CAC Exhibit 1

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF INDIANA MICHIGAN POWER COMPANY (I&M) FOR APPROVAL OF (1) ISSUANCE TO I&M OF CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY UNDER IND. CODE § 8-1-8.5-2 FOR THE ACQUISITION AND DEVELOPMENT THROUGH PURCHASE SALE AGREEMENTS (PSA) OF TWO SOLAR POWER GENERATING FACILITIES TO BE KNOWN AS LAKE TROUT, AND MAYAPPLE (CLEAN ENERGY PSA PROJECTS); (2) TO THE EXTENT NECESSARY, ISSUANCE OF AN ORDER PURSUANT TO IND. CODE § 8-1-2.5-5 DECLINING TO EXERCISE JURISDICTION UNDER. IND. CODE § 8-1-8.5-5(e) (3) APPROVAL OF EACH PSA PROJECT AS A CLEAN ENERGY PROJECT UNDER IND. CODE § 8-1-8.8-11; (4) APPROVAL OF TWO SOLAR RENEWABLE ENERGY PURCHASE AGREEMENTS FOR PROJECTS TO BE KNOWN AS ELKHART COUNTY AND SCULPIN (CLEAN ENERGY PPA PROJECTS) AS CLEAN ENERGY PROJECTS UNDER IND. CODE § 8-1-8.8-11; (5) ASSOCIATED TIMELY COST RECOVERY UNDER IND. CODE § 8-1-8.8-11 FOR ALL PSA AND PPA PROJECTS; AND (6) OTHER ACCOUNTING AND RATEMAKING AUTHORITY.	**CAUSE NO. 45868**

DIRECT TESTIMONY OF BENJAMIN INSKEEP

ON BEHALF OF

CITIZENS ACTION COALITION OF INDIANA

MAY 19, 2023

Confidential Information Redacted

I. INTRODUCTION

Q. Please state your name, position and business address.

A. My name is Ben Inskeep, and I am the Program Director at Citizens Action Coalition of Indiana, Inc. ("CAC"). My business address is 1915 West 18th Street, Suite C, Indianapolis, Indiana 46202.

Q. Please describe your current responsibilities.

A. I have served as CAC's Program Director since March 2022. In that role, I work to advance CAC's policy and programmatic priorities related to energy, utilities, and consumer affordability and protection.

Q. Please briefly summarize your prior employment and educational background.

A. I have more than a decade of experience working on energy and utility issues. My prior employment includes working as a policy analyst at the North Carolina Clean Energy Technology Center at North Carolina State University (2014-2016), where I co-created and served as lead author and editor of *The 50 States of Solar*, a quarterly report series tracking distributed solar policy developments in U.S. states. I also conducted policy research and contributed to the *Database of State Incentives for Renewables and Efficiency (DSIRE)* project and provided technical support, analysis, and workshops for state and local governments through the U.S. Department of Energy's SunShot Solar Outreach Partnership.

I also worked for EQ Research LLC, a clean energy policy consulting firm, from 2016-2022. I managed EQ Research's general rate case subscription service, contributed as a researcher and analyst to other policy service offerings, such as legislative and regulatory tracking services, and performed customized research and analysis for clients.

In addition, my client engagements included participation in state utility regulatory proceedings, including analyzing utility proposals and serving as an expert witness on ratemaking and energy policy issues.

I earned a Bachelor of Science in Psychology with Highest Distinction from Indiana University in 2009 and both a Master of Science in Environmental Science and a Master of Public Affairs from the O'Neill School of Public and Environmental Affairs at Indiana University in 2012. I completed the EUCI's Utility Accounting 101 course in April 2023.

Q. Have you previously filed testimony before the Indiana Utility Regulatory Commission ("IURC" or "Commission")?

A. Yes. Attachment BI-1 identifies the cases in which I have previously filed testimony.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of CAC.

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

A. The purpose of my testimony is to respond to Indiana Michigan Power Company's ("I&M") request for approval of a) the acquisition through two Purchase and Sale Agreements ("PSAs") of the Lake Trout and Mayapple solar power generating facilities ("Solar PSA Projects"); and b) two solar Renewable Energy Purchase Agreements ("REPAs," also referred to herein as power purchase agreements ("PPAs")) for the Elkhart County and Sculpin Projects ("Solar PPA Projects").

