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INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

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

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

PUBLIC'S EXHIBIT NO. 1

TESTIMONY OF OUCC WITNESS MICHAEL D. ECKERT

OCTOBER 12, 2021

Respectfully submitted,

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TESTIMONY OF OUCC WITNESS MICHAEL D. ECKERT
CAUSE NO. 45576
INDIANA MICHIGAN POWER COMPANY

I. INTRODUCTION

Q: Please state your name, employer, current position, and business address.

A: My name is Michael D. Eckert. I am employed by the Indiana Office of Utility Consumer Counselor ("OUCC") as an Assistant Director of the Electric Division. My business address is 115 W. Washington St., Suite 1500 South Tower, Indianapolis, Indiana 46204. For a summary of my educational and professional experience and my preparations for this case, please see Appendix A attached to my testimony.

Q: What is the purpose of your testimony?

A: I introduce and provide an overview of the OUCC's witnesses and their testimony. I describe the OUCC's revenue requirement analysis and Indiana Michigan Power Company's ("I&M" or "Petitioner") requested relief. More specifically, I address the OUCC's position on I&M's Life Cycle Management ("LCM") and Fuel Adjustment Clause ("FAC") Riders. I explain and support the OUCC's adjustment to I&M's proposed rate case expense and nuclear decommissioning expense. In addition, I support the OUCC's position regarding vegetation management and the Cook Coal Terminal and River Transportation (Barge) contracts and rates.

Q: To the extent you do not address a specific item or adjustment, should that be construed to mean you agree with Petitioner's proposal?

A: No. Excluding any specific adjustments or amounts I&M proposes does not indicate my approval of those adjustments or amounts. Rather, the scope of my testimony is limited to the specific items addressed herein.

II. OUCC WITNESSES

Q: Who are the OUCC's witnesses in this Cause?

A: The following OUCC witnesses provide testimony in this Cause:[1]

Mr. Mark Garrett testifies regarding revenue requirements and sponsors the OUCC's overall I&M revenue requirements recommendation. He recommends the Indiana Utility Regulatory Commission ("Commission") deny I&M's capital structure request to reduce the balance of accumulated deferred income tax by $160 million for a Net Operating Loss Carryforward ("NOLC") that was calculated on a stand-alone basis. Mr. Garrett recommends the Commission deny I&M's request to include prepaid pension asset in rate base. In addition, Mr. Garrett adjusts 1) short-term and long-term incentive compensation expense, 2) supplemental employee retirement plan expense, 3) employee benefits and benefits expense, 4) payroll expense, 5) payroll expense, and 6) factoring expense. In developing the OUCC's recommended revenue requirements, Mr. Garrett reflects the impact of other OUCC witnesses' recommendations in his revenue requirements calculations. (Public's Exhibit No. 2)

Mr. David Garrett testifies regarding depreciation expense and return on equity. Mr. Garrett explains the key factors driving his depreciation expense adjustment are: 1) removing contingency costs, 2) removing escalation factor, 3) proposing longer service lives for mass property accounts, and 4) rejecting I&M's accelerated depreciation proposal for Account 370 – Meters in favor of a standard depreciation rate estimate and calculations consistent with the other mass property accounts. Mr. Garrett also analyzes I&M's requested 10.0% return on equity[2] and recommends the Commission adopt the OUCC's proposed 9.0% return on equity. (Public's Exhibit Nos. 3 and 4)

Mr. Anthony Alvarez recommends the Commission approve $54.6 million of Advanced Metering Infrastructure ("AMI") capital costs with an offset of $20.2 million of avoided capital costs. In addition, he recommends the Commission

[1] The OUCC's Index of Witnesses and Issues is attached to my testimony as Attachment MDE-1.
[2] Cause No. 45576, Direct Testimony of Ann E. Bulkey, p. 8, ll. 4 - 11.

deny I&M's proposed AMI tracker. He recommends continuing the five-year average methodology of major storm expense and that I&M include a status report in any compliance filing with the Commission. Finally, he discusses I&M's Distribution Management Plan – Combined Projects and recommends the Commission deny the undefined and unsupported $28.1 million of Indiana Jurisdictional transmission-related project capital costs and $1.6 million "TA1692007: I&M – Dist Spare – IN – Chckbk" project embedded within I&M's distribution Combined Projects. (Public's Exhibit No. 5)

Dr. Peter Boerger, Ph.D. discusses and explains the proposed Cause No. 45546 Settlement Agreement regarding I&M's request to purchase Rockport Unit 2 at the end of its current lease term on December 7, 2022, and the effect of the Settlement Agreement on this rate case. He testifies I&M should refund the amount collected in rates pertaining to the Indiana and Michigan Municipal Distributors Association ("IMMDA") load through its RAR from the date of the Phase 1 Commission Order in this case until December 7, 2022. In addition, Dr. Boerger recommends the Commission not allow I&M to impose an opt-out provision on the Critical Peak Pricing program. (Public's Exhibit No. 6)

Ms. Cynthia Armstrong testifies regarding I&M's proposal to accelerate cost recovery of I&M's non-current SO2 allowance inventory and recommends changes to I&M's proposal. Ms. Armstrong also testifies that any future Coal Combustion Residuals ("CCR") ash-pond closure activities be first funded from AROs and not treated as a capital investment. (Public's Exhibit No. 7)

Mr. John Haselden testifies regarding I&M's request for recovery of electric vehicle ("EV") charging station costs associated with the Crossroads EV Corridor ("Crossroads EV") project and concludes ratepayers funding this initiative would be inappropriate. Ultimately, he recommends the Commission deny the proposed project's cost recovery. (Public's Exhibit No. 8)

Mr. Kaleb Lantrip recommends the Commission deny I&M's request to account for EZ Bill Program revenues and expenses above-the-line. In addition, he recommends the Commission deny I&M's request to include $11,706,849 in non-recurring Indiana Jurisdictional cybersecurity compliance capital costs and $3,902,373 Indiana Jurisdictional cybersecurity compliance O&M expenses in base rates. (Public's Exhibit No. 9)

Mr. Caleb Loveman provides testimony regarding I&M's: 1) request to more broadly implement remote disconnect and reconnect processes through a waiver of 170 Ind. Admin. Code 4-1-6(f), 2) proposal to recover test year capital and Operations and Maintenance ("O&M") costs related to its proposed Flex Pay Program, and 3) other adjustments I&M proposes to its test year. (Public's Exhibit No. 10)

Mr. Wes Blakley provides analysis and recommends the Commission: 1) accept I&M's proposal to track its Rockport Unit 2 operating lease refunds through its Resource Adequacy Rider ("RAR"), 2) require I&M to track its Rockport Unit 2 operating expenses through the RAR tracker, 3) remove I&M's Rockport Unit 2 pollution control investment from rate base and include it in I&M's Environmental Cost Recovery Rider ("ECR") tracker as a return "of," with no return "on," 4) recognize the retirement of Automatic Meter Reading ("AMR") meters as a decrease in depreciation expense if the Commission approves any new AMI Rider, 5) make adjustments to I&M's proposed bad debt expense, and 6) deny I&M's requested rate base treatment for its COVID-19 bad debt regulatory asset. (Public's Exhibit No. 11)

Mr. Glenn Watkins testifies about the reasonableness of I&M's retail class cost of service study and the allocation of revenue requirements to the various rate classes. He also addresses I&M's proposed residential rate design, including the proposed increase to the residential fixed monthly customer charge. (Public's Exhibit No. 12)

III. AFFORDABILITY

Q: Does the OUCC have concerns about the affordability of I&M's rate request?

A: Yes. Through Indiana Code § 8-1-2-.05, the Indiana General Assembly declared a policy recognizing utility service affordability for present and future generations. It stated affordability should be protected when utilities invest in infrastructure necessary for system operation and maintenance.[3]

Q: How does the issue of affordability tie into I&M's rate request?

A: I&M implemented annual revenue increases of $96,823,006[4] in May 2018, $84,138,167[5] in March 2020, and is now requesting a $110,713,174[6] annual revenue increase in 2021. I&M's proposal in this Cause will increase the bill of a residential customer using 1,000 kWh by 11.17% ($129.15 to $143.58). When

[3] I.C. § 8-1-2-.05.
[4] *In re Ind. & Mich. Pwr.*, Cause No. 44967, Final Order, p. 29 (Ind. Util. Regul. Comm'n May 30, 2018).
[5] *In re Ind. & Mich. Pwr.*, Cause No. 45235, Final Order, p. 79 (Ind. Util. Regul. Comm'n Mar. 11, 2020) ("Cause No. 45235").
[6] Cause No. 45576, Petitioner's Financial Exhibit A-1, p. 1 of 1, l. 7.

riders are included, a residential customer's bill (1,000 kWh) will initially increase by 13.61% ($145.97 to $165.85). Overall, since 2018, a residential customer's bill will have increased by 24.77% if this rate increase is approved. The cumulative economic effect on ratepayers necessarily implicates affordability.

Q: Do I&M's rate case requests meet the affordability policy objective?

A: No. For example, Mr. Mark Garrett highlights I&M's NOLC proposal, which serves to decrease I&M's zero cost capital by approximately $160 million. He explains that, like its sister companies in Texas and Oklahoma, I&M makes this proposal using a derived amount based on I&M *hypothetically* filing a stand-alone tax return. Mr. Haselden testifies that I&M is seeking to include approximately $3.7 million in rates to recover EV Crossroads costs that are not related to the provision of electric service and do not benefit I&M's ratepayers. Mr. Alvarez testifies that I&M did not provide adequate support for $28 million of transmission-related projects that are included in I&M's Distribution Management Plan. These concerns call into question whether I&M adequately considered affordability when developing its rate request in this Cause.

