STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF INDIANA MICHIGAN POWER COMPANY, AN INDIANA CORPORATION, FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN RATE ADJUSTMENT; AND FOR APPROVAL OF RELATED RELIEF INCLUDING: (1) REVISED DEPRECIATION RATES; (2) ACCOUNTING RELIEF; (3) INCLUSION IN RATE BASE OF QUALIFIED POLLUTION CONTROL PROPERTY AND CLEAN ENERGY PROJECT; (4) ENHANCEMENTS TO THE DRY SORBENT INJECTION SYSTEM; (5) ADVANCED METERING INFRASTRUCTURE; (6) RATE ADJUSTMENT MECHANISM PROPOSALS; AND (7) NEW SCHEDULES OF RATES, RULES AND REGULATIONS.	)	CAUSE NO. 45235

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

PUBLIC'S EXHIBIT NO. 8

TESTIMONY OF OUCC WITNESS

ANTHONY A. ALVAREZ

AUGUST 20, 2019

Respectfully submitted,

Tiffany T. Murray
Attorney No. 28916-49
Deputy Consumer Counselor

TESTIMONY OF OUCC WITNESS ANTHONY A. ALVAREZ
CAUSE NO. 45235
INDIANA MICHIGAN POWER COMPANY

I. INTRODUCTION

Q: Please state your name, business address, and employment capacity.

A: My name is Anthony A. Alvarez, and my business address is 115 West Washington Street, Suite 1500 South, Indianapolis, Indiana 46204. I am employed as a Utility Analyst in the Electric Division of the Indiana Office of Utility Consumer Counselor ("OUCC"). I describe my educational background and preparation for this filing in Appendix A to my testimony.

Q: Have you previously testified before the Indiana Utility Regulatory Commission ("Commission")?

A: Yes. I have testified in a number of cases before the Commission, including electric utility base rate cases; environmental and renewable energy Purchase Power Agreement ("PPA") and tracker cases; Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") cases; and applications for Certificates of Public Convenience and Necessity.

Q: What is the purpose of your testimony?

A: My testimony addresses Indiana Michigan Power Company's ("I&M" or "Petitioner") request for approval of the following proposals:

1. Deploying Advanced Metering Infrastructure ("AMI") technology in its Indiana service territory;[1]
2. Maintaining the funding level for its Major Storm Reserve;

[1] *See* I&M Verified Petition, at 9 in this Cause.

3. Implementing Asset Renewal and Reliability Programs through its Distribution Management Plan to replace aging infrastructure;[2]

4. Implementing Major Projects as part of its Distribution Management Plan intended to address capacity and contingency constraints;[3] and

5. Replacing the Rockport Generating Plant Unit 2 High Pressure ("HP") Turbine.

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

A: No. Exclusion from my testimony of any specific adjustments or amounts proposed by I&M does not indicate my approval of those adjustments or amounts, but rather that the scope of my testimony is limited to the specific items addressed herein.

Q: Please summarize the results of your review.

A: Through my review of I&M's requests, I recommend the following:

1. I&M did not provide adequate cost-benefit justification for its proposed AMI deployment. I&M's proposed AMI deployment lacks the basic financial justification that would allow the Commission, the OUCC, and other interested parties the opportunity to review and evaluate its reasonableness. Without this information, the parties and Commission cannot assess whether the proposal provides sufficient customer benefits to support the expense associated with this optional meter upgrade. I recommend the Commission require I&M to study and quantify AMI's operational benefits and use this information to perform a cost-benefit analysis prior to granting approval for full deployment of this technology. Because I&M did not supply this necessary information, I recommend removing the amounts in the forecasted test year related to AMI deployment: $14,167,000 capital expenditure and $2,410,722 operation and maintenance ("O&M") expenditure.

2. If the Commission decides to move forward with the AMI deployment, as an alternative, the Commission should approve a pilot program comprising of a limited deployment of approximately 15,000 AMI meters. This pilot program would involve a collaborative including Commission technical staff, the OUCC and interested parties ("collaborative pilot"). The

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[2] *See* Verified Petition, Exhibit B, Summary of Case-In-Chief Testimony, at 17 of 50.
[3] *Id*. Petition, Exhibit B – Summary, at 17 - 18 of 50.

collaborative pilot would build on I&M's previous AMI pilot, using new technology and lessons learned from the earlier pilot with the purpose of identifying the operational benefits of AMI, quantifying the customer savings and rate impact, and developing customer engagement programs to promote adequate customer participation that are lacking in I&M's current proposal.

3. I&M's Major Storm Reserve should continue to be based on the 5-year average methodology approved by the Commission in Cause No. 44075 to capture the variability and normalize the effects of major storm damage, and determine the Major Storm Reserve funding in this Cause. Based on the 5-year average of I&M's major storm expenses for the period 2014 - 2018, I recommend the forecasted Test Year Major Storm Reserve be decreased to $2,473,000.

4. As with the AMI deployment proposal, I&M did not provide adequate documentation and support for its proposed 2019 - 2020 Distribution Management Plan, Asset Renewal and Reliability Program. Although these projects are set to begin construction in the near term, I&M did not define each project's scope of work, description, cost breakdown (labor, materials, indirect costs, administrative/overhead), implementation strategy, and milestones. Absent this basic project information, the Commission, OUCC or any other interested party cannot evaluate the reasonableness or necessity of these projects. I recommend I&M be required to provide the corresponding project status and work order documentation of each distribution project in its Distribution Management Plan (2019-2020) prior to Commission approval. I recommended removal of $39,991,413 in capital and $1,006,154 in operation and maintenance ("O&M") expenditures for 2019 projects, and $35,129,917 in capital and $1,009,608 in O&M expenditures for 2020 projects in the forecasted Test Year.

5. Similarly, the "Major Projects" within I&M's Distribution Management Plan are poorly defined and lack necessary cost support to conduct a proper analysis of whether the projects are reasonable. I&M should provide detailed project cost estimates, including the corresponding approved Capital Improvement Requisition ("IR") of each Major Project (2019-2020) for review prior to Commission approval.[4] I recommend removing these projects' capital expenditures totaling $24,710,000 in 2019 and $7,860,000 in 2020 from I&M's forecasted Test Year.

6. Although I&M's lease on Rockport Unit 2 expires in December 2022, I&M is seeking approval to replace Rockport Unit 2's High Pressure ("HP") turbine. I&M expects the new Unit 2 turbine will be in-service by June 1,

[4] The IR is an internal designation by AEP, requiring a specific level of detail before projects are allowed to proceed.

2020. It is unreasonable to ask ratepayers to fund the replacement and/or rebuild of the turbine that will provide I&M's customers with electricity only through 2022, which is the remaining time of the Rockport Unit 2 lease. I recommend removal of $1.323 million (including AFUDC) in capital expenditures and all O&M expenditures associated with the Rockport Unit 2 HP turbine replacement project from the forecasted Test Year.

II. AMI DEPLOYMENT

Q: Please describe I&M's proposed AMI deployment.

A: I&M proposes to deploy "AMI across its Indiana service territory over a three-year period from 2020 through 2022."[5] The total forecasted capital investment is $93.6 million. O&M expense for AMI deployment from 2020 through 2022 is $2.4 million.[6] I&M plans to place 60,000 AMI meters in service at a total capital spend of $10.8 million by the end of its forecast period (December 31, 2020).[7] I&M witness Toby L. Thomas refers to AMI as "smart grid" or "smart metering," and describes the meters as "smart" because "they enable two-way communication between the meter and the utility's central systems."[8] Mr. Thomas testifies the transition to "smart" technologies enables a fundamental change to I&M's operations and serves as the necessary foundation to deliver customer services in the future.[9] He identifies in testimony the utility operations and customer benefits from the AMI deployment such as increased efficiency of meter operations;

[5] *Id*. Petition, Exhibit B – Summary, para. 4, at 18 of 50.
[6] Direct Testimony of Andrew J. Williamson, at 36, Figure AJW-2 and Figure AJW-3.
[7] Direct Testimony of David S. Isaacson, at 27, Figures DSI-11 and DSI-12.
[8] Direct Testimony of Toby L. Thomas at 20, lines 7 – 9.
[9] Thomas Direct at 27, lines 20 – 23.

improved meter accuracy, data for billing and operations, and power outage detection, etc.[10]

Q: Did I&M complete a cost-benefit analysis for its proposed AMI deployment?

A: No. When asked to provide "all cost benefit analyses performed by or on behalf of or reviewed by I&M to evaluate the effectiveness of installing AMI meters," I&M provided an analysis it characterized as "a generic draft analysis … using generic AEP template and inputs." I&M reports that neither the inputs nor the analysis were completed. I&M's incomplete analysis concluded that AMI, as it was evaluated, was not cost-justified.[11] Further, I&M was able to quantify the monthly fee or "charge that would apply to all customers choosing to opt-out of an AMI meter," to reflect I&M's cost to manually read opt-out customers' meters, however it did not quantify the AMI benefits to customer – meter reading savings being one of those benefits.[12] As I describe in more detail below, I&M failed to complete and utilize any meaningful cost-benefit analysis in developing its proposed AMI deployment.

Michigan AMI Deployment Plan for Support of Indiana AMI Deployment

Q: What support did I&M offer to quantify benefits of its proposed AMI deployment?

A: I&M offered little to no support in its case-in-chief. In OUCC Data Request ("DR") Set 15-08, the OUCC requested the financial analysis and internal documents

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[10] Thomas Direct, at 27 – 28.

[11] Public's Exhibit AAA-1 – I&M Response to South Bend DR Set 4-06 and Attachment to South Bend DR Set 4-06, AMI Draft Benefits/Cost Analysis.

[12] OUCC witness Lauren M. Aguilar, Direct at 2, line 17. *See also* Direct Testimony of Kurt C. Cooper, at 8, lines 21 – 22, and at 9, lines 1 – 2, Figure KCC-2.

presented to I&M's management supporting AMI deployment in Indiana.[13] In response, I&M offered only the AMI deployment plan for its Michigan operation and referred the OUCC to Mr. Thomas' direct testimony in this Cause for the "business case." [14]

Q: Please describe the project documents you received for the partial AMI deployment in I&M's Michigan territory.

A: In response to OUCC DR Set 15-07, I&M provided a document titled "Project Charter: MRO Meter Replacement Project" regarding I&M's partial deployment of 17,000 AMI meters in Michigan (the "Michigan Plan"). The "Work Scope Statement" in the Michigan Plan states: "I&M intends to deploy AMI meters to provide more accurate and timely circuit data. AMI meters will provide a gateway into the customer's premises to provide additional services to I&M customers." The Michigan Plan contains a "Project Benefits" category, which states "dispatching crews more efficiently to reduce customer outage duration" and "having remote operability capability, as well as automation, [that] allows I&M personnel to correct issues without being in the vicinity of electrified equipment."[15] However, the Michigan Plan does not quantify these operational benefits' financial or rate impact. In the project charter, I&M stated its primary "Success Criteria" was to "Meet Goals and Objectives established in this Charter [Michigan Plan]," but failed to articulate what those goals and objectives are, as there is no specific description of "Goals" or "Objectives" in the project charter. Similarly, another success criterion

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[13] Public's Exhibit AAA-2 – I&M Response to OUCC DR Set 15-08.
[14] Public's Exhibit AAA-3 – I&M Response to OUCC DR Set 15-07.
[15] *Id*.

was to achieve project "Key Milestones," simply defined as ordering and installing the meters.

