TROPOSPHERE LEGAL

January 18, 2024

Ms. Lisa Felice
Michigan Public Service Commission
7109 W. Saginaw Hwy.
Lansing, MI 48909

Via E-File

RE: MPSC Case No. U-21461

Dear Ms. Felice:

Attached please find the enclosed documents for filing:

- Direct Testimony and Exhibits of Robert G. Ozar PE on behalf of Citizens Utility Board of Michigan (Exs CUB-1 through CUB-19), and
- Proof of Service.

Thank you for your assistance in this matter. If you have any questions, please feel free to contact me.

Sincerely,

Holly L. Hillyer
holly@tropospherelegal.com

CC: Parties to Case No. U-21461

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **INDIANA MICHIGAN POWER COMPANY** for authority to increase its rates for the sale of electric energy and other related matters.	U-21461

DIRECT TESTIMONY OF ROBERT G. OZAR P.E.

ON BEHALF OF

CITIZENS UTILITY BOARD OF MICHIGAN

January 18, 2024

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I. INTRODUCTION & QUALIFICATIONS

Q. Please state for the record your name, position, and business address.

A. My name is Robert G. Ozar. I am a Senior Consultant at 5 Lakes Energy LLC, a Michigan limited liability corporation, located at Suite 710, 115 W Allegan Street, Lansing, Michigan 48933.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of the Citizens Utility Board of Michigan (CUB).

Q. Please summarize your work experience in the field of utility regulation.

A. I have worked in the area of energy policy and utility regulation for over 40 years. I began employment with the Michigan Public Service Commission (Commission or MPSC) in 1979, retiring in 2019. I began my employment with 5 Lakes Energy LLC in 2020.

Q. Please summarize your experience in the field of utility regulation.

A. During my tenure with the Commission, I testified as an expert witness in a multitude of contested regulatory proceedings, in both the gas and electric industries. I supported the Commission in its role advising the Michigan Legislature regarding energy related bills, and participated in legislative committees, providing technical input regarding draft energy legislation. I was Chair of the Energy Efficiency Workgroup, providing input to Michigan's 2007 comprehensive energy plan, titled the "21st Century Electric Energy Plan." I was a lead Staff representative on the Michigan Electric Vehicle Preparedness Task Force. I initiated and led the MPSC Smart Grid Collaborative. I also led the Michigan Energy Optimization Collaborative, overseeing the development of the framework for implementing energy efficiency programs for all Michigan Utilities, including

development of the technical reference manual (TRM) called "The Michigan Energy Savings Database." I was lead technical advisor for the MPSC Incentive Ratemaking Workgroup and a contributing author of the MPSC report to the legislature. I was a lead technical advisor to the MPSC's stakeholder workgroup charged to study a cost based distributed generation tariff. I authored the 2016 white paper, "A Reasoned Analysis for a New Distributed-Generation Paradigm – The Inflow & Outflow Mechanism – A Cost of Service Based Approach." I was a principal author of the 2018 study, "Report on the MPSC Staff Study to Develop a Cost of Service-Based Distributed Generation Program Tariff."

During my final decade with the MPSC Staff, I served as Manager of various Staff sections, supervising both engineering and other technical staff. I was Manager of the Electric Operations Section, having responsibility for electric reliability issues, resource adequacy, renewable energy, smart grid, electric meters, and advanced electric technologies, including plug-in electric vehicles and battery storage. I subsequently served as Manager of the Energy Efficiency Section, overseeing the implementation and enforcement of the Energy Optimization Program requirements of PA 295, emerging demand response issues, and revenue decoupling issues. Finally, I ended my tenure at the MPSC as Assistant Director of the Electric Resources Division, retiring in December 2019. My work experience is summarized in my resume, provided as Exhibit CUB-1.

Q. Have you testified before this Commission or as an expert in any other proceedings?

A. Yes. I have previously testified before the Commission in a multitude of cases over 40+ years.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit CUB-1:	Resume of Robert G. Ozar
Exhibit CUB-2:	Tariff sheet, Ex. IM-48, KCC-2, Case No. U-18370
Exhibit CUB-3:	I&M response to CUB 1-4
Exhibit CUB-4:	I&M response to CUB 1-9 through 1-14
Exhibit CUB-5:	I&M response to CUB 1-16 and 1-17
Exhibit CUB-6:	I&M response to CUB 2-8
Exhibit CUB-7:	I&M response to AG 5-99
Exhibit CUB-8:	I&M response to Staff 5-03
Exhibit CUB-9:	I&M response to CUB 1-18
Exhibit CUB-10:	I&M response to CUB 1-19
Exhibit CUB-11:	I&M response to CUB 1-20
Exhibit CUB-12:	I&M response to CUB 1-36
Exhibit CUB-13:	I&M response to CUB 1-39 with Attachment
Exhibit CUB-14:	I&M response to CUB 1-40
Exhibit CUB-15:	I&M response to CUB 1-41
Exhibit CUB-16:	I&M response to CUB 1-47
Exhibit CUB-17:	Line Extension Charges (CUB Proposal)
Exhibit CUB-18:	Lansing BPL Door Hanger
Exhibit CUB-19:	I&M response to AG 5-89

II. MODIFICATION OF CRITICAL PEAK PRICING TARIFFS (CPP)

Q. When did the Commission approve the Company's current residential and general service CPP tariffs, and what rate structure was approved?

A. The Commission approved the CPP tariffs in *ex parte* proceedings in Case No. U-20938. The tariffs include both seasonal and time-varying rate components. The time of use (TOU) rates embedded in the residential and general service CPP tariffs are composed of two time-varying pricing periods, peak and off-peak, plus a critical peak rate effective during a limited number of occasions when invoked by the utility.

Q. Why should the Commission reject the Company's proposal to modify its residential and general service CPP tariffs?

A. The proposal is a reversal in direction away from a rate structure that better reflects the underlying nature of the costs incurred to serve customers, *i.e.*, reflecting cost causation during peak and off-peak periods, and toward a simplistic, uniform per-kWh charge. Even the Company acknowledges that a single volumetric charge (as in the RS rate schedule) "does not provide price signals that effectively reflect the underlying nature of the costs incurred to serve the Company's residential customers."[1]

Q. Are there any issues with the current billing system with respect to implementing the current CPP tariffs?

A. Not that I am aware.

[1] Direct Testimony of Jennifer Duncan, p. 12.

Q. Then, on what basis does the Company request to modify its CPP tariffs?

A. The Company asserts that its proposed changes will "simplify" the tariffs "for ease of explanation and understanding by potential customers."[2] The question needing to be answered, though, is whether any asserted lack of understanding is due to the structure of TOU tariffs, or because of a deficiency in I&M's customer education efforts. Both Consumers Energy and DTE Electric, for example, have residential CPP tariffs that include even more complex three-part time varying rate structures.

Q. Is it your opinion that approving removal of the TOU pricing periods from the Company's CPP rate would constitute deficient regulatory policy?

A. Yes. The higher rate during peak periods and the lower rate during off-peak periods can induce customers to modify their usage, reflecting the fact that CPP tariffs constitute a demand response (DR) / demand-side resource. The Commission should note that the ability to facilitate TOU rates and capture demand-side resources is a major justification for the Company's advanced meter infrastructure (AMI). Removal of the TOU pricing periods from the CPP tariff necessarily results in a loss of value for the AMI investment being funded by ratepayers. In addition, the proposed simplification of the existing CPP tariff deleverages the level of granularity in usage information that the current customer information system (CIS) can accommodate, again resulting in a loss of value to ratepayers for the existing CIS system.

Q. Is the Company requesting approval to invest in a new CIS, with a primary justification being to implement even more complex CPP tariffs?

[2] Duncan Direct, p. 16.

A. Yes, Company witness Katherine Davis notes that a "primary benefit[]" of a new CIS is "the ability to adapt to the changing grid and evolving tariff designs that leverage more granular usage information" and to "allow[] for very complex time of use (TOU) tariffs to be offered to customers."[3] It would be bad enough that the Company's proposed modification to the CPP tariff throws to the wind existing metering and billing capabilities, but it is far worse for the Company to propose such modification while planning massive investments in a new CIS to allow more complex TOU rate structures. If the Company believes that its relatively simple residential and general service CPP tariffs are confusing or too complex for customers to understand, then it should take concrete corrective actions to better educate its customers rather than eliminate the TOU periods from the tariff.

Q. What is your recommendation regarding the Company's proposal to eliminate the TOU pricing periods from its residential and general service CPP tariffs?

A. I am recommending that the Commission reject the Company's proposed elimination of the time-varying pricing periods from the residential and general service CPP tariffs, and instruct I&M to develop a corrective plan to better educate customers on how to take advantage of TOU pricing.

III. DISTRIBUTED GENERATION (DG) TARIFFS

Q. Why is the Company proposing a new DG tariff?

A. As explained by the Company, it notified the Commission on May 12, 2023, that it had met and exceeded its statutory cap for Category 1 (installed generation capacity of 20 kW or less). As a result, the Company proposes to voluntarily offer a new market-based DG

[3] Direct Testimony of Katherine Davis, p. 18.

tariff, the DG 2 Rider, for Category 1 customers and for Category 2 and 3 customers after those caps have been met. The Company noted that it actually met the cap in December 2022 and had exceeded such cap by over 1,000 kW at the time it notified the Commission. The Company stated that any Category 1 customer that had applied for enrollment on or before May 15, 2023, would be enrolled in the existing DG tariff.

Q. How does I&M propose to handle Category 1 applications that are made after May 15, 2023?

A. Category 1 is closed to new enrollments in the existing DG program for any applications made after May 15, 2023. For applications made after May 15, 2023, the Company proposes to provide DG service under its yet-to-be-approved DG 2 Rider, which has market-based outflow credits. However, considering that a Commission order in this proceeding is not expected until July 15, 2024, new Category 1 enrollments in I&M's DG program would be in limbo for up to 14 months under the Company's proposal.

Q. Has the Michigan Legislature amended the law regarding electric utility DG programs?

A. Yes. House Substitute for Senate Bill No. 271 received Senate concurrence on November 8, 2023, and approval by the Governor on November 28, 2023. The new DG program requirements will go into effect 90 days after approval, which is February 27, 2024. Thus, the new DG program requirements will go into effect well before the scheduled date for a Commission order in this proceeding.

Q. What are the major changes to electric utility DG programs under the new law?

A. The new law (1) substantially raises the cap on new DG enrollments, from the current 1 percent cap to 10 percent of an electric utility's in-state peak load; (2) sets a new allocation of the DG cap to "not more than 50%" for generation between 20 kW and 550 kW; (3) bars any limitation on the underlying rate schedule that a customer takes service under; (4) sets credits for outflow at the cost of service; and (5) removes any limitation on bill credits offsetting transmission or distribution charges.

Q. What is your recommendation as to how the Commission should resolve the DG program issues in this proceeding?

A. The Commission cannot approve I&M's proposed DG 2 Rider as it is inconsistent with the new law. Therefore, I recommend that the Commission reject the proposed DG 2 Rider and direct I&M to continue enrolling Category 1 customers, including those who applied after May 15, 2023, in its existing DG program unless and until it receives approval for a new DG tariff that complies with the new law.

First, I&M will need to be in compliance with the new law on its February 27, 2024, effective date. Doing so will require an application from the Company for a replacement DG Rider that satisfies the new DG program requirements. The new DG Rider will apply to DG program enrollments that occur on and after the effective date of the new law. As the effective date is well in advance of the expected date of the Commission's order in this general rate proceeding, an I&M filing and contested proceeding that is separate from this proceeding will be required.

Second, the Company closed enrollment in its existing DG program for Category 1 customers on May 15, 2023. Closure was made unilaterally by the Company pursuant to its discretion provided by current law, thus placing new Category 1 enrollment applications in limbo. The Company asserts in its testimony that it will offer the proposed DG 2 Rider to customers who apply to enroll in the DG program between May 15, 2023, and the date of the Commission's order in this proceeding, on the presupposition that the DG 2 Rider will be approved. However, the new law precludes adoption of the proposed market-based outflow mechanism, requiring a "cost-of-service" rate instead. This creates a situation that could conceivably result in no enrollment at all between May 15, 2023, and the effective date of the new law on February 27, 2024. In my professional judgement, it would be exceedingly confusing, and adverse to the DG market, to have I&M close enrollment for Category 1 customers between May 15, 2023, and February 27, 2024, while allowing Category 2 and 3 customers to continue enrolling. Because the new law substantially raises the statutory cap on enrollments (to 10 times the statutory cap in effect on May 15, 2023), and because the cap is a discretionary cap at a utility's prerogative, it would be reasonable for the Company to continue to enroll all customers into the existing DG program who apply between May 15, 2023, and when the Company receives approval for a new DG tariff that complies with the new state law effective February 27, 2024. Although the Commission cannot enforce this recommendation, I believe it is the right thing to do as I&M provided no operational basis for closure of the program to Category 1 customers.

IV. PROPOSED RESIDENTIAL PREPAY PROGRAM

Q. Have you reviewed in detail I&M's proposed electric prepay program, PowerPay?

A. Yes, I have.

Q. What do you recommend with respect to I&M's requests that the Commission approve the PowerPay program, waive certain billing and notification rules so that I&M can implement PowerPay, and allow recovery for certain information technology (IT) costs associated with implementing PowerPay?

A. I recommend that the Commission deny I&M's requests for approval of the PowerPay program and the associated rule waivers that I&M would need to implement PowerPay and disallow any IT costs associated with PowerPay implementation. My recommendation is based on my professional judgement and comprehensive analysis of the program. PowerPay has compound issues, creating considerable risks to customers. PowerPay does have some benefits. For example, the program may allow I&M to leverage its expansive new investments in Advanced Metering Infrastructure (AMI) and its new Customer Information System (CIS), especially with respect to remote shut-off and service restoration capability. PowerPay may also be considered an alternate collection tool for the utility.[4] However, these would primarily benefit I&M, not customers. The real-time usage and cost data provided to PowerPay customers – also derived from the AMI investments –

[4] For PowerPay participants with an arrearage, I&M would apply 20% of each payment toward the past-due amount before applying the remainder toward credits for future electricity use. Exhibit A-16, Schedule F5.3, Section C, p. 4.

would benefit customers and likely increase customer satisfaction. However, this data can and should be made available to all customers without prepayment as a prerequisite.

I&M asserts that multiple segments of the residential class are target candidates for PowerPay. However, PowerPay appears primarily directed toward customers with low incomes, cash flow challenges, and poor or no credit. These customers would be particularly vulnerable to health and safety risks resulting from swift remote shutoffs and the waiver of certain billing and notification protections. Apparently recognizing these risks, the Company is proposing enrollment restrictions on seniors, customers with "medical, life threatening, or life support conditions,"[5] and customers who seek winter shut-off protection. I&M also proposes a two-strikes-and-you're-out policy with respect to shutoffs.

As to other target customer segments, the Company has not made a convincing case that sufficient numbers will enroll. Savvy residential customers will likely be drawn to the Company's demand response (DR) rate schedules and programs as a means to reduce their utility bills. Customers who cannot manage large seasonal swings in their electric bills would be better served by the Company's Average Monthly Payment (AMP) Plan or Equal Payment Plan (Budget), which are not available to PowerPay participants. It is my professional judgement that, in addition to the structural and conceptual issues that I will discuss in greater detail, the Company has not demonstrated that PowerPay will have sufficient enrollment to justify the high cost of development and implementation.

[5] Ex A-16, Schedule F5.3, Section C, p. 4.

Q. Do I&M's low-income customers in Michigan have greater issues with respect to their energy burden than the residential class as a whole?

A. Yes. CUB asked for detailed information regarding residential service disconnects, notices of disconnection, and arrearages in discovery. The data provided by I&M clearly shows that low-income customers of I&M's Michigan service territory have more difficulty in paying their electricity bills and have higher levels of arrearages, notices of disconnection, and actual disconnection, than the residential class as a whole. Low-income customers definitely need more assistance. I am not persuaded, however, that PowerPay is a solution to their unique needs. Rather, I am convinced that it would likely be detrimental to their interests.

Q. The Company describes PowerPay as "much like prepaid cell phones." Is this comparison an important issue to address?

A. Yes, absolutely. Electric prepay programs are commonly compared to prepaid cell phone plans. They are both marketed to cash-strapped and credit-challenged consumers by emphasizing the same attributes: no deposit, no credit check, and no reconnection or late fees. PowerPay would be no exception. Because electric prepay programs are relatively scarce[6] while prepaid cell phone plans are ubiquitous[7], a comparison between them and the resulting conclusion as to conceptual similarity is a critical and foundational issue that needs to be addressed up front. In my opinion, an incorrect conclusion regarding the conceptual similarity can profoundly bias the perceived public interest in approval of a

[6] Most electric prepay programs are offered by utilities in deregulated markets, and by electric cooperative and municipal utilities: https://www.electricchoice.com/blog/guide-pre-paid-electric/.

[7] For example, see Amazon.com for scores of prepaid cell phone plan options.

costly new prepay program for residential electric service. In addition, an erroneous conclusion of conceptual equivalency could lead to a misguided belief that, if the details are worked out, residential electric prepay programs can be equally successful as prepaid cell phone plans.

Clearly, I&M has put considerable effort into working out many details of PowerPay but, unfortunately, I believe that the Company has lost sight of the core foundations. The Company's comparison of PowerPay to prepaid cell phone plans and the obvious similarity in target market sectors (*e.g.*, credit-challenged customers[8]) reflects the Company's mistaken thinking.

Q. Do you agree with the conclusion that electric prepay programs are conceptually similar to prepaid cell phone plans?

A. No. They are not at all similar. I would go so far as to say that electric prepayment is radically and distinctly different from cell phone prepayment.

Q. How are they different?

A. Prepaid cell phone plans are an alternative to contract-based cell phone service, giving customers the flexibility to change providers whenever they like. Residential electric customers in Michigan cannot choose their electric service provider, which is determined by where they live. Therefore, this advantage of prepaid cell phone plans has no analogue for Michigan residential electric customers.

[8] https://www.prepaidbill.com/past-present-future-of-prepaid-phones.

Prepaid cell phone plans allow customers to conveniently and meaningfully control both usage (talk time) and prepayment amount. A J.D. Power survey[9] found that reported cell phone use per month was 218 minutes by prepaid phone users versus 528 minutes by users of traditional plans. In other words, prepaid usage, on average, is nearly 60% lower than postpaid usage. This may demonstrate the value of prepaid phone plans as an effective tool in controlling usage and the consequent costs. It may also indicate that no-frills prepaid plans with low rates are a good fit for light cell phone users while heavy users prefer traditional plans with unlimited data, texting, and minutes, phone upgrades, and other perks.

In contrast, electric prepay plans are fundamentally limited in their ability to provide cost control due to the well-established low price-elasticity of demand of residential electric services. The fact that PowerPay's focus is payment flexibility, not usage reduction, reflects that limitation. PowerPay may provide customers with some marginal flexibility to manage their payment amounts and timing, but it is inherently limited in providing customers with any realistic ability to control usage.

Q. Can you explain in more detail what is the price elasticity of demand, and why is it a relevant economic measure in evaluating the merits of PowerPay?

A. "Price elasticity of demand is a measurement of the change in the consumption of a product in relation to a change in its price." [10] A small negative price elasticity of demand indicates

[9] How Prepaid Cell Phones Work, available at https://electronics.howstuffworks.com/prepaid-cell-phones.htm, last accessed January 18, 2024.

[10] https://www.investopedia.com/terms/p/priceelasticity.asp.

that the consumption of a product is relatively fixed, regardless of price. In the limit, a value of zero indicates no change in demand with a change in price. With respect to electric service, a small negative price elasticity of demand is an indication that it is difficult, at best, to reduce consumption, requiring effective and substantial efforts. According to the Energy Information Administration (EIA)[11], the short-run Year 1 price elasticity of demand for residential electric usage is very small at only -0.13. This indicates that, over the course of one year, only minor changes in consumption are likely attainable. It doubles in Year 3 to -0.26, and quadruples to -0.50 in the long run at Year 30 but remains relatively small. The short-run price elasticity of demand is the factor most relevant to evaluating an electric prepaid program.

Q. Why is the short-run price elasticity of demand more relevant to evaluating the merits of electric prepay programs than the larger long-run price elasticity of demand?

A. The answer is somewhat complex, but very significant in understanding the intrinsic limits of PowerPay's ability to help enrolled customers reduce the size of their electric bills. Presumably, I&M will market PowerPay along the same lines as its sister company, Public Service Company of Oklahoma (PSO), which is currently implementing a similar program called Power Pay. Namely, the Company will lure customers to enroll in PowerPay by touting the same selling points: that prepaid "accounts do not require a deposit, a credit

[11] Price Elasticity for Energy Use in Buildings in the United States, January 2021, U.S. Energy Information Administration, available at https://www.eia.gov/analysis/studies/buildings/energyuse/pdf/price_elasticities.pdf, last accessed December 18, 2023.

check or any reconnect fees."[12] These core program attributes, clearly borrowed from prepaid cell phone plans, would appeal to customers who have cash flow problems, are credit challenged, or anticipate shutoffs. Another selling point for PowerPay is the ability to increase payment frequency, *i.e.*, to break up once-a-month electric bills into smaller amounts paid weekly or daily. Again, this would appeal to a cash-strapped customer but may be unappealing and burdensome to a typical residential customer. As a PowerPay customer would pay the same retail rates as a post-pay customer – another difference from prepaid cell phone plans, which typically offer cheaper rates – the only realistic way to significantly reduce their aggregate monthly electric charges would be to significantly reduce consumption. The lack of credit checks, deposit requirements, and reconnect fees, and the ability to make more frequent payments, have no direct impact on a person's electricity needs and thus little value in controlling aggregate electric usage and cost.

Cash-strapped and credit-challenged residential customers who are targeted to enroll in PowerPay likely lack resources that could be used to invest in long-term energy efficiency measures – the only measures that can significantly impact electric usage and cost. It is well known that a primary barrier to implementing long-term energy efficiency measures (e.g., purchase of high efficiency appliances, high-efficiency air conditioners, and building envelope improvements) is the large initial capital investment required.[13] Unfortunately, the only apparent way for a cash-strapped customer to cut electric consumption is through

[12] Power Pay Prepaid Electricity, available at https://www.psoklahoma.com/account/bills/pay/prepaid, last accessed December 19, 2023.

[13] Presumably, this is why I&M offers EWR rebates to buy down such initial investments.

short-term conservation[14] actions. The very low short-run price elasticity of demand indicates that such conservation efforts can only provide moderate reductions in usage. The Commission should be concerned that cash-strapped PowerPay customers may resort to desperate and dangerous measures to reduce consumption such as self-deprivation or even shut-off itself.

Q. How are electric prepay programs different from prepaid cell phone plans with respect to emergencies?

A. Electric prepay programs provide two options – either the power is on or it is off. When a customer's electric service is active, they can use it freely. When a customer's electric service has been shut off, they cannot use it at all – not even for emergencies. Shut-off of electric service comes with the risk of life-threating conditions being created.

In contrast, shutting off prepaid cell phone service (*i.e.*, "deactivation") does not involve disabling or depowering a phone. The phone can still be powered up, and in an emergency wireless operators are required by law to complete 911 emergency calls from deactivated phones. This protection, combined with low rates, the ability to change providers at will, and the meaningful ability to manage both usage and prepayment amounts, has created a strong market for prepaid cell phone plans with low-income customers by providing them a risk-free way to lower their monthly cost of phone service.

[14] Energy conservation generally includes actions to reduce the amount of energy end use. For example, installing energy-efficient lights is an energy efficiency (EE) measure, whereas turning them off when not needed, either manually or with timers or motion sensor switches, is an energy conservation (EC) measure. Use of Energy Explained – Energy Efficiency and Conservation, https://www.eia.gov/energyexplained/use-of-energy/efficiency-and-conservation.php, last accessed December 19, 2023.

Q. Are PowerPay's "no deposit" and "no credit check" attributes real benefits to enrolled customers?

A. No. Customers who are drawn to PowerPay because their financial situation makes it difficult for them to pay a deposit[15] or pass a credit check will likely have difficulty maintaining a positive balance. Such customers are high-risk candidates for shut-off. Although the Company may believe that its proposed limitations for enrollment (*i.e.*, no seniors, no customers with medical conditions, and no customers seeking winter heating assistance) will exclude those customers most vulnerable to the adverse impacts of shut-off, it is still courting customers at high risk of shut-off. The "no deposit, no credit check, no reconnect fees" marketing will draw the very customers the Company claims it is not targeting – *i.e.*, cash-strapped, credit-challenged customers who are likely to incur a shutoff.

Q. Is setting a negative $50 balance as the threshold for remote shutoff, as the Company has proposed, an effective protection against shutoff?

