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 IN RATE BASE OF QUALIFIED POLLUTION CONTROL PROPERTY AND CLEAN ENERGY PROJECT; (4) ENHANCEMENTS TO THE DRY SORBENT INJECTION SYSTEM; (5) ADVANCED METERING INFRASTRUCTURE; (6) RATE ADJUSTMENT MECHANISM PROPOSALS; AND (7) NEW SCHEDULES OF RATES, RULES AND REGULATIONS.	)	**CAUSE NO. 45235**

INDIANA MICHIGAN POWER COMPANY'S SUBMISSION OF RESPONSE TO DOCKET ENTRY DATED SEPTEMBER 27, 2019

Petitioner, Indiana Michigan Power Company (I&M), by counsel, hereby submits the attached response to the Docket Entry dated September 27, 2019

Respectfully submitted,

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CERTIFICATE OF SERVICE

The undersigned certifies that the foregoing was served upon the following via electronic email, hand delivery or First Class, or United States Mail, postage prepaid this 1st day of October, 2019 to:

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DMS 15212929v1

INDIANA MICHIGAN POWER COMPANY
INDIANA UTILITY REGULATORY COMMISSION
DATA REQUEST SET NO. IURC Set 1
IURC CAUSE NO. 45235 IN 2019 Base Case

DATA REQUEST NO Q-IURC Set 1-IURC 1-01

REQUEST

Please identify, on average, how many AMR meters I&M replaced annually during (a) 2017, (b) 2018, and (c) 2019 due to AMR meter failure.

RESPONSE

Please see the table below for the number of meters replaced for 2017, 2018, and 2019 as of 8/19/2019. The Number of AMR meters in the first column, "Number of AMR Meters Replaced (Indiana)" represents meter replacements in Indiana due to meter failure, and the number of meters in the second column "Number of AMR Meters Replaced (I&M)" represents the total number of meter replacements for all causes. The total number of replacements along with new meter installations are important for assessing AMR inventory levels.

Year	Number of AMR Meters Replaced (Indiana)	Number of AMR Meters Replaced (I&M)
2017	1,251	8,468
2018	1,392	8,739
2019	735	3,227

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DATA REQUEST NO Q-IURC Set 1-IURC 1-02

REQUEST

Please state whether I&M has an inventory or available stock of AMR meters that I&M uses for replacement purposes, and if I&M has such an inventory or source, please state how many AMR meters are currently in stock.

RESPONSE

As of 9/4/2019 there are a total of 13,487 AMR meters warehoused for the replacement of meters that need to be changed out or installed for various reasons.

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DATA REQUEST NO Q-IURC Set 1-IURC 1-03

REQUEST

Based upon AEP's history of AMI deployment in other service territories, please provide the saturation percentage of customers who use this software to gather information monthly and of that percentage, please provide the percentage who then use that information to change their behavior to save costs. (In providing the foregoing, please identify the territory(ies) and time period(s) upon which the information provided is based.)

RESPONSE

AEP has experience with AMI deployments in the Public Service Company of Oklahoma (PSO) and AEP Ohio. I&M has worked directly with both companies to take advantage of best practices related to customer education and engagement. It is important to point out that during the customer engagement process associated with AMI, AEP has found that customers have become better aware of other AEP customer offerings, such as the mobile app, outage alerts, e-billing, and home energy reports, which has improved the overall customer experience.

PSO completed their AMI deployment between February 2014 and July 2016. PSO provides a residential, commercial, and industrial web portal that utilizes AMI data to provide customers information on energy usage. PSO had 30,000 customers (5% of total) utilize the portal last year and a few hundred customers visit the portal each day. PSO has found the customer portal to be a strong complement to the e-mails customers receive from the behavioral energy efficiency reports. The number of customers using the portal increases directly after customers receive the behavioral report e-mails.

PSO also has initiated three customer programs that complement the AMI deployment. The first is a residential Time of Use (TOU) rate. PSO currently has approximately 22,000 customers (5% of residential) on the residential TOU rate, which incentivizes customers to be more efficient in when and how they use energy. The second is a pre-pay program that allows customer to pay in advance and manage their energy usage with the tools that PSO provides. There are approximately 10,000 customers (2% of residential) currently active in the program. Last is a commercial load reduction program. PSO has approximately 11,000 customers (16% of commercial and industrial) and 45MW's of demand enrolled in this program. As stated in Company witness Lucas rebuttal testimony (p.7, lines 3-8), I&M is actively considering offering these types of programs in Indiana as the AMI implementation continues to progress.

AEP Ohio is currently in the implementation phase of the AMI deployment that began in February 2017 and expected to continue through February 2021. Similar to PSO, AEP Ohio provides a residential web portal that utilizes AMI data to provide customers information on energy usage. Customers that receive Home Energy Reports (approximately 155,000 customers) have a login rate to the portal of 5.78%.

AEP Ohio also utilizes AMI data to provide three additional customer e-mails that provide information on the energy usage, energy efficiency tips, and potential high bills. The first e-mail program is the Home Energy Report. During the month of August 2018, this report was sent to approximately 134,000 customers and had an open rate of 36%. The second e-mail program is the High Bill and Usage Alert. During the month of August 2018, this alert was sent to approximately 49,000 customers and had an open rate of 45%. The High Bill and Usage Alert provide customers an early warning that their usage is high allowing them to change their behavior during the month to mitigate the size of their bill. The third e-mail program is the weekly AMI breakdown report. This e-mail, which customers must opt-in to, was sent to approximately 1,700 customers each week and has a 66% open rate.