Additionally, I reviewed I&M's IR document, which identifies the "Authorized Amount" for the partial AMI deployment (17,000 meters) in Michigan, as approximately $3.1 million, which will be recovered through Michigan base rates.[16] The IR also consists of: (1) a one-page summary endorsement of the Michigan Plan showing how much I&M's authorized capital funding is for the partial AMI deployment in Michigan; (2) one page showing "Funding and Approval"; and (3) one page of "Additional Information." Due to its summary nature, the document did not provide additional information defining the plan's parameters.

Q: Based on your review of I&M's Michigan AMI deployment documentation, what do you conclude?

A: The Michigan AMI Project Charter is four pages long, and addresses only the high-level elements of the 17,000 AMI meter deployment in Michigan. Not only is this information insufficient to evaluate whether ratepayers should fund any AMI deployment, it is inappropriate to provide data from Michigan to support an Indiana project. From an engineering perspective, using a rough sketch project template designed for another jurisdiction to implement in Indiana is inadequate. I&M is requesting pre-approval of its AMI deployment in this Cause through the use of a future test year; however, it does so without offering an plan identifying and quantifying benefits specific for Indiana. Basing a request for regulatory approval

[16] Public's Exhibit AAA-3.

in Indiana on "same as" or "as like" projects in Michigan could set the Indiana AMI deployment on a path towards project cost escalations due to poor project scope definition and a general lack of understanding of location-specific nuances. Additionally, absent defined ratepayer and operational benefits, success criteria, articulated objectives, quantified cost and benefits, and definitive project milestones, I&M's Michigan Plan is an inappropriate and incomplete source for AMI deployment in Indiana and should not be used. The magnitude of the proposed AMI meter deployment in Indiana would be much larger and more complex than in Michigan. Merely attempting to implement a scaled-up version of the Michigan Plan can lead to unintended consequences for Indiana. Any oversight or defect in the Michigan Plan would tend to be magnified in a larger and more complex deployment in Indiana. Further, with such a poorly defined plan, it would be difficult for regulators to determine if the implementation is appropriate and decide which policy and operational changes are most beneficial and important to ratepayers. It would be difficult for the Commission to establish equitable future-looking regulations with such a defective plan.

Smart Meter Pilot Program in Indiana

Q: Has I&M previously deployed AMI in its Indiana service territory?

A: Yes. Mr. Thomas testifies that ten years ago, I&M conducted a Smart Meter Pilot Program ("SMPP") (Cause No. 43607).[17] On March 29, 2011, I&M issued the final version of its <u>SMPP: Process and Impact Evaluation Report</u> ("SMPP Report"), describing I&M's deployment of approximately 10,000 smart meters in the South

[17] Thomas Direct at 22, lines 4 – 6.

Bend area by March 2009, and outlining I&M's conclusions and lessons learned from the use of AMI. The SMPP Report also provides I&M's recommendations for AMI deployment in the future.[18]

Q: Did you review the SMPP Report?

A: Yes.

Q: Please discuss and explain your analysis and understanding of the SMPP Report.

A: I&M's primary objectives of the SMPP were to gain operational experience with various smart grid technologies, including AMI, and evaluate any effect on reliability, distribution grid management, and customer service operations. I&M also aimed to define the effects of consumer programs on energy consumption and customer access to their own usage data.[19] I&M deployed 9,600 AMI meters, integrated two-way wireless communication network, grid management equipment, interactive web portal, an integrated suite of back-office systems including management systems for: AMI, meter data ("MDMS"), and distribution ("DMS"); and installed programmable communication thermostat (or "PCT") at selected homes.

The SMPP Report stated there were no equipment related issues that affected customer bills and services. However, customer interface equipment, such as the PCTs, experienced significant communications and technical issues with the smart meter, which prevented its (PCT) widespread deployment during the SMPP period. PCT interface and operational issues further curbed customer participation

[18] *See* Cause No. 43607, Smart Meter Pilot Program Process and Impact Evaluation Report (March 29, 2011).
[19] SMPP Report, Executive Summary, at 1.

with the cooling direct load control program (or "DLC") below the SMPP goal. There was a weak overall customer response (2.2%) to advanced consumer programs' time-of-day tariff offerings.

However, the SMPP Report showed time-of-day tariff participants realized tangible benefits from the deployment. Although the number of willing customer participants was limited, those who actively participated reduced their peak demand, shifted their energy consumption away from on-peak periods, reduced their total energy consumption, and saved money.[20] Further, the SMPP Report stated 75% of program participants realized savings, most which occurred from September to May due to the discounted off-peak rates offered during that period. There was an overall program satisfaction rate of 83% and no participants left aside from those who left the service territory.[21]

By September 2010, 34% of participants signed up and registered for the interactive web portal but 87% of these registered participants did not view their usage. There was no discernable difference on the consumption information between customers with and without web access. I&M reports that the program delivered improved customer service with quicker service reconnection after settlement of non-payment disconnection, more accurate billing, higher meter read rate, automated service order process execution, remote execution of service orders, and increased reliability thru distribution automation.[22] However, the SMPP system failed to integrate the smart meter's capability to communicate or send out

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[20] *Id*. at 2 – 3.
[21] *Id*. at 3.
[22] *Id*. at 4.

individual customer outage signals. Nevertheless, operations or customer service could "ping" or signal the smart meters to determine whether the meter has power or the outage condition is a utility- or customer-related issue.[23]

The SMPP Report showed that the SMPP's distribution benefits did not exceed the cost of an integrated smart grid deployment.[24] In order to be successful, the SMPP needed active participation of residential, commercial, and industrial customers, and a thorough understanding of the energy cost/benefits from a smart grid application. Even with an extensive advertising campaign and clear financial incentives designed to drive up participation, only 2.2% of customers in the SMPP participated. I&M's business modeling determined that in order to outweigh the costs of the SMPP, a minimum customer participation rate of between 11% and 25% was required, as well as an equal participation of all residential tariff offerings.[25] However, the SMPP Report showed a participation rate in excess of 10% would be difficult to achieve, even with extensive and aggressive marketing. The SMPP Report concluded that "[s]ubstantially greater customer interest will be necessary in order to justify the cost of this or similar future programs."[26]

The SMPP report stated any future deployment should use the existing SMPP installation to determine how to increase customer participation. Otherwise, without substantial customer interest and participation, the benefits of the deployment would not outweigh the costs.[27]

[23] *Id*.
[24] SMPP Report, Executive Summary, at 6.
[25] SMPP, Recommendations, at 124.
[26] *Id*. at 6.
[27] *Id*. at 124.

Q: What did I&M's SMPP Report recommend?

A: The SMPP Report recommended a definitive course of action before deploying any smart meter or AMI technology in its Indiana service territory:

> Assuming that I&M could confirm that customers were interested in and supported AMI programs to the point that the program is cost justifiable; expansion of the SMPP or other AMI projects could be considered.

(SMPP Process and Impact Evaluation Report, Recommendations, at p. 124.)

The SMPP Report recommended commercial and industrial customers engage, participate, and understand the energy cost benefits from a smart grid application.[28] The SMPP Report identified a need for I&M to develop a business case for any AMI deployment in the future that encompassed all aspects of the deployment, because I&M's prior business modeling of the SMPP overestimated (25%) its customers' interests versus the actual program participation rate (2.2%).[29] I&M's SMPP Report concluded that, absent compelling reasons to believe I&M customers would embrace the benefits of AMI and smart grid technology, the deployment benefits of AMI would not outweigh the costs.[30]

Q: Did I&M incorporate its SMPP findings and recommendations into the development of its AMI deployment proposed in this Cause?

A: It does not appear that I&M incorporated the SMPP's findings and recommendations in its case-in-chief. Rather, Mr. Thomas testifies that the SMPP "showed that the technology was still in its infancy" and "customers were not ready to put the technology to use." As such, Mr. Thomas states I&M "decided to wait

[28] *Id*.
[29] *Id.*, Executive Summary, at 2; and Recommendations, at 124.
[30] *Id*., Recommendations, at 124.

for the technology to mature."[31] However, even with additional time to consider any technological changes or growth in customer interest, I&M did not develop any subsequent business case, as recommended by the SMPP Report, to show its proposed AMI deployment has the level of customer interest necessary to outweigh the costs of a deployment.

Petitioner's witness Mr. David A. Lucas testifies, "I&M will provide customers with a variety of opportunities to learn about the AMI technology and explain the benefits that AMI meters bring to customers."[32] However, this contradicts I&M's own recommendations in the SMPP Report, which states that "I&M could confirm that its customers were interested in and supported AMI programs to the point that the program is cost justifiable;" before the "expansion of the SMPP or other AMI products could be considered."[33] Instead, Mr. Lucas states that I&M will send, sixty (60) days prior to AMI meter installation, postcards and emails to customers informing them of the AMI deployment, and providing high level overview of the benefits of the technology, link to I&M's website page addressing AMI deployment, and call center phone number to call for answers to questions.[34] Although I&M recognized in the SMPP that customer education and awareness is a critical component of new technology adoption, I&M did not design its customer engagement strategy for the current AMI deployment to develop or nurture its customers' interest.

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[31] Thomas, Direct at 22, lines 11 – 14.
[32] Petitioner's witness Mr. David A. Lucas, Direct at 38. Lines 16 – 20.
[33] SMPP Report, Recommendations, at 124.
[34] Lucas, Direct at 38, lines 9 – 17.

Q: Did I&M offer any operational data or information from its existing 10,000 AMI meters in South Bend to support its proposed AMI deployment in this Cause?

A: No, even though Mr. Thomas acknowledged, "the pilot provided substantial information regarding AMI and its use."[35] I&M's direct testimony shows no attempt to "utilize the existing SMPP infrastructure and customer base" to gather, analyze, and review critical data that is relevant to and could provide necessary context for its proposed AMI deployment in this Cause.[36]

OUCC Conclusion and Recommendation regarding I&M's AMI Request

Q: Is AMI deployment necessary to I&M's provision of utility service?

A: No. Aside from the 10,000 smart meters deployed in South Bend, there are more than 400,000 automatic meter reading ("AMR") meters currently deployed in I&M's Indiana service territory. Mr. Isaacson testifies, "35% of the AMR meters deployed in I&M's Indiana service territory will reach the end of their design life by the start of the proposed AMI deployment."[37] However, if any of the 35% are tested and proven to be operating satisfactorily, they can be placed back in service. That means that more than 65% of I&M's meters are in good working condition. Notwithstanding the type of meter, good operating practices dictate that electric meters should be kept in good operating condition at all times. Testing, repairing, and replacing defective meters are routine and part of I&M's daily operation. As such, the costs of operating and maintaining these meters (AMR and smart meters) in good condition and replacing the defective ones are likewise part of I&M's base

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[35] Thomas, Direct at 22, lines 10 – 11.
[36] SMPP Report, Recommendations, at 124.
[37] Isaacson, Direct at 28. Lines 13 – 16.

rates. AMI is an optional upgrade to I&M's meters and is not necessary to provide service to its customers; therefore, unless I&M can show the benefits of AMI deployment outweigh the additional costs of installing a new metering system with the associated communication infrastructure and back-office system improvements, the proposed AMI deployment should not be approved.

Q: What is your opinion regarding Mr. Thomas' list of AMI deployment benefits?

A: Mr. Thomas' testimony, at 27 – 28, including his Attachment TLT-4,[38] offers a list of AMI deployment benefits; however, this list shows only a high-level, non-I&M specific generic list of AMI benefits. I&M should have conducted its due diligence to quantify and identify the AMI benefits important to its ratepayers. Absent such due diligence, I&M's AMI deployment plan remains aspirational rather than an executable plan that will benefit Indiana ratepayers.

Q: During the course of your review, were you able to locate a robust utility cost-benefit analysis for AMI deployment?