Q: How should affordability be considered?

A: In light of the Indiana General Assembly's stated policy, affordability should be a constant consideration for all Indiana jurisdictional utilities, as well as the Commission as it deliberates its decisions. The concern is especially profound considering Indiana's focus on emerging energy policy and the current state of the economy.

Q. What are some of the contemporary issues regarding emerging energy policy and the current state of the economy that warrant attention to affordability?

A: The current trend involves increasing infrastructure to modernize the grid. There will be significant distribution and transmission investment for initiatives like Distributed Energy Resources and EVs. Affordability is an item in the toolbox that should provide guidance and help set spending parameters. The OUCC is not suggesting infrastructure investment is an all or nothing proposition. However, there are considerations that may help avoid "sticker shock" for customers. Perhaps examining concepts such as broader socialization, prioritization, and spreading out recovery over longer periods of time could help address the financial impact to the customer. Part of the solution could also mean looking at technology choices with long-range lives, scrutinizing whether the technology is sound for the long term, which could avoid potentially stranded assets.

In addition to all these considerations, the current state of the economy has an impact on affordability and in particular, the increase I&M is requesting. Due to the COVID-19 pandemic, Indiana ratepayers have faced unprecedented health and financial hardships over the last 18 months. Many Indiana ratepayers are now just beginning to get back on their feet and a significant increase to their utility bill will impact their ability to afford electric service.

I&M failed to show it considered any affordability criteria. To protect the affordability of utility service, the Commission should only approve necessary and reasonable requests for I&M to provide quality electric service at reasonable prices and take steps to moderate the imposition of higher rates over time.

IV. OUCC REVENUE REQUIREMENT ANALYSIS

Q: Please provide an overview of the process the OUCC uses to evaluate I&M's proposed revenue requirements.

A: As an investor-owned utility, I&M's rates and charges are regulated under I.C. ch. 8-1-2, *et seq*. To evaluate the merits of I&M's proposed rate increase, the OUCC compared the operating revenues, operating expenses, rate base figures, capital structure, and net operating income from I&M's historical calendar year (2020) against the same from its forecasted test year (2022). Adjustments to the forecasted test year revenue and expense data were generally made to reflect changes that will and are projected to occur by the end of the forecasted 2022 test year. The OUCC also adjusted Petitioner's forecasted rate base and proposed rate of return ("ROR") on rate base.

In developing its positions, the OUCC reviewed I&M's case-in-chief, exhibits, accounting schedules, attachments, and workpapers. OUCC staff and witnesses issued data requests and gathered financial information about I&M through discovery. The OUCC attended the public field hearings in this Cause and reviewed I&M ratepayers' written comments. Customer comments are included with the OUCC's case as Public's Exhibit No. 13.

V. I&M'S REQUESTED REVENUE REQUIREMENT

Q: What rate relief does I&M seek in this Cause?

A: I&M seeks a $110,713,174 overall revenue increase,[7] based on a $5,235,969,265

[7] Cause No. 45576, Petitioner's Financial Exhibit A-1, p. 1 of 1, l. 7.

adjusted Original Cost Rate Base.[8] As provided in its filing, I&M is seeking a $1,661,381,485 base rate revenue requirement.[9]

Q: What base rate revenue requirement was approved in I&M's last electric rate case?

A: The Commission's Cause No. 45235 Order, dated March 11, 2020, authorized a $1.627 billion base rate revenue requirement.[10]

Q: Have you performed a calculation showing how I&M's current trackers impact an Indiana residential customer's monthly bill based on 1,000 kWh per month usage?

A: Yes. Table 1 below illustrates the trackers' impact on a monthly bill of an I&M Indiana residential customer using 1,000 kWh per month. The current base rate portion of the monthly bill totals $129.15. The total monthly bill, including trackers, equals $145.97. Therefore, 11.52% of a typical I&M Indiana residential customer's monthly bill is associated with I&M's trackers and, if approved, the rate increase I&M proposes in this Cause would increase the dollar amount recovered through its trackers since its last base rate case.

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[8] Cause No. 45576, Petitioner's Exhibit A-1, p. 1 of 1, l. 1.
[9] Cause No. 45576, Petitioner's Exhibit A-5, p. 5 of 30, l. 7, column 34, ($1,557,042,829) and Petitioner's Exhibit A-1, p. 1, l. 12 ($104,388,656)
[10] *Cause No. 45235*, Final Order p. 78.

Table 1: Residential Customer Bill Calculation as of September 27, 2021[11]

Description:	kWh		Rate	$	% Of Bill
Service Charge				$15.00	10.28%
Energy Charge	900	*	$0.114820	103.34	70.79%
Energy Charge	100		$0.108090	10.81	7.40%
Demand Side management /Energy Efficiency Rider (DSM/EE) (43)	1,000	*	($0.002034)	(2.03)	-1.39%
Off-System Sales/PJM Rider (OSS/PJM) (46)	1,000	*	$0.023283	23.28	15.95%
Environmental Cost Rider (ECR) (45)	1,000	*	($0.000525)	(0.53)	-0.36%
Life Cycle Management Rider (LCM) (47)	1,000	*	($0.000033)	(0.03)	-0.02%
Resource Adequacy Rider (RAR) (48)	1,000		($0.000252)	(0.25)	-0.17%
Phase-In Rider (PIR) (49)	1,000	*	($0.002008)	(2.01)	-1.38%
Solar Power Rider (SPR) (50)	1,000	*	$0.000225	0.23	0.15%
Sub-Total				147.80	101.26%
Fuel Cost Adjustment Rider (FAC) (44)	1,000	*	($0.001833)	(1.83)	-1.26%
Total Billing Amount				$145.97	100.00%
Base and Energy Charge				$129.15	88.48%
Other Trackers				18.66	12.78%
FAC				(1.83)	-1.26%
Total				$145.97	100.00%

* Indiana Michigan's Online Tariffs as of September 27, 2021

Q: Have you calculated an Indiana residential customer's monthly bill using I&M's proposed rates based on 1,000 kWh per month usage?

A: Yes. Table 2 below calculates an Indiana residential customer's monthly bill using I&M's proposed rates based on 1,000 kWh per month. The proposed base rate portion of the monthly bill totals $143.58. The total monthly bill, including trackers, equals $165.85. Therefore, 13.43% of a typical I&M Indiana residential customer's monthly bill at proposed rates is associated with I&M's trackers.

[11] Indiana Michigan's Online Tariffs as of September 27, 2021.

Table 2: Residential Customer Bill Calculation at I&M's Proposed Rates

Description:	kWh	Rate	$	% Of Bill
Service Charge			$20.00	12.06%
Energy Charge	900	$0.124050	111.65	67.32%
Energy Charge	100	$0.119320	11.93	7.19%
Demand Side management /Energy Efficiency Rider (DSM/EE) (43)	1,000	$0.001242	1.24	0.75%
Off-System Sales/PJM Rider (OSS/PJM) (46)	1,000	$0.025731	25.73	15.52%
Environmental Cost Rider (ECR) (45)	1,000	$0.000000	0.00	0.00%
Life Cycle Management Rider (LCM) (47)	1,000	$0.000013	0.01	0.01%
Resource Adequacy Rider (RAR) (48)	1,000	($0.001179)	(1.18)	-0.71%
Phase-In Rider (PIR) (49)	1,000	($0.003753)	(3.75)	-2.26%
Solar Power Rider (SPR) (50)	1,000	$0.000214	0.21	0.13%
Sub-Total			165.85	100.00%
Fuel Cost Adjustment Rider (FAC) (44)	1,000	$0.000000	0.00	0.00%
Total Billing Amount			$165.85	100.00%
Base and Energy Charge			$143.58	86.57%
Other Trackers			22.27	13.43%
FAC			0.00	0.00%
Total			$165.85	100.00%

Q: Does the OUCC's review reveal I&M needs additional revenue?

A: No. The OUCC recommends I&M's revenue be decreased by no less than $6,335,487[12] as shown in Mr. Garrett's testimony.

VI. NUCLEAR DECOMMISSIONING TRUST FUND ("DTF")

Q: Please describe I&M's proposal to Indiana ratepayers' Nuclear DTF contribution.

[12] Cause No. 45576, OUCC Direct Testimony of Witness Mark E. Garrett, Schedule MG-3.

A: I&M proposes maintaining the $2 million Nuclear DTF annual funding level the Commission authorized in Cause No. 45235. I&M indicates this funding level will ensure adequate funds are available to decommission D.C. Cook Units 1 and 2 and mitigate the associated unpredictable events.

Q: Does the OUCC support I&M's Nuclear DTF proposal?

A: No. I&M's proposed $2 million contribution is not necessary to meet the decommissioning requirements beginning in 2034 for Cook Plant Unit 1 and 2037 for Cook Plant Unit 2. My analysis shows the current contribution of $2 million[13] to the DTF only adds to a fund that is already overfunded.

Q: What amount is currently in I&M's Nuclear DTF?