A. It is not. While it may prevent shutoffs for customers who use a little too much electricity before refilling their account, negative $50 is likely to become the new $0 for many customers. It is unrealistic to expect cash-strapped customers like those I&M is targeting for enrollment in PowerPay to carry a positive balance if they do not have to. With shut-off postponed until a negative $50 balance, it is reasonable to assume that many customers

[15] A new-customer deposit may not exceed two times the average monthly bill for the residence or two times the Company's average monthly bill. The Company may require additional amounts "as a condition of continuing or restoring service for existing customers." Welcome to Indiana Michigan Power – Answers to Questions about your Electric Service, p. 2, available at https://www.indianamichiganpower.com/lib/docs/global/CustomerHandbooks/Indiana_Michigan_Power_MI_Handbook.pdf, last accessed December 20, 2023.

will ignore low-balance notifications as they approach $0 and maintain a negative balance as long as they can.

Worse, the negative $50 "grace amount" must be repaid in full to restore service after shut-off. This means customers whose electricity needs have already outpaced their financial means will now need to find an extra $50 in addition to the funds to pay for future energy use. The negative $50 threshold provides no real protection against shut-off, in my opinion, and allows customers to fall farther behind than they otherwise would, thereby making it harder to afford restoration and future service.

Q. The Company asserts that their target market includes savvy customers who want to control their electric costs. Do you have any comments on this?

A. Yes. In my opinion, savvy residential customers who can afford a deposit and pass a credit check are more likely to be drawn to dynamic peak-pricing tariffs, CPP tariffs, or other DR programs (for example, the Company is proposing to move four DR programs from the pilot stage to permanent programs, two of which are specifically targeted to low-income customers). Instead of losing important protections provided by the rules I&M seeks to have waived and being limited to reducing their energy burden through conservation efforts alone, customers would be better off getting paid for reducing their demand via DR or CPP credits or by shifting their usage to low-cost off-peak periods. Also, encouraging savvy customers to enroll in existing programs/tariffs avoids the need for costly modifications to the billing system that have no other value outside of implementation of PowerPay.

Q. What relevance is the fact that the Company is proposing to exclude customers who have "medical, life threatening, or life support conditions?"

A. By excluding customers with medical, life threatening, or life support conditions, the Company is tacitly acknowledging that PowerPay does in fact create increased risks to health, safety, and life that are not characteristic of traditional post-pay service. In contrast, individuals with these conditions are eligible to enroll in the standard post-pay tariffs, as they are afforded reasonable and substantial protection via the billing and notification rules that the Company is petitioning the Commission to waive for PowerPay. With respect to PowerPay, the Company has failed to craft protections for vulnerable individuals.

Q. How is that?

A. The Company does not define "medical, life threatening, or life support conditions," but Company witness Katherine Davis testified that "[c]ustomer accounts that have medical certification and/or critical care protection" cannot participate in PowerPay.[16] Presumably, then, the Company means to exclude any customer with the appropriate paperwork on file documenting "an existing medical condition of the customer or a member of the customer's household . . . that will be aggravated by the lack of utility service" or that the customer "requires, or has a household member who requires, home medical equipment or a life-support system" and "an interruption of service would be immediately life-threatening." Mich Admin Code R 460.102(i); Mich Admin Code R 460.102a(i). Customers with such documentation receive special shutoff protection under the billing and notification rules.

[16] Davis Direct, p. 9.

Q. Does excluding customers with medical certification and/or critical care protection adequately mitigate the health and safety risks associated with PowerPay?

A. No. Much of the population has underlying medical conditions, and those conditions are considerably diverse (*e.g.*, diabetes, multiple sclerosis, scleroderma, paralysis, blindness). According to a study published by The Silver Book, the Alliance for Aging, "While medical innovations and public health gains in the past century have been measurable in leaps and bounds, significant progress against acute disease has revealed an equally enormous challenge—chronic disease on an unprecedented scale. Close to half of Americans have chronic conditions and 1 in 4 have more than one. They cause 7 out of every 10 deaths and cost our country 75 cents of every health care dollar." [17] Clearly, a considerable portion of the population may have health conditions that would be aggravated by lack of utility service or for whom interruption in service could be immediately life threatening. Loss of electric power may impact the operation of life support equipment, refrigeration of medications, maintenance of a healthy and safe indoor climate, and other conditions necessary for maintaining health and safety. However, only a small percentage of people are likely to have a medical certification or critical care protection form on file at any given time. Excluding from PowerPay only those customers with this documentation on file means that many vulnerable customers would be able to enroll in PowerPay and find themselves subject to swift remote shutoff.

[17] Condition: Chronic Disease - Silver Book, available at https://www.silverbook.org/condition/chronic-disease/, last accessed January 18, 2024.

Q. Do people with low incomes have worse health than the general population?

A. Yes. And it is significant that people with low incomes – the core target market for prepayment programs – do have worse health than the general population. The U.S. Department of Health and Human Services (HHS) notes that "Unmet social needs, environmental factors, and barriers to accessing health care contribute to worse health outcomes for people with lower incomes… For example, people with limited finances may have more difficulty obtaining health insurance or paying for expensive procedures and medications"[18] These well-documented health disparities mean that people with low incomes are more vulnerable than the general population to the health and safety risks associated with shutoff. PowerPay puts at risk a large portion of the Company's low-income customer base – customers who reasonably shouldn't be enrolled in a prepay program where they may face sudden shutoff without, among other things, adequate notice of the right to have shutoff postponed for medical reasons and time to obtain and submit the required documentation.

Q. Can you further explain the risk to customers who might successfully enroll in PowerPay with medical conditions that could be aggravated by loss of electric service or for whom service interruption would be immediately life-threatening?

A. Yes. PowerPay would provide for a very short interval between electronic notice and actual shutoff, made possible by the use of remote service-disconnect capabilities provided by the AMI system, along with requested waiver of current shut-off protection rules. As a result, customers or their household members who could qualify for shutoff postponement for

[18] https://health.gov/healthypeople/priority-areas/social-determinants-health/literature-summaries/poverty.

medical reasons but who do not currently have a signed medical certificate filed with the utility would be subjected to high risk of adverse health impacts or loss of life should their prepaid balance fall below the threshold. It is almost certain that there will be insufficient time to acquire a form from the Company or the MPSC website[19], to have that form signed by a physician or public health official, and to file such form with I&M in time to prevent a potentially dangerous remote shutoff. Particularly troublesome is that I&M will not provide information explaining medical shut-off protection and how to obtain it in the text or email notification of pending shutoff, given that the Company is requesting the Commission to waive current requirements to do so. Unfortunately, even if the Company did provide such information, the short time between electronic notification and shut-off would make this information unusable.

Complicating this issue is that medical emergencies could arise subsequent to enrollment in the program, thus rendering the enrollment prohibitions meaningless. In addition, certification for critical care protection must be renewed annually. Should a customer or member of their household not timely renew, the short interval between electronic notification and the actual remote shutoff likely precludes the certification process from being completed. These are profoundly important reasons why the PowerPay enrollment prohibitions are deficient in protecting vulnerable customers and their household members.

It is important for the Commission to note that four of the rules for which I&M requests waiver[20] are particularly important with respect to why the segment of the residential

[19] https://www.michigan.gov/mpsc/regulatory/medical-certification-form

[20] Direct Testimony of Dona Seger-Lawson, pp. 33-34.

customer class having or who may develop medical conditions would be at risk under PowerPay: (a) the 10-day notice rule (R. 460.139(1)); (b) the rules requiring two contact attempts one day before shutoff (R. 460.139(6); R. 460.143(1)); and (c) the rule requiring shut-off notices to include information about shutoff postponement for customers with medical certification (R. 460.140(2)).

The bottom line is that the proposed exclusion of customers with medical certifications on file is insufficient to protect the public from dangerous shutoff situations. The Commission should be aware that credit-challenged customers lured into the program due to the "no deposit, no credit check, and no reconnection fee" advantages touted by the Company may not truly understand the risks they are taking, especially if they have or will subsequently develop medical conditions, by trading off their rights with respect to shutoff protections in order to receive such financial benefits.

Q. Is it reasonable to expect that low-income customers would know at the time of enrollment in PowerPay that they or a member of their household may be entitled to shutoff protection for medical reasons?

A. No. One of the rules the Company seeks to have the Commission waive is Mich Admin Code R 460.140(2), which requires a notice of shutoff of residential service to include certain information including "that the utility will postpone the shut off of service if a certified medical emergency exists at the customer's residence and the customer informs and provides documentation to the utility of that medical emergency." Without such notice, customers with medical conditions (or household members with medical conditions) that

would be aggravated by loss of electric service, or for whom interruption of service would be immediately life-threatening, may never know postponement is an option.

Q. Is the issue of the tradeoff of customer protections in order to gain the "no deposit, no credit check, and no re-connection fee" advantages a substantial defect in the proposed PowerPay program?

A. Yes. I&M has not demonstrated that customers who enroll in PowerPay would knowingly and voluntarily relinquish their notification and disconnection protections. In my opinion, this core defect is one that the Commission should seriously consider when weighing the merits of the proposal.

Q. Has the Company been able to properly educate residential or general service customers with respect to its CPP rate; if not, does this shortcoming have relevance to PowerPay?

A. No, and it is highly relevant. As I explained in more detail in my testimony, the Company has not been able to properly educate residential or general service customers with respect to its CPP rate (which is limited to only two time-based pricing periods). The Company's inability to market and implement relatively low-complexity residential and general service CPP rate schedules leads to doubt that the Company can properly implement PowerPay, which will require consistent monitoring and understanding by customers of usage data, their prepayment balances, available payment methods, existing arrears (toward which 20% of payments will be directed), and all electronic notifications provided by I&M. A failure to properly educate enrolled PowerPay customers could result in swift remote disconnection of electric service.

Q. Have any studies been done to examine the value of near real-time feedback on prepaid electric customer energy usage?

A. Yes. In 2019, the American Council for an Energy Efficient Economy (ACEEE)[21] along with non-profit, Slipstream, sponsored a meta-analysis of available analysis/reports regarding electric prepayment programs across the country, and found that on average, electric prepayment programs resulted in customers reducing their usage by approximately 9%. As a result of its analysis, combined with interviews with experts and stakeholders, ACEEE drew the captivating conclusion that "prepay programs are likely to reduce energy use, but we aren't sure *why*." In explaining their reticence in pinning down the basis for energy reductions, ACEEE suggested that the bulk of the savings is likely from the detailed and frequent feedback motivating customers to ration their usage, and that prepayment itself may not be the catalyst for energy savings. The report also noted that the threat of shutoff may be an important factor in the energy reductions seen by prepaid customers.

Despite the moderate reductions in usage seen in prepay programs, ACEEE cautioned that they generally do not reduce the energy burden of low-income customers, *i.e.*, that they do not result in long-run reductions in usage. This observation raises the issue of whether prepay programs are actually promoting true energy efficiency, which ACEEE defined as "the same level of service with less energy," or merely short-run conservation, or even deprivation, as customers on prepaid billing tend to be "lower income and more likely to allow their credit to run out to save money." It is noteworthy that ACEEE found that shutoffs are more frequent under prepaid programs than post-paid service.

[21] https://www.aceee.org/blog/2019/05/prepay-saving-electricity-and-money (emphasis in original).

Q. Do the ancillary account/energy management and notification tools proposed to be included in PowerPay compensate for its shortcomings?

A. Despite the likelihood that such tools would be a source of strong customer satisfaction, they do not, in my opinion, compensate for PowerPay's shortcomings.

Q. Should PowerPay's account and energy management and notification tools be made available to all customers?

A. Yes. Because near real-time account status and energy use feedback appears to be a source of customer satisfaction, there is no reason to withhold it from the Company's traditional post-payment customers. Helping all customers manage their electric load through focused educational and data services (*e.g.*, web-based data applications, texts, emails, information on its Energy Waste Reduction programs, etc.) should be a priority following conclusion of the Company's AMI deployment. State-of-the-art tools to help customers manage their bills and reduce their consumption are not tied to the prepay concept itself, and thus could, and should, be made available to all customers. I see no meaningful advantage to restricting the availability of these tools to PowerPay participants, especially not one that justifies the costly expenditures needed to implement PowerPay.

Q. The Company asserts that a survey of utility customers indicates that they value billing flexibility. Do you have any comments on such justification for PowerPay?

A. Yes. "Billing flexibility" could mean many things, and there is no reason to conclude that survey respondents meant they valued prepayment. The survey question leading to the result I&M cites was likely quite generic and the word "flexibility" has a positive ring to it. I would expect most survey participants would respond favorably to such a generically

framed question. Thus, I would place minimal weight on the responses, as survey participants were not specifically asked if they wanted a prepay option that would entail swift remote shutoff and waiver of existing billing and notification protections in exchange for no deposit requirements, no credit checks, and no reconnect or late fees. Notably, the Company already provides billing flexibility by offering three options, none of which entails the same drawbacks as PowerPay. Customers can choose from traditional post-pay billing or two types of budget billing – the Equal Payment Plan and the Average Monthly Payment Plan.

Q. Do you see a problem with the Company proposal to use electronic means of communication of impending shutoff requiring either cell phone service (texts) or internet service (emails)?

A. Yes. It is reasonable to conclude that PowerPay customers who cannot afford to make a prepayment to cover their current electric usage are likely to have difficulty in paying for cell phone and internet services. It is also reasonable to assume that customers who are struggling to make ends meet will prioritize necessities like utility service over other bills like cell phone and internet service, meaning these customers are likely to lose cell phone and internet service before facing electric shut-off. The waiver of billing protections combined with a swift shutoff procedure puts such customers at risk. These risks highlight the egregious nature of waiver of the billing protections. This is an important issue, raised by the Commission in its order for DTE Electric's application for a prepaid program in Case No. U-21087. This issue was also a primary reason that San Diego Gas & Electric

had its proposed prepay program rejected in 2013.[22] Ten years later, the California Public Utilities Commission (CPUC) has yet to approve a prepay program for San Diego Gas and Electric.[23]

Another significant problem is that the Company would have no way of knowing if a PowerPay participant's cell phone or internet service had been shut off, and therefore no way of knowing when its low-balance and other important account alerts are not being received. The Company has emphasized the importance of PowerPay participants choosing a preferred communication method, stating that: "For a customer to have a positive experience with PowerPay a working communication channel is vital. This allows them to be aware of their remaining balance and their current usage. At any point in the program if the customer is unable to receive texts and or email due to any reason, they would receive a letter via USPS stating a customer has 30 days to choose a communication method. If they fail to do so their account will be changed to PostPay."[24] However, the Company cannot reliably know if a customer is unable to receive texts or access their email account, and therefore cannot know with certainty when to send a letter via USPS or change the customer's account to post-pay.

Q. Do you consider the remote disconnection and reconnection of electric services, with all electronic communications by the Company preceding shutoff, to be the foundation of PowerPay?

[22] https://ia.cpuc.ca.gov/agendadocs/3328.pdf and https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M083/K783/83783968.PDF.

[23] https://tariff.sdge.com/tm2/ssi/tariffs/inc_elec_rates_res.html.

[24] Ex. CUB-8 (I&M Response to Staff 5-03).

A. Yes, it is the very foundation of the program. Remote shutoff, because it eliminates the need for, and consequent costs of, a utility truck roll is also one of the key attributes of the new AMI system. It is apparent that the Company would want to extract as much value as possible out of its massive AMI investment, and using this new capability is certainly a way to do so. Because of the significant failures in the structure, marketing, design, and customer protections associated with PowerPay, I can only conclude that PowerPay was primarily conceived to support the Company's massive AMI investment rather than to meet actual customer needs.

Q. What is your opinion regarding whether I&M's requested waiver of the billing and notification rules is in the public interest?

A. Waiver of the rules would not be in the public interest. The rules ensure customer accounts are handled in a uniform manner, that customers receive adequate and timely information about their accounts and any assistance that may be available to them, and that customers are protected from harmful billing and shutoff practices. The Company has not shown that either customers or the public would benefit from PowerPay in any meaningful way and, as I have explained, I believe the program poses a very serious risk of harm to the health and safety of I&M's customers.

V. NET LOST REVENUE TRACKER

Q. What is the Company's request with respect to its Energy Waste Reduction (EWR) Net Lost Revenue (NLR) Tracker?

A. The Company is requesting two major changes to its current EWR NLR Tracker to broaden the tracker's reach: (1) that it would no longer be required to demonstrate that actual sales have declined from projected sales levels used to set final rates in this case; and (2) that the 3% cap on NLR (between rate cases) be removed. The combination of these two changes would allow for a surcharge even when load increases above rate case projected sales due to weather, economic conditions, or other factors, and would allow for an unlimited level of lost revenue recovery between rate cases.

Q. Under what legal authority may the Commission approve an EWR NLR Tracker for I&M?

A. Subsection (12) of the rate case statute at MCL 460.6a allows the Commission to approve "an appropriate revenue decoupling mechanism." The word "appropriate" suggests that the Commission has flexibility with respect to the details of the mechanism. However, the statute specifically defines the net lost sales threshold as being based on the difference between actual sales and the level set in a utility's most recent rate case. Subsection (12) reads in part: "Subject to subsection (13), if requested by an electric utility with less than 200,000 customers in this state, the commission shall approve an appropriate revenue decoupling mechanism that adjusts for decreases in actual sales compared to the projected levels used in the utility's most recent rate case that are a result of implemented energy waste reduction, conservation, demand-side programs, and other waste reduction measures …."

Q. Does subsection (12) rule out the Company's request to expand the calculation of net lost sales to include decreases beyond those caused by implementation of demand-side programs, such as weather impacts?

A. Yes. Subsection (12) limits the operation of the revenue decoupling mechanism to "decreases in actual sales" from rate case projected sales levels. Meeting such precondition, the statute allows for a limited portion of the difference between actual sales and rate case projected sales – *i.e.*, those "that are a result of implemented" EWR or other demand-side programs – to qualify for the decoupling mechanism. Thus, subsection (12) rules out the Company's request. In my professional opinion, the Company's current EWR NLR Tracker, as has been approved by the Commission, is consistent with the statute.

Q. Regarding the 3% cap on lost revenues between rate cases, has I&M demonstrated that such a 3% level is unduly restrictive when applied to a correct interpretation of the net lost-sales specifications?

A. No. The Commission set such cap to keep the level of surcharges between rate cases at a reasonable level. The Company has the right to file a new general rate request, should over a period of several years the 3% cap significantly reduce the level of lost revenue surcharges that would otherwise be retroactively billed customers. Large cumulative changes in actual sales levels due to implementation of EWR programing, and the consequent large level of lost revenue, are more appropriately handled in a contested general rate proceeding.

Q. Company witness Walter states: "Alternatively, if the Commission continues to require the inclusion of the impact from actual sales compared to the level used to set

base rates, a decline in actual sales more than the EWR-related impacts should be recoverable under the tracker as well."[25] Does subsection (12) provide any potential solution to this issue?

A. Yes, it does provide a way to mitigate the issue, although not an all-inclusive solution as requested by the Company. Part of the problem is that some of the non-EWR sales declines that the Company may experience but are not recognized in the current EWR revenue decoupling mechanism could come about due to implementation of other demand-side programs, such as the four DR programs for which I&M has requested approval in this case. Subsection (12) does allow the Commission to include sales losses from other implemented DR programs along with EWR sales losses in the revenue decoupling mechanism "if requested by an electric utility with less than 200,000 customers."[26] The Company has not yet asked for this modification. Such a request is the Company's responsibility.

Q. What is your recommendation with respect to the Company's EWR NLR Tracker request?

A. I recommend the Commission reject the Company's requests to modify its EWR NLR tracker to retroactively recover lost sales revenues related to any decline in sales regardless of cause (with respect to the sales level set in this rate case) and to remove the 3% cap. I further recommend that the structure of the current EWR NLR tracker be maintained.

[25] Direct Testimony of Jon Walter, p. 12.

[26] MCL 460.6a(12).

VI. CONTRIBUTION IN AID OF CONSTRUCTION (CIAC)

Q. Are the Company's current line extension charges, reflected in its Company Terms and Conditions of Service of Standard Service at Rule 12 and its Company Terms and Conditions of Open Access Distribution Service at Rule 17, out of date with respect to current costs?

A. Yes. The Company's approved line extension charges, *i.e.*, customer contribution in aid of construction (CIAC), do not reflect current costs of construction. The charges were last updated in the Company's April 12, 2018 general rate case, Case No. U-18370. Before that, charges were based on 2010 actual costs. In its Case No. U-18370 filing, the Company requested to align the charges with actual costs (presumably as of the 2016 historic test period). In its Order authorizing I&M to increase its rates, the Commission agreed to a partial update, phased in over a number of years, on the basis that the proposed charges were much higher than those being charged by other Michigan utilities, and that I&M's proposed charges would likely keep potential customers off the grid.[27] Unfortunately, the phase-in of 2016 actual costs was never completed as ordered by the Commission.

Q. Did the Commission increase all per-foot charges in the U-18370 initial phase-in?

A. No. As the Company did not request a change in overhead per-foot charges, the Commission only updated underground line extension charges and underground service line charges. In addition, the Commission increased associated transformer charges for commercial and industrial customers.[28] From the diverse mix in the level of approved

[27] Case No. U-18370, Order dated April 12, 2018, pp. 25-26.

[28] See Ex. CUB-17 (Line Extension Charges (CUB Proposal)).

increases from the then-existing 2010 charges, it is obvious that the phase-in of price increases was tied to a comparison of charges by other Michigan utilities.

Q. To what extent did the Commission increase underground line extension charges in Case No. U-18370?

A. All single-phase line extension charges were increased to 1.5 times the then-existing 2010 actual charges. Commercial/industrial three-phase line extension charges were increased twofold. It should be noted that excess footage charges for underground line extensions are in addition to the excess footage charges for overhead lines, which were left unchanged, so that the overall increase was less than the percent change in the incremental charges.

Q. What about service line per-foot charges?

A. Residential underground service line charges were increased to 1.5 times existing charges; charges for mobile homes, condos, and apartment complexes were tripled; and commercial/industrial service line charges (single-phase and three-phase) were kept unchanged. Underground service line charges are not incremental, but stand-alone.

Q. What about transformer charges?

A. For mobile homes, condos, and apartment complexes, transformer charges were increased to 1.4 times the existing 2010 charges (100% of the requested increase). For commercial and industrial transformers, the single-phase charge was left unchanged, and the three-phase charge was increased by a factor of 1.25.

Q. Is updating the price-per-foot charges for line extensions in excess of any free allowance a major change in CIAC policy?

A. No. Updating the price-per-foot charges in I&M's tariffs is a logical and straightforward step, given that such prices listed in the Company's tariffs are likely far out-of-date with respect to the current actual costs of construction. In addition, and unfortunately, the phase-in of 2016 actual costs was never completed, as expressly authorized by the Commission in U-18370. Thus, CUB, in this proceeding, requested updated average per-foot cost data, but the Company declined to provide it.[29]

Q. How does the failure to address the obsolete cost data behind the per-foot line extension charges impact the level of rates in this general rate proceeding?

A. It constitutes an implicit (or indirect) and unjustified rate increase.

Q. Can you provide more detail behind the connection between outdated line extension charges and the level of revenue requirements?

A. Yes. The shortfall in CIAC contributions associated with the variance of these charges from the current cost-basis increases the capital requirements associated with the Company's forecast for New Customer Connections. I would turn your attention to Exhibit A-12, Schedule B5.3, line 23. Herein, the Company is requesting $55,220,000 in new capital expenditures, on a total Company basis. It can be seen that New Customer Connections constitute a significant portion of the Company's total distribution plant capital request (being approximately 10 percent of such request). Line extension charges collected from new customers are a direct offset to the capital costs of construction for new connections. The lack of an update to line extension charges means that the Company's capital forecast for new customer additions is artificially inflated. The adverse impact on future rate base,

[29] Ex. CUB-5 (I&M Responses to CUB 1-9, 1-10, 1-11, 1-12, 1-13, and 1-14).

and customer rates, is compounded over time if line extension costs are persistently understated.

Q. Do you have a proposal to mitigate the understatement of customer contributions toward new connections, given that 2022 actual costs of construction are not being provided by I&M?

A. Yes. I am proposing to use the original proposed line extension tariff filed by I&M in Case No. U-18370 as Exhibit IM-48 (KCC-2)[30] as a basis for updating the per-foot costs of construction in I&M's current line extension tariffs, including transformer charges.

Q. Do you also have a recommendation for how to address the long-in-the-tooth residential overhead per-foot charge that was not addressed in Case No. U-18370?

A. Yes. I am recommending that this charge be increased by the same ratio of I&M-proposed (*i.e.*, actual) to existing charges (on a total charge basis) for single-phase underground line extensions as reflected in Case No. U-18370, Exhibit IM-48 (KCC-2). This recommended proposal is based on two assumptions that I believe are reasonable: 1) that construction costs for both overhead and underground distribution line extensions increased at roughly the same rate between 2010 and 2016; and 2) that the longstanding overhead line extension charge of $3.50 per foot was last updated no later than 2010. These two assumptions make it reasonable to increase the residential overhead charge of $3.50 per foot by the same percent as the underground construction costs actually increased between 2010 and 2016. That is a number known from Case No. U-18370, Exhibit IM-48 (KCC-2). Thus, on a combined charge basis – *i.e.*, overhead plus underground – the increased charge, based on

[30] Ex. CUB-2.

the actual increased construction costs, was 1.23 times the 2010-based charges. Therefore, use of the same 1.23 factor for updating the overhead per-foot charge would result in an analogous phase-in as I am recommending for underground line extension charges. Even if it could be shown that the overhead construction costs did not increase as quickly as underground construction costs, such calculation is fair in that it ignores any cumulative increase in construction costs between the 2016 and the 2022 historical test period in this proceeding, and thus constitutes a conservative update. The above calculation yields a recommended overhead line extension charge of $4.25 per foot, a $0.75 per foot increase from the 2010 (or earlier) cost of $3.50 per foot.