A: Yes. Ameren Illinois, one of the companies listed in the IEI Report at p. 9 of 21, conducted an AMI cost-benefit analysis in its application for AMI deployment in Illinois.[39] Ameren's cost-benefit analysis details what it considers as cost-beneficial AMI, including specific quantification of ratepayer benefits.[40] Ameren's analysis describes "quantified customer/societal benefits" as those that "…flow directly to Ameren Illinois customers. These will be captured by customers in the form of

[38]Attachment TLT-4 contains a report by The Edison Foundation, Institute for Electric Innovation, titled Electric Company Smart Meter Deployments: Foundation for a Smart Grid, December 2017 ("IEI Report").
[39] *See* Illinois Commerce Commission, Docket No. 12-0244, Corrected Petition for Rehearing of Ameren Illinois Company, Advanced Metering Infrastructure (AMI): Cost / Benefit Analysis, Ameren Ex. 3.1 (June 29, 2012). Website: https://www.icc.illinois.gov/downloads/public/edocket/324213.pdf Accessed: 8/7/19.
[40] *Id*.

reduced electric rates due to the avoidance of shared and pass-through costs, all things being equal."[41] While the analysis contains Ameren location-specific assumptions, the salient point is that a utility cost-benefit analysis quantifying AMI customer benefits through reduced rates can be done.[42]

Had I&M attempted such an analysis, the OUCC could evaluate its merits and make an informed judgment as to whether I&M's proposed AMI deployment is cost-justified. This is particularly important given AMI meters are an optional upgrade for 65% of I&M's meters that are not at the end of their useful service lives. To remedy this problem, I&M should develop and file a robust cost-benefit analysis providing quantifiable support for the benefits and specific costs of its proposed Indiana AMI deployment.[43]

Q: Please summarize your conclusions and recommendations regarding I&M's AMI deployment.

A: I&M did not provide project management documentation describing the complete cost, scope, and implementation plan for its AMI deployment. Instead, it asks the Commission to rely on the few details it made available for its 17,000-meter Michigan AMI deployment. Despite having deployed AMI meters in Indiana on a pilot basis, I&M failed to utilize the lessons learned from the SMPP and ignored its own recommendation in the SMPP Report to create a business case for any future AMI deployment. Further, even though I&M's AMI deployment is premised upon

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[41] *Id*. at 29.
[42] *Id*. Also, in Cause No. 44720, Settlement Agreement, Section 5(b), at 3, Duke Energy Indiana, LLC ("DEI") quantified the savings of its AMI deployment at $39.69 million over seven years.
[43] Even if I&M petitions for approval of its AMI deployment in a seven year TDSIC plan, the Commission must make a determination whether the estimated costs of the AMI deployment included in the plan are justified by incremental benefits attributable to the plan. *See* IC 8-1-39-10 (b).

assumed operational benefits and efficiencies, I&M did not quantify any financial or rate benefit for its proposed AMI deployment. Without a robust cost-benefit analysis and proper project management documentation, ratepayers are being asked to shoulder the costs of an AMI program that has not been fully scoped and approved at a corporate level and does not reflect the rate impacts that should result from the operational benefits the program intended to provide.

Therefore, I recommend the Commission require I&M to prepare a cost-benefit analysis (including financial analysis) and full business case prior to approving full deployment of AMI in I&M's Indiana service territory. I further recommend an adjustment to remove the capital expenditure amount of $14,167,000 (Figure AJW-2), and O&M expenditure amount of $2,410,722 (Figure AJW-3) associated with I&M's AMI deployment from the forecasted Test Year.[44]

Q: Should the Commission still be interested in approving AMI despite your concerns, should it approve I&M's entire AMI deployment as proposed?

A: No. Given the lack of a robust cost-benefit analysis that quantifies the customer rate impact of I&M's proposed AMI deployment, should the Commission be inclined to approve I&M's proposal over the OUCC's objections, it should approve only the proposed 2020 deployment of approximately 15,000 AMI meters, in addition to the approximately 10,000 already installed in the South Bend area, for a total of 25,000 AMI meters, as a pilot program to be evaluated within the context of a collaborative involving Commission technical staff, the OUCC, and interested parties ("collaborative pilot"). The purpose of the collaborative pilot would be to identify

[44] Williamson Direct at 36.

the operational benefits of AMI within the selected pilot program area(s) in order to quantify the customer rate impact of those benefits and flow that impact back to customers. Because customer engagement with AMI drives the level of operational benefits realized, the collaborative pilot should also develop I&M's customer engagement in the pilot program area to promote adequate customer participation. Based on the results of the collaborative pilot, future AMI deployment beyond the pilot program area may be appropriate.

Q: If the Commission approves the collaborative pilot, how should its costs be recovered?

A: The OUCC is recommending a 15,000 AMI meter pilot deployment and to calculate the collaborative pilot costs by using proportionate capital and O&M costs I&M supplied in Mr. Williamson's direct testimony (Figures AJW-2 & AJW-3, at p. 36). These costs should be recovered through an AMI tracker, subject to the recommendations of OUCC witness Wes R. Blakely.

III. MAJOR STORM DAMAGE RESTORATION RESERVE

Q: What is I&M's Major Storm Damage Restoration Reserve request?

A: I&M seeks to embed $4,047,529 for its Major Storm Damage Restoration Reserve ("Major Storm Reserve") in its forecasted Test Year, the same amount approved in I&M's previous rate case. However, using the most recent five-year average of major storm expense shows that I&M's Major Storm Reserve should be reduced.

Q: When the Commission initially authorized I&M's Major Storm Reserve, did it order I&M to base this Reserve on a five-year average of major storm expense?

A: Yes. In Cause No. 44075, the Commission approved the Major Storm Reserve to normalize the effect of major storms on I&M's expenses.[45] The Commission accepted the OUCC's recommendation to use a five-year average to normalize the level of major storm expenses, resulting in an annual amount of $4.2 million ($4,047,529 for Indiana Jurisdictional distribution O&M expense and $165,598 for total company transmission O&M expense).[46] In Cause No. 44967, the Commission approved a Settlement Agreement that continued the same level of funding for major storm expenses it approved in the previous rate case.[47]

Q: Do you have concerns regarding I&M's proposed level of funding for its Major Storm Reserve fund in this Cause?

A: Yes. I do not oppose I&M continuing the Major Storm Reserve; however, I have concerns regarding the level of funding I&M is seeking in this Cause. Consistent with the methodology last approved by the Commission in Cause No. 44075 Order, I&M should use the current five-year average (2014-2018) to determine the level of funding for its forward-looking test year.

By maintaining the Major Storm Reserve funding at its current level and ignoring the original basis for the Commission's approval, the purpose of establishing a methodology to normalize the effects of major storm expenses is defeated. I&M should utilize the five-year average methodology originally

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[45] Cause No. 44075, *Petition of Indiana Michigan Power Company, an Indiana Corporation, for Authority to Increase its Rates and Charges for Electric Utility Service*, Order at 68, (f) Commission Discussion and Findings (February 13, 2013).
[46] *Id*.
[47] Cause No. 44967, *Petition of Indiana Michigan Power Company, an Indiana Corporation, for Authority to Increase its Rates and Charges for Electric Utility Service*, Order at 11-12 (May 30, 2018). *See also* Stipulation and Settlement Agreement, Section I.A.6, at 7, attached to the Order.

approved by the Commission to normalize the effects of storm variability and determine the storm reserve funding level in this Cause. Accordingly, I recommend a $2,473,000 decrease to the forecasted Test Year Major Storm Reserve based on the five-year average major storm expenses for the period 2014 – 2018.[48]

IV. DISTRIBUTION MANAGEMENT PLAN: ASSET RENEWAL AND RELIABILITY PROGRAMS

Q: Please describe the asset renewal and reliability programs I&M proposes to construct by the end of its forecasted Test Year (2020).

A: I&M seeks to embed the costs associated with a number of distribution asset renewal and reliability programs it plans to place in service by the end of 2020.[49] Each program (e.g. "Overhead Line Rebuild Program") is made up of program categories (e.g. "Overhead Rebuild – Single Phase Line Rebuild," "Overhead Rebuild – Three Phase Line Rebuild," etc.), which are in turn made up of multiple individual projects.[50] Because I have issues with cost recovery of I&M's asset renewal and reliability programs, this portion of my testimony addresses only those program categories.[51]

Q: Did you review I&M's support for its proposed asset renewal and reliability programs?

A: Yes. I reviewed the asset renewal and reliability work plan, schedule of capital expenditures and Attachment DSI-1 provided by Mr. Issacson.[52] The work plan

[48] The Total Company Historical Base (2018) Major Storm expense amount of $3,465,000 in Figure DSI-17 of Mr. Isaacson's testimony, at 39, includes Michigan's portion of $1,428,400. See also Figure DSI-19, at 40.
[49] Isaacson Direct at 15 – 16.
[50] Isaacson Direct, Attachment DSI-1, at 1 – 17.
[51] I use the term "program category" to refer to the various "Program" line items listed in Mr. Isaacson's Figure DSI-6, at 18; Figure DSI-7, at 19; and table titles/headings found in his Attachment DSI-1, at 1 -17.
[52] Isaacson Direct at 18, Figure DSI-6 (work plan); Direct at 19, Figure DSI-7 (schedule of capital expenditures); and Attachment DSI-1, at 1 - 17.

identifies the asset renewal and reliability programs, work scopes of the projects (measured in feet, miles or units), and the implementation year (2019 or 2020); and the schedule of capital expenditures showed the total amounts for each program spend in 2019 and 2020.[53] Meanwhile, Mr. Isaacson's Attachment DSI-1 identified the various program categories and individual projects, including the total "Estimated Capital" and "Estimated O&M" expenditures of each category in 2019 and 2020, and the short description and work scopes of individual projects.

Q: Please discuss the results of your review.

A: Mr. Isaacson's Figure DSI-6 is a table titled "Asset Renewal and Reliability Work Plan (Indiana)" with four column headings: "Program," "Units," "2019," and "2020."[54] In Figure DSI-6, the column "Program" identifies the various program categories and column "Units" to reflect the work scope of each program category. To describe the work scope of each program category, the column "Units" (in Figure DSI-6) states either "Miles," "Units" or "Feet." By cross-referencing Figure DSI-6 with Attachment DSI-1, Attachment DSI-1 also indicates the corresponding total "Miles," "Units" or "Feet" of each program category. Attachment DSI-1 also lists the individual projects contained in each program category and provides a short description of each project with its corresponding work scope in miles, units or feet as well. The sum of the individual project's work scope miles, units or feet is the only work scope provided for each program category. Given that I&M's Distribution Management Plan is set to be constructed over 2019 and 2020, more

[53] Isaacson Direct at 17, lines 14 – 17.
[54] Isaacson, Figure DSI-6, at 18

detailed project scope information should have been provided. Without that detail, the reasonableness of I&M's programs and projects cannot credibly assessed.

Mr. Isaacson's Figure DSI-7 is a table titled "Asset Renewal and Reliability Program Capital Expenditures (Indiana - $000)," which shows the capital expenditure of each program for 2019 and 2020.[55] Although the capital expenditures shown in Figure DSI-7 correspond with the "Estimated Capital" amounts in Attachment DSI-1 for each program category, the information it provides is at a high program level and not project level. It does not provide any further details or insights into the cost structure of these programs.[56]

Additionally, nowhere in I&M's support for its asset renewal and reliability programs did it provide a detailed cost breakdown of the individual projects. At a minimum, I&M should provide the same level of detail for forecasted test year projects as it would for Year One and Two TDSIC projects. With these projects scheduled for 2019 and 2020, work order detail should already exist that breaks out material, equipment, labor costs as well as the overhead components and reasoning. This work is not considered state-of-the-art, but the same type of projects I&M does as part of their operations, and therefore, detailed estimation should not be burdensome. Without the individual project cost estimate information, it is difficult to credibly evaluate or conduct an independent analysis of the reasonableness of the costs for these programs and projects.