A: In response to OUCC Data Request ("DR") 21-01, I&M stated as of June 30, 2021, the Nuclear DTF contained $3,285,322,886,[14] an increase of $302,986,376 or 10.16% over the December 31, 2020 Nuclear DTF balance of $2,982,336,510.[15] As of June 30, 2021, the Indiana Jurisdictional portion of the Nuclear DTF was $2,373,983,262[16] (72.16%), while the Michigan Jurisdictional portion was $577,213,497[17] (17.57%).

Q: What is the estimated cost of decommissioning Cook Plant Units 1 and 2?

A: I&M's witness Roderick W. Knight testifies at pp. 12 – 13 (Figure RWK-2) that I&M's proposed total decommissioning cost estimate is $2.031 billion in 2018 dollars. There is an additional cost estimate of approximately $43.1 million for the

[13] Cause No. 45576, Pre-Filed Verified Direct Testimony of Aaron L. Hill, p. 22, ll. 3 - 5.
[14] Cause No. 45576, Attachment MDE-2.
[15] Hill, p. 10, l. 6.
[16] *See* Attachment MDE-2.
[17] *Id.*

eventual decontamination and removal of the Independent Spent Fuel Storage Installation ("ISFSI").

Importantly, I&M's total estimated decommissioning costs at the end of the licensing periods (Unit 1 – October 25, 2034, and Unit 2 – December 23, 2037) is approximately $2.075 billion[18] – about $1.2 billion *less* than the current balance of the DTF, $3,285,322,886.[19] In fact, the NRC 2017 Decommissioning Funding Status Report[20] shows the NRC Minimum Site-Specific Decommissioning Cost Estimate is $512,446,094 for Cook Plant Unit 1 and $516,999,630 for Cook Plant Unit 2, for a total of $1,029,445,724. Using the NRC's Estimate, I&M's current Nuclear DTF balance has $2 billion dollars more than is needed to decommission Cook Plant Units 1 and 2.

Q: Does the Nuclear Regulatory Commission ("NRC") audit I&M's Nuclear DTF?

A: Yes. Attached to my testimony are public audit reports available on the NRC's website, evaluating both the general status of the Nuclear DTF and the NRC's DTF evaluation for Cook Plant Units 1 and 2. These NRC reports verify I&M's compliance with NRC decommissioning funding assurance requirements.[21] The following documents from the NRC website are attached to my testimony:

a. 2017 Decommissioning Funding Status Report - Power Reactor Decommissioning Funding Assurance as of December 31, 2016 (Attachment MDE-4); and

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[18] Cause No. 45576, Pre-Filed Verified Direct Testimony of Roderick W. Knight, p. 14, Figure RWK-2.
[19] *See* Attachment MDE-2.
[20] *See* Attachment MDE-3.
[21] *See* Attachment MDE-4.

b. Letter dated March 27, 2019, from I&M's witness, Q. Shane Lies, to the NRC; D.C. Cook Nuclear Plant Units 1 and 2; Decommissioning Funding Status Report (Attachment MDE-3).

Q: Did you perform any other analysis regarding the Nuclear DTF?

A: Yes. I reviewed I&M's Nuclear DTF total annual market value balances as of December 31, 2020, for the nine-year period 2012 through 2020. I then took the year-to-year differences to detail how the Nuclear DTF performed on an annual basis. My analysis of I&M's Nuclear DTF market value shows that, at current contribution levels, I&M's Nuclear DTF value is expected to increase by over $100 million a year. [22]

Q: How did the Nuclear DTF's total market value perform over the last six years?

A: The Nuclear DTF increased annually on average by 10.21%, or $198.1 million per year.[23]

Q: How did the Nuclear DTF's total market value perform during the six-month period January 1, 2021 through June 30, 2021?

A: The Nuclear DTF increased 10.16% (over $302.9 million[24]) during the six-month period.

Q: What is the Indiana portion of I&M's Nuclear DTF actual market value at December 31, 2020 and forecasted market value on December 31, 2022?

A: The existing Indiana Nuclear DTF market value on December 31, 2020 is $2,144,126,624.[25] That balance is estimated to grow to $2,380,980,961[26] for the forecasted test year ending December 31, 2022.

Q: Is there a need to include an ongoing annual $2 million revenue requirement

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[22] *See* Attachment MDE-2.
[23] *See* Attachment MDE-5.
[24] *See* Attachment MDE-5.
[25] Hill, p. 10, l. 11-19.
[26] *Id.*

to the Nuclear DTF after the test year ends, December 31, 2022, in I&M's Indiana rates?

A: No. Both the liquidated value of the Indiana portion of the estimated Nuclear DTF on December 31, 2037 and NRC's estimate in its most recent Decommissioning Funding Status Report show there will be sufficient funds available as of December 31, 2037 to support a discontinuation of Indiana ratepayers' annual contribution to the Nuclear DTF in this case.

Asking customers to continue contributing to the Nuclear DTF is unnecessary. Further, if the Nuclear DTF is over-funded, any refund during the remaining life of the units could be credited to ratepayers who have not contributed to the Nuclear DTF, resulting in generational inequity. Either circumstance is unnecessary and unreasonable.

Q: Will the Nuclear DTF stop earning interest when the decommissioning process begins?

A: No. Although any annual contributions to the Nuclear DTF will cease once the decommissioning process begins, the Nuclear DTF will continue to earn interest until it is depleted.

Q: If for some reason the Nuclear DTF balance does not cover decommissioning expenses, could I&M seek recovery of such expenses?

A: Yes. If a shortfall develops over the next 20 years, Petitioner would still be able to seek recovery of all decommissioning costs.

VII. RATE CASE EXPENSE

Q: Have you reviewed Petitioner's proposed rate case expense calculation?

A: Yes. I reviewed Petitioner's proposed rate case expense calculation and the costs of the individual components comprising rate case expense. I do not agree with

Petitioner's proposal to include the cost of Communications Counsel of America ("CCA") Training nor the Advanced Metering Infrastructure Cost Benefit Study.

Q: What type of services did CCA provide I&M?

A: In general, CCA provided I&M training on the regulatory process and communication skills to its subject matter experts who prepared testimony in this Cause.

Q: Why did you exclude the cost of CCA's services from I&M's proposed rate case expense?

A: I excluded the cost of CCA's costs because CCA's training is not related solely to this rate case. The services and skillsets recipients of CCA's training receive can be applied beyond this case. For instance, only 9 of Petitioner's 24 witnesses are I&M employees. Those witnesses are Mr. Brent E. Auer, Mr. Kurt C. Cooper, Mr. David S. Isaacson, Mr. Quinton Shane Lies, Mr. David A. Lucas, Ms. Dona Seger-Lawson, Mr. Toby Thomas, Mr. Jon C. Walter, and Mr. Andrew J. Williamson. Thus, the remaining 15 witnesses are American Electric Power Service Corporation employees or consultants who can use the services and skill sets they learned from the CCA training in their work for other AEP companies for whom they provide services. Indiana customers should not bear the brunt of a cost that serves I&M's parent company and its affiliates.

Q: Why do you oppose I&M's proposal to include the cost of the Advanced Metering Infrastructure Cost Benefit Study in its rate case expense?

A: The cost of the Advanced Metering Infrastructure Cost Benefit Study is not an expense associated with the rate case. Rather, it is an expense related to I&M's Advanced Metering Infrastructure investment plan. Specifically, I&M witness Curtis H. Bech testified:

> As discussed by Company witness Thomas, Accenture was engaged by the Company to conduct a cost benefit analysis for the Company's AMI plan in Indiana. More specifically, Accenture mobilized the CBA effort, engaged with a cross-functional Company team, calculated AMI program costs and benefits, and developed a business case that leveraged both Company data and Accenture expertise.[27]

In addition, I&M witness Toby Thomas testifies:

> The AMI Project that is part of I&M's integrated distribution strategy is scheduled to occur over four years (2021 through 2024) and is estimated to have a cumulative capital cost of approximately $121 million. The age of our existing meters, our experience and knowledge of AMI, and a cost-benefit analysis prepared by Accenture (Accenture CBA) give us confidence that investing in AMI technology can provide many benefits to the distribution system and our customers. The Company proposes to include the capital cost contained in the 2021–2022 Capital Forecast Period in base rates and address the ongoing investment, as well as operational cost savings identified in the Accenture CBA through the proposed AMI Rider so that this benefit also flows through to customers as AMI is deployed.[28]

Q: What does the OUCC recommend regarding rate case expenses?

A: The OUCC recommends the Commission exclude the cost of the CCA Training ($134,485) and AMI Cost Benefit Study ($672,500) from rate case expense. This adjustment reduces rate case expense by $403,493 since the total amount of $806,986 was amortized over two years.

VIII. LIFE CYCLE MANAGEMENT RIDER

Q: What ratemaking treatment is I&M proposing with regard to its LCM Rider?

A: I&M is proposing the following: 1) file its next LCM reconciliation (LCM-11) in the third quarter of 2021, 2) make a compliance filing shortly after an order is

[27] Direct Testimony of Curtis H. Bech, p. 5, ll. 6 – 11.
[28] Direct Testimony of Toby Thomas, p. 5, ll. 11 - 21.

received in this Cause, and 3) address the final reconciliation of the LCM over/under recovery and on-going recovery of property tax expense on LCM investment made in 2022 in a subsequent ECR filing.

Q: Is the OUCC opposing Petitioner's proposals for the LCM Rider?

A: No.

IX. FUEL CLAUSE ADJUSTMENT RIDER

Q: Does the OUCC accept I&M's recommended base cost of fuel?