AEP Ohio is in the process of rolling out a new web and app based portal for its non-residential customers. I&M is working directly with AEP Ohio during the product development and roll-out of this program with plans to offer this same product in Indiana.

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DATA REQUEST NO Q-IURC Set 1-IURC 1-04

REQUEST

Since AMI meters allow for two-way communication between the customer's meter and the utility, please explain whether an AMI meter is more susceptible to being a gateway for cyber criminals to gain access to I&M' s system than the current AMR meters. What, if any, additional actions, investments, and/or costs does I&M anticipate will be needed to mitigate cyber access to its system via this gateway?

RESPONSE

In AEP's environment AMI meter infrastructure is no more susceptible than AMR meters to being a gateway for cyber criminals to gain access to I&M's system. The AMI meter infrastructure is hosted externally, mitigating the risk of the AMI network being direct gateway for cyber criminals to gain access to I&M's system.

I&M's distribution and AMI system is monitored by I&M/AEP's Security Cyber Intelligence Response Center 24 hours per day, 7 days per week. Threat intelligence and vulnerability information are constantly monitored, allowing immediate response and mitigation for any urgent risks.

I&M/AEP Security maintains strong relationships with peer utilities and government entities to help ensure awareness of any potential cyber or physical threats on the electric industry. I&M's existing AMI meters have been penetration tested, which identifies any vulnerabilities in either the hardware or software used to manage the AMI system. I&M plans to conduct additional penetration test in the future which will include any new meters that have been installed since the last test. The enterprise distribution system has been evaluated for potential security risks and mitigations have been implemented for anything identified.

I&M/AEP Security also conduct detailed third-party risk reviews on any vendor that would require access to customer data. These risk reviews include a detailed review of the vendor's cyber security policies and procedures, data management, and in some cases include a physical audit of the location where the data will be stored.

With respect to customer data privacy, I&M/AEP does not store customer identifying information, such as name, address or account number in the AMI meters and does not transmit this information across the network. I&M/AEP cannot provide usage data to 3rd parties without the customer's consent.

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REQUEST

Since I&M established amortization periods of two-years for most of its deferred balances based upon the expectation that this is the probable time period between resetting its base rates, please explain in detail and with specificity why, if the Commission were to approve deploying AMI meters, it would not be prudent for I&M to request cost recovery of AMI meters in its next base rate case (projected future test year of no earlier than December 31, 2022) when the AMI meters are projected to have been installed in lieu of the tracker proposed.

RESPONSE

I&M has requested that the Commission preapprove the deployment of AMI meters; such requests are permissible under Ind. Code §8-1-2-23. While recognizing new plant in service via a general rate case is one option, a rate adjustment mechanism is a better option for AMI.

AMI deployment is a significant, multiyear project that begins in the Test Year but continues through 2021 and 2022. Tracking the cost of AMI would promote rate gradualism by reflecting AMI costs in rates gradually over time, rather than through a one-time change in base rates. This gradual inclusion of AMI costs in rates better reflects the cost of providing service to customers over time. Tracking of AMI costs also allows for the Commission and stakeholders to receive timely and valuable updates on the progress of the deployment. Finally, while two years is the most likely time until I&M's next base rate case (*e.g.,* a forecasted test year of 2022), there are numerous factors that affect the timing of a base rate case, such as changes in load and in I&M's cost of service. Tracking would provide timely recovery of AMI costs in the event I&M's next base case is filed more than two years in the future (*e.g.*, a forecasted test year of 2023).

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DATA REQUEST NO Q-IURC Set 1-IURC 1-06

REQUEST

For I&M, based on its current proposal, please provide updated financial exhibits based on 2,230 FTE positions.

RESPONSE

In order to reflect a reduction in FTEs from the level included in I&M's filed financial exhibits an additional adjustment would need to be added to Exhibit A-5. Please see IURC 1-6 Attachment 1 for the calculation of the adjustment, and IURC 1-6 Attachment 2 for the update to financial Exhibit A-5 filed in the Company's case in chief. The forecasted total O&M included in the case was set at a level to accomplish the work plans presented in the case. To the extent I&M has unfilled positions in 2020 other components of the forecast, such as contract labor, overtime, or outside services could potentially increase. Therefore, if a reduction to the labor related O&M is made in the case then an increase in O&M related to increased contract labor, overtime and/or outside services should also be made. In any case, no adjustment should be made to capital or rate base due to an assumption of a lower level of FTEs. In order to complete the capital projects presented in this case labor is required either in the form of I&M employees or outside contractors.

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DATA REQUEST NO Q-IURC Set 1-IURC 1-07

REQUEST

Please provide examples of operation and maintenance expenses the Commission has adjusted for inflation in the past that I&M believes are analogous to the proposed inflationary adjustments.