Q: What are your concerns regarding I&M's support for its asset renewal and reliability programs?

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[55] Isaacson, Figure DSI-7, at 19.
[56] Isaacson, Attachment DSI-1, at 1 -17.

A: I&M did not provide adequate support and documentation in its case-in-chief to allow the OUCC, Commission and other interested parties the ability to conduct a necessary and proper review of these projects. Merely providing brief descriptions of a program or individual project and the total project cost amount or total program expenditure by year is not enough information to determine if the projects are reasonable and should be afforded cost recovery. Moreover, I&M's Distribution Management Plan contains projects that would likely be TDSIC-eligible, but it has failed to provide a similar level of cost support and project definition, as would be expected in a TDSIC filing. Given the level of similarity between the types of projects included in I&M's Distribution Management Plan and those anticipated in the TDSIC statute, it would be inappropriate to hold I&M to a lower standard of cost and project support in this case, simply because it is seeking cost recovery in forecasted test year rate case.

Q: Is I&M seeking pre-approval of capital investments through its forecasted Test Year?

A: Yes. By seeking cost recovery of these proposed projects in a forward-looking test year, I&M is seeking pre-approval for these projects. This has significance because I&M is asking for authority to build certain projects at its forecasted cost levels. The Commission, the OUCC and other interested parties must be able to review the detail underlying this forecast to ensure ratepayers' interests are served by those investments and costs. This is similar to the review and analysis done in 7-Year Plan, TDSIC and CPCN cases, but in this case, I&M's projected capital spend is for years 2019 and 2020 only, which makes the absence of this information even more egregious. Therefore, I&M should provide adequate support and documentation in its case-in-chief to sufficiently analyze these programs.

Q: Did the OUCC solicit additional detail in discovery?

A: Yes, in OUCC DR Set 8-10, the OUCC requested project management information for I&M's proposed projects. I&M responded indicating, "the request was unduly burdensome to compile in the format requested" but invited the OUCC to "access various systems at I&M's offices in Fort Wayne, Indiana."[57] On July 19, 2019, I and other OUCC staff met with I&M distribution and technical personnel.

In OUCC DR Set 8-12, the OUCC requested additional information on three projects with similar descriptions.[58] In response, I&M differentiated the three projects by identifying the specific pole numbers associated with each project and providing the corresponding work request of each project.[59] However, without I&M identifying the specific work request number of each project, it is difficult to match the work request documents to the corresponding projects because none of the information corresponded or matched.

Q: Please discuss your meeting with I&M distribution and technical personnel.

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[57] I&M Response to OUCC DR 8-10:

> I&M objects to this Request to the extent it seeks an analysis, calculation, or compilation which has not already been performed and to which I&M objects to performing. In addition, I&M objects to this request on the grounds and to the extent the request is unduly burdensome. In support of this objection, I&M states that this request seeks detailed information on over 670 projects. The information related to these 670 projects is maintained by I&M in various systems, such as the work order management system. The information is not maintained in the manner requested as part of I&M's ordinary course of business and would be unduly burdensome to compile in the format requested as I&M would have to pull each of the 670 projects on an individual basis from multiple systems. I&M will compile a sampling of identified projects at the OUCC's request. In the alternative, the OUCC is welcome to access the various systems at I&M's offices in Fort Wayne, Indiana, at a mutually agreeable time. A representative sample is also provided in response OUCC 8-12 and OUCC 8-13.

[58] Isaacson, Attachment DSI-1, at 1, projects with Map Reference Number 20, 21 and 22.

[59] Public's Exhibit AAA-4 and Confidential Exhibit AAA-4C – I&M Response to OUCC DR Set 8-12 and Confidential Attachments 1, 2, and 3.

A: On Friday, July 19, 2019, OUCC staff and I&M distribution personnel had a tech-to-tech meeting in Ft. Wayne, IN. Due to the time constraints; I was only able to walk through a single project. This discussion did not alleviate my concerns. As I discuss in more detail below, based on the few project cost breakdowns I have seen, I&M's project cost estimates include a substantial portion of overhead or indirect costs. This is troubling given that I&M's proposed Distribution Management Plan projects are to be constructed in the near-term. Based on my experience, I&M should have associated project information at the work-order level. However, with half of 2019 gone, a substantial number of the projects I&M proposed to place in service in 2019 were not at work-order level detail yet.

Based on the documentation provided for this meeting on July 19, 2019, I could not identify the status of each project, as a work order number may appear in some documents but remains "pending" in others. It would be difficult to determine which of the 2019 distribution projects are ready for implementation— and much more difficult to do so for I&M's 2020 projects.

Q: Based on the few project cost estimates I&M provided, do I&M's cost estimates appear reasonable?

A: No. I&M provided five "Work Request Cost Estimate Summary" documents or work requests in its responses to OUCC DR Sets 8-13 and 8-14 (in addition to OUCC DR Set 8-2 discussed above).[60] Four work requests were for "Single Phase Line Rebuild 2019" projects and one work request was for a "Three Phase Line Rebuild 2019" project. I evaluated the individual cost estimates contained in each

[60] Public's Exhibit AAA-5 and Confidential Exhibit AAA-5C – I&M Responses to OUCC DR Sets 8-13 and Confidential Attachment 1; and OUCC DR Set 8-14 and Confidential Attachment 1.

of the five work requests and noticed that the indirect costs allocated to these projects accounted for more than half of the total project costs (not including retirement). The indirect costs range from 55% to 62% of total project costs. The proportion of indirect costs of total project costs far exceeds what the OUCC has reviewed in other proceedings.[61] Based on such a high level of indirect costs shown in each of the five work requests, my conclusion is that the cost estimates of these five projects are excessive and unreasonable. If I&M's other Distribution Management Plan projects also contain this level of indirect costs, I&M's estimates would likewise be unreasonable, and should not be recovered.

Q: Did I&M provide adequate project cost detail so that the Commission, OUCC, and interested parties could use to "true up" I&M's projected rate base to its actual rate base by the end of the Forecasted Test Year?

A: No. The project descriptions in Pet. Attach. DSI-1, at pp. 1 – 17, do not match the information in I&M's corresponding work orders and cost estimate summaries. For example, the project I&M identified as "Three Phase Line Rebuild 2019; Map Reference Number 28; Station: Darden, Circuit: Allen; Description: Reconductor 4AS to 2AA (Maybe 556AAL), beyond JO137-344," in Pet. Attach. DSI-1, at p. 3 of 26, did not match any of the project information or description contained in "Work Request Cost Estimate Summary, Work Request: 70022722" document in "OUCC DR 8, Q14, Attachment 1, Page 1 of 1" that I&M provided to the OUCC. If this were the case for all of I&M's Distribution Management Plan projects, by

[61] The OUCC reviews project cost information in TDSIC cases for distribution and transmission improvement projects, many of which are similar to the projects I&M's proposes to recover in its Distribution Management Plan. Indirect costs typically account for less than 25% of the total project costs. *See* Cause No. 44720, Duke Energy Indiana TDSIC-5, Public's Exhibit No. 2, Public Testimony of Anthony Alvarez, at 18 (January 30, 2019).

the time those projects are completed by the end of 2020, the Commission and the parties would not able to verify I&M's projected spend against its actual spend by project. This is a critical comparison in terms of understanding whether I&M's project management capabilities are adequate, and to ensure that customers getting the biggest bang for their buck in terms of project completions.

Q: Given I&M is constructing the asset renewal and reliability projects in 2019 and 2020, what is a reasonable level of project estimate detail?

A: I&M should provide cost estimates with sufficient level of accuracy and detail to enable other parties and the Commission to conduct their own independent analysis of the asset renewal and reliability project estimated costs. With half of year 2019 over, it is reasonable to expect all remaining 2019 projects at work order level cost estimates and all completed projects should have corresponding completed work order documentation and costs information. I&M should provide the status of each project and identify all projects that moved from 2019 to 2020 and/or cancelled. It is also reasonable to expect all 2020 projects within 365 days of implementation should have work order level cost estimates, and all remaining projects at a Class 2 estimate (-5% to +20%), unless cancelled.

I&M should keep and maintain an updated master list of its projects containing detailed project information and cost estimate breakdown including support documents available for review by the Commission, the OUCC and other interested parties. I&M should maintain transparency in providing project and cost information. None of this information was provided.

Q: What is your recommendation regarding asset renewal and reliability projects?

A: Prior to Commission approval, I recommend I&M provide the corresponding project status and work order documentation of each distribution project in its Distribution Management Plan (2019-2020). This includes, at a minimum, the following information:

1. Project Reference Number
2. Project Identifier
3. Project Status
4. Work Request Number
5. Work Request Cost Estimate Summary
6. Work Order Number
7. Project Start Date
8. Project End Date
9. Total Project Cost
10. Total Material Cost
11. Total Labor Cost, including:
    i. Supervision, if applicable
    ii. Company or I&M Labor Cost
    iii. Contractor or Contract Labor Cost (non-Company)
12. Total Indirect of Overhead Cost, including:
    i. Material Overhead Cost (show reconciliation with Total Material Cost)
    ii. Labor Overhead (show reconciliation with Total Labor Cost)
13. Total Contingency Amount, including amounts embedded in:
    i. Material Cost
    ii. Labor Cost
    iii. Indirect or Overhead Cost
14. Management Reserve, if any
15. Cost Variance (Original Cost Estimate vs. As-Built or New Estimate) Amount ($) and in Percent (%)
16. Total O&M Expense, including
17. Material Cost

18. Labor Cost
19. Indirect or Overhead Cost

I also recommend the Commission allow the OUCC and other interested parties the opportunity and sufficient time to conduct independent review and evaluation after I&M makes appropriate showing.

In the absence of support for I&M's asset renewal and reliability projects, I recommend adjustments to remove the capital expenditures of $39,991,413 for 2019 and $35,129,917 for 2020; and adjustments to remove the O&M expenditures of $1,006,154 for 2019 and $1,009,608 for 2020, from the forecasted Test Year, as shown in Table 1 below.[62]

[62] Mr. Isaacson Direct at 19, Figure DSI-7, and Attachment DSI-1, at 1 – 14.

Table 1: Adjustment, Capital and O&M Expenditures - Asset Renewal And Reliability Program

Program	2019		2020	
	Capital ($)	O&M ($)	Capital ($)	O&M ($)
Overhead Rebuild – Single Phase Line Rebuild	$ 1,823,335	$ 122,766	$ 1,920,611	$ 139,283
Overhead Rebuild – Three Phase Line Rebuild	$ 5,727,838	$ 176,343	$ 7,731,945	$ 246,877
Overhead Rebuild – Circuit Ties	$ 2,755,150	$ 90,539	$ 0	$ 0
Overhead Rebuild – Voltage Conversions	$ 533,713	$ 55,072	$ 1,065,785	$ 116,840
Overhead Rebuild – Sectionalizing	$ 445,028	$ 3,509	$ 400,536	$ 3,285
Overhead Rebuild – Recloser Replacement	$ 283,438	$ 1,013	$ 253,026	$ 897
Overhead Rebuild – Capacitor Replacement	$ 589,191	$ 119	$ 348,970	$ 91
Overhead Rebuild – Porcelain Cutout & Lighting Arrester Replacement	$ 1,538,684	$ 31,024	$ 1,124,829	$ 28,093
Overhead Rebuild – Crossarm Replacement	$ 685,572	$ 43,084	$ 235,227	$ 23,866
Pole Replacement / Reinforcement	$ 4,767,105	$ 371,831	$ 4,090,273	$ 333,098
URD Cable and Live-Front Replacement	$ 3,932,748	$ 108,148	$ 4,147,323	$ 114,802
Underground Station Exit Cable Replacement	$ 892,135	$ 2,706	$ 827,997	$ 2,476
Distribution Feeder Breaker Replacement	$ 5,425,351	$ 0	$ 4,612,319	$ 0
UG Network Rebuild Program	$ 10,592,125	$ 0	$ 8,371,076	$ 0
Totals	**$ 39,991,413**	**$ 1,006,154**	**$ 35,129,917**	**$ 1,009,608**

V. DISTRIBUTION MANAGEMENT PLAN: MAJOR PROJECTS

Q: Please discuss your review of I&M's proposed distribution "Major Projects."