A: Yes. While I&M's base cost of fuel will need to be updated when the Rockport Unit 2 lease terminates in December 2022, the OUCC accepts I&M's recommended $13.110 mills per kWh base cost of fuel.[29]

Q: Does the OUCC continue to seek a reasonable accommodation in I&M's FAC Rider, consistent with the review timeframe all other large Indiana electric investor-owned utilities have agreed to?

A: Yes. Under the FAC statute, the OUCC is provided with only 20 days to review a utility's FAC filing. However, I&M is the only large, investor-owned electric utility filing a semi-annual FAC, which requires the OUCC to review six months of data in twenty days. Due to the short schedule, only one round of discovery is possible. This is unduly burdensome and prejudicial to the OUCC's review.

By agreement with Duke Energy Indiana, LLC, Indianapolis Power & Light Company d/b/a AES Indiana ("AES Indiana"), Northern Indiana Public Service Company, LLC ("NIPSCO"), and Southern Indiana Gas and Electric Company D/B/A CenterPoint Energy Indiana South ("CEI South"), the OUCC has 35 days after the utilities file their applications and testimony to review three

[29] Direct Testimony of Nancy A. Heimberger, p. 27, l. 2.

months of data and file a report and testimony. An accommodation to provide the OUCC with 35 days to review I&M's FAC filing is entirely appropriate given I&M's filing contains six months of data. Even more compelling, unlike the other large investor-owned electric utilities with FACs, I&M includes its Green Power Rider ("GPR") in its FAC proceeding. Therefore, within 20 days, the OUCC must review six months of FAC data and any GPR-related accounting requests. I&M has sought and received a deviation from the traditional scope of an FAC filing and has elected to make its filing only twice a year. The OUCC should be granted a commensurate accommodation in order to complete a thorough review of I&M's requests in each filing.

Therefore, should the Commission continue allowing I&M to include its GPR in its FAC filing, the OUCC requests the Commission make the approval contingent on I&M's agreement to allow the OUCC a minimum 35 days to review I&M's FAC filings.

X. VEGETATION MANAGEMENT

Q: Please describe I&M's vegetation management plan.

A: Mr. Isaacson describes I&M's vegetation management plan as moving from a reactive approach to managing vegetation (trees, brush, and vines) on a systematic, cycle-based approach. The systematic approach began with its initial four-year (2018-2021) program which involves two components: 1) expanding overhead conductor clearance zones and 2) application of remedial vegetation management.

Q: Does I&M's testimony state it has experienced improvement in vegetation-caused System Average Interruption Duration Index ("SAIDI")?

A: Yes. Mr. Isaacson testifies "I&M's vegetation caused SAIDI has favorably declined by nearly 30% (from the end of 2017 to the beginning of 2021)."[30] Mr. Isaacson believes continuing this program, starting with the next four-year vegetation management rotation period in 2022, is equally important to further improve reliability and avoid returning to a system plagued by controllable vegetation-caused service interruptions.

Q: Is I&M on schedule to complete its initial four-year program by the end of 2021?

A: Yes. I&M is on schedule to complete its initial four-year program by the end of 2021 and intends to begin its second four-year program in 2022.

Q: Has I&M previously underperformed with regard to its vegetation management plan?

A: Yes. In Cause No. 44967, I&M outlined a vegetation management plan to increase its spending significantly to perform remedial maintenance over an initial four-year period (2018-2021), and thereafter to continue a regular four-year maintenance cycle. In Cause No. 45235, the Company proposed to continue its planned remedial work and forecasted $16,241,025 in Indiana jurisdictional vegetation management expense for the test year ended December 31, 2020.

Q: Did the Commission approve I&M's $16.2 million request for vegetation management in Cause No. 45235?

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[30] Direct Testimony of David S. Isaacson, p. 21, ll. 10 – 11.

A: Yes. The Commission approved “$16.2 million for vegetation management since the record shows I&M’s test year level of vegetation management expense is consistent with that experienced in 2018 and with year-to-date results in 2019.”[31]

Q: How does I&M’s forecasted 2022 test year vegetation management cost level compare to its historical data?

A: I&M’s $16.2 million test year forecast is consistent with the four-year (2018-2021) average since it was granted $16.2 million for vegetation management plan expense in Cause Nos. 44967 and 45235.

Q: Is the OUCC opposing the $16.2 million expense I&M is including in base rates?

A: No. I&M has shown improvement in outage statistics and increased service reliability to customers. Thus, the OUCC is not opposing the $16.2 million request. However, because I&M has struggled recently with staying ahead of its system’s vegetation management needs and because vegetation management spending can be reduced throughout the year, it is reasonable for the Commission and interested stakeholders, like the OUCC, to stay apprised about I&M’s annual spending.

Q: What does the OUCC recommend?

A: The OUCC recommends I&M include its annual vegetation management plan expense and provide its vegetation related SAIDI, SAIFI, and CAIDI statistics as part of its annual Performance Metrics Collaborative Report filed under Cause No. 44967.

[31] *Cause No. 45235*, Final Order p. 76.

XI. COOK COAL TERMINAL AND RIVER TRANSPORTATION

Q: Is I&M's cost of coal delivery rising?

A: Yes. In I&M's most recent FAC proceeding (Cause No. 38702 FAC-87), I&M witness Jeffrey C. Dial testified "[t]he increase in delivered cost is primarily due to the increase in costs associated with transloading and barging as a result of lower actual generation than what was previously forecasted.[32]

Mr. Dial also provided the following table which show the variance for costs of coal and cost of transportation for the 6-month period December 2020 through May 2021:[33]

Table 1: Actual vs. Forecast Variances

		Variance	%
I&M Total	Tons (000)	(301)	-18.53%
	$/Ton FOB Mine	($0.19)	-1.22%
	$/Ton Transportation	$17.05	67.01%
	$/Ton Delivered	$16.86	41.33%
	¢/MMBTU	95.60	41.43%

Q: Did the OUCC comment on this issue in I&M's FAC-87?

A: Yes. OUCC witness Greg Guerrettaz testified:

> During the Reconciliation Period, the overall weighted average delivery cost was forecast to be $40.80/ton. Actual delivery cost was $57.66/ton or 326.34 cents/MMBtu. Fuel costs are expected to be higher in 2021 due to increased barging and transloading costs. The OUCC asked I&M to provide additional detailed calculations for the increased barging and transloading costs which may lead to additional questions by the OUCC. Due to the OUCC's very short FAC audit time (20 days), the OUCC recommends I&M provide testimony on all material cost increases in future FACs.[34]

[32] Cause No. 38707 FAC-87, Direct Testimony of Jeffrey C. Dial, p. 5.
[33] *Id.*
[34] Cause No. 38707 FAC-87, Direct Testimony of Gregory Guerrettaz, pp. 4 - 5.

Q: Did the OUCC's Data Request No. 20-02 seek any analysis AEP, I&M, AEPSC, any other affiliate, or consultant has conducted regarding the Cook Coal Terminal contract expiration?

A: Yes. I&M provided the following response:

> The current Cook Coal Terminal (CCT) Facility Lease extends through January 25, 2023. There are fixed costs associated with CCT such as the facility lease payment, equipment lease payments, United Mine Workers of America (UMWA) pension withdrawal liability, insurance, depreciation and amortization, property taxes, and minimum operating expenses that would be incurred regardless of whether CCT were to operate or not through the end of the lease. CCT remains the reasonable least cost alternative in comparison to other third party terminals when factoring in these fixed costs. AEPSC is currently evaluating the long term viability of CCT post lease expiration and will provide an update during the next FAC filing (FAC 88).[35]

Q: Is I&M experiencing similar issues with its barge costs?

A: Yes. There are fixed costs associated with the barge rates that would be incurred through the end of the CCT lease regardless of whether River Transportation was operating.

Q: Please explain why transloading and barge costs are rising while coal consumption is decreasing.

A: I&M must pay certain fixed CCT and barge costs regardless of the amount of coal it takes. As tons of coal decrease, the cost per ton of coal increases because there are fewer tons over which total CCT and barge costs are allocated.

Q: Is the OUCC concerned about the rising transloading and barging costs per ton as a result of lower actual coal generation?

A: Yes. Coal generation units are forecasted to be used less. I&M needs to closely examine its fuel costs and take immediate action to reduce such costs. I&M's current contract with CCT expires on January 23, 2023, and I&M should take aggressive actions to secure a better deal with CCT or another company. In

[35] Cause No. 45576, I&M Response to OUCC DR 20-2.

addition, I&M should also look to renegotiate its barge contract with River Transportation, which has no end date but allows the shipper to terminate with notice.

Q: What does the OUCC recommend?

A: The OUCC recommends I&M provide updates and testimony in all future FAC proceedings regarding CCT and River Transportation rates and contracts.

XII. RECOMMENDATIONS

Q: What do you recommend in this proceeding?

A: I recommend the Commission:

1) Deny Petitioner's request to maintain $2 million annual contribution to the Nuclear DTF and reduce the current annual contribution to $0 after December 31, 2022;

2) Reduce annual rate case expense by $403,493;

3) Approve I&M's proposal for the LCM Rider;

4) Authorize the OUCC 35 days from the time I&M files its FAC testimony to review I&M's FAC filing and file OUCC testimony;

5) Require I&M to include its annual vegetation management plan expense and provide its vegetation related SAIDI, SAIFI, and CAIDI statistics as part of its annual Performance Metrics Collaborative Report;

6) Require I&M to provide CCT and Barging contract updates through its testimony to the Commission and OUCC in future FAC proceedings; and

7) Require I&M to provide CCT and River Transportation rates and contract updates in testimony in all future FAC proceedings.