Q. Are you sponsoring any attachments to your testimony?

A. Yes. I am sponsoring Attachment BI-1: Benjamin Inskeep's Expert Witness Experience.

II. I&M's SOLAR PSA PROJECTS AND SOLAR PPA PROJECTS

Q. What is I&M requesting in this proceeding?

A. I&M is requesting approval of four solar projects, two of which are PPAs and two of which are PSAs. The projects total 749 MW of nameplate capacity.

a. Affordability and Environmental Sustainability

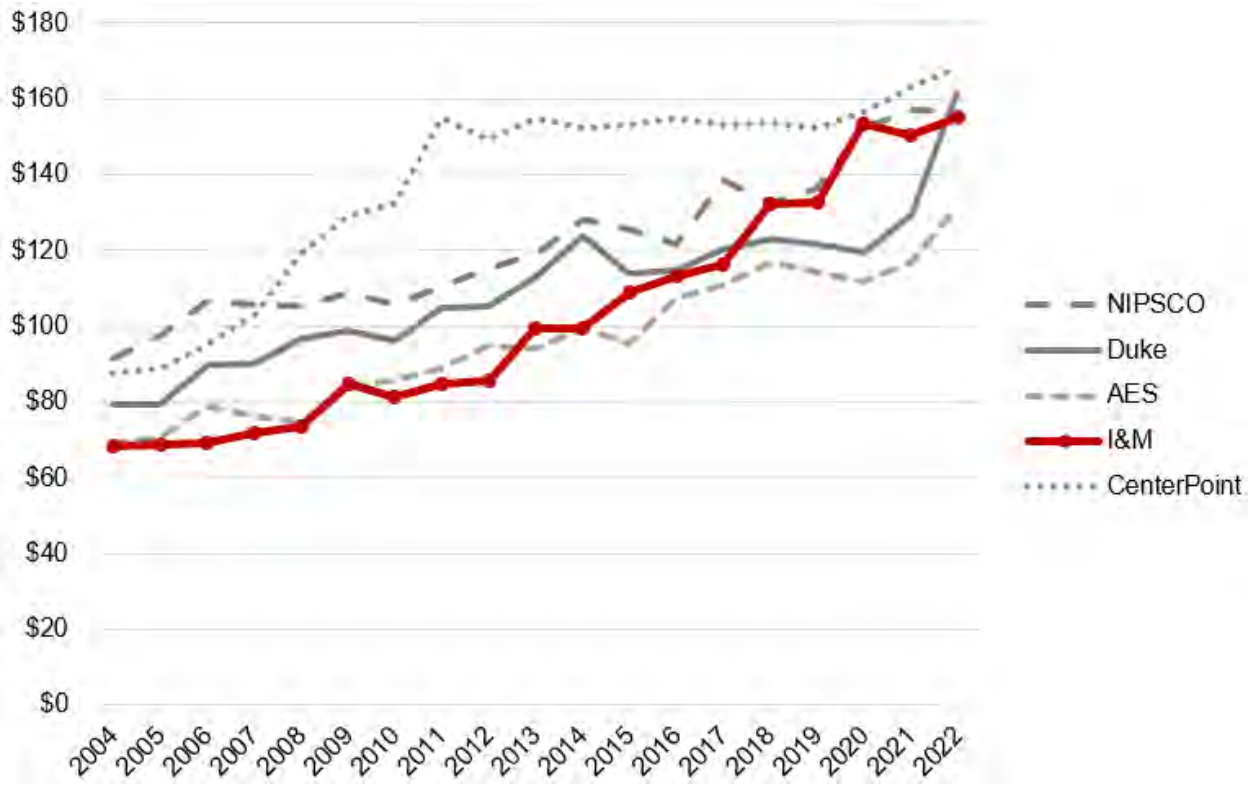
Q. Please explain the widespread bill unaffordability experienced by I&M's residential customers.

A. I&M's customers have experienced soaring electricity bills, resulting in many families being unable to afford their bills, which has led to an alarmingly high number of disconnection notices and disconnections.

I&M's residential customers are paying much more for electricity now than they did in the past. As shown in Figure 1, I&M's bills have risen precipitously in the past two decades, going from approximately $68.34 in 2004 to $155.13 in 2022, a 127% increase for 1,000 kWh of usage. It is important to note that inflation only accounts for a fraction of this increase. Adjusting for inflation, a $68.34 bill in 2004 is equivalent to a $106.90 bill in 2022 dollars.[1] In other words, **I&M's residential ratepayers have experienced a real bill increase (i.e., after adjusting for inflation) of 45.1% since 2004.** Furthermore, as is evident in Figure 1, I&M had the lowest bills of any of Indiana's investor-owned utilities in 2004. That is no longer the case, and I&M has dramatically reduced the spread between its residential bills at 1,000 kWh of usage and those of the highest-cost Indiana utilities.