A: As I understand, I&M's "Major Projects" go through an internal Investment Requisition ("IR") process. As I explained earlier, the IR contains a one-page summary identifying and describing the project, the authorized capital spend, cash flow, regulatory recovery, funding approval, and budget availability. Without an approved IR, my understanding is that I&M has not committed capital to construct the Major Project. As shown Confidential Attachment AAA-5, I&M's presentation during the July 19, 2019 tech-to-tech meeting, a number of both the 2019 and 2020 Major Projects proposed in this Cause did not have an approved IR.[63] This is both

[63] Public's Exhibit AAA-6 and Confidential Exhibit AAA-6C – I&M Response to OUCC DR Set 34-03 and Confidential Attachment 11, p.3 of 4.

important and concerning to me, as it indicates that I&M has not independently determined the scope and cost of a given Major Project, such that its internal management has endorsed allocating funds to its construction. Instead, it appears that I&M is waiting for regulatory approval before it will authorize funds for several of these Major Projects.

Q: Describe your review of I&M's proposed Major Projects.

A: I reviewed Mr. Isaacson's Attachment DSI-2 – Distribution Management Plan: Major Project Summary.[64] In so doing, I found it difficult to determine whether the transmission or distribution portion of the overall project work scope is what elevated or categorized the project as a Major Project, because the project summary discussed substations, lines, and equipment with voltages at both transmission (138 kV) and sub-transmission (69 kV) levels. I&M is requesting cost recovery for distribution projects; however, the project description includes both distribution and transmission elements. Typically, transmission personnel do the work within a transmission substation (inside the fence), and the scope and timing of any intended distribution work is dependent upon the transmission work and schedule. Without a well-defined distribution project scope of work and clear distinction between distribution and transmission functions, it is impossible to determine the reasonableness of these projects.

Q: Please give an example of one such project.

A: One such project is the "South Bend/Elkhart Area – Bosserman – New Carlisle Area Improvements" identified in Petitioner's Attachment DSI-2. [65] The project

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[64] Isaacson Direct, Attachment DSI-2, at 1 – 14.
[65] Isaacson Direct, Attachment DSI-2, at 1.

summary description identifies four different substations: New Carlisle, Silver Lake, Springville (later to be renamed as Marquette), and Bosserman.[66] The project includes creating a "looped 138 kV" line, thereby categorizing these four facilities as transmission substations.[67] Some individual project summary justifications contain age and condition of equipment as well as components pertaining to transmission, sub-transmission and distribution systems, which raised ambiguity of whether these were transmission or distribution work scopes. In the distribution line component section, substation and line works were described involving reconductoring, installing, constructing, and reconfiguring "station exit," "feeder" and "circuit," which may be inside (transmission) or outside (distribution) the substation fence. In the "benefits of the project" section, the description ascribed transmission benefits to distribution, and vice-versa, which further compounded the ambiguity between transmission and distribution work scopes. Given that I&M is seeking to recover its transmission project costs through NITS charges, as discussed by OUCC witness Mike Gahimer, distinguishing between distribution and transmission projects is an important factor in evaluating I&M's proposed Distribution Management Plan.

For Major Projects, I&M should provide adequate support and documentation for each project in its case-in-chief to allow all parties and the

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[66] *Id*.

[67] North American Electric Reliability Corporation ("NERC") defines Bulk Electric System (or BES) to include all "Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher." *See* NERC, *Bulk Electric System Definition Reference Document*, Version 3, August 2018. Website: https://www.nerc.com/pa/Stand/2018%20Bulk%20Electric%20System%20Definition%20Reference/BES_Reference_Doc_08_08_2018_Clean_for_Posting.pdf. Accessed: 08/11/2019.

Commission to conduct the necessary review of these projects. Without basic project information, regulators cannot evaluate and assess the reasonableness and necessity of these projects. As several of the projects do not have approved IRs, it seems inappropriate for I&M to seek regulatory pre-approval prior to receiving internal (or corporate) approval (approved IR) for these projects. This gives the appearance I&M is using regulatory pre-approval (through a future test year) as support and justification for seeking its own internal corporate approval and budget allocation for these projects.

Q: What is your recommendation regarding I&M's Major Projects?

A: I recommend the Commission require I&M to provide detailed project cost estimate with the corresponding approved IR for each Major Project for review, prior to any approval. Absent this support, I recommend a $24,710,000 adjustment to remove I&M's proposed capital expenditures for 2019, and a $7,860,000 adjustment to remove I&M's proposed capital expenditures for 2020, as shown in Table 2 below, from the forecasted Test Year revenue requirements.[68] I also recommend any O&M expenditures associated with these projects removed from the forecasted Test Year revenue requirements.

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[68] Isaacson Direct at 21, Figure DSI-8, and Attachment DSI-1, at 14.

Table 2: Adjustment, Capital Expenditures – Major Projects

Major Project	2019	2020	In-Service Year
Bosserman-New Carlisle	$ 9,682,000	$ 0	2019
Colfax Station	$ 347,000	$ 0	2019
Elkhart Area Network	$ 6,170,000	$ 0	2019
Liberty Center Station	$ 959,000	$ 0	2019
Limberlost Network	$ 2,381,000	$ 0	2019
Montpelier Underbuild	$ 139,000	$ 0	2019
Muessel Station	$ 347,000	$ 0	2019
Fuson Station	$ 1,919,000	$ 4,021,000	2020
Rosehill Station	$ 2,247,000	$ 343,000	2020
Royerton Station	$ 0	$ 44,000	2020
SDI Improvements	$ 116,000	$ 343,000	2020
Strawboard Station	$ 405,000	$ 3,109,000	2020
Totals	**$ 24,710,000**	**$ 7,860,000**	

Q: You have recommended denial of I&M's Distribution Management Plan and its Major Distribution Projects due to lack of adequate support. Should I&M be permitted to provide the missing support in its rebuttal testimony?

A: No. In *City of Evansville* and *Indiana-American*, the Commission has recently reminded utilities of the obligation to provide necessary evidence in cases-in-chief. In *City of Evansville*, the Commission stated that parties should not have to request basic supporting documentation in discovery:

> [The Petitioner] is reminded that it bears the burden of proof in demonstrating it is entitled to its requested relief. The OUCC should not have to request or otherwise seek basic supporting documentation that should have been provided with Petitioner's case-in-chief to supports its requested relief. Further, even if the OUCC is able to ascertain through discovery the information necessary to support Petitioner's requested relief, the Commission, which is the entity that must ultimately render a decision on the matter, would still lack the necessary information to make its determination because it is not privy to the parties' discovery.[69]

[69] *City of Evansville, Indiana*, Cause No. 45073, Order, at p. 8 (December 19, 2018).

In *Indiana-American*, the Commission reminded the utility that waiting until rebuttal to support its requested relief is a needless burden on the parties' time and resources:

> It is, and shall remain, any petitioner's burden to prove in its case-in-chief – not on rebuttal – the propriety of its requested relief. Waiting until rebuttal, after the other parties have filed their responsive cases-in-chief, or until after discovery needlessly wastes time and resources.[70]

Demonstrating that proposed investments are reasonable and necessary is I&M's obligation, and one that it should not be allowed to avoid by filing a rate case that uses a forecasted test year. Consistent with both good engineering and project management practice, I&M's Distribution Management Plan and its Major Distribution Projects should have been supported by Class 2 cost estimates (-5% to +20%), as these projects are due to be constructed by the end of 2020. This level of detail is necessary in order to evaluate whether I&M's proposed costs are reasonable and whether the proposed projects are necessary. It would be highly prejudicial if I&M were allowed to file rebuttal testimony intended to correct this deficiency. Rather than receiving this information in rebuttal with an opportunity to conduct only a cursory review, the OUCC must have a meaningful opportunity to review I&M's supporting documentation for its Distribution Management Plan and Major Projects. With other avenues of T&D cost recovery available to it, including recovery under the TDSIC statute, I&M should not be permitted to sidestep its obligation to provide a minimum level of adequate support for T&D projects it anticipates to complete by the end of its forecasted test year.

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[70] *Indiana-American Water Company*, Cause No. 45142, Order, at p. 23 (June 26, 2019).

VI. ROCKPORT UNTI 2 HP TURBINE REPLACEMENT

Q: Please describe I&M's request to include in the forecasted Test Year revenue requirements the capital expenditure for Rockport Unit 2 HP turbine replacement.

A: I&M seeks to include forecasted capital expenditures and associated O&M expenditures related to its proposed Rockport Unit 2 HP turbine replacement.[71] Petitioner's witness Timothy C. Kerns forecasted the "total cost of $1.323 million (including AFUDC)" for the Rockport Unit 2 HP turbine replacement project.[72] Rebuilding the HP turbine involves I&M installing a spare turbine rotor, inner shell or block, and (turbine) blade carriers, as well as rebuilding the low-pressure stages of the turbine. Mr. Kerns testifies I&M will place the Rockport Unit 2 HP turbine replacement project in-service by June 1, 2020.[73]

Q: Are you concerned I&M is embedding Rockport Unit 2 HP turbine replacement costs in the forecasted Test Year?

A: Yes. I&M already found it inadvisable to extend its lease on Rockport Unit 2 beyond December 2022.[74] As Mr. Thomas explained in Cause No. 44967 and reiterated in this Cause, "I&M did not then believe that extending the term of the Lease was advisable."[75] Mr. Thomas further states that its current Integrated Resource Planning ("IRP") process assumes I&M will not extend the Rockport Unit 2 lease.[76] In its IRP (2018-2019), I&M stated, "[a] key assumption in several scenarios is that the Rockport Unit 2 lease expires in late 2022."[77]

[71] Direct Testimony of Timothy C. Kerns, at 12, Figure TCK-6.
[72] Kerns Direct at 15, lines 5 – 11.
[73] *Id*.
[74] Thomas Direct at 32, lines 5 – 8.
[75] *Id*.
[76] *Id*. at 32, lines 10 – 13.
[77] I&M, Integrated Resource Plan (2018-2019) dated July 1, 2019, Executive Summary, p. ES-2.

Consequently, it is unreasonable to ask ratepayers to pay for the costs of replacing and/or rebuilding the turbine when the Rockport Unit 2 lease ends in December 2022. From a ratepayer's perspective, I&M's proposition is a bad deal because, after the lease ends in 2022, I&M will continue collecting (and ratepayers will continue paying) the return on and of its investment far beyond 2022. As Mr. Thomas' belief that it was not advisable to extend the lease, it would likewise be irresponsible to hold captive ratepayers responsible for paying long-term on a short-lived asset— this is a bad investment for ratepayers. Armed with the knowledge that "the Rockport Unit 2 lease expires in late 2022" was a key assumption across various IRP scenarios, it would be unreasonable to further expose ratepayers to the risks of taking on I&M's Rockport Unit 2 investments.