RESPONSE

To be clear, I&M is not proposing an inflationary adjustment to historical costs for the purposes of establishing the Test Year O&M expense forecast. As described in Company witness Lucas' Direct Testimony (p. 7, lines 1-23; and p. 9, lines 10-14), I&M's O&M forecast is developed based on specific work plans and emergent work performed in a particular year that are necessary to maintain ongoing operations.

Company witness Lucas' Direct Testimony (p. 9, lines 18-22) explains that "the comparisons included in Attachment DAL-1 are dollar-for-dollar comparisons without adjusting for inflation over the five-year period. An inflationary adjustment to historical costs would be necessary to correctly reflect that cost during the TY." This reference to inflation is simply pointing out that if one were to specifically compare the TY costs in 2020 to the historical costs in 2014, it would be reasonable to adjust the historical costs for inflation.

The one instance in which the Company has proposed an inflationary adjustment to O&M expense relates to the Major Storm Reserve and is discussed in Mr. Williamson's rebuttal testimony (pp. 63-64). I&M's Major Storm Reserve was approved in *Re Indiana Michigan Power Co.*, Cause No. 44075 (2/13/2013) at 72-73. In that case, the Commission used the five-year average for the period April 2006 through March 2011 as the base amount for purposes of the reserve. *Id.* at 68.

In the instant case, Company witness Williamson has accepted the OUCC's proposal to update the base amount to the five-year average for 2014-2018 but has proposed that the amounts be inflation adjusted, resulting in an increase of $202,000. See Williamson Rebuttal at 63 (proposing $2,675,000 five-year average); Alvarez at 3 (proposing $2,473,000 five-year average).

The Company has not identified another IURC order that inflation-adjusted major storm expense in a contested rate case for purposes of updating a storm reserve base amount but, as shown below, has identified two decisions from other jurisdictions that inflation-adjust storm expense.

The following IURC decisions recognize the concept of inflation with respect to property value and operating expense:

1. *Re Indiana Michigan Power Co.*, Cause No. 39314 (IURC 11/12/1993) at 41, 45 (discussing need to recognize the "commonly known and recognized fact of inflation" in determining value of utility property); see also *Indianapolis Water Co. v. Pub. Serv. Comm'n*, 484 N.E.2d 635, 640 (Ind. Ct. App. 1985); see also Cause No. 39314 Order, p. 97 (discussion of nuclear O&M expense adjustment recognizes OUCC witness analysis inflation adjusted 1990 non-labor expenses for purpose of comparison to 1991 non-labor expenses).

2. *Re Commission Investigation and Generic Proceeding of Rates and Unbundled Network Elements and Collocation for Indiana Bell Telephone*, Cause No. 42393 (IURC 1/5/2004) at 150-154, 2004 PUC LEXIS 117, *393-395 (discussing series of inflation factors SBC applied to the investment and operating expense inputs utilized by SBC's cost studies). The Commission found that "[a]t this time the Commission will not order any inflation adjustment since we agree with the CLECs that SBC does not factor in productivity." However, the Commission went on to state that it is "interested in using a productivity factor and inflation factor for ongoing adjustments to the rates." *Id.* at 154.

3. *Petition of Department of Waterworks*, Cause No. 43645 (IURC 2/2/2011) at 38, 2011 Ind. PUC LEXIS 30 at *109 made the following finding with respect to inflation adjusted operating expenses:

> However, as noted by Ms. Baumes, the NCPI, which allocates an agreed-upon weight to Labor, Chemical, Utility and other CPI expenses, does attempt to better reflect the types of costs incurred by a water utility. Such clauses are not unusual or unreasonable because the parties recognize that the costs associated with the services being provided under the Management Agreement will change over time. In this way, the value of the fee does not become out of sync with the operating costs upon which it is based. Therefore, we believe Petitioner's test year Fixed Fee should increase prospectively based on the 4.25% index factor computed by Ms. Baumes.

4. *Re Indiana Michigan Power Co.*, Cause No. 44075 (IURC 2/13/2013) at 105 (finding that inflation should be factored into dismantlement cost estimates).

5. *Re Indiana American Water Co.*, Cause No. 42520 (IURC 11/18/2004) at 69-70 (discussing inflation adjusted cost of debt).

At the time I&M first proposed its Major Storm Reserve, the Company identified other jurisdictions where an average concept and/or similar reserve was used. See I&M Reply Brief filed September 13, 2012 in Cause No. 44075, p. 83 n. 26.

One cited case was *Southern California Edison Company*, 1984 Cal. PUC LEXIS 1050, 105-106 (Cal. PUC 1984) wherein a five-year historical average was used to estimate storm damage. That decision (at *50-51) includes a general discussion of "historical escalation" which explained in pertinent part as follows:

> In order to compare recorded expense levels over several years, it is necessary to adjust the recorded data for the effects of inflation in the various years. Therefore, recorded and estimated expenses are adjusted to base year dollars so that comparisons of expense levels over time can be made on a comparable basis. Differences in adjusted historical expenses occur as a result of the use of different rates in escalating prior years' recorded expenses to the base year. In this case, 1982 was generally used as the base year.

