scoping of approximately 240,000 plant components to determine what will be considered as part of the SLR rule;
 - Screening from the defined scope of components to determine requirements for Aging Management Review;
 - Creation or revision of approximately 50 Aging Management Program documents; and
 - Summarization and review of approximate 900+ page SLRA.
- Specialty vendor to perform analyses on the extended life of the reactor vessel and surrounding components
- Specialty vendor to develop and review an Environment Report as input into the SLRA

- Cook staff to provide ongoing support of the project and provide operational data to support studies and analyses
- NRC and Legal fees to support onsite NRC audits, Advisory Committee on Reactor Safeguards meetings, and SLRA preparation

In addition to the scope of work to complete the SLRA, the Company will also be undertaking the necessary steps with the Commission and the Indiana Utility Regulatory Commission (IURC) to complete analysis and seek appropriate approvals.

The first significant milestone is determining the inclusion of the Cook SLR project in the Company's Preferred Portfolio during the next IRP cycle. The Company has committed to engaging stakeholders around the assumptions associated with the SLR and including the SLR in the Company's next IRP process. This milestone serves as an "off ramp" for the SLR project if the Cook SLR is not included in the Preferred Portfolio. If that were to occur, the Company would stop the efforts necessary to pursue the SLR and would only experience the costs incurred up to the point of that decision.

If the SLR is included in the Company's Preferred Portfolio a project schedule and execution plan will be formulated. Assuming the approval of the Company's proposal in this filing to begin the SLR process, our Company forecast indicates that work will begin in 2024 to ensure the SLRA will be submitted to the NRC before November 2027. It is expected that the NRC will take between 22 and 24 months to review and approve the SLRA. This would then allow the necessary time to perform the substantial number of inspections required prior to Unit 1's license expiration. Based on the timeline, the NRC would be notified of our intent to submit an SLRA

1 during the summer of 2024 to allow the NRC to plan and allocate resources for the
2 SLRA review.

3 Concurrent with this process, the Company would also plan to make the
4 appropriate regulatory filings with the Commission and IURC to obtain approval for
5 the entire SLR scope of work and associated costs once the SLRA work is complete
6 and full scope of work is defined. This would provide the Commission another
7 opportunity to evaluate the prudence and reasonableness of the costs necessary to
8 complete the SLR project and extend the operating life of the Cook facility.

9 **Q47. Why is the SLR Project work necessary?**

10 A47. The development and submittal of a SLRA outlined above is necessary and part of
11 the required process to obtain a second renewed license. In addition, renewing
12 Cook's license will provide I&M and its customers with reliable long term energy
13 security from a carbon-free resource and contribute to I&M's goal of zero carbon
14 emissions by 2045.

15 **Q48. What is the estimated cost of the proposed SLRA work?**

16 A48. Based on initial cost estimates it is expected the full costs of completing the SLRA
17 will be between \$40 million to \$45 million. This cost estimate will be better defined
18 once the Company fully engages the consultants necessary to complete the work
19 necessary to prepare the SLRA.

20 **Q49. Is it reasonable for the Company to incur an estimated cost of \$40 million to**
21 **\$45 million (Total Company) to assess, prepare, and administer the SLRA?**

22 A49. Yes. The cost estimate for the SLRA is reasonable considering the degree of
23 engineering, data gathering, outside vendor support and reviews required for this

1 volume of information. In benchmarking other SLR applicants, the cost estimate
2 provided in the Enercon Feasibility Study is reasonable and within the bounds of
3 other utilities that were contacted.

4 **Q50. Can you provide a high-level breakdown of the primary elements of the costs**
5 **associated with the preparation of the SLRA?**

6 A50. Yes. The following provides an overview of the primary elements and costs
7 associated with each for the preparation of the SLRA:

- 8 • Primary Architect and Engineering consultant contracted to support the
9 Cook SLRA: (\$17.5 million)
- 10 • Specialty vendor to perform analyses supporting the extended life of the
11 reactor vessel and surrounding components (e.g., neutron embrittlement)
12 (\$11.0 million)
- 13 • Specialty vendor to develop and review the Environmental Report as input
14 into the SLRA (\$2.0 million)
- 15 • Cook staff – project team supporting the project – (\$5.2 million); and
- 16 • NRC and Legal Fees (e.g., support three onsite NRC audits and two
17 Advisory Committee on Reactor Safeguards meetings at NRC
18 headquarters) – (\$7.0 million)

19 **Q51. How will the Company manage the SLRA process?**

20 A51. As described above, Cook will continue to utilize its NAM and LRP processes to
21 assign key personnel to specific tasks associated with the SLRA process. Tasks will
22 be prioritized and strategically scheduled with the goal of continued safe and reliable
23 operation of the Plant while moving through each of the SLRA responsibilities.

1 In addition, Cook uses a formal Project Change Request Form system for
2 monitoring, controlling, documenting and tracking changes in project scope,
3 schedule, budget or cost. It should be noted that the implementation of formal review
4 processes to manage project funding was installed many years ago and has proven
5 to be successful. When projects change phases as their percent complete increases,
6 they are required to go through a Project Review Board. If a project's cost is greater
7 than \$1,000,000 it must be reviewed by the Executive Project Review Board which
8 is comprised of Cook Senior Management. Cook Senior Management is also
9 responsible to inform the Company's and AEP's management teams of any material
10 changes in total project costs or schedule and obtain appropriate approvals. Finally,
11 the Cook organization holds weekly and monthly financial reviews of all ongoing
12 projects.

13 **Q52. Please describe the SLR process once a SLRA is submitted.**

14 A52. Once an SLRA has been submitted for approval to the NRC much of the immediate
15 work will involve responding to Requests for Information (RFI's) from the NRC. These
16 consist of technical questions or clarifications by the NRC on the submitted
17 application. RFI's may be received through the entire 22 to 24 months of NRC review
18 for approval timeframe and can be complex documents or require only simple
19 answers. No major work will take place until after the SLRA is approved by the NRC.
20 Upon approval, a substantial number of tests and inspections must be performed for
21 each of Cooks two units. The inspections themselves will be performed during the
22 Spring 2031, Fall 2032 and Spring 2034 refueling outages. The ensuing Unit 2 scope

1 and inspections will be developed and completed on a similar schedule prior to its
2 2037 license termination.

3 **Q53. Who describes the accounting and proposed ratemaking treatment for the**
4 **SLRA costs?**

5 A53. Please see the testimony of witnesses Ross and Seger-Lawson for accounting and
6 ratemaking treatment of the SLRA costs.

7 **Q54. Does this conclude your pre-filed direct testimony?**

8 A54. Yes.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of
INDIANA MICHIGAN POWER COMPANY
for authority to increase its rates for the
sale of electric energy and for approval of
other related matters.

Case No. U-21461

INDIANA MICHIGAN POWER COMPANY

PRE-FILED DIRECT TESTIMONY

OF

NICOLAS C. KOEHLER

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**DIRECT TESTIMONY OF NICOLAS C. KOEHLER
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY**

Introduction of Witness

Q1. Please state your name and business address.

A1. My name is Nicolas C. Koehler. My business address is 1 Riverside Plaza,
Columbus, OH 43215

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

A2. I am employed by the American Electric Power Service Corporation (AEPSC) as
Director of East Transmission Planning in AEPSC's transmission group, (AEP
Transmission). AEPSC provides operational expertise and efficiencies in the
provision of engineering, financing, accounting, planning, advisory, and other
services to the subsidiaries of the American Electric Power (AEP) system, one of
which is Indiana Michigan Power Company (I&M or the Company).

AEP Transmission is a combination of separate groups within AEP, Grid
Solutions and Energy Delivery. The Grid Solutions organization is responsible for
planning for the evolving needs of the transmission system, including technology
development, transmission asset strategy and policy, oversight of all transmission
policy and regulatory matters involving RTOs, Federal Energy Regulatory
Commission (FERC), and state regulations. It also supports commitments to
relevant aspects of North American Electric Reliability Corporation (NERC) Critical
Infrastructure Protection (CIP) and Operations and Planning requirements.

Energy Delivery is charged with improving Transmission's efficiency,
containing the costs of projects and capital excellence, and supporting commitments

1 to relevant aspects of NERC CIP and Operations and Planning requirements. The
2 organization is responsible for maintenance, engineering, project management,
3 operations, siting new transmission facilities, providing outreach and information
4 regarding transmission projects to the public, and Right-of-Way (ROW) acquisition
5 for transmission projects. For purposes of this testimony, I will use the phrase 'AEP
6 Transmission' to refer to these two groups, either singularly or collectively.

7 **Q3. Briefly describe your educational background and professional experience.**

8 A3. I received a Bachelor of Science in Electrical Engineering from Ohio Northern
9 University in Ada, Ohio. In 2008, I joined AEP as a Planning Engineer where I
10 advanced through increasing levels of responsibility. I received my Professional
11 Engineer license (PE) in the state of Ohio in 2012 (license number 76967). In May
12 2019, I assumed the position of Director, East Transmission Planning.

13 **Q4. What are your responsibilities as Director of East Transmission Planning?**

14 A4. My responsibilities include organizing and managing all activities related to
15 assessing the adequacy of AEP's transmission network to meet the needs of its
16 customers in a reliable, cost effective, and environmentally compatible manner.

17 **Q5. Have you previously testified before any regulatory commissions?**

18 A5. Yes. I have testified before the Michigan Public Service Commission (MPSC or
19 Commission) in Case No. U-20359 and before the Indiana Utility Regulatory
20 Commission in Cause Nos. 45576 and 45933; to support I&M's applications to
21 increase its rates for the sale of electric energy in those jurisdictions. I have also filed
22 testimony before the Public Service Commission of Kentucky and the State

Corporation Commission of Virginia in applications for Certificates of Public Convenience and Necessity to construct transmission assets.

Purpose of Testimony

Q6. What is the purpose of your testimony?

A6. The purpose of my testimony is to describe the transmission system that is necessary for I&M to provide retail service and to support 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 FERC, including the PJM Open Access Transmission Tariff (PJM OATT). My testimony supports the nature and reasonableness of those costs. Company witness Wnek will discuss the OATT charges and credits included in the Power Supply Cost Recovery factor.

Q7. Are you sponsoring any Exhibits?

A7. Yes, I am sponsoring:

Exhibit IM-10 (NCK-1) AEP Transmission Planning Criteria and Guidelines for End-Of-Life and Other Asset Management Needs

Exhibit IM-11 (NCK-2) Hartford Area Improvements

Q8. Was the exhibit you sponsor prepared or assembled by you or under your direction and supervision?

A8. Yes.

Q9. Please summarize your testimony.

A9. Transmission investment at AEP and across the industry is directed toward addressing aging grid infrastructure, maintaining, and improving stability, reliability,

1 and resilience, and protecting the grid from physical and cyber threats. Such
2 investment needs continue to increase, as do associated costs. As a Load Serving
3 Entity within PJM, I&M incurs costs to use the transmission system supported by
4 such investments, irrespective of whether it owns the facilities that are being used.

5 I&M's PJM costs, including the Network Integrated Transmission System
6 (NITS) costs that make up the bulk of its PJM costs, are reasonable and necessary
7 to provide reliable electric service to I&M's customers. They are supported by robust
8 PJM vetting processes for Baseline Upgrades and Network Upgrades, and detailed
9 protocols for consideration of AEP Owner Projects that assure only projects that are
10 needed in each transmission owner's service territory are pursued. Further, Owner
11 Projects are subject to a transparent stakeholder process to ensure that they are
12 appropriate, efficient, and cost-effective solutions for customers.

13 **I&M's Transmission System**

14 **Q10. Please describe I&M's transmission system.**

15 A10. I&M's transmission system is a highly networked grid that delivers electricity from
16 generation sources to the retail and wholesale consumers I&M serves.

17 There are approximately 5,340 circuit miles of transmission lines in the I&M
18 system, stretching from the eastern Indiana border with Ohio to the shore of Lake
19 Michigan in southeastern Michigan, as well as extending to western and
20 southeastern Indiana, connecting current and former I&M generation sources with
21 the Company's service territory.

22 Approximately 910 of these circuit miles are within Michigan. The voltage
23 levels of I&M's transmission system range from 34.5 kV to 765 kV and can be

divided into three categories based on voltage level: extra high voltage (EHV) (above 200 kV), transmission (100 kV to 200 kV), and subtransmission (34.5 kV to 100 kV). Finally, I&M's transmission system includes approximately 182 transmission substations, 52 of which are located in Michigan.

Q11. Please explain how I&M's transmission system is interconnected with the transmission system of other electric utilities.

A11. The I&M transmission system is part of the PJM RTO and is interconnected with AEP Ohio Power Company, American Transmission Systems, Inc., AES Ohio (formally Dayton Power and Light Co.), ComEd, as well as transmission providers in the Midcontinent Independent System Operator (MISO) RTO. I&M is also interconnected with various rural electric cooperatives and municipal electric utilities.

Q12. Please describe the overall condition of I&M's transmission facilities.

A12. The Company's transmission facilities are built and maintained in accordance with AEP standards that are based on industry regulations and Good Utility Practices.¹ Like other members of our industry, the Company is addressing the challenges of aging infrastructure along with the need to modernize transmission facilities, comply with regulations, and adapt to a changing generation portfolio.

¹ FERC has defined "Good Utility Practice" in Section 1.14 of the pro forma Open Access Transmission Tariff in Order 888 as: "Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region."

1 **Q13. Please explain.**

2 A13. The AEP transmission system has evolved over the last century. In the recent past,
3 the majority of transmission investment has been directed towards constructing
4 facilities to address RTO-identified constraints due to a shift in generation portfolio.
5 In addition, some investment has focused on connecting new demand while
6 maintaining compliance with changing federal and regional reliability standards.

7 More recently, investment has been refocused to address aging grid
8 infrastructure and resilience, to maintain and improve stability and reliability, and to
9 protect the grid from physical and cyber threats. Finally, I&M expects that the
10 transmission system will continue to evolve and change through technological
11 advancements such as the adoption of electric vehicles, integration of renewable
12 resources, retirement of fossil-fuel based generation, and the implementation of new
13 customer programs.

14 **Q14. Is I&M's transmission system currently adequate to serve its customers' load**
15 **reliably?**

16 A14. Yes. I&M's transmission system is compliant with all federal and regional reliability
17 standards. I&M will continue to invest appropriately in its transmission assets to
18 provide reliable electric service to its customers.

19 **Q15. Are I&M's transmission assets aging?**

20 A15. Yes. I&M's transmission assets on the I&M system are aging. At present, I&M's
21 average conductor age is roughly 45.4 years of service. Additionally, over 1,250 line-
22 miles are 60 years of age or older, and of these line miles, over 500 are over 70
23 years old. The average useful life of conductor is 70 years; therefore, there will be a

1 need to replace these assets at some point before their inevitable degradation starts
2 impacting the reliability of the system.

3 **Q16. How are AEP and I&M addressing the issue of aging transmission**
4 **infrastructure?**

5 A16. Although asset age is an important consideration, AEP and I&M develop
6 transmission projects based on several factors, including the performance and
7 condition of each asset and the risk that the failure of each pose to the system and
8 connected customers.

9 As the I&M infrastructure continues to age, the associated risk for any given
10 asset increases. AEP and I&M are implementing solutions to address these needs
11 on the system. As I will further discuss below, I&M and AEP are actively involved in
12 transmission projects internally and through the open transmission planning process
13 at PJM with stakeholder input and FERC oversight.

14 **PJM Interconnection**

15 **Q17. What is PJM?**

16 A17. FERC Order 2000 introduced the concept of an RTO or Independent System
17 Operator (ISO) whose purpose is to promote the regional administration of high
18 voltage transmission and ensure non-discriminatory access to transmission
19 systems.²

20 PJM Interconnection is a FERC-approved RTO that coordinates and
21 administers the movement of wholesale electricity in all or parts of thirteen states

² Regional Transmission Organizations, 89 ¶ 61,285 [FERC Order 2000] (Dec. 20, 1999).

1 and the District of Columbia. I&M's membership in PJM was approved by the
2 Michigan Public Service Commission (MPSC) in its order issued in Case No. U-
3 13360 Order dated June 29, 2004.

4 The AEP system—East Zone (AEP Zone), which includes I&M, integrated its
5 operations with PJM and began participating in the PJM energy market on October
6 1, 2004. I&M's membership in PJM has allowed I&M's customers to benefit from the
7 independent, regionally operated, and jointly planned and coordinated PJM
8 transmission grid. This grid enhances system stability, reliability, and security,
9 competitive wholesale markets, and resource diversity.³

10 **Q18. How do PJM and AEP coordinate planning and operation of I&M's**
11 **transmission system?**

12 A18. I&M's transmission system is part of the AEP eastern transmission system, which
13 consists of the transmission facilities of eleven AEP operating or transmission
14 companies including I&M and AEP Indiana Michigan Transmission Company. This
15 expansive system allows the economical and reliable delivery of electric power for
16 all AEP customers. Planning and operation of the system is integrated through the
17 coordinated efforts of PJM and AEP Transmission.

18 I&M management collaborates with AEP Transmission to ensure that the
19 transmission expenses charged to I&M through the PJM OATT approved by the
20 FERC are reasonable and necessary. I&M regularly reviews the projects that
21 underlie its transmission expenses and reviews the need and costs of such projects.

³ *Re Ind. Mich. Power Co.*, Cause No. 45235 at 110 (IURC Mar. 11, 2020).

1 I&M is fully involved in the transmission planning process and ensures that planned
2 investments are reasonable and beneficial for I&M's customers. The transmission
3 planning process is a partnership between AEP Transmission and its stakeholders,
4 including I&M. I&M and AEP Transmission work together to identify needed
5 investments on the transmission system and optimize capital expenditures.

6 I&M prioritizes investments based on the urgency of the need, the impact on
7 customers, and cost, among other factors. I&M specifically approves transmission
8 investments pursuant to internal procedures and controls. In this way, I&M makes
9 sure that planned transmission investments will address its customers' needs, in
10 terms of both maintaining reliable service and meeting the needs of expected new
11 load.

12 AEP Transmission works closely with neighboring utilities, other
13 interconnected entities, and PJM to plan and operate the transmission grid. RTOs
14 align the transmission planning and operating requirements set out in each RTO's
15 protocols and operating criteria, as further defined through NERC requirements.

16 **Q19. How does I&M participate in PJM?**

17 A19. I&M has three distinct roles within PJM: (1) Generator, (2) Load Serving Entity
18 (LSE), and (3) Transmission Owner (TO). There are various charges and credits
19 that the Company experiences resulting from each role. I will primarily discuss the
20 roles of an LSE and TO.

21 **Q20. How is I&M charged for using the PJM transmission system?**

22 A20. As an LSE, I&M is charged for costs associated with the functional operation of the
23 transmission system, management of the PJM markets, and general administration

of the RTO, irrespective of whether it owns the facilities that are being used. As such, I&M pays to use the PJM transmission system, including its own assets, through charges that are based upon I&M's demand on the system.

The costs include charges for I&M's purchase of NITS under the PJM OATT to serve its retail customers. I&M can incur NITS costs due to projects constructed by other transmission owners within the AEP Zone. I&M can also incur Transmission Enhancement Charges for projects constructed by other transmission owners outside of the AEP Zone.

Q21. Does I&M receive compensation from PJM as a TO?

A21. Yes. I&M is compensated by PJM for owning and operating transmission assets as a TO.

Q22. Please identify the types of PJM transmission costs incurred by I&M.

A22. I&M incurs costs and offsetting revenues in accordance with the FERC-approved PJM OATT and Operating Agreement, which currently include the following:

- NITS pursuant to PJM OATT Attachments H-14 and H-20.
- Firm and Non-Firm Point-to-Point (PTP) Revenues pursuant to PJM OATT Schedules 7 and 8.
- TO Scheduling, System Control, and Dispatch Service pursuant to PJM OATT Schedule 1A.
- PJM RTO Administration fees and other charges pursuant to PJM OATT Schedules 9 and 10.
- PJM Transmission Enhancement Charges pursuant to PJM OATT Schedule 12.
- Default Allocation Assessments, and any refunds of such assessments, pursuant to Section 15.2 of the PJM Operating Agreement.

1 From time to time, PJM modifies the charges and revenues related to membership
2 within PJM and for transmission service; as a result, the list above may not be fully
3 representative of I&M's PJM-related charges and revenues in the future.

4 **Q23. What are PJM NITS charges?**

5 A23. NITS charges represent the cost for I&M and other PJM network customers to
6 integrate, economically dispatch, and regulate their current and planned network
7 resources to service their network load. NITS charges in the AEP Zone are derived
8 from the transmission investments of all TOs in the AEP Zone.

9 **Q24. Please identify other PJM costs incurred by I&M.**

10 A24. I&M incurs expenses and receives credits from PJM for other activities associated
11 with I&M's role as a Generator and LSE. These charges and credits include net
12 transmission congestion charges and other ancillary services such as:

- 13 • Scheduling, System Control & Dispatch Service
- 14 • Reactive Supply and Voltage Control Service
- 15 • Regulation and Frequency Response Service
- 16 • Synchronized Reserve Service
- 17 • Supplemental Reserve Service and
- 18 • Black Start Service.

19 As previously noted, Company witness Wnek discusses the OATT charges and
20 credits included in the Power Supply Cost Recovery factor.

Transmission Planning

Q25. Please describe the PJM Regional Transmission Expansion Plan (RTEP) process.

A25. The PJM RTEP process is a 24-month planning process that identifies reliability issues over a 15-year horizon. The 24-month planning process consists of overlapping 18-month planning cycles to identify and develop shorter lead-time transmission upgrades and one 24-month planning cycle to provide sufficient time for the identification and development of longer lead-time transmission upgrades that may be required to satisfy planning criteria.

AEP Transmission participates on I&M's behalf in the PJM planning process, which is guided by PJM, NERC, ReliabilityFirst Corporation (RFC) and AEP planning criteria. The process results in three different categories of projects: Baseline Upgrades, Network Upgrades, and Supplemental Upgrades (also called "Owner Projects"). Each category is described below.

The first project category is Baseline Upgrades. Using the aforementioned criteria and guidelines, PJM and I&M, in conjunction with AEP Transmission, identify needs that are a result of a criteria violation. Baseline projects include transmission expansions or enhancements that are required to achieve compliance with respect to PJM's system reliability, operational performance, or market efficiency requirements as determined by PJM's Office of the Interconnection, as well as projects that are needed to meet Transmission Owners' local transmission planning criteria. The cost of Baseline Upgrades are allocated to the benefiting zones based on the following mechanisms:

1 345 kV single-circuit or lower voltage facilities are cost allocated based on
2 solution-based distribution factors (DFAX).

3 The costs of a 345 kV double-circuit or higher voltage facilities are allocated
4 as follows:

- 5 ○ 50% of project costs are allocated to all PJM zones based on
6 load ratio share (the AEP Zone load share percentage for
7 January to December 2020 is 14.18%).
- 8 ○ 50% of project costs are allocated on DFAX basis.

9 For market efficiency projects, Net Load Payment savings is used instead of
10 DFAX to determine cost allocation. Net Load Payment savings is the net present
11 value sum of energy and capacity market benefits for all benefiting transmission
12 zones.

13 The second project category is Network Upgrades. These transmission
14 projects result from transmission customer requests for generator interconnection,
15 merchant transmission additions, and long-term transmission service. Customers
16 that cause the need for Network Upgrades are responsible for the costs that are
17 incurred. As an example, if a generator requested to connect to a transmission line
18 and an upgrade was required to connect the generator, the generator would pay for
19 the network upgrade.

20 The third project category is Owner Projects. These projects are needed for
21 many reasons, including regulatory requirements, modernization and hardening of
22 the grid, replacement of failed equipment, proactive replacement of deteriorating
23 assets prior to failure and improved operational efficiency and performance. The

costs of Owner Projects are allocated to the transmission zone in which they are built.

Q26. How are Network Upgrade projects initiated?

A26. A customer will make a request via a queuing process managed by PJM. As an example, a generation developer that is planning a renewable project connecting to PJM would initiate such a request. Based on the request, PJM will prepare a feasibility study for that request to assess the practicality and cost. If the study supports the project, PJM will, based on an executed agreement with the requesting party, prepare a Generation Interconnection System Impact Study to analyze the connection and determine if there are any additional network upgrades necessitated by the request. Finally, if the System Impact Study determines the request can proceed, then a Facilities Study is performed focusing primarily on the design and cost of facilities necessary to physically connect the generation to the transmission system. Construction of the interconnection point will be managed by the transmission owner, in this case AEPSC on behalf of I&M.

Q27. How are costs for Network Upgrade projects recovered?

A27. For Network Upgrades, the requesting party is responsible for the costs of the interconnection. In addition, they will also be responsible for associated transmission upgrades that PJM identifies in the System Impact Study. These projects can be beneficial to all customers on the network because while funded by the requesting party, the upgrades will benefit all users as the upgrades increase the performance and reliability of the network.

1 **Q28. Do I&M and other Transmission Owners in the AEP Zone follow specific**
2 **guidelines to determine the necessity of Owner Projects?**

3 A28. Yes. All AEP affiliated transmission owners follow an established and detailed
4 protocol (presented as Exhibit IM-10 (NCK-1) and referred to herein as “the
5 Guidelines”) to evaluate and select Owner Projects that assures only projects that
6 are needed in each transmission owner’s service territory are pursued.

7 The Guidelines discuss the drivers or inputs that should be considered when
8 evaluating transmission system needs. They ensure that all AEP affiliated
9 transmission owners are applying consistent criteria in evaluations, while each
10 Transmission Owner ultimately determines the mix of Owner Projects needed to
11 maintain the stability and reliability of their transmission grid within the AEP Zone.

12 **Q29. What drivers or inputs does I&M consider in identifying Owner Projects?**

13 A29. Consistent with the Guidelines, the drivers considered in identifying Owner Projects
14 include:

- 15 • Equipment Condition, Performance and Risk: These are investments made
16 to ensure the safe and reliable operation of the transmission system. The
17 decision to pursue such projects can be based on equipment performance,
18 obsolescence and expected life concerns, equipment condition, reliability
19 impact, maintenance costs, environmental impact, and engineering
20 recommendations.
- 21 • Operational Flexibility and Efficiency: These projects can optimize system
22 configuration, lower equipment duty cycles, reduce the impact on and limit
23 the exposure to customers for planned or forced outages and can facilitate

improved restoration times. They also provide opportunities to bring the system up to current standards and design principles.

- Infrastructure Resilience: These projects can improve system ability to anticipate, absorb, adapt to and/or rapidly recover from disruptive natural or man-made events including severe weather, geo-magnetic disturbances, and physical and cyber security challenges.
- Customer Service: These projects accommodate new, increasing, or future load so that the system can reliably address customer needs.
- Other Drivers: Examples include industry recommendations, changes in established standards, state policy objectives, etc.

In addition to the above, there is a growing need for investment in better telecommunication connectivity on the transmission system to support supervisory control, data acquisition, and protection systems, which will lead to improved physical security of critical assets and a reduction in Customer Minutes of Interruptions (CMI) related to transmission outages.

Q30. Are these drivers under I&M's exclusive control?

A30. No. 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 and stability, 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.

1 Transmission Owners also do not have discretion to decline to make
2 reasonable and necessary investments in the transmission grid. Rather, these
3 investments must be made to fulfill I&M's obligation to operate pursuant to Good
4 Utility Practice and to serve customers. Each Transmission Owner in the AEP Zone,
5 including I&M affiliates, has an obligation to ensure capital investments are prudent
6 and necessary to maintain a reliable transmission grid.

7 **Q31. Can you provide an example of an I&M Owner Project that supports these**
8 **considerations?**

9 A31. Yes. I&M reviewed the need for the Hartford Area Improvements in Southwest
10 Michigan with stakeholders in the April 16, 2021, PJM Sub-Regional Regional
11 Transmission Expansion Plan (SRRTEP) committee meeting. See Exhibit IM-11
12 (NCK-2). In a subsequent meeting on July 16, 2021 the solution was presented with
13 a proposed in-service date in the fourth quarter of, 2024.⁴ This Project includes
14 rebuilding sections the 138-kV transmission line that connects Riverside Substation
15 to the Hartford Substation and rebuilding the 69kV transmission line that connects
16 South Haven Substation to the Hartford Substation.

17 Condition and performance issues on these lines warrant their replacement.
18 A majority of the towers on the Riverside-Hartford 138kV line are 1950s vintage
19 wood H-frames. Forty-eight structures (36% of the line) have open conditions such
20 as rot, corrosion, cracking, or woodpecker damage with 40 of these structures
21 having conditions affecting the crossarm, pole, or X-brace. As part of the upgrade,

⁴ See Sub Regional RTEP Committee: Western AEP Supplemental Projects dated July 16, 2021, at pages 32-35. [aep-supplemental-projects.ashx](https://www.aep-supplemental-projects.ashx) ([pjm.com](https://www.pjm.com))

1 approximately 16.85 miles of these aging wood H-frames will be replaced with steel
2 monopole structures that are able to support higher capacity conductors and more
3 readily withstand adverse weather conditions.

4 The South Haven - Hartford 69kV line is in similar condition. This line
5 consists of 18.68 miles of 1960's vintage wood monopoles. Ninety structures on
6 this line (29%) have open conditions with 52 structures having conditions affecting
7 the pole such as rot, splitting, or woodpecker damage. Additionally, these aging
8 wooden monopoles do not meet current National Electrical Safety Code (NESC)
9 standards or American Society of Civil Engineering (ASCE) strength requirements.
10 These aging wood monopoles will be replaced with steel monopole structures that
11 are able to support higher capacity conductors and more readily withstand adverse
12 weather conditions.

13 **Q32. Can you elaborate on the customer benefits associated with I&M Owner**
14 **Projects like this one?**

15 A32. Projects like the improvements on the Hartford Area improvements project are
16 essential to ensure continued reliable service is available for customers. These
17 improvements, in turn, contribute to a stable source of electricity critical for all our
18 customers.

19 **Q33. Is the designation of a project as a Baseline or Owner Project indicative of**
20 **whether the project is necessary, or how necessary it is?**

21 A33. No, it is not. The designation of a project as a Baseline or Owner Project is not
22 indicative of the level of, or absence of, need for the project. Instead, the

1 designations simply reflect that the project addresses different system reliability and
2 resilience needs.

3 The criteria for designation as an Owner or Baseline Project are not mutually
4 exclusive, and a single project can be needed under either or both. Under the
5 existing PJM RTO framework, Transmission Owners retain planning responsibility
6 for managing the maintenance and replacement of their transmission assets and
7 planning of their local transmission systems.

8 PJM planning criteria address the expansion and enhancement of
9 transmission facilities required to meet national and regional planning criteria.
10 Owner Projects improve or preserve a PJM Transmission Owner's ability to provide
11 reliable service to its customers, consistent with its obligation to serve, and are
12 grounded in Good Utility Practice.

13 **Q34. Does PJM factor the age or condition of equipment into its forward-looking**
14 **models for system reliability that are used to identify Baseline Projects?**

15 A34. No, it does not. The forward-looking models that PJM and Transmission Owners
16 employ to identify Baseline Projects assume the modeled system will perform as
17 designed without regard to the age or actual condition of all the elements of the
18 transmission system.

19 This means that for modeling purposes, a substation with 75-year-old
20 components that are deteriorating is assumed to function as designed and with the
21 same reliability as a five-year-old substation with newer components.

Q35. What is PJM's role in reviewing Owner Projects?

A35. All projects affecting the topology of the grid, whether PJM identified, or Transmission Owner identified, are subject to the stakeholder process within PJM. While PJM does not formally "approve" Owner Projects, these projects are submitted to PJM and reviewed with the Transmission Expansion Advisory Committee (TEAC) and Subregional RTEP Committee – Western on a periodic basis in accordance with PJM's M-3 Process. All TEAC and Subregional RTEP Committee – Western meetings are open, and any transmission stakeholder can attend and participate.

The M-3 process, which ensures stakeholders have an opportunity to review Owner Projects, includes the following meetings and posting requirements:

- Separate stakeholder meetings to discuss:
 - Models, criteria, and assumptions used to plant Owner Projects (Assumptions Meeting)
 - Need underlying Owner Projects (Needs Meeting) and,
 - Proposed solutions to meet those needs (Solutions Meeting)
- Posting of criteria, assumptions, and models at least 20 calendar days prior the Assumptions Meeting;
- Posting of criteria violations and drivers at least ten days in advance of the Needs Meeting;
- Posting of potential solutions and alternatives identified by the PJM Transmission Owners or stakeholders at least ten days in advance of the Solutions Meeting; and,

- A process to submit concerns at least ten days before the Local Plan is integrated into the RTEP for PJM Transmission Owner review and consideration.

Q36. How do stakeholders provide input as part of the M-3 Process?

A36. The previously described meeting and posting requirements provide multiple opportunities for stakeholders to comment on assumptions, provide input on additional needs, and propose alternative solutions for PJM Transmission Owners to consider.

First, they can do so verbally in the various stakeholder meetings. Each of these meetings is moderated by PJM. Second, written submissions can be submitted to PJM and posted using the PJM Planning Community Tool. These posts, along with responses provided by AEP Transmission, are available to the public. If discussions necessitate a change to materials that have been provided by AEP, the revised materials are posted as well.

Q37. Do I&M and AEP consider stakeholder input?

A37. Yes, I&M and AEP consider all input provided by stakeholders. Transmission Owners have an obligation to provide sufficient transparency for stakeholders to understand the Transmission Owner's Needs and Solutions. Stakeholders, on the other hand, have an obligation to advise of their Needs and Solutions for consideration by the Transmission Owner before Owner Projects are finalized and submitted to PJM for inclusion into the RTEP.

Additionally, I&M and AEP Transmission will consult with stakeholders that will be directly impacted by a project, prior to submission of the project's Solution to

1 PJM. For example, I&M and AEP Transmission communicate and coordinate with
2 customers that are directly connected to a transmission line that may need to be
3 rebuilt during the development of the project Solution for that Need.

4 I&M and AEP Transmission also coordinate with such stakeholders in
5 scheduling any outages required for the project in order to minimize outage impacts.
6 Thus, I&M and AEP consider input from directly affected stakeholders not only
7 during the M-3 Process, but also before a solution is presented in that forum.

8 **Q38. Do stakeholders have other opportunities to provide input regarding**
9 **transmission projects in Michigan?**

10 A38. Yes. I&M and AEP Transmission also go beyond what the M-3 Process requires by
11 annually meeting with customers to discuss transmission needs. This annual
12 meeting with connected customers is an additional opportunity for stakeholder
13 feedback and review of the needs on the system. Customers are also encouraged
14 to identify any additional needs or issues that may be directly affecting them. The
15 next stakeholder meeting is scheduled for October 2, 2023.

16 **Q39. Is there also a process for reviewing transmission projects at FERC?**

17 A39. Yes. In addition to the PJM stakeholder review, there is another opportunity to
18 evaluate the prudence of transmission projects at FERC. Specifically, AEP's annual
19 transmission formula rate filings include protocols that establish an open and
20 transparent process for any interested party to review the rates and challenge items,
21 including the ability to challenge the prudence of actual costs and expenditures.
22 Additionally, other Transmission Owners, of which I&M is charged for certain
23 transmission projects, have similar protocols associated with their formula rates.

1 **Q40. What are non-topology projects?**

2 A40. There are elements of many projects that either do not change the transmission
3 grid's topology, or that are implicit in the description of larger projects, and that are
4 not required to be submitted to PJM for explicit review because such project
5 elements do not affect the transmission grid analysis within the framework of PJM's
6 FERC-approved planning process. Nevertheless, these project elements are
7 essential to the larger projects that are submitted to and reviewed by PJM.

8 Non-topology projects are required for important operational functions such
9 as protecting against security threats, minimizing equipment damage, reducing
10 outage durations, and improving safety, as well as many others. Non-topology
11 changing projects can include station security, remote control, and monitoring (also
12 known as Supervisory Control and Data Acquisition or "SCADA") or
13 telecommunications modernization projects, among other examples.