[1] U.S. Bureau of Labor Statistics, "CPI [Consumer Price Index] Inflation Calculator," https://www.bls.gov/data/inflation_calculator.htm (used to calculate that $68.34 in July 2004 has the same buying power as $106.90 in July 2022).

Figure 1. Residential Monthly Bill for 1,000 kWh



The rapid rise of I&M electric bills results in an increasing number of customers who are unable to afford their electric bill, resulting in arrears or forcing families to undertake risky coping strategies (e.g., forgo food and medicine) to be able to pay their utility bills. When a Hoosier family cannot afford to pay their electricity bills, they are sent a disconnection notice from I&M, and can be involuntarily disconnected from service thereafter, jeopardizing their health and safety and creating a massive hardship that can prevent them from participating in society.

Over the six-month period September 2022 through February 2023, I&M reported that it issued more than 230,000 disconnection notices and disconnected residential customers for non-payment 24,501 times.[2] **If this data is extrapolated to a annual**

[2] I&M reporting in Cause No. 45736.

period, it indicates that I&M threatens to disconnect Hoosier families from essential utility service through disconnection notices 461,448 times each year – more disconnection notices than I&M's total number of residential customers (418,580 as of February 2023). It would also imply that I&M would disconnect Hoosier families more than 49,000 times each year.

Q. Of what relevance is electric bill unaffordability to this proceeding?

A. The trend of rising electricity costs and large number of disconnection notices and disconnections demonstrates that customers are in need of bill relief now. In the context of this proceeding, it reaffirms I&M's decision to move away from expensive coal-fired generation at its Rockport power plant and pursue a more cost-effective portfolio of replacement resources. It also highlights that any opportunities for near-term bill relief – such as by returning all production tax credit benefits to ratepayers as soon as possible – should be vigorously pursued. Finally, it emphasizes the importance of I&M pursuing the most cost-effective replacement resources, such as by using lower-cost renewable PPAs that pass through costs to ratepayers instead of more-expensive PSAs that significantly increase the cost of those resources as a result of I&M substantially increasing the revenue requirement to account for an annual rate of return.

I would also note that House Enrolled Act 1007 (2023) specifically adopted "affordability" as one of five pillars of the State's policy regarding decisions concerning Indiana's electric generation resource mix, energy infrastructure, and electric service ratemaking constructs. Affordability is a relative concept, with lower-income Hoosiers experiencing electric bill unaffordability at significantly higher rates than higher-income Hoosiers. Therefore, when evaluating a utility's planned investments and spending, I urge

the Commission to consider affordability in the context of low-income residential customers in particular.

Q. Please describe how environmental sustainability relates to this proceeding.

A. Another one of the pillars of Indiana's electricity policy adopted in HEA 1007 is "environmental sustainability," which includes (but is not limited to) the impact of environmental regulations on the cost of providing electric utility service and demand from consumers for environmentally sustainable sources of electric generation.

I&M's plan to retire the Rockport plant and to procure a substantial amount of renewable energy this decade to replace a portion of this capacity, as identified in the preferred portfolio of its most recent Integrated Resource Plan, is consistent with Indiana's electricity policy of environment sustainability. In addition to reducing massive quantities of air, water, land, and climate pollution caused by coal-fired generation at Rockport, ceasing coal-fired generation at Rockport is prudent because it reduces regulatory risk regarding planned environmental regulations that could have costly impacts on coal-fired power plants. A notable example of this is the U.S. Environmental Protection Agency's recently issued proposed rule under Section 111 of the Clean Air Act that would establish new Emissions Guidelines on existing coal-fired power plants, among other fossil fuel generators. For existing coal plants planning to operate in the long-term, the best system of emissions reductions is based on carbon capture and sequestration that would capture 90% of carbon dioxide emissions from the facility, which would require costly new equipment to be installed and result in a substantial "parasitic load" to operate, adding further costs. In addition, I&M's decision to retire coal-fired generation at Rockport allows

I&M to shift investments to renewable generation, consistent with consumers' demands for more environmentally sustainability electricity generation.