Q: Does this conclude your testimony?

A: Yes.

APPENDIX A

Q: Please describe your educational background and experience.

A: I graduated from Purdue University in West Lafayette, Indiana in December 1986, with a Bachelor of Science degree, majoring in Accounting. I am licensed in the State of Indiana as a Certified Public Accountant. Upon graduation, I worked as a Field Auditor with the Audit Bureau of Circulation in Schaumburg, Illinois until October 1987. In December 1987, I accepted a position as a Staff Accountant with the OUCC. In May 1995, I was promoted to Principal Accountant and in December 1997, I was promoted to Assistant Chief Accountant. As part of the OUCC's reorganization, I accepted the position of Assistant Director of its Telecommunications Division in July 1999. From January 2000 through May 2000, I was the Acting Director of the Telecommunications Division. As part of an OUCC reorganization, I accepted a position as a Senior Utility Analyst. In September 2017 I accepted the position of Assistant Director in the Electric Division. As part of my continuing education, I have attended the National Association of Regulatory Utility Commissioner's ("NARUC") two-week seminar in Lansing, Michigan. I attended NARUC's spring 1993 and 1996 seminar on system of accounts. In addition, I attended several CPA sponsored courses and the Institute of Public Utilities Annual Conference in December 1994 and December 2000.

Q: Please describe the review and analysis you conducted in order to prepare your testimony.

A: I read I&M's Petition and prefiled testimony in this proceeding, as well as relevant Commission Orders. I reviewed Petitioner's workpapers and its Minimum Standard Filing Requirements ("MSFR") filing. In addition, I participated in the preparation of discovery questions, both formal and informal, and reviewed Petitioner's responses to OUCC questions and Intervenors' data requests.

Q: Have you previously filed testimony before the Commission?

A: Yes.

Indiana Office of Utility Consumer Counselor
Indiana Michigan Power Company
Cause No. 45576
Index of Issues, Requests, and Supporting Witnesses[1]

REVENUE REQUIREMENT			
Subject	**OUCC Request**	**Supporting Witness**	**Workpaper or Exhibit Reference**
Overall Revenue Increase	• Total annual decrease in revenue of $6,335,486 approximately to be phased in over 2 steps.	• Mark Garrett	• Public's Exhibit No. 2, Schedule MG-3
Financial Forecast	• Set rates based on the OUCC's adjustments to Petitioner's Test Year financial forecast. • Reflect forecasted revenues, O&M, and capital. investments in rates.	• Michael Eckert (O&M) • Mark Garrett (O&M, Capital Investment, Capital Structure) • Anthony Alvarez (Capital Investment, O&M) • John Haselden (Capital Investment) • Kaleb Lantrip (O&M) • Caleb Loveman (O&M, Capital Investment) • Wes Blakley (Capital Investment, O&M)	• Public's Exhibit No. 1 • Public's Exhibit No. 2, Schedules MG-8, MG-11 through MG-15, and MG - 17 • Public's Exhibit No. 5 • Public's Exhibit No. 8 • Public's Exhibit No. 9 • Public's Exhibit No. 10 • Public's Exhibit No. 11

[1] This Index of the OUCC's case-in-chief is intended to highlight issues and is ***not an exhaustive summary*** of the OUCC's testimony in this proceeding. A complete account of the OUCC's requested relief can be found in the OUCC's case-in-chief, including but not limited to its testimony and attachments.

REVENUE REQUIREMENT			
Subject	**OUCC Request**	**Supporting Witness**	**Workpaper or Exhibit Reference**
Return on Equity (ROE)	• Authorize 9.10% ROE.	• David Garrett	• Public's Exhibit No. 3, Attachment DJG 1-2 to DJG 1
Weighted Average Cost of Capital (WACC)	• Authorize WACC of 5.60% applied to forecasted rate base.	• Mark Garrett	• Public's Exhibit No. 2, Schedule MG-20
Depreciation	• Set new depreciation rates and reflect the resulting depreciation expense in base rates based on the OUCC's changes to Petitioner's depreciation study.	• Mark Garrett (Depreciation Expense) • David Garrett (Depreciation Rates and Expense)	• Public's Exhibit No. 2, Schedule MG-18 • Public's Exhibit No. 4, Attachment DJG-2-2 to DJG 2-11
Taxes	• Reflect forecasted test year tax expense in base rates. • Apply gross revenue conversion factor (GRCF).	• Mark Garrett	• Public's Exhibit No. 2, Schedule MG-2
Forecasted Rate Base	• Recommended rejection of OPEB/Pension "Assets" and incentive program (STI & LTI). • Recommended rejection of unsupported capital projects and AMI Program costs • Removal of Flex Pay Program costs • Removal of non-recurring cybersecurity capital costs • Recommended removal of EV Fast Charging • Recommended removal of bad Debts Expense and Rockport Unit 2 SCR from Rate Base	• Mark Garrett • Anthony Alvarez • Caleb Loveman • Kaleb Lantrip • John Haselden • Wes Blakley	• **Public's Exhibit No. 2, Schedule MG-12, MG-13, and MG-16** • Public's Exhibit No. 5 • Public's Exhibit No. 8 • Public's Exhibit No. 9 • Public's Exhibit No. 10 • Public's Exhibit No. 11

COST OF SERVICE AND RATE DESIGN			
Subject	**OUCC Proposal**	**Supporting Witness**	**Workpaper or Exhibit Reference**
Class Cost of Service Study (COSS)	• Changes to Petitioner's proposed allocation methodologies.	• Glenn Watkins	• Public's Exhibit No. 12
Overall Rate Design	• Changes to Petitioner's proposed subsidies. • Changes to Petitioner's proposed monthly customer service charges.	• Glenn Watkins	• Public's Exhibit No. 12
Rider Proposals	• Approval of Petitioner's proposed Fuel Cost Adjustment ("FAC") and Life Cycle Management ("LCM") riders.	• Michael Eckert	• Public's Exhibit No. 1
Rider Proposals	• Approval of Petitioner's Resource Adequacy Rider ("RAR") Rockport Unit 2 lease termination refund proposal. • Proposal to reflect Rockport Unit 2 pollution control technology in Environmental Cost Rider ("ECR"). • Proposed Modifications to Advanced Metering Infrastructure ("AMI") Rider. • Changes to Petitioner's proposed Tax Rider.	• Wes Blakley	• Public's Exhibit No. 11

COST OF SERVICE AND RATE DESIGN			
Subject	**OUCC Proposal**	**Supporting Witness**	**Workpaper or Exhibit Reference**
Rider Proposals	• Recommended denial of Petitioner's proposed AMI Rider.	• Anthony Alvarez	• Public's Exhibit No. 5
Terms and Conditions of Service and Tariffs	• Deny opt-out provision and recommend reporting • Changes to Petitioner's Terms and Conditions Relating to Customer Deposits.	• Peter Boerger (Critical Peak Pricing Program) • Caleb Loveman (Remote Disconnect and Reconnect)	• Public's Exhibit No. 6 • Public's Exhibit No. 10

Miscellaneous Issues			
Subject	**OUCC Proposal**	**Supporting Witness**	**Workpaper or Exhibit Reference**
Cook Coal Terminal	• Provide negotiation updates in future FAC proceedings.	• Michael Eckert	• Public's Exhibit No. 1
Barge Rates	• Provide negotiation updates in future FAC proceedings.	• Michael Eckert	• Public's Exhibit No. 1
Rockport Unit 2 Settlement (45546)	• Introduce and explain a settlement.	• Peter Boerger	• Public's Exhibit No. 6
Indiana Michigan Municipal Distributors Association's ("IMMDA") load	• Require I&M to refund the amount related to IMMDA-related amounts collected between the date of implementation of Phase 1 rates in this Cause and December 7, 2022.	• Peter Boerger	• Public's Exhibit No. 6
SO_2 Allowance Inventory	• Amortize Cost over 12 years.	• Cynthia Armstrong	• Public's Exhibit No. 7
Coal Combustion Residuals closure activities	• Activities should be funded through Asset Retirement Obligations.	• Cynthia Armstrong	• Public's Exhibit No. 7
EZ Bill	• Deny I&M's request to account for EZ Bill Program above-the-line.	• Kaleb Lantrip	• Public's Exhibit No. 9

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 21
IURC CAUSE NO. 45576

DATA REQUEST NO OUCC 21-01

REQUEST

Please provide the following information for 1) Total Company; 2) Indiana Jurisdictional; 3) Michigan Jurisdictional; and 4) FERC Jurisdictional portions of the D.C. Cook Decommissioning Trust:
a. Balance of the D.C. Cook Decommissioning Trust as of December 31, 2020, March 31, 2021, and June 30, 2021;
b. Projected balance of the D.C. Cook Decommissioning Trust as of December 31, 2021; June 30, 2022, and December 31, 2022;
c. Balance of the D.C. Cook Decommissioning Trust as of 1) December 31, 2016; 2) December 31, 2017; 3) December 31, 2018; 4) December 31, 2019; and 5) December 31, 2020;
d. If the balances provided in subpart a. contain annual contributions from Michigan and Indiana ratepayers, please provide the 1) total company; 2) Indiana Jurisdictional; 3) Michigan Jurisdictional; and 4) FERC jurisdictional amounts contributed to each year;
e. 2020 annual contribution to the D.C. Cook Decommissioning Trust Fund;
f. 2021 and 2022 forecasted annual contribution to the D.C. Cook Decommissioning Trust Fund;
g. Annual earnings (dollars and percent) on the Balance of the D.C. Cook Decommissioning Trust as of 1) December 31, 2016; 2) December 31, 2017; 3) December 31, 2018; 4) December 31, 2019; and 5) December 31, 2020, and
h. Projected annual earnings (dollars and percent) on the Balance of the D.C. Cook Decommissioning Trust as of 1) December 31, 2021, and 2) December 31, 2022.
i. Docket number and final order for Michigan Public Utility Commission ("PUC") proceeding that established the current annual contribution to the D.C. Cook Decommissioning Trust Fund for Michigan ratepayers.