14 As a specific example, AEP has historically used leased analog lines to
15 provide communication paths for system protection and control. As phone
16 companies move to digital technology, the analog signals and communication paths
17 will no longer function going forward.

18 To address this issue, AEP's telecom network is being upgraded through use
19 of fiber communication paths and microprocessor relays. Although these projects
20 do not affect any load flow model used by PJM, they are still necessary for the
21 continued safe, efficient, secure, and reliable operation of the transmission grid.

Forecast of PJM Charges

Q41. Please explain the development of the forecast PJM revenues and costs.

A41. The forecasted PJM charges are developed internally by AEP and its affiliated companies that have projected transmission investments over the forecast period. The forecast methodology is described in detail by Company witness Wnek; however, at a high level, the projected necessary capital investment, combined with the required operations and maintenance expense, is modeled to develop an estimated revenue requirement for I&M's projected transmission plant in service. Through an analysis of historical and forecasted transmission system usage, the forecasted amount to be allocated to I&M through its role as an LSE is determined.

Q42. What is the Company's forecast of PJM costs for the Test Year?

A42. As provided by Company witness Wnek, PJM NITS⁵ charges are forecasted to be approximately \$408.7 million (Total Company) for the Test Year. In addition, I&M is forecasted to incur approximately \$33.9 million (Total Company) in non-NITS costs in the Test Year.

As discussed below, increases in the Company's PJM costs are being driven primarily by the increases in PJM NITS costs. In particular, PJM NITS costs are growing primarily due to charges in Accounts 4561035 and 5650016, which are billed by PJM to I&M in its role as the LSE for I&M's native load customers.

⁵ PJM NITS charges consist of the NITS, Point-to-Point revenue credits, and Schedule 1A charges, while non-NITS charges are comprised of Transmission Enhancement Charges and PJM administration fees as defined in Q22 above.

1 **Q43. What is driving the increase in NITS charges for I&M?**

2 A43. The increase in NITS charges are being driven by investment in transmission
3 infrastructure throughout the AEP Zone. In recent history, transmission investment
4 was focused on system needs arising from retirement of generation due to
5 environmental regulations.

6 As previously described, the transmission system currently requires
7 substantial investment to address aging infrastructure, cyber and physical security
8 threats, and modernization of protection and control equipment. This requires
9 infrastructure improvements occurring both within I&M's service territory and the
10 remainder of the AEP Zone. The costs associated with these investments are billed
11 to the AEP Zone and charged to I&M through the monthly PJM bill and the AEP
12 Transmission Agreement.

13 **Q44. Are projects within the AEP Zone the only project type contributing to**
14 **transmission charges from PJM?**

15 A44. No. Transmission projects that solely benefit the AEP Zone are fully allocated to all
16 LSEs in the AEP Zone, including I&M, and these costs are included in NITS charges.
17 As previously discussed in the response to Q25 above, the cost of baseline
18 transmission projects that benefit more than one PJM zone are shared over the
19 larger PJM footprint as determined by PJM. As a result, I&M may incur costs from
20 multi-zonal projects included in non-NITS charges.

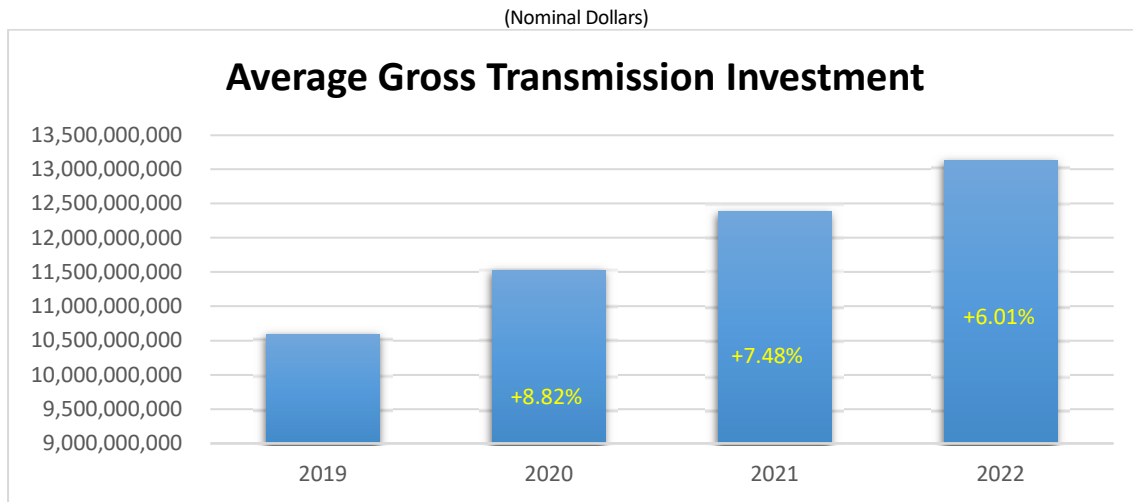
1 **Q45. Is the need for transmission infrastructure investment unique to I&M or PJM?**

2 A45. No. Industry wide, utilities are investing in the transmission system to meet the
3 above-described needs. Nationally, transmission investment has increased steadily
4 over the past several years.

5 For instance, as shown in Figure NCK-1 below, a summary of historic
6 transmission investment in the United States, accumulated from gross transmission
7 investment balances taken from FERC Form 1 reporting, shows increases in
8 investment from 2019 through 2022, suggesting a general trend towards higher
9 investment expenditure in the future.

10 **Q46. Please describe Figure NCK-1.**

11 A46. Figure NCK-1 shows average combined transmission investment from 2019-2022,
12 along with year-over-year growth for a sample of investor owned utility holding
13 companies with gross asset valuations of over \$3 billion: Ameren Corp., American
14 Electric Power Company Inc., American Transmission Company LLC, Berkshire
15 Hathaway Inc., CenterPoint Energy Inc., Dominion Energy Inc., Duke Energy Corp.,
16 Edison International, Entergy Corp, Evergy Inc, Eversource Energy, Exelon Corp.,
17 FirstEnergy Corp., Iberdrola SA, ITC Holdings Corp, National Grid Plc, PG&E Corp.,
18 Pinnacle West Capital Corp., PPL Corp., Public Service Enterprise Group Inc.,
19 Sempra Energy, Southern Company, and Xcel Energy Inc,. The underlying gross
20 transmission investment data is accumulated from pages 204-207 of the FERC
21 Form 1s for the subsidiaries of the listed utility holding companies.

Figure NCK-1: Average Historical Transmission Investment for 2019-2022

1 **Q47. Do you expect this trend to continue?**

2 A47. Yes. Consistent with this national trend, I&M expects robust levels of investment will
3 continue beyond the Test Year.

4 **Q48. Does this conclude your pre-filed direct testimony?**

5 A48. Yes

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of
INDIANA MICHIGAN POWER COMPANY
for authority to increase its rates for the
sale of electric energy and for approval of
other related matters.

Case No. U-21461

INDIANA MICHIGAN POWER COMPANY

PRE-FILED DIRECT TESTIMONY

OF

JOE BRENNER

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**PRE-FILED DIRECT TESTIMONY OF JOE BRENNER
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY**

I. INTRODUCTION OF WITNESS

Q1. Please state your name and business address.

A1. My name is Joe Brenner, and my business address is 1 Riverside Plaza, Columbus, Ohio, 43215.

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

A2. I am employed by American Electric Power Service Corporation (AEPSC) as the Vice President, Business Solutions.

Q3. Please briefly summarize your educational and professional background.

A3. I received a Bachelor of Science degree in Aerospace Engineering from the University of Notre Dame, South Bend Indiana in 1990.

Before joining AEPSC, I spent three and a half years as Group Vice President, Chief Information Officer at Sally Beauty, two years as Executive Vice President, Chief Information Officer at Signet Jewelers, eleven years as Director and then Vice President Technology at Target Corporation, three years as Director of Technology and Security at Best Buy, and ten years serving as an Aviation officer in the United States Army.

I have held my current leadership role since joining American Electric Power Company, Inc. (AEP) in 2020. In this role, I am responsible for a wide range of Technology and Security areas including business applications, infrastructure, operations, support, digital transformation, and innovation for Indiana Michigan Power Company (I&M or Company) and all other AEP Operating Companies.

1 **Q4. What are your principal areas of responsibility with I&M?**

2 A4. I am responsible for oversight in the Technologies and Securities portion of AEP's
3 business, including Information Technologies and new technical project rollouts, all
4 together with software and hardware.

5 **Q5. Have you previously testified in any regulatory proceedings?**

6 A5. Yes. I have submitted testimony on behalf of I&M before the Indiana Utility Regulatory
7 Commission in Cause No. 45933. In addition, I provided written testimony in Docket
8 No. 54608 – Application of Electric Transmission Texas, LLC for authority to change
9 rates before the Public Utility Commission of Texas.

10 **II. PURPOSE OF TESTIMONY**

11 **Q6. What is the purpose of your testimony in this proceeding?**

12 A6. I provide an overview of AEP's Technology and Security organization and support
13 the historical (2022) and forward-looking (2024) Test Year (TY) operations and
14 maintenance (O&M) expenses and capital expenditures in the Capital Forecast
15 Period (2023 and 2024) for Technology and Security projects. I also provide the
16 project costs, timeline, and project management processes associated with three of
17 the strategic technology investments in this case: Field Mobility, the Customer
18 Information System (CIS), the Advanced Distribution Management System (ADMS),
19 and the Distributed Energy Resource Management System (DERMS).

20 All O&M expenses and capital investments that I present in my testimony,
21 both historical and forecasted, represent total Company levels and are not
22 representative of the Michigan jurisdictional share. Company witness Morgan
23 describes the Michigan jurisdictional allocation of the Test Year O&M expenses and

capital investments. I also support two Adjustments to the Test Year, RB/O&M-2, to increase customer billing system costs to implement the PowerPay program, and RB/O&M-3 to provide for the need of additional IT capital and O&M.

Q7. Are you sponsoring any exhibits?

A7. Yes. I support a portion of Exhibit A-12, Schedule B5.4: Projected Information Technology. In addition, I co-sponsor the Information Technology information contained in Exhibit IM-22 (ZBW-11), the I&M Project Life File which contains a list of all capital projects; capital expenditures by month during the Capital Forecast Period; and plant in-service information.

Q8. Were the Exhibits prepared or assembled by you or under your direction and supervision?

A8. Yes.

Q9. Please summarize your testimony

A9. Technology is critical to I&M's operations, and I&M is making the investments necessary to meet current and future operational needs and expectations. My testimony summarizes the capital and O&M-related technology investments identified by I&M to provide safe and reliable power to customers, better protect customer's data from cybersecurity threats, meet our customer's evolving expectations, and take advantage of new technologies to increase the efficiency of our operations.

More specifically, my testimony describes and supports three significant IT projects that will harness modern technology designed to improve I&M's operations and customer service. The first project is I&M's Field Mobility program that will

1 provide the Company's distribution organization with a more connected, proactive,
2 and transparent system to perform their daily work. The second project reflects
3 modernizing I&M's CIS which is used to manage customer account and premise
4 information, including billing and metering. The legacy CIS is over 30 years old (albeit
5 with additions over time); the new CIS will provide an integrated platform with
6 enhanced billing, messaging, and meter data management capabilities while
7 preserving and fortifying existing cybersecurity protections. The third project I discuss
8 is the ADMS and DERMS, which will unify I&M's Outage Management and
9 Distribution Management systems into a single platform providing advanced
10 functionality necessary to manage and operate I&M's electric distribution grid.

11 III. ORGANIZATION OF TECHNOLOGY AND SECURITY

12 **Q10. Please describe how the I&M manages the Technology and Security functions**
13 **of the business.**

14 A10. The Company works with a group of professionals in AEPSC's Technology and
15 Security organization to manage the Technology and Security functions of the
16 business. This approach provides the Company with access to experts in the areas
17 of technology development; cyber security policies, trends, and technologies;
18 technology infrastructure and support; and forward-looking strategies regarding
19 technology trends. AEPSC Technology and Security leadership provides regular
20 updates to Company leadership reenforcing the partnership between technology
21 development and business unit implementation.

Q11. What support does the AEPSC Technology and Security organization provide to the Company?

A11. AEPSC Technology and Security provides support for:

Business Solutions: responsible for maintaining collaborative relationships with the operational business units leading to the development and/or implementation of technology solutions to meet their needs.

Infrastructure, Operations, and Support: responsible for deploying and maintaining stable and secure infrastructure allowing I&M's technology solutions to be readily available and operational; for providing application, infrastructure, and network monitoring and support; and for internal customer facing support including PC deployment and support, service desk, and collaboration technology services.

Planning & Governance: responsible for driving standard project, supplier, training, and financial practices and ensuring standard technology architecture and tools across the Technology and Security organization; and

Security: responsible for providing integrated management and monitoring of physical and cyber security.

Q12. Are the services provided by Technology and Security necessary to provide reliable utility service?

A12. Yes. Technology and Security supports the systems that allow I&M to effectively serve customers and provide accurate customer billing, facilitate the coordination of outage response and repair, perform system operations, manage system construction and maintenance, maintain systems to detect and protect against cyber security threats, and account for its costs.

1 **IV. OPERATION AND MAINTENANCE EXPENSE**

2 **Q13. What are the historical and Test Year levels for Technology and Security**
 3 **operations and maintenance (O&M) costs?**

4 A13. *Figure JB-1* provides the Total Company historical, Test Year, and Adjusted Test
 5 Year Technology and Security operations and maintenance O&M expense, by
 6 category:

Figure JB-1. **Historical Test Year and Adjusted Test Year O&M in Millions**

	2022	Test Year	Adjusted Test Year
Technology and Security O&M	\$21.27	\$21.92	\$27.97

7 In addition, the Technology and Security O&M costs are also shown on Exhibit A-13,
 8 Schedule C-5.

9 **Q14. Is Technology and Security proposing any adjustments for the 2024 Test Year?**

10 A14. Yes. I support two Adjustments to the Test Year: RB/O&M-2, to account for the costs
 11 to implement the PowerPay program; and RB/O&M-3, to provide for needed
 12 additional IT O&M expenses.

13 **Q15. Please explain the RB/O&M-2 Adjustment.**

14 A15. Adjustment RB/O&M-2 reflects the Customer Billing System Costs of \$650,000 to
 15 implement the PowerPay program. This program and its benefits are further
 16 described and supported by Company witness Davis. The adjustment includes a
 17 one-time technical upgrade to AEP's Marketing Accounting and Customer Services
 18 System (MACSS) that is required to facilitate the programs transactions, along with
 19 the labor expense required to configure and deploy the software updates. Of this
 20 \$650,000 cost, \$520,000 will be a capital expense for the upgrades themselves, and

1 the remaining \$130,000 is for O&M and the expenses required for the approved
2 implementation.

3 In addition, please see Exhibit IM-50 (JWM-1) Summary of Projected
4 Adjustments, which identifies the 2024 Forecast Period rate base adjustments and
5 provides a brief description, the adjustment amount, and the page and line number
6 where the adjustment is located in the jurisdictional cost-of-service allocation study.

7 **Q16. Please explain the RB/O&M-3 Adjustment.**

8 A16. Adjustment RB/O&M-3 is an increase in IT incremental costs over the Test Year
9 forecast for O&M and capital by approximately \$7.41 million. Of the \$7.41 million,
10 \$1.482 million will be a capital expense and the remaining \$5.928 million will be O&M.
11 This adjustment reflects spending needed to address aging technology and security
12 infrastructure. In particular, the O&M expenses reflect an increased focus on stability
13 and security issues, including a shift to cloud-based technologies. With this shift, I&M
14 recognizes increased expenses for subscription services versus historical capital
15 investments. While cloud technologies optimize overall capital and expense
16 efficiency in the long run, the short-term impact is an increase in O&M expenses.
17 Lastly, increasing costs of software, hardware, and labor services related to
18 technology and security are showing significant year-over-year increases.
19 Adjustment RB/O&M-3 is reasonable and necessary to account for these increases.

20 Please see Exhibit IM-50 (JWM-1) Summary of Projected Adjustments, which
21 identifies the 2024 Forecast Period rate base adjustments and provides a brief
22 description, the adjustment amount, and the page and line number where the
23 adjustment is located in the jurisdictional cost-of-service allocation study.

Q17. Please explain the difference in Technology and Security O&M expenses between 2022 and the Adjusted Test Year?

A17. The cost of providing Technology and Security services has grown and is anticipated to grow in the future, corresponding to growth in the demand for Technology and Security services, which is increasingly critical to all aspects of operations. More specifically, ongoing drivers of the variance include increasing demand for technology services to meet internal efficiency and customer needs, the escalating external costs of software and hardware products / services globally, the escalating cost of technology and security labor in the general market (impacting both internal and external labor), and operational sustainability investments made in support of maintaining stable, secure, and resilient technology platforms. Technology and Security works to offset these cost increases by using lower cost external labor partners at scale, rationalizing the use of technology and security toolsets, conducting competitive bids for technology where applicable, and automating processes where applicable.

Q18. What is the Capital Forecast Period considered in this filing?

A18. The projected period with respect to capital investment (Capital Forecast Period) is the period from January 1, 2023 through December 31, 2024. The Capital Forecast Period includes all of the Company's projected generation capital expenditures in 2023 and 2024.

The investment outlined in this testimony relates to the work plans developed to manage its system. This level of capital is included in the Capital Forecast presented by Company witness Wnek.

Q19. What is the amount of capital to be invested in Technology and Security during the Capital Forecast Period?

A19. *Figure JB-2* establishes that I&M plans technology and security capital expenditures during the Capital Forecast Period of approximately \$109.6 million. This figure does not include the aforementioned adjustments listed above.

Figure JB-2. Technology and Security Capital Expenditures (\$000, excluding AFUDC)

<u>Category</u>	<u>2023</u>	<u>2024</u>	<u>Total</u>
Major Projects	\$41,310	\$57,411	\$98,720
Other Capital Investments	\$7,982	\$2,897	\$10,880
Total	\$49,292	\$60,308	\$109,600

The expenditures during the Capital Forecast Period through the Test Year in each category are described in more detail below, and provided in Exhibit A-12, Schedule B5.4 and in Exhibit IM-22 (ZBW-11), the I&M project life file which contains a list of all Cook capital projects, capital expenditures by month during the Capital Forecast Period, and plant in-service information.

Q20. Please explain the variability of Capital Expenditures for 2023 to 2024.

A20. Unlike O&M that is more routine in nature, capital investments are dependent on the needs and projects at a specific point in time. In 2024, the Company has scheduled multiple large projects that are necessary to replace obsolete systems and take advantage of new technologies. I discuss these large projects in greater detail later in my testimony.

1 **Q21. What are the types of capital expenditures forecasted for the Technology and**
2 **Security during the Capital Forecast Period?**

3 A21. In the Major Projects category, I have included all Technology and Security capital
4 projects with capital expenditures exceeding \$5 million during the Capital Forecast
5 Period. I describe these in detail below.

6 The Other Capital Investment category includes capital expenditures
7 associated with multiple smaller projects and that blanket of cost can be seen in
8 Exhibit A-12, Schedule B5.4. Each project itself is included in the Project Life File
9 (Capital Forecast by Project), included as Exhibit IM-22 (ZBW-11) to Company
10 witness Wnek's testimony. These planned projects are necessary and reasonable
11 and are representative of typical projects in a typical year.

12 **Q22. Please identify the generation projects with capital expenditures greater than**
13 **\$5 million during the Capital Forecast Period.**

14 A22. *Figure JB-3* shows Technology and Security projects that will involve capital
15 expenditures greater than \$5 million during the Capital Forecast Period. These costs
16 exclude AFUDC and present I&M's ownership share of the investment.

Figure JB-3. Total Company Technology Major Project Capital Expenditures (\$000, excluding AFUDC)

<u>Project Title</u>	<u>2023-2024</u>
1- I&M Capital Software	\$36,238
2- CIS Project	\$25,116
3- Security Blanket	\$17,323
4- ADMS Implementation	\$8,362
5- HR HCM Modernization	\$6,404
6- Field Mobility Program	\$5,277

See also, Exhibit A-12, Schedule B5.4.

Q23. Please summarize the projects identified in *Figure JB-3*.

A23. The following projects have been or will be placed in service during the Capital Forecast Period:

- Project 1 – I&M Capital Software Development.* This project is comprised of blanket work orders used commonly for capital projects that are smaller in scope and cost, usually high-volume, and have the same depreciable life and plant accounting category. Blanket work orders are a standard property accounting and industry solution that efficiently govern and account for these ongoing capital items, such as maintenance and development of software applications. For example, it would be impractical to separately track and depreciate each instance of a programmer modifying a program.
- Project 2 - CIS Project.* This project represents the next step in a multi-year initiative by AEP to improve customer interactions with the utility. The CIS project will replace and modernize the system the Company uses for billing,

1 customer records, and to maintain all approved rates and tariffs. The CIS
2 project is discussed in greater detail later in my testimony.

- 3 • *Project 3 – Security Blanket.* Similar to Project 1 above, this project is
4 comprised of blanket work orders for smaller projects to manage the
5 security of the Company's systems.

- 6 • *Project 4 – ADMS and DERMS Implementation.* The Distribution Outage
7 Management System (OMS), Distribution Management System (DMS), and
8 Supervisory Control and Data Acquisition (SCADA) systems are critical to
9 real-time operations but are at end of life. Situational awareness of the
10 distribution grid requires an ADMS and a Distributed Energy Resource
11 Management System (DERMS). The ADMS program is discussed in
12 greater detail later in my testimony; the ADMS and DERMS project is
13 described in greater detail by Company witness Isaacson.

- 14 • *Project 5 – HR Human Capital Management (HCM) Modernization.* I&M's
15 current HR/Payroll system is over 20-years old and is costly to maintain.
16 This project will replace the existing system with a modern solution that will
17 support continuous business improvement, deliver customer-driven self-
18 service options, and provide real-time decision making and business
19 intelligence. The new HR/Payroll system will also allow for regular
20 application and security/technology updates.

- 21 • *Project 6 – Field Mobility Program.* The Field Mobility program will provide
22 distribution operations personnel across AEP with new capabilities, mobile

1 devices, and connectivity to improve operational efficiency, reduce costs,
2 and enhance both worker and customer safety. The program will deploy
3 new iPads using public cellular to eliminate the need for mobile data
4 computers. The Field Mobility project is discussed in greater detail later in
5 my testimony.

6 **V. CAPITAL AND O&M COST CONTROL**

7 **Q24. How are the Technology and Security capital costs recorded and tracked?**

8 A24. Capital charges are recorded by Technology and Security to work orders by project.
9 These work orders are set up to bill to appropriate benefiting locations using
10 allocation factors that reflect cost causation principles.

11 **Q25. What processes does the Company and AEPSC's Technology and Security**
12 **organization have in place to ensure that the costs of these projects are**
13 **reasonable?**

14 A25. Internal planning, budgeting, approval, and quality control processes combine to
15 control the costs of Technology and Security O&M. These same processes equally
16 apply to Technology and Security capital project costs. The proposal for each project
17 identifies the high-level requirements and goals for the project. Project estimates are
18 prepared after an analysis phase that includes collaboration of business partners,
19 system analysts, and application developers. Estimates are reviewed and refined
20 through a series of increasingly narrower thresholds to the final approval. The
21 estimates are reviewed by Technology and Security management and approved on
22 a weekly basis. In addition, each major project is approved by management from
23 Technology and Security management, the Company, and the Business Unit

1 depending on what employees and processes are impacted by the project. Once a
2 proposal is approved, it is actively monitored to ensure that the requirements are met
3 and the project is within budget.

4 **Q26. What type of budgeting schedule is employed with regard to Technology and**
5 **Security O&M?**

6 A26. Budgets are developed annually for each organization by the Technology and
7 Security group. The current year budget is compared to actual spend on a monthly
8 basis and year-end projections are revised as appropriate. The budget and forecast
9 are created and updated by considering financial and business requirements.

10 **Q27. Once budgets are in place, what further cost monitoring occurs?**

11 A27. The Company keeps in constant contact regarding the Technology and Security
12 budgets and reviews any requested changes to the budgets throughout the course
13 of the year. Within Technology and Security, leadership from both the operating
14 company and the service corporation are responsible for monitoring and controlling
15 budgets that are assigned to their respective teams or projects. Actual costs are
16 monitored against project and program budgets on a regular basis and any changes
17 or deviations for the budget are discussed with the appropriate level of leadership
18 from Technology and Security organization. For major projects, project status
19 discussions are held periodically with the Technology and Security leadership team
20 to discuss cost and schedule performance, as well as any changes to the overall
21 project plan.

VI. FIELD MOBILITY

Q28. What is Field Mobility and why is it critical for the Company's operations?

A28. Field Mobility is a set of applications and hardware that I&M uses to communicate, organize, and complete distribution work. Field Mobility includes the processes and technology distribution employees use to complete their respective operational objectives and includes:

- Mobile computing
- Data connectivity in trucks
- Daily resource tracking
- Work packets to view AEP assets and work assignments.
- Resources for storm assistance

Examples of these objectives include anything from construction, restoration, and additional workflows. These objectives are critical to daily workflow, as it establishes the standards for efficiency and communication in a distribution company's operating procedure.

Q29. What are the solutions provided by the new Field Mobility system?

A29. The Company will deploy new technologies across the enterprise, offering crews more convenient and practical ways to complete their daily tasks. The new system puts all these benefits together into one cohesive package. This package will deliver an improved employee experience and an enhanced customer focused solution.

To deliver on this, the Company is using its existing software vendor, ARCOS, to expand I&M's on-field potential. The Company will make use of key software applications (called Crew Manager, Resource Assist, and Mobile Workbench),

1 through an enhanced communication network. Benefits include enhanced
2 capabilities regarding what kind of work can be done on the go via a tablet, the
3 efficiency of equipment inspections, storm damage assessments, and gained
4 efficiencies when working with equipment that has been damaged by third parties.

5 **Q30. How will these new systems impact I&M current work management**
6 **processes?**

7 A30. Crew Manager is a tool that allows for the creation of crew profiles, including
8 employees and the tools and vehicles they have access to. Additionally, it outlines
9 the area of duty of which these crews and materials are located, offering greater
10 visibility to the work groups that manage them. In storm situations, it will also allow
11 for a transfer of responsibility. For example, if I&M experiences a large weather event,
12 the crew manager can reassign an Ohio crew to the Michigan area. This will then
13 offer work schedulers in Michigan the ability to manage that crew's specific
14 responsibility. Additionally, this adds impacts to the Distribution Dispatch Centers as
15 it will dynamically allow for dispatch to assign them work orders outside of their home
16 jurisdiction.

17 Resource Assist is an application that allows the Company to procure
18 assistance from off-system work groups more effectively. The Company uses this as
19 a callout of sorts, which attempts to obtain support from contract groups and other
20 electric utilities across the nation. Once those resources answer and move
21 themselves to Michigan, dispatch and work schedulers can access their workflow
22 just as if they were an on-system employee.

1 Mobile Workbench is a solution that allows for more efficient daily operations,
2 as documentation such as work orders, construction packets, and damage outside
3 party (DOP) reports are all presented, submitted, and processed in an electronic
4 fashion. This not only removes lag-time but offers a degree of additional visibility and
5 enhanced resource utilization. Many more members of the operating company will
6 have shared visibility to these documents, meaning collaboration for something just
7 as simple as daily tasks can even increase. Obtaining these enhancements can
8 reduce Customer Minutes Interrupted, improve the company's capture rate for DOP
9 dollars, and increase capital deployment, ultimately reducing O&M. The Company
10 will also use Mobile Workbench to visually overlay various pieces of information on
11 geographic information system (GIS) maps. This will allow crews to see each other
12 on a map and easily communicate outage areas, pictures of damage, and other
13 important restoration details.

14 In order to run all these applications, there must also be improvements to the
15 communication infrastructure. The current Field Mobility system is field connected
16 through an 800mhz radio system. Public cellular networks are exponentially faster
17 than what the radio infrastructure can offer, ensuring that these advanced
18 applications are practically usable in the field when away from a wired connection.
19 With the throughput of public cellular networks, field employees will be able to
20 instantly send data such as pictures and video whenever there is a demand. Moving
21 from mobile computers to iPads will allow crews to remain connected around the
22 worksite. Each of these aspects supports real-time data transfer that enables the
23 high-bandwidth, common visibility of customer restoration information.

Q31. Will these systems impact system reliability and customer outage metrics?

A31. With the increased efficiencies brought to the Company via the improvements above, distribution experts expect to see a decrease in Customer Minutes Interrupted (CMI) as well as outage duration indices. Perhaps most of the improvements will come in storm situations, ones that involve off-system resources in particular. The back-office portion of the Field Mobility program, the interface where non-field employees interact, will provide storm coordinators managerial insights that will help with key decision making. It is through this scope that the Company will better be able to not only recognize areas that have been the most impacted but be able to have a more granular approach when deciding where crews and equipment need to go. This will allow for a quicker reaction time and provide for the opportunity to make more educated decisions so specialized crews' abilities do not go to waste.

This will not prevent outages from happening in the first place, but when outages do occur, this greater level of visibility will help the Company make the right decision faster, ultimately leading towards a better customer experience.

Q32. How was a vendor selected for the Field Mobility System?

A32. When the Company started their search for their new Field Mobility host, a measurable part of that review was factored upon I&M's relationship between in-service software and current communications infrastructure.

ARCOS as a software suite has been used at AEP starting with crew callout 12 years ago. Since that time, AEP has evolved to using ARCOS for various other tasks like schedule making and crew roster management. Throughout the past 12 years, ARCOS had proven to be a reliable resource that aided in managing efficient

field processes. Crew callout has become such an integral part of current field mobility processes, so AEP finds value in continuing to work with ARCOS to further expand company field management abilities. Another key benefit to having this software suite host the Field Mobility upgrades, is the relative usability and efficiencies from using one consistent source. Having too many places to enter and view information can be a detriment to the operating company's productivity and efficiency. Keeping this solution in one familiar space will encourage a more streamlined implementation and allows for the Company to bring this solution to market faster.

Q33. What is the estimated cost for the Field Mobility improvement?

A33. As shown in Figure JB-4 below, the Company's allocated capital expenditures for the Field Mobility rollout totals to approximately \$5.277 Million, all of which is included in 2023. Additional expenses are required however, such as obtaining the iPad devices that the field will use in order to utilize new and improved software that is currently rolling out through Q4 of 2023.

Figure JB-4. Field Mobility Capital and O&M Costs (excluding AFUDC)

2023-2024 I&M CapEx	2024 I&M O&M Costs
\$5.3M	\$0.00M

Q34. What processes does Technology and Security have in place to ensure that the Field Mobility costs are reasonable?

A34. The Company will work closely with the AEPSC team responsible for implementing the AEP wide implementation of the Field Mobility solution to monitor the costs and timeline of the project with oversight from the Technology and Security leadership

team and project sponsors. Any project revisions that are outside of scope will be separately reviewed with executives and the vendor.

Q35. Please describe the I&M timeline for the new Field Mobility Implementation?

A35. I&M is using a two-phase approach with a final, total project completion date set for the end of 2023. The first phase of the project started in Q1 of 2022 when crews started to get their hands on the new Field Mobility software applications. For distribution field employees, they have started to employ the use of Crew Manager, Resource Assist, and Mobile Workbench in order to perform their daily job duties. Additionally, these same crews will receive the ability to have enhanced capabilities for equipment assessment, reports for DOP, and digital work packet publication. The second phase of this process will be focus on full-scale deployments of all the new Field Mobility software and work processes. Once all the processes are complete and the field's use of the Field Mobility software suite is saturated, this will allow the company to phase out the old products. Overall, a full distribution level implementation is set for a Q4 2023 rollout, wherein all Field Mobility software rollouts are completed.

VII. CUSTOMER INFORMATION SYSTEM (CIS)

Q36. What do you mean when you use the term “Customer Information System”?

A36. A Customer Information System, or CIS, is a technology platform and central repository for all customer information. It manages the billing, accounts receivable, and rates for the Company. In addition, it links the consumption and metering process to third-party service providers, payment options for customers, collection activities, and other downstream processes.

1 A CIS manages customer premise information to provide a holistic view of the
2 customer, and enables customer capabilities, such as complex billing and settlement
3 options for distributed customer behind the meter assets, as the industry and grid
4 continue to evolve. In addition, as customers may have various devices at their
5 premise, such as solar panels or plug-in vehicle (PEV) chargers, modern CIS
6 systems provide the capabilities to manage these devices on the customer's account
7 and offer flexibility in how customer programs and tariffs are supported.

8 **Q37. What is the status of the Company's current CIS System?**

9 A37. AEP currently uses a "Customer-One" legacy CIS system that supports billing,
10 revenue reporting, account and receivables management, online transactions,
11 customer, and premise data management. AEP utilizes one system across all seven
12 distribution operating companies. The technology is over 30 years old and, over the
13 course of that time, prudent investments in auxiliary systems and integrations have
14 been made to improve functionality or increase capabilities. Some of these auxiliary
15 systems include large power billing, Advanced Metering Infrastructure (AMI) meter
16 data management, bill output and customer programs, to name a few.

17 **Q38. Can the existing CIS System effectively fulfill evolving customer needs going**
18 **forward?**

19 A38. No. To extend the useful life of the current CIS, the Company has made prudent
20 investments in peripheral systems to support new functionality, including smart
21 meters. However, CIS limitations to what can be billed and the speed at which new
22 tariffs can be implemented are barriers to meeting customer and regulator
23 expectations in an evolving grid with more complex pricing signals.

1 AEP's legacy CIS was designed for a time when utilities sent one bill per billing cycle
2 to the customer; only the largest of customers had a generation resource or interval
3 metered usage data; and complex tariffs leveraging that interval data for variable time
4 rates were limited to manually billed industrial customers.

5 Today, customers in I&M can have a generation resource on their property or
6 have more granular usage interval data from a smart meter, which can allow for new
7 tariffs to be offered. However, with the Company's current legacy CIS, the time that
8 is required to implement a new tariff or customer program can vary depending on the
9 complexity of a new program or tariff rate design. The more complex the tariff or
10 program, the more coding and development that is required.

11 In addition, AEP's current CIS cannot process interval usage data. Currently,
12 it must be processed outside the system to calculate billing determinants. Efforts like
13 this must be performed manually through spreadsheets or other analytics tools,
14 leading to a more efficient process.

15 Although investments have been made to improve the current system, the
16 Company recognizes the need to move forward with planning a CIS replacement due
17 to the continued proliferation of distributed generation, advancing AMI functionality
18 needs, evolving customer expectations, more complex pricing signals, and growing
19 risks related to an antiquated technology platform.

20 **Q39. Does the Company's current CIS provide a safe and reliable avenue for**
21 **customer billing?**

22 A39. The Company's CIS platform has always been and will continue to be a secure
23 platform to process customer data, information, and payments. This is a standard

1 that will remain unchanged through the implementation of a new CIS. Additionally,
2 once the new CIS is in place, the same expectation of a safe and accurate platform
3 will continue to be upheld. The foundational issue here is that given the recent
4 changes in the advancement of interval data, new customer programs and tariffs,
5 and the expected increase in distributed energy resources, now is the appropriate
6 time for the Company to implement a new, modernized CIS that will position the
7 Company to efficiently meet the expectations of its customers and the Commission
8 in the years to come.

9 **Q40. How will a modern CIS improve from AEP's current CIS?**

10 A40. At the core of transformation between the Company's CIS and modern CIS systems
11 is the underlying data structure. The Company's legacy CIS system data structure is
12 built around a premise and a rate that is applied to create a bill for that premise using
13 non-interval data. Modern CIS system data structures are based upon the customer
14 participation in programs, the devices installed at their home or business, and how
15 the customers use the grid. While the Company's current systems may have
16 databases used to bill the customer, a database used for market settlement, a
17 database for customer programs like alerts, and a database for interval data, a
18 modern CIS system would utilize one common database that minimizes integrations
19 between systems. Modern CIS systems leverage a common database for all these
20 processes, simplifying or eliminating the integration requirements between a meter
21 data management system, settlement systems, and CIS billing systems. In addition,
22 unlike the Company's current CIS system where rate changes are hard coded,

1 modern CIS systems are more configurable, shortening the timeframe and cost
2 associated with implementing new customer programs.