Q: What is your recommendation regarding the Rockport Unit 2 HP turbine replacement?

A: I recommend a $1.323 million adjustment (including AFUDC) to remove the capital expenditures found in Mr. Kerns' Direct Testimony, Figure TCK-6, at p. 12, and all O&M expenditures associated with and related to the Rockport Unit 2 HP turbine replacement project, from the forecasted Test Year.

VII. RECOMMENDATIONS AND CONCLUSIONS

Q: What are your recommendations regarding AMI, Major Storm Reserve, Distribution Projects, and Rockport Unit 2?

A: Based on the results of my analysis, I recommend the Commission:

1. Require I&M complete the necessary financial and cost-benefit analysis prior to any approval for full deployment of AMI technology in I&M's Indiana service territory. This analysis should be provided to the Commission, the OUCC, and interested parties with adequate time to fully review. Remove the capital expenditure amount of $14,167,000, and O&M expenditure amount of $2,410,722, associated with I&M's AMI deployment from the forecasted Test Year.

2. Should the Commission remain interested in approving an AMI deployment, I recommend the approval of approximately 15,000 AMI meters within the context of a "collaborative pilot" program involving Commission technical staff, the OUCC and interested parties.

3. Require I&M use the five-year average methodology and decrease the forecasted Test Year Major Storm Reserve to $2,473,000 based on the five-year average major storm expenses for the period 2014 – 2018.

4. Require I&M to provide the corresponding project status and work order documentation of each distribution project in its Distribution Management Plan (2019-2020) for review prior to any Commission approval. Remove $39,991,413 in capital and $1,006,154 in O&M expenditures for 2019 projects, and $35,129,917 in capital and $1,009,608 in O&M expenditures for 2020 projects, in the forecasted Test Year.

5. Require I&M provide detailed project cost estimates, including the corresponding approved Capital IR of each Major Project (2019-2020), for review prior to any Commission approval. Remove $24,710,000 for 2019 projects and $7,860,000 for 2020 projects in capital expenditures in the forecasted Test Year.

6. Require removal of $1.323 million (including AFUDC) in capital expenditures found in Mr. Kerns' Direct Testimony, Figure TCK-6, at p. 12, and all O&M expenditures associated with and related to the Rockport Unit 2 HP turbine replacement project, from the forecasted Test Year.

Q: Does this conclude your testimony?

A: Yes.

APPENDIX A

I. EDUCATIONAL BACKGROUND AND EXPERIENCE

Q: Please describe your educational background and experience.

A: I hold an MBA from the University of the Philippines ("UP"), in Diliman, Quezon City, Philippines. I also hold a Bachelor's Degree in Electrical Engineering from the University of Santo Tomas ("UST"), in Manila, Philippines.

I joined the OUCC in July 2009, and have completed the regulatory studies program at Michigan State University sponsored by the National Association of Regulatory Utility Commissioners ("NARUC"). I have also participated in other utility and renewable energy resources-related seminars, forums, and conferences.

Prior to joining the OUCC, I worked for the Manila Electric Company ("MERALCO") in the Philippines as a Senior Project Engineer responsible for overall project and account management for large and medium industrial and commercial customers. I evaluated electrical plans, designed overhead and underground primary and secondary distribution lines and facilities, primary and secondary line revamps, extensions and upgrades with voltages up to 34.5 kV. I successfully completed the MERALCO Power Engineering Program, a two-year program designed for engineers in the power and electrical utility industry.

Q: What did you do to prepare your testimony?

A: I reviewed the petition, direct testimony and attached exhibits filed by I&M in this Cause. I wrote discovery questions and reviewed corresponding I&M responses. On July 15, 2019, I attended the I&M field hearing held in Muncie, IN associated with this Cause. On July 19, 2019, I attended and participated in a technical meeting in Fort Wayne, IN with I&M distribution and technical personnel to discuss topics and issues related to project management information and cost estimates of the case. I participated in meetings and discussions with OUCC staff and case team related to issues identified in this Cause.

INDIANA MICHIGAN POWER COMPANY
CITY OF SOUTH BEND
DATA REQUEST SET NO. SB DR 4
IURC CAUSE NO. 45235

DATA REQUEST NO SB 4-06

REQUEST

Provide all cost benefit analyses performed by or on behalf of or reviewed by I&M to evaluate the effectiveness of installing AMI meters.

RESPONSE

A generic discussion draft analysis was prepared by an I&M operations employee using a generic AEP template and inputs. Neither the inputs nor the analysis were completed. The template was not focused on the transition from AMR to AMI via a planned deployment versus a reactive deployment, which is the technology issue here. As a result the draft analysis was not used by I&M management. See "SB 4-06 AMI Draft.pdf."

gridSMART

I&M AMI Full Deployment Benefits / Cost Analysis

May 2016

DRAFT

Summary – Major Assumptions

- Business Case reflects company spend and customer cost/benefit perspective
- Full Service Territory (IN & MI figures shared as well)
- 3 Year Deployment of Meters
- Net MRO FTE reduction of 3 FTEs (12 reduced / 9 new positions)
- 5 Year Ramp Up of Consumer Programs including Prepaid Metering, Direct Load Control (DLC), TOU and TOU w/ CPP, and energy usage through web portal
- Remote disconnect functionality included and fully operational
- Prepay is deployed

Summary – Full Deployment

- Full AMI deployment – install additional 608,000 meters over 3 years
  - $82 million capital investment (3 years)
  - $6.0 million O&M (3 years) – Security and ITRON Cost (License, SaaS, Maint)
  - $3 - $4M post-deployment O&M increase can be offset by labor reductions ($0.75 - $1.0M) and credit/collection savings ($4 - $5M)
  - ~$56M in stranded meter assets (AMR depreciated over 25 years)
    - 41,333,420 (Indiana)
    - 14,786,436 (Michigan)
  - Other non-financial benefits include customer experience benefits from AMI-enabled consumer programs, data analytics, and CO2 reduction
- Consumer Program assumptions
  - $2 million capital investment for Prepay / Consumer program IT enhancements (first 3 years)
  - $16.5 million O&M (first 5 years) and $1.8M ongoing (potentially recoverable through EE riders) – Not sure where the O&M is coming from. Assumption is I&M will continue to use current portal. Capital projects for TOU and other tariff offerings but should not have additional O&M tail. O&M Removed from totals but kept benefits
  - Spend more than offset by energy/demand reductions in long-term
- Customer rate impact TBD (will engage Regulatory when appropriate)

I&M gridSMART / Benefit Analysis (15 year view)

15 Year Benefits:	$78,600,150.66
15 Year Costs:	($110,519,812.57)
Benefit / Cost Ratio:	0.71
15 Year NPV Benefits:	40,745,740
15 Year NPV Costs:	(90,021,811)
NPV Benefit / Cost Ratio:	0.45

Combined benefit / cost ratio of 0.71. Regulatory business case would be built around customer experience including enablement of programs / technologies and application of analytics

Other Options to Consider

- Broader gridSMART deployment including Volt Var Optimization (VVO) and DACR (Distribution Automation – Circuit Reconfiguration) to strengthen overall business case
  - VVO – Energy, peak load reduction savings
  - DACR – SAIDI / Customer Outages Avoided savings
- Phased AMI deployment (e.g., urban settings first like AEP-OH)
- Targeted AMI deployment (e.g., Micro AP for credit/collections benefits)

Appendix

- "Hard" Field loaded labor net reductions – $0.8M annually
  - Meter Reading - $0.6M annually
  - Limited savings by full deployment of
- "Medium" Credit / Collections / Revenue Enhancements - $4-5M annually
  - *Assumes remote disconnect*
  - Reduced delinquency / bad debt
  - Reduction in theft
  - Lower consumption on inactive meters
  - Benchmarked to ensure in reasonable range of peer business cases

- Other “soft” O&M / Capital benefits – $500K annually
  - o Billing/call center inflow reduction – $100K annually
  - o Obsolete meter avoidance - $1.8M over 3-year installation
  - o Capacity planning efficiency - $200K annually
- Peak load reduction savings (Programs) - $5-7M annually
- Energy reduction savings (Prepay) - $3-4M annually – Removed
- Reduction bad debt (Prepay) - $81K annually

- Enables implementation of consumer programs (e.g., Direct Load Control, TOU) and new technologies (e.g., Powerley)
  - o Significant energy / peak load reduction serves to offset the customer costs of AMI investment
- Enables prepaid metering that has proven customer satisfaction benefits (e.g., Salt River Project, Oklahoma Electric Cooperative and Arizona Public Service)
- Creates opportunity for increased customer flexibility / satisfaction through billing accuracy / better usage data (MDM, web portal)

- Provides platform for proactive data analysis
  - o Quicker identification of reliability / power quality issues
  - o Decrease outage restoration times (CAIDI)
  - o "Pinging" meters to confirm outages can reduce truck rolls and decrease CAIDI
  - o Automation of outage orders (work in progress) could further reduce CAIDI
  - o Load data ensures more precise capacity planning
  - o Timely and accurate identification of theft / consumption on inactive meters
  - o Improved mapping of transformer ties – improved outage prediction and quality of mobile alerts
  - o Supports fuller view of 360 view of the customer
- Reduction of CO_2 from energy reduction (Prepay) and truck roll avoidance (will be quantified if we move forward)

- Model includes components for AMI and Consumer Programs
  - Cost / benefit analyses were done on stand-alone basis
  - Program management expenses were included in AMI analysis
- 15-year project life
- AMI capital depreciated over 15 years; IT capital depreciated over 30 years
- Weighted Average Cost of Capital – 7.02%
- Customer growth rate – 0.5%
- PJM Energy and estimated Capacity pricing from CP&B
- AMI Deployment
  - 613,607 total meters – 585,929 single phase, 26,678 poly-phase, 1000 MicroAP
  - Financial benefits driven largely by credit / collections benefit requiring approval of remote disconnect; labor savings relatively small given AMR technology deployment
  - Average Meter Cost – $91 per meter – single phase, $188 per meter – poly-phase
  - Blended installation cost of network and meter at $20 device
  - Replacement Rate for Meter-Related Capital – 1% Years 1 – 20

❑Consumer Programs

- Costs based largely on PSO experience (e.g., Prepay)
- Prepaid Metering assumes 8% penetration rate, 10% energy reduction
- Other programs ramp up to max participation over 5 years (Years 2 through 6)
- No assumed participation in Year 1
- Participation/penetration rates:
  - Direct Load Control – 7%
  - TOU – 5%
  - TOU w/ CPP – 0.6%
  - Web Portal – 5%
- Peak load reduction %s:
  - Direct Load Control – 35%
  - TOU – 10%
  - TOU w/ CPP – 10%
  - Web Portal – 1%

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 15
IURC CAUSE NO. 45235

DATA REQUEST NO OUCC 15-08

REQUEST

Please provide the AMI Business Case(s) including the financial analysis and all internal documents used and presented to its management in support of I&M' s AMI deployment in Indiana.

a) Please provide a summary the different Business Cases (i.e. A, B, C, or #1, #2, #3, as the case maybe) presented to management.

b) Please provide the support document showing its approval of and the authorized capital spent for the AMI deployment in Indiana.

RESPONSE

Please see Company's response to OUCC 15-07.