Q. Can you further expand upon the rationale for proposing to use such chronologically old charges delineated in the Company's Case No. U-18370 Exhibit IM-48 as a basis for updating I&M's line extension tariffs?

A. As I previously explained, the Commission in Case No. U-18370 declined to approve the full amount of actual cost increases in setting line extension charges but agreed with the Staff's recommendation to transition to the higher charges by approving a portion of the Company's requested increase. The Commission directed that the balance of the increase needed (for charges to reflect the 2016 actual costs) would be reached through a multiyear transition, which unfortunately never took place. Most, if not all, of the balance of the increase in line extension charges should have been approved in the 2020 rate proceeding, Case No. U-20539, as a substantial portion of I&M's U-18370 requested increase (for the major categories of charges) was already in place. Here we are in 2024, and no further progress has been made since 2018. The unresolved problem created by the clear failure to transition is that construction costs are continually increasing and are thus a moving target.

It is therefore reasonable to assume that substantial increases in costs of construction have taken place since the U-18370 proceeding. If, as I am recommending, the Commission approves charges that reflect all of the 2016 actual costs originally requested by I&M in Case No. U-18370, it is highly likely that the new line extension charges will still not achieve parity with 2022 actual costs, and further transition to actual costs will be required. Waiting for the next I&M general rate case to begin phasing in actual cost increases will only exacerbate the error in setting line extension charges.

Q. In Case No. U-18370, the Commission noted that an additional basis for not approving the full cost increase was that the line extension charges of other utilities in Michigan (presumably Consumers Energy and DTE Electric) were lower than those requested by I&M. Does that reasoning still have merit in your opinion?

A. No. If one were to strictly hold to the principle of comparison of out-of-date tariffs to out-of-date tariffs as a basis for updating utility charges, a vicious circle is created that would preclude any meaningful effort to update the Company's line extension tariffs. If such a regulatory policy has merit, it begs the question, "Why aren't I&M retail rates set equal to the lowest rates in the state?" Fortunately, the Commission has recognized the issue of out-of-date line extension charges in DTE's recent general rate case, Case No. U-21297, ordering DTE to update its charges in the next rate case.[31] The Commission has an opportunity to move I&M's transition further toward current-cost parity in this proceeding. Waiting for yet another I&M general rate case does not strike me as being in the public interest.

[31] Case No. U-21297, Order dated December 1, 2023, pp. 313-314.

VII. DISTRIBUTED ENERGY RESOURCE MANAGEMENT SYSTEM (DERMS)

Q. Why is the Company proposing investment in a Distributed Energy Resource Management System (DERMS)?

A. The Company states that the DERMS will "provide advanced functionality necessary to manage and operate I&M's future electric distribution grid."[32]

Q. Has I&M performed any studies to gauge future levels of customer-sited distributed generation, and in particular, solar photovoltaic (PV)?

A. Yes. The Company in its recent Integrated Resource Plan (IRP) docket, Case No. U-21189, delineated its evaluation of distributed energy resource (DER) potential. The Company hired GDS Inc. to perform analysis of DER potential from the planning horizon 2023 through 2042. Company witness Walter described the results of such study: "Ultimately, the GDS analysis concluded that residential and commercial solar and commercial CHP were not economically feasible for customer installation, based on system capability and costs known today and projected into the future planning horizon of the I&M Michigan MPS."[33] In response to this finding, I&M revealed that "the Company does not plan to offer utility incentives to additionally entice customers to install these systems on their own."[34] I&M ultimately used a DER technical potential, that assumes zero cost, for IRP modeling of MWh and MW demand-side resources[35], which in my opinion provides nearly

[32] Application, p. 6.

[33] Case No. U-21189, Direct Testimony of Jon C. Walter, 2 TR 280.

[34] *Id.*

[35] *Id.* at 2 TR 281 (Figure JCW-9).

unusable information supporting current grid modernization investments that address future DER.

Q. What is your interpretation of the Company's overall presentation in its IRP regarding customer-sited distributed generation (DG)?

A. Clearly, the Company does not see a market for customer-sited solar PV in its service territory. Further, the Company has little interest in pursuing economic incentives to motivate its customers to install solar PV systems, in light of the GDS analysis. Even though the GDS technical potential analysis shows that customer-sited DER can create both MWh and MW demand-side resources (on the assumption that costs were zero), I&M apparently made no further analysis to determine if it is even possible to craft a customer incentive program that would expand the market of customer-sited solar PV, while simultaneously satisfying a benefit/cost analysis.

Q. With respect to the need for DERMS, does the Company have existing issues on its circuits that are the result of high levels of deployed DER?

A. No. In discovery, CUB asked I&M to identify two example circuits and their associated substations with existing issues resulting from high levels of customer-sited DG and, for such circuits, to detail the issues the Company is experiencing and explain how DERMS will provide solutions to the issues experienced. The Company identified the two circuits with the highest level of DER penetration but identified no associated problems, indicating that such issues do not exist at this time.[36] The Company also pointed to its response to a discovery request from the Attorney General, in which it stated that "aggregation of DER

[36] Ex. CUB-6 (I&M Response to CUB 2-8).

equipment is functionally impossible" without DERMS.[37] However, the inability to aggregate DER equipment is not a problem resulting from high levels of customer-sited DG, and is at most a limitation that would prevent DER users from aggregating their resources for sale into the wholesale market, should they wish to do so. I&M has not shown that any demand for aggregation exists among current or potential DER users.

Q. Who should bear the costs of investment in DERMS?

A. Any costs of investment in DERMS should be recovered from the DER users who will benefit from it. If the purpose of investing in DERMS is to facilitate DER aggregation, then the users who wish to aggregate their resources for sale into the wholesale market should bear the costs. The Company has shown no demand for aggregation, nor has it shown that DER users would be willing to pay for investment in DERMS.

Q What is your recommendation regarding the need for I&M investment in DERMS in the projected test year, 2024?

A. I am recommending that the Commission reject any requests for approval of capital or O&M costs associated with the proposed DERMS, as such investment is currently premature. The Company has not shown a demand for the aggregation such DERMS would facilitate, nor the willingness of DER users to bear its costs.

[37] Ex. CUB-7 (I&M Response to AG 5-99).

VIII. MAJOR STORM RESTORATION

Q. Did the Commission provide guidance to I&M regarding how to estimate major storm restoration expenses in prior general rate proceedings?

A. Yes. In the settlement agreement resolving I&M's last rate case, Case No. U-20359, the parties agreed that the Company would propose that its major storm expense be based on a five-year average. The Company has done so.

Q. Should the Commission consider adjusting such methodology for future rate cases?

A. Yes. I am recommending that the Commission direct I&M to adjust its historical five-year average for inflation less productivity for future rate cases. The Company asserts it has been experiencing substantial improvements in reliability due to its capital investments in distribution and its improvements in vegetation management. Company witness Isaacson noted a 25% improvement.[38] Because historical cost data for service restoration does not fully reflect improvements in reliability in past years, nor improvements expected via investments in reliability made through the projected test year, adjustment of historical data is appropriate. In this way, ratepayers will obtain the full benefits of the investments which they are funding through their rates. As to inflation, it is reasonable to also adjust historical data for cost increases not fully reflected in historical data.

[38] Direct Testimony of David S. Isaacson, p. 9.

IX. VEGETATION MANAGEMENT

Q. Do you have any recommendations with respect to I&M's request for approval of a four-year vegetation management cycle for its Michigan distribution system, beginning mid-2024?

A. Yes. The Company's plan to successively move to a shorter uniform cycle length (of four years) before the Company has even completed its first cycle of a five-year trimming interval, in my opinion, is premature. The proposed four-year cycle is not necessarily the full story with respect to a path forward to continued reliability improvements, and the Company has apparently not rigorously investigated other options for improvement in its vegetation management program, let alone performed a cost benefit analysis to determine the program structure that would optimally balance cost, reliability improvement, and the rate burden placed on ratepayers, *i.e.*, cost effectiveness. I am recommending that the Commission condition its approval of the Company's proposed move to a four-year cycle-based program upon the Company implementing an information-gathering pilot so that it may perform such optimality analysis.

Q. Besides the shortening of its cycle-based program by one year, is there any other approach that I&M should thoroughly evaluate?

A. Yes. In my opinion, it would be reasonable for I&M to evaluate the merits of transitioning its current cycle-based program to a state-of-the-art risk-based approach such as Consumers Energy is beginning to use. At the very least, it would be prudent for the Company to determine if elements of a risk-based vegetation management program could be successfully incorporated into its current approach. I am also recommending that I&M

file a report on its progress with this endeavor in its annual MPSC tree trimming reports and in its subsequent general rate cases.

Q. Does the Commission need to provide additional monies to cover the cost of such an investigation?

A. No. The Company is requesting a significant increase in vegetation management over prior years to reflect additional miles trimmed to conclude the first five-year cycle and the move to a four-year cycle mid-2024. The additional monies requested are likely far in excess of what is needed to cover the cost of the recommended investigation. Should the Company acknowledge an agreement in this case to implement the recommended pilot, I am recommending that the Company's proposed vegetation management expense for 2024 be set to the 2023 forecasted vegetation management cost amount, as shown in Figure DSI-7 of Company witness Isaacson's testimony, and that the Company be granted regulatory asset treatment for any reasonable capital costs (such as high technology equipment) or O&M needed to pilot a risk-based approach. Otherwise, I am recommending that the Commission set the Company's proposed vegetation management expense for the 2024 projected test period at the 2023 forecasted vegetation management cost amount identified in Figure DSI-7.[39] I make this latter recommendation because the Company has failed to demonstrate that the proposed shortening of the cycle length by one year provides the optimal combination of reliability improvement and cost effectiveness.

Q. Why might there be doubt that a reduced cycle time is the optimal approach to improve reliability?

[39] Isaacson Direct, pp. 22-23.

A. I&M moved to a cycle-based vegetation management program several years back as a way to improve the effectiveness of its then-existing program. The change involved switching from a "reactive" program to a "proactive" program that was cycle-based.[40] I agree that change was a positive move, particularly because the Company reformed the foundation of the program. However, there are shortcomings with respect to the uniform cycle concept. In particular, the use of a uniform cycle-length does come with a core deficit.

Q. Please explain such core deficit.

A. Implementation of the uniform cycle-length concept conflicts with the fact that not all circuits, or sections of circuits, have uniform tree cover, uniform tree species (uniform growth rates), uniform risk of tree growth into conductors, uniform risk of trees falling into conductors, uniform customer density, outage history, wire-down history, etc. In other words, distribution circuits do not all have uniform risks with respect to tree-related outages. For this reason, a uniform trimming schedule can produce inefficiencies. A simple example would be that a distribution line running through farmland may not need to be on the same trimming schedule as a line running through a heavily wooded area. And neither of those may need to be on the same schedule as an urban line. The move from a uniform five-year cycle to a uniform four-year cycle may improve reliability, but because of this core inefficiency associated with the uniform cycle concept, there is no guarantee that a reduced cycle-time is the most cost-effective option. In contrast, a risk-based vegetation management approach is worth evaluating as it directly addresses the inefficiencies of a uniform cycle throughout the service territory.

[40] Case No. U-18370, Order dated April 12, 2018, p. 16.

Q. What other inefficiencies are associated with a uniform cycle-based vegetation management program?

A. Uniform cycle-based vegetation management programs present cost effectiveness issues as cycle periods decrease. The issue is rooted in the essential nature of tree growth. Tree growth tends to increase non-linearly with time. The diameter of tree branches; the mass of wood removed, chipped, and disposed; and the subsequent disposal requirements all increase in a positive curvilinear relationship with an increase in the time interval between trimmings.[41] The converse must also be true. It stands to reason that if a utility progressively moves to a series of shorter uniform cycle lengths, as I&M is proposing, the incremental reliability gains become progressively smaller with each decrease in cycle time. Thus, there is a diminishing return on shortening the tree trimming cycle. Because I&M's current five-year uniform cycle length is already relatively short, the move to a four-year cycle will likely produce a reduced level of reliability improvement than the utility originally gained by moving to a five-year cycle length.

Q. How would you expect program costs to change as cycle lengths decrease?

A. Per mile costs should decrease, given a reduced trimming time and reduced tree mass to be disposed. However, more miles are trimmed in each cycle, as cycle lengths decrease, offsetting the per-mile savings, and the over-trimming of those circuits that do not require such a short maintenance schedule will further offset the cost savings. With uniform cycle times tied to the needs of the worst-performing circuit, the resultant unnecessary vegetation

[41] Browning, D. Mark and Wiant, Harry V., "The Economic Impacts of Deferring Electric Utility Tree Maintenance," May 1997, available at https://joa.isa-arbor.com/article_detail.asp?JournalID=1&VolumeID=23&IssueID=3&ArticleID=2761, last accessed January 18, 2024.

management costs associated with the balance of the circuits will ruin cost effectiveness, adding unnecessary costs to ratepayer bills. Obviously, there is a balance involved with a uniform cycle approach, and likely a sweet spot with respect to the optimal uniform period between trimming that produces the best balance between reliability gains and program costs. I&M has yet to present credible evidence that the proposed four-year vegetation management cycle provides the best balance.

Q. What is the defect in the Company's analysis of improvements in reliability since implementation of a uniform five-year cycle?

A. The Company explained the success of the initial five-year vegetation management program as a "an improvement of nearly 20% in vegetation caused non-Major event day (MED) SAIDI and SAIFI (from the end of 2019 through 2022)."[42] The Company's Exhibit IM-4 (DSI-1) consists of a chart that shows SAIDI and SAIFI by cause of outage for 2018 through 2022. Although the 2022 data for both performance indices is better than the 2020 data, no clear trend can be seen in the "Trees (In, Out, and Vines)" cause category, given that 2020 is the start year of the new uniform five-year cycle, and that 2021 data is much worse and 2022 data better. Unfortunately, all we have is a three-year analysis due to the partial completion of the first five-year cycle at the time the Company prepared its case. I would expect the new five-year uniform cycle to yield improvements in reliability from past tree trimming practices, however, there is simply not enough data to support an immediate move to a four-year cycle. That information is vital to a clear understanding of the base from which further improvements could be made.

[42] Isaacson Direct, p. 22.

Q. Are there any further issues with respect to I&M's vegetation management practices or policy?

A. Yes. I&M acknowledges in its testimony that trees outside of its ROW result in two thirds of tree-related outages on its distribution system.[43] This is an astounding level of impact. If there was any reliability issue that requires immediate, direct, and comprehensive action, it is this.

Q. Is not the intended purpose of the Company's plan to move to a four-year cycle to address the impact trees outside of I&M's distribution ROW are causing on outages?

A. Indeed, I&M's core reason for decreasing the cycle time by one year is to "provide a better customer experience by being able to eliminate reliability threats from dead and dangerous trees outside the right of way and [] reduce reliability events occurring from trees inside the right of way."[44] However, the Company has not provided a rational explanation, or any credible evidence, that the proposed one-year reduction in the trimming cycle time, from five years to four years, is a solution commensurate with the scope of the problem, or a cost-effective approach.

Q. Why is that?

A. It is obvious that the current uniform five-year vegetation management cycle has not solved this massive issue. Since trees outside the ROW are farther from the conductor than trees within the ROW, it stands to reason that tree growth is not the cause of the high level of

[43] See Isaacson Direct, p. 22. Note that trees (within the ROW, outside of ROW, and vines) are by far the largest cause of I&M's SAIDI and SAIFI indexes, See Exhibit IM-4 (DSI-1). Thus, by extension, trees outside of the ROW cause the largest adverse impact on the Company's reliability indices.

[44] Ex CUB-19 (I&M Response to AG 5-89).

outages associated with trees outside of the ROW. A nominally reduced time for tree growth into the ROW, or clearance zone, appears to be a minor advantage of shortening the cycle time by one year. The only rational explanation for the problem is that trees outside of the ROW are falling into the conductor at a high occurrence level, despite the already relatively short maintenance cycle of the current program. A possible advantage provided by the reduction in cycle time is perhaps that the arborist crews can survey lines and identify problematic trees outside of the ROW every four years rather than every five. The Company suggested this as the benefit of a four-year cycle.[45] However, the ability to identify newly-diseased trees, or trees beginning the process of dying, one year sooner using the business-as-usual methods of survey seems likely to provide only marginal value. It is dubious that such a small evolutionary step would adequately resolve the current program's massive failure to address these outages or correct the deficiency in the program that makes it so ineffective in reducing outages caused by trees outside of the ROW. In my opinion, the Company failed to provide a convincing argument that simply shortening the trim cycle by one year is an efficient or effective plan to resolve its major reliability problem. The ultimate solution appears to be not a shorter uniform trimming cycle but a detailed investigation by I&M into why its current program has failed so substantially to address the issue of trees outside of its ROW followed by the development and implementation of ancillary programs, policies, or practices, including new high tech survey methods, to specifically target this issue. Such a solution would fit right into a

[45] Isaacson Direct, p. 22.

transition to a risk-based approach for I&M's vegetation management program. I am recommending that I&M initiate this two-step approach immediately.

Q. What is a risk-based vegetation management program?

A. The essence of a risk-based vegetation management program is a continuing series of risk assessments, followed by an evolving work plan corresponding to such risk assessments. Thus, a risk-based maintenance program moves away from uniform cycle times, toward variable and targeted maintenance schedules based on risk factors. T&D World's recent article entitled *How Risk-Based Vegetation Management Slashes Costs* succinctly defines the foundation of a risk-based vegetation management program: "Using survey-grade aerial lidar, advanced data insights, 3D modeling and predictive analytics, utilities can target vegetation management work to the areas where there is the most risk, making these efforts more cost-effective, efficient and impactful."[46] Of particular significance to I&M's tree-related outage issues, the article notes that aerial lidar can provide "[d]etailed information about the landscape, including variables such as slope, stand structure, overstrike potential, and wind-exposure that can predict the likelihood any given tree will fall [and] make contact with conductors."[47]

Q. Is the Company participating in the Michigan LiDAR mapping initiative?

A. The Company stated[48] that it has participated in applying for grant funding for a statewide light detection and ranging (LiDAR) database, but otherwise has not demonstrated either

[46] https://www.tdworld.com/vegetation-management/article/21258571/how-risk-based-vegetation-management-program-slashes-costs.

[47] *Id.*

[48] See Isaacson Direct, p. 45, and Walter Direct, pp. 30-31.

commitment or a concrete action plan to make effective use of LiDAR data. Besides the statewide LiDAR initiative, it is reasonable to assume that the Company has tremendous advantages, being a part of AEP, to collaborate in piloting efforts and share insights and learnings among its sister electric utilities. This should prove beneficial in helping I&M take advantage of the new advanced analytics and LiDAR aerial survey methods and incorporate them into its vegetation management program.

Q. With respect to overhead service lines, what is the Company's policy for addressing tree-related outages at overhead service drops?

A. The Company has language in its MPSC rate book[49] indicating that customers are responsible for maintaining the Company's facilities free from obstruction, which the Company relies upon as the core basis of its tree trimming policy with respect to overhead service drops. Pursuant to I&M's response to discovery request CUB 1-19, the Company confirms that such policy applies to overhead service lines: "Each property owner is responsible for vegetation maintenance around their service drops or other service drops running through their property."[50]

Q. Does the Company incidentally inspect service drops in the process of carrying out their five-year vegetation management program?

A. Yes. However, there is a significant caveat. In its response to CUB 1-19(b), the Company detailed the limitation that it has imposed on any trimming following such inspection: "Any limb putting tension on a service drop, regardless of whose service drop it is, is trimmed if

[49] Terms and Conditions of Standard Service, Section C, Sheet No. C-6.00.

[50] Ex. CUB-10.

it appears to be compromising the insulation of that service drop."[51] The Company clearly does not trim limbs in the vicinity of service drops, or otherwise create any type of clearance zone, even a limited zone, despite the fact that an incidental inspection will not occur for another five years. I would note that the Company owns such lines, not customers.[52]

Q. In your opinion, would you characterize the Company's policy with respect to its maintenance of overhead service lines as reasonable and prudent?

A. No, I would not. Although I&M transitioned to a proactive vegetation management program approximately five years ago, that change was limited to primary and secondary distribution lines. The Company's overhead service line policy is still highly reactionary, meaning that the Company relies upon customer compliance with its tariff language as the primary means of maintaining a clearance zone around its overhead service lines. The Company intervenes when and if there is a service line outage through its service restoration efforts. For example, the Company's response to CUB 1-19(a) notes: "If a tree falls on the service drop, I&M will perform the work necessary to restore service."[53] But that reactionary mode of intervention is too little, too late. Unfortunately, and contrary to sound reasoning, the Company views outages "caused by a customer's failure to keep clear

[51] *Id.*

[52] *Id.*

[53] *Id.*

from vegetation the service line" as "beyond the Company's control," [54] and that is simply not the case.

Q. Is the failure of the Company to maintain an appropriate vegetation clearance zone along residential overhead service lines, by shifting the primary maintenance responsibility to customers, creating potential safety issues?

A. Yes. In the case of downed service drops caused by improper maintenance of a clearance zone, significant public safety issues are created. Service drops can carry a considerable amount of power, are not fused, do not have a circuit breaker, and do not have any overcurrent protection. Downed service drops can kill.

Q. How many tree-related service line outages is the Company experiencing?

A. Pursuant to CUB (1-20), in the 2022 historical test period, the Company experienced 1,273 Non-MED outages and 1,795 MED outages for a total of 3,068 outages.[55] If one extrapolates this over the course of a 10-year period, about 30,000 overhead service line outages are tree-related.

Q. Is the failure of the Company to proactively maintain a reasonable clearance zone along its overhead service lines likely a contributor to the level of outages related to tree contact?

[54] Seger-Lawson Direct, p. 21.

[55] Ex. CUB-11.

A. Yes, it is highly likely. Shifting the onus to customers presents multiple obstacles to line maintenance. It would be difficult to ascribe negligence to such failures, as there are legitimate barriers to compliance.

Q. Is the Company's policy with respect to maintaining a clearance zone along overhead service lines a realistic expectation for the Company's low-income customers, given the financial and affordability challenges facing such customers?

A. No. It is an unrealistic expectation. I&M's residential population is roughly 25% income-qualified customers, which is a significant level of low-income customers.[56] The economic challenge created by placing responsibility for properly maintaining the Company's overhead service lines upon low-income customers is likely a significant barrier to compliance, in my opinion. Tree trimming is particularly expensive as it requires highly skilled workers with expertise to work along energized power lines. For some customers, especially low-income customers, covering the high cost of hiring a tree trimming specialist to maintain a clearance zone along an I&M service line (or in some cases multiple service lines) is considerable barrier to accomplishing prudent vegetation management and proper maintenance of the Company's distribution assets.

Q. Are there other reasons why customers might fail to maintain I&M service lines?

A. Yes. Not all residential customers may be aware of the Company's policy, and that may be an additional factor causing more tree-related outages on service lines than there should be. Rental houses may also create challenges in compliance with I&M's policy, where the

[56] Case No. U-21189, Direct Testimony of Roger Colton, 3 TR 874. See also Exhibit MEC-12 from that case.

landowner/landlord is not the customer and may not have a direct interest in reliable electric service. In addition, the non-customer landlord is technically not bound by the Company's Section C, Sheet No. C-6.00 tariff requirement for "the customer" to maintain service lines. Also, in general, it is reasonable to assume that most people do not want to see their trees cut or pruned, as they are a major source of beauty, often hiding views of electric poles and wires, and for this reason will be reluctant to initiate line clearance on their own. Lastly, it is completely reasonable for customers to assume that the Company will maintain its assets, especially as they see I&M contractors trimming along the Company's distribution lines and the portion of the service line within the Company's ROW. The bottom line is that there are compound problems impeding customer/landowner compliance with the I&M requirement that they are responsible for maintaining a clearance zone around their service lines. Clearly, I&M's maintenance responsibility is comprehensive, including intervention to maintain an appropriate tree clearance zone around service lines should customers legitimately fail to provide proper clearance.

Q. Do you agree with I&M that its policy requiring customers to maintain a clearance zone around overhead service lines is sufficiently justified by the fact that many other utilities also require customers to maintain a clearance zone around overhead service lines?

A. No. The fact that some other utilities may not maintain their service lines is not sufficient justification for I&M's policy, in my opinion. That is not benchmarking best practices. The Company should be focused on learning from utilities that have superb intervention policies. Because tree-related outages are the predominant cause of outages in its service territory, it behooves the Company to take every reasonable action to reduce the level of

those outages and mitigate the cost of restoration and adverse impact to customers experiencing such outages, irrespective of what other utilities do. Additionally, the increasing severity of weather being experienced by utilities in recent years may cause some of those utilities to rethink policies that were developed in the more distant past.