3 **Q41. Are there other IT technologies that would need to be updated related to the**
4 **CIS System?**

5 A41. Yes. The Company expects that the Special Billing and Messaging System, primary
6 billing system including MACSS, AMI Integrations with meter systems, and the MV90
7 integrations should be replaced. All of these are within the scope of this project and
8 core to meter-to-cash processing. In addition, there are integrations with over 150
9 edge systems that will be updated, such as customer web account access, customer
10 usage portals and payment processing vendors.

11 **Q42. Which potential vendors have been engaged for the CIS system replacement?**

12 A42. There are two vendors that currently provide CIS software for multijurisdictional Tier
13 1 utilities such as AEP: Oracle and Systems Applications and Products (SAP). Given
14 that AEP already uses Oracle software for the Customer Relationship Management
15 System (CRM), Meter Data Management system (MDM), and the HR/financial
16 systems (PeopleSoft), it made sense to engage Oracle as AEP would not have to
17 replace a full suite of ancillary software to integrate the new CIS.

18 **Q43. What is the Company's overall plan to replace the current CIS System?**

19 A43. To manage risk associated with this enterprise-wide project, the Company plans to
20 deliver some functionality early prior to a full deployment. Automation of manually
21 intensive industrial customer spreadsheet billing onto the new technology platform is
22 a valuable initiative, delivering new capabilities earlier. These large industrial
23 accounts are clients that the current CIS cannot calculate so processing is currently

1 done outside of the system manually. In addition to this delivered automation, the
2 team will finalize plans around MDM system needs related to the new CIS, as well
3 as overall architecture planning for the program. Merging these two values together
4 will deliver value earlier and inform the overall deployment plan as a means forward
5 to a successful CIS implementation.

6 **Q44. Are there risks associated with replacing a CIS?**

7 A44. Yes. However, the phased approach the Company is taking mitigates risks by
8 proving out the usability of the technology prior to deploying it to the first operating
9 company to understand common and unique requirements.

10 AEP has also deployed an industry best-practice in utilizing a third-party
11 quality assurance / quality control consultant (QA/QC) for the program. A QA/QC
12 consultant's role is to provide unbiased review of program processes and procedures
13 to assure risks are mitigated and reports directly to the program leadership team
14 monthly. AEP's approach also uses a third-party system integrator that specializes
15 in large scale CIS implementations, providing an additional level of expertise the
16 Company can leverage.

17 **Q45. What is the estimated cost and timeline for the CIS improvement applicable to**
18 **I&M customers?**

19 A45. The current capital cost estimate for I&M's share of a new CIS and market supporting
20 tools is approximately \$132 million. These costs are based on the best information
21 available at the time my testimony was prepared. There are multiple components to
22 this complex project that are at various stages of project scoping and cost estimation.
23 The team managing this project is using project management best practices to

1 progressively elaborate the project scope and refine the cost estimates as final
2 contract negotiations and phase gate approvals are completed. Since these are
3 estimates, actual costs will vary from the current total and complete projected rollout
4 estimates, however these costs are representative of the costs the Company expects
5 for the project and provide the Commission a reasonable basis to evaluate the CIS
6 project. All actual costs will be audited and will be presented in future filings for
7 commission review and approval. Regarding an applicable upgrade to I&M's
8 customers in Michigan, we will first launch the special billing automation process for
9 commercial and industrial customers. This new platform will provide for
10 improvements on what was formally a manually intensive process outside of our
11 current billing system, to turn into a centralized, automated, and more efficient
12 process. This new billing process will have a near immediate benefit on I&M
13 customers as this portion of the project is set to go live in September of 2023. Lastly,
14 this CIS implementation is one that will be an improvement across the entirety of the
15 AEP enterprise. Included, to visualize the impact of I&M's portion of the project
16 versus the rest of AEP's footprint, is a listing regarding the total cost to AEP as a
17 whole. A breakdown of the estimated capital and O&M costs of deployment is in
18 *Figure JB-5* below.

Figure JB-5. CIS Capital and O&M Costs (excluding AFUDC)

2023-2024 I&M CapEx	Forecasted I&M CapEx Total	Forecasted Enterprise CapEx
\$25.1M	\$131.7M	\$1,028.1M
2022 I&M O&M Costs	2024 I&M O&M Costs	
\$0.00M	\$0.6M	

Q46. How were the projected Capital and O&M expenses for the Company developed?

A46. The cost estimates were developed by evaluating existing functionality and capabilities for AEP's operating environment and identifying required integrations with edge systems that interface with CIS. Taking those capability and integration requirements and applying average expected resource needs to convert customers to the new systems and integrate with AEP systems, and based upon prior experiences with similar sized utilities, AEP was able to derive an initial planning estimate. As the project continues the progress through the project management phases for project scoping, contracting, schedule development, and resource identification, the project cost estimate is further refined. In order to develop an estimated designation of the total estimated costs between capital expenditures and O&M costs, the Company evaluated various potential contractual structures that may be used to acquire the vendor supported CIS system in context of the relevant generally accepted accounting principles in the United States (U.S. GAAP), as well the Company's accounting policies for their application.

1 **Q47. Is the Company proposing to recover any of the cost of the CIS replacement in**
2 **this proceeding?**

3 A47. As discussed further by Company witness Seger-Lawson, and as proposed in these
4 proceedings, actual capital expenditures included in the test year would be recovered
5 through base rates. Additionally, as described further by Company witnesses Ross
6 and Seger-Lawson, the Company is also requesting deferral authority of post-test
7 year costs incurred related to CIS deployment.

8 **Q48. What processes does Technology and Security have in place to ensure that**
9 **the CIS costs are reasonable?**

10 A48. A formal process has been implemented with Key Performance Indicator (KPI)
11 metrics that are tracked as a part of the project. This includes monthly financial
12 checkpoints with the project team and reports to senior leadership. Any substantive
13 changes to scope, deliverables, and costs, are scrutinized and approved by project
14 leadership.

15 The KPIs include indexes for the following:

- 16 • Cost performance
- 17 • Schedule performance
- 18 • Risk/issues
- 19 • Quality of solution
- 20 • Resource turnover
- 21 • SOW scope changes
- 22 • Potentially shippable products

- Training
- End user adoption

VIII. ADMS

Q49. What are I&M's current distribution operations system platforms?

A49. I&M currently uses an Outage Management System (OMS) and Distribution Management System (DMS or SCADA) to manage and operate the electric distribution grid.

Q50. How does I&M utilize OMS?

A50. OMS is a software engine used to identify and locate outages within the electric distribution network and manage the restoration process. It is critical in helping I&M identify and locate outages in its service territory where real-time telemetry/SCADA communication is not deployed.

Q51. How does I&M utilize DMS?

A51. DMS is used for real-time monitoring and control of Distribution SCADA-connected equipment located in the field. This includes monitoring and control of isolation equipment (breakers, reclosers), voltage control equipment (voltage regulators), reactive control (capacitors), and enabling/disabling and making other adjustments to third-party Distribution Automation Circuit Reconfiguration (DACR) and Volt-Var Optimization (VVO) control systems deployed during grid modernization efforts.

Q52. What is ADMS and DERMS and what are the benefits?

A52. ADMS is a modular software platform that is used to visualize, manage, and optimize a complex electric distribution network. It offers fully integrated OMS and DMS capabilities that are utilized through one network model and one user interface.

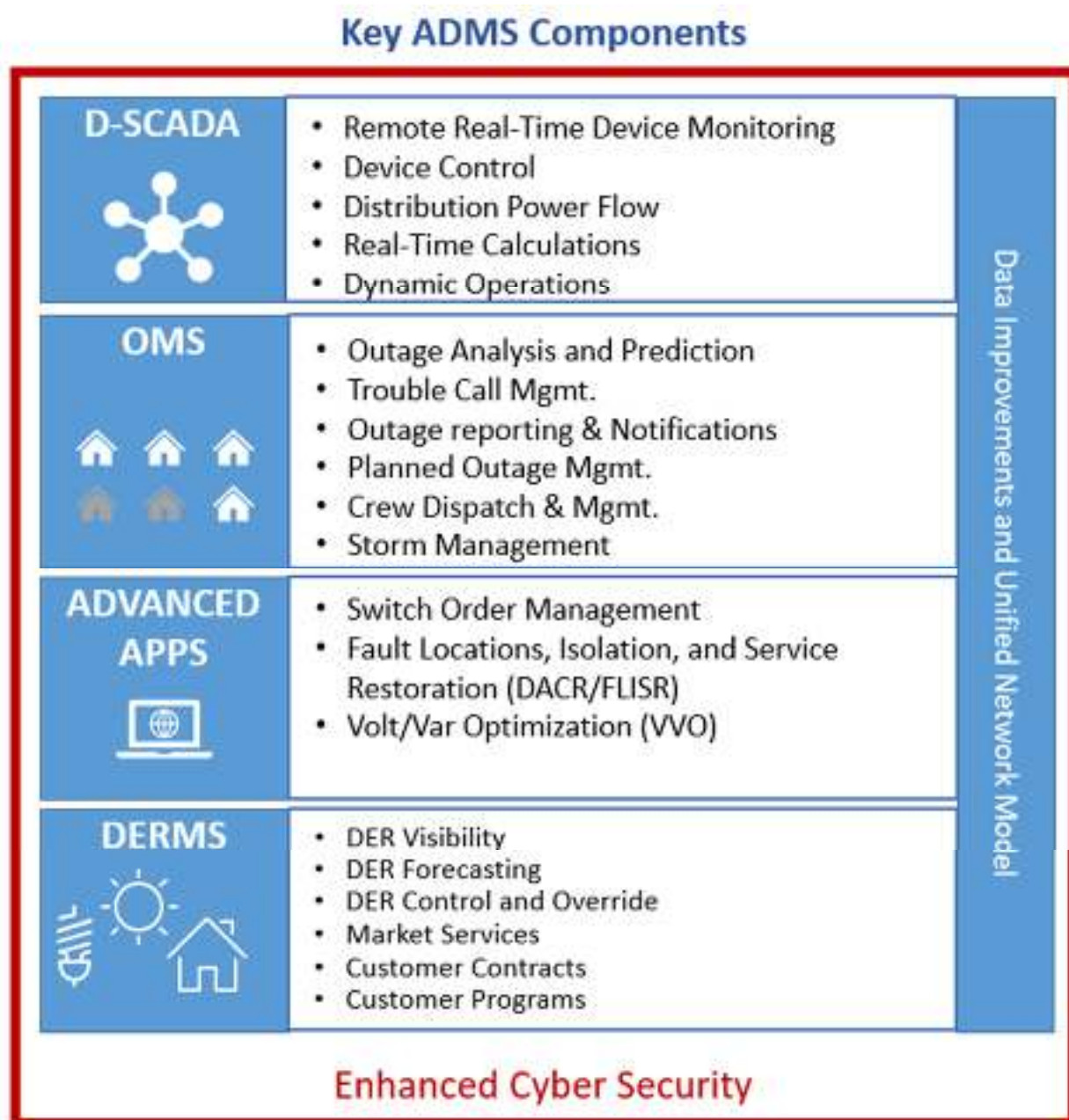
The ADMS also offers fully integrated operational Distributed Energy Resource Management System (DERMS) capabilities that will be used to manage the complexities associated with Distributed Energy Resources (DERs). DERMS capabilities include, but are not limited to:

- Administration: Establish DER records and maintain data on customer/location, nameplate, initial device settings, metering configuration, market/customer program status, interconnection application records and status;
- Visualization: Visualization of DERs in the ADMS network model and aggregation simplification; and
- Operations: DER integration with load flow/power analysis studies and advanced applications, operational forecasting, override capability, flexible and secure data exchanges and architecture.

Company witness Isaacson discusses the operational benefits of ADMS and DERMS.

1 See Figure JB-6 for a visual of ADMS's key components.

Figure JB-6.



2 **Q53. Has the Company identified a need to upgrade its existing systems to manage**
 3 **and operate an increasingly complex distribution network?**

4 **A53.** Yes. First and foremost, the Company's current OMS vendor has indicated its OMS
 5 platform is nearing end of life and has begun to sunset the application in 2022 as it

1 transitions existing and new OMS capabilities to its new ADMS platform over the
2 coming years. During that time, upgrades and enhancements to the current OMS
3 product will be very limited, with changes focused on critical patching required to
4 keep the system functioning properly.

5 Additionally, the current OMS and DMS platforms lack a unified network
6 model. A unified model with integrated power flow capabilities is essential for the
7 advanced functionality/capabilities and increased situational awareness that will be
8 necessary to manage and operate the increasingly complex grid going forward.

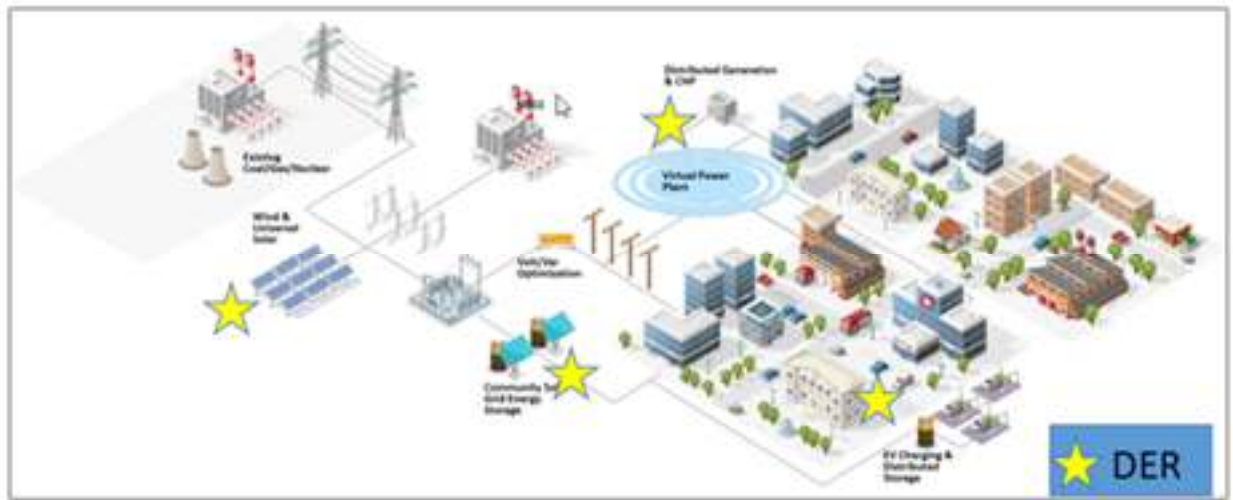
9 **Q54. Please describe the foundational capabilities that will be needed to manage**
10 **and operate the grid of the future?**

11 A54. As demonstrated in *Figure JB-7* and below, there are numerous capabilities required
12 to address evolving needs on the Company's electric distribution network that are
13 currently not fully supported by the Company's OMS and DMS systems:

14 The Distribution network of the future will require advanced technology to manage
15 the growing scale (control points) and complexity (DERs).

- 16 • DERs are creating multisource power flows on the electric distribution network
17 that was designed to operate with one source, in one direction.
- 18 • The electric distribution network will become a critical part of the overall
19 generation/load balancing equation. DER generation will need to be moved
20 appropriately to maintain the overall balance between generation and
21 customer loads across transmission and Distribution.

Figure JB-7.



Additional foundational capabilities required to operate an integrated grid of the future:

- ADMS solution fully integrated with operational DERMS
- A single distribution network model with robust power flow analysis
- Full integration of DER into network model, including operational forecasting
- Dynamic DACR and VVO grid controls
- Hardened Distribution Real Time OT Infrastructure and operating environments with robust cyber, physical, and access controls
- Real-time data exchanges across G, T & D control platforms
- Highly secure data exchanges for enhanced situational awareness

Q55. Without the proposed upgrade to ADMS, will I&M be able to provide customers with the level of service expected in the future?

A55. No. While the current OMS/DMS systems have been adequate for managing and operating the grid so far, the complexity of grid operations is quickly rising to a level

that will be difficult to manage without greater situational awareness and dynamic control capabilities. Without ADMS, operators will be required to manually perform complex studies and investigations, which will result in slower response times, and result in a negative customer experience and longer outages.

Q56. Please summarize the benefits associated with the Company's proposed ADMS upgrade.

A56. A unified network model, single user interface, centralized, dynamic DACR, VVO, fault location capabilities, and overall real-time grid awareness are expected to result in a positive impact to the outage lifecycle and achieve greater utilization of existing DACR/VVO investments. Additionally, the DERMS module in ADMS will enable and support the widespread customer use of DERs and electric vehicles while minimizing impact to the operation of the electric distribution network. This will allow AEP to better integrate and manage these technologies.

Together, the capabilities of ADMS are expected to equip operators with the tools required to operate the complex distribution network of the future safely and effectively, while allowing customers to continue to utilize DERs, electric vehicles, and other grid-connected technologies.

IX. ADMS PLATFORM EVALUATION

Q57. Please describe the procurement process AEP undertook to select an ADMS vendor.

A57. An ADMS evaluation effort was kicked off in early 2021 with a Request for Information (RFI), administered by AEP Procurement and a leading industry consultant. The RFI was sent to six of the industry leading ADMS vendors. RFI responses were analyzed,

1 and AEP selected the top three vendor products to advance in the Request for
2 Proposal process.

3 **Q58. What were the results of the Company's evaluation?**

4 A58. AEP used its internal Procurement and IT organizations, along with a third-party
5 consultant to administer a comprehensive, formal RFP process that included multiple
6 leading ADMS vendors. While all the vendors evaluated had desirable capabilities,
7 AEP selected a vendor that offered a solution that best meets its collective needs
8 regarding system architecture, scalability, usability, advanced functionality/capability,
9 and future product roadmap.

10 Along with technical and strategic considerations, costs were evaluated
11 against the costs of similar size and scope ADMS deployments at North American
12 utilities and were deemed comparable to those costs of ADMS deployments for
13 similarly sized companies.

14 **Q59. Please describe the I&M implementation and timeline for ADMS.**

15 A59. AEP executed a contract and statement of work with the selected vendor and system
16 integrator in September 2022 for an enterprise-wide ADMS solution. Immediately
17 following, AEP kicked off the project, and began the implementation/build with the
18 vendor and a system integrator, establishing project and resource plans, and making
19 decisions related to system architecture, graphic/displays, SCADA, etc. The
20 implementation and build phase is expected to conclude at the end of 2024 including
21 production readiness. Once the core ADMS software is deployed to production, the
22 teams will continue to setup and deploy the dynamic circuit reconfiguration and

volt/var capabilities offered in ADMS. The deployment schedule for those capabilities will be determined at a later date.

Q60. As new technology is incorporated into I&M's grid, can ADMS advance with the technology?

A60. Yes. The ADMS platform is modular in nature, allowing AEP and I&M to add additional capabilities as technology, complexity, and customer needs continue to evolve in the utility industry.

Q61. What additional work is needed in support of the ADMS implementation?

A61. In support of the ADMS software implementation and included in the ADMS program, AEP and I&M will also work to improve source data and cyber security. Some examples of source data improvements needed to support the unified network model in ADMS include addressing data inaccuracies, missing data, and digitization of workflows. AEP will establish a Distribution System Network, which consists of cyber security hardware and software, that will ensure the ADMS has the proper isolation, access control and data exchanges in place.

X. ADMS AND DERMS PROJECT COST

Q62. What is the project cost for the ADMS and DERMS?

A62. Estimated expenditures for capital costs and ongoing O&M for the I&M portion of the enterprise ADMS implementation are shown in Figure JB-8 below. The capital costs include software licensing, implementation costs, source data and cyber security improvements. O&M costs include ongoing vendor software support, other IT support costs, and internal costs.

Figure JB-8. ADMS and DERMS Capital and O&M Costs (excluding AFUDC)

2023-2024 I&M CapEx	Forecasted I&M CapEx Total	Forecasted Enterprise CapEx
\$8.4M	\$11.2M	\$102.4M

2022 I&M O&M Costs	2024 I&M O&M Costs
\$0.06M	\$0.4M

Q63. What steps has the Company taken to minimize the costs of the ADMS deployment?

A63. I&M has also applied for applicable federal grant opportunities. As further supported by Company witness Walter. AEP seeking over \$27 million in United States Department of Energy funding in order to support the deployment of ADMS and DERMS. If awarded, I&M would receive a portion of that funding. However, it is possible that a notification of whether or not the Company has received a portion of that reward will not come until Fall 2023.

Q64. What processes does Technology and Security have in place to ensure that the ADMS costs are reasonable?

A64. The Technology and Security organization will use a similar project management and monitoring approach as previously described for the Field Mobility and CIS projects. The project team will provide monthly updates on project costs and schedule, any significant changes from the plan will require the approval of the Project Sponsors and the Technology and Security leadership team. Additionally, the Project Team will provide periodic updates to the Company regarding the cost and implementation timelines specific to I&M. Combining the competitive procurement process to select the vendor and the project management practices that will be used to control the

1 project costs, the Company is confident the costs to complete the project are
2 reasonable and necessary to obtain the technology needed to effectively manage
3 the grid of the future.

4 **Q65. Does this conclude your pre-filed testimony?**

5 A65. Yes.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of
INDIANA MICHIGAN POWER COMPANY
for authority to increase its rates for the
sale of electric energy and for approval of
other related matters.

Case No. U-21461

INDIANA MICHIGAN POWER COMPANY

PRE-FILED DIRECT TESTIMONY

OF

KATHERINE K. DAVIS

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**PRE-FILED DIRECT TESTIMONY OF KATHERINE K DAVIS
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY**

INTRODUCTION OF WITNESS

Q1. Please state your name and business address.

A1. My name is Katherine K. Davis, 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?

A2. I am employed by Indiana Michigan Power Company (I&M or Company) as the Vice President of External Affairs and Customer Experience.

Q3. Please briefly summarize your educational and professional background.

A3. I earned a bachelor's degree with honors in Communications and Spanish from the University of California, Davis. I also studied Spanish at the Universidad de Granada in Granada, Spain.

Prior to I&M, I spent more than a decade at Pacific Gas and Electric Company (PG&E) in California. Beginning in December 2008, I served in various positions including as a program manager in energy efficiency. In this role, I managed energy efficiency contracts with local governments and non-profits. I also led a team of Local Public Affairs Representatives covering an area representing approximately 4.6 million Californians where we served as liaisons to local governments, managed the charitable giving program, and interfaced with key community organizations. In my last position with PG&E, I served as Director and Chief of Staff to the CEO where I provided intelligence, advice, feedback, and counsel to the CEO and senior leaders on company strategy, policy matters, regulatory proceedings, communications, and

1 key organizational matters. Additionally, I helped the company navigate bankruptcy
2 proceedings, navigate its response to some of the most catastrophic wildfires in
3 California's history, led the company's transformational restructuring plan to become
4 more localized, and facilitated the creation and rollout of an enterprise safety
5 management plan. I also led the creation of an enterprise asset management
6 strategy, peer review process of public safety risk mitigation plans, and created
7 employee engagement strategies to shift culture and preserve employee morale
8 during very uncertain times.

9 From early 2020, until I took my current position with I&M, I was employed at
10 Duquesne Light Company (DLC) in Pittsburgh, PA where I served as the Vice-
11 President of External Affairs leading the Communications, Legislative, Regulatory,
12 Community Relations, and Sustainability teams creating an integrated external
13 affairs strategy designed to increase DLC's influence with key decision-makers and
14 thought-leaders to achieve positive business outcomes. I took my current position
15 with I&M in March 2021.

16 **Q4. What are your principal areas of responsibility with I&M?**

17 A4. I lead the Corporate Communications, Government Relations, External Affairs, and
18 Customer Experience teams. The purpose of these teams is to advance the way I&M
19 interacts with its customers, communities, stakeholders, and employees to positively
20 impact the customer experience and community objectives.

21 **Q5. Have you previously testified in any regulatory proceedings?**

22 A5. Yes. I have submitted testimony on behalf of I&M before the Michigan Public Service
23 Commission (Commission or MPSC) in I&M's 2024 and 2025 Energy Waste

Reduction (EWR) Plan in U-21323 and before the Indiana Utility Regulatory Commission in Cause No.45933, I&M's most recent Indiana base rate case.

PURPOSE OF TESTIMONY

Q6. What is the purpose of your testimony in this proceeding?

A6. The purpose of my testimony is to sponsor and support the following:

- Proposal to implement the PowerPay Program;
- Customer benefits associated with the Company's proposed Customer Information System (CIS);
- An update on the Company's Advanced Metering Infrastructure (AMI) deployment related to customer education and programs; and
- Request to continue the IM Plugged In.

Q7. Please summarize your testimony.

A7. My testimony describes the Company's proposed PowerPay Program, a voluntary, pre-pay billing option for its residential customers. PowerPay will provide benefits to I&M's residential customers and allow them to interact with I&M on their terms to improve customer satisfaction.

My testimony also describes the customer benefits associated with the Company's new CIS. The new CIS will give the Company more flexibility to implement evolving and more complex tariff designs to benefit customers and provide more tools for Demand-Side Management and improved customer communications.

I provide an update on the Company's AMI deployment related to efforts the Company has taken to engage and educate customers on the benefits of the AMI

1 technology and minimize the number of customers that opt out of the program. As of
2 August 2023, I&M's opt out rate in Michigan was 0.36%. I also discuss the customer
3 programs the Company is now offering to leverage the AMI technology, including DR
4 programs.

5 Last, I request that the Company be allowed to extend IM Plugged In so we
6 can continue to collect necessary data to be used in the creation of I&M's more
7 comprehensive electric vehicle (EV) programming proposal to be made in 2024. I
8 also outline our plans to engage with stakeholders to develop future enhancements
9 as EV adoption continues to increase.

10 **POWERPAY PROGRAM**

11 **Q8. Please describe the Company's proposed PowerPay Program.**

12 A8. The Company is proposing the PowerPay Program to be available to customers in
13 2025. The PowerPay Program is a voluntary payment option that allows customers
14 to pre-pay their electric bills, much like prepaid cell phones. We recognize that each
15 customer is unique, and therefore wants different levels of engagement with their
16 electric utility as well as various levels of control over their energy use. As shown in
17 *Figure KKD-1*, we currently have one way customers can pay their bills – monthly
18 with charges that vary based on actual usage, (Post-Pay). The PowerPay Program,
19 represented in the second row of *Figure KKD-1*, will add another option for customers
20 that want greater control over the frequency and timing of their payments, desire a
21 better understanding of their consumption, and want to better manage their account
22 with I&M.

Figure KKD-1. Payment Options

Billing Option	Charge Frequency	Charge	Level of Engagement from Customers
Post-Pay	Monthly	Variable Based on Usage	Medium
PowerPay*	Pre-Pay	Balance Draw Down Based on Actual Usage	High

*Designates a change or new items proposed in this testimony.

1 **Q9. What approvals is the Company seeking regarding its proposed PowerPay**
2 **offering?**

3 A9. As supported by Company witness Cooper, the Company is seeking certain
4 modifications of its Terms and Conditions of Service to include the PowerPay
5 Program. Additionally, as explained further by Company witness Brenner, the
6 Company is proposing to recover certain Information Technology-related costs
7 associated with implementing PowerPay. Company witness Seger-Lawson also
8 supports waivers associated with the Company's proposed PowerPay Program.

9 **Q10. How will the PowerPay Program benefit customers?**

10 A10. Programs such as Amazon Prime and Instacart are popular because customers want
11 choices and variety in the way they shop and pay for services to fit their lifestyle and
12 needs. Similarly, I&M's PowerPay Program offering would provide customers with
13 more choices with respect to how and when they engage with I&M to better suit their
14 respective lifestyles.

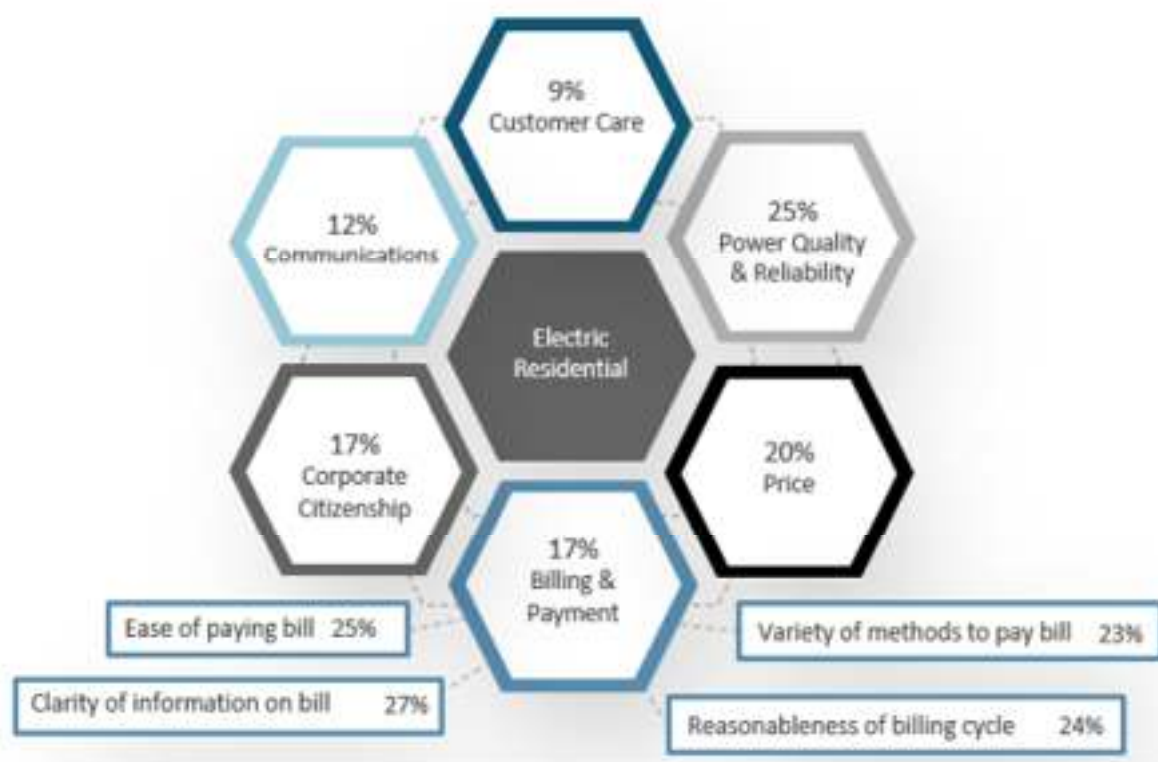
Specifically, customer benefits of the PowerPay Program include:

- 1 • Providing customers, a choice of when and how to pay their electric bills,
2 including giving them the opportunity to make payments that are more in-line
3 with their cash flow;
- 4 • Helping customers avoid larger-than-expected bills by receiving daily updates
5 on their usage and costs;
- 6 • Removing the requirements for deposits, reconnection, and/or late fees. This
7 helps remove barriers that arise for new customers needing to make deposits
8 to establish service and helps reduce account balances;
- 9 • Allocating existing deposits toward arrearages and/or to purchase electricity;
- 10 • Providing customers greater awareness of their usage and costs, giving them
11 greater ownership of their energy bill and energy reduction strategies;
- 12 • Receiving more frequent communications from I&M to help customers manage
13 their accounts and avoid potential shut offs;
- 14 • Creating an expedited process for reconnections if a customer is shut off (as
15 compared to a post-pay option) because there would be no deposit nor
16 arrearage payments required to reconnect service; and
- 17 • Establishing a Shut Off Grace Amount, which provides a grace period from
18 termination of service should a customer's balance reach \$0. Instead of a next
19 day shut off, a customer's account will be allowed to go negative, up to -\$50.

Q11. Does the Company have information that supports the position that customers value having multiple payment options?

A11. Yes. I&M receives customer feedback through J.D. Power's Electric Utility Residential Customer Satisfaction Study. As shown in *Figure KKD-2* below, billing and payment represents 17% of the customer satisfaction scoring index.

Figure KKD-2. Customer Satisfaction Scoring Index



There are four components included in the J.D. Power Billing and Payment category: ease of paying the bill, variety of methods to pay the bill, clarity of information on the bill, and reasonableness of the billing cycle.

The PowerPay Program provides customer benefits in each of these components:

- 1 1. Ease of paying the bill: Customers can make as many or as few payments as
2 they want through a variety of payment channels.
- 3 2. Variety of methods to pay the bill: This would be our most flexible payment
4 option because customers can choose to pay in more frequent, smaller
5 payments based on cash flow or, conversely, can make a larger, lump sum
6 payment so the account will draw down over a longer period.
- 7 3. Clarity of information on the bill: This program provides participants the
8 opportunity to better observe the correlation between usage and cost, thereby
9 creating more awareness as to what their electric service costs, and how long
10 their dollars last. This awareness then gives them the ability to see how
11 adjustments in energy use and behaviors affect the length of time their dollars
12 last, thus fostering more control over energy usage and the opportunity to
13 achieve more savings.
- 14 4. Reasonableness of the billing cycle: This program gives customers ultimate
15 control over their billing cycle because they determine how often they make
16 payments.

17 **Q12. Are you aware of any similar offering by any of I&M's affiliate companies?**

18 A12. Yes. I&M's sister company, Public Service Company of Oklahoma (PSO), has
19 offered its customers a similar PowerPay Program since 2016 and has had positive
20 feedback from customers that take advantage of the program.

21 Currently 2.2% of PSO's customers are participating in the program. PSO has
22 also experienced benefits from the program for non-participating customers. The
23 80/20 split, where 80% of a customer's payment is applied to the PowerPay balance,

1 with the remaining 20% applied to the arrears amount, has enabled PowerPay
2 customers to reduce their beginning arrearages of \$5.1 million by approximately \$3.5
3 million since the program began. This has reduced potential bad debt expenses,
4 which benefits all PSO customers.

5 **Q13. What are the eligibility requirements to participate in the PowerPay Program?**

6 A13. All new residential accounts and any existing residential customers, including
7 accounts with an existing deposit and/or arrears less than \$500, are eligible for the
8 PowerPay Program provided they have an AML meter.

9 Customers who cannot participate in the PowerPay Program are as follows:

- 10 • Customer accounts that have medical certification and/or critical care
11 protection;
- 12 • Seniors;
- 13 • Customers on payment plans;
- 14 ▪ The Budget Plan
- 15 ▪ Average Monthly Payment Plan
- 16 • Customers with on-site generation operated in parallel with the Company's
17 system;
- 18 • Customers who seek assistance for shut off protection.

19 **Q14. What rate schedule will apply to PowerPay Program customers?**

20 A14. PowerPay customers will continue to be billed under their current, applicable tariff
21 with portions of the rate converted to a daily rate. In other words, the standard tariff
22 remains the basis for the bill calculation. Thus, the customer's daily rate will be
23 calculated as the effective base rate and all applicable riders and fees for the

customer's daily usage within a 24-hour period. Fixed charges will be charged daily and prorated based on the number of days in the billing cycle. These amounts will be subtracted from the customer's daily account balance. If a customer has arrears, 20% will be applied toward arrears and 80% will be used toward funding the PowerPay account.

Q15. How will customers enroll in the PowerPay Program?

A15. Eligible I&M customers will be able to enroll at any time. They can do so either by calling the Customer Solutions Center or by signing up on our website. Any customer wanting to enroll in PowerPay will need to establish a credit account balance of \$40. This could either be in the form of a deposit that is already credited on the account, a new payment, or a combination of both. This amount was calculated based on an account balance equal to approximately one week of service based on the daily cost of roughly \$5.00 for a residential customer using 1,000 kWh.

Below are three different scenarios outlining how the \$40 prepayment and/or the arrearage payment would work.

1. New account: A customer establishing a new account must make an initial payment of \$40 to enroll in the program. Although an initial payment is required to fund the PowerPay account, the \$40 payment is immediately available to pay for electric service.

The initial payment must be made within two days of enrollment into the program; otherwise, the new customer will automatically revert to the post-payment option. New customers establishing a PowerPay account do not,

1 however, have to make a traditional security deposit that would normally be
2 used to secure an account.