Q. What do you recommend?

A. I recommend that the Commission consider the affordability of electricity bills paid by I&M residential customers, especially low-income customers, when making its findings and conclusions in this proceeding. I also recommend that the Commission take into consideration environmental sustainability, consistent with HEA 1007, when it evaluates I&M's resource decisions.

b. Concerns with Solar PSA Projects

Q. Are there important differences between solar PPAs and PSAs?

A. Yes. Under a PSA, the solar facility is developed and constructed by a separate entity, but then ownership and operation of the facility are transferred to the utility. In contrast, the utility purchases the output (e.g., energy, capacity, ancillary services, and environmental attributes) of a solar project under a PPA, but the utility does not take ownership of the solar facility.

Because utilities own and operate projects under the solar PSA model, they are typically responsible for paying various types of costs that they would otherwise not be directly responsible for under a PPA, including interconnection costs, operating and maintenance costs, and decommissioning costs. Likewise, under a solar PSA model, the utility will also directly receive the benefits of ownership, such as the ability to earn federal tax credits on the production or investment related to the facility. These types of costs and benefits would only indirectly be part of a solar PPA, as it would be incumbent on the counterparty to price in their costs and benefits to their pricing terms; should the

counterparty overestimate the benefits or underestimate the costs (e.g., of operating and maintaining the facility over the PPA term), the counterparty rather the utility and its customers would be on the hook for the cost increases unless otherwise specified by the contract. In this respect, PPAs can be a much less risky proposition for utility customers that PSAs.

This distinction also has significant ramifications for the utility's ratepayers under utility accounting and ratemaking. Namely, utilities generally pass through to ratepayers without a markup of the costs of its purchases under a solar PPA, whereas utilities are typically authorized to recover a rate of return on solar PSA projects. PPAs can therefore offer a lower cost to customers, while still providing the same energy, capacity, and environmental attribute benefits to customers.

Q. Are there significant differences in cost to ratepayers between I&M's Solar PSA Projects and Solar PPA Projects?

A. Yes. As shown in Confidential Figure 2, the Solar PSA Projects have weighted average levelized cost of energy ("LCOE") of $[redacted]/MWh, whereas the Solar PPA Projects have a weighted average cost of [redacted] $[redacted]/MWh.[3] In other words, the Solar PSA Projects are [redacted]% [redacted] [redacted] than the Solar PPA Projects. Furthermore, the lowest-price Solar PPA Project ([redacted]) has an LCOE of $[redacted]/MWh, which is [redacted]% [redacted] than the $[redacted]/MWh LCOE of the highest-cost Solar PSA Project ([redacted]). While there are many variables that can affect the LCOE of a solar project, these differences are quite large. Furthermore, these project costs are significantly [redacted] than other solar projects that have been recently approved by the Commission that are indicative of current utility-scale solar costs. For

[3] Calculations based on data provided by I&M in Confidential Figure MAB-4.

example, the Commission approved an updated levelized cost of $65.65/MWh to $67.11/MWh (depending on bonus tax credit eligibility) for CenterPoint's Pike County Solar Project in Cause No. 45754.

Confidential Figure 2. Capacity-Weighted LCOE Comparison of Solar PSA Projects to PPA Projects

Q. Do you have any concerns about why the Solar PSA Projects are [redacted] than the Solar PPA Projects to ratepayers?

A. Yes. While there can be legitimate differences that explain the differences between LCOE across solar projects, a major reason appears to be a result of I&M's proposed ratemaking differences between the PSA and PPA projects. For the Solar PSA Projects, I&M has included in revenue requirement a return on rate base; whereas for the Solar PPA Projects, I&M is passing through the cost to ratepayers without a similar markup. While this difference may sound modest, its impact to ratepayers is actually extraordinary: **Overall, I&M would earn a return on rate base associated with the two Solar PSA Projects of**

nearly $ [redacted][4] over the 35-year expected life of the facilities, which is approximately [redacted]% of the $[redacted] total revenue requirement over the 35-year expected life.[5] This calls into question I&M's overall proposal in this proceeding that is more heavily weighted toward PSA projects (469 MW, or 63% of total nameplate capacity) than PPA projects (280 MW, or 37% of total nameplate capacity), as this finding suggests that I&M's decision is motivated by I&M's desire to increase profits rather than benefit ratepayers.