RESPONSE

See attachment "45576_IndMich_OUCC 21-01_Attachment 1_09172021.xlsx"

2021 IURC Data Request 21.1

		Balances	Total Company	Indiana	Michigan	FERC
Q 21.1.	a.	12/31/2020	$ 2,982,336,510	$ 2,144,126,624	$ 536,187,515	$ 302,022,371
		3/31/2021	$ 3,088,748,945	$ 2,228,336,159	$ 546,768,395	$ 313,644,391
		6/30/2021	$ 3,285,322,886	$ 2,373,983,262	$ 577,213,497	$ 334,126,126

Q 21.1. b. Short term projections are inherently unpredictable, however Witness Hill provides projected Indiana NDT balances as of 12/31/2021 and 12/31/2022 in Workpaper ALH-6, based on a 5.3% annual expected return.

		Balances	Total Company	Indiana	Michigan	FERC
Q 21.1.	c.	12/31/2020	$ 2,982,336,510	$ 2,144,126,624	$ 536,187,515	$ 302,022,371
		12/31/2019	$ 2,652,217,217	$ 1,904,519,741	$ 479,929,931	$ 267,767,545
		12/31/2018	$ 2,158,403,478	$ 1,542,554,623	$ 399,834,766	$ 216,014,089
		12/31/2017	$ 2,215,858,795	$ 1,589,021,995	$ 406,432,282	$ 220,404,518
		12/31/2016	$ 1,945,738,908	$ 1,390,697,559	$ 363,467,065	$ 191,574,284

		Contributions	Total Company	Indiana	Michigan	FERC
Q 21.1.	d.	2020	$ 4,683,229	$ 2,000,000	$ 1,744,817	$ 938,412
		YTD 3/31/21	$ 992,652	$ 500,000	$ 375,000	$ 117,652
		YTD 6/30/21	$ 1,985,304	$ 1,000,000	$ 750,000	$ 235,304

		Contributions	Total Company	Indiana	Michigan	FERC
Q 21.1.	e.	2020	$ 4,683,229	$ 2,000,000	$ 1,744,817	$ 938,412

		Forecasted Contributions	Total Company	Indiana	Michigan	FERC
Q 21.1.	f.	2021	$ 3,995,869	$ 2,000,000	$ 1,500,000	$ 495,869
		2022	$ 3,995,869	$ 2,000,000	$ 1,500,000	$ 495,869

			Total Company		Indiana		Michigan		FERC	
Q 21.1.	g.	Annual Earnings	Dollars	Percent	Dollars	Percent	Dollars	Percent	Dollars	Percent
		2020	$ 342,420,885	12.95%	$ 249,750,553	13.17%	$ 57,643,594	12.02%	$ 35,026,739	13.09%
		2019	$ 497,858,980	23.08%	$ 367,736,118	23.87%	$ 79,314,809	19.81%	$ 50,808,053	23.47%
		2018	$ (57,257,682)	-2.66%	$ (44,691,038)	-2.82%	$ (8,230,232)	-2.01%	$ (4,336,412)	-2.74%
		2017	$ 282,259,242	14.42%	$ 208,107,292	15.00%	$ 43,747,424	12.03%	$ 30,404,526	14.74%
		2016	$ 153,154,649	8.38%	$ 112,185,369	8.76%	$ 23,640,564	6.96%	$ 17,328,716	8.47%

Q 21.1. h. Short term projections are inherently unpredictable, however Witness Hill provides projected Indiana NDT balances as of 12/31/2021 and 12/31/2022 in Workpaper ALH-6, based on a 5.3% annual expected return.

Q 21.1. i. Case No. U-20359

INDIANA MICHIGAN POWER®
A unit of American Electric Power

Indiana Michigan Power
Cook Nuclear Plant
One Cook Place
Bridgman, MI 49106
IndianaMichiganPower.com

March 27, 2019

AEP-NRC-2019-10
10 CFR 50.75(f)(1)

Docket Nos.: 50-315
50-316

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-001

Donald C. Cook Nuclear Plant Units 1 and 2
DECOMMISSIONING FUNDING STATUS REPORT

In accordance with the requirements of 10 CFR 50.75(f)(1), Indiana Michigan Power Company, the licensee for Donald C. Cook Nuclear Plant (CNP), Units 1 and 2, hereby submits the biennial report on the status of decommissioning funding. The recovery of decommissioning funds for the eventual decommissioning of CNP Units 1 and 2 is fully assured through cost of service regulation and the resulting contribution of funds into an external trust.

When projected to the current license expiration date for each unit, the Nuclear Decommissioning Trust balance is greater than the U. S. Nuclear Regulatory Commission calculated minimum cost of decommissioning pursuant to 10 CFR 50.75(b) and (c), confirming compliance with the financial assurance requirements of 10 CFR 50.75.

This letter contains no new commitments. If you have any questions regarding the report or decommissioning funding, please contact Mr. Michael K. Scarpello, Regulatory Affairs Director, at (269) 466-2649.

Sincerely,

Quinton S. Lies

Q. Shane Lies
Site Vice President

JMT/mll

Enclosure: Indiana Michigan Power Company, Donald C. Cook Nuclear Plant Units 1 and 2 2018 U. S. Nuclear Regulatory Commission Financial Assurance Requirements Report for Decommissioning Nuclear Power Reactors

A001
NRR

c: R. J. Ancona – MPSC
R. F. Kuntz – NRC Washington DC
MDEQ – RMD/RPS
NRC Resident Inspector
D. J. Roberts – NRC Region III
A. J. Williamson – AEP Ft. Wayne, w/o enclosure

ENCLOSURE TO AEP-NRC-2019-10

Indiana Michigan Power Company, Donald C. Cook Nuclear Plant Units 1 and 2
2018 U. S. Nuclear Regulatory Commission Financial Assurance Requirements Report for Decommissioning Nuclear Power Reactors

As provided in 10 CFR 50.75(f)(1), each power reactor licensee is required to report to the U. S. Nuclear Regulatory Commission (NRC) on a calendar year basis, beginning on March 31, 1999, and every two years thereafter, on the status of its decommissioning funding for each reactor or share of reactors it owns.

1. The minimum decommissioning cost estimate, pursuant to 10 CFR 50.75(b) and (c) is:
   a. Cook Unit 1 $512,446,094
   b. Cook Unit 2 $516,999,630
   c. Total $1,029,445,724

   These cost estimates were determined using the burial cost escalation values and the methods outlined in NUREG-1307, Revision 17, to determine minimum values.

2. The amount accumulated in the fund allocated to radiological decommissioning reflects the market value of the funds accumulated through December 31, 2018, net of all taxes currently due for items included in 10 CFR 50.75(b) and (c) are:
   a. Cook Unit 1 $648,808,262
   b. Cook Unit 2 $590,864,127
   c. Total $1,239,672,390

3. A schedule of the annual amounts to be collected for items in 10 CFR 50.75(b) and (c) are as follows:

   See Table 1 (attached) for schedule of contributions. While there are no changes for Indiana and Michigan, the FERC contributions are expected to decline in years 2019, 2020, 2021, 2026, 2027, and 2034 as wholesale customer's contracts expire.

   The citations for the Orders that provide these rates are the State of Michigan Case Numbers U-15276 and U-18370 and the State of Indiana Cause Number 44967.

4. The assumptions used regarding rates of escalation in decommissioning costs, rates of earnings on decommissioning funds, and rates of other factors used in funding projections are as follows:

   A two percent real rate of return is applied to the annual balance for future funding projections. Incorporating the two percent real rate of return on trust assets as well as future contributions to the trust results in projected trust fund balances of approximately $871 million for Unit 1 and $840 million for Unit 2 net of tax at the time those units are shut down. These amounts are above the NRC minimum decommissioning cost estimates shown in item 1 above.