3 2. Existing customer with deposit and no arrears balance: An existing customer
4 with a deposit who wishes to enroll in PowerPay can use the deposit to cover
5 the initial \$40 prepayment. The customer would not be required to make an
6 additional payment to enroll. Any remaining deposit balance would be applied
7 to the PowerPay balance and be available for future electric use.

8 3. Existing customer with a deposit and arrears amount: An existing customer
9 with a deposit and \$500 maximum in arrears who wishes to enroll in
10 PowerPay would still need to make an initial payment of \$40. The customer's
11 deposit could be credited against their arrearage. The remaining account
12 balance will be carried into an arrears amount that will be paid with each future
13 payment at an 80/20 split: 80% will be applied to the PowerPay balance, and
14 the remaining 20% will be applied to the arrears amount. A customer may not
15 carry over more than \$500 in arrearage to PowerPay. Anything above \$500
16 must be paid prior to enrollment in PowerPay. I&M will not charge any
17 additional late fees on the deferred balance while it is being paid down through
18 the PowerPay program's 80/20 allocation.

19 **Q16. Will the Company's website be updated to allow customers to sign up for the**
20 **PowerPay Program?**

21 A16. Yes. Should the PowerPay offering be approved, the Company will make updates to
22 its website to allow customers to sign up for PowerPay. The Company anticipates
23 this functionality will be available in early 2025.

1 **Q17. How will I&M communicate account information with PowerPay Program**
2 **customers?**

3 A17. Upon enrolling in the program, customers must choose at least one preferred
4 channel to receive all communications related to the PowerPay Program. The
5 communication channels available to PowerPay customers are e-mail, text, or both.
6 In addition to the selected communication channel, customers will also be able to
7 check their account balance by calling the customer operations center, calling an
8 Interactive Voice Request (IVR), or logging into their account at
9 www.indianamichiganpower.com or on the Company's mobile app. Customers will
10 be required to keep their contact information up to date to remain enrolled in the
11 program.

12 If I&M is unable to communicate with the customer either by e-mail or text, a
13 letter will be sent to the customer letting them know they have thirty days to enroll in
14 their chosen communication method to remain enrolled in the program. If they do not
15 do so, the customer will be removed from the PowerPay Program and enrolled in
16 traditional post-pay billing. The customer will receive information about this process
17 when enrolling in the program.

18 In addition to selecting a preferred communication method(s), participants
19 must also select a low-balance amount of at least \$25 for notification purposes. The
20 low balance notification amount is for notification purposes only and does not
21 represent the minimum amount that must be kept in the account to continue receiving
22 electric service. The customer will be notified when the account balance reaches the
23 selected low balance notification amount, or the amount of \$25, whichever is greater.

1 The customer will continue to receive daily alerts so long as their account
2 remains below the low balance notification amount. In addition to the individual
3 communications, PowerPay participants will also have access to the customer
4 engagement platform through the Company's website or mobile app. This tool
5 provides access to energy usage and cost information during the billing period,
6 allowing customers to act during the month to manage energy costs.

7 **Q18. Please describe the payment channels that program participants may utilize.**

8 A18. Authorized payment channels available to PowerPay participants include immediate
9 payment via telephone, website, or mobile app using electronic check, debit or credit
10 cards, and any authorized in-person pay stations. Customers may also set up
11 recurring payments through their bank bill pay feature or mail in a check to the
12 remittance office. Customers will not be charged a transaction fee for using a credit
13 card.

14 **Q19. When are customers unenrolled in PowerPay?**

15 A19. Customers can choose to unenroll themselves and convert to post-pay at any time.
16 They follow the same procedure as when they enrolled by calling either the Customer
17 Solutions Center or, once available, through the website.

18 Customers who have had their service shut off twice while participating in the
19 PowerPay Program, will be unenrolled and will receive notification on other post-pay
20 options.

1 Additionally, customers will be removed from PowerPay in the following
2 circumstances:

- 3 • If a customer unsubscribes from alerts, they will receive a letter advising them
4 to re-register in 30 days or they will be removed from the program;
- 5 • If a customer needs to participate in any Shutoff Protection Programs or
6 Energy Assistance;
- 7 • If a customer voluntarily closes the account, the account will revert to post-
8 pay requirements;
- 9 • If the customer has an AMI meter but then submits a request to opt out of an
10 AMI meter; and/or
- 11 • If a customer changes to one of the ineligible tariffs or other payment
12 arrangements.

13 **Q20. Are there costs associated with the PowerPay Program?**

14 A20. Yes. As explained further by Company witness Brenner, there is a \$650,000
15 adjustment for software and programming changes necessary to enable the
16 Company's billing system to accommodate PowerPay. Company witness Brenner
17 further explains the necessary technical upgrades to support the PowerPay Program
18 in his testimony.

19 Last, we anticipate a budget of \$20,000 to launch the program and educate
20 customers about the new payment option. As PowerPay will be available
21 approximately 12-18 months from the date of approval, these costs are not reflected
22 in the Company's cost of service in this proceeding as they will begin after the test-
23 year period.

Q21. If approved, when can the PowerPay Program be implemented?

A21. It will take roughly 12-18 months from the final order to make the updates needed to implement the PowerPay Program.

Q22. What happens when a participant's account balance reaches zero?

A22. A customer's account reaching \$0 will not result in immediate shut off or termination of service. As mentioned above, I&M is providing PowerPay customers with a Shut Off Grace Amount that would delay shut off until the account reaches -\$50.

Additionally, as mentioned above, the Company will provide ample notifications to any customer whose account reaches \$25 or their "low balance notification" amount, whichever is greater. If an account reaches zero, customers will continue receiving electronic balance notifications and an alert that their service will be shut off when they reach -\$50. Customers enrolled in PowerPay will receive daily usage information and, as such, will likely be more accustomed to checking their balance frequently. Since customers are tracking their balance, the Shut Off Grace Amount is provided in a dollar amount versus days or kilowatt hours. It is easier for a customer to track balance in dollars versus kilowatt hours. In addition, this gives the customer more control over how long the grace period will last based on how the customer uses energy during that period.

If the balance reaches -\$50, the customer will receive notification that their service will be shut off the following business day during normal business hours (8:00 a.m. to 3:00 p.m., Monday through Thursday and 8:00 a.m. to 12:00 p.m. on Friday, excluding Company-observed holidays). Shut off will not occur if the customer makes a payment to re-establish a positive account balance. If shut off does occur, electric

1 service will be automatically restored, typically within 15 minutes, after the payment
2 has been posted.

3 **Q23. Does the PowerPay program take into consideration Winter Protection Plan**
4 **(WPP) Rules?**

5 A23. Yes. If a customer enrolls in shut off protection programs, they will be removed from
6 PowerPay and their account will be transferred to post pay. Their service will not be
7 shut off. The customer can re-enroll in PowerPay after the Winter heating season by
8 meeting all of the enrollment criteria discussed above. Customers will not be shut off
9 during Extreme Weather Guidelines when the temperatures are predicted to rise
10 above 95 degrees or fall below 25 degrees in the following 24-hour period.

11 **Q24. Please describe how I&M will educate and engage its customers about the**
12 **PowerPay program.**

13 A24. I&M's communications plan will include several means of outreach with its customers
14 as well as different communication methods such as visuals and videos (where
15 appropriate) that will be included in printed material, email, social media, and
16 information on I&M's website. This education campaign will let customers know a
17 new payment option is available, outline all the specifics of the program, and provide
18 explanations of the enrollment process. The communications plan will also include
19 comparisons between existing payment options and the new option, so customers
20 are well informed before making their choice.

21 In addition, education efforts will continue beyond the initial outreach for
22 enrollment. When a customer initially enrolls in the program, the customer will receive
23 alert notifications via e-mail, text messaging, or both depending on the customer's

1 chosen communication method. Customers will know they are enrolled in the
2 program by receiving a “Welcome to PowerPay” alert message. After receiving the
3 initial alert message, alerts are triggered by customer activity such as payments
4 received and daily balance information, and notifications from I&M. PowerPay
5 customers have the potential to receive up to nineteen types of alerts that will
6 continue throughout a customer’s participation in the program.

7 Understanding that customers that take advantage of this type of program
8 have a tendency to closely monitor energy usage, I&M will also provide customers
9 with education on “ways to save” through our energy waste reduction program
10 offerings on the www.ElectricIdeas.com website, as well as help them identify how
11 to see their account usage and other energy savings tools available 24/7 on the
12 customer engagement platform.

13 Prior to implementation of PowerPay, I&M customer service employees as
14 well as call center personnel, will receive specific training related to PowerPay to
15 better support both interested customers and ongoing participants.

16 **Q25. Is the Company requesting any waivers in this proceeding to implement the**
17 **I&M Power Pay program?**

18 A25. Yes. As described by Company witness Seger-Lawson, I&M is requesting waivers of
19 certain billing, notice, and shut off provisions exclusively applied to customers
20 enrolled in PowerPay.

CUSTOMER INFORMATION SYSTEM

Q26. Please describe the benefits to the customer of replacing the Customer Information System (CIS).

A26. There are several primary benefits to I&M's customers in modernizing the Company's CIS as described by Company witness Brenner.

The first is the ability to adapt to the changing grid and evolving tariff designs that leverage more granular usage information. This allows for very complex time of use (TOU) tariffs to be offered to customers. Modern CIS systems, offered by third parties specializing in the technology, evolve with changing industry needs, and new releases offer changing functionality. For example, as Plug-in Electric Vehicle (PEV) growth continues, having effective TOU programs that can incentivize usage shifts or leverage their batteries as generation resources at peak to minimize or delay the need for capital infrastructure investment requirements will be very important.

The second primary benefit is speed to market tariff offerings. In addition to complex tariff design, modern CIS systems offer more flexibility around complex payment programs as well. Today, new, complex tariff changes must be hard coded or handled manually. Modern CIS systems are designed to ingest interval data and allow for more configurable rate implementation. As customers may have solar panels and PEV chargers at their homes and wish to participate in generation aggregation programs, a new CIS system is able to accommodate very complex tariff offerings to support their needs.

The third primary benefit is providing more tools for customers participating in Demand Side Management programs. To realize the ultimate value in a smart grid,

1 time-of-use offerings must be billable, and those pricing signals must provide benefits
2 to the customer. With a modern CIS system, interval usage for customers can be
3 paired with granular pricing to bill customers with real-time-pricing programs. Those
4 benefits may result in lower hourly costs for customers that can shift their load to
5 lower price hours.

6 The fourth primary benefit involves the protection of customer data, which is
7 explained further by Company witness Brenner.

8 Finally, a modern CIS will position I&M for better communication with its
9 customers by leveraging a more customer-centric data structure with customer
10 communication preferences that creates efficiencies in speed at which
11 communications can be sent.

12 **Q27. How will the new CIS system improve customer communications?**

13 A27. The current billing system was designed to produce a customer bill once per month,
14 not manage multi-channel communications based upon different events that
15 customers now want to know about in a timely manner. Modern CIS systems include
16 customer communication preferences as part of the system with the customer data,
17 not as an add-on requiring multiple integrations across platforms. For example, today
18 customer outage communications stem from a trigger in the outage management
19 system (OMS), which in turn prompts the system to generate an outage message to
20 a customer based on the customer's preference of communication. However, the
21 system is not able to produce communications for planned outages, and targeted
22 communications need to be created manually.

1 Customers are also expecting different communication channels depending
2 on the subject. For instance, customers may want outage or high usage alerts
3 through text or smart phone app notifications, while information about new rate
4 programs could be delivered via email. While not every customer is interested in
5 leveraging new technology, I&M recognizes that traditional communication
6 approaches no longer meet the needs of all customers.

7 Furthermore, the system will be able to target customers with outage alert
8 messages for anticipated outages as well as for outages due to scheduled
9 maintenance in real time. However, traditional communication channels such as bill
10 inserts, and the customer solutions center will still be available to customers that
11 prefer them.

12 **Q28. How does the implementation of a new CIS system improve communications**
13 **related to demand response?**

14 A28. Three types of demand response communications enabled by the new CIS system
15 will benefit customers.

16 First, there are communications that are affiliated with Commercial and
17 Industrial (C&I) demand response events. In the event of a curtailment, customers
18 will be able to receive a notification to opt into the event. Also, customers will be able
19 to receive day-ahead notifications to potentially reduce their energy use during peak
20 load periods.

21 Second, customers will be able to receive notifications for residential demand
22 response events. Similar to the C&I notifications, customers will be able to receive
23 opt-in notifications to participate in residential events (HVAC, EV, Water Heater

options) as well as day-ahead notifications to reduce their use during peak load periods.

The third type of notification would be a Distributed Energy Resource (DER) response notification. This communication would let customers with batteries, generators, or other DER technology have better information about market and grid conditions so that they know when it is more advantageous to send energy back to the grid.

AMI CUSTOMER ENGAGEMENT AND EDUCATION

Q29. Please provide a status on the Company's AMI deployment in Michigan.

A29. The Company has now successfully completed its AMI deployment in Michigan. All customers that have not opted-out of the AMI program have received an AMI meter. This is further discussed by Company witness Isaacson.

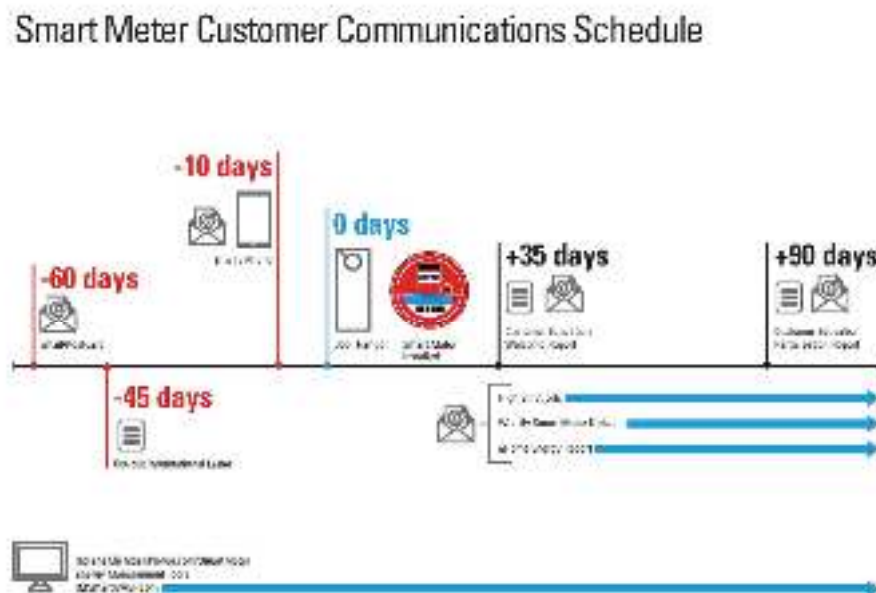
Q30. What efforts did the Company undertake to ensure customers were fully informed regarding the AMI technology?

A30. The Company implemented a comprehensive and structured approach to customer education and engagement as demonstrated in *Figure KKD-3. AMI Communication to customers:*

- 60 days prior to the AMI installation customers were sent an email and a post card to inform them of the AMI meter installation.
- 45 days prior to the AMI installation customers were mailed opt out informational letter.
- 10 days prior to the installation customers received an email and/ or phone call.

- The day of installation after the meter was changed a door hanger was left at customer's property.
- 35 days after the installation customers received a Customer Education Welcome Report via email or regular mail.
- 90 days after installation customers received Customer Education Participation Report.
- Customers continue to receive communication regarding high bill alerts, weekly smart meter updates and eHome energy report on an ongoing basis after the AMI installation.
- Customers can visit IndianaMichiganPower.com/SmartMeter to learn more about their energy consumption and energy management tools. They can reach out to our AMI customer specialists via email IMSmart@aep.com.

Figure KKD–3: Smart Meter Customer Communications Schedule



Q31. What percentage of I&M's customers have received an AMI meter?

A31. As a result of the Company's expanded efforts to inform and educate customers, 99.64% of I&M's Michigan customers have adopted the AMI technology.

Q32. What benefits have customer's experienced as result of the AMI deployment?

A32. The AMI technology is still very new to many I&M customers with most customers only having their meter for less than a year, however customers are already starting to recognize direct benefits of the AMI technology. As discussed by Company witness Isaacson, AMI technology is now being used in a variety of ways by the distribution team to improve the customer experience by identifying outages and reducing restoration times, using predictive analysis to mitigate future system issues, and provide more real-time information to assist in resolving customer service issues.

In addition to the distribution operational benefits, AMI allows customers the ability to readily have access to near real-time data regarding their electric use. This allows them to monitor and manage use, like in the case of the PowerPay Program. I&M has also used the AMI technology to offer new time differentiated rate options and incentives for demand response.

These programs include:

- Changes to existing tariffs RS-TOD, GS-TOD, RS-TOD2, and GS-TOD2
- New Residential Critical Peak Pricing (Residential CPP) Tariff
- New General Service Critical Peak Pricing (GS CPP) Tariff

- Changes to the existing Home Energy Management (HEM) Rider, including:
 - New Residential Customer Engagement Demand Response Pilot
 - New Residential AMI HVAC Direct Load Control Pilot
 - New Residential AMI Electric Water Heater Direct Load Control Pilot
- Changes to existing Work Energy Management (WEM) Rider to include Small Business AMI Direct Load Control Pilot

Q33. Can you please provide a status of these programs?

A33. Yes. All time of day and critical peak pricing tariffs are now available for customer enrollment. The Company has completed pilot activities on the four pilots and has filed the required reports with the Commission. The Company is proposing in this case that all four pilots are appropriate and reasonable to move forward as future programs. Company witness Walter provides a more detailed discussion of our proposals in this case.

Q34. Please describe the Company's strategy to educate and engage customers to increase participation in the programs.

A34. I&M has a comprehensive marketing and outreach plan to make customers aware of the offerings the Company has available, and the potential benefits customers can realize through participation. With demand response programs, the Company has learned that providing the customer with a clear understanding of how the program works, the control they have during the program to opt-in or opt-out, how the financial incentive works, and any program requirements is critical for the customer to make

1 the decision to participate. Additionally, an easy way to enroll is also very important
2 for customers to fully complete the enrollment steps.

3 To address this, I&M is in the process of creating an online enrollment tool
4 which will significantly improve the customer's enrollment experience. This tool has
5 been several years in the making and is being created in partnership with multiple
6 implementation vendors who support the Demand Response program portfolio. The
7 enrollment tool will serve as a place for residential customers to enter their account
8 information and answer a couple of questions about their energy use. The enrollment
9 portal will then show the customer all the demand response programs in which they
10 are eligible to participate. The enrollment portal will also give a recommendation on
11 what program would be the best fit for the customer. The customer can use the
12 recommendation, or they can choose from one of the other programs they are eligible
13 for based on their energy profile.

14 **ELECTRIC VEHICLE (EV) PROGRAMS**

15 **Q35. Is I&M proposing any new EV programs in this case?**

16 A35. No. I&M is not proposing any new EV programs in this case. In accordance with the
17 January 23, 2020, Order for settlement in Case No. U-20359, I&M implemented IM
18 Plugged In. Per the terms of settlement, IM Plugged In has a program duration of
19 either 1) a term of 4.5 years from the date of the January 23rd Order; or 2) the
20 effective date of a Commission order in I&M's next base rate case filing. In this case,
21 I&M is proposing to continue IM Plugged In until the Commission issues a ruling on
22 I&M's comprehensive EV program filing that I&M anticipates making in early 2024.

Q36. Why should the Commission extend IM Plugged In?

A36. Extending IM Plugged In allows the Company to continue to offer customers EV incentives while assessing customer adoption, barriers, and emerging technologies. Company witness Seger-Lawson discusses cost recovery for this extension. Part of the assessment process includes gathering of feedback from current EV owners and potential EV owners (people who plan to purchase an EV in the next 12 months).

The feedback includes the following data points:

- Barriers to EV charging installation
- Ownership vs lease of equipment
- Rebate opportunities to purchase EV chargers
- Utility incentive levels to drive off peak charging

Our engagement with customers includes focus groups and surveys. Once we have analyzed the results and customer feedback, we will use that information to drive our EV strategy and enhance our program offerings.

Q37. Please describe IM Plugged In.

A37. IM Plugged In consists of several elements that each play an important role in encouraging plug-in electric vehicle (PEV) adoption in a way that optimizes the overall electric system. The elements include:

1. Residential and small commercial PEV charging.

- i. Available under provisions of the Company's Tariff RS/PEV and GS/PEV. IM Plugged In offers a \$500 incentive to participating customers with proof of a qualifying PEV purchase on or after the

1 approval date of this program, subject to the IM Plugged In spending
2 cap.

3 2. Multi-Unit Dwelling PEV charging.

- 4 i. I&M provides opportunity to take advantage of one of two incentive
5 options to offset some of the costs of establishing PEV charging
6 systems of tenants.

7 3. Commercial and industrial fleet and workplace PEV charging.

- 8 i. I&M provides customers with opportunity to take advantage of one of
9 two incentive options to offset some of the costs of establishing a fleet
10 of PEVs.

11 4. Interstate corridor PEV charging.

- 12 i. Supports the Michigan Department of Environment, Great Lakes, and
13 Energy Charge up Michigan Program, an EV Charter Placement
14 project that aims to build the infrastructure for DC fast charging stations
15 in the state of Michigan to ensure feasibility of all long-distance trips for
16 EV users.; and

17 5. EV education and technical development.

- 18 i. I&M works with customers to increase awareness and knowledge of
19 PEVs and programs through specific outreach campaigns.

20 **Q38. Does this conclude your pre-filed verified testimony?**

21 A38. Yes.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

**In the matter of the application of
INDIANA MICHIGAN POWER COMPANY
for authority to increase its rates for the
sale of electric energy and for approval of
other related matters.**

Case No. U-21461

INDIANA MICHIGAN POWER COMPANY

PRE-FILED DIRECT TESTIMONY

OF

DANIEL M. WHITE

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**DIRECT TESTIMONY OF DANIEL M. WHITE
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY**

INTRODUCTION OF WITNESS

Q1. Please state your name and business address.

A1. My name is Daniel M. White, and my business address is 1 Riverside Plaza
Columbus, OH 43215.

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

A2. I am employed by American Electric Power Service Corporation (AEPSC) as the
Managing Director of Economics and Supply Forecasting. AEPSC supplies
engineering, accounting, planning, advisory, and other services to the subsidiaries
of the American Electric Power (AEP) system, one of which is Indiana Michigan
Power Company (I&M or the Company).

**Q3. What are your responsibilities as Managing Director of Economics and
Supply Forecasting?**

A3. I serve as the company's Chief Economist and manage teams responsible for our
economic, load, and supply cost forecasting. Those forecasts are provided to each
of the AEP operating companies, including I&M.

Q4. Briefly describe your educational background and professional experience.

A4. I received a Bachelor of Business Administration Degree in both Finance and
International Business from New Mexico State University in 2006. In 2008 I received
a Master of Arts Degree in Economics, also from New Mexico State University.

1 I have worked as an economist since 2008 when I served as a financial economist
2 for the New Mexico Legislative Finance Committee. In that role I forecasted
3 revenues and advised policymakers on a wide range of public policy issues
4 concentrated around economic development, public investment, and debt
5 management.

6 In 2010 I joined Moody's Analytics as an economic forecaster and ultimately
7 served in a variety of roles including Director of Public Sector Research, Director of
8 Economic Consulting, and Senior Director of Economic Research. In March of 2023,
9 I joined AEPSC as Managing Director of Economics and Supply Forecasting.
10 Additionally, since 2016 I have taught classes as a member of the economics faculty
11 at Villanova University.

12 **Q5. Have you previously testified before any regulatory commissions?**

13 A5. Yes. I have submitted testimony with the Indiana Utility Regulatory Commission in
14 I&M's most recent base rate filing, Cause No. 45933. In addition, I have testified in
15 front of other types of legislative and governmental bodies around economics and
16 revenue forecasting.

17 **PURPOSE OF TESTIMONY**

18 **Q6. What is the purpose of your testimony?**

19 A6. The purpose of my testimony is to present the kilowatt-hour (kWh or energy),
20 customer, and kilowatt (kW or peak) forecasts used by the Company to develop its
21 test year billing determinants. I also discuss the processes and methodology
22 employed to forecast the Test Year, which is the 12-month period ending December
23 2024.

Q7. How is your testimony organized?

A7. My direct testimony is organized into three major sections. First, I share the Test Year load forecast results, showing the comparison to the recent historical actual results. Then I describe the methodology used to develop the Test Year load forecast. Finally, I provide an explanation of some of the key assumptions and drivers of the forecast that are influencing the Test Year load forecast results.

Q8. Are you sponsoring any Exhibits?

A8. Yes, I am sponsoring the following Exhibits:

- Exhibit A-15, Schedule E-1 – Sale, Load, and Customer Data.
- Exhibit IM-25 (DMW-1), which contains the summarized load forecast results (kWh, kW, customers) used in the Test Year. All of the input data, model equations, and statistical results for the various forecast models used to develop the Test Year load forecast are provided in the workpapers described below.

Q9. Were the Exhibits that you sponsor prepared or assembled by you or under your direction?

A9. Yes. Exhibit IM-25 (DMW-1) was prepared and assembled before I joined AEPSC by teams that I now supervise. I have since reviewed these documents and found them to be reasonable.

Q10. Please summarize your testimony.

A10. The Test Year forecast is a reasonable projection of I&M's customer count, sales, and peak load. The sales levels reflect reasonably anticipated market and economic

1 conditions the Company expects to influence sales during the Test Year, as well as
2 reasonably anticipated energy conservation and efficiency programs.

3 I&M's load forecast methodology, which is consistent with the prior rate case,
4 Case No. U-20359, is proven to produce reasonable projections that are useful for
5 planning and setting rates. All load forecast numbers discussed in my testimony are
6 inclusive of Electric Customer Choice customers. The forecast techniques utilized
7 by the Company are widely accepted across the electric utility industry and utilize
8 data inputs from recognized third-party sources.

9 This methodology produced a Michigan retail jurisdictional forecast that is 53
10 GWh lower than the weather normalized actuals in 2022. This includes an increase
11 in Commercial class sales that is more than offset by lower Residential and Industrial
12 class sales.

13 The Test Year forecast reflects an economy dealing with a tight labor market,
14 escalating rates of inflation, and a shift from expansionary to contractionary
15 monetary policy. Inflation (as measured by year over year growth in the Consumer
16 Price Index: Urban Consumer – All Items) reached a high of 8.9% in June 2022. The
17 pace of inflation has slowed since the Federal Reserve began its aggressive
18 monetary tightening policy. However, higher costs and wages have become more
19 entrenched in overall consumer prices which will cause inflation to continue at levels
20 above the Federal Reserve's target into at least 2024.

TEST YEAR FORECAST RESULTS

Q11. What are the Test Year load, customer, and peak demand projections?

A11. Exhibit IM-25 (DMW-1) contains the monthly summary of the load forecast that was used to develop the Test Year billing determinants. Total I&M retail sales are projected to grow in the Test Year, while the Michigan portion of I&M's retail sales are forecast to fall slightly from recent actuals. This reflects continued declines in population and a slower pace of economic growth.

For the Michigan retail jurisdiction of I&M in 2024, I&M is projecting 2,807 GWh with an average customer count of 131,587 and an annual peak demand of 641 MW.

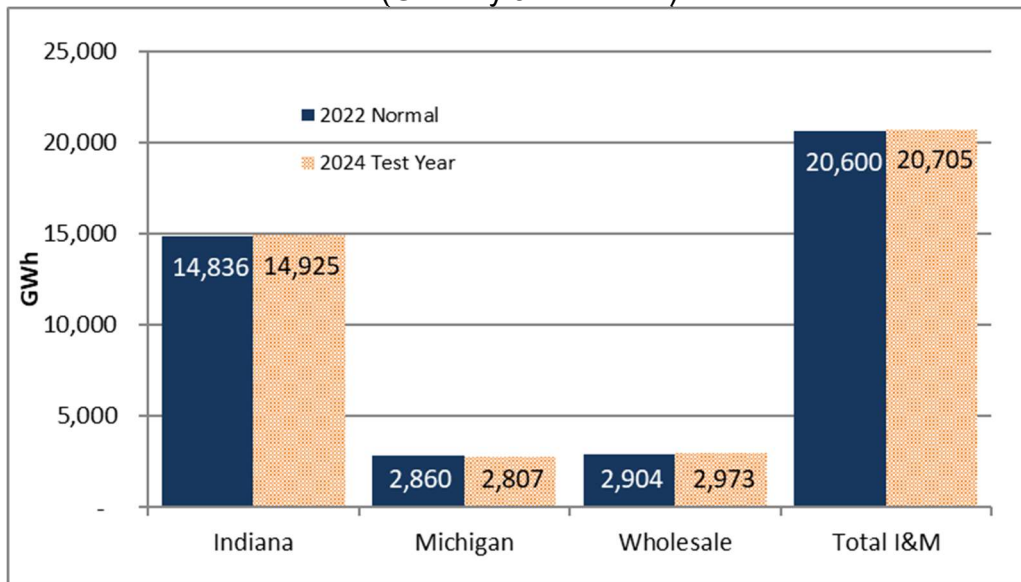
For the total I&M system, including the retail jurisdictions in Indiana and Michigan as well as the wholesale class, the total Test Year energy is 20,705 GWh with an average customer count of 611,486 and an annual peak demand of 3,981 MW.

Q12. How do the forecasted energy sales for the Test Year compare to actuals in 2022 by jurisdiction?

A12. *Figure DMW – 1* shows I&M's GWh sales forecast comparison over the projected period for each I&M jurisdiction. In summary, total Test Year sales are approximately 105 GWh above the weather normalized 2022 actual sales.

The increase in I&M Test Year sales reflects gains of 89 GWh and 69 GWh in Indiana and the company's wholesale class, respectively. These gains are offset by a projected 53 GWh decrease in Michigan retail sales.

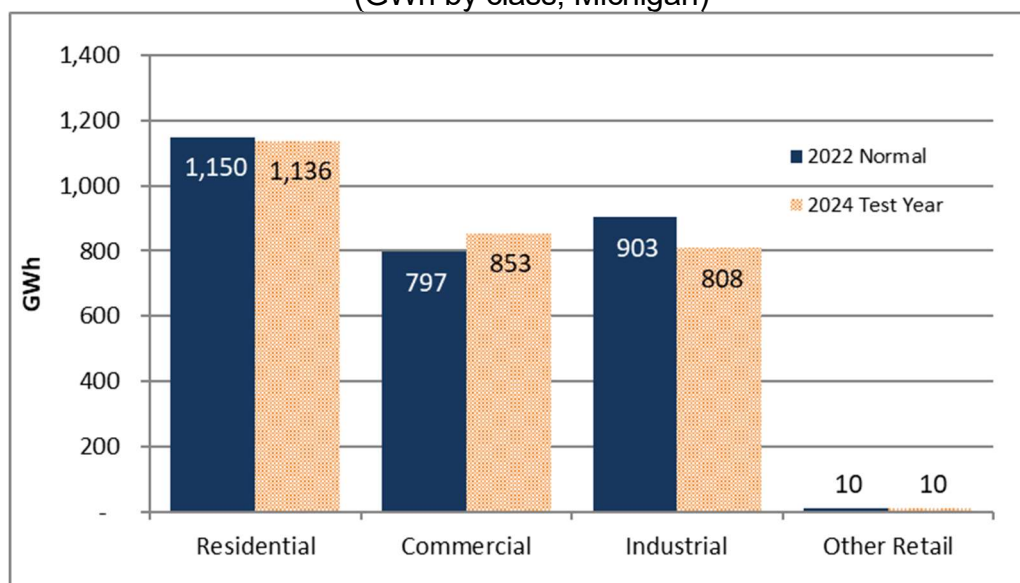
Figure DMW - 1: Comparison of 2022 Weather Normalized Actuals to Forecasted Test Year
(GWh by Jurisdiction)



Q13. How do the forecasted energy sales for the Test Year compare to actuals in 2022 by class for the Michigan jurisdiction?

A13. Michigan Test Year sales are projected to be down 53 GWh compared to the normalized actuals in 2022. *Figure DMW - 2* shows the forecast comparison for the Michigan retail jurisdiction by class. The increase in Commercial class sales (56 GWh) offset lower Residential and Industrial class sales (down 14 GWh and 95 GWh, respectively) when compared to the 2022 weather normalized actuals.

Figure DMW - 2: Comparison of 2022 Weather Normalized Actuals to Forecasted Test Year
(GWh by class, Michigan)



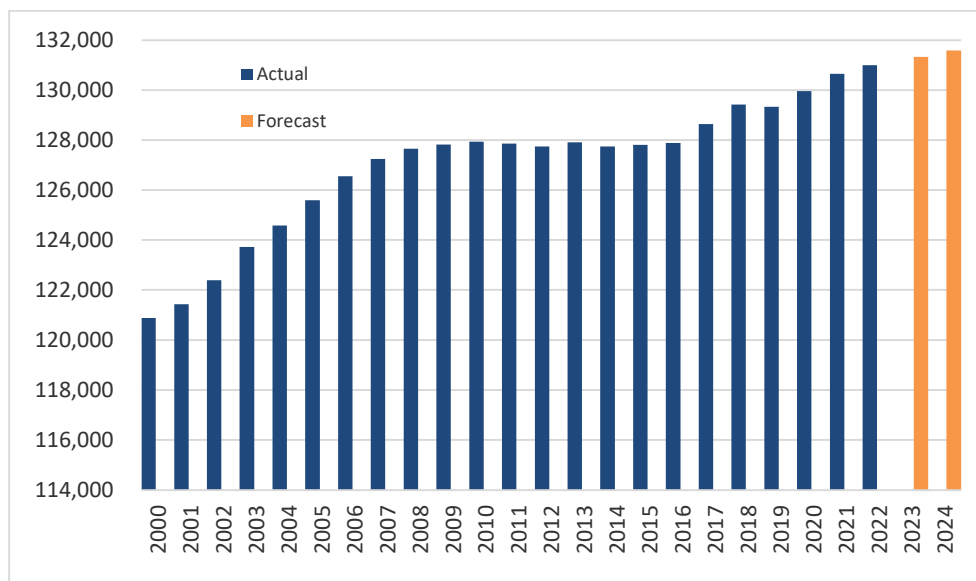
Offsetting trends in commercial and industrial load are primarily attributable to a reclassification of load. Since 2022, a large customer has been reclassified from I&M's industrial class to its commercial class. This accounts for a majority of the commercial gains and industrial losses through the 2024 test year compared to 2022 weather normalized actual load. The downward trend in overall load is attributable to tighter economic conditions as we get farther from the initial stages of the post-COVID recovery.

Q14. Please summarize I&M's customer count forecast for the Michigan jurisdiction.

A14. Overall, the forecasted customer count for the Michigan jurisdiction grows at a pace less than that of the previous two years. This is in line with the rate of growth experienced prior to the COVID-19 pandemic and consistent with the demographic and economic projections that are discussed in Section IV below.

Figure DMW - 3 shows how the forecasted customer count aligns with the historical data series for I&M's Michigan jurisdiction. Compared to 2022 actuals, I&M's forecasted Michigan jurisdiction customer count for 2024 is 587 higher than the average customer count in 2022.

Figure DMW - 3: I&M Michigan Retail Customer Count Forecast



As a result of the moratorium on disconnects that was implemented in 2020, customer counts were temporarily inflated as the Company suspended its normal operating procedures. Since the moratorium was lifted, customer count growth has slowed. The Test Year forecast in this case reflects a continuation of that trend.

Q15. Please summarize I&M's peak forecast.

A15. I&M's Total Company forecasted peak demand for the Test Year is 3,981 MW in July of 2024. By comparison, I&M's actual peak demand in 2022 was 3,850 MW on June 21, 2022, and weather normalized peak estimate for 2022 was 3,978 MW. For

1 its Michigan service territory, I&M projects peak demand for the Test Year of 641
2 MW including Electric Customer Choice customers.