Q. What other concerns do you have about the difference between Solar PSA Projects and Solar PPA Projects?

A. The [redacted] of the Solar PSA Projects is amplified for residential customers in particular because of the different cost allocation mechanisms that would be used for cost recovery in this proceeding. The Solar PSA Projects are recovered from ratepayers through the Solar Power Rider ("SPR"), whereas the Solar PPAs are recovered through the Fuel Adjustment Clause ("FAC"). Since the SPR allocates a larger share of costs to residential customers (41.8%) than the FAC (35.9%), I&M's portfolio of solar projects that is more heavily weighted towards PSAs than PPAs means that residential customers are paying a higher proportionate burden of the net revenue requirement collected from ratepayers. Specifically, the Solar PSA Projects have a 2026 residential revenue requirement of [redacted] million, whereas the Solar PSA Projects' revenue requirement is only $[redacted] million. Put another way, the Solar PSA Projects account for 63% of the nameplate capacity and [redacted]% of the expected annual generation of the four solar

[4] I&M Confidential Workpaper AJW-3 (where the sum of cells B31 through AJ31 in tab "PSA OPCO Rev Req Levelized" is $[redacted]).
[5] I&M Confidential Workpaper AJW-3.

projects, yet they account for [redacted]% of the total Indiana jurisdictional revenue requirement and [redacted]% of the forecasted 2026 revenue requirement for residential customers specifically. This illustrates how the Solar PSA Projects are not only [redacted], but that [redacted] expense is borne in larger proportion by residential customers.

Q. Could I&M have procured the Solar PSA Projects using a PPA structure instead of a PSA structure?

A. Based on information provided in I&M's confidential Workpaper MAB-1C, [redacted]

Q. Do you have any other observations about the Solar PSA and PPA Projects?

A. It has been conventional wisdom that larger generation projects can offer an "economies of scale" benefit to ratepayers. [redacted] In my review of the projects, I did not reach a conclusion as to whether this result was due to specifics of these four projects or a larger market trend.

Regardless, I believe the other headwinds identified by I&M in its testimony with respect to procuring renewable capacity further reinforces the relevance of distributed rooftop solar and community solar as solutions warranting far greater attention and analysis

in future IRP processes. Likewise, the LCOEs of the projects call into question the fairness of the current, much smaller and extraordinarily volatile compensation rates provided to distributed solar and small power production facilities under I&M's current tariffs. These types of solar can benefit from avoiding lengthy PJM and MISO interconnection queues that often entail expensive interconnection costs that can easily result in the tens of millions of dollars in project costs. While the methodology for setting the compensation rate for Excess Distributed Generation tariffs is provided by statute, I&M has considerable discretion to propose additional options for consumers through the Alternative Regulatory Plan statute. CAC would welcome the opportunity to discuss such options further with I&M and other stakeholders so that smaller resources that can complement I&M's utility-scale resources can also be pursued to the benefit of ratepayers.

Q. What do you recommend regarding the Solar PSA Projects?

A. I recommend that the Commission deny the Solar PSA Projects and approve the Solar PPA Projects. In lieu of the Solar PSA Projects, I&M should pursue more cost effective solar PPA projects and/or wind PPA projects as well as creating one or more tariff options for distributed solar and third-party community solar.

c. Federal Production Tax Credit ("PTC") Benefits

Q. What is I&M proposing for the Solar PSA Projects regarding federal tax credits?

A. I&M is proposing to utilize the federal production tax credit on both of the Solar PSA Projects. I&M proposes that it forecast the total value of the PTCs earned over the first ten years and levelize those costs over a twenty-year period. As PTCs are earned, I&M would defer the difference between the produced PTC value and the annual amortized PTC expense as a regulatory liability.

Q. What is the impact to ratepayers if I&M's proposal to levelize the PTC over a 20-year period is approved?

A. This approach would result in ratepayers experiencing a higher revenue requirement and a larger bill increase during the first ten years of the Solar PSA Projects and a lower revenue requirement and lower bill increase during the subsequent 10-year period relative to a traditional ratemaking approach that would pass along the benefits of the PTC to ratepayers as they are earned (i.e., over the first 10 years of operation).

Q. Does this approach benefit I&M?

A. Yes. While I&M tries to frame its proposal as benefitting customers by smoothing and reducing associated rate volatility, I&M states that this approach "increases I&M's cash flows and reduces risk that I&M's credits metrics will decline."[6]

Q. Do you have concerns about I&M's approach?

A. Yes. As detailed above, I&M's residential customers are already facing widespread bill unaffordability and need bill relief now. Yet, I&M's proposal to spread the production tax credit benefits over a longer time period would result in a higher immediate bill impact to I&M ratepayers. The acute, real affordability concerns of I&M's ratepayers today and in the near future outweigh the more speculative benefits associated with I&M's proposal ten to twenty years into the future. Therefore, it is in the best interest of ratepayers and residential customers in particular for I&M to pass along all production tax credit benefits earned by the Solar PSA Projects to ratepayers as quickly as possible.