The above referenced brief also cited *Louisville Gas and Electric*, Case No. 2003-00433, 2004 Ky. PUC LEXIS 525, *60-61 (KY PSC June 30, 2004) which calculated storm damage expense using an inflation factor. The short finding is set forth below (footnotes omitted):

> Storm Damage Expense
>
> LG&E proposed to normalize its storm damage expense by using a 10-year historic average adjusted for inflation. LG&E stated that this was the same methodology utilized by the Commission in Case No. 1990-00158. The normalization resulted in an increase of $ 70,492 over the test-year actual expense.
>
> While the Commission agrees with the methodology used by LG&E, the inflation factor was not determined in a manner consistent with the approach used by the Commission in previous cases. The inflation factor previously used by the Commission is based upon the Consumer Price Index -- All Urban Consumers ("CPI-U"). To determine the inflation factor for a particular year, the Commission divides the CPI-U for the base year by the CPI-U for the particular year. The Commission has recalculated the storm damage expense adjustment using the inflation factor approach

previously utilized, and determined that LG&E's storm damage expense should be increased by $ 83,765.

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REQUEST

Part of the basis for the OUCC and Intervenors' positions that OSS margin benefits should be shared 100% to the ratepayers is premised upon I&M having minimal involvement in the process because PJM sells I&M's excess generation and I&M is required to include all of its generation on PJM. Mr. Thomas is requested to elaborate upon, with specificity, how I&M's expertise in the wholesale energy market creates value for I&M and for its ratepayers.

RESPONSE

American Electric Power Service Corporation's (AEPSC's) Commercial Operations Department has adopted a highly integrative approach that incorporates the abilities of I&M's generation fleet along with Commercial Operations' expertise in the various PJM energy and ancillary revenue markets. To claim that "PJM sells I&M's excess generation" is an incorrect view of the high level of coordination undertaken by both I&M and Commercial Operations. When preparing bids, coordinating unit status and determining which units, and under what parameters, to offer to the market, Commercial Operations bases its decisions in light of the total revenue expected.

Furthermore, the PJM Day-Ahead market is designed to determine the least-cost solution to meet the Energy Bids and Reserve requirements for the entire PJM footprint. Commercial Operations, on behalf of I&M, is able to focus its efforts on providing additional benefits in the form of lower purchased power cost used to serve customers and in capturing additional opportunities for off-system sales margins by extending its analysis of a unit's economic operation over a period of at least seven days. The projected economics of I&M's generation over this longer period of time allows I&M's units to be used in a more efficient manner.

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REQUEST

In his rebuttal testimony, Mr. Thomas states that "[r]emoving all incentive to participate in the market will not properly compensate I&M for its efforts to effectively compete in the market and the risks it is taking to create the value being shared with customers." Mr. Thomas (in addition to other witnesses I&M deems appropriate) is requested to provide examples and explain fully and with specificity the types of efforts I&M makes to compete in the market. Also, please explain in greater detail the risks I&M is taking to create the value being shared with customers.

RESPONSE

The referenced testimony is from I&M witness Thomas' rebuttal testimony in Cause No. 44967, not the instant case. I&M witness Williamson describes in his rebuttal testimony the types of activities undertaken to optimize the value of I&M's generating assets. Specifically, at p. 24:

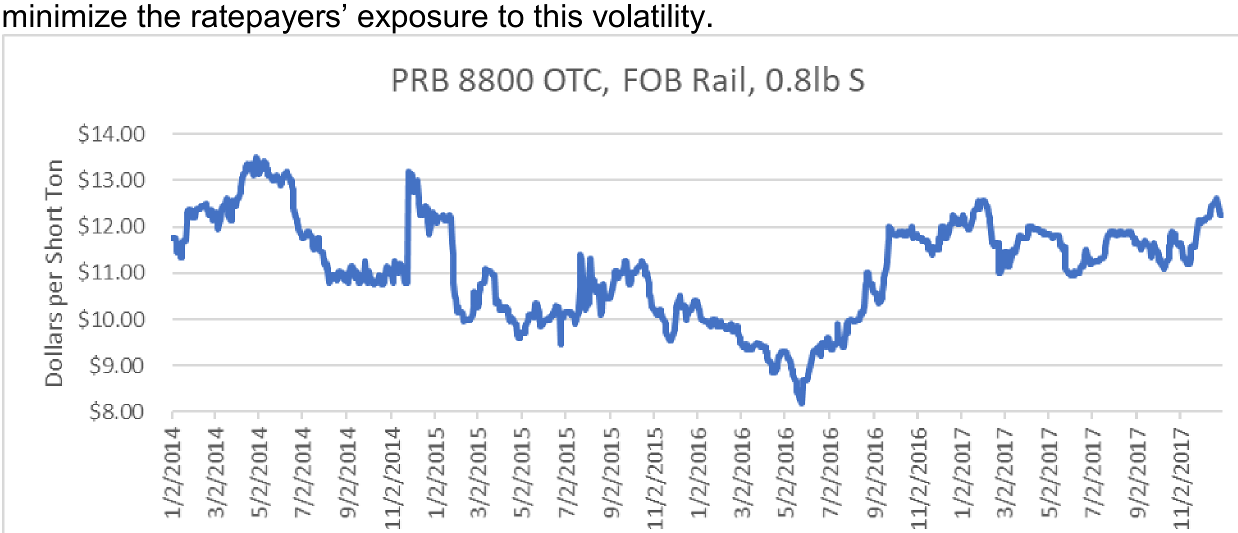
> I&M utilizes an integrated approach to optimizing OSS margins through the American Electric Power Service Corporation's (AEPSC's) Commercial Operations. This integrated model leverages the synergies of the company's physical generation fleet in close coordination with the organization's non traditional utility commercial activities. Such non-traditional activities include the company's participation in competitive energy auctions, marketing mid-term to long-term energy supply to wholesale customers, the use of financial energy trading instruments, and active hedging. This model has proven to provide the Company and its customers greater benefits than an approach limited to merely selling surplus energy into the wholesale power market.