3 A weather normalized peak represents what the peak value would have been
4 if the temperature on the peak day had been normal for a peak day. The normal
5 temperature for any given day is determined by a rolling 30-year average as I will
6 discuss below. In 2022, the temperatures were cooler than normal for a peak day,
7 so the actual peak came in lower than it would have been under normal peak day
8 conditions.

9 **Q16. How is the Test Year load forecast you sponsor used in this Case?**

10 A16. Company witness Duncan uses the Test Year load forecast to develop the
11 forecasted billing determinants used in rate design. In addition, Company witnesses
12 Morgan and Hornyak use the load forecast in the jurisdictional and the class cost
13 study allocations, respectively.

14 **LOAD FORECAST METHODOLOGY**

15 **Q17. How often does I&M prepare a load forecast?**

16 A17. I&M generates a new load forecast once a year as part of its normal planning
17 process. The load forecast is one of the first inputs used in the development of I&M's
18 long-term financial forecast. Typically, the load forecast is completed in the summer
19 months while the rest of I&M's work plans are still being developed.

20 **Q18. Is the load forecast monitored or updated during the year?**

21 A18. Yes. Because the load forecast is completed early in the planning process, we
22 monitor its performance during the last half of the year to ensure accuracy is

1 maintained. Updates to the load forecast may occur during this time period,
2 depending on the degree of the differences between the load forecast and the actual
3 results.

4 **Q19. When was the load forecast used in this proceeding prepared?**

5 A19. The load forecast used in this proceeding was originally completed in May 2022
6 using actual data through December 2021. However, as part of our normal
7 monitoring process, we noticed some slight forecast variance trends developing
8 over the first seven months of 2022. The most impactful trend was within the
9 Industrial sector which was experiencing a slower near-term economic recovery
10 than was previously assumed. Smaller upward revisions were made to both the
11 Residential and Commercial classes. We alerted I&M's management team of the
12 trend and recommended an overall downward adjustment to the load forecast which
13 was subsequently made. The load forecast presented as the Test Year in this
14 proceeding is the update that was completed in August 2022, and is the same
15 vintage used for I&M's 2023 Control Budget.

16 **Q20. Why are forecasts of customers, energy (kWh), and hourly demand (kW)**
17 **prepared?**

18 A20. Forecasts of customers, energy sales (kWh), and demand (kW) are prepared to
19 provide planning information for a variety of business uses. These uses include
20 financial, fuel, capacity, and rate planning.

1 **Q21. Does I&M prepare forecasts specifically for the Michigan portion of its service**
2 **territory?**

3 A21. Yes. Forecasts are prepared for the Michigan and Indiana portions of I&M's service
4 territory separately, using similar methodologies. Those forecasts are then
5 combined to constitute the overall I&M load forecast. This ensures that customer
6 activity and trends in both states are adequately accounted for.

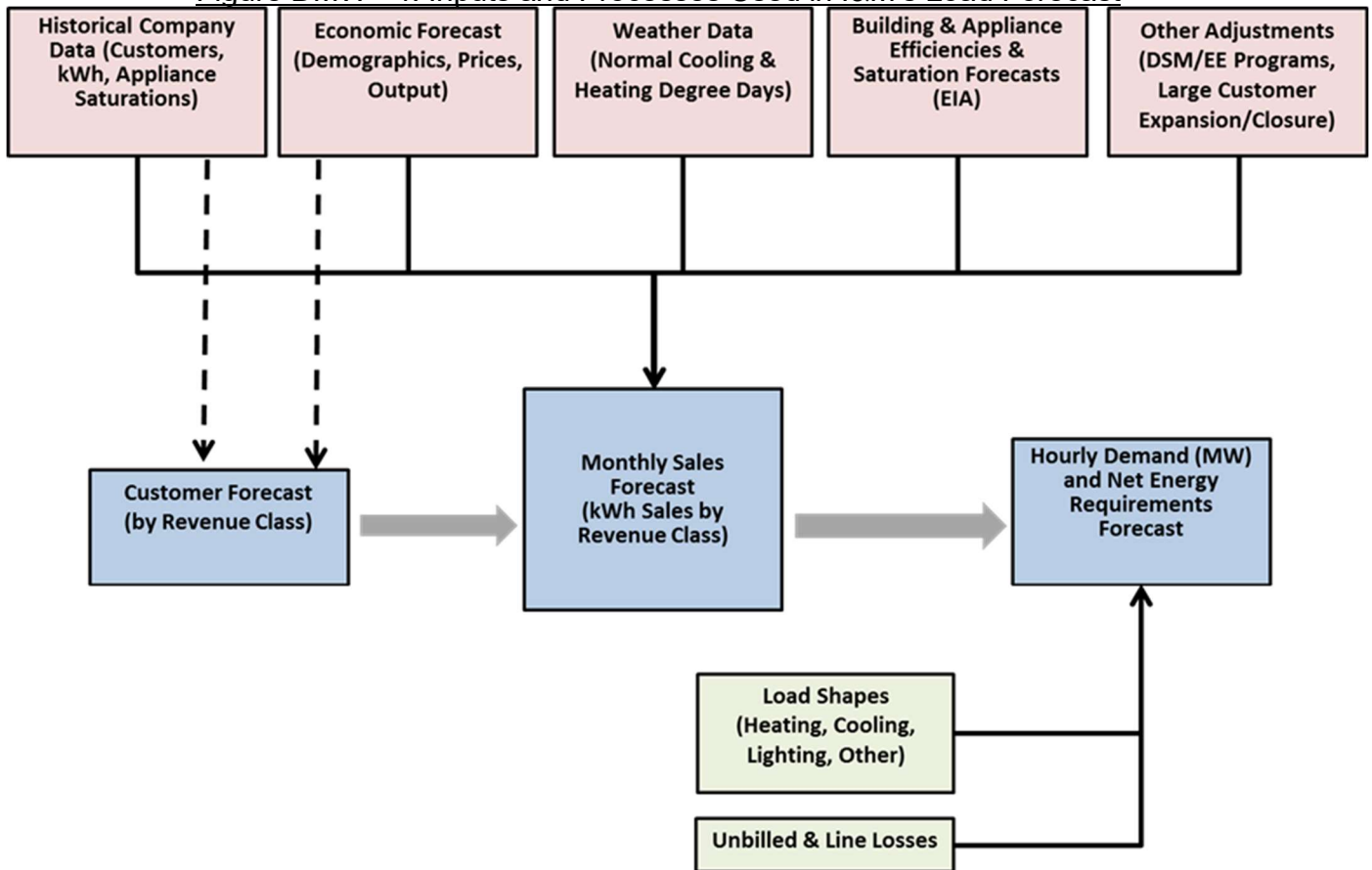
7 **Q22. What are the major objectives considered when determining how the**
8 **Company will prepare its load forecast?**

9 A22. The primary objectives when determining how to model the Company's load
10 forecast are accuracy and transparency. In other words, we select models that are
11 sophisticated enough to be able to produce accurate and reliable results, yet simple
12 enough that they can be readily shared with and understood by management,
13 regulators, intervenors, and other stakeholders.

14 **Q23. How are the kWh energy, customer, and kW demand forecasts prepared?**

15 A23. I&M uses a methodical approach to forecasting load. *Figure DMW - 4* illustrates the
16 various inputs and processes involved in the development of the load forecast. The
17 final forecast is the culmination of a series of underlying forecasts that build on each
18 other (i.e., customer forecast feeds the sales forecast which goes into the demand
19 forecast).

Figure DMW - 4: Inputs and Processes Used in I&M's Load Forecast



Q24. What methods does I&M use to develop the load forecast?

A24. Two distinct methods were used for forecasting customers and kWh for the short-term (0 to 24 months following the last actual data point utilized) and the long-term (0 to 30 years following the last actual data point utilized).

The last actual data point utilized in the 2022 vintage forecast presented in this proceeding was July 2022. Because the 2024 Test Year fell outside the short-term forecast period, the Test Year forecast used data from the long-term process, and thus I will focus most of my description on the long-term forecast methodology.

1 To ensure the highest levels of accuracy, the short-term forecast was used as a
2 reference to confirm the reasonableness of the long-term forecast.

3 I&M used Itron's Statistically Adjusted End-use (SAE) models to forecast
4 long-term residential and commercial kWh sales. SAE econometric models are
5 widely used across the industry for long-term planning because of their reliability
6 and their ability to specifically account for energy efficiency impacts. SAE models
7 start with the construction of structured end-use variables that capture underlying
8 trends in end-use equipment saturation levels and efficiencies. Factors are also
9 included to account for changes in energy prices, household size, home size,
10 income, and weather conditions.

11 The long-term process for forecasting Industrial and Other Retail kWh sales
12 starts with economic forecasts provided by Moody's Analytics. Regional and
13 national economic and demographic variables are combined with forecasts for
14 energy prices and customer-specific information in econometric models to produce
15 the forecasts.

16 The results of the kWh sales models, in turn, are inputs to the peak demand
17 (kW) models. As part of the forecast review process, the Company evaluates and
18 validates the historical relationship between the energy (kWh) and peak demand
19 (kW) based on metered load factors.

Q25. Why does I&M use different methods for short-term and long-term kWh forecasting?

A25. I&M uses processes that take advantage of the relative strengths of each methodology. The short-term process utilizes time-series regression models that capture patterns within recent sales and weather data to represent the variation in kWh sales on a monthly basis for short-term applications like capital budgeting and resource allocation. Although these models can produce accurate forecasts in the short run, without logical ties to long-term economic factors, they are less capable of capturing the structural trends in electricity consumption that are important for longer-term planning.

The long-term process, with its explicit ties to economic, demographic, efficiency, and saturation trends, is more appropriate for longer-term decisions such as capacity planning and distribution planning.

Q26. How were class kWh level energy sales forecasts translated into an hourly load forecast?

A26. Historical load and temperature data was used to develop hourly load representations (load shapes) for specific temperature increments by revenue class and load type (e.g., Residential cooling shape, Commercial heating shape, etc.). These load shapes are then applied alongside normal weather data to the sales forecasts to generate hourly load forecasts.

The aggregate of the load shapes for each of the classes is the system load profile. If necessary, the system load profile is calibrated based on the load factor trend to produce an hourly load and peak kW forecast. In this case, the peak forecast

1 is primarily used for production costing and jurisdictional cost allocation
2 development for rate design.

3 **Q27. What are the sources of the data used in the forecast?**

4 A27. All kWh sales, customer, and peak load data are taken from Company billing and
5 operational records. Weather data is provided by the National Oceanic and
6 Atmospheric Administration from weather stations in I&M's service territory (i.e., Ft.
7 Wayne, IN and South Bend, IN).

8 The economic forecasts are based on data gathered by federal, state, and
9 local authorities, as well as propriety sources of Moody's Analytics for the counties
10 served by I&M. The appliance saturations and efficiencies come from company
11 surveys and/or Itron's SAE models which are linked to the Energy Information
12 Administration (EIA's) National Energy Modeling System by census region.

13 Energy Waste Reduction (EWR)/Energy Efficiency assumptions come from
14 the Energy Waste Reduction Plan (EWR) filed in Case No. U-20877. And the large
15 customer assumptions come from I&M's customer service engineers who have
16 direct contact with our customers.

17 **Q28. Is Moody's Analytics a reliable source of economic forecast information?**

18 A28. Yes. Moody's Analytics is a trusted and reputable provider of economic forecast
19 data. In addition to numerous accuracy accolades, Moody's Analytics has a broad
20 client base across the globe including approximately fifty utilities throughout the US.

1 This includes at least four utilities that provide electricity service to customers in the
2 state of Michigan.

3 Furthermore, PJM, the RTO of which I&M is a member, also utilizes Moody's
4 Analytics as its economic forecast provider in the development of its load forecasts.
5 While it is not required for I&M to use the same economic forecast provider as PJM,
6 there are benefits to having some of the load forecast model assumptions in sync.

7 **Q29. Is Itron's SAE model a reliable forecasting tool used by others in the electric**
8 **utility industry?**

9 A29. Yes. Itron Inc. is a leading technology provider to the global energy and water
10 industries. They introduced SAE models in the early 2000's. Today, over sixty
11 companies across North America utilize Itron's SAE models for forecasting including
12 the PJM load forecasting team.

13 **Q30. Does the Test Year forecast assume normal weather conditions, and if so,**
14 **how is this accomplished?**

15 A30. Yes. The forecast assumes normal weather conditions throughout the entire
16 forecast horizon including the Test Year. It is appropriate to utilize weather
17 normalized billing determinants when setting customer rates since it represents the
18 most likely outcome (i.e., highest probability of occurrence) that minimizes the
19 possibility that the Company will under or over collect the intended revenue
20 requirement set by the Commission. The Company uses a rolling 30-year average
21 of heating and cooling degree days to compute the projected normal degree days
22 that are used in the forecast models. This is consistent with previous I&M filings.

1 **Q31. How does the Company account for energy efficiency in the long-term load**
2 **forecast?**

3 A31. The SAE model used in our long-term methodology integrates end-use saturation
4 and efficiency information into the forecast. This information incorporates the impact
5 of federal energy standards and other relevant energy efficiency factors.

6 The appliance saturation statistics are calibrated with the Company's periodic
7 Residential Appliance Saturation Survey results, which are conducted every three
8 to four years. In addition to the energy efficiency impacts that are included in the
9 base SAE model framework, I&M also adjusts the load forecast for the impacts of
10 its EWR and Energy Efficiency programs that are approved by the Commission for
11 the longer term, contained within the Company's IRP.

12 **Q32. What EWR program assumptions were used to adjust the load forecast?**

13 A32. The Company used the most recent EWR assumptions available at the time the
14 load forecast was developed. That means that for the Test Year, the Company
15 adjusted the load forecast for the impact of EWR programs that had been
16 implemented prior to 2022 or were included in I&M's 2022-2023 EWR Plan filing in
17 in Case No. U-20877.

18 **Q33. Please explain the impact EWR had on the Company's load forecast.**

19 A33. Historical impacts of energy efficiency programs are already captured in the
20 company's load modelling process. Energy efficiency savings projections from
21 I&M's 2022-2023 EWR Plan filing in Case No. U-20877 EWR program assumptions
22 are then incorporated into the final load forecast. For the Test Year, I&M estimates
23 the following energy efficiency savings for its Michigan service territory:

- Sales – 22.7 GWh
- Energy – 24.8 GWh
- Summer Peak – 3.7 MW
- Winter Peak – 4.5 MW

Q34. How does the Company account for changes in specific large customer loads (i.e., a major expansion or closure) within the load forecast?

A34. As part of the normal forecast process, the economic forecasting group reaches out to I&M's customer service engineers to ask about any significant load additions or closures that are expected during the forecast horizon.

Once the list of expansions or closures is compiled, the list is compared with the base forecast to see if these known expansions are implicitly accounted for in the base economic forecast. To the extent the specific customer changes are material and not already included in the base forecast, we make an adjustment to account for the difference.

Q35. What Electric Vehicle (EV) and Distributed Generation assumptions were used to adjust the load forecast?

A35. I&M assumed a continuation of the current growth trajectory for EVs and Photovoltaic (PV) Distributed Generation units in the Test Year forecast. This assumption was informed by internal modeling efforts to project EV penetration and PV adoption within I&M's service territory as noted in Case No. U-21189. These forecasts can be found in *Figure DMW-5* below.

Figure DMW - 5: I&M Forecasts for Michigan Service Territory

	2018	2019	2020	2021	2022	2023	2024
Electric Vehicles	443	556	680	893	1,312	1,709	2,207
% change	28%	26%	22%	31%	47%	30%	29%
PV Installations	93	143	193	347	389	431	468
% Change	48%	54%	35%	80%	12%	11%	9%

Q36. Is the methodology used to produce the load forecast reasonable?

A36. Yes. I&M's load forecast methodology is proven to produce reasonable projections that are useful for planning and setting rates. The forecast techniques utilized by the Company are widely accepted across the electric utility industry. The necessary input data comes from reliable sources (i.e., National Oceanic and Atmospheric Administration, Moody's Analytics, the U.S. EIA, Itron, and I&M's customer billing and accounting systems, etc.). Additionally, as discussed below, the historical accuracy of I&M's load forecast methodology provides confidence that the Company's load forecast is reasonable and useful.

Q37. Is this the same load forecast methodology that is used in I&M's Power Supply Cost Recovery (PSCR) Plan filings?

A37. Yes. The same methodology is used in every filing where the Company's projection of kWh sales is used to set rates. The most recent at the time of the filing of this testimony being the 2023 PSCR Plan filing in Case No. U-21261.

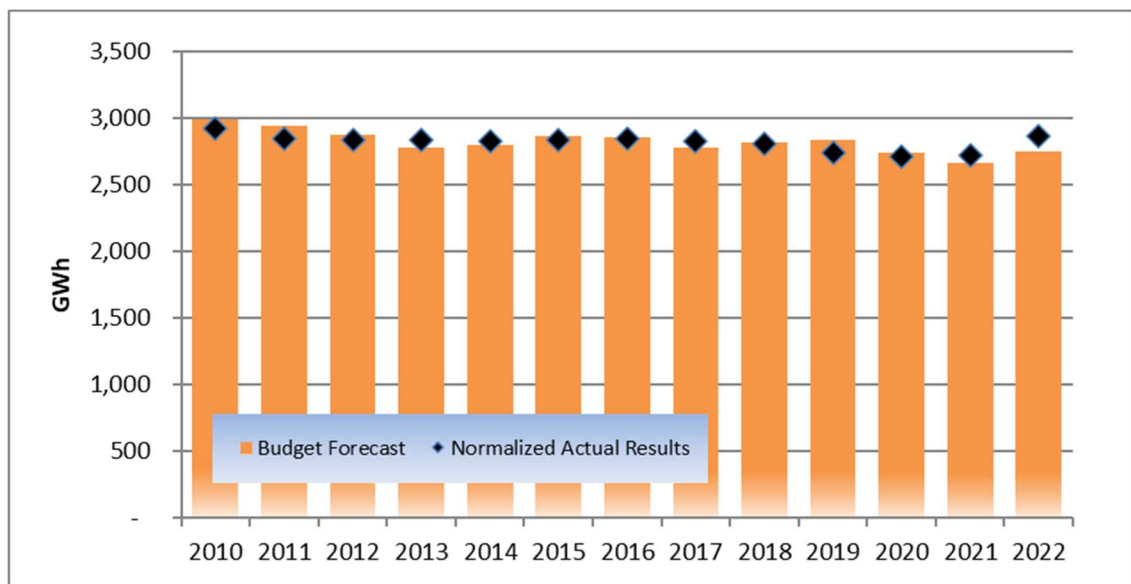
Q38. Do you know how accurate the Company's forecasts have been using the methodology described above?

A38. Yes. Part of my job is to monitor the performance of our load forecast on a routine basis. As part of that monitoring process, we first identify the forecast variance that

is caused by weather (deviations from normal weather). Since our forecast is based on normal weather, we focus most of our attention on the weather-normalized variances to determine how well the forecast is performing.

Since 2010 our budget load forecasts (GWh) for I&M have been within 0.2% of weather normalized actuals. Annual detail is shown in *Figure DMW – 6* below.

Figure DMW - 6: I&M-MI Normalized Budget Variance (GWh)



DRIVERS OF THE TEST YEAR LOAD FORECAST

Q39. Please summarize the results of the economic forecast for I&M's Michigan service territory.

A39. Economic growth in the Michigan portion of I&M's service territory is forecast to be relatively weaker during the Test Year than what the area has experienced since the end of the pandemic. These trends are most evident when examining the outlooks for population and employment, as shown in *Figure DMW - 7*.

Figure DMW - 7: I&M MI Economic Forecasts (Avg Annual % Change)

	Population	Employment
2023-2024	-0.29%	1.45%
2021-2022	-0.28%	2.75%
2010-2019	-0.16%	0.89%

Moody's Analytics projects the population of I&M's Michigan service territory to continue declining throughout the forecast. Population losses through the Test Year are expected to be slightly larger than the long-term average, but consistent with what the area has experienced since the pandemic.

A much more significant slowdown is expected in the labor market. Moody's Analytics expects the pace of job growth to fall to roughly half of the pace seen during the post-COVID recovery period. This is consistent with national trends resulting from the Federal Reserve's efforts to tame historic levels of inflation.

Q40. How does the economic forecast for I&M's Michigan service territory influence Test Year load growth?

A40. Population declines projected by Moody's Analytics result in smaller residential load. Even as customer counts remain relatively flat, fewer people and smaller household sizes contribute to less demand for electricity in the Test Year.

Incomes and employment are projected to continue to grow, albeit at a slower pace than during the initial post-COVID recovery. This reflects slower growth in demand for electricity within the commercial and industrial sectors as the economy adapts to tighter credit conditions and fewer federal stimulus dollars.

1 **Q41. Is I&M's load forecast reasonable?**

2 A41. Yes. The forecasts provided in this case are I&M's best estimate of future electric
3 sales and peak demand. As with any forecast, actual conditions may differ from
4 those assumed in these projections. I&M has utilized reliable methods and
5 reasonable inputs to minimize forecast risk and produce useful results for planning
6 purposes.

7 **Q42. Does this conclude your pre-filed direct testimony?**

8 A42. Yes.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of
INDIANA MICHIGAN POWER COMPANY
for authority to increase its rates for the
sale of electric energy and for approval of
other related matters.

Case No. U-21461

INDIANA MICHIGAN POWER COMPANY

PRE-FILED DIRECT TESTIMONY

OF

TYLER H. ROSS

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**PRE-FILED DIRECT TESTIMONY OF TYLER H. ROSS
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY**

INTRODUCTION OF WITNESS

Q1. Please state your name and business address.

A1. My name is Tyler H. Ross and my business address is 1 Riverside Plaza, Columbus, OH 43215.

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

A2. I am employed by American Electric Power Service Corporation (AEPSC) as Director of Regulatory Accounting Services. AEPSC supplies engineering, accounting, planning, advisory, and other services to the subsidiaries of the American Electric Power (AEP) system, one of which is Indiana Michigan Power Company (I&M or the Company).

Q3. What are your responsibilities as Director of Regulatory Accounting Services?

A3. As Director of Regulatory Accounting Services, my primary responsibilities include providing the AEP electric operating subsidiaries, such as I&M, with regulatory and general accounting expertise in support of regulatory filings, including the preparation of cost of service adjustments, accounting schedules and accounting testimony. I also monitor regulatory proceedings, settlements, orders, and legislation for accounting implications and participate in determining the appropriate regulatory accounting and financial reporting treatment of regulatory transactions.

Q4. Briefly summarize your educational background and professional experience.

A4. I earned a Bachelor of Science Degree in Business Administration with a major in Accounting from The Ohio State University in 1996. I have been a Certified Public

1 Accountant since 2003. Starting with my hiring by AEPSC in August 2001, I held staff
2 and leadership positions within AEP's External Financial Reporting department. I was
3 a Staff Accountant in External Financial Reporting from August 2001 through
4 February 2005. In March 2005, I was promoted to Manager of External Financial
5 Reporting and in August 2008, I was promoted to Director of External Financial
6 Reporting. For AEP and its reporting subsidiaries, I led External Financial Reporting
7 in the preparation and filing of quarterly and annual reports in accordance with both
8 Generally Accepted Accounting Principles (GAAP) and the reporting requirements of
9 both the Securities and Exchange Commission (SEC) and the Federal Energy
10 Regulatory Commission (FERC). In January 2014, I started my present position as
11 Director of Regulatory Accounting Services.

12 **Q5. Have you previously testified before any regulatory commissions?**

13 A5. Yes. I have filed testimony and testified before the following commissions on behalf
14 of I&M and affiliated companies:

- 15 • The Michigan Public Service Commission (MPSC) on behalf of I&M (filed
16 testimony only) – submitted testimony in Case No. U-20359;
- 17 • The Indiana Utility Regulatory Commission (IURC) on behalf of I&M;
- 18 • The Kentucky Public Service Commission on behalf of Kentucky Power
19 Company;
- 20 • The Public Utilities Commission of Ohio on behalf of Ohio Power Company;
- 21 • The Virginia State Corporation Commission on behalf of Appalachian
22 Power Company (APCo); and

- The Public Service Commission of West Virginia on behalf of APCo and Wheeling Power Company.

PURPOSE OF TESTIMONY

Q6. What is the purpose of your testimony in this proceeding?

A6. The purpose of my pre-filed testimony is to:

- Support certain 2022 historical period (2022 Historical Period) schedules and adjustments.
- Support 2018 through 2022 Historical Period financial metrics.
- Support certain adjustments for the 2024 forward-looking test year (2024 Forecast Test Year).
- Discuss regulatory accounting treatment and related amortization for certain I&M Michigan jurisdictional items.

In my testimony, I discuss I&M Total Company amounts unless the balance is 100% jurisdictional to Michigan, in which case I specifically identify it as I&M Michigan jurisdictional. For the I&M Total Company amounts, Company witness Morgan supports I&M's Michigan jurisdictional separation study. Also in my testimony, when I refer to the Rockport Plant, I am referring to only I&M's ownership share of the Rockport Plant that excludes the portion of the Rockport Plant owned by AEP Generating Company.

Q7. Are you sponsoring or co-sponsoring any exhibits in this proceeding?

A7. Yes. I am sponsoring or co-sponsoring the exhibits listed below which include I&M's total Company 2022 Historical Period data required by the standard filing instructions in Case No. U-18238.

2022 Historical Period Exhibits:

- Exhibit A-1, Schedule A2 – 2018 through 2022 Historical Period Financial/Ratemaking Metrics.
- Exhibit A-2, Schedule B1 - 2022 Historical Period End of Year Total Company Rate Base (co-sponsored with Company witness Morgan).
- Exhibit A-2, Schedule B2 - 2022 Historical Period End of Year Total Company Utility Plant.
- Exhibit A-2, Schedule B3 - 2022 Historical Period End of Year Total Company Accumulated Provision for Depreciation.
- Exhibit A-2, Schedule B4 - 2022 Historical Period End of Year Total Company 13-Month Working Capital (co-sponsored with Company witness Morgan).
- Exhibit A-3, Schedule C1 - 2022 Historical Period Total Company Adjusted Net Operating Income (co-sponsored with Company witness Morgan).
- Exhibit A-3, Schedule C3 - 2022 Historical Period Total Company Operating Revenue.
- Exhibit A-3, Schedule C4 - 2022 Historical Period Total Company Fuel and Purchased Power Expense.
- Exhibit A-3, Schedule C5 - 2022 Historical Period Total Company Operation and Maintenance (O&M) Expense.
- Exhibit A-3, Schedule C6 - 2022 Historical Period Total Company Depreciation and Amortization Expense.
- Exhibit A-3, Schedule C11 - 2022 Historical Period Allowance for Funds Used During Construction.

1 **Q8. Were the Exhibits that you sponsor prepared or assembled by you or under**
2 **your direction and supervision?**

3 A8. Yes.

4 **Q9. Are the adjustments that you sponsor consistent with adjustments made in**
5 **I&M's most recent Michigan Base Rate Case?**

6 A9. Yes, the adjustments described in my testimony are consistent with previous
7 adjustments made in Case No. U-20359 and/or previous deferral authority granted
8 by the Commission. Please see Exhibit IM-50 (JWM-1) Summary of Projected
9 Adjustments, which identifies each adjustment I sponsor and provides a brief
10 description, the adjustment amount, and the page and line number where the
11 adjustment is located in the jurisdictional cost-of-service study.

12 **Q10. Please describe the preparation of the portions of the schedules in exhibits**
13 **that you sponsor.**

14 A10. The source of the historical data is I&M's books and records, which are kept in
15 conformity with the FERC Uniform System of Accounts (USofA) and the MPSC
16 USofA. As an SEC registrant company, I&M is also required by the SEC to follow
17 GAAP, comply with specific SEC reporting requirements and maintain controls over
18 financial reporting in compliance with the Sarbanes Oxley Act of 2002

19 **Q11. Is the FERC USofA the same as the MPSC USofA for I&M's historical data?**

20 A11. Yes, I&M's Historical Period data for the calendar year 2022 is the same for both the
21 FERC USofA and the MPSC USofA. If the FERC were to adopt new accounts in the
22 future, there would be a difference between the FERC USofA and the MPSC USofA
23 until the MPSC adopts the new accounts in the FERC USofA.

1 **Q12. Please summarize your testimony.**

2 A12. The 2022 Historical Period adjustments and schedules that I sponsor are reasonable
3 and necessary to support I&M's 2022 Historical Period cost of service calculation,
4 and 2022 Historical Period financial presentation.

5 The 2024 Forecast Test Year ratemaking adjustments I sponsor are
6 reasonable and necessary to properly reflect I&M's cost of service for the forward-
7 looking 2024 Forecast Test Year.

8 The data I rely on was acquired from numerous sources, including but not
9 limited to I&M and AEPSC accounting records. This is the type of supportable data
10 that has been found to be reliable and regularly used in I&M's business for this type
11 of analysis. I&M's financial reporting to the SEC relies on the same accounting
12 records used in preparing the historical data provided in this case.

13 I&M's retail and wholesale rates are regulated by three Commissions: the
14 IURC, the MPSC, and the FERC. Because of this, certain adjustments to net electric
15 plant balances are required to reflect the ratemaking conventions used by these
16 respective Commissions.

17 The adjustments I sponsor have been prepared in a manner consistent with
18 accounting-related adjustments included in prior I&M rate cases. If these adjustments
19 were not made, I&M's Michigan jurisdictional rate base, operating expenses and
20 I&M's base rates would not be properly stated. All of the adjustments I sponsor
21 related to changes in electric plant in service and accumulated depreciation were
22 included in calculations of depreciation expense and accumulated depreciation in the
23 forward-looking 2024 Forecast Test Year. The O&M and rate base adjustments were

1 also provided to Company witness Morgan for inclusion in I&M's jurisdictional
2 separation study.

3 My testimony also describes deferral accounting that the Company would
4 perform in accordance with GAAP and FERC USofA related to new regulatory
5 deferrals proposed by Company witness Seger-Lawson.

6 **2022 HISTORICAL PERIOD – SCHEDULES**

7 **Q13. Please describe Exhibit A-1, Schedule A2 2018 through 2022 Historical Period**
8 **Financial/Ratemaking Metrics.**

9 A13. Exhibit A-1, Schedule A2 2022 Historical Period Financial Metrics provides historical
10 financial data for the periods ending December 31, 2022, 2021, 2020, 2019 and 2018
11 required by the standard filing requirements in Part 1 A-1 Schedule A-2.

12 **Q14. Please describe Exhibit A-2, Schedule B1 2022 Historical Period End of Year**
13 **Total Company Rate Base Items.**

14 A14. Exhibit A-2, Schedule B1 contains the 2022 Historical Period Total Company Rate
15 Base information required by the standard filing requirements in Part 1 A-2 Schedule
16 B1. This summary schedule of rate base items is based upon the actual total
17 Company December 31, 2022 balances, except for working capital which is based
18 upon 13-month averages, as required.

Q15. Please describe Exhibit A-2, Schedule B2 2022 Historical Period End of Year Total Company Utility Plant and Exhibit A-2, Schedule B3 2022 Historical Period End of Year Total Company Accumulated Provision for Depreciation.

A15. Exhibit A-2, Schedule B2 and Exhibit A-2, Schedule B3 contain the total Company December 31, 2022 balances required by the standard filing requirements in Part 1 A-2 Schedules B2 and B3, respectively.

Q16. Please describe Exhibit A-2, Schedule B4 2022 Historical Period End of Year Total Company 13-Month Working Capital.

A16. Exhibit A-2, Schedule B4 contains I&M's total Company 13-month average balance sheet required by the standard filing requirements in Part 1 A-2 Schedule B4. Each account was analyzed to determine whether it should be included in working capital, utilizing the balance sheet methodology in accordance with Case No. U-7350. Each working capital item was further analyzed to determine if the balance could be directly assigned to a jurisdiction or should be allocated.

Q17. Please describe Exhibit A-3, Schedules C1 and C3 through C6 2022 Historical Period Total Company Revenues, Expenses, and O&M Detail.

A17. Exhibit A-3, Schedules C1 and C3 through C6 provide the detailed income statement information for the twelve-month Historical Period ended December 31, 2022 and contain the total Company details required by standard filing requirements in Part 1 A-3, Schedules C1 and C3 through C6.

Q18. Please describe Exhibit A-3, Schedule C11 2022 Historical Period Allowance for Funds Used During Construction.

A18. Exhibit A-3, Schedule C11 2022 Allowance for Funds Used During Construction (AFUDC) provides the standard filing requirements in Part 1 A-3 Schedule C11 related to total Company AFUDC per books adjusted to remove AFUDC on pollution control investments based on the Commission's order on Case No. U-5281.

2022 HISTORICAL PERIOD – ADJUSTMENTS TO RATE BASE

Q19. Please explain the rate base adjustments included in 2022 Historical Period Adjustment RB-1.

A19. 2022 Historical Period Adjustment RB-1 decreases I&M Total Company electric plant in service by \$520,328,427 and decreases I&M's accumulated provision for depreciation by \$196,878,388. In accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 410, I&M previously established non-cash assets for AROs related to ash ponds, asbestos removal, batteries and nuclear decommissioning. Adjustment RB-1 removes these non-cash ARO-related electric plant in service and accumulated provision for depreciation balances from rate base. If this adjustment was not made, I&M's rate base would be overstated. This adjustment is consistent with the 2018 I&M historical period rate base adjustment included in Case No. U-20359.

Q20. Please explain the rate base adjustment included in 2022 Historical Period Adjustment RB-2.

A20. 2022 Historical Period Adjustment RB-2 removes from rate base I&M's per books \$5,129,941 original purchase price of land related to the operations of the St. Joseph

1 Solar Farm (SJSF) in South Bend, Indiana. This adjustment is consistent with the
2 settlement agreement approved by the Commission in Case No. U-20765. If this
3 adjustment was not made, I&M's rate base would be overstated.

4 **Q21. Please explain the rate base adjustments included in 2022 Historical Period**
5 **Adjustment RB/O&M-1.**

6 A21. 2022 Historical Period Adjustment RB/O&M-1 is a two-part adjustment, Part A and
7 B, to present certain components of net electric plant in service on an accounting
8 basis as required by this Commission. Part A describes adjustments to increase 2022
9 electric plant in service and accumulated provision for depreciation to reflect CWIP
10 ratemaking treatment related to test Rockport Unit 1 legacy energy credit as
11 prescribed by the Commission in Case Nos. U-6148 and U-7791. Part B describes
12 adjustments to increase 2022 electric plant in service and accumulated depreciation
13 related to CWIP ratemaking treatment for Rockport Unit 1 pollution control equipment
14 as prescribed by the Commission in Case No. U-7791. These adjustments are
15 consistent with the 2018 I&M historical period rate base adjustment included in Case
16 No. U-20359 and are also reflected in 2024 Forecast Test Year Adjustment RB-1.

17 **Q22. Please explain the rate base adjustment included in Part A of 2022 Historical**
18 **Period Adjustment RB/O&M-1.**

19 A22. Part A of 2022 Historical Period Adjustment RB/O&M-1 recognizes an increase in
20 electric plant in service and accumulated provision for depreciation related to the
21 treatment of test energy by the MPSC. MPSC accounting requirements provided that
22 test energy be valued on a displacement basis; that is, the average cost of fuel that
23 would have been consumed at the Company's other generating units had the test

energy not been available. I&M's Indiana jurisdictional share of Rockport Unit 2 test energy was valued at the actual cost of fuel consumed by the unit being tested. The "actual cost" method used in Indiana produces a larger reduction to electric plant in service than the "displacement" method used in Michigan for Rockport Unit 1 test energy. Therefore, an increase must be made to net electric plant in service in order to fully reflect, for ratemaking purposes, the test energy methodology required by this Commission. This part of the adjustment increases I&M Total Company electric plant in service and accumulated provision for depreciation by \$9,679,916 and \$13,451,657, respectively. If this adjustment was not made, I&M's rate base would be overstated. This adjustment is consistent with the 2018 I&M historical period rate base adjustment included in Case No. U-20359.

Q23. Please explain the rate base adjustment included in Part B of 2022 Historical Period Adjustment RB/O&M-1.