Q. What do you recommend?

[6] Williamson Direct Testimony, p. 11, line 11, through p. 12, line 6.

A. I recommend that, if the Commission approves the Solar PSA Projects contrary to my recommendation, it direct I&M to return all production tax credit benefits to ratepayers over a 10-year period instead of I&M's proposed 20-year period. Furthermore, I recommend that any increase in federal tax benefits not included in I&M's cost estimates, such as any bonus adders that might ultimately be realized but not fully reflected in I&M's estimates, be fully passed on to ratepayers as quickly as possible.

III. IRP and RFP

Q. Does CAC participate in opportunities regarding I&M's resource planning?

A. CAC actively participates as a stakeholder in I&M's Integrated Resource Plan ("IRP") process, including I&M's 2021 IRP. CAC's staff and consultants attend I&M's public IRP meetings and technical stakeholder meetings, serve informal data requests, provide informal comments in response to many public IRP meetings, and submit comments on I&M's final IRP and the subsequent draft Director's Report. CAC also reviews and provides input on draft Requests for Proposals when I&M allows for this opportunity, which CAC greatly appreciates. In summary, CAC is a very active and constructive participant in I&M's IRP and RFP processes, while advocating for outcomes consistent with our priorities as a consumer and environmental advocate.

While CAC's comments[7] on I&M's 2021 IRP pointed out some flaws and disagreements with the process, assumptions, data, and methodologies used by I&M, CAC

[7] Chelsea Hotaling, et al., "Report on Indiana Michigan Power Company's 2021 Integrated Resource Plan," submitted to the IURC on August 3, 2022, 2020, https://www.in.gov/iurc/files/IM-IN-2021-IRP-CAC-Earthjustice-VS-Comments-8-8-2022_Redacted.pdf.

does not dispute that it is reasonable and prudent for I&M to close the Rockport power plant on the schedule identified and procure at least 2,100 MW of solar and wind generation and 60 MW of battery storage by 2028. However, I do have concerns about the high demand and low supply of wind projects in Indiana, and I urge I&M to continue its efforts to procure cost-effective wind PPAs that can benefit customers and complement its solar resources. I believe this highlights the urgency of addressing local siting barriers in Indiana and expanding regional transmission capacity to increase Hoosier access to low-cost out-of-state wind facilities to the extent demand cannot be fulfilled by in-state projects at a reasonable cost.

Q. Do you have any concerns about the Request for Proposals from which the Solar PSA Projects and Solar PPA Projects were selected?

A. Yes. I&M applied unduly restrictive criteria that limited potential bidders. These provisions result in fewer projects bidding into the RFP, meaning there is less competition between projects. Ultimately, consumers could pay higher costs as a result of restrictions that prevent more cost-effective projects from participating or being selected.

Q. Please describe the concerns you have regarding the RFP's geographic restrictions.

A. I&M applied restrictive geographic requirements in its RFP. Wind projects were limited to Indiana, Michigan, Ohio, or Illinois. Solar (and storage) projects were limited to Indiana and Michigan.

I&M's restrictive geographic siting requirements means that projects that are potentially more cost-effective and provide better value to ratepayers, but are located outside of those states, would not be eligible for consideration by I&M. The arbitrary nature of these restrictions is evident from the differing geographic restrictions between wind and

solar. If a wind project in Illinois or Ohio is eligible, so too should a solar project located in these states. In comments submitted to I&M regarding its draft 2022 RFP, CAC recommended that Ohio be an eligible location for solar projects. While I recognize there are benefits to I&M procuring a portion of its resource portfolio from resources in-state and located closer to load, and I do not object to I&M's stated preference for projects that provide economic benefits to Indiana and Michigan,[8] that does not mean I&M should not consider adding some resources from other locations if they can provide value to ratepayers without creating an undue risk with respect to deliverability. In an inflationary environment where there is high demand for both new solar and wind projects, I&M should cast as wide a net as possible when considering potential resources to ensure it is not inadvertently excluding many beneficial projects from consideration.