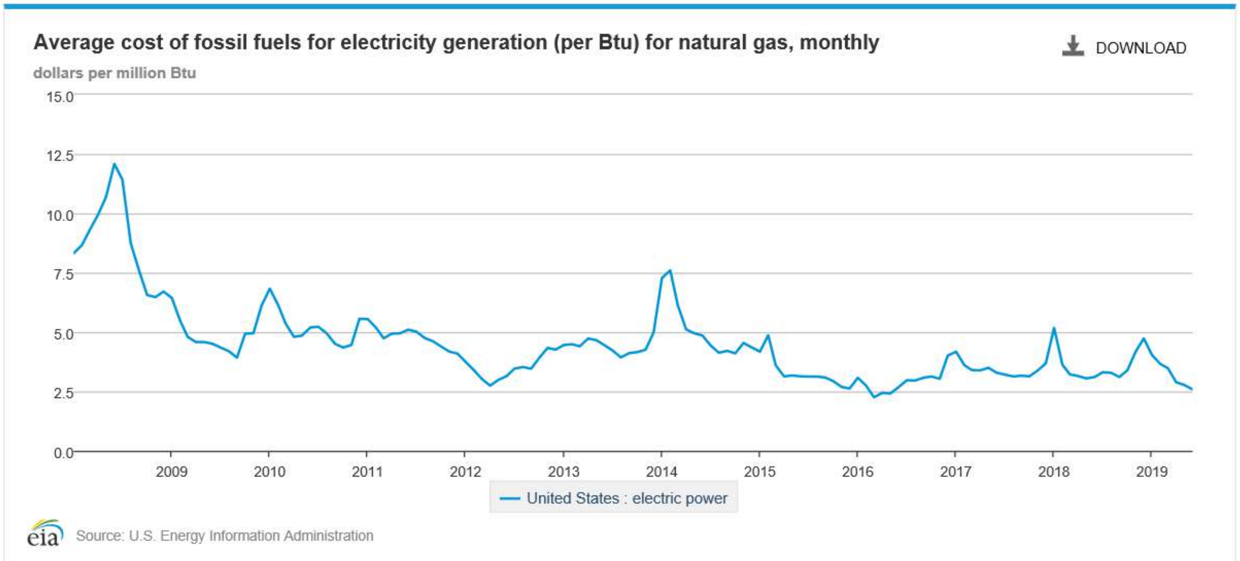
I&M utilizes an integrated approach to optimizing the value of its generation assets through the AEPSC Commercial Operations. Commercial Operations leverages the Company's physical generation fleet through commercial activities by participating in capacity auctions, selling into energy and ancillary revenue markets, marketing energy supply to wholesale customers., the use of financial trading instruments, and active hedging.

To further expand on the discussion included in the response to question eight, the daily activities include a range of individuals with expertise in PJM's commercial markets, engineers with expertise in power plant operations, financial analysts, meteorologists to forecast weather impacts, economists to forecast load and demand, and transmission specialists to evaluate transmission limitations and congestion. Daily activities include an analysis of projected load at I&M, its sister companies, and PJM as a whole as well as the available generation for those three regional footprints incorporating both meteorological expectations of weather and economic expectations of load. The projection of load is coupled with a projection of available generation both internally and in the PJM energy market using engineering expertise and commercial markets analysis. This analysis of available generation includes available generation as well as what could be made available given known start-up times and ramp rates for Company generation. While these evaluations are done daily in advance of the Company's offerings into the Day-Ahead Energy and Ancillary Markets, they are constantly updated throughout the day in order to respond to changes in the Real-Time Energy and Ancillary Markets.

The Company is exposed to various forms of risk that include: the variable cost of generation, credit risk, counterparty performance risk, volumetric risk, and basis risk.

Variable Cost of Generation. The primary driver of the Company's cost of generation is the cost of the Company's fuel. The first graph below shows the daily price movement of Powder River Basin Coal, a coal similar to the primary form of coal used to power the Company's Rockport units. This provides a visual representation of the volatility in the coal market that the Company must navigate in order to supply power from its coal-fired units. The second graph demonstrates the price volatility of natural gas used to generate electricity, the primary driver of market price volatility. In both cases, Commercial Operations must have the expertise and capability to manage peak pricing periods and minimize the ratepayers' exposure to this volatility.





Credit Risk. As the transaction will involve two counterparties, there is the risk that the counterparty may not have the ability to pay its obligations. AEPSC employs extensive and stringent credit analysis in order to manage credit risk. AEP's Credit Risk group independently monitors AEPSC's counterparty credit risk exposure on a daily basis.