A23. Part B of 2022 Historical Period Adjustment RB/O&M-1 relates to allowance for funds used during construction (AFUDC) associated with Rockport Plant Unit 1. The FERC and MPSC (Case No. U-7791) allowed I&M to include Rockport Unit 1 pollution control facilities in rate base during the construction period of 1978 through 1984. Therefore, I&M ceased recording AFUDC on the Michigan and FERC jurisdictional CWIP amounts. The IURC did not include CWIP in rate base. In order to reflect the correct I&M Michigan jurisdictional basis of Rockport Unit 1, the effect of recording AFUDC allowed by the IURC must be added back to net electric plant in service for Michigan ratemaking purposes. This part of the adjustment increases I&M Total Company electric plant in service and accumulated depreciation by \$5,367,556 and

1 \$7,459,001, respectively. If this adjustment was not made, I&M's rate base would be
2 overstated. This adjustment is consistent with the 2018 I&M historical period rate
3 base adjustment included in Case No. U-20359.

4 **Q24. Please explain the rate base adjustment included in 2022 Historical Period**
5 **Adjustment RB/O&M-2.**

6 A24. 2022 Historical Period Adjustment RB/O&M-2 decreases accumulated provision for
7 depreciation by \$64,686,096 to reflect the Commission-approved Michigan
8 depreciation rates rather than I&M's multi-jurisdictional composite depreciation rates
9 used in the Total Company per books financial statements. If this adjustment was not
10 made, I&M's rate base would be understated. This adjustment is consistent with the
11 2018 I&M historical period rate base adjustment included in Case No. U-20359.

12 **Q25. Please explain the rate base adjustments included in 2022 Historical Period**
13 **Adjustment RB/O&M-3.**

14 A25. The rate base component of 2022 Historical Period Adjustment RB/O&M-3 is a four-
15 part adjustment, (Parts A through D) to restate I&M Total Company balances of
16 electric plant in service and accumulated provision for depreciation in order to
17 allocate the proper amounts to the I&M Michigan jurisdiction. This adjustment is
18 based on actual costs through December 31, 2022. These adjustments are
19 necessary due to the specific rate treatment approved by the MPSC and the IURC
20 for I&M related to the Rockport Unit 1 and Unit 2 Dry Sorbent Injection (DSI) projects,
21 the Rockport Unit 1 and Unit 2 Selective Catalytic Reduction (SCR) project and the
22 Cook Plant Life Cycle Management (LCM) project. These adjustments restate the

1 total Company balances of electric plant in service and accumulated provision for
2 depreciation in order to allocate the proper amounts to the Michigan jurisdiction.

3 For I&M's Michigan and FERC jurisdictions, the Company recorded AFUDC
4 for portions of the Rockport DSI, Rockport SCR and Cook Plant LCM projects that
5 were alternatively recorded as return on CWIP for I&M's Indiana jurisdiction. Thus,
6 on a total company basis, the total amount of AFUDC currently being capitalized is
7 less than the total amount of AFUDC that would have been capitalized if calculated
8 on a Michigan basis to reflect the accrual of AFUDC on 100% of the CWIP balances.
9 Therefore, in order to allocate the proper amount of Electric Plant in Service and
10 accumulated provision for depreciation to the Michigan jurisdiction, the total company
11 balances were increased to reflect the accrual of AFUDC on 100% of the CWIP
12 balances.

13 Since the Rockport Unit 1 and Unit 2 DSI, Rockport Unit 1 and Unit 2 SCR
14 and Cook LCM projects have been placed in service, the respective adjustments
15 described above for electric plant in service will remain constant in future I&M
16 Michigan base rate case filings until these plant assets are retired. Conversely, I&M's
17 future Michigan ratemaking adjustments to accumulated depreciation for Rockport
18 Unit 1 and Unit 2 DSI, Rockport Unit 1 and Unit 2 SCR and Cook Plant LCM will vary
19 from the proposed accumulated depreciation adjustments described above due to
20 ongoing depreciation of these assets over their remaining useful lives.

Q26. Please explain the rate base adjustment included in Part A of 2022 Historical Period Adjustment RB/O&M-3.

A26. Part A of 2022 Historical Period Adjustment RB/O&M-3 results in increases to electric plant in service and accumulated provision for depreciation for AFUDC associated with the Rockport Unit 1 and Unit 2 DSI project. The IURC approved return on CWIP recovery for these projects in Cause No. 44331 rather than AFUDC that was recorded for I&M's Michigan and FERC jurisdictional shares of Rockport DSI. In order to arrive at the proper rate base value of the Rockport DSI project on an I&M Michigan jurisdictional basis for ratemaking purposes, I&M Total Company electric plant in service and accumulated depreciation are increased by \$1,920,876 and \$911,868, respectively. If this adjustment was not made, I&M's rate base would be understated. This adjustment is consistent with the 2018 I&M historical period rate base adjustment included in Case No. U-20359 and is also reflected in 2024 Forecast Test Year Adjustment RB-3.

Q27. Please explain the rate base adjustment included in Part B of 2022 Historical Period Adjustment RB/O&M-3.

A27. Part B of 2022 Historical Period Adjustment RB/O&M-3 results in increases to electric plant in service and accumulated provision for depreciation for AFUDC associated with the Rockport Unit 1 SCR project. The IURC approved return on CWIP recovery for I&M's Indiana jurisdictional share of this project in Cause No. 44523 rather than AFUDC that was recorded for I&M's Michigan and FERC jurisdictional shares of Rockport Unit 1 SCR. In order to arrive at the proper rate base value of the Rockport Unit 1 SCR project for I&M Michigan ratemaking purposes, I&M Total Company

1 electric plant in service and accumulated provision for depreciation are increased by
2 \$5,189,045 and \$2,339,441, respectively. If this adjustment was not made, I&M's
3 rate base would be understated. This adjustment is consistent with the 2018 I&M
4 historical period rate base adjustment included in Case No. U-20359 and is also
5 reflected in 2024 Forecast Test Year Adjustment RB-3.

6 **Q28. Please explain the rate base adjustment included in Part C of 2022 Historical**
7 **Period Adjustment RB/O&M-3.**

8 A28. Part C of 2022 Historical Period Adjustment RB/O&M-3 results in increases to electric
9 plant in service and an increase to accumulated depreciation for AFUDC associated
10 with the Rockport Unit 2 SCR project. The IURC approved CWIP recovery for I&M's
11 Indiana jurisdictional share of this project in Case No. 44871 ECR 1 rather than
12 AFUDC that was recorded for I&M's Michigan and FERC jurisdictional shares of
13 Rockport Unit 2 SCR. In order to arrive at the proper rate base value of the Rockport
14 Unit 2 SCR project for I&M Michigan ratemaking purposes, I&M Total Company
15 electric plant in service and accumulated provision for depreciation are increased by
16 \$8,877,785 and \$2,852,568, respectively. If this adjustment was not made, I&M's
17 rate base would be understated. This adjustment is also reflected in 2024 Forecast
18 Test Year Adjustment RB-3.

19 **Q29. Please explain the rate base adjustment included in Part D of 2022 Historical**
20 **Period Adjustment RB/O&M-3.**

21 A29. Part D of Historical Period Adjustment RB/O&M-3 results in an increase to electric
22 plant in service and an increase to accumulated depreciation associated with the
23 Cook LCM Project. The IURC approved CWIP recovery for I&M's Indiana

jurisdictional share of the LCM project in Cause No. 44182. As described in the settlement agreement approved in Cause No. 44967, I&M ceased recording a return on CWIP and began recording AFUDC on the I&M Indiana jurisdictional share of Cook Plant LCM starting July 1, 2022. In order to arrive at the proper value of the Cook LCM project for I&M Michigan ratemaking purposes, I&M's Total Company electric plant in service and accumulated provision for depreciation are increased by \$50,072,724 and \$9,211,629, respectively. If this adjustment was not made, I&M's rate base would be understated. This adjustment is consistent with the 2018 I&M historical period rate base adjustment included in Case No. U-20359 and is also reflected in 2024 Forecast Test Year Adjustment RB-3.

Q30. Did you also provide the 2022 Historical Period rate base adjustments described above to Company witness Morgan for inclusion in I&M's jurisdictional separation study?

A30. Yes, I did.

2022 HISTORICAL PERIOD-ADJUSTMENTS TO NET OPERATING INCOME

Q31. Please explain the net operating income adjustments included in 2022 Historical Period Adjustment O&M-1.

A31. 2022 Historical Period Adjustment O&M-1 includes operating income increases related to debt AFUDC of \$2,464 and equity AFUDC of \$7,090. In accordance with the Commission's order on Case No. U-5281, this adjustment removes the net income statement impact of AFUDC related to I&M fossil plant pollution control equipment investments. If this adjustment was not made, I&M's 2022 Historical Period operating income would be understated. This adjustment is consistent with

the 2018 historical period operating income adjustments included in Case No. U-20359.

Q32. Please explain the net operating income adjustments included in 2022 Historical Period Adjustment RB/O&M-1.

A32. 2022 Historical Period Adjustment RB/O&M-1 includes increases to depreciation expense of \$869,256 and \$482,007 for I&M Michigan jurisdictional ratemaking treatment of Rockport Unit 1 legacy test energy and Rockport Unit 1 pollution control facilities, respectively. Further background for this adjustment is described in the rate base adjustment above for 2022 Historical Period Adjustment RB/O&M-1. If these adjustments were not made, I&M's 2022 Historical Period operating income would be overstated. These adjustments are consistent with the 2018 I&M historical period operating income adjustments included in Case No. U-20359.

Q33. Please explain the net operating income adjustment included in 2022 Historical Period Adjustment RB/O&M-2.

A33. 2022 Historical Period Adjustment RB/O&M-2 includes a combined net decrease to depreciation expense of \$3,040,408 to reflect the Commission-approved Michigan depreciation rates rather than I&M's multi-jurisdictional composite depreciation rates used in the Total Company per books financial statements. If this adjustment was not made, I&M's 2022 Historical Period operating income would be understated. This adjustment is consistent with the 2018 I&M historical period operating income adjustment included in Case No. U-20359.

Q34. Please explain the net operating income adjustments included in 2022 Historical Period Adjustment RB/O&M-3.

A34. 2022 Historical Period Adjustment RB/O&M-3 includes the following increases to depreciation expense related to jurisdictional ratemaking differences as described in the rate base adjustment above for 2022 Historical Period Adjustment RB/O&M-3:

- \$163,693 increase – Rockport Unit 1 and Unit 2 DSI
- \$546,925 increase – Rockport Unit 1 SCR
- \$1,107,060 increase – Rockport Unit 2 SCR
- \$1,775,745 increase – Cook Plant LCM

If these adjustments were not made, I&M's 2022 Historical Period operating income would be overstated. These adjustments are consistent with the 2018 I&M historical period operating income adjustments included in Case No. U-20359.

Q35. Please explain the net operating income adjustment included in 2022 Historical Period Adjustment RB-1.

A35. Part of the 2022 Historical Period Adjustment RB-1 removes non-jurisdictional ARO accretion expense of \$2,435,359 and non-jurisdictional ARO depreciation expense of \$4,284,998 from the 2022 Historical Period. These adjustments are necessary due to I&M's separate inclusion of Michigan jurisdictional ARO accretion and ARO depreciation in I&M Michigan depreciation rates consistent with the MPSC Staff's methodology used in determining net salvage in Case No. U-16801 and adopted by the MPSC.

Q36. Did you also provide the 2022 Historical Period adjustments to net operating income described above to Company witness Morgan for inclusion in I&M's jurisdictional separation study?

A36. Yes, I did.

2024 FORECAST TEST YEAR – ADJUSTMENTS TO RATE BASE

Q37. Please explain the rate base adjustments included in 2024 Forecast Test Year Adjustment RB-1.

A37. 2024 Forecast Test Year Adjustment RB-1 increases the balances of electric plant in service and accumulated provision for depreciation due to MPSC-approved ratemaking treatment of Rockport Unit 1 legacy test energy and Rockport Unit 1 pollution control facilities as described in the rate base adjustment for 2022 Historical Period Adjustment RB/O&M-1:

- Rockport Unit 1 Legacy Energy Credit (Case Nos. U-6148, U-7791) –
 - \$9,679,916 increase to electric plant in service
 - \$13,451,657 increase to accumulated provision for depreciation
- Rockport Unit 1 Pollution Control Facilities (Case No. U-7791) –
 - \$5,367,556 increase to electric plant in service
 - \$7,459,001 increase to accumulated provision for depreciation

If these adjustments were not made, I&M's 2024 Forecast Test Year rate base would be understated. These adjustments are consistent with I&M's 2020 forecast period rate base adjustments included in Case No. U-20359.

1 **Q38. Are your rate base adjustment amounts included in 2024 Forecast Test Year**
2 **Adjustment RB-1 the same as the rate base adjustments included in 2022**
3 **Historical Period Adjustment RB/O&M-1?**

4 A38. Yes. For both 2024 Forecast Test Year Adjustment RB-1 and 2022 Historical Period
5 Adjustment RB/O&M-1, my electric plant in service and accumulated provision for
6 depreciation adjustments are based on the same calculations performed as of
7 December 31, 2022. In 2024 Forecast Test Year Adjustment DEP-1 that I also
8 sponsor, 2024 Forecast Test Year Adjustment RB-1 is included as an initial
9 adjustment to I&M's December 31, 2022 total company electric plant in service
10 balances. 2024 Forecast Test Year Adjustment DEP-1 then calculates the monthly
11 depreciation expense and accumulated depreciation impact of these rate base
12 adjustments for the period January 2023 through December 2024.

13 **Q39. Please explain the rate base adjustments included in 2024 Forecast Test Year**
14 **Adjustment RB-2.**

15 A39. 2024 Forecast Test Year Adjustment RB-2 decreases I&M Total Company electric
16 plant in service by \$520,426,490 and decreases I&M Total Company accumulated
17 provision for depreciation by \$199,306,130 to remove non-cash ARO balances
18 through December 31, 2024. These rate base adjustments to remove non-cash RO
19 rate base balances are similar to 2022 Historical Period Adjustment RB-1 as
20 described earlier in my testimony. If this adjustment was not made, I&M's 2024
21 Forecast Test Year rate base would be overstated. These adjustments are consistent
22 with I&M's 2020 forecast period rate base adjustments included in Case No.
23 U-20359.

Q40. Please explain the rate base adjustments included in 2024 Forecast Test Year Adjustment RB-3.

A40. 2024 Forecast Test Year Adjustment RB-3 increases I&M Total Company electric plant in service and accumulated provision for depreciation related to the ratemaking treatment of Rockport Plant DSI and SCR projects and the Cook Plant LCM project as described in the rate base adjustment for 2022 Historical Period Adjustment RB/O&M-3 above and as summarized below:

- Rockport Unit 1 and Unit 2 DSI:
 - Increase electric plant in service by \$1,920,876
 - Increase accumulated provision for depreciation by \$911,868
- Rockport Unit 1 SCR:
 - Increase electric plant in service by \$5,189,045
 - Increase accumulated provision for depreciation by \$2,339,441
- Rockport Unit 2 SCR:
 - Increase electric plant in service by \$8,877,785
 - Increase accumulated provision for depreciation by \$2,852,568
- Cook Plant LCM:
 - Increase electric plant in service by \$50,072,724
 - Increase accumulated provision for depreciation by \$9,211,629

If these adjustments were not made, I&M's 2024 Forecast Test Year rate base would be understated. These adjustments are consistent with I&M's 2020 forecast period rate base adjustments included in Case No. U-20359.

Q41. Are your rate base adjustment amounts included in 2024 Forecast Test Year Adjustment RB-3 the same as the rate base adjustments included in 2022 Historical Period Adjustment RB/O&M-3?

A41. Yes. For both 2024 Forecast Test Year Adjustment RB-3 and 2022 Historical Period Adjustment RB/O&M-3, my electric plant in service and accumulated provision for depreciation adjustments are based on the same calculations performed as of December 31, 2022. In 2024 Forecast Test Year Adjustment DEP-1 that I also sponsor, 2024 Forecast Test Year Adjustment RB-3 is included as an initial adjustment to I&M's December 31, 2022 total company electric plant in service balances. 2024 Forecast Test Year Adjustment DEP-1 then calculates the monthly depreciation expense and accumulated depreciation impacts of these rate base adjustments for the period January 2023 through December 2024.

Q42. Please explain the rate base adjustment included in 2024 Forecast Test Year Adjustment RB-5.

A42. 2024 Forecast Test Year Adjustment RB-5 removes from rate base I&M's per books \$5,129,941 original purchase price of land related to the operations of the St. Joseph Solar Farm (SJSF) in South Bend, Indiana. This is consistent with the settlement agreement approved by the Commission in Case No. U-20765. If this adjustment was not made, I&M's 2024 Forecast Test Year rate base would be overstated. This adjustment is consistent with 2022 Historical Period Adjustment RB-2 described above.

1 **Q43. Did you consider the proposed rate base adjustments described above in your**
2 **proposed depreciation adjustments described below?**

3 A43. Yes, for 2024 Forecast Test Year Adjustment DEP-1 as described below, I included
4 the rate base adjustments described above in the application of the Company's
5 current depreciation rates previously approved by the Commission to the Company's
6 forecasted depreciable plant balances.

7 **Q44. Please explain the rate base adjustment included in 2024 Forecast Test Year**
8 **Adjustment DEP-1.**

9 A44. 2024 Forecast Test Year Adjustment DEP-1 decreases the Company's 13-month
10 average accumulated depreciation balance by \$26,541,510 by applying I&M
11 Michigan jurisdictional depreciation rates previously approved by the Commission to
12 the Company's forecasted depreciable plant balances. This adjustment is consistent
13 with the 2020 forecast period adjustment reflected in I&M's base rates approved in
14 Case No. U-20359.

15 **Q45. Did you also provide the 2024 Forecast Test Year rate base adjustments**
16 **described above to Company witness Morgan for inclusion in I&M's**
17 **jurisdictional separation study?**

18 A45. Yes, I did. Please see Exhibit IM-50 (JWM-1) Summary of Projected Adjustments,
19 which identifies the 2024 Forecast Test Year rate base adjustments and provides a
20 brief description, the adjustment amount, and the page and line number where the
21 adjustment is located in the jurisdictional cost-of-service allocation study.

2024 FORECAST TEST YEAR – ADJUSTMENTS TO NET OPERATING INCOME

Q46. Please explain the net operating income adjustment included in 2024 Forecast Test Year Adjustment RB-2.

A46. 2024 Forecast Test Year Adjustment RB-2 removes non-jurisdictional ARO accretion expense of \$500,256 and non-jurisdictional ARO depreciation expense of \$1,341,673 from the 2024 Forecast Test Year. These adjustments are necessary due to I&M's separate inclusion of Michigan jurisdictional ARO accretion and ARO depreciation in I&M Michigan depreciation rates consistent with the MPSC Staff's methodology used in determining net salvage in Case No. U-16801 that was adopted by the MPSC.

Q47. Please explain the net operating income adjustment included in 2024 Forecast Test Year Adjustment O&M-1.

A47. 2024 Forecast Test Year Adjustment O&M-1 increases forecasted 2024 I&M Michigan major storm expenses by \$1,600,523 annually to reflect I&M's most recent five-year average of Michigan major storm expenses of \$3,759,548 for the period 2018 through 2022. Company witness Seger-Lawson supports the proposed regulatory recovery of this going level of I&M Michigan major storm expenses incurred. This adjustment is consistent with the major storm expense adjustment included in Case No. U-20359.

Q48. Please explain the net operating income adjustment included in 2024 Forecast Test Year Adjustment O&M-2.

A48. 2024 Forecast Test Year Adjustment O&M-2 increases annual O&M expense by \$66,806 to reflect the Company's amortization of deferred COVID bad debt

1 expenses. This adjustment is the result of I&M's proposal to amortize its
2 December 31, 2022 regulatory asset balance of \$133,612 for Michigan jurisdictional
3 COVID bad debt expense deferrals over two years. In accordance with the
4 Commission's order on Case No. U-20757, I&M deferred "uncollectible, or bad debt,
5 expense incurred beginning March 24, 2020 (the date of Governor Whitmer's
6 Executive Order 2020-2021) that are in excess of the amount used to set current
7 rates." As also stated in the Commission's order on Case No. U-20757, "The
8 Commission further finds it appropriate for I&M and UPPCo to include their
9 uncollectible expense deferral amounts in their next general rate case. The
10 uncollectible expense deferral amounts will be subject to review and Commission
11 approval."

12 **Q49. Please explain the net operating income adjustment included in 2024 Forecast**
13 **Test Year Adjustment O&M-3.**

14 A49. As stated in the settlement agreement approved by the Commission in the
15 Company's most recent base rate case, Case No. U-20359, "I&M agrees to present
16 a benefit/cost study on the deployment of advanced metering infrastructure (AMI) in
17 its next general rate case if I&M begins deployment of AMI in Michigan prior to, or
18 proposes to deploy AMI as part of, its next general rate case." I&M proposes to
19 amortize its December 31, 2022 Michigan AMI study cost regulatory asset balance
20 of \$693,800 over two years. 2024 Forecast Test Year Adjustment O&M-3 increases
21 annual O&M expense by \$346,900 for the amortization of I&M Michigan AMI study
22 costs that were previously incurred and deferred as a regulatory asset. This

adjustment is the result of the I&M's proposal to amortize its December 31, 2022 AMI study cost regulatory asset of \$693,800 over two years.

Q50. Please explain the net operating income adjustment included in 2024 Forecast Test Year Adjustment O&M-4.

A50. 2024 Forecast Test Year Adjustment O&M-4 increases O&M expense by \$169,103 for the amortization of deferred I&M Michigan AMI pilot program costs. This adjustment is based on I&M's proposal to amortize its December 31, 2022 Michigan AMI pilot program cost regulatory asset balance of \$338,205 over two years. In accordance with the Commission's order on Case No. U-20938, the Company deferred O&M expenses incurred related to the Residential Customer Engagement Demand Response Pilot, the Residential AMI HVAC Direct Load Control Pilot, the Residential AMI Electric Water Heater Direct Load Control Pilot and the Small Business AMI Direct Load Control Pilot. The Company will continue to defer costs incurred associated with I&M's four AMI-based load management pilot programs until base rates are reset in this case. Company witness Walter further discusses I&M's load management programs.

Q51. Please explain the net operating income adjustment included in 2024 Forecast Test Year Adjustment O&M-5.

A51. 2024 Forecast Test Year Adjustment O&M-5 proposes to increase annual O&M expense by \$412,505 for the amortization of deferred I&M Michigan Home Energy Management (HEM), Work Energy Management (WEM) and Electric Energy Consumption Optimization (EECO) expenses. I&M proposes to amortize the Company's combined HEM/WEM/EECO regulatory asset deferral of \$825,009 over

1 two years. In accordance with the Commission's January 23, 2018 order in Case No.
2 U-18263, the Company continues to defer these incremental HEM, WEM and EECO
3 costs that are currently not being recovered through base rates.

4 **Q52. Please explain the net operating income adjustment included in 2024 Forecast**
5 **Test Year Adjustment O&M-6.**

6 A52. 2024 Forecast Test Year Adjustment O&M-6 increases annual O&M expense by
7 \$1,304 to reflect the Company's proposed amortization of deferred nuclear dry cask
8 storage costs. I&M proposes to amortize its December 31, 2022 Michigan
9 jurisdictional dry cask storage regulatory asset balance of \$2,608 over two years. As
10 approved by the Commission in Case No. U-18370, I&M continues to defer all costs
11 associated with dry cask storage costs that are not reimbursed by the Department of
12 Energy (DOE). Company witnesses Ferneau and Seger-Lawson provide further
13 description of the dry cask storage process, I&M's current mechanism for submitting
14 and recovering related costs from the DOE and I&M's request to continue deferral of
15 Michigan jurisdictional dry cask storage costs that are not reimbursed by the DOE.

16 **Q53. Please explain the net operating income adjustment included in 2024 Forecast**
17 **Test Year Adjustment O&M-7.**

18 A53. 2024 Forecast Test Year Adjustment O&M-7 increases annual O&M expense by
19 \$13,603 to reflect the Company's proposed amortization of deferred IM Plugged In
20 costs. I&M proposes to amortize its December 31, 2022 IM Plugged In regulatory
21 asset balance of \$27,206 over two years. I&M's IM Plugged In and related rebate
22 deferral authority was granted by the Commission in Case No. U-20359. As

discussed by Company witness Seger-Lawson, the Company requests to continue this deferral of IM Plugged In costs.

Q54. Please explain the net operating income adjustment included in 2024 Forecast Test Year Adjustment O&M-8.

A54. 2024 Forecast Test Year Adjustment O&M-8 increases annual O&M expense by \$353,670 to reflect the Company's annual amortization of cumulative low-income customer discounts. The Company requests to amortize over two years the \$707,340 of cumulative I&M Michigan customer discounts issued through December 31, 2022 related to low-income customers. The Company continues to track these low-income customer discounts as approved by the Commission in Case No. U-18370 and consistent with Act 341.

Q55. Please explain the net operating income adjustment included in 2024 Forecast Test Year Adjustment O&M-15.

A55. 2024 Forecast Test Year Adjustment O&M-15 increases annual I&M Total Company O&M expense by \$5,051,789 for the proposed amortization of I&M's noncurrent sulfur dioxide (SO₂) allowance inventory. As further described by Company witness Seger-Lawson, the Company is seeking authority to accelerate recovery of the noncurrent SO₂ allowance inventory that is currently recorded in FERC Account 158. The Company proposes to recover the Michigan jurisdictional share of the I&M Total Company December 31, 2022 noncurrent SO₂ allowance inventory of \$25,258,945 over a five-year period.

1 **Q56. Please explain the net operating income adjustment included in 2024 Forecast**
2 **Test Year Adjustment DEP-1.**

3 A56. 2024 Forecast Test Year Adjustment DEP-1 increases depreciation expense by
4 \$29,418,419 by applying I&M Michigan jurisdictional depreciation rates previously
5 approved by the Commission to the Company's forecasted depreciable plant
6 balances as of December 31, 2024. This adjustment is consistent with the
7 adjustment reflected in I&M's base rates approved in Case No. U-20359. As
8 described by Company witness Seger-Lawson, the Company proposes to update
9 depreciation rates upon receipt of an order on this base case filing based on
10 depreciation rates that are ultimately approved by the Commission in the Company's
11 pending depreciation case, Case No. U-21412.

12 **Q57. Please describe the rationale for the amortization period proposed for the**
13 **regulatory assets described above and the starting point for the period of**
14 **amortization.**

15 A57. With the exception of 2024 Forecast Test Year Adjustment O&M-15 and for purposes
16 of determining the adjustment to retail rates for amortizations of various regulatory
17 assets described above, the Company proposes a two-year amortization. The
18 amortization period is based on a reasonable period of time the base rates approved
19 in this proceeding may be in effect as further described by Company witness Seger-
20 Lawson.

Q58. Did you also provide the 2024 Forecast Test Year adjustments to net operating income described above to Company witness Morgan for inclusion in I&M's jurisdictional separation study?

A58. Yes, I did. Please see Exhibit IM-50 (JWM-1) Summary of Projected Adjustments, which identifies the 2024 Forecast Test Year adjustments to net operating income and provides a brief description, the adjustment amount, and the page and line number where the adjustment is located in the jurisdictional cost-of-service allocation study.

ACCOUNTING FOR ROCKPORT UNIT 2

Q59. How has the Company reflected the merchant operations of Rockport Unit 2 in both the Company's 2022 Historical Period and the 2024 Forecast Test Year?

A59. Rockport Unit 2 activity is included in I&M's regulated operations and accounted for in I&M's regulated ledger through the end of the Rockport Unit 2 lease on December 7, 2022. Effective December 7, 2022, a separate business unit and ledger was established to maintain the ongoing accounting related to the merchant operations of Rockport Unit 2. I&M's forecast uses the same approach (separate business unit) for the 2024 Forecast Test Year to maintain consistency with the Company's accounting records. This approach ensures that ongoing Rockport Unit 2 merchant operations are excluded from I&M's 2024 Forecast Test Year.

Q60. Is the Company tracking its Michigan jurisdictional share of Rockport Unit 2 merchant operations?

A60. Yes. As prescribed by the approved Settlement Agreement to Case No. U-21189, the Company began tracking 50% of the cumulative positive net income of the I&M

Michigan jurisdictional share of Rockport Unit 2 merchant operations starting January 1, 2023.

Q61. How has the Company included in base rates I&M's Rockport Unit 2 leasehold improvements that were made prior to the end of the Rockport Unit 2 lease on December 7, 2022?

A61. Consistent with the approved Settlement Agreement to Case No. U-21189, I&M has included in its proposed base rates its remaining Michigan jurisdictional net book value of Rockport Unit 2 leasehold improvements:

The Parties agree that I&M's Michigan jurisdictional NBV of Rockport Unit 2 at the end of the Lease will be fully recoverable in retail rates through 2028, including a pre-tax weighted average cost of capital (WACC) return on the NBV. Upon the implementation of rates resulting from the Company's next base rate case, the return shall be calculated using a 9% return on equity ("ROE"). In all other respects, the WACC return shall reflect the cost of capital and capital structure approved by the Commission in each of the Company's base rate cases through 2028.

As a result, I&M continues to reflect Rockport Unit 2 leasehold improvements in electric plant in service in I&M's regulated generation business unit.¹

PROPOSED NEW DEFERRAL ACCOUNTING

Q62. Does the Company request any new or modified deferral accounting in this base case filing?

A62. Yes. As described below, the Company seeks new deferral accounting authority for certain costs incurred related to:

- New Customer Information System (CIS),

¹ See Exhibit A-11, A-1, column e.

- 1 • Implementation of Interconnection and Distributed Generation Standards
- 2 (MIXDG) established by the MPSC in Case No. U-20890,
- 3 • Certain costs incurred associated with the grant application process,
- 4 • Nuclear decommissioning study costs,
- 5 • Credits issued to I&M customers for certain customer outages,
- 6 • The Tax Rider, and
- 7 • The Subsequent License Renewal (SLR) project.

8 **Q63. What is needed to establish deferral accounting as proposed by the Company?**

9 A63. Financial Accounting Standards Board's Accounting Standards Codification (FASB
10 ASC) 980 prescribes deferral accounting when a regulatory commission requires
11 over-/under-recovery accounting for certain costs that are recovered in current rates
12 charged to customers or when a commission provides deferral authority for certain
13 costs with recovery to be determined at a later date. Eligible costs for recovery in
14 these scenarios are subject to any prudence and audit reviews ordered by the
15 Commission. In order to perform regulatory deferral over/under-recovery true-up
16 accounting and record regulatory liabilities (Account 254) or regulatory assets
17 (Account 182.3), it must be probable that the regulatory liability will be credited to
18 customers in the future or that the regulatory asset will be recovered from customers
19 in the future.

20 **Q64. Please describe the Company's CIS project.**

21 A64. As further discussed by Company witnesses Seger-Lawson and Brenner, the CIS
22 will be used by all AEP Operating Companies, including I&M, and will replace the
23 existing billing system.

Q65. What deferral accounting does the Company propose with regard to CIS assets placed in service following I&M's 2024 Forecast Test Year?

A65. With the Commission's approval, the Company will defer as a FERC Account 182.3 regulatory asset, I&M Michigan jurisdictional depreciation expense and debt and pre-tax equity return on CIS rate base (plant in service less accumulated depreciation) for assets placed in service after the 2024 Forecast Test Year. As further discussed by Company witness Seger-Lawson, the Company would continue to defer CIS depreciation expense and debt and equity return until the related assets are reflected in base rates in a future I&M Michigan base rate proceeding.

Q66. How will the Company identify and account for costs related to the CIS Deferral?

A66. I&M will use unique projects and work orders to identify and track the costs associated with the cost deferrals described above.

Q67. Please describe the Company's proposed deferral accounting for costs incurred related to the Interconnection and Distributed Generation Standards (MIXDG) established by the MPSC.

A67. As further discussed by Company witness Seger-Lawson, I&M will incur incremental programing, IT costs, labor and administrative costs associated with implementing and managing new practices and procedures that are required by MIXDG rules for the interconnection of distributed energy resources in I&M's service territory. With the Commission's approval, I&M will defer, as a FERC Account 182.3 regulatory asset, all O&M costs incurred related to the MIXDG rules and will request recovery of this regulatory asset in a future I&M Michigan base rate proceeding.

1 **Q68. Please describe the Company's proposed deferral accounting for certain costs**
2 **incurred related to grant application and writing costs.**

3 A68. As further described by Company witness Seger-Lawson, the Company is currently
4 pursuing government grants for certain grid modernization investments to help
5 reduce the costs to customers. The Company requests deferral authority for
6 Michigan jurisdictional grant application and writing costs for grants that are not
7 ultimately awarded to I&M or for Michigan jurisdictional grid modernization
8 investments that are not ultimately constructed by the Company. Upon receiving
9 deferral authority from the Commission, the Company would defer these costs as a
10 FERC Account 182.3 regulatory asset and would request recovery of this regulatory
11 asset in a future I&M Michigan base rate proceeding.

12 **Q69. Please describe the Company's proposed deferral accounting for costs**
13 **incurred related to nuclear decommission study.**

14 A69. As further described by Company witness Seger-Lawson, the Company is requesting
15 deferral authority for future nuclear decommissioning study expenses. Upon
16 receiving deferral authority from the Commission, the Company would defer the I&M
17 Michigan jurisdictional nuclear decommissioning costs incurred as a FERC Account
18 182.3 regulatory asset and would request recovery of this regulatory asset in a future
19 I&M Michigan base rate proceeding.

20 **Q70. Please describe the Company's proposed deferral accounting for certain**
21 **customer outage credits.**

22 A70. As further described by Company witness Seger-Lawson, the Company requests
23 approval of deferral accounting authority for certain outage credits provided to

1 customers that result from certain conditions, such as outages or other limited
2 circumstances. Upon receiving deferral authority from the Commission, the
3 Company would defer these costs as a FERC Account 182.3 regulatory asset and
4 would request recovery of this regulatory asset in a future I&M Michigan base rate
5 proceeding.

6 **Q71. Please describe the components of the Company's proposed Tax Rider.**

7 A71. As further described by Company witnesses Seger-Lawson and Criss, I&M proposes
8 a new Tax Rider to: a) credit back the remaining unamortized balance of unprotected
9 (also called non-normalized) excess accumulated deferred federal income tax
10 (ADFIT) benefits that have previously been included in I&M Michigan base rates, b)
11 reflect Production Tax Credits (PTC) applicable due to electricity produced by the
12 Cook Plant nuclear generating facility related to the period 2024 through 2032, and
13 c) collect the impact of the Corporate Alternative Minimum Tax (CAMT).

14 The direct testimony of Company witness Criss discusses the current regulatory
15 liability treatment related to remaining I&M Michigan jurisdictional unprotected
16 excess ADFIT benefits and the proposed regulatory liability treatment for the lag
17 between the monetization of PTCs and when the PTCs are reflected in Tax Rider
18 rates. As discussed by Company witness Criss, it is currently estimated that I&M's
19 Michigan jurisdictional share of excess ADFIT benefits will be fully amortized in 2025.

20 With I&M being subject to the CAMT and since the calculation of the tentative
21 minimum tax will vary year-over-year based on the operations of the Company, I&M
22 proposes to include its Michigan jurisdictional share of the CAMT as an eligible cost
23 for recovery through the Tax Rider.

Q72. Please describe the Company's proposed Tax Rider over-/under-recovery accounting.

A72. Monthly Tax Rider over-/under-recovery will be calculated by comparing monthly Tax Rider revenues/revenue credits against the per books I&M Michigan level of net Tax Rider expenses/credits that are described above for unprotected excess ADFIT amortization, Cook Plant PTCs, and CAMT. I&M also proposes to include, within monthly Tax Rider over-/under-recovery calculations and entries for the benefit of customers, a pre-tax WACC return on the I&M Michigan jurisdictional regulatory liability balances of both unamortized unprotected excess ADFIT and PTCs. Based on this monthly comparison of Tax Rider revenues/revenue credits to I&M Michigan Tax Rider expenses/credits as described above, I&M will then record a Tax Rider under-recovery or over-recovery adjustment to FERC Account 182.3 or 254, respectively, in accordance with GAAP, specifically ASC 980 in accounting for regulated operations.