Q. Do you have an example of an electric utility that proactively trims overhead service lines?

A. Yes. The Lansing (Michigan) Board of Water and Light (Lansing BWL) does inspect and trim along overhead service lines. This occurs simultaneously with the inspection and trimming of the utility's distribution circuits (in a five-year cycle). I personally talked to a contract arborist, who explained the BWL's policy noting that "proper clearance wouldn't happen if the utility didn't do it." The Lansing BWL obtains signed customer approval to trim along the customer's service line, and does not trim absent customer approval, except for any overhead service lines crossing over to neighbors' homes. Lansing BWL trimming is not restricted, as is I&M's imprudent policy, to limbs "putting tension on a service drop … if it appears to be compromising the insulation of that service drop."[57] Exhibit CUB-18 is an example of a Lansing BWL door tag, with notification that an overhead service line runs through junipers and that trimming is required. Significantly, the Lansing BWL door hanger (consent form) explains that "All planned work will be at no cost to the customer." It is manifest that Lansing BWL is aggressive in preemptively addressing tree-related outages associated with overhead service lines. The Company ought to take note of what I consider a best practice.

[57] Ex. CUB-18.

Q. Who bears the ultimate cost of non-compliance with the Company's policy to shift primary vegetative management responsibility of overhead service lines to customers?

A. The ultimate cost is borne by customers through their retail rates. When an outage occurs due to tree contact with a service line, not only does the impacted customer suffer from the loss of electric service, but the high cost of restoring service is borne by all customers and is a part of the major and minor storm restoration expenses[58] that the Company is requesting to recover in its rates. That ultimate cost includes not only the costs of repairs (equipment and labor), but also the cost of reactive tree trimming following an outage.

Q. What is your recommendation regarding vegetation management of overhead service lines?

A. It makes rational sense to take every possible action to preemptively trim clearance obstructions so as to avoid the ultimate reactive cost of service restoration. This is a compelling reason for the Company to reevaluate its policy regarding responsibility for maintenance. I am recommending that I&M develop a concrete plan to remediate is imprudent maintenance policy with respect to overhead service lines, including a pilot if deemed necessary by the Company, and file a proposal in its next general rate proceeding.

[58] Ex. CUB-10 (I&M response to CUB 1-19(c), "A majority of these cost are O&M.")

X. DEFERRAL OF CUSTOMER CREDITS FOR EXCEEDING OUTAGE RESTORATION THRESHOLDS

Q. Has the issue of cost recovery of outage credits been previously addressed by the Commission?

A. Yes. DTE Electric raised the issue in its recent general rate proceeding, Case No. U-20836.

Q. Are the details behind the outage credit cost-recovery issue, as raised by DTE, relevant to I&M's proposal to defer outage credits?

A. Yes. The reason why DTE raised the issue of the method of cost recovery, how it proposed a solution, and what the Commission ultimately approved is highly relevant, as I&M is asking to defer the cost of certain outage credits "[c]onsistent with the Commission's November 18, 2022 Order in Case No. U-20836."[59]

Q. Can you outline the issue as presented by DTE in Case U-20836?

A. Yes. In its filing, DTE argued that the upcoming change to the Commission's Service Quality and Reliability Standards,[60] requiring automatic payment of credits, will increase the overall level of credits paid. An increased level of payments was expected by DTE because outage credits will no longer be dependent upon a customer having to initiate a request for credit (not all customers requested payment under the prior procedures). DTE noted that it was using the "change in Commission rules to propose a different treatment for recovery of those costs."[61] Consistent with this proposal, DTE removed all outage

[59] Seger-Lawson Direct, p. 21.

[60] Mich Admin Code, R 460.701-752, effective April 10, 2023.

[61] Case No. U-20836, Direct Testimony of Adele F. Crozier, 7 TR 2360.

credits from its projected O&M expenses, which is how it had previously recovered costs, and requested to defer recovery of outage credit costs as a regulatory asset. The fact that DTE removed all outage credits from O&M expenses is significant, as it shows an intent for the proposed regulatory asset treatment to be a full replacement, and not an adjunct recovery method. DTE then tied deferral of credits to a nearly all-encompassing standard: outages that were "not the fault of the utility."[62] In my view, use of such a broad standard for regulatory asset treatment is consistent with the removal of all credits from O&M expenses. It also would provide confidence that the deferred costs would be recoverable as a regulatory asset. DTE then presented multiple examples of what they considered not their fault or responsibility, such as transmission outages, trees outside of the right of way, animal damage, vehicle accidents, customer failure to clear vegetation near service lines etc. so that the proposal raised firm objection from Staff and intervenors.

Q. What was the Commission's response?

A. The Commission acknowledged the general concept that credits paid for some outage categories could be deferred for possible future recovery but rejected DTE's excessively broad "outages not the fault of the utility" criterion. The Commission found reasonable a more restrictive, but only partially developed, proposal from the Commission's Staff, and directed DTE to work with Staff to fully develop the proposal.

[62] Case No. U-20836, Order dated November 18, 2022, p. 363.

Q. What was the Staff cost recovery standard that the Commission recognized in U-20836?

A. The Case No. U-20836 Order summarized the Staff proposal taken from its replies to exceptions: "Staff makes clear that it finds that DTE Electric should recover only those credits that were paid due to outages that are not within the company's control to resolve such as outages caused by the transmission system operator and outages caused by customer negligence."[63] The ALJ agreed found the Staff's "incomplete proposal" reasonable and the Commission adopted the ALJ's findings and conclusions, including her recommendation that DTE "work with Staff toward the full development of the Staff's proposed limited recovery of outage credits."[64]

Q. Is I&M requesting the same approval as was granted DTE?

A. I&M asserts that it is requesting similar approval as was provided DTE, although the Company acknowledges it is "making other customer outage credits proposals"[65] – *i.e.*, I&M has added additional categories.

Q. What is your general analysis and recommendation regarding I&M's credit deferral request?

A. It is my professional opinion that the specific qualifying outage categories put forth by I&M are in direct conflict with the limitation principles set forth in the DTE order; are unreasonable and unsupported; and should be rejected in totality. Importantly, the

[63] Case No. U-20836, Order dated November 18, 2022, p. 366.

[64] *Id*.

[65] Seger-Lawson Direct, p. 21.

Commission recognized that the Staff proposal in U-20836 was not fully developed and ordered DTE to work with Staff to craft a fully developed proposal. By asking for the same cost recovery treatment granted DTE, I&M failed to recognize that, in essence, the Commission did not actually approve a workable regulatory asset deferral mechanism for DTE. I&M did not attempt to rectify the shortcomings acknowledged by the Commission in U-20836. My analysis of the I&M proposal is that, in large measure, I&M merely added back the very outage circumstances that would be precluded by the Staff's proposal in U-20836. I certainly would not characterize such expansion as completing the development of the Staff's DTE proposal.

Q. Is I&M disadvantaged by expensing outage credits?

A. I&M provided no evidence that the Company is disadvantaged by the current method of expensing outage credits, or that the level of outage credits has or will increase so substantially that a change in recovery method is even warranted.[66] With this in view, I&M's request for deferral of outage costs could be characterized not only defective, but a solution in search of a problem.

Q. Must a utility pay outage credits irrespective of the underlying cause of its inability to resolve an outage within the maximum thresholds set by Rules 44-6?

A. No. Rule 51 provides that a utility may petition for a waiver or exception "when specific circumstances beyond the control of the electric utility or cooperative render compliance impossible, or when compliance would be economically burdensome, or technologically

[66] Note that pursuant to Staff discovery request 5-03, I&M's level of outage credit payments in 2022 was only $50. Ex CUB- 8.

infeasible." A utility need not meet the outage restoration standards or pay the credits for failure to meet them under certain circumstances.

Q. Are outage credits a penalty or compensation for the cost and inconvenience of an unreasonably extended outage?

A. They are both, simultaneously, in my opinion, as the Company has a responsibility to operate and maintain its system in a way that allows it to avoid paying outage credits. Before April 2023, the rules labeled the credits a "penalty." While the rules now call them a "customer accommodation," their nature has not changed. A utility must pay them when it takes an unacceptably long time to restore service after an outage or when a customer experiences an unacceptably high number of outages in a year.

Q. Should the Company or customers bear the cost of outage credits?

A. The Company should. Customers should never have to bear the cost of outage credits.

Q. Who should bear the cost of credits issued when outage restoration is "outside of the Company's ability to resolve," *i.e.* it is impossible for the Company to meet the Rule 44-46 restoration standards?

A. No one, because the credits should not be issued. In such circumstances, the Company has a responsibility to petition the Commission for a waiver or exception under Rules 51 and 52. It is unfair for customers to shoulder the costs of credits paid out when utility compliance is impossible, given the availability of a waiver or exception that would relieve the utility of the obligation to pay the credits.

Q. Who should bear the cost of credits issued when an outage is caused by "customer negligence?"

A. The Company. While the Commission in U-20836 adopted the ALJ's conclusion that it was "reasonable" to allow DTE recovery of credits paid for outages caused by "customer negligence," I respectfully disagree with that conclusion and believe it conflates responsibility for the outage with responsibility to restore service in a timely manner. Irrespective of the cause of the outage, the Company has a responsibility to restore service within the timeframes specified by the rules. One possible exception is where the credits are for a customer who has experienced more than 6 outages in a 12-month period and some or all of the outages are attributable to the customer's own conduct. However, credits either should not be issued in such a circumstance (*i.e.*, the Company should request a waiver or exception) or the Company should bear the cost of the credits because it did not act to prevent or mitigate the outages (*e.g.*, if the Company knew repeated outages were caused by excess vegetation growing on a service line, it should have arranged for the vegetation to be cleared because it has an obligation to "operate and maintain its distribution system in a manner that will permit it to provide service to its customers without experiencing an unacceptable level of performance." Rule 21.)

Q. Does the Company carry significant responsibilities to mitigate outages and the duration of restoration?

A. Yes. Rule 21 requires I&M to operate and maintain its distribution system to meet the Commission's Service Reliability and Quality Standards. It is reasonable to conclude that I&M should take reasonable and prudent precautions, such as preemptive programs to mitigate the risks of damage to its distribution system and the consequent customer outages

and the duration of such outages. I&M should not be allowed to pass on to its customers the consequent costs of outage credits required to be paid should restoration of service not occur within the specifications set forth in the Commission's Rules 44-46.

Q Is the failure of a customer to maintain a vegetation clearance zone around service lines "customer negligence?"

A. No. Significantly, neither the ALJ nor the Commission in U-20836 provided any guidance regarding what might constitute "customer negligence." In that proceeding, DTE offered "an outage that occurs due to a customer failing to keep vegetation away from the service line crossing his or her property" as one example of customer negligence, but this would be at most a violation of a utility's terms and conditions of service, not negligence. Negligence is a legal concept that has no place here. There are many reasons a customer might not keep a vegetation clearance zone around the overhead service line to their home (or their neighbors' service drops crossing their yard) that would not constitute "negligence," *i.e.*, failing to exercise the level of care expected of a reasonable person under the circumstances as I previously explained in my analysis of I&M's overhead service-line maintenance policy.[67] The Commission should not allow a utility to recover costs based on its own self-serving determinations of customer "negligence." It is the utility that has an obligation to operate and maintain its distribution system in such a manner that it does not fail to meet the Service Quality and Reliability Standards – not the utility's customers.

[67] See Forbes Advisor https://www.forbes.com/advisor/legal/personal-injury/negligence/.

Q. What are the outage types that I&M has proposed to be recognized?

A. Company witness Seger-Lawson initially states that I&M "proposes to defer the costs only for those customer outage credits paid for which the outage duration/restoration is not attributable to I&M's actions," but then immediately discusses outages where the cause – not just the duration – was beyond I&M's control. This disconnect is a fundamental failure in the Company's request. As examples of outages outside I&M's control, she provides the following: "trees falling from outside of the right of way; public interference: outages caused by customer negligence and those caused by the transmission system operator."[68] In response to a discovery request from CUB, the Company identified the following examples of "customer negligence": "acts of vandalism, customer performed tree removal, or a customer inadvertently crashing a vehicle into equipment."[69] The Company also seeks to defer costs for credits paid where an outage was "caused by a customer's failure to keep clear from vegetation the service line and the customer's service entrance cable to the meter."[70]

Q. Should the Commission approve the Company's request?

A. No. First, some parts of the Company's proposal for deferred recovery of customer outage credits fall outside the limitations that the Commission found reasonable within the context of Staff's proposal for DTE – *i.e.*, "outages that are not within the company's control to resolve" or "outages caused by customer negligence." Ms. Seger-Lawson provided examples of outages outside the Company's control that were not limited to customer

[68] Seger-Lawson Direct, p. 21.

[69] Ex. CUB-9 (I&M Response to CUB 1-18).

[70] *Id.*

negligence or outages outside the Company's control to resolve, such as outages caused by trees falling from outside of the right of way. These are the kind of outages that the Staff in Case No. U-20836 excluded from the scope of its proposal, having "argued that restoring service for an outage caused by an auto accident or by a storm is a function that is expected of the company."[71]

Further, the Company failed to explain why its examples were not within its control to resolve or how they would constitute customer negligence. While an outage under the control of the transmission operator might not be within DTE Electric's control to resolve, I&M exercises control to resolve outages at both the distribution and transmission levels. American Electric Power (AEP) owns both the transmission company (AEP Transmission) and the distribution company (I&M). That fact alone is sufficient evidence to reject the conclusion that transmission outages are not within the Company's ability to resolve. In fact, I&M prioritizes service restoration during minor and major storm events to address transmission circuits first.[72] And for reasons I previously discussed above, merely failing to maintain a vegetation clearance zone around a service drop is not "customer negligence."

Finally, the Company provided no evidence that it has unfairly paid or has a reasonable probability of paying outage credits.[73]

[71] Case No. U-20836, Order dated November 18, 2022, p. 364.

[72] Ex CUB-3 (I&M Response to CUB 1-4).

[73] Ex CUB-4 and CUB-8 (I&M response to CUB 1-16, 1-17 (these responses do not show examples of outages exceeding duration standards caused by tree falling from outside ROW); and I&M Audit Response BMK-5(3) (only paid $50 in outage credits in 2022).)

Q. What is your recommendation?

A. I am recommending the Commission reject the Company's request for deferred recovery of outage credits. The Company provided no basis for finding it needs deferred accounting treatment for payment of these credits. I further recommend that the Commission reject any request for recovery of outage credits as O&M or other expenses, as the Company should either use the mechanism provided in the Service Quality and Relaiblity Standards for obtaining a waiver or exception where its inability to comply with the Standards is due to circumstances beyond its control, or itself bear the costs of paying credits where it has failed to meet the Standards without qualifying for a waiver or exception. It is not in the public interest to make ratepayers bear the cost of a utility's failure to meet the Standards.

XI. DISTRIBUTION CAPITAL REPLACEMENT

Q. Have you reviewed the Company's Capital Replacement program?

A. Yes. I have reviewed the Company's testimony, exhibits and discovery responses related to I&M's capital replacement program, which I&M identifies as "Asset Renewal Projects."

Q. Are there any issues with respect to the Asset Renewal program?

A. Yes. I have concluded that the overall basis for the Company's proposed distribution replacement expenditures, based on age, load growth, reliability, and modernization is disconnected from the level of expenditure requested. As such, the combination of factors does not provide a compelling reason for approval of the full amount requested. With respect to aging distribution assets, I have also concluded that the high level of replacements is not consistent with the principle that most replacements should be based on actual failure, incipient failure, or impending failure, and thus the Company did not

demonstrate that the high level of distribution asset replacements are necessary and reasonable. In addition, with respect to its Asset Renewal Projects, the Company failed to show that it considered affordability criteria in selecting projects to undertake, and thus failed to support that the aggregate cost of its proposed Asset Replacement investments is reasonable and prudent. The Company simply provided no compelling evidence that the requested costs strike a reasonable balance with the price burden borne by customers, especially residential customers who will carry a predominate share of the proposed distribution investment costs. I am recommending that the Commission reduce the Company's Asset Renewal Projects request for the projected test year by 20%.

Q. Has I&M had an opportunity to provide evidentiary support beyond what it provided in its testimony and exhibits?

A. Yes. In particular, CUB sought through discovery the inspection and engineering reports approving a sample of two Michigan projects selected from each of the major project categories of the Asset Renewal capital projection. Those categories are: Single Phase Line Rebuilds; Three Phase Line Rebuilds; Circuit Ties; Sectionalizing Projects; Recloser Replacements. With respect to the proposed Combined Projects (that include both substation and associated distribution lines), CUB requested the reports approving all 10 proposed Combined Projects. There were additional project categories, namely Roadside Relocations; Porcelain Cutout and Arrestor replacements; Crossarm Replacements; Pole Replacements; and URD Cable Replacements for which CUB requested additional information that was not included in the Company's direct testimony.

Q. Is it typical for utilities to create a summary engineering report prior to management approval of large capital projects such as distribution asset replacements?

A. Yes. Based on my review of large distribution capital projects proposed by other electric utilities in their general rate proceedings, I would expect I&M to prepare an engineering report facilitating management approval of proposed distribution capital projects that would generally have the following components: description of the nature of the proposed project, alternatives considered, economic analysis, and justification for the project recommended. I would assume that such basic information is not only essential for utility management to sign off on a proposed project, but to facilitate the Commission's review of the underlying reasonableness and prudence of such investments and ultimate cost recovery by ratepayers.

Q. What was the Company's response to CUB's request?

A. The Company provided no engineering reports like those I would have expected to see based on my experience with other electric utilities, and asserted that the requested reports were too voluminous in nature and contained customer-specific information such that it would only make them available for inspection at its counsel's office. The Company provided summaries for some of the requested projects that were nearly identical to the limited information already included in its case-in-chief, along with some maps of line/component locations.

Q. Do you have a conclusion regarding I&M's internal review process for distribution capital investments for Asset Renewal?

A. Yes. The fact that the Company is only able to provide the Commission the raw data related to proposed projects and a brief summary that fails to demonstrate cost effectiveness is evidence that the internal Company process for project review and approval is deficient. With the same information I&M provided the Commission, it would be nearly impossible for Company management to prioritize and select a mix of capital projects that strike a reasonable balance between cost and the price burden carried by ratepayers. I would not expect I&M management to comb through massive, detailed data to attempt to understand the reasonableness and prudence of each proposed project, to prioritize, and select the best mix. A management that would approve all projects put before it is simply failing in its responsibility. Thus, I cannot in good faith recommend Commission approval of the full level of expenditure requested.

Q. What are your findings and conclusions regarding Asset Renewal Projects subcategory Three Phase Line Rebuilds?

A. As examples of Three Phase Line Rebuilds, I randomly selected and reviewed project # 6, Kalamazoo Eagle, and project #14 Valley 34.5 kV, including summary data I&M provided in discovery regarding the number of customers served, the load served, a 10-year history of outages, the cause of outages, dates of outages, and tree trimming history over the past 10 years.[74] This is the kind of data I would expect to be included in an engineering report requesting management approval. The data provided for both projects show that

[74] Ex CUB-13 (I&M Response to CUB 1-39).

transmission stations and transmission lines are associated with a major portion of outages. With respect to the Kalamazoo Eagle 3-phase line rebuild, distribution equipment failures over the past 10 years include two arrestors, an overhead switch, a regulator, and an insulator. High winds caused a conductor failure. The Valley line rebuild was similar, showing almost no distribution equipment failures: a single distribution outage over the past 10 years was caused by a failed crossarm. A single transmission outage was caused by a failed insulator. The Company explained that most line rebuilds are a complete rebuild of infrastructure: "Line rebuilds replace all poles, crossarms, insulators, switches and conductors."[75] In addition, transformers, reclosers and capacitor banks may be replaced based on condition.[76] Based on this information, I can only conclude that a complete line rebuild for these projects is not justified by the line history and does not strike a reasonable balance between cost and the price burden placed on ratepayers. I am also led to conclude that unsupported line rebuilds are likely pervasive among the 91 Single Phase and Three Phase Line Rebuild projects listed in Exhibit IM-6 (DSI-3). Compounding the problem is the Company's line rebuild policy that prioritized replacement over remediation.

Q. What are your findings and conclusions regarding the Asset Renewal Projects subcategory called Roadside Relocations?

A. In discovery, I&M stated that all of the relocations listed in the Company's Exhibit IM-6 (DSI-3) are initiated by the Company itself.[77] The stated purpose of the relocations is to improve access by Company trucks and equipment, as "[t]he lines are in off-road rights-

[75] Ex CUB-12 (I&M Response to CUB 1-36).

[76] *Id.*

[77] Ex CUB-14 (I&M Response to CUB 1-40).

of-way and difficult to access."[78] I&M thus relocates those lines along the road. When asked if it reuses existing distribution assets in Roadside Relocations, the Company disclosed that they are near-complete rebuilds: "Roadside Relocations replace all poles, crossarms, insulators, switches and conductors."[79] Replacement of these core line components is clearly a policy decision and not based on line condition, in contrast with the Company's approach to replacement of pole top equipment (*e.g.*, transformers, capacitors, reclosers), which the Company states is dependent upon the condition of the facilities.[80] I find it not only hard to believe, but astounding, that for the 55 Michigan Roadside Relocation projects listed in Exhibit IM-6 (DSI-3), at an aggregate cost of $21.2 million for the 2-year period 2023 and 2024, that near-complete rebuilds are standard policy and the Company cannot find a way to save ratepayers money by reusing assets that are simply relocated. At a minimum, it is reasonable to infer that a good share of poles could be retreated and thus reused on-site or at other relocation sites. In addition, the Company could explore other options to save money, such as testing the use of specialized equipment for use in maintaining hard-to-access distribution lines, as an alternative to spending $21.2 million in 2 years to relocate and rebuild such lines. In my opinion, the Company has not demonstrated any reliability benefits gained by this program are commensurate with the cost incurred.

[78] *Id.*

[79] Ex CUB-15 (I&M Response to CUB 1-41).

[80] Ex CUB-12 (I&M Response to CUB 1-36).

Q. What are your findings and conclusions regarding Pole Replacements?

A. Pole replacements are a component of the Company's Asset Renewal Projects. The Company's Exhibit IM-6 (DSI-3) shows a planned pole replacement level for 2023 of 422 poles at an expected cost of $1,786,369, and for 2024 a replacement level of 430 poles at an expected cost of $1,879,855. When asked in discovery if it was reinforcing deteriorated poles, the Company responded that it was not reinforcing poles, only replacing them.[81] It is clear from the response that the decision to sidestep a reinforcement option for decayed poles is a Company policy decision, and not a case-by-case determination of serviceability. In my opinion, the Company's policy of replacement-only is a red flag indicator that the Company is not being judicious in its Asset Renewal Projects, resorting to a wholesale replacement policy across multiple subcategories of project types. It also raises the question of whether the Company is also substituting replacement for other possible kinds of remediation of deteriorated poles. For example, the U.S. Department of Agriculture Rural Utilities Service (RUS) Bulletin 1730B-121 - Wood Pole Inspection and Maintenance[82], notes that "Stubbing can frequently be done at one-half to one third of the cost of replacement, particularly when replacement would require a considerable amount of transfer work." The Bulletin also specifically refers to reinforcement as a potentially less costly option to replacement.

[81] Ex CUB-16 (I&M Response to CUB 1-47).

[82] https://www.usbr.gov/power/data/fist/fist_vol_4/vol4-6.pdf.

Q. Does excessive pole replacement have a compounding effect on costs?

A. Yes. Pole replacement would generally involve replacement of associated crossarms, insulators, and perhaps other pole top equipment. The additional costs are not only related to such material expenses, but also the significant additional labor costs to transfer the line to the new pole.

Q. Is it possible that the Company's policy to replace and not reinforce or stub poles is based on inspection results that show I&M poles cannot be remediated?

A. No. That is an unrealistic presupposition. However, for sake of argument, suppose that of the thousands of pole inspections each year, it is determined that no poles found to have decay or other damage, or very few, could be remediated, and the majority must be replaced. Under those circumstances, there would be no reasonable alternative but for I&M to aggressively investigate shorter inspection intervals along with more aggressive treatment or remediation as a means to reduce pole replacements. Inspecting on a shorter interval would allow the identification of decay before it progressed to the point that treatment, reinforcement, or stubbing was not an option. Shorter inspection intervals would increase the proportion of inspected poles determined to be serviceable, because decay would be caught sooner. If, in fact, I&M is finding that it cannot remediate poles, I am recommending that I&M investigate if shortening inspection intervals would allow for an economical extension of pole service life and thus reduce the level of replacements. I am also recommending that the Company report to the Commission in its next general rate case filing on its investigation progress.