Counterparty Performance Risk. The counterparty may not be able to deliver on a transaction, such as in the case where an independent power producer's generating facility experiences a forced outage, or transmission congestion may prevent the delivery of contracted energy.

Volumetric Risk. There is volumetric risk associated with unanticipated variations in load, or in the availability of generation. AEPSC manages these variations through its trading activity.

Basis Risk. An additional risk that AEPSC must manage is basis risk. Prices are based at numerous and liquid trading hubs. Thus, the basis risk results from the possibility that the market price will vary as a result of associated congestion costs, for example, between the generation source and delivery point. Although this does not constitute an exhaustive list of the risks that are confronted in the wholesale power market, these are primary risks that AEPSC faces on a daily basis.

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DATA REQUEST NO Q-IURC Set 1-IURC 1-10

REQUEST

In his rebuttal testimony, I&M witness Thomas states that the amount Kroger witness Bieber proposes to embed in base rates as a credit is excessive as it is 24 times larger than the margin amount I&M expects to receive in 1018 under the proposed sharing arrangement. If the Commission were to embed an amount of off-system sales margins into base rates as a credit, (a) what amount does I&M deem to be the appropriate amount, (b) why is that amount appropriate, and (c) how would that change the sharing ratio?

RESPONSE

(a) The referenced testimony is from I&M witness Thomas' rebuttal testimony in Cause No. 44967, not the instant case. That said, the questions posed raise an important point that embedding any amount in base rates will effectively deny I&M the opportunity to receive the intended share on OSS margins. As such, the appropriate amount to embed in base rates is zero, as explained in I&M witness Williamson's rebuttal testimony on pp. 25-26:

> Embedding such a high level of OSS margins in base rates and tracking above and below that amount shifts a significant amount of risk to the Company's shareholders in exchange for a very small potential benefit of retaining 5% if annual OSS margins exceed the Test Year level. Under Mr. Bieber's proposal, if market energy prices in a given year don't allow the Company to realize the Test Year level of OSS margins, the Company has no opportunity to make up the 5% of OSS margins embedded in base rates that customers still benefit from. To say this another way, each year the Company is at risk of the market supporting the Test Year level of OSS margin, otherwise the Company continues to provide customers a benefit that didn't exist. There are many factors influencing market energy prices that are completely outside I&M's control, such as energy use and demand, natural gas prices, increased renewable penetration and the impact of federal subsidies. In recent years these factors have put significant downward pressure on energy prices. The most appropriate and reasonable way to share the risk and reward of OSS margins is to

share those between the customer and the Company from $0 so neither party is harmed or at risk of the level of margins realized annually. I&M's proposal to share from $0 is consistent with I&M's current OSS margin sharing mechanism.

(b) Embedding zero dollars is appropriate because it avoids artificially reducing I&M's revenue requirement, while continuing to provide both customers and I&M with their share of the OSS margins. Even if the sharing is set at 100% to customers, I&M should not be expected to guarantee revenues that may not materialize by embedding an amount into the revenue requirement. Put another way, as discussed below, if an amount is embedded in basic rates a decline in OSS margins going forward could dramatically reduce the Company's operating income. Sharing from dollar zero avoids this result and avoids making the Company's authorized return on retail service unreasonably dependent on the competitive wholesale market.

As Mr. Williamson explained in his direct testimony (at 50), OSS margins are "largely contingent on PJM market energy prices which are variable due to a number of factors outside the control of the Company and in total OSS margins are significant and can vary significantly from year to year". Tracking OSS margins from $0, rather than embedding a certain level in base rates, recognizes this uncertainty and reasonably balances the interests of both the customers and the Company. Further, continuing the existing sharing mechanism provides I&M with an incentive to optimize OSS margins in a manner that will benefit I&M customers.

The approach of sharing from zero dollars has been in place because of a settlement in the last rate case and has functioned fairly and appropriately to assure that customers timely and accurately receive their share of the OSS margins.

If margins are not shared up and down to dollar zero, I&M will be denied a reasonable opportunity to realize its share as shown in the example set forth in subpart (c) below.

(c) The effect on the sharing ratio of embedding an amount of OSS margins could be significant and unreasonable if the "sharing" is not based on dollar zero. In other words, if annual OSS margins are less than the embedded amount (but greater than zero dollars), 100% of the difference should be recognized in any "sharing mechanism". As shown in the table below, consider an example where the actual results were $5 million, and $10 million of OSS margins are embedded in basic rates. A 95/5 sharing around the difference would divide the $5 million deficit between I&M ($250,000) and customers ($4,750,000), but the reality is that customers would still receive a total benefit greater than the level of OSS margins realized or $5.25 million ($10 million embedded credit minus $4.75 million recovered through OSS rider) and I&M would have a loss of $0.25 million.

In other words, customers would receive 105% of actual OSS margins of $5 million, with the extra amount coming from I&M's shareholders who created the value. Embedding OSS margin puts all the risk on the Company. Conversely, sharing from dollar zero eliminates the risk for any party and ensures both the Company and customers benefit from OSS margins with customers continuing to receive nearly all the benefits.