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 15
IURC CAUSE NO. 45235

DATA REQUEST NO OUCC 15-07

REQUEST

Please provide the AMI Business Case(s) including the financial analysis and all internal documents used and presented to management in support of I&M' s AMI deployment in Michigan.

a) If there are differences between the Business Cases (i.e. A, B, C, or #1, #2, #3, as the case maybe) presented to management, please describe those differences.

b) Please provide the support document showing its management's approval of and capital authorization for the AMI deployment in Michigan.

c) Please describe the Business Case(s) evaluation process for Michigan.
d) Does the same Business Case(s) evaluation process apply to Indiana? If no, please explain why.

RESPONSE

Please see Company witness Thomas' testimony beginning on page 24, line 6 through page 28, line 15 and Attachment TLT-4 for the business case supporting I&M's AMI deployment. Company witnesses Lucas and Isaacson also provide further support for the benefits of AMI in the management of the distribution system and in enhancing the customer experience.

a. Not applicable.

b. To date, I&M has obtained formal management approval to replace 17,000 AMR meters with AMI meters in the St. Joseph and Benton Harbor, MI area. This approval was initially documented in the Project Charter (see "OUCC 15-07 17K MRO Meter Replacement Charter_Signed.pdf") and then formally in the AEP Improvement Requisition (IR) process (see "OUCC 15-07 MIPLC2019 - Appd IR.pdf"). Formal approvals for the remaining AMI meters to be installed will be made closer to the implementation date.

c. I&M conducted an evaluation of the AMI implementation in accordance with the normal the capital planning processes. The benefits of the testimony as described in Company witness Thomas testimony referenced above, combined with the need to replace existing AMR meters, provided the business case to prioritize this program. During the capital planning process, this program was evaluated within the context of the overall capital portfolio to establish the project timeline for implementation.

d. The same business case and justification applies to both Michigan and Indiana.

Project Charter
MRO Meter Replacement Project

Work Scope Statement	Indiana Michigan Power (I&M) has a 2019 budget to support the change out of approximately 17,000 Automatic Meter Reading (AMR) meters with Advanced Metering Infrastructure (AMI) meters within the St. Joseph and Benton Harbor, MI area. I&M intends to deploy AMI meters to provide more accurate and timely circuit data. AMI meters will provide a gateway into the customer's premises to provide additional services to I&M customers.
Project Description:	Replace approximately 17,000 AMR meters with AMI meters and associated support. The meters will be replaced by an external contractor and the internal MRO staff will need to complete access points and relays, which will be included in the 2019 Work Plan.

AMI Meter Project Costs (Direct Dollars)

Replacement Meter	Capital	O&M	Removal	Contingency
AMI Meter	2,145,484	$ 47,073	$ 198,750	$ 333,286

District	Number of Meters
Michigan	Approximately 8,000 in Benton Harbor Approximately 9,000 in St Joseph

Project Benefits

- AMI can be integrated with service restoration systems to more accurately detect power outage locations dispatching crews more efficiently to reduce customer outage duration.
- Enhances public safety by providing mechanisms to proactively de-energize the grid from a control center (DDC). Having more visibility into the system provides additional information that helps minimize risk and safety hazards by enabling early detection of issues on the system. Additionally, having remote operability capability, as well as automation, allows I&M personnel to correct issues without being in the vicinity of electrified equipment. Also, with AMI there is no longer a need to send meter specialists to a customer's yard on a monthly basis, thereby avoiding potential dangerous conditions, such as vicious dogs, or inaccessible locations.
- In addition to improved safety and reliability, AMI will provide a unique and fundamental tool to improve the customer's experience in other ways by providing the following benefits:
  - Customers will have the ability to view daily or hourly usage data via a web page or app, including the ability to receive alerts based upon energy usage.
  - If a customer experiences trouble, the Company will be able to remotely "ping" the meter to aid in determining if the meter is operating properly.
  - Customers will experience shorter wait times for electric service turn-on and turn-off because the company will be able to do so remotely

	instead of needing to send an employee to the customer's meter. o The Company can be notified when a customer's power goes out without the customer needing to contact the Company. If the customer is not at home, I&M can be notified of an outage and make repairs before the customer even returns home. o Customers will be able to participate in new advanced programs as they are developed which may provide further, more innovative opportunities for customer convenience, reduced energy consumption, and reduced bills.
Success Criteria	• Meet Goals and Objectives established in this Charter. • Achieve the project Key Milestones. • Maintain Indiana Michigan Power Sponsor and Stakeholder satisfaction as indicated by ongoing feedback. • Complete the work within the approved budget, safely and in harmony with the environment (Zero Harm), on schedule, and consistent with regulatory requirements. • All identified meters are replaced and operational by December 31, 2019.

Milestone Schedule	**MRO AMR Cellular Metering Project Milestones** Charter Approval — January 2019 Order AMI meters — January 2019 Receive AMI meters — Q3 2019 Start Construction — End of Q3 2019 Complete Construction — December 31, 2019
Implementation Strategy:	Request material purchase by January of 2019 with delivery in Q3 of 2019. The meter replacement will be completed by contract staff and MRO staff and included in the 2019 Work Plan.
Evaluation, Measurement & Verification:	The project will be tracked with the MRO Work Plan and budget. A monthly status will be provided.
Project Operating Budget	**AMI Meters** **Capital** — **$ 2,145,484** **O&M** — **$ 47,073** **Removal** — **$ 198,750** **Contingency** — **$ 333,286** **Total cost** — **$ 2,724,593** * Contingency approved by project manager

Project Charter
MRO Meter Replacement Project

Project Constraints	**AMI Constraints (Risks):** • The AMI meters have an eight (8) month lead time and any delay in receiving the meters could impact the ability of the contractor and MRO staff to replace the meters by December 31, 2019. • If a residential customer opts out of AMI, an AMR meter will need to be installed. • Timeframe to design the mesh network (IT or outside vendor) • Two month bid process for installation contractor • Contractor availability or interest, since other companies have larger AMI projects in process or planning • Inspectors availability to validate the installation contractor's work • Weather

Key Stakeholders

Tom Kratt	Vice President – Distribution Region Operations	Project Sponsor
Dave Lucas	Vice President – Finance	Project Sponsor
Dave Isaacson	Director – Distribution Risk & Project Management	Key Stakeholder
Nick Elkins	Director – Customer Services & Business Development	Key Stakeholder
Jarrod Wilson	Meter Revenue Operations Manager	Key Stakeholder
Jason Baker	Distribution Projects Manager	Key Stakeholder
Ken Dimpfl II	Meter Engineering Manager	Stakeholder
Mike Deaton	Distribution Project Manager Principal	Project Manager

Charter Approvals

Project Role	Individual	Signature	Date
Project Sponsor	Tom Kratt	DocuSigned by: Thomas A Kratt FE2BAABFB40C4CE...	1/20/2019
Project Sponsor	Dave Lucas	DocuSigned by: Dave Lucas 343FA41398D3444...	1/19/2019
Key Stakeholder	Dave Isaacson	DocuSigned by: David Isaacson A7A4BD1024E34A1...	1/18/2019
Key Stakeholder	Nick Elkins	DocuSigned by: Nick Elkins 39E926E3020A4B1...	1/18/2019
Key Stakeholder	Jarrod Wilson	DocuSigned by: [signature] BD6485428A3B49D...	1/17/2019
Key Stakeholder	Jason Baker	DocuSigned by: [signature] 38E709DB593A445...	1/17/2019

RISK Register - Michigan AMI 17k Meter Replacement 1/8/2019 Rev 01

					SCHEDULE IMPACT		BUDGET IMPACT		
RISK #	REVIEWED DATE	DESCRIPTION	IMPACT	PROBABILITY	DAYS	CONTIGENCY DAYS (Prob. X Days)	COST	CONTIGENCY COST (Prob. X Cost)	NOTES
1	1/3/2019	Weather delays	HIGH	80%	10	8	$ 11,970	$ 9,576	Cost of internal labor overtime (21 meters/day * 10 days * $57/meter)
2	1/3/2019	Delay in receiving meter and network equipment (8 month lead time)	MED	40%			$ 115,050	$ 46,020	21 days * 4 people * 80 meters/day * $16/meter and MRO employee overtime
3	1/3/2019	Availability and intrest of contrator to replace meters	LOW	25%			$ 840,000	$ 210,000	Internal crew working overtime to replace meters (16,000 * ($35 * 1.5))
4	1/3/2019	Michigan AMI opt out	LOW	1%			$ 969,000	$ 9,690	17,000 meters * $57/meter
5							$ -	$ -	

Management Reserve - Michigan AMI 17k Meter Replacement 1/8/2019 Rev 01

	REVIEWED DATE	DESCRIPTION						COST	NOTES
	1/3/2019	Management Reserve						$ 58,000	Unknown unknowns (2% of estimated construction cost)
				+/- SCHEDULE IMPACT		8		$ 333,286	CONTIGENCY BUDGET

Assumptions

- Unit price contract for installation of approximately 17,000 AMI meters and removal of AMR meters by an external contractor
- 21 working days per month
- 900 polyphase/transformer rated meters replaced by internal crew (900 meters/42 days = 21 meters/day)
- 100 hours to install Network equipment with internal crew
- Due to the number of large AMI projects in other areas, it may be difficult to obtain a contractor for a small project

Capital Improvement Approval Requisition

One Page Summary

Company:	Indiana Michigan Power Company **Version: 1**
Project:	MIPLC2019 - MI AMR Meter Replacement -
Location:	St. Joseph & Benton Harbor Areas
Description:	Replace 17,000 Automated Meter Reading (AMR) meters in the St. Joseph and Benton Harbor, MI area with Advanced Metering Infrastructure (AMI) meters. I&M intends to deploy AMI meters to provide more accurate and timely circuit data. AMI meters will provide a gateway into the customer's premises to provide additional services to I&M customers.

Authorization Amount:

Company	Function	Previously Approved Amount	This Submission	Total Approved Project Cost
IMPCO	Distribution	$0	$3,091,854	$3,091,854
	Total	**$0**	**$3,091,854**	**$3,091,854**

Cash Flow:

	Prior Years	2019	2020	Future Years	Total
Capital	$0	$2,893,103	$0	$0	$2,893,103
Removal	$0	$198,751	$0	$0	$198,751
Total To Be Authorized	**$0**	**$3,091,854**	**$0**	**$0**	**$3,091,854**
Less CIAC/Other Credits	$0	$0	$0	$0	$0
Total Project Cost	$0	$3,091,854	$0	$0	$3,091,854
Total Expense	$0	$14,097	$0	$0	$14,097

Project Dates:	**Start Date :** 01/15/2019 **In Service Date :** 12/31/2019 **Completion Date:** 12/31/2019	
Regulatory Recovery:	I&M Distribution – $3.1M (100%) I&M MI base rate case filing, Projected TYE 12/31/18, effective 5/31/20.	
Funding:	**IRC Approved :** Yes	**In Budget :** Yes
Approved By : Toby L Thomas		**Approved On :** 01/25/2019

Capital Improvement Approval Requisition

Funding and Approval

Direct Cost Funding:

	Prior Years	2019	2020	Future Years	Total
In Forecast $	$0	$0	$0	$0	$0
Offsets Required	$0	$2,677,521	$0	$0	$2,677,521
Total Direct Cost	**$0**	**$2,677,521**	**$0**	**$0**	**$2,677,521**

Required Signatures:

Status	Name	Date
Approved	Emi C Sauer	01/16/2019
Approved	Jason E Baker	01/16/2019
Approved	David S Isaacson	01/17/2019
Approved	Robert D Gladman	01/17/2019
Approved	Thomas A Kratt	01/21/2019
Approved	David A Lucas	01/22/2019
Approved	Toby L Thomas	01/22/2019
Approved	James P Justus-Lee	01/23/2019
Approved	Alesia A Austin	01/25/2019