Q. What are your findings and conclusions regarding the Asset Renewal category, Combined Projects?

A. The Combined Projects are a major cost category, consisting of large asset renewal efforts that include substation and associated circuits, replacement of existing old equipment and new asset additions. Combined Projects have an estimated cost of $5.3 million in 2023 and $0.8 million in 2024. In Exhibit IM-7 (DSI-1), the Company presented limited information for 10 combined projects in Michigan. The 10 projects have completion dates ranging from 2023 through 2026. Seven of the proposed projects have expected completion dates in the 2023 bridge period. The Empire Station project includes expenditures in 2023 only for the purchase of land, with material and labor costs estimated for 2026. Two projects, Valley Station and Hickory Creek, have planned expenditures in 2024.

In my opinion, of the 10 projects, only 1, the Main St. Station Project, looks to have compelling merit (given the limited information provided) on the basis of "poor condition evaluations" and consequent "risk of station failure" and the fact that "spare parts are no longer available." It appears reasonable to consider these signs of imminent station failure, which is reasonable basis for investment.

The remaining nine projects are justified on the basis of four factors, consisting of capacity for expected load growth, economic development, increased reliability, and modernization.

Q. Does I&M's load growth support the necessity of the Company's proposed Combined Project asset replacements?

A. Not in my opinion. I am rejecting load growth as a reasonable basis for I&M's proposed Combined Projects. The Company failed to provide compelling evidence that it has been

experiencing sufficient load growth to justify the projects. To be specific, the Company's Exhibit A-15, Schedule No. E-1 D.M. White, shows the Company's five-year load forecast for the years 2024 through 2028. The exhibit indicates that over the forecast period, Michigan retail load (retail sales plus customer choice) is expected to decline by 2%. The Company's own sales forecast is in direct conflict with the asserted need to invest in additional distribution capacity through the proposed Combined Projects.

Q. Does the new Michigan energy law have implications for further reductions in load beyond that forecasted by the Company?

A. Yes. The new law (House Substitute for Senate Bill 273), which was signed by the Governor on November 28, 2023, increases the required level of the Energy Waste Reduction (EWR) target for electric utilities from 1% to 1.5% per year starting in 2025. The law also mandates an average life of eight years for energy reduction measures to ensure that the reductions are long-lived. That additional 0.5% reduction per year, when combined with the Company's own internal view of declining load firmly puts into doubt the prudency of major asset replacements justified on the basis of future load growth.

Q. What about economic development as a basis for new transmission/distribution capital investment?

A. The Company provided no evidence of new or changing economic factors that will accelerate the level of new load additions. In my opinion, the Company's "economic development" basis for investment in increased capacity appears to be no more than a hope that the negative load growth will turn around. I am recommending that the economic development basis for Combined Projects also be rejected by the Commission.

Q. With respect to the Combined projects, what does the Company need to do to make a showing that asset replacement is appropriate?

A. The Commission has faulted I&M in past rate cases for failing to provide information showing the outage and failure history of proposed distribution asset replacements, and specifically for failing to show that the primary causes of past outages for selected replacement projects were not due to tree contact but a history of actual equipment failures. Except for the Main Street Station project, the project justifications I&M provided to the Commission in this case similarly do not show a history of actual failure or a current state of incipient or imminent failure. Three projects (Sodus, West St., and Scottdale) are primarily justified on the basis of equipment being old or at its end of life. I would call these "proactive" replacements. Proactive replacement needs to be done very judiciously and with restraint in order to achieve a reasonable balance between cost, reliability gains, and the impact on customers who bear the cost. A policy of replacing old assets merely because they are old is unlikely to achieve such a balance because of the limited increase in reliability.

Q. Why does proactive replacement yield a limited increase in reliability?

A. Understanding the basic concepts of failure has important ramifications with respect to replacement policy. Namely, it is erroneous to presume that when an asset reaches the design life it will immediately or shortly fail simply because it has reached its design life. In other words, there is no cause and effect tied to the numerical value of the design life. The design life is a mean, or mathematical expectation of service life that reflects an underlying probability distribution curve with respect to failure. This is where strong inspection strategies are needed to single out and to clearly identify for replacement the

relatively small portion of surviving assets that are in a state of incipient or imminent failure at any given time. In addition, if an asset has a history of past failures, that can be a strong indication that imminent failure is likely. Wholesale replacement of assets that have reached the design life can waste the asset value already paid for by ratepayers, as the policy has a high probability cutting short the remaining service life. Such a policy is unlikely to strike a reasonable balance between cost, reliability, and the need to keep utility rates affordable. Based on my reviews, I&M appears to have a pattern of replacement over reuse, remediation, or intensive monitoring as alternatives. The Company's low level of load growth may be a factor in driving the utility toward replacement, as the opportunity for growth-based investments is absent.

Q. How are the remaining six Combined Projects justified by the Company?

A. The remaining six Combined Projects are justified on the basis of providing increased opportunity for load transfers during emergency situations. Most also include the presumed benefit of accommodating load growth or economic development, which I have already addressed as deficient.

Q. What are your conclusions regarding the load transfer projects?

A. Two of the six load transfer projects are exceptionally expensive. They are the Crystal Station project, at an estimated cost of $2.2 million, and the proposed Empire Station, at an estimated cost of $5.1 million. These two projects require, in my opinion, a detailed cost-benefit analysis, including an analysis of alternatives. In addition, an analysis of outage history at the substations and associated distribution lines should be a mandatory requirement for approval. This would allow a detailed look at what is causing outages and

alternative options to reduce such outages. I am recommending that Commission approval of cost recovery for these two projects be deferred until the lack of support is resolved. The other four load-transfer projects, the Sodus Station, Stubey Station, Valley Station, and Hickory Creek Station are relatively lower cost reliability projects, especially the proposed Hickory Creek Station. As the Company has not had a general rate proceeding since 2020, two of these projects, (Sodus and Stubey) have a 2023 completion date but did not receive advance review in the prior rate proceeding.

Q. What is your overall recommendation for the Asset Renewal capital program?

A. Based on my spot review of subcategories within the Asset Renewal capital program, as previously described, I have concluded that the Company's excessive replacement policy defective and likely pervasive across the board. It would be impossible for an intervenor to review every project in detail and recommend a specific disallowance for each project. Therefore, I am recommending that the Commission reduce the Asset Renewal capital program for the 2024 projected test-year by 10%, which represents a reasonable amount in light of the Company's failure to demonstrate that its projects are cost-effective and necessary. In addition, I am recommending that the Commission defer cost recovery of the 2023 capital expenditures for the Crystal Station project until the lack of support is resolved as discussed above. I am also recommending that the Commission defer approval of the proposed 2023 through 2026 Empire Station project, for the same reason, (noting that only $18,944 has been spent in 2023 on a land purchase for the upcoming project.

XII. CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your recommendations.

A. In summary, for the reasons explained above, I recommend that the Commission:

(1) Reject the Company's proposed elimination of the time-varying pricing periods from the residential and general service critical peak pricing (CPP) tariffs and instruct I&M to develop a corrective plan to better educate customers on how to take advantage of time-of-use (TOU) pricing.

(2) Reject the proposed DG 2 Rider and direct I&M to continue enrolling Category 1 customers, including those who applied after May 15, 2023, in its existing distributed generation (DG) program unless and until it receives approval for a new DG tariff that complies with the new state law effective February 27, 2024.

(3) Deny I&M's requests for approval of the PowerPay program and the associated rule waivers that I&M would need to implement PowerPay and disallow any IT costs associated with PowerPay implementation.

(4) Reject the Company's requests to modify its EWR net lost revenue tracker to retroactively recover lost sales revenues related to any decline in sales regardless of cause (with respect to the sales level set in this rate case) and to remove the 3% cap, and direct the Company to continue using the existing, approved form of the tracker.

(5) Direct the Company to update the per-foot costs of construction in its Company Terms and Conditions of Service of Standard Service at Rule 12 and its Company Terms and Conditions of Open Access Distribution Service at Rule 17.

(6) Disallow the Company's proposed Distributed Energy Resource Management System (DERMS) capital expense as being premature.

(7) Direct I&M to change its methodology for calculating its major storm restoration costs by adjusting its historical five-year average for inflation less productivity for future rate cases.

(8) Condition approval of the Company's proposed move to a four-year cycle-based vegetation management program upon the Company implementing an information-gathering pilot so that it may perform an appropriate cost-benefit analysis; should the Company agree to implement the recommended pilot, I am recommending that the Company's proposed vegetation management expense for 2024 be set to the 2023 forecasted vegetation management cost amount, as shown in Figure DSI-7 of Company witness Isaacson's testimony, and that the Company be granted regulatory asset treatment for any reasonable capital costs (such as high technology equipment) or O&M needed to pilot a risk-based approach; otherwise, the Commission should set the Company's proposed vegetation management expense for the 2024 projected test period at the 2023 forecasted vegetation management cost amount identified in Figure DSI-7.

(9) Direct I&M to develop a concrete plan to remediate is imprudent maintenance policy with respect to overhead service lines, including a pilot if deemed necessary by the Company, and file a proposal in its next general rate proceeding.

(10) Reject the Company's request for deferred recovery of outage credits and also reject any request for recovery of outage credits as O&M or other expenses.

(11) Reduce the Asset Renewal capital program for the 2024 projected test-year by 10%, defer cost recovery of the 2023 capital expenditures for the Crystal Station project, and defer approval of the proposed 2023 through 2026 Empire Station project.

(12) If I&M cannot remediate rather than replace poles, investigate whether shortening inspection intervals would allow for an economical extension of pole service life and thus reduce the level of replacements and report to the Commission in its next general rate case filing on its investigation progress.

Q. Does that complete your testimony?

A. Yes.

Robert G. Ozar P.E.

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Suite 710, 115 W Allegan Street, Lansing, Michigan 48933.

rozar@5lakesenergy.com

- 5 Lakes Energy: Senior Consultant
- MPSC: Assistant Director, Electric Reliability Division

WORK EXPERIENCE

5 Lakes Energy **March 2020 – May 2022**

Professional Accomplishments

- Expert witness in multiple MPSC hearings with respect electric distribution infrastructure, cost analysis, rate design, and regulatory theory
- Modeling and analysis of energy storage and solar PV using the HOMER Grid for the Michigan Energy Storage Roadmap

Michigan Public Service Commission **Nov 1979 – Dec 2019**

Natural Gas Regulatory Accomplishments

- Created Quartile Exponential Smoothing Strategy for gas distribution utility hedging during periods of high market volatility
- Created Contingency Factor regulatory process for setting Gas Cost Recovery Factors
- Performed energy market analysis and projections of natural gas supply/demand/prices
- Review of gas transmission infrastructure projects requested by regulated gas utilities
- Developed residential, commercial and industrial sales forecasts and weather normalization methods for use in gas utility general rate-case proceedings
- Testified in numerous contested case proceedings on issues related to natural gas engineering, economics, and regulatory theory, policy and practice

Energy Efficiency Accomplishments

- Chair of the Energy Efficiency Workgroup in the Capacity Needs Forum for development of a statewide Integrated Resource Plan
- Created, led and managed the Michigan Energy Efficiency Workgroup
- Created the first Energy Optimization Program Incentive-Mechanism for meeting and exceeding performance targets set by Michigan statute

- Led the development of the Michigan Deemed Savings Database, used to set uniform achieved savings levels for Michigan utilities
- Led the regulatory review of Energy Optimization Plans and annual financial reconciliations for Michigan utilities
- Wrote the Request for Proposal (RFP) for the creation of *Michigan Saves*, a statewide program for financing energy efficiency improvements by Michigan utility customers

Electric Industry Accomplishments

- Chief lead for MPSC staff in the Michigan Electric Vehicle Preparedness Taskforce
- Created and led the Michigan Smart Grid Collaborative facilitating the introduction of electric utility infrastructure and regulatory structure for review and approval of capital expenditures. Led Staff review of utility requests for rate approval of advanced metering infrastructure (AMI)
- Created the request for proposal (RFP) for a $5 million electric vehicle study of the potential impact of market growth of plug-in EV's on electric utility distribution systems and electric generation systems in Michigan, and the need for active management by utilities of EV charging by utility customers
- Created the concept of using a twenty-year levelized cost of renewable energy programs which was codified in PA 295
- Author of the Inflow/Outflow pricing model adopted by the MPSC as a cost based regulatory structure to replace Net Energy Metering (NEM) in Michigan

Depreciation Engineering

- Wrote a MATLAB model for review of life curves and remaining life of utility assets for use by the MPSC Staff

EDUCATION

Michigan State University, East Lansing, MI **2001**
Master's in Chemical Engineering

Michigan State University, East Lansing, MI **1979**
BS in Chemical Engineering, with Honors

- Recipient of the Schlumberger Scholarship in Chemical Engineering
- Inducted into the national engineering honor societies Tau Beta Pi, and Omega Chi Epsilon

TEACHING

Mr. Ozar has spoken as an energy expert at energy industry conferences having both national and international audiences. He has regularly taught at the Michigan State University Institute of Public Utilities (IPU) Fundamentals, Intermediate and Advanced Regulatory Studies Program.

M.P.S.C. 16 – ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)

~~**FIRST REVISED**~~ **ORIGINAL SHEET NO. C-1.00**
~~**CANCELS ORIGINAL SHEET NO. C-1.00**~~

COMPANY TERMS AND CONDITIONS OF STANDARD SERVICE

1. APPLICATION

These Terms and Conditions of Standard Service apply to service under the Company's tariffs that provide for Power Supply (generation and transmission), and Delivery (distribution) service. Customers requesting only distribution service from the Company, irrespective of the voltage level at which service is taken, as provided for in the Customer Choice and Electricity Reliability Act, shall be served under the Company's tariffs and the Terms and Conditions of Open Access Distribution Service.

Standard Service furnished by the Company is subject to the terms and conditions of the applicable tariffs and Terms and Conditions of Standard Service which are at all times subject to revision, change, modification, or cancellation by the Company, subject to the approval of the Michigan Public Service Commission, and which are, by reference, made a part of all standard contracts (both oral and written) for Standard Service. Failure of the Company to enforce any of the terms of these tariffs and Terms and Conditions of Standard Service shall not be deemed a waiver of its right to do so.

A copy of all tariffs and Terms and Conditions of Standard Service is on file with the Michigan Public Service Commission and may be inspected by the public in any of the Company's business offices. Upon request, the Company will supply, free of charge, a copy of the rate schedules applicable to service available to existing customers or new applicants for service. When more than one rate schedule is available for the service requested, the customer shall designate the rate schedule on which the application or contract shall be based. Where applicable the customer may change from one rate schedule to another once at the end of each full 12-month period or as specified by tariff or contract, upon written application to the Company. In no case will the Company refund any difference in charges between the rate schedule under which service was supplied in prior periods and the newly selected rate schedule.

A written agreement may be required from each customer before service will be commenced. A copy of the agreement will be furnished to the customer upon request.

By receiving service under a specific tariff, the customer has agreed to all terms and conditions of that tariff. A customer's refusal or inability to sign a contract or agreement as specified by the tariff, in no way relinquishes the customer's obligations as specified in the tariff.

When the customer desires delivery of energy at more than one point, a separate agreement will be required for each separate point of delivery. Service delivered at each point of delivery will be billed separately under the applicable tariff. Conjunctive billing and/or aggregate demands are prohibited. Under certain circumstances the Company may have provided two services to fulfill the customer's lighting and power requirements at a single location and the metering for the two services have been combined for billing. Existing such arrangements are explicitly grandfathered until an account change occurs. Once an account change occurs, combined billing of grandfathered multiple meters

(Continued on Sheet No. C-2.00)

M.P.S.C. 16 – ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)

~~**FIRST REVISED**~~ **ORIGINAL SHEET NO. C-2.00**
~~**CANCELS ORIGINAL SHEET NO. C-2.00**~~

(Continued from Sheet No. C-1.00)

would end. Each point of delivery would then require a separate agreement for each separate point of delivery. For new service/accounts, multiple metering is permitted only for Company convenience

2. BILLS FOR STANDARD ELECTRIC SERVICE

A. General

Bills for electric service will be rendered monthly at intervals of approximately 30 days in accordance with the tariff selected applicable to the customer's service. All bills are rendered as "net" bills and are subject to a late payment charge if the account is delinquent. Late payment charges will be assessed on Residential bills in accordance with Rule 460.122 and on Commercial and Industrial bills in accordance with Rule 460.1614. A late payment charge shall not be assessed against any residential customers who are participating in the winter protection plan as described in Rule 460.148 and Rule 460.149 of the Consumer Standards and Billing Practices for Residential Customers. Any governmental agency shall be allowed such additional period of time for payment of the net bill as the agency's normal fiscal operations require, not to exceed 30 days.

It may be necessary for the Company to render a bill on an estimated basis if extreme weather conditions, emergencies, work stoppage, or other circumstances of force majeure prevent actual meter readings. Pursuant to Rule 460.113, any bill rendered on an estimated basis shall be clearly and conspicuously identified. In the event of the stoppage of or the failure of any meter to register an accurate amount of energy consumed, as described in Rule 460.116, the customer will be charged or credited for such period on an estimated consumption based upon energy use during a similar period of like use. Meter errors shall be reconciled in accordance with Rule 460.3309. This estimation shall include adjustments for changes in customer's load during the period the meter was not registering properly. As stated in Rule 460.116 (2), any meter in service that remains broken as determined by a specific test of the meter or that does not correctly register customer usage for a period of 6 months or more shall be removed and customers will not be required to pay bills generated from these meter readings beyond the 6-month period from the date the meter malfunction occurred. This rule does not alter the provisions of Rule 460.3613 governing the testing and replacement of electric meters.

A bill shall be mailed, transmitted, or delivered to the customer not less than 21 days before the due date. Failure to receive a bill properly mailed, transmitted, or delivered by Company does not extend the due date. Upon request the Company will advise the customer of the approximate date on which the bill will be mailed each month, and if the bill is lost, the Company will issue a duplicate.

B. Non-residential

Billing errors for non-residential accounts shall be rectified as described in Rule 460.1617. If a customer has been overcharged, the utility shall refund or credit the amount of the paid overcharge to the customer. Overcharges shall be credited to customers with 7% interest,

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(Continued from Sheet No. C-2.00)

commencing on the 60th day following payment. The Company is not required to adjust, refund, or credit an overcharge beyond the 3-year period immediately preceding discovery of the billing error, unless the customer is able to present a record establishing an earlier date of occurrence or commencement of the error.

In cases of unauthorized use of utility service the customer may be back billed for the amount of the undercharge. The back bill may include interest at the same 7% interest rate applied to overcharges.

In cases not involving unauthorized use of utility service, the customer may be back billed for the amount of the undercharge during the 12-month period immediately preceding discovery of the error. The Company shall offer the customer at least the same number of months for repayment equal to the time of the error. The back bill shall not include interest.

C. Residential

Billing errors for residential accounts shall be rectified as described in Rule 460.126. If a customer has been overcharged due to a billing error, the Company shall refund or credit the amount of the paid overcharge plus 7% APR interest on the bill immediately following the discovery of the error. Upon customer request, overcharges greater than $10 shall be refunded within 30 days. The Company is not required to adjust, refund, or credit an overcharge plus 7% APR interest for more than the 3 years immediately preceding discovery of the billing error, unless the customer is able to establish an earlier date for commencement of the error. The interest on the overcharge shall be applied on the 60th day following the paid overcharge.

If the Company undercharges a customer, the following provisions apply:

In cases that involve unauthorized use of utility service the utility may back bill the customer for the amount of the undercharge using the commission-approved process for estimating the bill. The utility may charge fees for unauthorized use of utility service in accordance with commission-approved tariffs.

In cases that do not involve unauthorized use of utility service, the utility may back bill the customer for the amount of the undercharge during the 12-month period immediately preceding discovery of the error, and the utility shall offer the customer reasonable payment arrangements for the amount of the back bill, which shall allow the customer to make installment payments over a period at least as long as the period of the undercharge. The utility shall take into account the customer's financial circumstances when setting payment amounts.

D. Budget Bill Payment Options

In addition to paying the actual monthly bill amount, Residential customers using electric service with a satisfactory payment history shall have the option of paying bills under one of the Company's two budget billing plans – the Equal Payment Plan (EPP) or the Average Monthly Payment Plan (AMPP), both of which are described below.

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(Continued from Sheet No. C-3.00)

Under the Equal Payment Plan (EPP), the total service for the succeeding 12-month period is estimated in advance and bills are rendered monthly on the basis of one-twelfth of the 12-month estimate. The Company may at any time during the 12-month period adjust the estimate so made, and the bills rendered in accordance with such estimate, to conform more nearly with the actual use of service being experienced.

In case the actual service used during any equal payment period exceeds the bills as rendered on the EPP, the amount of such excess shall be paid on or before the due date of the bill covering the last month of the equal payment period in which such excess appears. Such excess may be added to the estimated use for the next normal equal payment period of 12 months and shall be payable in equal monthly payments over such period, except that if the customer discontinues service with the Company under the EPP, any such excess not yet paid shall become payable immediately. In case the actual service used during the equal payment period is less than the amount paid under the EPP during such period, as specified in R460.118, if a customer has a credit balance of more than $10.00 at the end of the period, upon the request of the customer, the utility shall either return the credit balance or credit it to the next month's bill. If the balance is less than $10.00, the utility shall credit the amount to the customer's account.

If a customer fails to pay bills as rendered on the EPP, the Company shall have the right to withdraw the EPP with respect to such customer and restore the customer to billing as provided for in the applicable tariffs, in addition to any other rights which the Company may have under such tariffs in case of arrearage in payment of bills. If a customer requests removal from the EPP, the amount of any excess payments made under the EPP will be applied as a credit on the next month's bill. Likewise, if there is a deficiency in payments, the amount of deficiency will be added to next month's bill.

Under the Average Monthly Payment Plan (AMPP), variations in customer billings are minimized by allowing the customer to pay an average amount each month based on the current month's billing plus the eleven (11) preceding months, divided by the total billing days associated with those billings to get a per day average. The average daily amount will be multiplied by thirty (30) days to determine the current month's payment under the AMPP. At the next billing period, the oldest month's billing history is dropped, the current month's billing is added and the average is recalculated to find a new payment amount. The average is recalculated each month in this manner.

In such cases where sufficient billing history is not available, an AMPP account may be established allowing the first month's amount due to be the average based on the actual billing for the month. The second month's amount due will be the average based on the first and second billing. The average will be recomputed each month using the available actual history throughout the first AMPP year.

Actual billing will continue to be based on the applicable rate and meter readings obtained to determine consumption. The difference between actual billings and the averaged billings under the AMPP will be carried in a deferred balance that will accumulate both debit and credit differences for the duration of the AMPP year – twelve (12) consecutive months. At the end of the AMPP year (anniversary month), the net accumulated deferred balance is divided by twelve (12) and the result is included in the average payment amount starting with the first billing of the new

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(Continued from Sheet No. C-4.00)

AMPP year and continuing for twelve (12) consecutive months. Settlement occurs only when participation in the plan ends.

If a customer fails to pay bills as rendered on the AMPP, the Company shall have the right to withdraw the AMPP with respect to such customer and restore the customer to billing as provided for in the applicable tariffs, in addition to any other rights the Company may have under such tariffs in case of arrearage in payment of bills. If a customer requests removal from the AMPP, the amount of any overpayment made under the AMPP will be applied as a credit on the next month's bill. Likewise, any amount of under payment will be applied as a charge to the next month's bill.

3. INSPECTION

It is to the interest of the customer to properly install and maintain customer-owned wiring and electrical equipment, and the customer shall at all times be responsible for the character and condition thereof. The Company makes no inspection thereof and in no event shall be responsible therefore.

Where a customer's premises are located in a municipality or other governmental subdivision where inspection laws or ordinances are in effect, the Company may withhold furnishing service to new installations or disconnected existing installations until it has received evidence that the inspection laws or ordinances have been complied with. In addition, if such municipality or other governmental subdivision shall determine that such inspection laws or ordinances are no longer being complied with in respect to an existing installation, the Company may suspend the furnishing of service thereto until it has received evidence of compliance with such laws or ordinances.

Before furnishing service, Company shall require a certificate or notice of approval from a duly recognized authority stating that customer's wiring has been installed in accordance with local and state requirements.

No responsibility shall attach to the Company because of any waiver of these requirements.

4. SERVICE CONNECTIONS

The Company will, when requested to furnish service, designate the location of its service connection. The customer's wiring must, except for those cases listed below, be brought outside the building wall nearest the Company's service wires so as to be readily accessible thereto. When service is from an overhead system, the customer's wiring must extend a distance beyond the building as established by local codes and Company standards. Where customers install service entrance facilities as specified by the Company and/or install and use certain utilization equipment as specified by the Company, the Company may provide or offer to own certain facilities beyond the point where the Company's service wires attach to the building.

The Company reserves the right to make final determination of selection, application, location, routing and design of its service facilities and meter location. If the customer requests special routing of the service facilities and or meter location, the customer will be required to pay the extra cost, if any, resulting from the special routing of service facilities and or meter location.

All customers' wiring must be grounded in accordance with the requirements of the National Electrical Code or the requirements of any local inspection service authorized by a state or local authority.