Embedded amount	Actual OSS margins	Delta	Customer 95% Sharing from Dollar Zero	Company 5% Sharing from Dollar Zero	Customer 95% of difference from embedded amount	Company 5% of difference from embedded amount
$10 million	$5 million	($5 million)	$4.75 million	$250,000	$5.25 million (105% of actual OSS margins)	$250,000 loss

INDIANA MICHIGAN POWER COMPANY
INDIANA UTILITY REGULATORY COMMISSION
DATA REQUEST SET NO. IURC Set 1
IURC CAUSE NO. 45235 IN 2019 Base Case

DATA REQUEST NO Q-IURC Set 1-IURC 1-11

REQUEST

Please fully explain the basis for Mr. Williamson's claim that the inclusion of EZ Bill program revenues in the cost of service is expected to benefit I&M' s customers by offsetting the cost of service and mitigating potential future increases.

RESPONSE

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As noted in Mr. Williamson's direct testimony (pp. 65-66), I&M has not included any EZ Bill revenues or costs in the Test Year revenue requirement in this proceeding. As approved in Cause No. 45114, EZ Bill program bills are based on each customer's forecasted usage, forecasted rates, include a program fee to account for program risks, and a usage adjustment factor to adjust for temporary changes in customer behaviors. Each month, I&M will calculate the difference between what each customer was billed under the EZ Bill program and what he or she would have been billed under the standard base rate tariff and applicable riders. The program fee included in the customer billing amount ensures that the loss suffered from weather risk, model risk, and risks from variations in usage in any year would be less than 10%.[1] Therefore, I&M expects that, over time, the EZ Bill revenues will exceed the level of revenue that would have otherwise been billed under standard tariff rates. (See Williamson Direct at 65). It is this incremental amount of revenue that will offset I&M's cost of service and reduce future rate increases, benefitting I&M's customers.

[1] Company witness Kinateder (p. 13) Direct testimony; Cause No.45114.

INDIANA MICHIGAN POWER COMPANY
INDIANA UTILITY REGULATORY COMMISSION
DATA REQUEST SET NO. IURC Set 1
IURC CAUSE NO. 45235 IN 2019 Base Case

DATA REQUEST NO Q-IURC Set 1-IURC 1-12

REQUEST

With respect to the apprenticeship and training pilot program and the building development pilot program, please state whether I&M will match all ratepayer contributions toward these programs with shareholder dollars to fund these programs. If not, please fully explain why.

RESPONSE

I&M has not proposed a matching of funds for a number of reasons. As an initial matter, I&M notes that I&M's entire business is funded with "shareholder dollars" (*i.e.,* it is funded with I&M's debt, equity, and other sources of capital).

If the Commission accepts I&M's request to include these pilot programs in I&M's cost of service, customers will not make "contributions towards these programs." Because customers pay for electric service, not for any particular component of I&M's cost of service, I&M will fund the costs of these programs. Accordingly, requiring I&M to "match all ratepayer contributions toward these programs with shareholder dollars" would be, effectively, disallowing a portion of the pilot program costs (the "shareholder contribution") from I&M's cost of service. Disallowing a portion of the costs would not be appropriate because the programs are properly a part of I&M's provision of electric service to customers. In other words, the Company has included these costs in the Test Year forecast because they are reasonably necessary in the provision of retail electric service and not excessive.

I&M's economic development activities are a reasonable and increasingly important component of providing retail electric service, provide benefits to all I&M customers, and are appropriately included in the cost of service. Customer load continues to be flat to declining and it is becoming exceedingly difficult to manage customer rates by managing costs. It is reasonable and necessary for the Company to do more to retain and attract customers to its service area. Doing so benefits all customers by maintaining or increasing the base over which the Company's cost of service is spread and this in turn reduces customer bills compared to what they otherwise would be.

Current market conditions warrant additional and new types of activities to support economic development. In other words, today successful economic development requires more than a discount on electric service. The availability of a skilled workforce and appropriate sites for new businesses are key components in the current market. As stated in the direct testimony of Mr. Lucas, the current building inventory in the I&M service territory is critically low and, as a result, the area has been unable to compete for some new investments.

The apprenticeship and training pilot program will support the retention and expansion of customers in I&M's service area by providing an increased opportunity for companies to train their workforce on new technologies that will increase the efficiency of their current operations. Additionally, having a well-trained and experienced workforce will also provide a talent pool for companies expanding or seeking new opportunities in I&M's service area.

Because of our knowledge of electric utility infrastructure, costs and pricing, I&M is uniquely positioned to collaborate with state and local agencies and the communities we serve to provide economic development programs. The economic development pilot programs I&M has offered in this case benefit all customers by spreading our fixed costs over a broader base of customers. It is therefore appropriate and reasonable that the economic development program costs be reflected in the revenue requirement used to establish rates in this proceeding.

INDIANA MICHIGAN POWER COMPANY
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DATA REQUEST NO Q-IURC Set 1-IURC 1-13

REQUEST

Since participation in the IM Plugged In program will require the use of an AMI meter, will I&M customers who choose to participate in this program receive priority in the installation of AMI meters or will such customers need to wait until they receive an AMI meter in the normal course of business to participate in the IM Plugged In program?

RESPONSE

Customers participating in the IM Plugged In program would receive an AMI meter as part of the program and would not wait until they would otherwise receive an AMI meter.