5. Any contracts upon which the licensee is relying pursuant to 10 CFR 50.75(e)(1)(v):

   None

6. Any modifications occurring to a licensee's current method of providing financial assurances since the last submitted report:

   None

7. Any material changes to trust agreements:

   None

Table 1

Unit 1

	Contributions			
	Indiana	Michigan	FERC	Total
2019	$620,000	$930,000	$726,099	$2,276,099
2020	$620,000	$930,000	$484,171	$2,034,171
2021	$620,000	$930,000	$318,707	$1,868,707
2022	$620,000	$930,000	$318,707	$1,868,707
2023	$620,000	$930,000	$318,707	$1,868,707
2024	$620,000	$930,000	$318,707	$1,868,707
2025	$620,000	$930,000	$318,707	$1,868,707
2026	$620,000	$930,000	$308,246	$1,858,246
2027	$620,000	$930,000	$300,773	$1,850,773
2028	$620,000	$930,000	$300,773	$1,850,773
2029	$620,000	$930,000	$300,773	$1,850,773
2030	$620,000	$930,000	$300,773	$1,850,773
2031	$620,000	$930,000	$300,773	$1,850,773
2032	$620,000	$930,000	$300,773	$1,850,773
2033	$620,000	$930,000	$300,773	$1,850,773
10/25/2034	$516,667	$775,000	$111,483	$1,403,150

Unit 2

	Contributions			
	Indiana	Michigan	FERC	Total
2019	$620,000	$930,000	$726,099	$2,276,099
2020	$620,000	$930,000	$484,171	$2,034,171
2021	$620,000	$930,000	$318,707	$1,868,707
2022	$620,000	$930,000	$318,707	$1,868,707
2023	$620,000	$930,000	$318,707	$1,868,707
2024	$620,000	$930,000	$318,707	$1,868,707
2025	$620,000	$930,000	$318,707	$1,868,707
2026	$620,000	$930,000	$308,246	$1,858,246
2027	$620,000	$930,000	$300,773	$1,850,773
2028	$620,000	$930,000	$300,773	$1,850,773
2029	$620,000	$930,000	$300,773	$1,850,773
2030	$620,000	$930,000	$300,773	$1,850,773
2031	$620,000	$930,000	$300,773	$1,850,773
2032	$620,000	$930,000	$300,773	$1,850,773
2033	$620,000	$930,000	$300,773	$1,850,773
2034	$620,000	$930,000	$133,780	$1,683,780
2035	$620,000	$930,000	$50,739	$1,600,739
2036	$620,000	$930,000	$50,739	$1,600,739
12/23/2037	$620,000	$930,000	$50,739	$1,600,739

2017 DECOMMISSIONING …NDING STATUS REPORT for Operating Power Reactor Licensees (December 31, 2016)

Plant Name	Expected Shutdown Date as of 3/31/2017	Approx. No. of Years Remaining Before Expected Shutdown	Decommissioning Trust Fund (DTF) Balance (As of 12/31/16)	Projected DTF Balance[1] Before Decommissioning (2016$)	NRC Minimum[2] or Site-Specific Cost Estimate (SSCE[3]) (2016$)
Arkansas Nuclear One, Unit 1	05/20/2034	17	$466,300,000	$660,417,745	$450,023,926
Arkansas Nuclear One, Unit 2	07/17/2038	22	$368,400,000	$633,237,038	$468,608,006
Arnold (Duane) Energy Center	02/21/2034	17	$444,145,372	$677,415,095	$585,618,349
Beaver Valley Power Station, Unit 1	01/29/2036	19	$286,595,306	$419,649,610	$711,726,383 (SSCE)
Beaver Valley Power Station, Unit 2	05/27/2047	30	$378,702,702	$695,463,425	$481,865,787
Braidwood Station, Unit 1	07/29/2046	30	$322,022,000	$584,519,336	$492,055,879
Braidwood Station, Unit 2	10/17/2047	31	$348,139,000	$645,755,179	$492,055,879
Browns Ferry Nuclear Plant, Unit 1	12/20/2033	17	$341,250,600	$793,690,165	$642,093,163
Browns Ferry Nuclear Plant, Unit 2	06/28/2034	17	$332,599,271	$796,415,079	$642,093,163
Browns Ferry Nuclear Plant, Unit 3	07/02/2036	20	$301,524,766	$801,099,004	$642,093,163
Brunswick Steam Electric Plant, Unit 1	09/08/2036	20	$501,904,491	$744,774,169	$619,772,102
Brunswick Steam Electric Plant, Unit 2	12/27/2034	18	$554,893,905	$793,784,479	$619,772,102
Byron Nuclear Generating Station, Unit 1	09/16/2044	28	$353,618,000	$615,697,177	$492,055,879
Byron Nuclear Generating Station, Unit 2	08/02/2046	30	$340,758,000	$616,471,434	$492,055,879
Callaway Plant, Unit 1	10/18/2044	28	$446,444,950	$1,864,611,558	$492,055,879
Calvert Cliffs Nuclear Power Plant, Unit 1	07/31/2034	18	$358,696,000	$509,713,687	$456,881,370
Calvert Cliffs Nuclear Power Plant, Unit 2	08/13/2036	20	$459,606,000	$680,872,811	$456,881,370
Catawba Nuclear Station, Unit 1	12/05/2043	27	$397,017,662	$760,101,155	$449,502,529
Catawba Nuclear Station, Unit 2	12/05/2043	27	$398,905,102	$775,766,406	$449,502,529
Clinton Power Station, Unit 1	09/29/2026	10	$513,387,000	$623,823,594	$652,254,613
Columbia Generating Station	12/20/2043	27	$244,500,000	$623,663,351	$481,783,363
Comanche Peak Nuclear Power Plant, Unit 1	02/08/2030	13	$474,200,000	$794,814,101	$392,607,229
Comanche Peak Nuclear Power Plant, Unit 2	02/02/2033	16	$537,800,000	$898,472,009	$392,607,229
Cooper Nuclear Station	01/18/2034	17	$581,769,773	$891,329,227	$607,664,555
Davis-Besse Nuclear Power Station, Unit 1	04/22/2037	20	$552,423,474	$829,350,670	$467,638,661
Diablo Canyon Power Plant, Unit 1	11/02/2024	8	$1,201,600,000	$1,941,720,985	$494,417,329
Diablo Canyon Power Plant, Unit 2	08/26/2025	9	$1,571,000,000	$2,371,881,818	$494,417,329
Donald C. Cook Nuclear Power Plant, Unit 1	10/25/2034	18	$459,454,502	$699,079,244	$487,722,039
Donald C. Cook Nuclear Power Plant, Unit 2	12/23/2037	21	$418,248,246	$686,747,364	$492,055,879
Dresden Nuclear Power Station, Unit 2	12/22/2029	13	$651,199,000	$842,971,857	$631,058,754
Dresden Nuclear Power Station, Unit 3	01/12/2031	14	$665,882,000	$882,311,071	$631,058,754
Farley (Joseph M.) Nuclear Plant, Unit 1	06/25/2037	20	$402,098,838	$683,368,501	$458,423,281
Farley (Joseph M.) Nuclear Plant, Unit 2	03/31/2041	24	$388,100,905	$724,462,843	$458,423,281

1 Includes growth from earnings and contributions.
2 Derived from minimum formula at Title 10 of the *Code of Federal Regulations* (10 CFR) 50.75(c). Incorporates labor, energy, and low-level waste (LLW) burial escalation factors.
3 Four licensees provided SSCEs.
4 In years 2017 through 2022, licensee plans include significant contributions of approximately $600 million from a combination of Omaha Public Power District collections and a lump sum transfer from the Fort Calhoun Station, Unit 1, Supplemental Decommissioning Trust Fund.

2017 DECOMMISSIONING FUNDING STATUS REPORT
for Operating Power Reactor Licensees (December 31, 2016)

Plant Name	Expected Shutdown Date as of 3/31/2017	Approx. No. of Years Remaining Before Expected Shutdown	Decommissioning Trust Fund (DTF) Balance (As of 12/31/16)	Projected DTF Balance[1] Before Decommissioning (2016$)	NRC Minimum[2] or Site-Specific Cost Estimate (SSCE[3]) (2016$)
Fermi, Unit 2	03/20/2045	28	$1,220,000,000	$2,149,316,422	$1,044,205,513
Fitzpatrick (James A.) Nuclear Power Plant	10/17/2034	18	$784,670,000	$1,120,615,113	$626,383,692
Fort Calhoun Station, Unit 1	12/31/2016	0	$285,838,000	$285,838,000 [4]	$931,973,000 (SSCE)
Ginna (Robert E.) Nuclear Power Plant	09/18/2029	13	$423,414,000	$546,283,548	$434,407,855
Grand Gulf Nuclear Station, Unit 1	11/01/2044	28	$844,900,000	$1,748,516,125	$642,093,163
Hatch (Edwin I.) Nuclear Plant, Unit 1	08/06/2034	18	$521,093,476	$759,852,063	$614,678,163
Hatch (Edwin I.) Nuclear Plant, Unit 2	06/13/2038	21	$471,737,376	$743,840,684	$614,678,163
Hope Creek Generating Station, Unit 1	04/11/2046	29	$536,295,000	$963,779,663	$1,080,204,000 (SSCE)
Indian Point Nuclear Generating, Unit 2	04/30/2020	3	$564,010,000	$602,858,889	$495,196,193
Indian Point Nuclear Generating, Unit 3	04/30/2021	4	$719,100,000	$784,145,786	$495,196,193
LaSalle County Station, Unit 1	04/17/2042	25	$476,685,000	$790,844,062	$652,254,613
LaSalle County Station, Unit 2	12/16/2043	27	$477,242,000	$817,220,477	$652,254,613
Limerick Generating Station, Unit 1	10/26/2044	28	$408,501,000	$959,233,937	$666,764,953
Limerick Generating Station, Unit 2	06/22/2049	32	$430,247,000	$1,173,496,388	$666,764,953
McGuire Nuclear Station, Unit 1	03/03/2041	24	$498,556,391	$809,415,989	$484,152,529
McGuire Nuclear Station, Unit 2	03/03/2043	26	$545,933,242	$922,474,457	$484,152,529
Millstone Power Station, Unit 2	07/31/2035	19	$614,000,000	$890,116,378	$440,838,021
Millstone Power Station, Unit 3	11/25/2045	29	$641,200,000	$1,142,750,488	$468,691,699
Monticello Nuclear Generating Plant, Unit 1	09/08/2030	14	$498,602,413	$656,275,125	$589,618,844
Nine Mile Point Nuclear Station, Unit 1	08/22/2029	13	$581,113,000	$748,497,367	$595,890,308
Nine Mile Point Nuclear Station, Unit 2	10/31/2046	30	$477,193,000	$866,178,509	$666,764,953
North Anna Power Station, Unit 1	04/01/2038	21	$380,700,000	$583,079,283	$465,118,419
North Anna Power Station, Unit 2	08/21/2040	24	$364,770,000	$585,347,885	$465,118,419
Oconee Nuclear Station, Unit 1	02/06/2033	16	$412,499,053	$569,807,223	$417,816,454
Oconee Nuclear Station, Unit 2	10/06/2033	17	$410,143,404	$574,151,493	$417,816,454
Oconee Nuclear Station, Unit 3	07/19/2034	18	$538,023,018	$764,540,714	$417,816,454
Oyster Creek Nuclear Generating Station	12/31/2019	3	$888,501,000	$932,931,000	$1,083,421,000 (SSCE)
Palisades Nuclear Plant	03/24/2031	14	$425,730,000	$565,985,300	$457,246,441
Palo Verde Nuclear Generating Station, Unit 1	06/01/2045	28	$966,731,000	$1,708,464,988	$494,417,329
Palo Verde Nuclear Generating Station, Unit 2	04/24/2046	29	$1,031,011,000	$1,852,837,402	$494,417,329
Palo Verde Nuclear Generating Station, Unit 3	11/25/2047	31	$1,009,047,000	$1,871,658,523	$494,417,329
Peach Bottom Atomic Power Station, Unit 2	08/08/2033	17	$565,607,000	$853,184,291	$666,764,953
Peach Bottom Atomic Power Station, Unit 3	07/02/2034	18	$586,693,000	$908,662,871	$666,764,953