(Continued on Sheet No. C-6.00)

ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE MICHIGAN PUBLIC SERVICE COMMISSION DATED
IN CASE NO. U-18370

M.P.S.C. 16 – ELECTRIC **~~FIRST REVISED~~ORIGINAL SHEET NO. C-6.00**
INDIANA MICHIGAN POWER COMPANY **~~CANCELS ORIGINAL SHEET NO. C-6.00~~**
STATE OF MICHIGAN
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(Continued from Sheet No. C-5.00)

When a customer desires that energy be delivered at a point or in a manner other than that designated by the Company, the customer shall pay the additional cost of same, including any and all required engineering studies.

When a customer requests additional engineering studies beyond the normal overhead and/or underground options providing an adequate plan of service, as designated by the Company, for a new or relocated service, the Company shall charge the customer, payable in advance, for actual cost incurred by the Company to conduct such studies. Normal engineering studies include any obvious options such as overhead and underground installations.

Where service is supplied from an underground distribution system which has been installed at the Company's expense, the customer shall make arrangements with the Company for the Company to supply and install a continuous run of cable conductors including necessary ducts from the manhole or connection box to the meter location where it is necessary that the location of the meter be inside the customer's building. The customer shall reimburse Company for the cost of the portion of cable and duct from the property line to the terminus of cable inside the building.

5. LOCATION AND MAINTENANCE OF COMPANY'S EQUIPMENT

The Company shall have the rights to construct its poles, lines, and circuits on the property, and to place its transformers and other apparatus on the property or within the buildings of the customer, at a point or points convenient for the purpose, as required to serve the customer. The customer shall keep company equipment clear from obstruction and obstacles including landscaping, structures, etc., and provide suitable space for the installation, repair and maintenance of necessary measuring instruments so that the instruments may be protected from injury by the elements or through negligence or deliberate acts of the customer or any other person who is not an agent or employee of the Company.

When Company facilities are damaged due to customer actions or negligence, the Customer shall be responsible for the costs of repairs.

6. RELOCATION OF COMPANY'S FACILITIES AT CUSTOMER'S REQUEST

Whenever, at customer's request, the Company's facilities are relocated solely to suit the convenience of customer, the customer shall reimburse the Company for the entire cost incurred in making such change including any and all required engineering studies.

7. COMPANY'S LIABILITY

The Company will use reasonable diligence in furnishing a regular and uninterrupted supply of energy, but does not guarantee uninterrupted service. The Company shall not be liable for damages in case such supply should be interrupted or fail by reason of an act of God, the public enemy, accidents, labor disputes, or orders or acts of civil authority. Further, the Company shall not be liable for damages in case such supply should be interrupted due to causes or conditions beyond the Company's reasonable control, including extraordinary repairs, breakdowns or injury to machinery, transmission lines, distribution lines, or other facilities of the Company. Further, the Company shall not be liable for damages for interrupting service to any customer, whenever in the judgment of the Company such interruption is necessary in order to prevent or limit any instability or disturbance on the electric system of

(Continued on Sheet No. C-7.00)

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STATE OF MICHIGAN
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(Continued from Sheet No. C-6.00)

the Company or any electric system interconnected with the Company, such interruptive action to be taken in accordance with predetermined plan and only in situations that threaten massive curtailments of service on the Company's system.

Unless otherwise provided in a contract between Company and customer, the point at which service is delivered by Company to customer, to be known as "delivery point," shall be the point at which the customer's facilities are connected to the Company's facilities. The metering device is the property of the Company; however, the meter base and all internal parts inside the meter base are customer owned and are the responsibility of the customer to install and maintain. The Company shall not be liable for any loss, injury, or damage resulting from the customer's use of customer-owned equipment or occasioned by the energy furnished by the Company beyond the delivery point.

The customer shall provide and maintain suitable protective devices on the customer's equipment to prevent any loss, injury, or damage that might result from single-phasing conditions or any other fluctuation or irregularity in the supply of energy. The Company shall not be liable for any loss, injury, or damage resulting from a single-phasing condition or any other fluctuation or irregularity in the supply of energy that could have been prevented by the use of such protective devices. . The Company shall not be liable for any damages, whether direct or consequential, including, without limitations, loss of profits, loss of revenue, or loss of production capacity occasioned by interruptions, fluctuations or irregularity in the supply of energy.

The Company is not responsible for loss or damage to customer's property caused by the disconnection or reconnection of service to the customer's facilities. The Company is not responsible for loss or damages to customer's property caused by the theft or destruction of Company facilities by a third party.

The Company will provide and maintain the necessary line or service connections, transformers (when the same are required by conditions of contract between the parties thereto), meters, and other apparatus that may be required for the proper measurement of and protection to its service. All such apparatus shall be and remain the property of the Company.

8. CUSTOMER'S LIABILITY

In the event of loss or injury to the property of the Company through misuse by, or the negligence of, the customer or the employees of the same, the cost of the necessary repairs or replacement thereof shall be paid to the Company by the customer.

The customer shall be responsible and, therefore, shall insure that no one except Company employees or agents of the Company shall make any internal or external adjustments to, or otherwise interfere with, or break the seals of meters or other Company-owned equipment installed on customer's property.

The Company shall have the right to enter, at all reasonable hours, the premises of the customer for the purpose of installing, reading, removing, testing, replacing, or otherwise disposing of its apparatus and property, and the right of entire removal of the Company's property in the event of termination of service for any cause. The customer must keep the immediate area and access area in and around the Company's equipment clean and free of debris.

(Continued on Sheet No. C-8.00)

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INDIANA MICHIGAN POWER COMPANY **~~CANCELS FIRST REVISED SHEET NO. C-8.00~~**
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(Continued from Sheet No. C-7.00)

9. USE OF ENERGY BY CUSTOMER

The tariffs for electric energy given herein are classified by the character of use of such energy and are not available for service other than as provided herein. Service will not be furnished under any tariff of the Company on file with the Commission to any customer, applicant, or group of applicants desiring service with the intent or for the purpose of reselling any or all of such service. For purposes of this tariff, the provision of electric vehicle charging service for which there is no direct per kWh charge shall not be considered resale of service. It shall be understood that upon the expiration of a contract the customer may elect to renew the contract upon the same or another tariff published by the Company available in the locality in which the customer resides or operates and applicable to the customer's requirements. In no case shall the Company be required to maintain transmission, switching, or transformation equipment (either for voltage or form of current change) different from, or in addition to, that generally furnished to other customers receiving electrical supply under the terms of the tariff elected by the customer.

A customer may not change from one tariff to another during the term of contract except with the consent of the Company or within a reasonable period after a Commission-approved change in tariffs.

The service connections, transformers, meters, and appliances supplied by the Company for each customer have a definite capacity and no additions to the equipment, or load connected thereto, will be allowed except by consent of the Company.

The customer shall install only motors, apparatus, or appliances which are suitable for operation with the character of the service supplied by the Company, which shall not be detrimental to same, and the electric power must not be used in such a manner as to cause unprovided-for voltage fluctuations or disturbances in the Company's transmission or distribution system. The Company shall be the sole judge as to the suitability of apparatus or appliances, and also as to whether the operation of such apparatus or appliances is, or will be, detrimental to its general service.

The customer is responsible to provide any timing equipment and timing control signals to operate time differentiated load.

No attachment of any kind whatsoever may be made to the Company's lines, poles, crossarms, structures, or other facilities without the express written consent of the Company.

All apparatus used by the customer shall be of such type as to secure the highest practicable commercial efficiency, power factor, and the proper balancing of phases. Motors which are frequently started or arranged for automatic control must be of a type to give maximum starting torque with minimum current flow and of a type equipped with controlling devices approved by the Company. The customer agrees to notify the Company of any increase or decrease in the customer's connected load.

The operation of certain electrical equipment can result in disturbances (e.g., voltage fluctuations, harmonics, etc.) on the Company's transmission and distribution systems that can adversely impact the operation of equipment for other customers. Customers are expected to abide by industry standards, such as those contained in ANSI/IEEE 519 or the IEEE/GE voltage flicker criteria, when operating such equipment. The Company may refuse or disconnect service to customers for using

(Continued on Sheet No. C-9.00)

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electricity or equipment that adversely affects distribution service to other customers. Copies of the applicable criteria will be provided upon request.

The Company will not supply service to customers who have other on-site sources of electric energy supply except under the tariffs that specifically provide for same.

The customer shall not be permitted to operate the customer's own generating equipment in parallel with the Company's service except on written permission of the Company or under specifically approved tariffs.

The Company may provide service to and take service from certain qualifying facilities defined as cogeneration or small power production facilities. Such sales and purchases are subject to contract and Commission authorization.

10. RESIDENTIAL SERVICE

Individual residences shall be served individually with single-phase service under the appropriate residential tariff. Customer may not take service for three or more separate living units through a single point of delivery under any tariff, irrespective of common ownership of the several residences, except that in the case of an existing apartment house with a number of individual apartments, the landlord shall have the choice of providing separate wiring for each apartment so that the Company may supply each apartment separately under the residential tariff, or of purchasing the entire service through a single meter under the appropriate general service tariff without submetering the service to the apartments. This central metering provision shall not be permitted for new customers.

In a two-family dwelling the owner may, at the owner's option, take service through a single meter under the residential tariff instead of providing separate wiring for both dwelling units. When service is taken through a single meter, the two-family dwelling will be billed as a single-family residence.

The residential tariff shall cease to apply to that portion of a residence which becomes regularly used for business, professional, institutional, or other gainful purposes or which requires three-phase service. Single-phase motors of 10 HP or less may be served under the appropriate residential tariff. Larger single-phase motors may be served where, in the Company's sole judgment, the existing facilities of the Company are adequate.

Under these circumstances, customer shall have the choice of: (1) separating the wiring so that the residential portion of the premises is served through a separate meter under the residential tariff and the other uses as enumerated above are served through a separate meter or meters under the appropriate general service tariff, or (2) taking the entire service under the appropriate general service tariff.

Detached building or buildings actually appurtenant to the residence, such as a garage, stable, or barn, may be served by an extension of the customer's residence wiring through the residence meter.

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EFFECTIVE FOR SERVICE RENDERED ON AND AFTER

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(Continued from Sheet No. C-9.00)

11. RESORT SERVICE

Where customers desire electric service for summer homes, summer resort hotels, or other summer resort establishments which are located adjacent to existing distribution lines of the Company and can be served without the extension of primary lines, they shall have the privilege of purchasing all-year service under the applicable all-year tariffs or of purchasing service for less than a full year under the applicable residential or general service tariffs, subject to payment in advance of an amount commensurate with the cost of handling the customer's account, for connection to and disconnection from the Company's lines.

12. EXTENSION OF SERVICE

A. Residential Service

i. Charges

For each permanent, year-round dwelling, the Company will provide a single-phase line extension excluding service drop at no additional charge for a distance of 200 feet. Distribution line extension in excess of the above footage will require an advance deposit of $3.50 per foot for all such excess footage. There will also be a nonrefundable contribution equal to the cost of right-of-way and clearing on such excess footage. Three-phase extensions, as required to service large developments, will be on the same basis as Commercial and Industrial.

ii. Measurement

The length of any main line distribution feeder extension will be measured along the route of the extension from the Company's nearest facilities from which the extension can be made to the customer's property line. The length of any lateral extension on the customer's property shall be measured from the customer's property line to the service pole. Should the Company for its own reasons choose a longer route; the applicant will not be charged for the additional distance; however, if the customer requests special routing of the line, the customer will be required to pay the extra cost resulting from the special routing.

iii. Refunds

During the five-year period immediately following the date of payment, the Company will make refunds of the charges paid for a financed extension under provisions of paragraph (i) above. The amount of any such refund shall be $165 for each permanent electric service subsequently connected directly to the facilities financed by the customer. Directly connected include any amount of contribution in aid of construction for underground service made under customers are those that do not require the construction of more than 100 feet of lateral primary distribution line. Such refunds will be made only to the original depositor and will not

(Continued on Sheet No. C-11.00)

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EFFECTIVE FOR SERVICE RENDERED ON AND AFTER

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include any amount of contribution in aid of construction for underground service made under the provisions of the Company's underground service policy as set forth in this section. The total refund shall not exceed the refundable portion of the contribution.

B. Commercial or Industrial Service

i. Company Financed Extensions

Except for contributions in aid of construction for underground service made under the provisions of Item 13, C of these rules, the Company will finance the construction cost necessary to extend its facilities to serve commercial or industrial customers when such investment does not exceed two times the annual capacity power supply and delivery charge revenue anticipated to be collected from customers initially served by the extension.

ii. Charges

When the estimated cost of construction of such facilities exceeds the Company's maximum initial investment as defined in paragraph (i), the applicant shall be required to make a deposit in the entire amount of such excess construction costs. Owners or developers of mobile home parks shall be required to deposit the entire amount of the estimated cost of construction, subject to the refund provisions of paragraph (iii).

iii. Refunds

That portion of the deposit related to the difference in the cost of underground construction and the equivalent overhead facilities shall be considered nonrefundable. This amount shall be determined under the applicable provisions of the Company's underground service policy as set forth in this section.

The Company will make refunds on remaining amounts of deposits collected under the provisions of paragraph (ii) above in cases where actual experience shows that the capacity power supply and delivery charge revenues supplied by the customer are sufficient to warrant a greater initial investment by the Company. Such refunds shall be computed as follows:

(1) Original Customer

At the end of the first complete 12-month period immediately following the date of initial service, the Company will compute a revised revenue credit based on two times the actual capacity power supply and delivery charge revenue provided by the original customer in the 12-month period. Any amount by which twice the actual annual capacity power supply and delivery charge revenue exceeds the Company's initial revenue estimate will be made available for refund to the customer; no such refund shall exceed the amount deposited under provisions of paragraph (ii) above.

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EFFECTIVE FOR SERVICE RENDERED ON AND AFTER

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M.P.S.C. 16 – ELECTRIC **ORIGINAL SHEET NO. C-12.00**
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(Continued from Sheet No. C-11.00)

(2) Refunds for additional new customers directly connected to the financed extension during the refund period will be governed by Section 12, A, iii.

iv. Loads of Uncertain Duration

When, in the opinion of the Company, the permanence and continuance of the customer's load is questionable, the Company may require the applicant to make an advance deposit for line construction or service to cover the Company's costs of extending its electric lines and furnishing and installing necessary transformation, metering and protective equipment to supply electricity to the customer's premises. The advance deposit with the Company will be made up of two components (1) the estimated cost of constructing the facilities to serve the customer, including labor, material, stores freight and handling expenses, and a charge for overhead, plus (2) the estimated cost of removing said facilities and returning the materials to the Company storeroom, minus the estimated value of salvaged materials to be returned to storeroom at the end of the electrical service.

Any customer making an advance deposit under this section is eligible for a rebate of the monies advanced under (1) of the preceding paragraph, beginning with the first full billing month for full operation of the customer's facility and ending with the 24th consecutive month thereafter. The rebate will be 40% of the monthly electric service paid by the customer. The total amount of all rebates shall not exceed the amount of the monies advanced under (1) of the preceding paragraph. In addition, following the continuous use of electric service for twenty-four (24) months, any monies held by the Company will be promptly refunded to the customer. The Company, at its discretion, may accept a letter of credit or performance bond, payable to the Company, in lieu of an advance deposit.

C. General

The Company will extend its lines to serve domestic customers and farm customers for year-round service under applicable tariffs subject to the following conditions:

i. Extensions hereunder shall be built by the Company in accordance with its construction standards and shall be single phase unless the Company elects to build polyphase lines.

ii. In those cases where it is not feasible or practicable to construct lines on public rights-of-way and it is necessary to secure rights-of-way on private property or tree trimming permits, the applicant or applicants shall secure the same without cost to the Company, or assist the Company, in obtaining such rights-of-way on private property or tree trimming permits before construction

(Continued on Sheet No. C-13.00)

ISSUED **EFFECTIVE FOR SERVICE RENDERED ON**
BY TOBY L. THOMAS **AND AFTER**
PRESIDENT
FORT WAYNE, INDIANA **ISSUED UNDER AUTHORITY OF THE**
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370

M.P.S.C. 16 – ELECTRIC **ORIGINAL SHEET NO. C-13.00**
INDIANA MICHIGAN POWER COMPANY ~~**CANCELS ORIGINAL SHEET NO. C-13.00**~~
STATE OF MICHIGAN
(RATE CASE U-18370)

(Continued from Sheet No. C-12.00)

shall commence. The Company shall be under no obligation to construct lines in event the necessary rights-of-way or tree-trimming permits cannot be so obtained.

13. UNDERGROUND ELECTRIC LINES

A. General

In case of all direct burial underground extensions of electric distribution facilities as covered by conditions as set forth in this Section 13, the real estate developer or customer shall make a nonrefundable contribution in aid of construction to the Company in an amount equal to the estimated difference in cost between overhead and direct burial underground facilities. "Distribution facilities" means those operated at 20,000 volts or less to ground for wye connected systems and 20,000 volts or less for delta connected systems. Charges in this Section 13 are in addition to any charges that may be required in Section 12 for equivalent overhead facilities.

B. Residential

i. In Subdivisions

(1) Distribution Facilities

The distribution system in a new residential subdivision and an existing residential subdivision in which electric distribution facilities have not already been constructed shall be placed underground, except that a lot facing a previously existing street or county road and having an existing overhead distribution line on its side of the street or county road shall be served with an underground service from these facilities and shall be considered a part of the underground service area.

The owner or developer of such shall be required to make a nonrefundable contribution in aid of construction to the Company, for direct burial underground distribution facilities, in an amount equal to the sum of the lot front-foot measurement multiplied by $ 5.50~~3.00~~, which amount shall be considered to be the difference in cost between overhead and direct burial underground distribution facilities.

The front-foot measurement of each lot to be served by a residential underground distribution system shall be made along the contour of the front lot line. The front lot line is that line which usually borders on or is adjacent to a street.

However, when streets border on more than one side of a lot, the shortest dimension shall be used. In case of a curved lot line that borders on a street or streets and represents at least two sides of the lot, the front-foot measurements shall be considered as one-half the total measurement of the curved lot line. Where a lot is served by an underground service

(Continued on Sheet No. C-14.00)

ISSUED **EFFECTIVE FOR SERVICE RENDERED ON**
BY TOBY L. THOMAS **AND AFTER**
PRESIDENT
FORT WAYNE, INDIANA

ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18370

M.P.S.C. 16 – ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)

~~**FIRST REVISED**~~ **ORIGINAL SHEET NO. C-14.00**
~~**CANCELS ORIGINAL SHEET NO. C-14.00**~~

(Continued from Sheet No. C-13.00)

from an overhead distribution line, the lot front-foot measurement shall be deleted. The construction provided for in the $ 5.50~~3.00~~ per lot front-foot contribution in aid of construction includes the extension of electric underground distribution facilities to the lot line of each lot in the subdivision.

The use of the lot front-foot measurement in these rules shall not be construed to require that the underground electric distribution facilities be placed on the front of the lot.

(2) Service Facilities

The Company shall install, own, and maintain the service line from the property line to the customer's meter. For normal installation of the service line, the developer or customer shall make a nonrefundable contribution in aid of construction to the Company in an amount equal to $11.75~~4.00~~ per trench foot.

ii. Outside of Subdivisions

(1) Distribution Facilities

The customer located outside of subdivisions shall be required to make a nonrefundable contribution in aid of construction to the Company in an amount equal to the estimated total difference in cost between overhead and underground construction costs.

(2) Service Facilities

For normal installation of the service line, the customer shall make a nonrefundable contribution in aid of construction to the Company in an amount equal to $11.75~~4.00~~ per trench foot.

iii. Mobile Home Parks, Condominiums and Apartment House Complexes

The distribution and service facilities for new and existing mobile home parks, condominiums, and apartment house complexes in which electric facilities have not already been constructed shall be placed underground.

The owner or developer of such mobile home parks, condominiums, and apartment house complexes shall be required to make a nonrefundable contribution in aid of construction to the Company for distribution facilities in an amount equal to $5.50~~3.00~~ per trench foot and service facilities in an amount equal to $12.25~~3.80~~ per trench foot and $11.25~~8.00~~ per kVA for transformers (installed). Owners or developers of mobile home parks shall be required to deposit the entire amount of the estimated cost of construction, subject to the refund provisions of Section 12 B (iii).

(Continued on Sheet No. C-15.00)

ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR SERVICE RENDERED ON AND AFTER

ISSUED UNDER AUTHORITY OF THE MICHIGAN PUBLIC SERVICE COMMISSION DATED
IN CASE NO. U-18370

M.P.S.C. 16 – ELECTRIC
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)

~~**FIRST REVISED**~~**ORIGINAL SHEET NO. C-15.00**
~~**CANCELS ORIGINAL SHEET NO. C-15.00**~~

(Continued from Sheet No. C-14.00)

C. Commercial and Industrial

Commercial distribution and service lines in the vicinity of the customer's property and constructed solely to serve a customer or group of adjacent customers shall be placed underground. This will specifically include, but not be limited to, service to shopping centers.

Industrial distribution and service lines shall be placed underground at the option of the customer.

The developer or customer shall be required to make a nonrefundable contribution in aid of construction to the Company for the following facilities which amount shall be considered to be the difference in cost between overhead and direct burial underground facilities:

i. Distribution facilities - Single-phase - $5.50~~3.00~~ per trench foot.
Three-phase - $4.50~~1.50~~ per trench foot.

ii. Transformers - Single-phase - $9.25~~8.00~~ per kVA (installed).
Three-phase - $13.75~~10.00~~ per kVA (installed).

iii. Service, as this term is generally understood in the electric utility field, (on customer's property) - Single-phase - $10.75~~8.00~~ per trench foot.
Three-phase - $14.75~~12.50~~ per trench foot.

D. Special Conditions

Where practical difficulties exist, such as water conditions, rock near the surface, or where there are requirements for deviation from the Company's construction standards such as directional boring, the per foot charges in B and C will not apply, and the contribution in aid of construction will be equal to the estimated difference in cost between overhead and underground facilities but not less than the charge calculated under B and C.

An additional amount of $1 per foot shall be added to the trenching charges for the practical difficulties associated with winter construction in the period from December 15 to March 31, inclusive. This charge will not apply to jobs that are ready for construction and for which the construction meeting has been held prior to November 1.

E. Replacement of Existing Overhead Electric Facilities

Existing overhead residential, commercial, and industrial electric distribution and service lines shall be replaced with underground facilities at the option of the affected customer or customers. Before construction is started, the customer shall be required to pay the Company the depreciated cost (net cost) of the existing overhead facilities plus the cost of removal less the salvage value thereof and, also, make a nonrefundable contribution in aid of construction in an amount equal to the estimated difference in cost between new underground and new overhead facilities including, but not limited to, the costs of breaking and repairing streets, walks, parking lots, and driveways, repairing lawns, and replacing grass, shrubs, and flowers.

(Continued on Sheet No. C-16.00)

ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR SERVICE RENDERED ON AND AFTER

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M.P.S.C. 16 – ELECTRIC **ORIGINAL SHEET NO. C-16.00**
INDIANA MICHIGAN POWER COMPANY
STATE OF MICHIGAN
(RATE CASE U-18370)

(Continued from Sheet No. C-15.00)

14. TEMPORARY SERVICE.

Temporary service is electric service that is required during the construction phase of a project and/or electric service that is provided to new customers for a period not to exceed 12 months except in cases of large construction projects and the customer has notified the Company of the need to extend this timeframe. Such service is available only upon approval of the Company. In order to qualify for temporary service, the customer must demonstrate to the Company's satisfaction that the requested service will, in fact, be temporary in nature.

Temporary service for residential construction will be supplied using Tariff R.S. Temporary service for general service construction will be supplied under the appropriate published general service tariff applicable to the class of business of the customer. Temporary service will be supplied when the Company has available unsold capacity of lines, transformers, and generating equipment. The customer will be charged a minimum temporary service installation charge, payable in advance, based on the Company's actual cost to install and remove, less salvage, the required facilities to provide the temporary service. In no case shall revenue credits apply to cover costs associated with temporary service. The Company reserves the right to require a written contract for temporary service, at its option.

15 DENIAL OR DISCONTINUANCE OF SERVICE

Pursuant to Rules 460.136, 460.137, and 460.1625, the Company reserves the right to shutoff service to any customer without notice, in case of an emergency or to prevent fraud upon the Company. Additional shutoff of service rules applicable to nonresidential service are set forth in the MPSC Rules in Part 7 of the Billing Practices Applicable to Non-Residential Electric and Gas Customers, as referenced herein, and are set forth, as applicable, to residential service in Part 8 of the Consumer Standards and Billing Practices for Electric and Gas Residential Service, as referenced herein.

Any shutoff of service shall not terminate the contract between the Company and the customer nor shall it abrogate any minimum charge that may be effective.