INDIANA MICHIGAN POWER COMPANY
INDIANA UTILITY REGULATORY COMMISSION
DATA REQUEST SET NO. IURC Set 1
IURC CAUSE NO. 45235 IN 2019 Base Case

DATA REQUEST NO Q-IURC Set 1-IURC 1-14

REQUEST

If the Commission does not approve I&M's proposed AMI meter program, please explain how this will impact I&M offering the IM Plugged In program, including whether this program will continue to be offered or will be modified and offered, describing any such anticipated modifications.

RESPONSE

I&M would continue to offer the IM Plugged In Program and provide stand alone AMI meters to participating customers in the event the AMI meter program was not approved. Recognizing that I&M's proposed AMI meter program is based on a 3-year timeline, I&M has already planned for IM Plugged In participants to receive a stand alone AMI meter where necessary. The impact to the IM Plugged In program if the AMI program is not approved will include the incremental costs associated with utilizing all stand alone meters as compared to a lower cost, more efficient system-wide AMI implementation.

Indiana Michigan Power Company

FTE Adjustment
($000)

Line	Description	Total Company (1)	O&M Expense (2)
	2020 Total Company		
	I&M Direct Payroll Costs[1]		
1	Base Wages & Salaries	$ 195,026	
2	Overtime	16,269	
3	Incentives	26,093	
4	Total Payroll	$ 237,388	
5	O&M / Capital Percent[2]	100.00%	66.61%
6	Payroll Expenses	$ 237,388	$ 158,124
7	Total Employee Benefits[3]		39,913
8	Total Employee Expenses		$ 198,037
	2020 Indiana Jurisdiction		
	I&M Direct Payroll Costs[4]		
9	Base Wages & Salaries	$ 100,515	$ 66,953
10	Overtime	$ 9,441	$ 6,289
11	Incentives	21,763	15,647
12	Total Payroll	$ 131,719	$ 88,889
13	Total Employee Benefits[5]		22,146
14	Total Employee Expenses		$ 111,035
15	Number of Employees[6]		2,305
16	Expense per Employee		$ 48.171
17	Proposed Employee Level[7]		2,230
18	Adjusted Employee Expenses		$ 107,422
19	**Employee Adjustment**		**$ (3,613)**

Sources and Notes:
[1] I&M response to OUCC 9-26.
[2] I&M response to OUCC 9-25.
[3] MSFR 1-5-8(a)(13) Projected.
[4] I&M responses to OUCC 29-01, 29-02 and 29-03.
[5] Calculated based on the labor allocation.
[6] I&M response to OUCC 9-29.
[7] Per IURC Question 6.

(1)	(2)	(3)	(4)	(5)	(31)	(32)	(33)	IURC 1-6
Line No.	**Description**	**Total Company Per Books Before Assignment**	**Other Regulatory Items**	**Total Company Per Books After Assignment**	**Total Company Adjustments**	**Total Company AFTER Adjustments**	**Indiana Jurisdictional**	**Adjustment to 2,230 FTE Positions**
1	**Operating Revenues - Electric**							
2	**Firm Sales**	1,877,797,124	0	1,877,797,124	(249,894,931)	1,627,902,193	1,148,678,098	
3	**Interruptible Sales**	144,731,156	0	144,731,156	(8,922,793)	135,808,363	94,345,014	
4	**Sales for Resale - Non-Firm**	215,425,427	0	215,425,427	(35,882,584)	179,542,843	124,696,131	
5	**Other Operating Revenues**	50,477,176	0	50,477,176	129,613,996	180,091,172	129,987,221	
6	**Emission Allowances**	51,360	0	51,360				
7	**Total Operating Revenues**	**2,288,482,243**	**0**	**2,288,482,243**	**(165,086,312)**	**2,123,395,931**	**1,497,742,135**	
8	**Operating Expenses**							
9	**Fuel**	233,075,002	0	233,075,002	(543,434)	232,531,568	161,331,863	
10	**Purchased and Interchange Power**	425,140,035	0	425,140,035	7,412,682	432,552,717	302,778,965	
11	**Other Operation**	599,157,363	9,989,276	609,146,639	(160,403,066)	448,743,573	328,015,663	3,613,000
12	**Maintenance**	220,984,935	0	220,984,935	(1,750,183)	219,234,752	149,294,134	
13	**Depreciation and Amortization**	401,483,474	0	401,483,474	43,992,099	445,475,573	322,482,905	
14	**Regulatory Debits/Credits**	3,248,011	1,310,661	4,558,672	(3,248,010)	1,310,662	1,310,661	
15	**Taxes Other than Income Taxes**	107,107,431	0	107,107,431	96,000	107,203,431	83,988,863	
16	**State Income Taxes**	1,203,570	(593,927)	609,643	(459,957)	149,686	(1,295,865)	
17	**Federal Income Taxes**	(7,477,651)	(2,248,262)	(9,725,913)	**(123,683,619)**	**1,868,696,299**	**1,328,826,146**	
18	**Total Operating Expenses**	**1,983,922,170**	**8,457,748**	**1,992,379,918**				
19	**Net Electric Operating Income**	**304,560,073**	**(8,457,748)**	**296,102,325**	**(41,402,692)**	**254,699,633**	**168,915,989**	3,613,000