1 Includes growth from earnings and contributions.
2 Derived from minimum formula at Title 10 of the *Code of Federal Regulations* (10 CFR) 50.75(c). Incorporates labor, energy, and low-level waste (LLW) burial escalation factors.
3 Four licensees provided SSCEs.
4 In years 2017 through 2022, licensee plans include significant contributions of approximately $600 million from a combination of Omaha Public Power District collections and a lump sum transfer from the Fort Calhoun Station, Unit 1, Supplemental Decommissioning Trust Fund.

2017 DECOMMISSIONING FUNDING STATUS REPORT for Operating Power Reactor Licensees (December 31, 2016)

Plant Name	Expected Shutdown Date as of 3/31/2017	Approx. No. of Years Remaining Before Expected Shutdown	Decommissioning Trust Fund (DTF) Balance (As of 12/31/16)	Projected DTF Balance[1] Before Decommissioning (2016$)	NRC Minimum[2] or Site-Specific Cost Estimate (SSCE[3]) (2016$)
Perry Nuclear Power Plant, Unit 1	03/18/2026	9	$515,467,559	$620,124,568	$652,254,613
Pilgrim Nuclear Power Station	06/08/2032	15	$960,300,000	$1,362,333,603	$603,802,586
Point Beach Nuclear Plant, Unit 1	10/05/2030	14	$410,419,939	$541,107,110	$425,698,629
Point Beach Nuclear Plant, Unit 2	03/08/2033	16	$386,710,421	$535,074,299	$425,698,629
Praire Island Nuclear Generating Plant, Unit 1	08/09/2033	17	$358,639,700	$500,383,161	$420,626,236
Praire Island Nuclear Generating Plant, Unit 2	10/29/2034	18	$395,626,640	$565,008,465	$420,626,236
Quad Cities Station, Unit 1	12/14/2032	16	$642,578,582	$883,205,114	$631,058,754
Quad Cities Station, Unit 2	12/14/2032	16	$692,669,921	$952,054,167	$631,058,754
River Bend Station, Unit 1	08/29/2025	9	$712,800,000	$952,751,255	$626,963,546
Robinson (H.B.) Steam Electric Plant, Unit 2	07/31/2030	14	$567,362,845	$744,296,567	$409,189,430
Salem Nuclear Generating Station, Unit 1	08/13/2036	20	$609,543,000	$978,464,478	$468,691,699
Salem Nuclear Generating Station, Unit 2	04/18/2040	23	$522,417,000	$914,388,925	$468,691,699
Seabrook Station, Unit 1	03/15/2030	13	$650,671,791	$847,918,705	$503,341,699
Sequoyah Nuclear Plant, Unit 1	09/17/2040	24	$188,706,076	$617,218,777	$484,152,529
Sequoyah Nuclear Plant, Unit 2	09/15/2041	25	$179,770,274	$618,074,373	$484,152,529
Shearon Harris Nuclear Power Plant, Unit 1	10/24/2046	30	$492,852,452	$894,602,817	$465,443,031
South Texas Project, Unit 1	08/20/2027	11	$427,522,753	$554,442,462	$392,607,229
South Texas Project, Unit 2	12/15/2028	12	$521,377,891	$692,255,492	$392,607,229
St. Lucie Plant, Unit 1	03/01/2036	19	$1,014,177,909	$1,489,972,801	$468,364,546
St. Lucie Plant, Unit 2	04/06/2043	26	$974,637,287	$1,649,609,139	$468,364,546
Summer (Virgil C.) Nuclear Station, Unit 1	08/06/2042	26	$288,662,169	$535,727,919	$430,323,755
Surry Power Station, Unit 1	05/25/2032	15	$406,800,000	$560,636,237	$450,794,881
Surry Power Station, Unit 2	01/29/2033	16	$407,700,000	$569,801,321	$450,794,881
Susquehanna Steam Electric Station, Unit 1	07/17/2042	26	$551,104,747	$918,889,289	$666,764,953
Susquehanna Steam Electric Station, Unit 2	03/23/2044	27	$606,705,392	$1,045,854,722	$666,764,953
Three Mile Island Nuclear Station, Unit 1	04/19/2034	17	$625,913,000	$885,001,626	$467,860,424
Turkey Point Nuclear Generating, Unit 3	07/19/2032	16	$839,232,304	$1,145,841,732	$453,107,747
Turkey Point Nuclear Generating, Unit 4	04/10/2033	16	$948,100,859	$1,314,032,109	$453,107,747
Vogtle Electric Generating Plant, Unit 1	01/16/2047	30	$329,287,219	$644,938,354	$484,152,529
Vogtle Electric Generating Plant, Unit 2	02/09/2049	32	$326,615,373	$645,363,837	$484,152,529
Waterford Steam Electric Station, Unit 3	12/18/2024	8	$427,900,000	$564,502,446	$484,152,529
Watts Bar Nuclear Plant, Unit 1	11/09/2035	19	$239,158,220	$614,613,518	$484,152,529
Watts Bar Nuclear Plant, Unit 2	10/21/2055	39	$90,362,048	$627,320,193	$484,152,529
Wolf Creek Generating Station, Unit 1	03/11/2045	28	$444,676,000	$1,149,722,758	$492,055,879

1 Includes growth from earnings and contributions.
2 Derived from minimum formula at Title 10 of the *Code of Federal Regulations* (10 CFR) 50.75(c). Incorporates labor, energy, and low-level waste (LLW) burial escalation factors.
3 Four licensees provided SSCEs.
4 In years 2017 through 2022, licensee plans include significant contributions of approximately $600 million from a combination of Omaha Public Power District collections and a lump sum transfer from the Fort Calhoun Station, Unit 1, Supplemental Decommissioning Trust Fund.

Nuclear Decommissioning Fund
Market Fund Growth

Date	Total Fund Market Value (a)	Increase from Previous Year ($)	Increase from Previous Year (%)
December 31, 2012	$1,397,612,009		
December 31, 2013	1,622,790,606	$225,178,597	16.11%
December 31, 2014	1,786,696,775	163,906,169	10.10%
December 31, 2015	1,797,432,092	10,735,317	0.60%
December 31, 2016	1,945,738,907	148,306,815	8.25%
December 31, 2017	2,215,858,794	270,119,887	13.88%
December 31, 2018	2,158,403,479	(57,455,315)	-2.59%
December 31, 2019	2,652,217,217	493,813,738	22.88%
December 31, 2020	2,982,336,510	330,119,293	12.45%
Total		$1,584,724,501.00	81.68%
Divide by 6 years		8	8
6 Year Average		$198,090,563	10.21%

Calculation of 6 Month Growth between December 31, 2018 and June 30, 2019

December 31, 2020	$2,982,336,510		
June 30, 2021	$3,285,322,886	$302,986,376	10.16%

Note A: Information from Indiana Michigan response to OUCC Data Request Set 21, Question 1.

AFFIRMATION

I affirm, under the penalties for perjury, that the foregoing representations are true.

Michael D. Eckert
Assistant Director of the Electric Division
Indiana Office of Utility Consumer Counselor
Cause No 45576
Indiana Michigan Power Co.

October 12, 2021

CERTIFICATE OF SERVICE

This is to certify that a copy of the Indiana Office of Utility Consumer Counselor's Testimony Filing has been served upon the following parties of record in the captioned proceeding by electronic service on October 12, 2021.

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