The Company may disconnect service without request by the customer and with proper notification in writing of at least 14 days when:

(a) The customer does not provide adequate access to the meter during normal business hours or denies access to other Company equipment; or
(b) The customer does not provide adequate safe clearance in front of and around metering and associated equipment; or
(c) The customer does not allow safe egress and regress across the customer's property to access metering and other Company equipment; or
(d) The meter is located in an inaccessible location such as a basement, fenced area, porch, etc., and the customer denies the Company reasonable access; or
(e) The customer's equipment falls into disrepair due to aging or abuse and needs to be replaced due to eminent safety considerations; or
(f) The meter installation does not fall under commonly acceptable installation practices or where conditions at the customer's site change, causing the meter installation to no longer meet acceptable installation guidelines.

(Continued on Sheet No. C-17.00)

ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR SERVICE RENDERED ON AND AFTER

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M.P.S.C. 16 – ELECTRIC **~~FIRST REVISED~~ORIGINAL SHEET NO. C-17.00**
INDIANA MICHIGAN POWER COMPANY **~~CANCELS ORIGINAL SHEET NO. C-17.00~~**
STATE OF MICHIGAN
(RATE CASE U-18370)

(Continued from Sheet No. C-16.00)

The Company may disconnect service without request by the customer and without prior notice only:

(a) If a condition dangerous or hazardous to life, physical safety, or property exists; or
(b) Upon order by any court, the Commission or other duly authorized Public Authority; or
(c) If fraudulent or unauthorized use of electricity is detected and the Company has reasonable grounds to believe the affected customer is responsible for such use; or
(d) If the Company's regulating or measuring equipment has been tampered with and the Company has reasonable grounds to believe that the affected customer is responsible for such tampering.

16. SPECIAL SERVICE CHARGES.

The following schedule reflects the amounts to be charged for the special services stipulated. The Company will endeavor to comply with customer requested work subject to a minimum of three days prior notification and / or manpower availability.

SCHEDULE OF CHARGES	AMOUNT
1. Reconnect ~~for nonpay~~ during regular business hours.	$75~~50~~.00
2. Reconnect ~~for nonpay~~ during workday overtime hours and all day Saturday.	$85.00~~78.75~~
3. Reconnect ~~for nonpay~~ on Sundays or holidays.	$163~~25~~.00
~~4. Reconnect for customer convenience, i.e., three month vacation, lake cottage, etc. will be same charges as 1 through 3 above and 7 through 10 below as applicable.~~	
~~5.~~4. Trip charge where Company employees are sent to customer premises to specifically notify the customer that bill payment is due.	$29.00~~23.75~~
~~6.~~5. Disconnect trips where notification is left for the customer at the premises because of access or other issue , ~~the customer pays the bill,~~ or the customer signs a Company form ~~indicating~~ agreeing to make payment by the end of business the same day and no disconnect is made.	$37.00~~27.50~~
~~7.~~6. Reconnect ~~for nonpay~~ when disconnect is required to be made from a vault, manhole, or service box.	$126~~5468.7~~
~~8.~~7. Reconnect ~~for nonpay~~ when disconnect is required to be made at pole during regular business hours.	$110.00~~62.50~~
~~9~~8. Reconnect ~~for nonpay~~ when disconnect is required to be made at pole during workday overtime hours and all day Saturday.	$122.00~~93.75~~
~~10~~9. Reconnect ~~for nonpay~~ when disconnect is required to be made at pole on Sunday or holidays.	$230.00~~162.50~~
~~11~~10. Trip charge for ~~N~~no-power service call when the customer's facilities are clearly at fault or for scheduled work and customer is not ready and the customer was advised of the charge.	$57.00~~27.50~~
~~12~~11 Meter test or change when charge is permitted in accordance with the provision of MPSC Consumer Standards and Billing Practice Rules	$77~~25~~.00
~~13~~12. Customer's check returned for nonsufficient funds.	$20~~15~~.00

(Continued on Sheet No. C-18.00)

ISSUED
BY TOBY L. THOMAS
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FORT WAYNE, INDIANA

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M.P.S.C. 16 – ELECTRIC **~~FIRST REVISED~~ORIGINAL SHEET NO. C-18.00**
INDIANA MICHIGAN POWER COMPANY **~~CANCELS ORIGINAL SHEET NO. C-18.00~~**
STATE OF MICHIGAN
(RATE CASE U-18370)

(Continued from Sheet No. C-17.00)

17. MISCELLANEOUS CUSTOMER CHARGES

When the Company detects that its regulating, measuring equipment, or other facilities have been tampered with or when fraudulent or unauthorized use of electricity has occurred, a rebuttable presumption arises that the customer or other user has benefited by such fraudulent or unauthorized use of such tampering. Therefore, that customer or other user is responsible for payment of the reasonable cost of the service used during the period such fraudulent or unauthorized use or tampering occurred or is reasonably assumed to have occurred and is responsible for the cost of field calls and the cost of making repairs necessitated by such use and/or tampering, plus a charge of $50 per occurrence. Under such circumstances the Company will institute the procedures outlined in the Consumer Standards and Billing Practice Rules. ~~Rule 63~~.

18. CUSTOMER OWNED EQUIPMENT TROUBLESHOOTING.

When requested by the customer to investigate any problems with customer owned equipment that is connected to the Company's system, such as a generator, transformer, or other unique customer-owned facilities, the Company will conduct investigations at no charge to the customer. Company will make all reasonable attempts to resolve any problems when the Company is found to be at fault. If the customer owned equipment is found to be at fault, the Company may at the customer's request, and upon mutual agreement, continue troubleshooting the problem if the customer consents to paying for all additional charges which shall be based on actual labor and material incurred.

19 VOLTAGES

The standard nominal distribution service voltages within the service area of the Company are:

Secondary		Primary	
Single Phase	Three Phase	Single Phase	Three Phase
120/240 Volts	120/208 Volts	2400 Volts**	4160/2400 Volts**
120/208 Volts	120/240 Volts*	7200 Volts	12470/7200 Volts
480 Volts	277/480 Volts	19950 Volts	34500/19950 Volts
	480 Volts*		
* Not available when supplied from 34500/19950 primary distribution systems.			
** Limited to existing 4160/2400 volt distribution systems or from a dedicated subtransmission or transmission station.			

(Continued on Sheet No. C-19.00)

ISSUED
BY TOBY L. THOMAS
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR SERVICE RENDERED ON AND AFTER

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M.P.S.C. 16 – ELECTRIC **~~FIRST REVISED~~ORIGINAL SHEET NO. C-19.00**
INDIANA MICHIGAN POWER COMPANY **~~CANCELS ORIGINAL SHEET NO. C-19.00~~**
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(Continued from Sheet No. C-18.00)

The standard subtransmission and transmission service voltages within the service area of the Company are:

Subtransmission	Transmission
Three Phase	Three Phase
34.5 kV	138 kV
69 kV	345 kV
	765 kV

Voltages listed above are not available at all locations. The Company must be consulted regarding their availability at any particular location.

20. TAX ADJUSTMENT AND FRANCHISE FEES

Bills to customers receiving service within the limits of political subdivisions which levy special license fees, franchise fees or any other such fee against the Company or its operation or the production or sale of electric energy shall be increased by a uniform per meter surcharge calculated on an annual basis to offset such special fee or any new or increased special fee, thereby preventing other customers from being compelled to share such local fees.

INDIANA MICHIGAN POWER COMPANY
CITIZENS UTILITY BOARD OF MICHIGAN
DATA REQUEST SET NO. CUB 1
CASE NO. U-21461

DATA REQUEST NO. CUB 1-4

Request
How does I&M prioritize restoration during minor and major storm events. Where do overhead service lines fall in terms of restoration priority?

Response
In order to restore service to the most customers in the shortest amount of time, the Company generally works through restoration in the following overall order, prioritizing the stability and integrity of the entire transmission and distribution grid:

- Transmission circuits that could result in cascading station outages (outages that could lead to outages on subsequent circuits if overall demand remains the same after the initial outage)
- Subtransmission circuits that could also result in cascading station outages
- Subtransmission circuits that result in station outages
- Stations
- Distribution feeder circuits
- Distribution three phase branch circuits
- Two-phase and single-phase laterals
- Secondary/ Services
- Street lighting

Accordingly, for distribution, the first emphasis is on the main feeder circuits, followed by the laterals, and secondary/services. Finally, street lighting is addressed. Of course, although this is the general work plan, the Company's crews in practice will work multiple facilities in parallel paths to the extent possible so that service can be restored as quickly as possible. Additionally, even though the overall work plan listed above indicates that restoration of transmission facilities comes prior to restoration of distribution facilities, the transmission and distribution work teams also proceed in parallel paths so that service can be restored as quickly as possible.

However, field conditions may alter the prioritization plan to some extent. Factors considered for prioritization include, but are not limited to:

- Public safety, employee safety,
- Number of customers affected by single outage case,
- Customers effected due to prioritization (e.g., hospitals, shelters, critical needs, etc.),
- Resource allocation limits,
- Material availability.

INDIANA MICHIGAN POWER COMPANY
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The Company does take into consideration customers that may have specific needs such as life support, etc.

Preparer:
Isaacson

INDIANA MICHIGAN POWER COMPANY
CITIZENS UTILITY BOARD OF MICHIGAN
DATA REQUEST SET NO. CUB 1
CASE NO. U-21461

DATA REQUEST NO. CUB 1-9

Request

Please refer to Exhibit A-16, Schedule F5.5, Section E, Rule 17 Extension of Service. Rule 17(A)(i) requires an advance deposit of $3.50 per foot for single-phase main-line feeder extensions in excess of 200 feet.
a. What is the current average cost per foot for single-phase primary voltage line extensions, excluding the cost of ROW and clearing?
b. What is the current average cost of ROW and clearing?

Response

a. I&M has not performed the analysis of the current cost on an average per foot basis.

b. Average ROW clearing cost is $3.00 per foot. Public ROW is designated for utility use and there is no cost associated with using it.

Preparer:
Cooper

INDIANA MICHIGAN POWER COMPANY
CITIZENS UTILITY BOARD OF MICHIGAN
DATA REQUEST SET NO. CUB 1
CASE NO. U-21461

DATA REQUEST NO. CUB 1-10

Request

Please refer to Exhibit A-16, Schedule F5.5, Section E, Rule 18 Underground Electric Lines. For residential underground service in subdivisions, Rule 18(B)(i)(1) requires a non-refundable deposit of $4.50 per foot which reflects the difference between overhead and underground costs of construction for single phase extensions. What is the current cost per foot for overhead and underground construction?

Response

I&M has not performed the analysis of the current cost on an average per foot basis.

Preparer:
Cooper

INDIANA MICHIGAN POWER COMPANY
CITIZENS UTILITY BOARD OF MICHIGAN
DATA REQUEST SET NO. CUB 1
CASE NO. U-21461

DATA REQUEST NO. CUB 1-11

Request

Please refer to Exhibit A-16, Schedule F5.5, Section E, Rule 18 Underground Electric Lines. Rule 18(B)(i)(2) requires a deposit equal to $6.00 per foot for underground service extensions. What is the current average cost per foot?

Response

I&M has not performed the analysis of the current cost on an average per foot basis.

Preparer:
Cooper

INDIANA MICHIGAN POWER COMPANY
CITIZENS UTILITY BOARD OF MICHIGAN
DATA REQUEST SET NO. CUB 1
CASE NO. U-21461

DATA REQUEST NO. CUB 1-12

Request

Please refer to Exhibit A-16, Schedule F5.5, Section E, Rule 18 Underground Electric Lines. For residential service extensions outside of subdivisions, Rule 18(B)(ii)(1) requires a non-refundable contribution equal to the estimated difference in cost between overhead and underground construction costs.
a. Does the Company include the cost of ROW in the cost figure for underground extensions?
b. What are the current average costs per foot for overhead and for underground construction including and excluding ROW?

Response

a. Underground / overhead primary extensions get installed in easements or public ROW. The customer agrees to provide an easement at no charge to be able to provide service to that customer. If the underground primary traverses an adjacent property (typically not the case), it is up to the customer requesting service to secure / pay for that easement. There is no cost associated with placing utilities in public ROW.

b. I&M has not performed the analysis of the current cost on an average per foot basis.

Preparer:
Cooper

INDIANA MICHIGAN POWER COMPANY
CITIZENS UTILITY BOARD OF MICHIGAN
DATA REQUEST SET NO. CUB 1
CASE NO. U-21461

DATA REQUEST NO. CUB 1-13

Request

Please refer to Exhibit A-16, Schedule F5.5, Section E, Rule 18 Underground Electric Lines. For mobile home parks, condominiums, and apartment house complexes, Rule 18(B)(iii) requires a non-refundable contribution equal to $12.25 per trench foot for service lines.
a. Why is the stated cost different than the $6.00 per foot for all other residential service lines?
b. What is the current average cost per foot?

Response

a. Michigan Administrative Code pertaining to Underground Electric Lines R 460.513 requires utilities to treat apartment house complexes and similar properties as commercial entities in regards to providing electric service extensions.

b. I&M has not performed the analysis of the current cost on an average per foot basis.

Preparer:
Cooper

INDIANA MICHIGAN POWER COMPANY
CITIZENS UTILITY BOARD OF MICHIGAN
DATA REQUEST SET NO. CUB 1
CASE NO. U-21461

DATA REQUEST NO. CUB 1-14

Request

Please refer to Exhibit A-16, Schedule F5.5, Section E, Rule 18 Underground Electric Lines. For commercial and industrial underground connections, Rule 18(C) sets forth per- foot price differences for distribution extensions, service lines and transformers. Please provide the current average price difference and costs per foot for such underground facilities and associated transformers.

Response

I&M has not performed the analysis of the current cost on an average per foot basis.

Preparer:
Cooper

INDIANA MICHIGAN POWER COMPANY
CITIZENS UTILITY BOARD OF MICHIGAN
DATA REQUEST SET NO. CUB 1
CASE NO. U-21461

DATA REQUEST NO. CUB 1-16

Request

Please refer to Seger-Lawson, p. 21. Please provide, for historical test year 2022 through April 9, 2023:
a. An example of when I&M failed to restore service to a customer within 120 hours after an interruption that occurred during the course of catastrophic conditions (as defined in R. 460.702) where the cause of the outage was tree contact from a tree outside the ROW or tree contact of an overhead service line.
b. An example of when I&M failed to restore service to a customer within 16 hours after an interruption that occurred during normal conditions (as defined in R. 460.702) where the cause of the outage was tree contact from a tree outside the ROW or tree contact of an overhead service line.
c. An example of when an I&M customer experienced more than 7 interruptions in a 12-month period due to a same-circuit repetitive interruption (as defined in R. 460.702) where the cause of the outages was tree contact from a tree outside the ROW or tree contact of an overhead service line.

Response

a. I&M is unaware of an example during the referenced time period.

b. I&M is unaware of an example during the referenced time period.

c. I&M is unaware of an example during the referenced time period.

Preparer:
Seger-Lawson
Isaacson

INDIANA MICHIGAN POWER COMPANY
CITIZENS UTILITY BOARD OF MICHIGAN
DATA REQUEST SET NO. CUB 1
CASE NO. U-21461

DATA REQUEST NO. CUB 1-17

Request

Please refer to Seger-Lawson, p. 21. Please provide, from April 10, 2023, to date:
a. An example of when I&M failed to restore service to a customer within 96 hours after the start of a sustained interruption that occurred during the course of catastrophic conditions (as defined in R. 460.702) where the cause of the outage was tree contact from a tree outside the ROW and where the cause of the outage was tree contact of an overhead service line.
b. An example of when I&M failed to restore service to a customer within 48 hours after the start of a sustained interruption that occurred during the course of gray sky conditions (as defined in R. 460.702) where the cause of the outage was tree contact from a tree outside the ROW and where the cause of the outage was tree contact of an overhead service line.
c. An example of when I&M failed to restore service to a customer within 16 hours after the start of a sustained interruption that occurred during normal conditions (as defined in R. 460.702) where the cause of the outage was tree contact from a tree outside the ROW and where the cause of the outage was tree contact of an overhead service line.
d. An example of when an I&M customer experienced 6 or more sustained interruptions (as defined in R. 460.702) in a 12-month period where the cause of the outages was tree contact from a tree outside the ROW and where the cause of the outage was tree contact of an overhead service line.

Response

I&M objects to the Request to the extent it seeks an analysis, calculation, or compilation which has not already been performed and which it objects to performing. Notwithstanding, I&M states the following:

a-d. I&M is unaware of an example during the referenced time period.

Preparer:
Isaacson
Seger-Lawson

As to Objection:
Counsel

INDIANA MICHIGAN POWER COMPANY
CITIZENS UTILITY BOARD OF MICHIGAN
DATA REQUEST SET NO. CUB 2
CASE NO. U-21461

DATA REQUEST NO. CUB 2-8

Request

Please identify two example circuits and their associated substations, for which the Company is experiencing difficulty in operating such circuits because of the high level of customer-sited distributed generation (DG). For such circuits, please detail the issues the Company is experiencing and how DERMS will provide solutions to the issues experienced.

Response

The two circuits currently with the highest level of DER Penetration in Michigan are the (1) Ryno Road circuit on the West Street station and the (2) Bertrand circuit on the Niles station. Please see the Company's response to AG DR 5-99 subpart (a) for how DERMS will provide solutions to the current limitations that the Company faces integrating DER facilities. Further, please see Q54 on Page 39 of Witness Isaacson regarding how the DERMS system will benefit distribution operations.

Preparer:
Isaacson

INDIANA MICHIGAN POWER COMPANY
MICHIGAN DEPARTMENT OF ATTORNEY GENERAL
DATA REQUEST SET NO. AG DR 5
CASE NO. U-21461

DATA REQUEST NO. AG DR 5-99

Request
Refer to lines 19 to 30 on page 40 of Mr. Isaacson's direct testimony on capital projects for DERMS and DER integration. Please:

a. Explain what limitations the Company currently faces with integrating existing DER facilities.

b. Provide the number of DER facilities that the Company managed at the end of 2022 and the total number forecasted at the end of 2023 and 2024. Provide the basis for the 2023 and 2024 forecasts.

c. Do DER facilities currently pay a fee either in the Michigan or Indiana jurisdiction that allows the Company to recover the cost of integrating and managing the DER facilities to the power grid? If yes, identify the monthly fee billed. If no, explain why not.

d. If and when the DERMS is implemented, does the Company plan to implement a fee to recover the cost of the investment, operation, and administration of the DERMS from the DER facilities for using the DERMS? If no, explain why not.

Response
For the sake of these responses, the Company is interpreting the reference to "DER" as Distributed Energy Resources owned and operated by an entity other than the Company.

a. I&M's current Distribution Management System (DMS) does not support a network model. This means that every DER is a manual addition to the system and each integration with the DMS, let alone every other DER, must be operated on an individual basis. This means that aggregation of DER equipment is functionally impossible. Without updated tools, adherence to FERC Order 2222 is not possible.

b. The Company does not manage any customer owned DERs.

c. Michigan interconnection fees are governed by the Michigan Interconnection and Distributed Generation Standards, Rule 26, unless modified under Rule 28. In addition, interconnection customers may incur monthly metering charges as described in IN TB 17, Tariff Cogen/SPP, Rider NMS-1 and NMS-2.

d. The cost for ADMS/DERMS platform implementation is currently included in I&M's cost of service.

Preparer:
Isaacson
Brenner

INDIANA MICHIGAN POWER COMPANY
MICHIGAN DEPARTMENT OF ATTORNEY GENERAL
DATA REQUEST SET NO. AG DR 5
CASE NO. U-21461

Seger-Lawson

INDIANA MICHIGAN POWER COMPANY
MICHIGAN PUBLIC SERVICE COMMISSION STAFF
DATA REQUEST SET NO. 5
CASE NO. U-21461

DATA REQUEST NO. Staff DR 5-03

Request

Refer to Exhibit A-13, Schedule C5, which shows projected operation and maintenance expenses. Please break out any historical and projected expenses for customer outage credits.

Response

I&M's 2024 Test Year does not include any forecasted customer outage credits. Outage credits for the 2022 Historical Period were $50. As addressed in the testimony of Company witness Seger-Lawson (questions 50-52), I&M has requested accounting authority to defer outage credits when the outage was caused by customer negligence or the transmission system operator, among other limited circumstances.

Preparer:
Seger-Lawson

INDIANA MICHIGAN POWER COMPANY
CITIZENS UTILITY BOARD OF MICHIGAN
DATA REQUEST SET NO. CUB 1
CASE NO. U-21461

DATA REQUEST NO. CUB 1-18

Request

Please refer to Seger-Lawson, pp. 21-22.
a. How does I&M determine an outage to be "caused by customer negligence?" Please provide any policy documentation underlying your response.
b. Please provide three examples of outages I&M has determined were "caused by customer negligence."

Response

a. I&M classifies an outage to be caused by customer negligence when an outage is a result of undue external forces outside of I&M's control, wherein those external forces are performed by individuals who did not exercise the appropriate amount of caution that would be expected of a reasonable person.

b. Examples of some outages caused by customer negligence would be acts of vandalism, customer performed tree removal, or a customer inadvertently crashing a vehicle into equipment. In other words, this describes circumstances in which the customer's negligent actions were beyond the Company's control.

Preparer:
Isaacson
Seger-Lawson

INDIANA MICHIGAN POWER COMPANY
CITIZENS UTILITY BOARD OF MICHIGAN
DATA REQUEST SET NO. CUB 1
CASE NO. U-21461

DATA REQUEST NO. CUB 1-19

Request

Please confirm that I&M owns overhead service drops. If yes:
a. Who does I&M consider responsible for removing a tree that has fallen on an I&M service line? Please provide any policy documentation underlying your response.
b. If multiple service drops emanate from a distribution transformer, or the attached secondary voltage power line, and a service line crosses one customer's property on its way to a neighboring customer's property, does I&M consider the customer through whose property the neighbor's service line passes responsible for clearing vegetation from around the neighbor's service line? If not, who is responsible? Please provide any policy documentation underlying your response.
c. Does I&M restore service for outages resulting from customers' failure to clear vegetation from service lines? If yes:

i. Is the cost of such restorations included in the Company's capital and O&M expenses? If yes, what cost components are capital and what cost components are O&M?

ii. Over the past three years, has I&M ever exceeded the Commission's restoration time standards (as defined in the Commission's Service Quality and Reliability Standards at R. 460.744 – 460.746) for a tree-related outage of a service line? If so, please detail the occurrences and the reasons for the excessive time for restoration.

d. If an overhead service line is damaged or downed by tree contact, how does the Company determine whether the customer was negligent in causing the resulting outage?

Response

a. I&M owns the service drops on residential and most commercial overhead. If a tree falls on the service drop, I&M performs the work necessary to restore service. In that situation, the customer would be responsible for removing any debris resulting from this type of damage.

b. Each property owner is responsible for vegetation maintenance around their service drops or other service drops running through their property. However, I&M inspects service drops during its systematic vegetation planning that occurs when a circuit is scheduled for maintenance. Any limb putting tension on a service drop, regardless of whose service drop it is, is trimmed if it appears to be compromising the insulation of that service drop.

c. Yes.

i. A majority of these costs are included as O&M.

INDIANA MICHIGAN POWER COMPANY
CITIZENS UTILITY BOARD OF MICHIGAN
DATA REQUEST SET NO. CUB 1
CASE NO. U-21461

ii. 19(c)(ii): I&M's outage restoration metrics under normal, catastrophic and all conditions are available in annual reports filed in Case No. U-12270

d. The customer is negligent only if the customer causes the tree or limb to fall on the service. I&M will schedule outages, including removal/reconnection of the service drop to mitigate the risk of a customer felling a tree on our equipment. In cases where the customer damages the Company's equipment through negligence, I&M bills that customer through our damage by other party (DOP) process.

Preparer:
Isaacson

INDIANA MICHIGAN POWER COMPANY
CITIZENS UTILITY BOARD OF MICHIGAN
DATA REQUEST SET NO. CUB 1
CASE NO. U-21461

DATA REQUEST NO. CUB 1-20

Request

How many outages in the 2022 historical test year were caused by tree contact with overhead service lines?

Response

Non MED (Major Event Day) – 1273 outages caused by tree contact with overhead service lines, where overhead service line is defined as any overhead distribution line.

MED included – 1795 outages caused by tree contact with overhead service lines, where overhead service line is defined as any overhead distribution line.

Preparer:
Isaacson

INDIANA MICHIGAN POWER COMPANY
CITIZENS UTILITY BOARD OF MICHIGAN
DATA REQUEST SET NO. CUB 1
CASE NO. U-21461

DATA REQUEST NO. CUB 1-36

Request

With reference to Exhibit IM-6 (DSI-3) Asset Renewal Projects, Line Rebuilds:
a. Do line rebuilds involve a total replacement of all distribution facilities (e.g., poles, conductors, cross arms, insulators, and pole top equipment)?
b. If not a total replacement, what components are being replaced?
c. Is line clearing included in such projects' capital costs?

Response

a. Most line rebuilds are a complete rebuild of infrastructure with the exception of pole top equipment (e.g., transformers, reclosers, and capacitor banks). Whether pole top equipment involves a replacement is entirely dependent on the condition of the facilities.
b. Line rebuilds replace all poles, crossarms, insulators, switches and conductors. Whether or not pole top equipment involves a replacement is entirely dependent on the condition of the facilities.
c. Vegetation clearing associated with existing line rebuilds are all O&M in Michigan unless it involves a complete relocation of facilities.