Q73. Company witnesses Seger-Lawson and Ferneau discuss the Company's plans to initiate efforts to evaluate relicensing costs for the Cook Plant nuclear generating facility. How does the Company plan to account for these SLR-related costs?

A73. The SLR project is expected to span across several years. I&M will account for preliminary study/survey costs associated with the possible extension of Cook Plant licenses (SLR Costs) in accordance with the FERC USofA, specifically FERC Account 183. FERC USofA states that Account 183 "shall be charged with all

1 expenditures for preliminary surveys, plans, investigations, etc., made for the
2 purpose of determining the feasibility of utility projects under contemplation.”

3 **Q74. How would the Company account for SLR costs incurred if the SLR results in**
4 **the construction of an asset?**

5 A74. FERC USofA further states for costs initially recorded to Account 183 that “if
6 construction results, this account (Account 183) shall be credited and the appropriate
7 utility plant account charged.” Accordingly, if the construction of assets results from
8 the Cook Plant SLR, I&M will record proper accounting adjustments to ensure that
9 Cook Plant SLR costs are included with the Cook Plant asset when placed in service
10 (FERC Account 101 – Electric Plant in Service). This asset will then be depreciated
11 over the remaining life of the Cook Plant.

12 **Q75. How would the Company account for the SLR costs if these study costs do not**
13 **result in the construction of an asset?**

14 A75. As included in the testimony of Company witness Seger-Lawson, I&M requests
15 deferral authority, as a FERC Account 182.3 regulatory asset, for any SLR costs
16 incurred that do not result in the construction of an asset. If the Commission grants
17 this deferral authority and the Company’s SLR work performed does not result in the
18 construction of an asset, I&M will reclassify all SLR costs incurred from Account 183
19 to Account 182.3. The Company will then seek recovery of this regulatory asset in a
20 future I&M Michigan base rate proceeding.

21 **Q76. Does this conclude your pre-filed direct testimony?**

22 A76. Yes.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*** * * * ***

**In the matter of the application of
INDIANA MICHIGAN POWER COMPANY
for authority to increase its rates for the
sale of electric energy and for approval of
other related matters.**

Case No. U-21461

INDIANA MICHIGAN POWER COMPANY

PRE-FILED DIRECT TESTIMONY

OF

JESSICA M. CRISS

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**PRE-FILED DIRECT TESTIMONY OF JESSICA M. CRISS
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY**

INTRODUCTION OF WITNESS

Q1. Please state your name and business address.

A1. My name is Jessica M. Criss and my business address is 1 Riverside Plaza,
Columbus, OH 43215.

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

A2. I am employed by American Electric Power Service Corporation (AEPSC) as a Tax
Accounting and Regulatory Support Manager. AEPSC supplies engineering,
accounting, planning, advisory, and other services to the subsidiaries of the American
Electric Power (AEP) system, one of which is Indiana Michigan Power Company
(I&M or the Company).

Q3. Please briefly summarize your educational and professional background.

A3. I earned a Bachelor of Science in Business Administration with a focus in Accounting
and a Masters of Accounting from St. Louis University School of Business. I have
been a Certified Public Accountant in the State of Ohio since 2015.

While pursuing my degrees I was employed part time at a regional public
accounting firm in Chesterfield, MO from February 2012 to December 2013. I was
hired at a regional public accounting firm in Akron, OH as a Tax Accountant in
January 2014 and was promoted to Senior Tax Accountant in January 2016.

In December 2016 I was hired at L Brands, Inc., a retail corporation in
Columbus, OH as a Tax Analyst and was promoted to Senior Tax Analyst in April
2019. I joined AEPSC in January 2020 as a Principal Tax Analyst and was promoted

to my current position of Tax Accounting and Regulatory Support Manager effective February 20, 2021.

Q4. What are your principal areas of responsibility with I&M?

A4. I participate in the recording of the tax accounting entries and records and the review of federal and state tax returns of AEP and its subsidiaries. I am also responsible for coordinating and developing state and federal tax data provided by the AEPSC Tax Department for use in regulatory proceedings. I have attended numerous tax, accounting, and regulatory seminars throughout my professional career.

Q5. Have you previously testified in any regulatory proceedings?

A5. Yes. I have submitted testimony before the Indiana Utility Regulatory Commission (IURC or Commission) on behalf of I&M in Cause No. 45576 (2021 Base Rate Case) and Cause No. 45933 (2023 Base Rate Case). I have also submitted testimony before the Tennessee Public Utility Commission (TPUC), Virginia S.C.C., and West Virginia Public Service Commission (PSC).

PURPOSE OF TESTIMONY

Q6. What is the purpose of your testimony in this proceeding?

A6. I present and support:

- Federal and state income tax expense for the historical period ended December 31, 2022 (Historical Period) and for the forecasted test year ended December 31, 2024;
- Accumulated Deferred Federal Income Taxes (ADFIT) and Accumulated Deferred Investment Tax Credit (ADITC) incorporated in the capital structure used by Company Witness Luedtke to calculate the Weighted Average Cost of Capital (WACC);

- Income tax expense adjustments related to certain ratemaking adjustments made to the Test Year as supported by other Company witnesses;
- Certain adjustments to income tax expense and accumulated deferred income taxes;
- Calculation of the gross revenue conversion factor (GRCF) and certain taxes other than income taxes; and
- Calculation of effective federal and state income tax rates.

Q7. Are you sponsoring any Exhibits in this proceeding?

A7. Yes. I am sponsoring the following exhibits:

- Exhibit A-3, Schedule C2 Historical Computation of GRCF
- Exhibit A-3/A-13, Schedule C7 Historical/Projected General Taxes
- Exhibit A-3/A-13, Schedule C8 Historical/Projected Federal Income Taxes
- Exhibit A-3/A-13, Schedule C9 Historical/Projected State Income Taxes
- Exhibit A-3/A-13, Schedule C10 Historical/Projected Other (or Local) Taxes
- Exhibit A-13, Schedule C2 Projected Computation of GRCF

In addition, I support the following exhibits:

- IM-26 (JMC-1) – Stand Alone Net Operating Loss Carryforward (NOLC)
- IM-27 (JMC-2) – Adjustments to ADFIT
- IM-28 (JMC-3) – Jurisdictional Corporate Alternative Minimum Tax (CAMT)

In addition, I am co-sponsoring the following schedules and exhibits:

- Exhibit IM-48 (DSL-1): Tax Rider Revenue Requirement

Q8. Were the Exhibits that you are sponsoring prepared by you or under your direction?

A8. Yes.

1 **Q9. Please summarize your testimony.**

2 A9. My testimony describes the methods used to develop the federal and state income
3 tax expense for the Test Year. The methods used are consistent with prior rate filings.
4 The Company's state and federal income tax expense has been properly
5 recomputed to reflect the appropriate tax effects resulting from the various
6 ratemaking adjustments supported in this case. The adjusted Test Year level of other
7 tax expense is appropriate and necessary and reflects the proper amount of going-
8 level expense.

9 The Company's ADFIT balances have been properly recomputed to reflect
10 the balance of deferred assets and liabilities necessary as an adjustment to the
11 capital structure. The Company's proposed treatment of its net operating loss
12 carryforward is reasonable and consistent with Commission precedent as well as
13 Internal Revenue Service (IRS) normalization requirements. The GRCF calculated
14 on Exhibit A-13, Schedule C2 represents the appropriate factor that is applied to the
15 income deficiency in order to determine the amount of incremental revenue needed
16 to obtain the required level of operating income.

17 The Company proposes treatment of tax items since the filing of Case No. U-
18 20359. It is appropriate and necessary in order to align its ratemaking such that the
19 taxes are normalized throughout the origination and reversal of the cost of removal
20 (COR) timing difference, amortize specific deferred tax balances due to customers,
21 and account for the implications of the Inflation Reduction Act (IRA) enacted on
22 August 16, 2022.

1 The proposed tax rider is a reasonable and necessary mechanism to credit
2 customers the remaining unprotected excess amortization and reflect the expected
3 net benefits related to the corporate alternative minimum tax (CAMT) and Nuclear
4 Production Tax Credits (PTCs) benefits associated with the Investment Reduction
5 Act (IRA) which are expected to be significant, variable and volatile and largely
6 outside the Company's control.

7 **STAND-ALONE NET OPERATING LOSS CARRYFORWARD ADJUSTMENTS**

8 **Q10. How was Income Tax Expense within Cost of Service and ADFIT and ADITC**
9 **within the capital structure determined in the filing?**

10 A10. Consistent with the Commission Order dated October 14, 2010, which approved a
11 Settlement Agreement between all parties in I&M's Case No. U-16180, and affirmed
12 in I&M's Case No. U-16801, the Company's federal and state income tax expense
13 are calculated using the "stand-alone" return methodology. Consistent with previous
14 cases, federal income taxes are calculated using normalized method of tax
15 accounting and state Income Taxes are calculated using flow-through method of tax
16 accounting.

17 **Q11. Please describe the "stand-alone" basis as prescribed in Case No. U-16180.**

18 A11. The stand-alone basis is the calculation of income tax expense for ratemaking
19 purposes for the regulated utility without the impact of activities of affiliated
20 companies. In Case No. U-16180, the Domestic Production Activities Deduction
21 ("DPAD") was included in the calculation of I&M's federal income tax expense based
22 upon preliminary 2007 tax return information at the AEP Consolidated level and then
23 appropriated to I&M. MPSC staff witness Liu argued that for ratemaking purposes,

1 “I&M should be considered as a stand-alone entity separated from its affiliated
2 companies; therefore its tax expenses should be calculated on a stand-alone basis”¹
3 and adjusted the DPAD to reflect only I&M’s regulated operations. In rebuttal
4 testimony, Company witness Kelly agreed to this treatment stating “The Company’s
5 income tax expense for ratemaking purposes should be calculated on a...stand-
6 alone basis. In other words, the income tax calculations should not be dependent on
7 the activities of other companies that are included in the AEP consolidated Federal
8 income tax return.”²

9 **Q12. Has the Commission ordered the use of calculating income tax on a stand-
10 alone basis?**

11 A12. Yes. In I&M’s Case No. U-16180, Commission staff witness Liu refers to precedent
12 set by the Commission in their final order for Case No. U-15645 for Consumers
13 Energy Company (Consumers).

14 **Q13. Please describe Case No. U-15645.**

15 A13. In Case No U-15645, Consumers did not include a DPAD benefit due to the
16 consolidated group being unable to claim the deduction. Similar to I&M’s case U-
17 16180, Commission staff witness Liu stated “or ratemaking purposes... Consumers
18 should be considered as a stand-alone entity; therefore, its tax expenses should be
19 calculated on a stand-alone basis. The potential benefits to the ratepayers should not
20 be harmed by the financial results of the Company’s non-utility affiliates....ratepayers

¹ *Michigan Public Service Commission*, Case No. U-16180. Direct Testimony of Kevin Liu, 3 TR 989, lines 6-7.

² *Indiana Michigan Power Company*, Case No. U-16180. Rebuttal Testimony of Michael N. Kelly, 3 TR 503, lines 17-21.

1 should not bear the unnecessary costs because of the non-profitability of CMS' other
 2 subsidiaries.”³ In other words, the stand-alone method ignored the fact that no
 3 deduction was able to be taken for the DPAD on the consolidated federal income tax
 4 return and rather determined that Consumers would have been able to take a DPAD
 5 deduction on a stand-alone basis.

6 In addition, the Proposal for Decision (PDF) released by the Administrative
 7 Law Judge (ALJ) Sharon L. Feldman recommended that the Commission adopt the
 8 staff's adjustment. Ms. Feldman states that “Mr. Liu's analysis is persuasive and
 9 consistent with the approach the Commission has taken in setting other components
 10 of Consumer Energy's rates...[and] recommends that Staff's federal income tax
 11 adjustment be adopted.”⁴

12 **Q14. What are the other components of Consumer Energy's rates that the**
 13 **Commission utilized a stand-alone approach to calculating?**

14 A14. In setting Consumers' gas rates in the December 7, 1989 order in Case No. U-8676,
 15 the Commission set rates utilizing a hypothetical capital structure that treats the
 16 electric operations as a separate entity from CMS Energy. This hypothetical capital
 17 structure provided Consumers the benefit of a ratemaking capital structure with a
 18 44.8% debt to 40.51% equity ratio rather than mirroring its corporate parent's
 19 ratemaking capital structure with a 58.9% debt to 26.5% equity ratio.

³ *Michigan Public Service Commission*, Case No. U-15645. Direct Testimony of Kevin Liu, 10 TR 1237 12-21.

⁴ Case No. U-15645 Proposal for Decision, page 138 (September 2, 2009).

Q15. What was the conclusion of Case No. U-15645?

A15. In their final order dated November 2, 2009, the Commission agreed with the ALJ and Commission staff witness Liu. The position summarized in the order is as follows:

The Commission agrees with the Staff and the ALJ that, if a utility garners a significant benefit, on one hand, from being treated as a stand-alone company for one aspect of ratemaking (ratemaking capital structure) , then, on the other hand, the utility's complaints about such treatment for a different aspect of ratemaking (determination of federal income tax expenses) ring hollow. In this case, it appears from the Staff's testimony that the reason given by Consumers to the Staff in response to an audit request regarding the inapplicability of the DPAD to CMS Energy was that "at the consolidated level, CMS, Consumers' parent company, did not have net operating income to qualify" for the deduction. The Staff's position is explained as follows:

In essence, Consumers is alleging that it could not claim the DPAD for its 2007 Federal Income Tax return because the non-utility operation of CMS had a net operating loss. It is Staff's position that the tax benefits Consumers could have enjoyed should not be denied because of the Company's non-utility affiliates. The ratepayers should not bear the unnecessary costs because of the non-profitability of CMS' other subsidiaries.

The Commission finds this reasoning persuasive. Therefore, the Commission finds that the Staff's negative adjustment for DPAD should be included in the calculation of Consumers' FIT.⁵

Q16. Are there tax attributes, similar to DPAD from Case No. U-16180, that are calculated at the consolidated group level for financial statement purposes?

A16. Yes. The tax NOLC of I&M, recorded as a deferred tax asset (DTA), is calculated utilizing a consolidated group approach for financial statement purposes.

Q17. What is a Tax NOLC?

A17. A tax NOLC occurs when, in a given year, a taxpayer has more deductions than taxable revenues, resulting in negative taxable income within its tax return. When a

⁵ Case No. U-15645 Order, page 45 (November 2, 2009)

NOLC occurs, the IRC allows the taxpayer to carry the NOLC forward to subsequent years and offset taxable income produced in that year.

Q18. What might cause a taxpayer to incur a Tax NOLC?

A18. Tax NOLCs are the product of tax return deductions exceeding taxable revenues. Due to the capital-intensive nature of the utility industry, deductions associated with accelerated tax depreciation can lead to tax years in which overall deductions exceed taxable revenues.

More specifically, bonus depreciation provisions of the IRC providing for accelerated tax depreciation in the year an asset is placed in service, have resulted in the creation of tax NOLCs for many utilities.

Q19. How does the Company calculate the NOLC DTA recorded on its financial books and records at the end of the historical or forecast test period?

A19. The books and records of the Company are presented in accordance with GAAP, governed by Accounting Standard Codification 740 (ASC 740). ASC 740 allows a corporation to use one of several methods in determining income taxes in the separate financial statements of the members of a consolidated tax return group. Specifically, ASC 740-10-30-27 does not require the use of any particular allocation method and only requires that the method adopted be systematic, rational, and consistent with the broad principles of ASC 740.

The members of the AEP consolidated federal income tax return (the “AEP consolidated return group”) have elected the method of tax allocation that follows a “benefits for loss” methodology for GAAP reporting. Accordingly, I&M does not have an NOLC recorded on its financial books and records at the end of the historical or

forecast test year because the AEP consolidated return group has produced taxable income sufficient to offset the losses previously contributed by I&M to the group. In other words, the GAAP financial statements of I&M reflect its proportionate share of the AEP consolidated return group's NOLC.

Q20. How has this been treated for ratemaking purposes in this filing?

A20. For ratemaking purposes, in order to comply with the stand-alone ratemaking as prescribed by the Commission, it is necessary to reflect the NOLC generated strictly based on I&M's stand-alone taxable income.

The AEP consolidated return group's accounting policy is an election under GAAP that establishes how taxes are allocated to the books and records of the consolidated group which does not change the contribution of each member of the group's tax burden on a stand-alone basis. Accordingly, in order to present ADFIT on a stand-alone basis, consistent with income tax expense, a ratemaking adjustment for the stand-alone NOLC is required when I&M is in a stand-alone NOLC position to remove the impacts of the AEP consolidated return group.

Q21. Why is it appropriate to determine income tax expense and ADFIT in the Capital Structure using a stand-alone approach?

A21. The stand-alone approach is consistent with ratemaking principles established by the MPSC in cases mentioned above as well as required to comply with the normalization rules of the Internal Revenue Code (IRC) regarding tax benefits of accelerated depreciation. Such rules require consistency among tax expense and the corresponding components of cost of service and the capital structure as a part of determining the WACC. The stand-alone approach ensures that income taxes

within the filing represent only those associated with the revenues and expenses of the regulated operations and assets of the Company, without regard to the Company's unregulated activities or the operations of the AEP Consolidated group. As such, income taxes are consistent with the regulated assets reported in the capital structure as a part of determining the WACC and the regulated revenues and expenses included in Cost of Service. The use of a stand-alone approach prevents the cross-subsidization among the Company's affiliates.

Q22. In addition to GAAP reporting, are there normalization requirements within the IRC?

A22. Yes. The Internal Revenue Code contains provisions requiring utility ratemaking to apply a normalized method of accounting with respect to tax benefits associated with accelerated tax depreciation, NOLCs due to accelerated depreciation, and Investment Tax Credits.

Q23. What are the components of the stand-alone NOLC?

A23. Any stand-alone NOLC ratemaking adjustment impacts multiple ADFIT accounts and the cost of service. These impacts are illustrated in Exhibit IM-26 (JMC-1). The stand-alone NOLC ratemaking adjustment represents:

1. Stand-alone NOLC as of the test year at 21% which impacts ADFIT account 1901001.
2. Reduction to protected excess deferred income tax (EDIT) liability as a result of TCJA as of December 31, 2017 which impacts accounts 2811001, 2821001, and the regulatory liability for excess in accounting 2544001. The NOLC represents a deficient offset to the excess liability.

3. Increase in deferred tax expense due to the decrease in protected excess amortization for the NOLC deficient tax offset to the excess liability.

Q24. How was it determined that the stand-alone NOLC is considered protected?

A24. A “with-and-without” test, as prescribed by the IRS in various private letter rulings (PLR)⁶, was performed for the Company prospectively starting with the tax period ended December 31, 2017. It was determined that the NOLC as of December 31, 2017 was 100% related to accelerated depreciation. Therefore, the remeasurement of excess ADFIT to include the deficient offset of the stand-alone NOLC is considered protected.

In addition, the historical test period ended 2022 was determined to be 100% related to accelerated depreciation. However, for the forecasted test period ending 2024, the Company is expected to generate enough income to offset previous losses and eliminate the stand-alone NOLC DTA.

Q25. Why is it necessary to include the stand-alone NOLC deficient as an offset to the regulatory liability for excess?

A25. The premise behind excess ADFIT is that there is a dollar-for-dollar return of cash that was over-collected as a result of a rate change. The inclusion of the deficient ADFIT associated with the NOLC and reduction to the regulatory liability for excess ensures that the Company credits only the amount of cash that it collected from customers through rates for its deferred taxes. If the Company’s position is not accepted, it would result in I&M crediting customers an amount beyond the amount reflected in prior rates.

⁶ Private Letter Rulings 201436037, 21438003, 201519021, 201534001, 201548017, 201709008, 202010002

Q26. What, if any, are the impacts to the company resulting from the stand-alone NOLC from a financial statement perspective?

A26. As previously mentioned, the stand-alone NOLC adjustment is made up of three components. The first component, the NOLC at the federal statutory rate of 21%, will continue to be a ratemaking adjustment only on a prospective basis as the accounting methodology for the Company's financial records reflects the NOLC related to the consolidated group, not the Company on its own. The second and third components, related to the NOLC deficient offset to the regulatory liability for excess, will be recorded to the Company's financial statements. The stand-alone NOLC deficient will be a one-time journal entry, net with the regulatory liability in account 2544001, which reduces the liability in future periods. In addition, the protected amortization of the NOLC deficient will reduce the protected excess amortization in future periods. Exhibit IM-26 (JMC-1), mentioned previously, outlines the impact of each component.

Q27. How is the protected amortization of the NOLC deficient balance calculated?

A27. Similar to excess protected, the NOLC deficient protected is amortized via the average rate assumption method (ARAM) as prescribed by the normalization rules.

OTHER TAX ADJUSTMENTS

Q28. What is normalized tax accounting?

A28. Normalized tax accounting is a method of tax accounting in which the taxes reflected within an entity's income statement for a given period are matched with the associated revenues and expenses.

This methodology, also known as “deferred income tax” accounting, is required for financial reporting under Generally Accepted Accounting Principles (GAAP) (Financial Accounting Standards Board Accounting Standards Codification Topic 740 (“ASC 740”), formerly Statement of Financial Accounting Standards No. 109).

Q29. Why is normalized tax accounting necessary?

A29. The determination of net income for financial reporting purposes under GAAP differs from the determination of taxable income under the IRC. As a result, revenues and expenses may be reflected in taxable income earlier or later than when such items are reflected within an income statement under GAAP. These “book-to-tax” differences result in a determination of taxes payable for a given period that differs from the amount of financial statement income tax expense.

Under a normalized method of tax accounting, the tax liability that would have been payable if determined solely under GAAP principles is merely deferred and not saved permanently. Therefore, financial statement reporting in accordance with GAAP requires a provision for deferred taxes to account for the tax effects of temporary book-to-tax differences.

Q30. Can you provide an example of normalized tax accounting?

A30. Yes. As an example, in the early years of an asset’s life, accelerated tax depreciation often exceeds book depreciation expense reported in the financial statements allowing for the deferral of income taxes due to the taxing authority. In such an instance, the taxes deferred are debited to a deferred tax expense account with a corresponding credit to a deferred tax liability.

In later years, when the book-to-tax difference reverses, the increase in tax due is mitigated by also reversing the deferred tax liability through a corresponding credit to deferred income tax expense. *Figure JMC-1* illustrates this point.

Figure JMC-1 Example of Normalized Accounting

	Year 1	Year 2	Year 3	Year 4	Year 5	Total
Revenues	1,000	1,000	1,000	1,000	1,000	5,000
Operating Expenses	(500)	(500)	(500)	(500)	(500)	(2,500)
Book Depreciation	(100)	(100)	(100)	(100)	(100)	(500)
Pre-tax Book Income (PTBI)	400	400	400	400	400	2,000
Tax Depreciation	(250)	(100)	(75)	(50)	(25)	(500)
Federal Taxable Income	250	400	425	450	475	2,000
Federal Current Tax Expense	53	84	89	95	100	420
Federal Deferred Tax Expense	32	-	(5)	(11)	(16)	-
Total Federal Tax Expense	84	84	84	84	84	420
Book/ Tax Depreciation Difference	(150)	-	25	50	75	-
DTA/ (DTL)	(32)	(32)	(26)	(16)	-	-

Q31. What is the alternative to normalized accounting?

A31. The alternative to a normalized method of tax accounting is referred to as “flow-through” accounting. A flow-through approach bases income tax expense reported within the financial statements on the tax liability as reported on the tax return, as opposed to that determined in accordance with ASC 740. *Figure JMC-2* illustrates this point.

Figure JMC-2 Example of Flow-through Accounting

	<u>Year 1</u>	<u>Year 2</u>	<u>Year 3</u>	<u>Year 4</u>	<u>Year 5</u>	<u>Total</u>
Revenues	1,000	1,000	1,000	1,000	1,000	5,000
Operating Expenses	(500)	(500)	(500)	(500)	(500)	(2,500)
Book Depreciation	(100)	(100)	(100)	(100)	(100)	(500)
Pre-Tax Book Income	400	400	400	400	400	2,000
Tax Depreciation	(250)	(100)	(75)	(50)	(25)	(500)
Federal Taxable Income	250	400	425	450	475	2,000
Federal Current Tax Expense	53	84	89	95	100	420
Federal Deferred Tax Expense	-	-	-	-	-	-
Total Federal Tax Expense	53	84	89	95	100	420
Book/Tax Depreciation Difference	(150)	-	25	50	75	-
DTA/(DTL)	(32)	(32)	(26)	(16)	-	-
Regulatory Asset	32	32	26	16	-	-

Comparing *Figure JMC-2* and *Figure JMC-3*, the amount of total federal tax expense is the same under both normalized and flow-through approaches – the difference is timing and the variability of tax expense from year to year.

The term “normalization” evolved with respect to utilities because income taxes computed on a normalized basis caused net income to appear “normal,” in contrast to flow-through, an approach based on the cash liability reported on the tax return.

Q32. Has normalized tax accounting always been the method of accounting utilized by the Company?

A32. No. Prior to the issuance of SFAS 109 by the FASB in February 1992, non-property related deferred tax timing differences could be treated as flow-through. Property timing differences have historically been treated as normalized mainly due to the Tax

Reform Act of 1969 permitting utilities the right to make an election to abandon flow-through treatment of post 1969 utility property.⁷

Q33. What is SFAS 109?

A33. SFAS 109 required an asset and liability approach for the financial reporting for income taxes, i.e., a normalized method of accounting. One of the objectives of SFAS 109 was to recognize deferred tax liabilities and assets for the future tax consequences of items that have been recognized on a company's financial statements or tax returns.

SFAS 109 also provided guidance to utilities for book vs. tax timing differences that were previously treated as flow-through. Paragraph 29 addressed accounting for income taxes by regulated utilities and specifically required recognition of a deferred tax liability for tax benefits that are flowed through to customers when temporary differences originate. Additionally, when the regulated utility recovers from or return to customers the future increase or decrease in tax payable for tax benefits flowed through to customers, a regulatory asset or liability is recognized for that future revenue or reduction in future revenues.

Q34. How did the Company transition to a normalized method of tax accounting as required by SFAS 109?

A34. The AEP System's operating companies, including I&M, adopted SFAS 109 effective January 1, 1993.⁸ All timing differences treated as flow-through previous to transitioning to normalized treatment continue to unwind utilizing a flow-through

⁷ Tax Reform Act of 1969, §441, 26 U. S. C. §167 (1)

⁸ *Indiana Michigan Power Company*, Case No. U-10083. Direct Testimony of Scott M. Krawec, page 12, lines 5-7.

1 methodology. This results in an increase to tax expense, reflective of tax expense
2 due that a tax benefit was received for previously. All timing differences originating
3 after the transition were accounted for on a normalized basis except for the cost of
4 removal (COR or removal costs) deduction, which continued to be accounted for on
5 a flow-through basis. This accounting is consistent with previous filings including
6 Case Nos. U-16801, U-18370, and U-20359.

7 **Q35. What are removal costs?**

8 A35. A removal cost is an amount that a utility expects to incur to decommission an asset
9 at the end of its life based on the price levels in effect at the time it is removed.

10 **Q36. How have removal costs been treated for ratemaking purposes?**

11 A36. For ratemaking purposes, an accrual for estimated COR is included as part of the
12 overall book depreciation expense in the Company's cost of service. This cost is
13 recalculated periodically and reflected in rates over a period that approximates the
14 remaining life of the plant. While there is not exact matching, this approach seeks to
15 recover the total cost of the plant, including COR, through depreciation expense
16 recognized during the period which the underlying asset was used and useful in the
17 provision of service to customers. I&M is requesting approval of updated depreciation
18 rates which include an estimated COR accrual in Case No. U-21412.

19 **Q37. How are removal costs accounted for on the Company's financial statements?**

20 A37. As previously discussed, the removal costs are included in the overall book
21 depreciation. On the income statement, the book depreciation for removal costs is
22 recorded to account 403 under FERC's Uniform System of Accounts (USoA). On the

balance sheet, the accumulated accrual of removal costs is recorded to account 108 and are included in the accumulated book depreciation.

Q38. Is the timing of the recognition of removal costs the same for federal income tax and financial statement purposes?

A38. No. For financial statement purposes, removal costs are recognized over the life of an asset but for tax purposes they are recognized at the time costs are actually incurred to remove an asset. COR is defined as an allowable deduction under IRC §162 rather than IRC §168. IRC §162 defines general trade or business expenses while IRC §168 defines the method of depreciation for property. Therefore, rather than recognizing removal costs over the life of an asset, the COR is not recognized for tax purposes until the costs are actually incurred at the end of the asset's life.

Q39. How is this difference in the recognition of COR expense accounted for?

A39. Because the financial statements have recognized an expense for COR prior to the allowable recognition for tax purposes, the book depreciation expense is excluded from the calculation of taxable income, and a deferred tax asset (DTA) is recorded. This DTA represents the future tax benefit that will be received when the asset is retired, and COR is incurred.

Q40. Discuss the ratemaking for income tax expense related to COR using a normalized method of accounting.

A40. Please see *Figure JMC-3*, which assumes that \$10 of the \$100 book depreciation is related to COR and the asset is retired in year six.

Figure JMC-3 COR: Normalized

	<u>Year 1</u>	<u>Year 2</u>	<u>Year 3</u>	<u>Year 4</u>	<u>Year 5</u>	<u>Year 6</u>	<u>Total</u>
Revenues	1,000	1,000	1,000	1,000	1,000	900	5,900
Operating Expenses	(500)	(500)	(500)	(500)	(500)	(500)	(3,000)
Book Depreciation	(90)	(90)	(90)	(90)	(90)	-	(450)
Book Depreciation - COR	(10)	(10)	(10)	(10)	(10)	-	(50)
Pre-Tax Book Income	400	400	400	400	400	400	2,400
Tax Depreciation	(250)	(80)	(60)	(40)	(20)	-	(450)
COR Deduction	-	-	-	-	-	(50)	(50)
Federal Taxable Income	250	420	440	460	480	350	2,400
Federal Current Tax Expense	53	88	92	97	101	74	504
Federal Deferred Tax Expense	32	(4)	(8)	(13)	(17)	11	-
Total Federal Tax Expense	84	84	84	84	84	84	504
Book/Tax Timing - COR	10	10	10	10	10	(50)	-
Book/Tax Timing - Depreciation	(160)	10	30	50	70	-	-
DTA - COR	2	4	6	8	11	-	-
(DTL) - Depreciation	(34)	(32)	(25)	(15)	-	-	-

In the example above, the cost of service includes \$84 of annual federal income tax expense, the net of both current and deferred tax expense. During the life of the asset, the COR depreciation is not deductible for tax purposes and the future benefit is recorded to deferred tax expense. As such, in the ratemaking process, customers are provided the benefit of the future tax deduction as the removal cost book depreciation is recognized over the life of the asset.

Q41. Discuss the ratemaking for income tax expense related to COR using a flow-through method of accounting.

A41. Please see *Figure JMC-4*, which illustrates the previous example with COR being treated as flow-through.

Figure JMC-4 COR: Flow-through

	<u>Year 1</u>	<u>Year 2</u>	<u>Year 3</u>	<u>Year 4</u>	<u>Year 5</u>	<u>Year 6</u>	<u>Total</u>
Revenues	1,000	1,000	1,000	1,000	1,000	900	5,900
Operating Expenses	(500)	(500)	(500)	(500)	(500)	(500)	(3,000)
Book Depreciation	(90)	(90)	(90)	(90)	(90)	-	(450)
Book Depreciation - COR	(10)	(10)	(10)	(10)	(10)	-	(50)
Pre-Tax Book Income	400	400	400	400	400	400	2,400
Tax Depreciation	(250)	(80)	(60)	(40)	(20)	-	(450)
COR Deduction	-	-	-	-	-	(50)	(50)
Federal Taxable Income	250	420	440	460	480	350	2,400
Federal Current Tax Expense	53	88	92	97	101	74	504
Federal Deferred Tax Expense	34	(2)	(6)	(11)	(15)	-	-
Total Federal Tax Expense	86	86	86	86	86	74	504
Book/Tax Timing - COR	10	10	10	10	10	(50)	-
Book/Tax Timing - Depreciation	(160)	10	30	50	70	-	-
DTA - COR	2	4	6	8	11	-	-
(DTL) - Depreciation	(34)	(32)	(25)	(15)	-	-	-
Reg Liability - COR	(2)	(4)	(6)	(8)	(11)	-	-

As evidenced by comparing *Figure JMC-2* and *Figure JMC-4*, total tax expense over time remains \$504 and only the timing of the tax expense differs.

In *Figure JMC-4*, the cost of service includes \$86 of annual federal income tax expense in years 1-5 and \$74 for year six – the decrease resulting from the tax deduction for the incurred removal costs. The cost of service includes the deferred tax impact related to the book to tax timing difference on depreciation, which is treated as normalized. However, the cost of service only includes a current tax impact, excluding deferred tax, related to the cost of removal. Because of this, the deferral of the tax benefit to a future year is recorded as a regulatory liability. Flow-through treatment provides the tax benefit or expense up-front as it is incurred on the tax return and the regulatory asset or liability is established to recognize that this

benefit or expense will reverse over time as the book to tax timing difference reverses.

Q42. Please provide your conclusions regarding the tax treatment of removal costs and the impact to ratemaking.

A42. The tax impact of removal costs, or any book to tax timing difference, can be flowed through rates as it originates and flowed through as it reverses. Conversely, the tax impact can be normalized as it originates and normalized as it reverses. Either approach will yield the same tax expense over the life of the timing difference.

Q43. Has the Commission addressed normalization in the ratemaking process?

A43. Yes. On February 8, 1993, the MPSC issued an opinion and order granting general authorization for utilities to practice deferred tax accounting (i.e., normalization). In the case, the ALJ recommended the Commission approve comprehensive deferred tax accounting for utilities because:

(1) it matches the tax effects of revenues and expenses with the book recognition of those revenues and expenses, (2) deferred tax accounting is the generally accepted accounting principle adopted by the Financial Accounting Standards Board and flow-through accounting is not a fully accepted alternative, (3) a general authorization would eliminated the resources spend on individual deferred tax applications, and (4) deferred tax accounting promotes rate stability.⁹

The Commission agreed with the ALJ's conclusion and reasoning and it was ordered that electric and gas utilities regulated by the Commission are granted general authorization to use a normalized method of tax accounting to comply with SFAS 109 as of January 1, 1993¹⁰.

⁹ *Michigan Public Service Commission*, Case No. U-10083. Opinion and Order, page 4

¹⁰ *Id* at p. 13

Q44. Should the COR deduction be accounted for on a normalized basis rather than flow-through prospectively?

A44. Yes. First, the above referenced Commission decisions support use of the normalized method of tax accounting. In addition, this methodology maintains inter-generational equity; that is, customers receive the income tax benefits commensurate with the expenses reflected in the cost of service.

Q45. Have you presented the COR book/tax timing difference as normalized in the cost of service in this proceeding?

A45. Yes. As part of Tax Expense Adjustment 3, as shown on Exhibit IM-50 (JWM-1), and discussed later in my testimony, the DFIT expense was adjusted for the COR deduction book/tax timing difference for the forecasted year.

This aligns the Company's ratemaking such that the taxes are normalized throughout the origination and reversal of the COR timing difference. The AEP System, including I&M, reviewed book and tax timing differences and the ratemaking impacts of those timing differences. As such, part of this review entailed the identification of fixed asset related timing differences between book and tax that support the tax regulatory assets and liabilities on the Company's financial statements.

In this review, it was identified that the ratemaking for COR differed between the origination and reversal of the timing difference. The origination of the timing difference is the reversal of the book depreciation, resulting in a DTA until such time that the removal cost is incurred. The reversal of the timing difference occurs when the removal cost is incurred, reducing the DTA to zero. To date, the ratemaking

normalized the COR timing difference at its origination but also flowed-through the impact at the reversal of the timing difference. With the treatment of normalized at origination and flowed through at reversal, the benefit provided in the cost of service did not naturally allow the reversal of the regulatory asset.