Q. Please describe the concerns you have with respect to the RFP's interconnection requirements.

A. In both its 2022 and 2023 All-Source RFPs, I&M required projects interconnecting to have completed Phase 3 of MISO's Definitive Planning Phase ("DPP") and have the Final DPP SIS and Network Upgrade Facilities Study and have secured Firm Transmission into PJM.[9] These are very restrictive requirements, as projects will have had to have been quite far along the interconnection process in order to qualify. While it is understandable that I&M seeks to mitigate interconnection cost and delay risks, a more nuanced and flexible approach would be to allow for projects earlier in the interconnection process to still be eligible to respond to RFPs, but to score them lower in this category when evaluating these

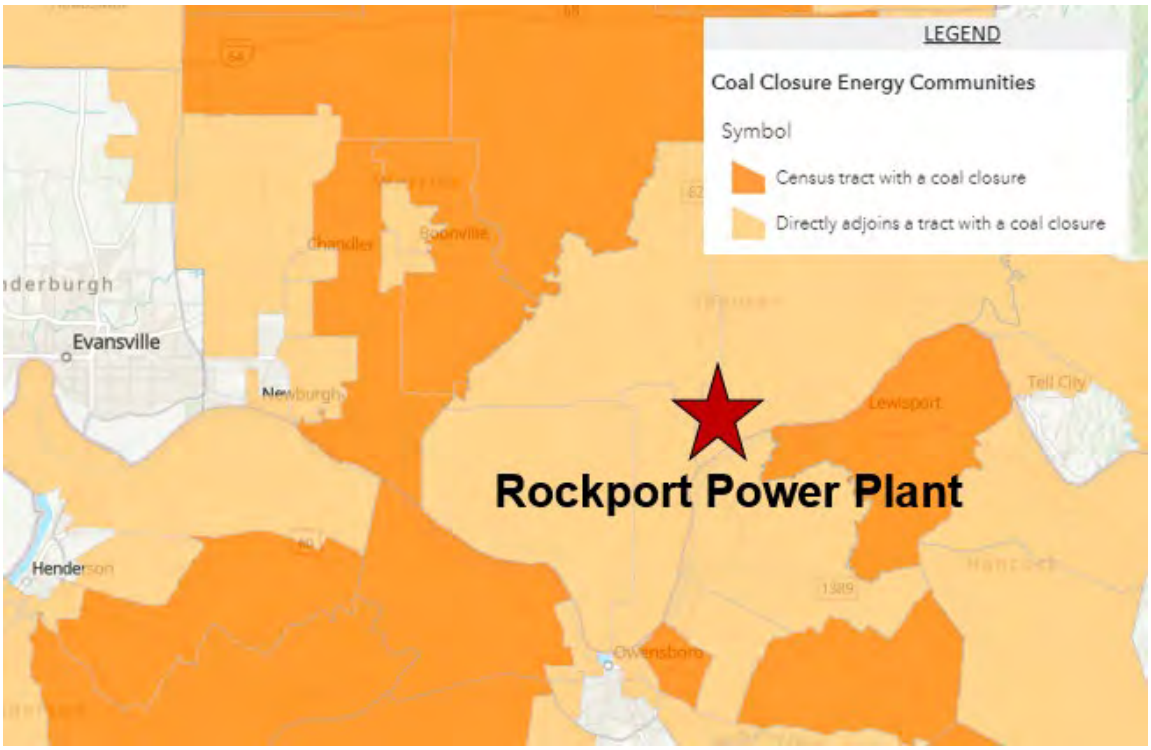
[8] 2022 I&M All Source RFP, Section 3.6.
[9] 2022 I&M All Source RFP, Section 3.9.3.

projects relative to projects that are farther along the interconnection process. This would allow I&M to consider more projects that could still come online by the timeline needed while still taking into consideration that projects earlier in the interconnection process have additional risks.

Another issue CAC commented on in response to I&M's draft 2022 and 2023 RFPs pertains to the issue of interconnection rights at I&M's Rockport power plant. None of the four solar projects proposed by I&M in this proceeding utilized these interconnection rights. Yet, as Rockport's capacity is retired – all of it by 2028 – it will allow for alternative resources to take its place. Repurposing Rockport's current interconnection rights for renewable energy and battery storage resources in the future would allow those new resources to skip the lengthy interconnection queue and avoid grid improvement costs, delays, and other unexpected modifications.

Making this proposition even more valuable is the fact that southwestern Indiana where Rockport is located is the area of Indiana most likely to qualify for significant additional federal tax credits and can reduce resource costs passed on to customers. Specifically, the Rockport site and all of the entire area surrounding it appear to qualify as federally designated Energy Communities, making solar, battery energy storage, and other types of clean generation sited in these areas eligible for a bonus 10% federal investment tax credit or production tax credit. The cost- and time-saving aspects of repurposing Rockport's interconnection rights in combination with the availability of lucrative, additional federal tax incentives for these projects provide a huge upside for I&M's customers for locating renewable energy and battery energy storage projects at the Rockport site or using its interconnection rights.