Project Contacts:

Type	Name
Detail Provider	NIELSEN,CHRIS A
Project Manager	DEATON,MICHAEL D

Capital Improvement Approval Requisition

Additional Information

IR Justification:	Indiana Michigan Power (I&M) has a 2019 budget to support the change out of approximately 17,000 Automatic Meter Reading (AMR) meters with Advanced Metering Infrastructure (AMI) meters within the St. Joseph and Benton Harbor, MI area. I&M intends to deploy AMI meters to provide more accurate and timely circuit data. AMI meters will provide a gateway into the customer's premises to provide additional services to I&M customers.
Alternatives Considered:	1. Maintain the system as is until failure. Replace failed meters with Automatic Meter Reading (AMR). 2. Replace AMR sytem with AMI system.
Conclusion:	Alternative 2 was chosen. Replacing the AMR system with AMI will allow us to continue to maintain our 99% reading attainment, keep meter reading expenses low, utilize the added benefits of AMI metering, and position us for a future AMI deployment in the state of Michigan. Due to demographics and Energy Efficiency Opportunities, we chose to complete the project in Benton Harbor and St. Joseph, MI.
Application of Transco Project Selection Guidelines:	

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 8
IURC CAUSE NO. 45235

DATA REQUEST NO OUCC 8-12

REQUEST

In Attachment DSI-1, page 1 of 26, Mr. Isaacson identified the following projects with their respective "Map Reference Number":

Single Phase Line Rebuild 2019				
Map Reference Number	Station	Circuit	Description	Miles
20	Grabill	Antwerp	Reconductor 4 ACSR to 2 AA	1.90
21	Grabill	Antwerp	Reconductor 4 ACSR to 2 AA	1.42
22	Grabill	Antwerp	Reconductor 4 ACSR to 2 AA	1.00

a) Please provide support distinguishing each project from the others. If none, please explain why.
b) Please provide support showing the respective locations of the projects with corresponding "Map Reference Number(s) 20, 21 and 22." If none, please explain why.
c) Please provide support defining the respective scope of work of each project with corresponding Map Reference Number(s) 20, 21 and 22. If none, please explain why.
d) Please provide the work order level cost estimate for each project with corresponding Map Reference Number(s) 20, 21 and 22. If none, please explain why.
e) What is the total project cost of each project with corresponding Map Reference Number(s) 20, 21, and 22?
f) Please provide the detailed cost breakdown including material, labor and indirect costs of each project with corresponding Map Reference Number(s) 20, 21, and 22.
g) Please identify the cost components of the indirect costs I&M attributes to each project with corresponding Map Reference Number(s) 20, 21, and 22. Please describe and explain each indirect cost component.

RESPONSE

a. The first project, Map Reference 20, is to rebuild 1.92 miles of 4AS single phase line to 2AA from pole AL280-149 to pole AL279-101. (Work Request 69793483). The second project, Map Reference 21, is to rebuild 1.42 miles of 4AS single phase and two phase line to 2AA from pole AL224-143 to pole AL250-51. (Work Request 66935372). The third project, Map Reference 22, is to rebuild 0.85 miles of 4AS single phase line to 2AA from pole AL250-51 to pole AL249-87. (Work Request 69793447)

b. Please see (a) above.

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 8
IURC CAUSE NO. 45235

c. Please see (a) above.

d. I&M objects to the extent this question seeks information that is confidential, proprietary, competitively sensitive and/or trade secret. Without waiving this objection, I&M will provide the confidential information pursuant to the July 6, 2006 Standard Form Nondisclosure Agreement between I&M and the OUCC. Please see the following documents:

- OUCC 8-12 CONFIDENTIAL Attachment 1 69793483.pdf
- OUCC 8-12 CONFIDENTIAL Attachment 2 66935372.pdf
- OUCC 8-12 CONFIDENTIAL Attachment 3 69793447.pdf

e. For the total project cost of each project with corresponding Map Reference Number(s) 20, 21, and 22, please refer to I&M's response to OUCC 8-12(d) above.

f. For a detailed cost breakdown including material, labor and indirect costs of each project with corresponding Map Reference Number(s) 20, 21, and 22, please refer to I&M's response to OUCC 8-12(d).

g. For each project with corresponding Map Reference Number(s) 20, 21, and 22, the indirect costs applicable to these projects are "Admin Overhead" and "Labor Overhead" which are part of Company Construction Overheads. The table below shows the indirect cost for each of these projects.

	Work Request Number	Admin Overhead	Labor Overhead
Map Reference 20	69793483	$11,802.96	$25,626.77
Map Reference 21	66935372	$23,141.70	$39,071.84
Map Reference 22	69793447	$10,813.08	$27,072.13

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 8
IURC CAUSE NO. 45235

DATA REQUEST NO OUCC 8-13

REQUEST

Please provide the work order level cost estimate for the 0.60 mi. single phase line rebuild 2019 project with Map Reference Number 11 - Station: Selma Parker; Circuit: Parker; Description: RA45CI-67 to RA45CI-48 Replace 6CU and 4 CU with 2 AA; in Attachment DSI-1, page 1 of 26.

a) What do the terms “RA45CI-67” and “RA45CI-48” refer to in this project? Please explain.
b) Please provide the detailed cost breakdown including material, labor and indirect costs of this project. If none, please explain why.

RESPONSE

a. The terms RA45CI-67 and RA45CI-48 are both pole identification numbers which are tied to a geographic location within I&M’s Geographic Information Systems.

b. I&M objects to the extent this question seeks information that is confidential, proprietary, competitively sensitive and/or trade secret. Without waiving this objection, I&M will provide the confidential information pursuant to the July 6, 2006 Standard Form Nondisclosure Agreement between I&M and the OUCC. Please see " OUCC 8-13 CONFIDENTIAL Attachment 1 70570251.pdf."

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 8
IURC CAUSE NO. 45235

DATA REQUEST NO OUCC 8-14

REQUEST

Please provide the work order level cost estimate for the 1.10 mi. three phase line rebuild 2019 project with Map Reference Number 28 – Station: Darden; Circuit: Auten; Description: Reconductor 4AS to 2 AA (Maybe 556 AAL), beyond JO137-344; in Attachment DSI-1, page 3 of 26.

a) How many more spans are there to reconductor “beyond JO137-344”?

b) Please provide the detailed cost breakdown including material, labor and indirect costs of this project. If none, please explain why.

RESPONSE

a. There are 31 spans to reconductor beyond JO137-344.

b. I&M objects to the extent this question seeks information that is confidential, proprietary, competitively sensitive and/or trade secret. Without waiving this objection, I&M will provide the confidential information pursuant to the July 6, 2006 Standard Form Nondisclosure Agreement between I&M and the OUCC. Please see “OUCC 8-14 CONFIDENTIAL Attachment 1 70022722.pdf.”

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 34
IURC CAUSE NO. 45235

DATA REQUEST NO OUCC DR 34-3

REQUEST

Please provide electronic copies of I&M's presentation materials from OUCC's site visit to I&M on July 19, 2019.

RESPONSE

I&M objects on the grounds and to the extent this question seeks information that is confidential, proprietary, competitively sensitive and/or trade secret. Without waiving this objection, I&M will provide the confidential information pursuant to the July 6, 2006 Standard Form Nondisclosure Agreement between I&M and the OUCC. In addition, I&M states:

Please see "OUCC 34-3, Confidential Attachment 1.pdf" through "OUCC 34-3, Confidential Attachment 11" for the requested information.

AFFIRMATION

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

Anthony A. Alvarez
Utility Analyst II
Indiana Office of Utility Consumer Counselor

Cause No. 45235
Indiana Michigan Power Company

8/19/2019

Date

CERTIFICATE OF SERVICE

Indiana Office of Utility Consumer Counselor Public's Exhibit No. 8 Testimony of OUCC Witness Anthony A. Alvarez has been served upon the following parties of record in the captioned proceeding by electronic service on August 20, 2019.

Tiffany T. Murray
Deputy Consumer Counselor

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
115 West Washington Street
Suite 1500 South
Indianapolis, IN 46204
infomgt@oucc.in.gov
317/232-2494 – Phone
317/232-5923 – Facsimile

45235 IN-MI Service List

I&M
Teresa Morton Nyhart
Jeffrey M. Peabody
BARNES & THORNBURG LLP
tnyhart@btlaw.com
jpeabody@btlaw.com

Matthew S. McKenzie
AMERICAN ELECTRIC POWER SERVICE CORP.
msmckenzie@aep.com

CAC and INCAA
Jennifer A. Washburn
Margo Tucker
CITIZENS ACTION COALITION
jwashburn@citact.org
mtucker@citact.org

City of Marion
J. Christopher Janak
Kristina Kern Wheeler
BOSE MCKINNEY & EVANS LLP
cjanak@boselaw.com
kwheeler@boselaw.com

SDI
Robert K. Johnson
RK JOHNSON, ATTORNEY-AT-LAW, INC.
rjohnson@utilitylaw.us

WVPA
Randolph G. Holt
Jeremy L. Fetty
Liane K. Steffes
PARR RICHEY
r_holt@wvpa.com
jfetty@parrlaw.com
lsteffes@parrlaw.com

City of South Bend, Indiana
Robert Glennon & Assoc., P.C.
robertglennonlaw@gmail.com

39 North Conservancy District
Shaw Friedman
FRIEDMAN & ASSOCIATES
sfriedman.associates@frontier.com

Keith Beall
BEALL & BEALL
kbeall@indy.rr.com

Kroger
Kurt J. Boehm
Jody Kyler Cohn
BOEHM, KURTZ & LOWRY
kboehm@bkllawfirm.com
jkylercohn@bkllawfirm.com

Kevin Higgins
ENERGY STRATEGIES, LLC
khiggins@energystrat.com

John P. Cook
JOHN P. COOK & ASSOCIATES
john.cookassociates@earthlink.net

Industrial Group
Bette J. Dodd
Joseph P. Rompala
Anne E. Becker
Amanda Tyler
Ellen Tenant
LEWIS & KAPPES P.C.
bdodd@lewis-kappes.com
jrompala@lewis-kappes.com
abecker@lewis-kappes.com
atyler@lewis-kappes.com
etennant@lewis-kappes.com

City of Fort Wayne, Indiana
Brian C. Bosma
Kevin D. Koons
Ted W. Nolting
KROGER GARDIS & REGAS, LLP
bcb@kgrlaw.com
kdk@kgrlaw.com
twn@kgrlaw.com

Walmart, Inc.
Eric E. Kinder
Barry A. Naum
SPILMAN, THOMAS & BATTLE, PLLC
ekinder@spilmanlaw.com
bnaum@spilmanlw.com

ICC
Jeffrey Earl
BOSE MCKINNEY & EVANS LLP
jearl@boselaw.com

City of Auburn
W. Erik Weber
MEFFORD WEBER AND BLYTHE ATTORNEY AT LAW
erik@lawmwb.com

Mark W. Cooper
Attorney at Law
attymcooper@indy.rr.com

OUCC Consultants
GARRETT GROUP CONSULTING, INC.
Heather A. Garrett
garrett@wgokc.com

Edwin Farrar
edfarrarcpa@yahoo.com

Garry Garrett
ggarrett@garrettgroupllc.com

Mark E. Garrett
mgarrett@garrettgroupllc.com

RESOLVE UTILITY CONSULTING PLLC
David J. Garrett
dgarrett@resolveuc.com

TECHNICAL ASSOCIATES, INC.
Glenn A. Watkins
Jennifer R. Dolen
watkinsg@tai-econ.com
jenny.dolen@tai-econ.com