Preparer:
Isaacson

INDIANA MICHIGAN POWER COMPANY
CITIZENS UTILITY BOARD OF MICHIGAN
DATA REQUEST SET NO. CUB 1
CASE NO. U-21461

DATA REQUEST NO. CUB 1-39

Request

With respect to the projects indicated in questions 37 and 38 above, please provide:
a. The number of customers served by the line segment proposed to be replaced;
b. The load being served;
c. A 10-year history of outages on such line segment (outages relating directly to the line segments proposed to be renewed;
d. The duration and frequency of outages;
e. The cause of outages (e.g., non-standard construction, trees or other vegetation, third-party damage, poles, crossarms, insulators, and pole top equipment);
f. The dates of directly related outages; and
g. The tree trimming history over the past 10 years.

Response

a. Kalamazoo – Eagle: 29 Customers; Valley – Valley 34.5 kV: 959 customers

b. Kalamazoo – Eagle: 252 kVA Valley – Valley 34.5 kV: 2293 kVA

c-g. Please see “U-21461 CUB DR 1-39 Attachment 1.xlsx” for the requested information.

Preparer:
Isaacson

U-21461 CUB DR 1-39 Attachment 1

Outage Start Date and Time	Outage End Date and Time	Substation Name	Circuit Name	Major Cause Name	Minor Cause Name	Equipment Name Abbreviation	CI	CMI	Total Outage Duration
Sep 23, 2014 3:06:00 PM	Sep 23, 2014 5:55:00 PM	SCHOOLCRAFT	SCHOOLCRAFT	DISTRIBUTION STATION	EQUIPMENT FAILURE	ARRESTER	1,618	273,442	169
Sep 29, 2016 3:51:00 AM	Sep 29, 2016 4:54:00 AM	SCHOOLCRAFT	SCHOOLCRAFT	DISTRIBUTION LINE	EQUIPMENT FAILURE	SWITCH, OH	1,173	73,899	63
Apr 27, 2017 1:41:00 PM	Apr 27, 2017 3:36:00 PM	SCHOOLCRAFT	SCHOOLCRAFT	TRANSMISSION LINE	RELAY MIS-OPERATION	NONE	1,625	186,875	115
Jun 23, 2018 10:41:00 AM	Jun 23, 2018 11:53:00 AM	SCHOOLCRAFT	SCHOOLCRAFT	DISTRIBUTION STATION	ANIMAL BUS	NONE	1,654	119,088	72
Jan 11, 2019 8:54:00 AM	Jan 11, 2019 1:32:00 PM	SCHOOLCRAFT	SCHOOLCRAFT	TRANSMISSION STATION	EQUIPMENT FAILURE	XFR STNSVC	1,666	463,148	278
Mar 14, 2019 10:47:00 PM	Mar 14, 2019 10:56:00 PM	SCHOOLCRAFT	SCHOOLCRAFT	DISTRIBUTION LINE	EQUIPMENT FAILURE	JMPR/RISR	1,669	15,021	9
Mar 22, 2019 10:26:00 AM	Mar 22, 2019 12:39:00 PM	SCHOOLCRAFT	SCHOOLCRAFT	DISTRIBUTION LINE	EQUIPMENT FAILURE	JMPR/RISR	1,669	221,977	133
Apr 12, 2019 2:30:00 AM	Apr 12, 2019 11:37:00 AM	SCHOOLCRAFT	SCHOOLCRAFT	DISTRIBUTION STATION	EQUIPMENT FAILURE	FDR BKR	1,666	860,856	547
Aug 18, 2019 8:43:00 AM	Aug 18, 2019 7:47:00 PM	SCHOOLCRAFT	SCHOOLCRAFT	TRANSMISSION LINE	EQUIPMENT FAILURE	POLE	1,664	1,104,896	664
Nov 6, 2019 5:07:00 PM	Nov 6, 2019 8:07:00 PM	SCHOOLCRAFT	SCHOOLCRAFT	DISTRIBUTION STATION	EQUIPMENT FAILURE	ARRESTER	1,659	298,620	180
Nov 20, 2020 4:48:00 AM	Nov 20, 2020 5:08:00 AM	KALAMAZOO	EAGLE	DISTRIBUTION STATION	EQUIPMENT FAILURE	REGULATOR	490	9,800	20
Feb 27, 2021 3:05:00 AM	Feb 27, 2021 8:18:00 AM	KALAMAZOO	EAGLE	DISTRIBUTION LINE	EQUIPMENT FAILURE	INSULATOR	36	11,268	313
May 9, 2022 2:52:00 PM	May 9, 2022 3:30:00 PM	KALAMAZOO	EAGLE	DISTRIBUTION LINE	WEATHER - HIGH WINDS (EXCEEDING 60 MPH)	OH COND	499	18,962	38

U-21461 CUB DR 1-39 Attachment 1

Outage Start Date and Time	Outage End Date and Time	Substation Name	Circuit Name	Major Cause Name	Minor Cause Name	Equipment Name Abbreviation	CI	CMI	Total Outage Duration
Apr 1, 2014 3:26:00 PM	Apr 1, 2014 4:26:00 PM	VALLEY	VALLEY 34.5KV	TRANSMISSION STATION	ERROR - FIELD	NONE	1,605	96,300	60
Apr 20, 2017 7:48:00 PM	Apr 21, 2017 4:50:00 AM	VALLEY	VALLEY 34.5KV	SUBTRANSMISSION LINE	EQUIPMENT FAILURE	INSULATOR	1,602	857,974	542
Apr 30, 2017 9:41:00 AM	Apr 30, 2017 1:44:00 PM	VALLEY	VALLEY 34.5KV	DISTRIBUTION LINE	EQUIPMENT FAILURE	CROSSARM	1,651	395,793	243
May 17, 2017 3:25:00 PM	May 17, 2017 5:10:00 PM	VALLEY	VALLEY 34.5KV	TRANSMISSION STATION	OTHER	NONE	1,596	167,580	105
Jun 17, 2017 8:06:00 PM	Jun 18, 2017 2:32:00 AM	VALLEY	VALLEY 34.5KV	DISTRIBUTION STATION	ERROR - FIELD	NONE	1,604	619,144	386
Jun 18, 2017 2:36:00 AM	Jun 18, 2017 2:56:00 AM	VALLEY	VALLEY 34.5KV	DISTRIBUTION STATION	ERROR - FIELD	NONE	1,604	32,080	20
Jun 6, 2019 9:32:00 AM	Jun 6, 2019 10:05:00 AM	VALLEY	VALLEY 34.5KV	DISTRIBUTION LINE	ERROR - FIELD	NONE	1,593	52,569	33
Jul 8, 2019 10:43:00 AM	Jul 8, 2019 1:16:00 PM	VALLEY	VALLEY 34.5KV	TRANSMISSION STATION	ANIMAL - OTHER	NONE	1,589	243,117	153
Jun 13, 2022 7:49:00 PM	Jun 14, 2022 12:26:00 AM	VALLEY	VALLEY 34.5KV	DISTRIBUTION LINE	TREE OUT OF ROW	NONE	359	99,443	277

U-21461 CUB DR 1-39 Attachment 1

Outage Start Date and Time	Outage End Date and Time	Substation Name	Circuit Name	Major Cause Name	Minor Cause Name	Equipment Name Abbreviation	CI	CMI	Total Outage Duration
Aug 26, 2014 2:56:00 PM	Aug 26, 2014 4:18:00 PM	STUBEY ROAD	WEST	DISTRIBUTION LINE	WEATHER - LIGHTNING	NONE	1,488	122,016	82
Sep 21, 2014 5:12:00 PM	Sep 22, 2014 12:48:00 AM	STUBEY ROAD	WEST	DISTRIBUTION LINE	TREE INSIDE ROW	NONE	1,491	317,345	456
Dec 28, 2015 5:45:00 PM	Dec 28, 2015 6:20:00 PM	STUBEY ROAD	WEST	DISTRIBUTION LINE	TREE INSIDE ROW	NONE	33	1,155	35
Jan 31, 2016 10:03:00 PM	Feb 1, 2016 6:32:00 AM	STUBEY ROAD	WEST	DISTRIBUTION STATION	ANIMAL BUSHING XFMR	NONE	1,446	567,358	509
May 8, 2017 6:50:00 AM	May 8, 2017 7:30:00 AM	STUBEY ROAD	WEST	DISTRIBUTION LINE	TREE INSIDE ROW	NONE	34	1,360	40
Jul 28, 2017 3:00:00 PM	Jul 28, 2017 6:08:00 PM	STUBEY ROAD	WEST	DISTRIBUTION STATION	SCHEDULED COMPANY	NONE	1,478	277,864	188
Sep 19, 2017 8:07:00 AM	Sep 19, 2017 8:15:00 AM	STUBEY ROAD	WEST	TRANSMISSION STATION	RELAY MIS-OPERATION	NONE	1,486	11,888	8
Oct 7, 2017 10:01:00 AM	Oct 7, 2017 11:43:00 AM	STUBEY ROAD	WEST	DISTRIBUTION STATION	SCHEDULED COMPANY	NONE	1,486	151,572	102
Oct 7, 2017 7:48:00 PM	Oct 7, 2017 8:40:00 PM	STUBEY ROAD	WEST	TRANSMISSION LINE	EQUIPMENT FAILURE	POLE	1,486	77,272	52
Oct 10, 2017 5:46:00 AM	Oct 10, 2017 2:45:00 PM	STUBEY ROAD	WEST	TRANSMISSION LINE	OTHER UTILITY	NONE	1,486	800,954	539
Dec 19, 2018 12:01:00 AM	Dec 19, 2018 1:47:00 AM	STUBEY ROAD	WEST	DISTRIBUTION LINE	SCHEDULED COMPANY	NONE	1,453	154,018	106
May 23, 2019 5:00:00 AM	May 23, 2019 3:34:00 PM	STUBEY ROAD	WEST	TRANSMISSION LINE	EQUIPMENT FAILURE	INSULATOR	1,495	947,830	634
May 23, 2019 9:21:00 AM	May 23, 2019 3:42:00 PM	STUBEY ROAD	WEST	NO INTERRUPTION	DUPLICATE OUTAGE TICKET	NONE	0	0	381
Jun 1, 2019 9:08:00 PM	Jun 1, 2019 11:13:00 PM	STUBEY ROAD	WEST	TRANSMISSION LINE	OTHER UTILITY	NONE	1,474	184,250	125
Jun 27, 2019 3:49:00 PM	Jun 27, 2019 5:28:00 PM	STUBEY ROAD	WEST	DISTRIBUTION LINE	EQUIPMENT FAILURE	INSULATOR	1,496	148,104	99
Jun 18, 2020 6:00:00 PM	Jun 18, 2020 10:21:00 PM	STUBEY ROAD	WEST	DISTRIBUTION LINE	EQUIPMENT FAILURE	OH COND	1,494	195,186	261
Aug 11, 2021 4:03:00 PM	Aug 14, 2021 12:59:00 PM	STUBEY ROAD	WEST	DISTRIBUTION LINE	TREE INSIDE ROW	OH COND	33	102,600	4,136
Aug 12, 2021 5:51:00 AM	Aug 14, 2021 2:28:00 PM	STUBEY ROAD	WEST	DISTRIBUTION LINE	TREE OUT OF ROW	OH COND	873	906,239	3,397
Jul 5, 2022 10:24:00 PM	Jul 6, 2022 8:39:00 AM	STUBEY ROAD	WEST	TRANSMISSION LINE	TREE OUT OF ROW	OH COND	1,509	928,035	615
Aug 3, 2022 5:26:00 PM	Aug 3, 2022 8:32:00 PM	STUBEY ROAD	WEST	DISTRIBUTION LINE	WEATHER - UNKNOWN	POLE	1,511	281,046	186
Apr 19, 2023 11:57:00 AM	Apr 19, 2023 2:01:00 PM	STUBEY ROAD	WEST	DISTRIBUTION LINE	TREE OUT OF ROW	OH COND	34	4,216	124
Jun 25, 2023 1:12:00 AM	Jun 25, 2023 8:22:00 AM	STUBEY ROAD	WEST	DISTRIBUTION STATION	EQUIPMENT FAILURE	INSULATOR	1,505	647,150	430
Jul 22, 2023 7:43:00 PM	Jul 22, 2023 9:31:00 PM	STUBEY ROAD	WEST	DISTRIBUTION LINE	TREE OUT OF ROW	OH COND	33	3,564	108
Oct 19, 2023 9:23:00 AM	Oct 19, 2023 10:41:00 AM	STUBEY ROAD	WEST	TRANSMISSION LINE	FACILITATION OF WORK	NONE	1,499	116,922	78

U-21461 CUB DR 1-39 Attachment 1

	Year	Work
Kalamazoo Eagle	2015	Herbicide Application
	2018	Full Circuit Clear
	2019	Herbicide Application
	2022	Herbicide Application
Valley Valley	2015	Herbicide Application
	2018	Herbicide Application
	2020	Mechanical clearing (jaraff/mower)
	2021	Full Circuit Clear
Stubey West	2015	Herbicide Application
	2018	Herbicide Application/Mechanical Clearing (jaraff/mower)
	2019	Full Circuit Clear
	2020	Herbicide Application

INDIANA MICHIGAN POWER COMPANY
CITIZENS UTILITY BOARD OF MICHIGAN
DATA REQUEST SET NO. CUB 1
CASE NO. U-21461

DATA REQUEST NO. CUB 1-40

Request

With reference to Exhibit IM-6 (DSI-3), Roadside Relocations:
a. Please identify those 2023 or 2024 relocations initiated by the Company, and the basis for the relocation.
b. Are all relocations listed in Exhibit IM-6 (DSI-3) for 2023 and for 2024, and not initiated by the Company, based on written requests made by governmental agencies or authorities, or customers? If not, how were such projects identified?
c. Do relocations requested by governmental agencies or authorities, or customers, require a contribution in aid of construction? If yes, were such contributions netted from the estimated capital costs delineated in Exhibit IM-6 (DSI-3)?
d. Have relocations requested by governmental agencies or authorities, or customers, such as those listed in Exhibit IM-6 (DSI-3) been cancelled prior to the estimated construction? If yes, what portion of projected relocations projected in 2020, for 2022, were cancelled?

Response

a. All relocations listed in Exhibit IM-6 (DSI-3) were initiated by I&M. These lines are in off-road rights-of-way and are difficult to access. I&M has initiated projects to rebuild these assets along the road where accessibility by trucks and other equipment is improved. This results in faster restoration time for customers and safer operating working conditions for employees. Locations along the road have less exposure to trees and other vegetation which reduces the probability of vegetation caused outages.

b. No. Relocation projects that are based on written requests made by a third party are under a different category of investment (Public Project Relocation (PPR) – customer service). Please see subpart (a) for how projects were identified.

c. No.

d. No. PPR work is not included in Exhibit IM-6 (DSI-3).

Preparer:
Isaacson

INDIANA MICHIGAN POWER COMPANY
CITIZENS UTILITY BOARD OF MICHIGAN
DATA REQUEST SET NO. CUB 1
CASE NO. U-21461

DATA REQUEST NO. CUB 1-41

Request

With reference to Exhibit IM-6 (DSI-3), Roadside Relocations:
a. Does the Company reuse existing distribution assets in a relocation?
b. If not, please explain why not.
c. If yes, what components are reused in relocations and is such reuse reflected in the cost estimates listed in the exhibit?

Response

a. Please refer to CUB 1-36 for the requested information.

b. Roadside Relocations replace all poles, crossarms, insulators, switches and conductors. Whether or not pole top equipment involves a replacement is entirely dependent on the condition of the facilities.

c. See part b above.

Preparer:
Isaacson

INDIANA MICHIGAN POWER COMPANY
CITIZENS UTILITY BOARD OF MICHIGAN
DATA REQUEST SET NO. CUB 1
CASE NO. U-21461

DATA REQUEST NO. CUB 1-47

Request

With reference to Exhibit IM-6 (DSI-3), Pole Replacement:
a. Are the projected number of poles to be replaced in 2023 and 2024, of 442 and 430 respectively, based on actual inspection results, or are they a top-down estimate based on prior years workload?
b. Why are no pole reinforcements included in the projected workload and estimated cost?
c. Are poles replaced due to being non-standard construction (e.g., not meeting current construction standards like pole strength) even though they could be repaired/reinforced?
d. Are poles being replaced for simply being non-standard construction or beyond expected life?
e. Please provide a copy of I&M's pole replacement/reinforcement standards.

Response

a. The projected replacement numbers 442 and 430 are based upon actual inspection results.
b. Pole reinforcement options were excluded based on the field input to prioritize replacement of the reinforceable rejects.
c. Poles are being replaced based on American Electric Power Specifications for Inspection, Groundline Treatment & Reinforcement of Standing Wood Poles ("Specification 125"), not the current construction standards.
d. Poles are being replaced based on American Electric Power Specifications for Inspection, Groundline Treatment & Reinforcement of Standing Wood Poles ("Specification 125"), not the current construction standards or expected life.
e. Please see "U-21461 CUB DR 1-47_Attachment 1.pdf" for the requested information.

Preparer:
Isaacson

CUB-17. IM Line Extension Charges for IM U-21461 (CUB Proposal)

		U-18370			U-18370	U-21461
		I&M	Commission		Approved	CUB
Only Incremental Charges for Underground*	**Prior**	**Proposed**	**Approved**		**Ratio Increase**	**Proposed**
OVERHEAD						
Distribution Line Extension						
Residential	$3.50	$3.50	$3.50			$4.25
Commercial and Industrial	Excess Cost above 2x (Annual Capacity Power Supply +Distribution)					
UNDERGROUND						
Subdivisions						
Distribution Line Extension - Subdivisions	$3.00	$5.50	$4.50		1.50	$4.75
Service Line - Subdivisions	$4.00	$11.75	$6.00		1.50	$11.75
Outside Subdivisions						
Distribution Line Extension	Excess Cost above 2x (Annual Capacity Power Supply +Distribution)					
Service Line	$4.00	$11.75	$6.00		1.50	$11.75
Mobile Home, Condo, Apartment Complex						
Distribution Line Extension	$3.00	$5.50	$4.50		1.50	$4.75
Service Line	$3.80	$12.25	$12.25		3.22	$12.25
Transformers - Per kVa	$8.00	$11.25	$11.25		1.41	$11.25
Commercial and Industrial						
Distribution - Single Phase	$3.00	$5.50	$4.50		1.50	$4.75
Distribution - Three Phase	$1.50	$4.50	$3.00		2.00	$3.75
Transformers - Single Phase - Per kVa	$8.00	$9.25	$8.00		1.00	$9.25
Transformers - Three Phase - Per kVa	$10.00	$13.75	$12.50		1.25	$13.75
Service Line - Single Phase	$8.00	$10.75	$8.00		1.00	$10.75
Service Line - Three Phase	$12.50	$14.75	$12.50		1.00	$14.75
Winter Construction Surcharge						
Per Foot	$1.00	$1.00	$1.00			$1.00
* Only for line extensions, not service lines						
Total Cost Overhead Plus Incremental Underground*		**U-18370**				
	Prior	**Proposed**	**Approved**		**Increase**	
OVERHEAD						
Distribution Line Extension						
Residential	$3.50	$3.50	$3.50			
Commercial or Industrial	Excess Cost above 2x (Annual Capacity Power Supply +Distribution)					
UNDERGROUND						
Subdivisions						
Distribution Line Extension - Subdivisions	$6.50	$9.00	$8.00		1.23	
Service Line - Subdivisions	$4.00	$11.75	$6.00		1.50	
Outside Subdivisions						
Distribution Line Extension	Excess Cost above 2x (Annual Capacity Power Supply +Distribution)					
Service Line	$4.00	$11.75	$6.00		1.50	
Mobile Home, Condo, Apartment Complex						
Distribution Line Extension	$6.50	$9.00	$8.00		1.23	
Service Line	$3.80	$12.25	$12.25		3.22	
Transformers - Per kVa	$8.00	$11.25	$11.25		1.41	
Commercial and Industrial						
Distribution - Single Phase	$6.50	$9.00	$8.00		1.23	
Distribution - Three Phase	$5.00	$8.00	$6.50		1.30	
Transformers - Single Phase - Per kVa	$8.00	$9.25	$8.00		1.00	
Transformers - Three Phase - Per kVa	$10.00	$13.75	$12.50		1.25	
Service Line - Single Phase	$8.00	$10.75	$8.00		1.00	
Service Line - Three Phase	$12.50	$14.75	$12.50		1.00	
Winter Construction Surcharge						
Per Foot	$1.00	$1.00	$1.00			
* Only for line extensions, not service lines						

TREE TRIMMING NOTIFICATION

LANSING BOARD OF WATER & LIGHT

741 Highland — 12/7
Address — Date

Kyle
Planner

(517)230-9617
Phone

To ensure your safety and maintain reliable electric service, the Board of Water & Light performs tree maintenance near power lines. Tree limbs that come in contact with power lines are a major cause of downed wires and loss of power.

A work planner inspected our electric line right of way and the results of the inspection show:

☒ Trimming is required (painted "dot" on base of tree)

All removed brush and tree branches smaller than 4" in diameter shall be chipped and removed from the site. All timber larger than 4" in diameter shall be cut into handling lengths and stacked nearby. *All planned work done at no cost to the property owner.*

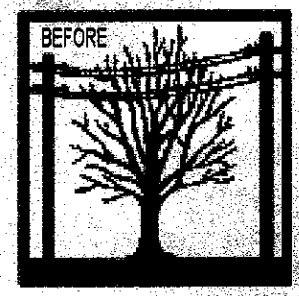
If the wood is not wanted, and for information on our 5 year tree trimming cycle along with other related information please visit www.lbwl.com/customers/tree-trimming

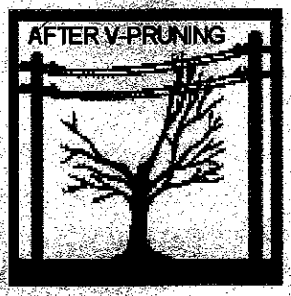
Thank you again for your cooperation. If you have any questions, would like a 24 hour notice, or have special circumstances, (such as dog in yard or a locked gate) *** Refer to planner phone number listed above.**

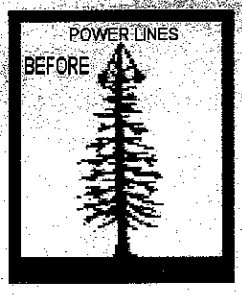
Estimated Arrival: 3-6 weeks

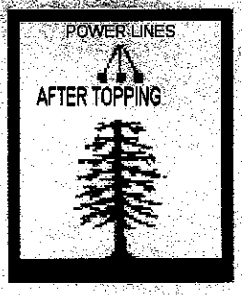
BWL Comments Service lines trees through sidewalks. (Willing to)

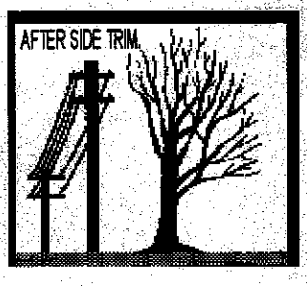
Customer Comments:











INDIANA MICHIGAN POWER COMPANY
MICHIGAN DEPARTMENT OF ATTORNEY GENERAL
DATA REQUEST SET NO. AG DR 5
CASE NO. U-21461

DATA REQUEST NO. AG DR 5-89

Request

Refer to lines 11-16 on page 22 of Mr. Isaacson's direct testimony. Please explain how the Company determined that a four-year tree clearing cycle is the optimal cycle instead of 5 years, given that DTE Electric and Consumers Energy have determined that a 5-year and 7-year clearing cycle is optimal.

Response

The Company initially selected a 5-year clearing cycle. While this has proven to make an impact on vegetation related outages, a 4-year cycle will provide a better customer experience by being able to eliminate reliability threats from dead and dangerous trees outside the right of way and will reduce reliability events occurring from trees inside the right of way. I&M cannot comment on other utilities cycles as factors impacting other utilities are not the same as those impacting I&M. Please refer to I&M's Five-Year Plan as filed in Case No. U-20147 for commentary on the tree growth rate and density in the Company's Michigan footprint as compared to other areas of Michigan.

Preparer:
Isaacson

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **INDIANA MICHIGAN POWER COMPANY** for authority to increase its rates for the sale of electric energy and for other related matters.	Case No. U-21461

Proof of Service

On the date below, an electronic copy of **Direct Testimony and Exhibits of Robert G. Ozar PE on behalf of Citizens Utility Board of Michigan (Exhibits CUB-1 through CUB-19)** was served on the following:

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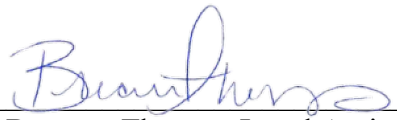
The statements above are true to the best of my knowledge, information and belief.

Troposphere Legal, PLC
Counsel for CUB

Date: January 18, 2024

By: 

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