Figure 3. Rockport Power Plant Relative to Federally Designated Energy Communities[10]



While I&M's 2022 RFP did not expressly allow for use of its Rockport injection rights, I&M's 2023 RFP did expressly allow for natural gas combustion turbines or battery energy storage systems to propose using a portion of the Rockport site, while prohibiting other technologies from using the Rockport site. To its credit, I&M did also clarify that certain off-site projects are eligible for Rockport's injection: "I&M will offer the Rockport injection point to offsite projects of any generation type, however, such proposals will need to demonstrate site control that does not introduce an unacceptable level of risk and

[10] This figure currently shows areas that the U.S. Department of Energy has determined meet the following eligibility requirement: "Census tracts and directly adjoining tracts that have had coal mine closures since 1999 or coal-fired electric generating unit retirements since 2009." Additional Energy Communities not currently shown will also be designated later in May 2023. In addition, brownfields are eligible but are not shown. https://arcgis.netl.doe.gov/portal/apps/experiencebuilder/experience/?id=a2ce47d4721a477a8701bd0e08495e1d

uncertainty with respect to execution, schedule, and cost."[11] However, I&M limited both the use of its Rockport site and injection rights only to projects using a PSA model and expressly prohibited PPAs.[12] This means that a solar facility sited nearby the Rockport plant could not bid a PPA project into the 2023 RFP, and all solar or solar-plus-storage facilities sited at the Rockport plant were ineligible.

Q. What do you recommend regarding I&M's interconnection requirements in its All-Source RFPs?

A. I recommend that I&M not include any undue barriers or restrictions for project interconnection as part of its All-Source RFPs, including allowing projects earlier in the interconnection queue to bid into the RFPs and using scoring criteria as appropriate to reflect the higher risk of earlier-stage projects. I also recommend that I&M utilize existing interconnection rights at its Rockport power plant for renewable energy and/or battery storage projects.

[11] 2023 All-Source RFP, Section 2.16.
[12] 2023 All-Source RFP, Section 2.16.

IV. CONCLUSION

Q. What are your recommendations?

A. I recommend that the Commission:

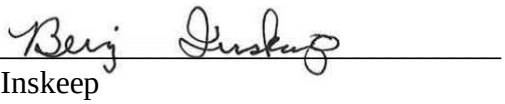
- Deny the Solar PSA Projects and direct I&M to procure more renewable energy through cost-effective PPAs;
- Approve the Solar PPA Projects;
- If it approves the Solar PSA Projects, deny I&M's request to levelize the PTC over a 20-year period and instead direct I&M to return the full benefits of the PTC to ratepayers as they are earned (i.e., over a 10-year period).
- Direct I&M to "cast a wide net" as it procures additional resources to replace Rockport, including allowing projects from a broad geographic area to submit bids, removing undue restrictions on the use of the Rockport site and interconnection rights for prospective replacement projects, and to create new tariffs that enable consumers to invest in distributed generation and community solar while receiving a stable and fair compensation rate for their excess generation.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

I, Ben Inskeep, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.



May 19, 2023

Ben Inskeep

Attachment BI-1: Benjamin Inskeep's Expert Witness Experience

Indiana Utility Regulatory Commission

Cause No.	Case Description
38703 FAC 133-S1	AES Indiana Eagle Valley Outage
45504	AES Indiana Excess Distributed Generation Tariff
45505	NIPSCO Excess Distributed Generation Tariff
45506	I&M Excess Distributed Generation Tariff
45508	Duke Energy Indiana Excess Distributed Generation Tariff
45700	NIPSCO Michigan City Coal Ash Compliance Project
45701	I&M Demand-Side Management Plan 2023-2025
45722	CenterPoint Securitization of AB Brown
45740	Duke Energy Indiana and International Paper Special Contract
45749	Duke Energy Indiana Coal Ash Compliance Project
45772	NIPSCO Electric Rate Case
45775	Duke Energy Indiana Low-Income Consumer Protections
45795	CenterPoint Culley East Coal Ash Compliance Project
45797	NIPSCO Schahfer Coal Ash Compliance Project
45803	Duke Energy Indiana Demand-Side Management Plan 2024-2026
45836	CenterPoint Wind Project CPCN
45843	AES Indiana EV Portfolio

Kentucky Public Service Commission

Case No.	Case Description
2020-00174	Kentucky Power's 2020 Rate Case
2020-00349	Kentucky Utilities' 2020 Rate Case
2020-00350	Louisville Gas & Electric's 2020 Rate Case