Q46. Please demonstrate the impact of this determination.

A46. Please see *Figure JMC-5*, which illustrates the previous example with the COR deduction being treated as flow-through.

Figure JMC-5 COR: I&M Historical Practice

	<u>Year 1</u>	<u>Year 2</u>	<u>Year 3</u>	<u>Year 4</u>	<u>Year 5</u>	<u>Year 5</u>	<u>Total</u>
Revenues	1,000	1,000	1,000	1,000	1,000	900	5,900
Operating Expenses	(500)	(500)	(500)	(500)	(500)	(500)	(3,000)
Book Depreciation	(90)	(90)	(90)	(90)	(90)	-	(450)
Book Depreciation - COR	(10)	(10)	(10)	(10)	(10)	-	(50)
Pre-Tax Book Income	400	400	400	400	400	400	2,400
Tax Depreciation	(250)	(80)	(60)	(40)	(20)	-	(450)
COR Deduction	-	-	-	-	-	(50)	(50)
Federal Taxable Income	250	420	440	460	480	350	2,400
Federal Current Tax Expense	53	88	92	97	101	74	504
Federal Deferred Tax Expense	32	(4)	(8)	(13)	(17)	-	(10)
Total Federal Tax Expense	84	84	84	84	84	74	494
Book/Tax Timing - COR	10	10	10	10	10	(50)	-
Book/Tax Timing - Depreciation	(160)	10	30	50	70	-	-
DTA - COR	2	4	6	8	10	-	-
(DTL) - Depreciation	(34)	(32)	(25)	(15)	-	-	-
Reg Asset - COR	-	-	-	-	-	10	-

In the example above, the cost of service includes \$84 in years 1-5 and, similar to *Figure JMC-3*, provides customers the tax benefit of the COR book depreciation. In year six, however, tax expense in the cost of service reflects the flow-

through impact of the COR deduction, again providing customers the tax benefit of \$10. This results in a \$10 regulatory asset.

Q47. Does a tax regulatory asset related to the additional benefit of removal costs exist on the Company's financial statements?

A47. Yes. The Company has a tax regulatory asset related to flow-through of COR reversal of \$92,620,800 as of the financial statement period ended December 31, 2022. The Total Company balance is forecasted to be \$104,200,178 as of December 31, 2023, which reflects the fact that the rates associated with the current case will not be effective until 2024. If the Company's proposal to normalize the origination and reversal of the COR timing difference is reflected in I&M's cost of service approved in this case, the tax regulatory asset balance will no longer increase.

Q48. How did the Company identify and substantiate the regulatory asset value related to COR?

A48. The tax regulatory asset per the financial statement was grouped by timing difference in the PowerTax software system so that the reversal of the timing differences can be tracked separately. The Company has three timing differences which have been treated as flow-through which would make up the tax regulatory asset: (1) AFUDC Equity, (2) Method/Life on Pre-1981 property, and (3) COR. The first two were known based on the past timing tax return deductions and book depreciation taken on these items. These items will reverse over time based on future book depreciation. The remaining balance is attributable to COR. However, due to the treatment of the normalization of the book depreciation portion of the timing difference, the regulatory asset for COR is not reasonably designed to allow the reversal of the regulatory

1 asset. The regulatory asset represents the future reversal of the tax benefit passed
2 to customers and that will reverse over time.

3 **Q49. Is this regulatory asset included as a component of ADFIT or as an increase to**
4 **rate base?**

5 A49. No. Consistent with the treatment of other flow-through timing differences, state taxes
6 for example, the regulatory asset is not a component of rate base and the offsetting
7 deferred tax liability (DTL) is not included in ADFIT as a component of WACC. Only
8 the tax expense impact associated with the COR regulatory asset is included in I&M's
9 proposed cost of service, which is discussed in Q46 above.

10 **Q50. Did the analysis of ADFIT identify any other concerns?**

11 A50. Yes. In addition to the review surrounding regulatory assets, all deferred tax timing
12 differences were analyzed. Known as a tax basis balance sheet study (TBBS), this
13 review was conducted as a standardization measure to align all AEP subsidiaries to
14 one approach for substantiating ADFIT. A TBBS verifies the basis of all book vs. tax
15 timing differences to substantiate deferred tax assets and liabilities and is a standard
16 procedure completed annually with the filing of the federal tax return. Upon review, it
17 was determined that adjustments were required to deferred income tax liabilities. In
18 the case of I&M, a decrease was required to properly adjust the ADFIT.

19 **Q51. How was the decrease to ADFIT recorded on the Company's financial**
20 **statements?**

21 A51. For the reduction to ADFIT, a corresponding regulatory liability of \$13,870,107 was
22 recorded to account for the deferred tax expense that is to be reflected in cost of
23 service.

Q52. Is this regulatory liability included in ADFIT as a component of WACC or as a reduction to rate base?

A52. Yes. The TBBS regulatory liability, account 2456001, is included in the working capital component of rate base. Since the identified balance can be amortized according to each retail commission's determination, the remaining balance for one jurisdiction can differ from another. Specifically, the amortization period can be very different, as well as when the balance begins amortizing. Due to these differences, the most appropriate way to ensure base rates accurately reflect the remaining ADFIT benefit is by reducing rate base by the Michigan specific unamortized balance. The Michigan specific unamortized balance is calculated by applying the gross plant allocator, calculated by Company witness Morgan.

Q53. How does the Company propose to treat the COR regulatory asset and TBBS regulatory liability?

A53. The Company proposes to amortize these balances over a twenty-year period through the cost of service. The calculation of the annual amortization is included in Tax Expense Adjustment 3, as shown on Exhibit IM-50 (JWM-1), and discussed later in my testimony.

Q54. Why is twenty years a reasonable period?

A54. The twenty-year period represents a period of time that reasonably reflects the reversal of the book/tax timing differences related to fixed assets. Specifically, the COR timing difference is spread over the life of assets. Additionally, the biggest ADFIT item for I&M is the book/tax timing difference related to depreciation which is

also spread over the life of assets. The use of the twenty-year period reasonably amortizes these items over a timeframe similar to which they were generated.

Q55. What are the consequences of not reversing the regulatory asset related to removal costs?

A55. As mentioned previously, the premise of flow-through treatment is that as a tax benefit or expense is incurred it is passed through the tax expense included in rates and this proposal provides a reasonable reversal within the ratemaking process for COR reversal that has been treated as flow-through. This proposal also provides for equitable ratemaking going forward by updating the treatment of COR reversal to normalized.

This ensures that the Company will avoid a significant mismatch with intergenerational equity. In addition, it adjusts the tax treatment to assure the ratemaking reversal occurs to avoid penalizing the Company.

If this proposal is not accepted, the Company will have to write-off the regulatory asset because the ratemaking is not reasonably designed to allow this asset to be recovered. This imposes a penalty on the Company for flowing this benefit to customers.

INFLATION REDUCTION ACT OF 2022 (IRA)

Q56. What is the Inflation Reduction Act of 2022?

A56. H.R. 5376, approved by Congress and signed into law on August 16, 2022, is referred to as the Inflation Reduction Act of 2022 or IRA. The stated purpose of the law was to curb inflation by reducing the deficit through the creation of significant changes relating to tax, climate change, energy, and health care.

Q57. What are the most notable provisions of the IRA having an impact on the Company?

A57. The most notable provisions of the IRA include:

- *Corporate Alternative Minimum Tax (CAMT)* – for applicable corporations with adjusted financial statement income (AFSI) above \$1 billion, the IRA imposes a tax equal to the excess of 15% of the corporation’s AFSI (tentative minimum tax) for the taxable year over its regular income tax liability.
- *Enhancements to Current Tax Credits* – the current clean energy tax credit framework has been extended and prospectively allows for the transferability of qualified credits. The benefit to customers of future renewable tax credits is addressed in Cause No. 45868 renewable filing.
- *Creation of the Nuclear Production Tax Credit (PTC)* – introduces a new tax credit applicable to electricity produced from existing nuclear facilities and sold to unrelated parties for tax years 2024 through 2032. This new tax credit is eligible for transferability.

Q58. Please describe the CAMT.

A58. The CAMT is a provision of the IRA which imposes a 15% minimum tax on the AFSI of applicable corporations as defined in IRC §59(k)¹¹. The CAMT is effective for tax years beginning after 2022. The amount of CAMT paid is the excess of the computed tentative minimum tax for the taxable year over the regular income tax liability. For example, if an applicable corporation had a tentative minimum tax of \$110 and a

¹¹ IRC § 55(a)(2)

regular income tax of \$100, the applicable corporation will pay \$10 of CAMT and \$100 of regular income tax (\$10 CAMT + \$100 regular income tax = \$110 tentative minimum tax). The IRA was passed in a budget reconciliation process, which means that incremental tax benefits need to be funded through incremental tax payments or receipts. The CAMT represents the mechanism within the IRA.

Q59. What is AFSI?

A59. AFSI is the basis on which the CAMT is calculated and is equal to an entity's net income or loss reported on its applicable financial statements with adjustments for various provisions provided in the IRA. AFSI includes an adjustment to disregard any federal income taxes which are taken into account on the taxpayer's applicable financial statement. AFSI also includes adjustments to allow tax depreciation deductions and disregard associated financial statement depreciation taken on such property. To the extent items included in financial statement depreciation relate to amounts that do not result in tax depreciation (i.e., tax repairs), no adjustment is required to disregard that financial statement depreciation.

Q60. Please provide an example of an AFSI calculation.

A60. Please see *Figure JMC-6*, for an example of an AFSI calculation.

Figure JMC-6 AFSI Calculation

Pre-Tax Book Income	5,000
Federal Income Tax	<u>(1,050)</u>
Financial Statement Income	3,950
 Add: Federal Income Tax	 1,050
Add: Book Depreciation	500
Deduct: Tax Depreciation	<u>(3,000)</u>
Adjustments	(1,450)
 Adjusted Financial Statement Income	 <u>2,500</u>

In this example, the financial statement income is \$3,950 after federal income tax of \$1,050. Adjustments to the financial statement income include an addition for federal income tax of \$1,050, an addition for book depreciation of \$500, and a deduction for tax depreciation of \$3,000 for a total adjustment to the financial statement income of (\$1,450). The AFSI is then \$2,500 (\$3,950 financial statement income - \$1,450 of adjustments = \$2,500 AFSI).

Q61. How does the calculation of AFSI compare to the calculation of taxable income the regular income tax?

A61. The calculation of AFSI is limited in the adjustments for differences between the recognition of income and expense for book financial statement and tax purposes. The calculation of taxable income for the regular income tax incorporates all of these differences. Please see *Figure JMC-7*, for a comparison of the calculation of AFSI and taxable income for the regular income tax.

Figure JMC-7 AFSI and Taxable Income Calculation

	AFSI	Taxable Income
Pre-Tax Book Income	5,000	5,000
Federal Income Tax	(1,050)	(1,050)
Financial Statement Income	3,950	3,950
Add: Federal Income Tax	1,050	1,050
Add: Book Depreciation	500	500
Deduct: Tax Depreciation	(3,000)	(3,000)
Add: Other Misc. Book/Tax Differences	0	200
Deduct: Other Misc. Book/Tax Differences	0	(1,200)
Adjustments	(1,450)	(2,450)
AFSI / Taxable Income	2,500	1,500

In this example comparison, the taxable income for the regular income tax includes an addition of \$200 and a deduction of \$1,200 for two differences in book and tax recognition of revenue and expenses that were not included in the calculation of AFSI. Common examples of these adjustments are the timing difference associated with the book accrual of expenses which are not deductible for tax purposes until paid or the book deferral of expenses that are recognized in the future in conjunction with rate recovery but are deductible for tax purposes the year in which the expenses are incurred.

Q62. What tax rates are applied to the AFSI and Taxable Income?

A62. The calculation of the CAMT applies a 15% tax rate to AFSI while the calculation of regular income tax applies a 21% rate to taxable income.

Q63. What is the tentative minimum tax and how is it calculated?

A63. The tentative minimum tax is the CAMT due before considering any amount of tax due for the regular income tax. The tentative minimum tax is equal to 15% of AFSI.

Q64. How is the CAMT calculated?

A64. CAMT is the excess, if any, of the tentative minimum tax over the regular 21% income tax. If the tentative minimum tax does not exceed the regular income tax, no CAMT is due.

Please see *Figure JMC-8* for a calculation continued from *Figure JMC-6*. In this example, the tentative minimum tax is \$375 ($\$2,500 \text{ AFSI} \times 15\% = \$375$) and the regular income tax is \$315 ($\$1,500 \text{ taxable income} \times 21\% = \$315$). Because the tentative minimum tax exceeds the regular income tax, the taxpayer in this example is liable for a CAMT of \$60 in addition to the regular income tax of \$315 ($\$375 \text{ tentative minimum tax} - \$315 \text{ regular tax} = \$60 \text{ CAMT}$).

Figure JMC-8 CAMT Calculation

Adjusted Financial Statement Income	2,500
CAMT Rate	15%
Tentative Minimum Tax	375
Taxable Income	1,500
Income Tax Rate	21%
Regular Income Tax	315
Corporate Alternative Minimum Tax	60

In this example, the taxpayer would have total taxes payable of \$365, an increase of \$60 over the taxes that would have been payable absent the CAMT imposed with the enactment of the IRA.

Q65. Can the CAMT paid in a prior period tax year be used as a credit against a future income tax liability?

A65. Yes. A taxpayer is eligible to claim a tax credit against the regular income tax for CAMT paid in a prior tax year to the extent that the regular income tax liability exceeds the tentative minimum tax in that tax year (“Minimum Tax Credit”). The carryforward of the Minimum Tax Credit is indefinite and can be used in any subsequent tax year.

If the taxpayer in *Figure JMC-8* has AFSI of \$2,500 and taxable income of \$2,000 in the year subsequent to that example (“Year 2”) it would result in a tentative minimum tax of \$375 ($\$2,500 \text{ AFSI} \times 15 \text{ percent} = \$375$) and regular income tax of \$420 ($\$2,000 \text{ taxable income} \times 21 \text{ percent} = \$420$). Because the tentative minimum tax does not exceed the regular income tax, the taxpayer does not have a CAMT payable in Year 2.

In this example, the taxpayer had paid \$60 of CAMT in Year 1 and is eligible to claim a Minimum Tax Credit against the regular income tax liability in a future tax year to the extent that the regular income tax liability exceeds the tentative minimum tax in that tax year. In Year 2, the regular income tax exceeds the tentative minimum tax by \$45 ($\$420 \text{ regular income tax} \text{ less } \$375 \text{ tentative minimum tax} = \$45$). In Year 2, the taxpayer would therefore have taxes payable of \$375 ($\$420 \text{ regular income}$

tax + \$0 CAMT - \$45 Minimum Tax Credit = \$375 taxes payable). Please see *Figure JMC-9* which illustrates the above example.

Figure JMC-9 Minimum Tax Credit

	Year 1	Year 2
Adjusted Financial Statement Income	2,500	2,500
CAMT Rate	15%	15%
Tentative Minimum Tax	375	375
Taxable Income	1,500	2,000
Income Tax Rate	21%	21%
Regular Income Tax	315	420
Corporate Alternative Minimum Tax	60	0
Total Tax Due before CAMT Credit	375	420
Less: CAMT Credit Utilized	0	45
Total Tax Due	375	375

In this example, the taxpayer would have \$15 of Minimum Tax Credit available to claim against the regular income tax in Year 3 and beyond (\$60 CAMT paid in Year 1 less \$45 Minimum Tax Credit claimed in Year 2 = \$15 CAMT Credit remaining).

Q66. Is I&M an applicable corporation subject to the CAMT?

A66. Yes. Based on the definition of Applicable Corporation in IRC §59¹² and the guidance issued by the IRS in Notice 2023-7¹³ it has been determined that I&M is an applicable corporation subject to the CAMT.

¹² §59(k)(1)

¹³ Notice 2023-7 2.01(4)(b)(ii)

Q67. How has the CAMT been calculated for this case?

A67. The CAMT for I&M was calculated for the 2024 Test Year in the manner described earlier in my testimony on an MI jurisdictional level using Exhibit A-13, Schedule C-8 and Exhibit A-16, Schedule F-1 as supported by Company witness Morgan, including the relevant book and tax depreciation and all other pertinent adjustments to arrive at the Company's AFSI and taxable income. The calculation resulted in higher taxable income than the tentative minimum tax, resulting on \$0 CAMT. The calculation is shown IM-28 (JMC-3).

Q68. Does the Company anticipate CAMT in the future?

A68. Yes. Once subject to CAMT, an applicable corporation will continue to be subject to CAMT. The calculation of the tentative minimum tax will vary year over year based on the operations of the Company and could generate CAMT. In addition, the mechanics of the calculation are not finalized and further guidance from the IRS is expected.

Q69. How does the Company propose to treat the CAMT?

A69. The Company proposes to net the CAMT impact in the proposed Tax Rider with potential Nuclear PTCs from Cook Nuclear Plant (discussed later in this testimony). As mentioned previously, CAMT was the tool that Congress used to be able to fund the tax credits in the IRA and the benefit of the PTCs comes with the cost of the CAMT. As the Company will continue be subject to CAMT going forward, the alternative minimum tax will need to be calculated as compared to the standard tax and the Company could be subject to this additional tax in any given year. Given that guidance remains to be issued and the annual impact is largely outside the

Company's control, could be significant in amount and volatile or variable in nature, including the CAMT with nuclear PTCs is both reasonable and necessary, capturing the full impact of the IRA.

Q70. Could you provide more details regarding the Nuclear PTC?

A70. The IRA enacted a Nuclear PTC under IRC §45U that is available with respect to existing nuclear plants for electricity produced and sold for taxable years beginning after December 31, 2023 and before December 31, 2032, provided the nuclear plant is not an "advanced nuclear power facility" under IRC §45J and is placed in service before the IRA enactment. The nuclear PTC is an annual base credit of \$3/MWh with a bonus up to \$15/MWh when certain prevailing wage requirements are met. However, the credit amount is also subject to a reduction or "phase-out" as a facility's revenue increases above a \$25/MWh.

Q71. Does Cook Nuclear Plant qualify for the PTC?

A71. Yes. The Nuclear PTC is available to nuclear plants that do not qualify as an "advanced nuclear power facility" under IRC §45J for facilities placed in service after August 8, 2005 and are placed in service before the IRA enactment. Because the Cook Nuclear Plant was placed in service prior to August 8, 2005 and is not an advanced nuclear power facility, it qualifies for the Nuclear PTC under IRC §45U.

Q72. What are the prevailing wage requirements?

A72. The prevailing wage requirement ensures that any laborers and mechanics employed by the taxpayer, or any contractor or subcontractor, performing any alteration or repair of the qualifying nuclear facility shall be paid wages at rates not less than the prevailing rates established by the Secretary of Labor.

Q73. Please explain the Nuclear PTC reduction calculation.

A73. For purposes of the Nuclear PTC calculation, the term 'reduction amount' refers to a reduction of the \$3/MWh base credit based on the determined revenue from the facility. More specifically, the reduction amount equals 16% of the excess of the facility's determined revenue less the product of \$25 multiplied by the facility's MWh of electricity generated and sold. Formulaically, once a facility's revenue per MWh exceeds \$43.75, the credit is reduced to zero. The credit cannot be reduced below zero. In summary, the PTC credit begins to phase out as revenue per MWh begins to exceed \$25. The determination of a facility's revenue has yet to be defined and the Company anticipates the IRS will be issuing guidance on this topic.

Q74. Is the Company able to quantify the future Nuclear PTCs?

A74. I&M has estimated the annual value of the nuclear PTCs could range from \$0 to upwards of \$125 million in any given year. The value of future nuclear PTCs will be dependent upon three main variables. First, further guidance is necessary from the IRS on the definition revenue. There have been multiple proposals to the IRS on how to define revenue which will impact the phase-out, or reduction, of the credit, potentially resulting in \$0 PTC in any given year.

Second, the prevailing wage requirements provide for a bonus to the per MWh credit of up to \$15/MWh. The cost of compliance with this requirement must be considered in relationship to the potential benefits.

Lastly, the credit is dependent on the MWhs generated, which can fluctuate greatly year over year. This fluctuation will provide for a different level of PTCs per

1 year. In addition, this fluctuation may change the revenue per MWh, which would
2 change the potential phase-out.

3 **Q75. What is the Company's proposal regarding the nuclear PTCs?**

4 A75. Due to the fact that the nuclear PTCs are largely outside the control of the Company,
5 are potentially significant in amount, and volatile or variable in nature, it is necessary
6 that the proposed Tax Rider be utilized to reflect the benefit of the PTCs to customers.
7 Through the rider, the Company proposes to defer the pass back of the PTC benefit
8 until 2025 once monetized either by utilization on the federal tax return or via a
9 transfer net of transfer costs (discussed in Section VI of my testimony). Company
10 witness Seger-Lawson discusses the utilization of the proposed Tax Rider to pass
11 the PTCs to customers. Company witness Ross provides further guidance regarding
12 the proposed Tax Rider over-/under- recovery accounting.

13 **Q76. Why is it reasonable and necessary to defer the pass back to 2025 and only**
14 **when they have been monetized?**

15 A76. Deferring to 2025 gives the Company the ability to accurately quantify the credits
16 after final regulations are issued by the IRS. Waiting to pass the credit to customers
17 once monetized ensures that the amount of PTCs reflected in I&M's cost of service
18 is fixed, known and measurable. As explained above, there are multiple factors that
19 can significantly impact the amount and value of PTC's Cook earns from year to year.
20 It also ensures that I&M does not reflect PTCs in customer rates before it has
21 received the cash benefit, which if done would generate a deferred tax asset and
22 would be necessary to include in rate base and earn a pre-tax weighted cost of capital
23 return.

CREDIT LIMITATIONS AND DEFERRAL OF CASH TAX BENEFITS

Q77. Does AEP have the ability to sell the PTC generated by Cook Nuclear rather than carry it forward or back?

A77. Yes. The IRA enacted IRC §6418 to provide that a taxpayer may transfer certain income tax credits to an unrelated taxpayer. This provision applies to tax years beginning after December 31, 2022. The PTC is among the list of tax credits enumerated in the IRC as being eligible for transfer.¹⁴ The legislation specifies that any amount paid by a taxpayer as consideration for a credit:

- Shall be required to be paid in cash;
- Shall not be includible in gross income of the transferring taxpayer; and
- Shall not be deductible by the transferee taxpayer.¹⁵

Q78. What impact would the transfer of tax credits have on the tax credit carryforward DTA?

A78. To the extent that a tax credit is transferred to a third party, as provided for under §6418, it would no longer be available to carry forward to offset a future tax liability. Therefore, a tax credit carryforward DTA would not be established for the transferred credit.

Q79. Are there limitations on the Company’s ability to use nuclear PTCs to offset its annual income tax liability?

A79. Yes. IRC Section 38(c) generally limits a taxpayer’s use of General Business Credits (of which PTCs are a component) to 75 percent of the taxpayer’s regular tax liability

¹⁴ 26 U.S.C. § 6418(f)(1)(A).

¹⁵ 26 U.S.C. § 6418(b).

before applying any credits. Any General Business Credits (GBC) unable to be utilized in offsetting regular tax in a given year may be carried forward and used to reduce regular tax liabilities in the succeeding 20 years or carried back to reduce regular tax liabilities in the preceding year.

Q80. How are tax credit carry forwards accounted for and what are the implications of the associated tax deferral?

A80. As previously noted, GBCs that cannot be utilized in a given tax year due to Section 38(c) limitations may be carried forward and used, subject to limitation, to offset regular tax liability in the succeeding 20 years or carried back to reduce regular tax liabilities in the preceding year. Any credits not utilized after the 20-year carry forward period expire.

GBCs that are carried forward to be used to offset the tax liability in a future tax year are recognized as a DTA on the balance sheet to the extent the taxpayer anticipates the ability to utilize the credits prior to their expiration.

Q81. Does I&M file a federal income tax return as part of a consolidated group?

A81. Yes. I&M is included in the consolidated income tax return of American Electric Power and its subsidiaries (Consolidated Return Group).

Q82. Can you describe the process by which PTCs will be monetized?

A82. Yes. The monetization of the PTCs generated by the Cook Nuclear will occur in three steps. In Step 1, the PTCs will be utilized to offset I&M's tax liability. This reduces the necessary cash payment up to its parent company for the liability. While it is anticipated to be an uncommon scenario, the utilization of credits in Step 1 could be limited in a scenario in which the credit utilization limitations under Section 38(c) for

the Consolidated Return Group is less than the sum of the Step 1 utilization of credits for all companies within the group.

In Step 2, the PTCs would be used to offset the tax liability of the Consolidated Return Group. The ratio of the remaining PTCs after Step 1 to the total tax credits available for the Consolidated Return Group would be used to determine the extent of the PTCs generated by Cook Nuclear would be used to offset the tax liability in this step. For example, if after Step 1 I&M had \$10 of PTCs available to offset the Consolidated Return Group's tax liability and the other companies in the Consolidated Return Group had \$90 of PTCs available, 10% of the credits used to offset the tax liability of the Consolidated Return Group would be from Cook Nuclear (\$10 I&M PTC divided by \$100 total tax credit = 10%). To the extent that I&M's credits are used to offset the tax liability of the Consolidated Return Group, I&M would receive the full cash value of the PTC.

In Step 3, a determination would need to be made whether any remaining PTCs should be carried forward to offset a future tax liability or transferred to a third party.

Q83. Do you expect that PTC generated by Cook Nuclear will be transferred?

A83. The PTC will be transferred to a third-party if it is reasonable and necessary to do so based on the facts and circumstances at the time. Based on the expected length of time between when PTCs are generated and the ability to utilize the PTCs to offset an income tax liability, it is anticipated that it may be beneficial to transfer all, or a portion, of the credits generated by Cook Nuclear.

Q84. What facts and circumstances will weigh in any decision to transfer a tax credit or use it to offset a tax liability?

A84. There are a couple factors that will weigh into any decision as to whether it is prudent and appropriate to transfer a PTC. The first factor is the ability to utilize the PTC to offset an income tax liability. If the tax credit can be used to offset an income tax liability, I&M would retain the credit and receive a dollar-for-dollar benefit of the credit generated.

The second factor that will weigh into any decision to transfer a PTC is the net proceeds that could be obtained from a transfer of the tax credit. If the PTC is not able to be utilized in the same period that it is generated, I&M would evaluate the net proceeds a transfer of PTC would generate compared to the present value of the future cash tax benefit from the PTC if it were not transferred.

Q85. What impact would a transfer of tax credits have on customers?

A85. The impact of a transfer of the PTCs generated by Cook Nuclear would be twofold. First, a transfer of PTCs would mean that the PTC has been monetized and the PTC benefit would be reflected in I&M's cost to serve customers.

The second impact to customers would be the discount associated with the transfer of the PTC. The discount is the difference between the value of the PTC and the net proceeds received from the transfer of the PTC. While it is not known at this time what the market price for the PTC will be or the costs to engage in such a transaction, it is certain that the net proceeds obtained from a transfer will be less than the full value of the PTC itself. To the extent that the PTCs generated by Cook

Nuclear are transferred, the net benefit received as a result of that transfer will be included as a reduction to the tax benefit reflected in the proposed Tax Rider.

UNPROTECTED EXCESS ADFIT

Q86. Are there additional tax items you are proposing to add to the tax rider?

A86. Yes, I am proposing to add the remaining unprotected excess amortization to the tax rider.

Q87. Why is it prudent to remove unprotected excess amortization from base rates and into a rider?

A87. In Case U-20359, the amortization period was updated from 10 years to 5 years. With this update, unprotected excess ADFIT will be fully amortized in 2025. Utilization of a rider will allow I&M to align the amount of unprotected excess ADFIT credited to customers with the remaining unamortized balance.

Q88. What is the remaining balance of unprotected excess as of the projected test period?

A88. As shown in Exhibit IM-2 (DSL-1), the remaining balance as of December 31, 2024 will be \$1,573,751.

Q89. Please summarize the tax components to be included in the proposed Tax Rider.

A89. The proposed Tax Rider will include the following components:

1. Nuclear PTCs, net of transfer costs when applicable
2. CAMT incurred and CAMT credits utilized
3. Unprotected excess amortization until balance is zero in 2025

WEIGHTED AVERAGE COST OF CAPITAL

Q90. Did you provide the balances of ADFIT and ADITC used by Company Witness Luedtke in Exhibit A-14 Schedule D-1 and Exhibit A-4 Schedule D-1?

A90. Yes. *Figure JMC-10* identifies the ADFIT and ADITC balances I calculated and provided to Company Witness Luedtke.

Figure JMC-10 ADFIT and ADITC

Year	2022 12-mo Average	2024 13-mo Average
ADFIT	\$1,082,396,165	\$1,096,208,288
ADITC	\$20,188,705	\$11,510,491

Q91. What adjustments have been made to ADFIT, as recorded, to arrive at the balances shown Exhibit A-14 Schedule D-1?

A91. Adjustments made to the ADFIT balances include the following:

1. Adjustments for ratemaking purposes, such as removing ADFIT that does not relate to the MI jurisdiction or that are not related to the provision of electric service;
2. Adjustments related to reducing ADFIT for the NOLC balance;
3. Adjustment to remove the TBBS DTL;
4. Adjustment to remove of the PTC DTA related to Cook Nuclear;
5. Adjustment to increase ADFIT for the COR DTL to reflect the proposed update to account for the COR deduction on a normalized basis;
6. Adjustment to remove the DTL related to the balance of unprotected excess ADFIT consistent with Case No. U-20359.

Please see IM-27 (JMC-2) for summary of the above adjustments and a reconciliation of ADFIT from the balance sheet in Exhibit IM-14 (ZBW-3) to the ratemaking ADFIT in Exhibit A-14 Schedule D-1.

EXHIBITS AND SCHEDULES

Q92. Please describe Exhibit A-3, Schedule C2?

A92. Exhibit A-3, Schedule C2 shows the calculation of the GRCF necessary to determine the incremental amount of gross revenue required to generate an additional dollar of operating income after payment of all public utility assessment fees and federal and state income taxes.

Q93. Please describe Exhibits A-3/A-13, Schedules C7 through C10.

A93. Exhibits A-3/A-13, Schedules C7 through C10 present amounts for the historical period ended December 31, 2022 and the 2024 forecasted test year, respectively on a Total Company basis and on a Michigan Retail jurisdictional basis. Company witness Morgan is responsible for the jurisdictional allocators shown on those Schedules. Specifically:

- Exhibits A-3 /A-13, Schedule C7 reflects taxes other than income tax expense.
- Exhibits A-3/A-13, Schedule C8 indicates the total current and deferred federal income tax expense.
- Exhibits A-3/A-13, Schedule C9 reflects the total state current and deferred income tax expense.
- Exhibit's a-3/A-13, Schedule C10 indicates local or other income tax expense.

Q94. Please describe taxes other than income taxes.

A94. Exhibits A-3/A-13, Schedule C7 details the taxes other than income taxes for the 2022 historical period and the 2024 forecasted test year, respectively, by type of tax.

Q95. Please describe federal and state income tax expense.

A95. Exhibits A-3/A-13, Schedules C8-C10 indicate income tax expense that reflects 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. The overall Total Company and Michigan jurisdictional effective federal income tax rate before rate relief for the 2022 historical period is 0.81% and -6.43%, respectively, and the overall Total Company and Michigan jurisdictional effective federal income tax rate before rate relief for the 2024 forecasted test year is 17.79% and 16.52%, respectively. The effective federal income tax rate is calculated by dividing total federal income tax expense by pre-tax electric operating income including interest expense.

Q96. Please describe the calculation of the effective state income tax rate.

A96. The composite state income tax rates for the 2022 historical period and the 2024 forecasted test year, respectively, were developed by using the appropriate state income tax rates and apportionment factors. The 2024 composite state income tax rate set forth in Exhibit A-13, Schedule C2 includes the Indiana state income tax rate of 4.9% and the Michigan state income tax rate of 6%. This composite rate is used to compute current state income tax expense and is used in the development of the GRCF.

1 **Q97. Please explain the methodology used to develop federal and state income tax**
2 **expense for the 2024 forecasted test year.**

3 A97. The computation of the Company's federal and state income tax expense reflected
4 in Exhibit A-13 Schedules C8-C10 is stated on an electric utility, 2024 forecasted test
5 year. Consistent with the Commission Order dated October 14, 2010, which
6 approved a Settlement Agreement between all parties in I&M's Case No. U-16180,
7 and affirmed in I&M's Case No. U-16801, the Company's federal and state income
8 tax expense are calculated using the "stand-alone" return methodology. The
9 Company's income tax expense is based to a large part on Company witness
10 Morgan's components of pre-tax book income and expense and the forecast of other
11 various Schedule M items that would impact the computation of current and deferred
12 income tax expense for the 2024 forecasted test year.

13 The calculation of forecasted current federal income tax expense is based
14 primarily upon the pre-tax book income and Schedule M's as mentioned above.
15 Exhibit A-13 Schedule C8 summarizes all deferred federal income taxes included in
16 the cost-of-service. All deferred federal income taxes were computed based upon
17 the related Schedule M items and other adjustments as previously described.
18 Adjustments have been made, Adjustment Nos. Tax 1-3, to federal and state income
19 taxes for the various items discussed earlier in testimony.

20 **Q98. Please describe Tax Expense Adjustment No. 1.**

21 A98. Tax Expense Adjustment No. 1, as shown on Exhibit IM-50 (JWM-1), increases Total
22 Company state income tax expense by \$5,983,378 to reflect the adjustments to state
23 taxable income resulting from the ratemaking adjustments supported by various

1 Company witnesses that affect pre-tax state book income and the related book vs.
2 tax timing differences.

3 This adjustment includes all state income tax expense where the Company
4 has a business presence. Consistent with past rate treatment by this Commission,
5 no deferred state income tax expense has been recorded in utility cost of service,
6 consistent with the flow-through methodology.

7 **Q99. Please describe Tax Expense Adjustment No. 2.**

8 A99. Tax Expense Adjustment No. 2, as shown on Exhibit IM-50 (JWM-1), increases Total
9 Company CFIT expense by \$124,571,973 to reflect the current federal income tax
10 effect at 21% of the federal taxable income related to the ratemaking adjustments
11 supported by various Company witnesses, which affect pre-tax book income and the
12 related book vs. tax timing differences.

13 In addition, CFIT has been adjusted to remove the Total Company \$115
14 million PTC credit (\$125 million generated less \$10 million carryforward reclassified to
15 deferred tax expense) and the \$14.6 million CAMT to be included in the proposed
16 Tax Rider. As discussed earlier in this testimony, due to uncertainty and further
17 guidance to be issued by the IRS, the Company proposes to remove these items
18 from base rates and utilize the proposed Tax Rider to ensure future guidance is
19 reflected in the ratemaking process and rates reflect the actual calculations once
20 available.

21 **Q100. Please describe Tax Expense Adjustment No. 3.**

22 A100. Tax Expense Adjustment No. 3, as shown on Exhibit IM-50 (JWM-1), increases Total
23 Company DFIT by \$24,590,919. This adjustment is broken down as follows:

- 1 1. Deferred tax adjustments related to the ratemaking adjustments supported by
2 various Company witnesses, which affect the related book vs. tax timing
3 differences.
- 4 2. Tax adjustments necessary to reflect the ITC amortization of pre-2020
5 generated credits and protected excess amortization based on most recently
6 available calculations.
- 7 3. Reflect Total Company excess ADFIT amortization including excess ADFIT
8 related to the stand-alone NOLC.
- 9 4. Inclusion of the proposed amortization of the TBBS regulatory liability.
- 10 5. Inclusion of the proposed amortization of the COR regulatory asset.
- 11 6. Remove the deferral of \$10M nuclear PTC credit.
- 12 7. Include COR deferred tax offset to CFIT to apply a normalized method of
13 accounting.

14 **Q101. Does this conclude your pre-filed direct testimony?**

15 A101. Yes.